Book 1
Transmission
Planning Studies

2016

Chapter 2

MTEP16 Overview

2016

2.1 Investment Summary

The 383 MTEP16 new Appendix A projects represent $2.69 billion[1] in transmission infrastructure investment and fall into the following categories:

- **106 Baseline Reliability Projects (BRP) totaling $691.2 million —** BRPs are required to meet North American Electric Reliability Corp. (NERC) reliability standards.
- **32 Generator Interconnection Projects (GIP) totaling $142.7 million** — GIPs are required to reliably connect new generation to the transmission grid.
- **1 Market Efficiency Project (MEP) totaling $108 million** — MEPs meet Attachment FF requirements for reduction in market congestion.
- **1 Transmission Delivery Service Project (TDSP) totaling $350,000** — TDSPs are Network Upgrades driven by Transmission Service Requests (TSR).
- **243 Other Projects totaling $1.75 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 24 percent of the total cost and are distributed across the MISO region (Figure 2.1-1).

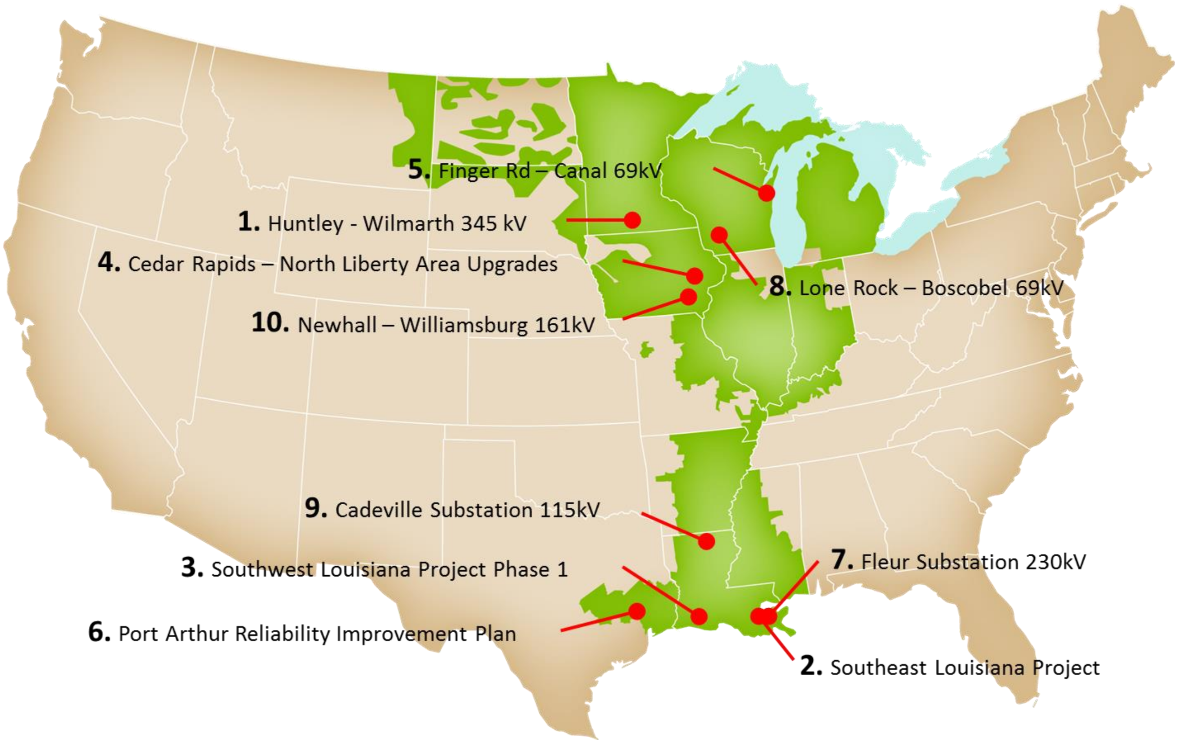


Figure 2.1-1: Top 10 MTEP16 new Appendix A projects (in descending order of cost)

[1] The MTEP16 report and project totals reflect all project approvals during the MTEP16 cycle, including those approved on expedited project review basis prior to December 2016.

The new projects recommended for approval in MTEP16 Appendix A are broken down by region and project type (Table 2.1-1). New projects in MTEP16 Appendix A contain 10 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 (MEP)	Transmission Delivery Service Project (TDSP)	Other	Total
Central	$8,208,000	$0	$0	$0	$151,331,000	$159,539,000
East	$59,690,000	$81,033,000	$0	$0	$423,297,000	$564,020,000
West	$147,026,000	$42,776,000	$108,000,000	$350,000	$728,654,000	$1,026,806,000
South	$476,297,000	$18,962,000	$0	$0	$443,881,000	$939,140,000
Grand Total	**$691,221,000**	**$142,771,000**	**$108,000,000**	**$350,000**	**$1,747,163,000**	**$2,689,505,000**

Table 2.1-1: MTEP16 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 that are not dictated by NERC standards. The remaining projects mostly address distribution concerns, with a small percentage of projects targeting localized economic benefits or line relocations to accommodate other infrastructure.

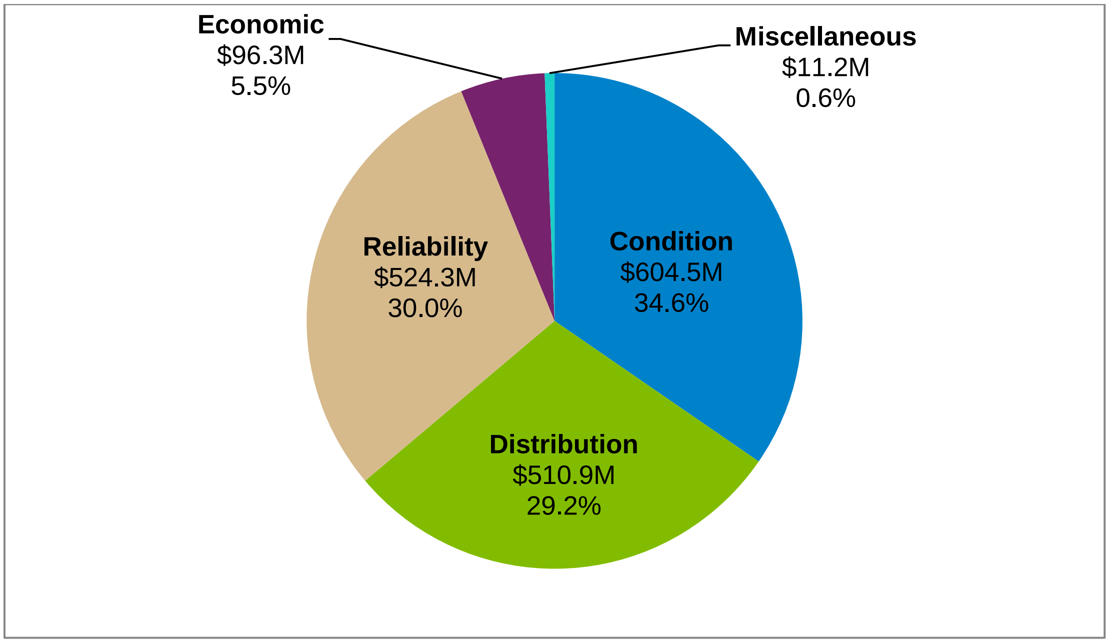


Figure 2.1-2: Subtype breakdown of new MTEP16 Appendix A Other projects

Facility Type

Each MTEP project is composed of one or more facilities, where each facility represents an individual element of the project. Examples of facilities include substations, transformers, circuit breakers or various types of transmission lines (Figure 2.1-3). The majority of facility investment in this cycle, 52 percent, is dedicated to substation or switching station related construction and maintenance. This includes completely new substations as well as terminal equipment work, circuit breaker additions and replacements, or new transformers. 28 percent of MTEP costs go toward line upgrades including rebuilds, conversions and relocations. Only about 20 percent of facility cost is dedicated to new lines on new right-of-way across the MISO footprint.

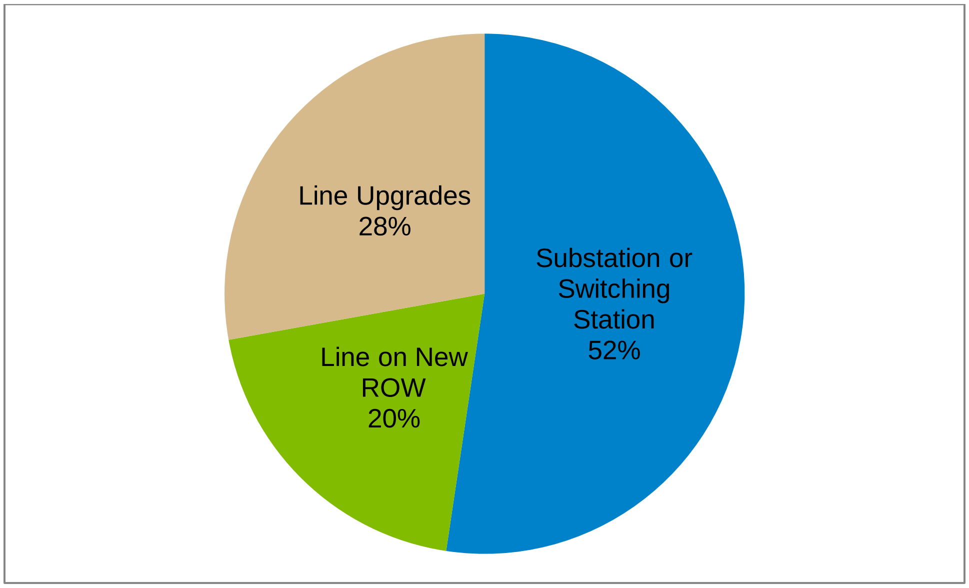


Figure 2.1-3: Facility type for new MTEP16 Appendix A projects

New Appendix A projects are spread over 13 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.

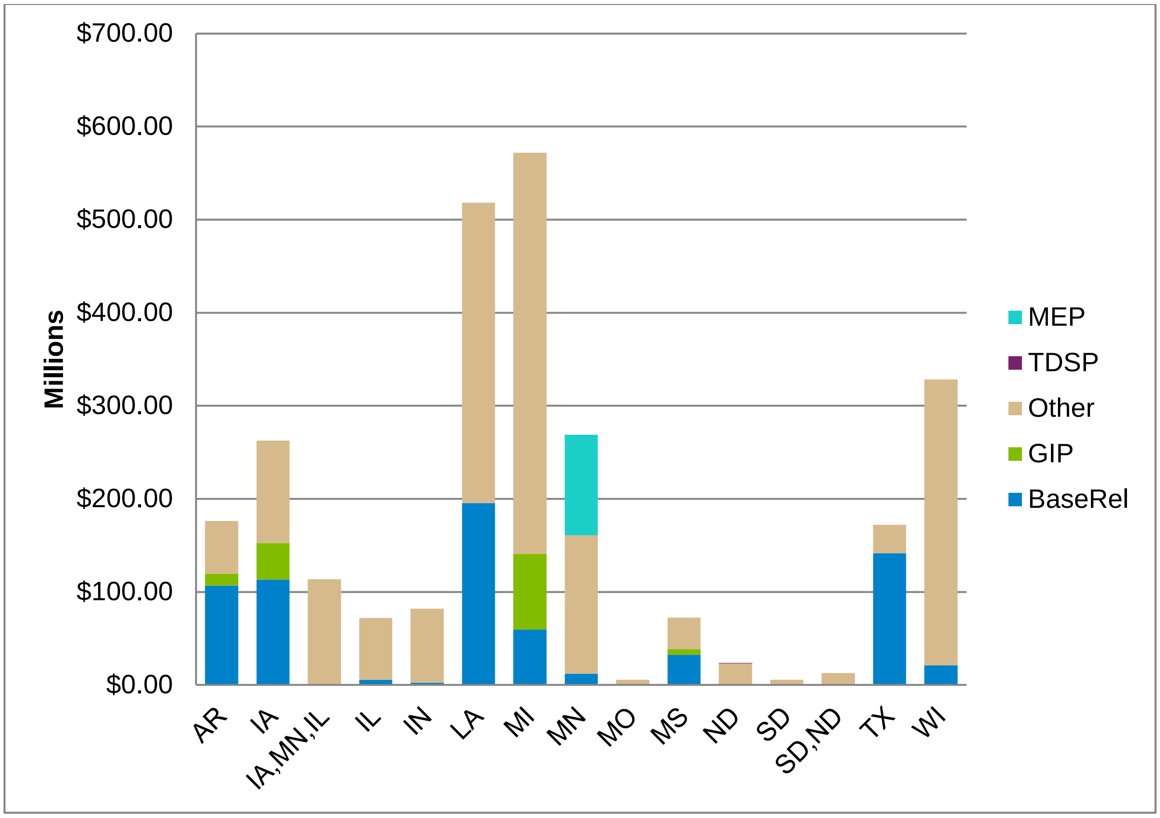


Figure 2.1-4: New MTEP16 Appendix A investment categorized by state

Active Appendix A Investment

The active project spending for Appendix A, with the addition of MTEP16 new projects, increases to 964 projects amounting to approximately $13.3 billion of investment (Figure 2.1-5). MTEP16 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. It does not reflect projected cash flow or the fact that certain components of a project may be placed in service as a project progresses.

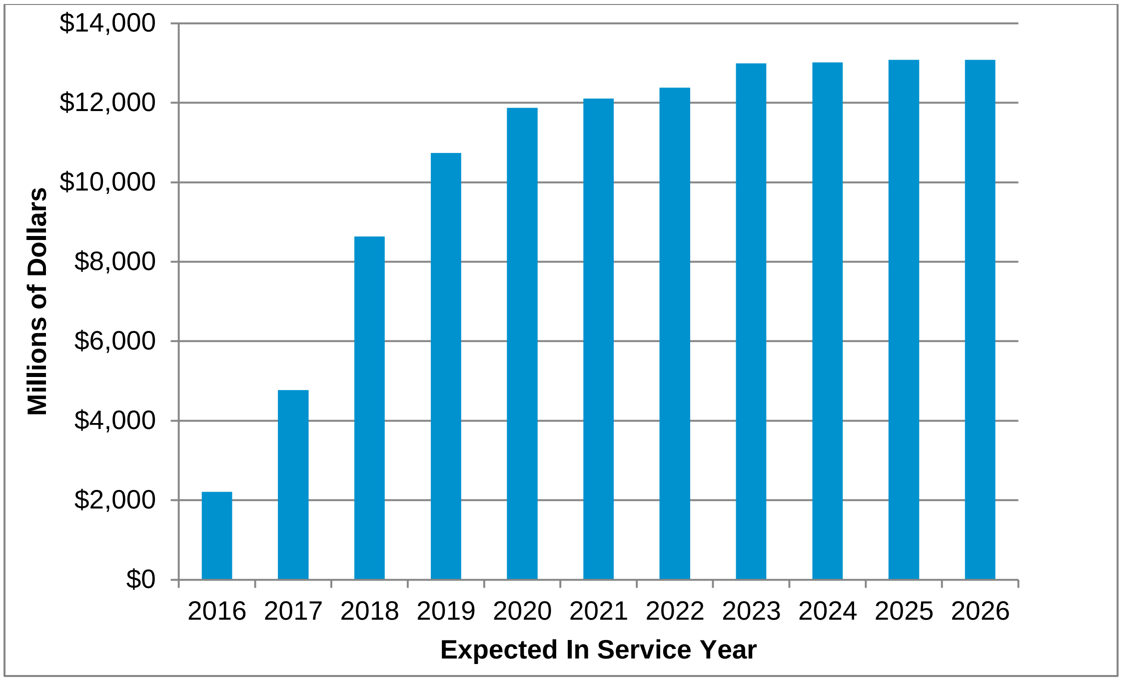


Figure 2.1-5: MTEP16 Appendix A projected cumulative investment by year

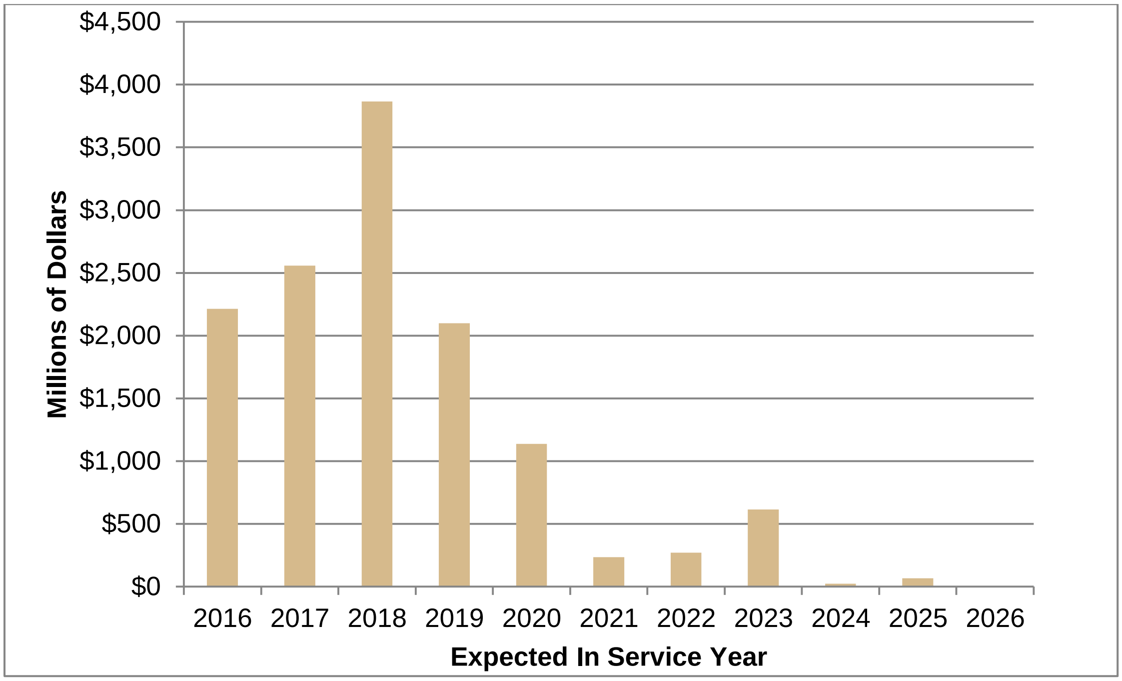


Figure 2.1-6: MTEP16 Appendix A projected incremental investment by year (includes projects from previous MTEP cycles not yet in service)

MISO Transmission Owners[2] have committed to significant investments in the transmission system (Table 2.1-2). Cumulative MTEP transmission investment for Appendix A is approximately $13.3 billion with another $3.0 billion in Appendix B. New MTEP16 Appendix A projects represents $2.69 billion of this investment. Projects associate primarily with a single planning region, though some projects may involve multiple planning regions. About $5.1 billion of the $13.3 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	$2,783,670,000	69	$132,807,000
East	219	$1,848,890,000	46	$579,008,000
West	387	$6,616,663,000	90	$1,754,715,000
South	188	$2,027,862,000	46	$505,244,000
Total	**964**	**$13,277,085,000**	**251**	**$2,971,774,000**

Table 2.1-2: Projected transmission investment by planning region

Figure 2.1-7: MISO footprint and planning regions

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

Active Appendix A Line Miles Summary

MISO has approximately 67,600 miles of existing transmission lines. There are approximately 7,100 miles of planned new or upgraded transmission lines projected in the 10-year planning horizon in MTEP16 Appendix A (Figure 2.1-8, Table 2.1-3).

- 4,300 miles of upgraded transmission line on existing corridors are planned
- 2,800 miles of new transmission line on new corridors are planned

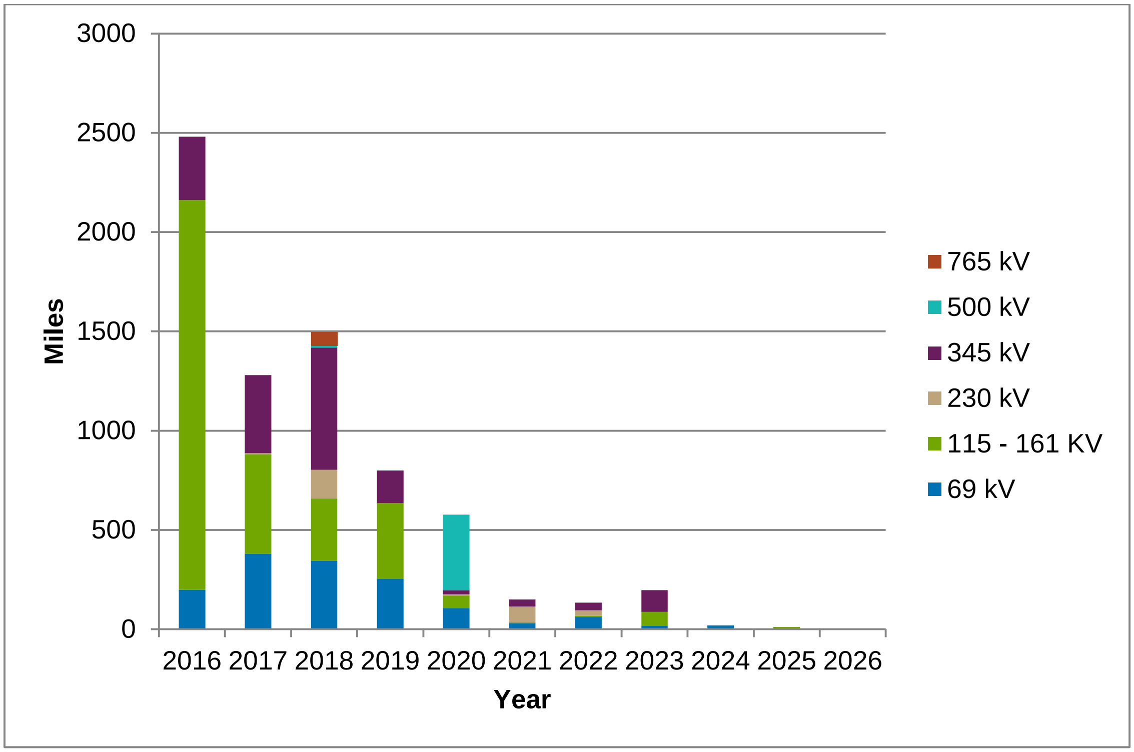


Figure 2.1-8: Planned new or upgraded line miles by voltage class (kV) in Appendix A through 2026

Year	69 kV	115-161 kV	230 kV	345 kV	500 kV	765 kV	Grand Total
2016	199	1963	0	320	0	0	**2,481**
2017	381	500	6	393	0	0	**1,280**
2018	344	316	143	616	7	69	**1,495**
2019	255	381	0	165	0	0	**800**
2020	107	62	8	20	380	0	**577**
2021	32	2	81	35	0	0	**150**
2022	62	6	27	39	0	0	**134**
2023	17	71	0	109	0	0	**197**
2024	20	0	0	0	0	0	**20**
2025	3	8	0	0	0	0	**11**
2026	0	0	0	0	0	0	**0**
Grand Total	**1,419**	**3,309**	**264**	**1,696**	**387**	**69**	**7,145**

Table 2.1-3: Planned new or upgraded line miles by voltage class (kV) in Appendix A through 2026

2.2 Cost Sharing Summary

New MTEP16 Appendix A Cost-Shared Projects

MTEP16 recommends a total of 13 new cost-shared projects, with a total project cost of $183.5 million for inclusion in Appendix A. The 11 cost-shared projects include:

- 12 Generator Interconnection Projects (GIP) with a total project cost of $75.5 million, with $31.2 million allocated to load and the remaining $44.3 million allocated directly to generators[3]
- One Market Efficiency Project (MEP) with a total project cost of $108 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 at the end of MTEP18.[4] The cost-shared projects in MTEP16 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

[3] Note that the $44.3million 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.
[4] 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 170 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[5] (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 $10.0 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, Table 2.2-2). The distribution of cost-shared projects includes:

- Baseline Reliability Projects (BRP) — 75 projects, $3.118 billion
- Generation Interconnection Projects (GIP) — 76 projects, $237 million (excluding the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) — four projects, $186 million
- Multi-Value Projects (MVP) — 17 projects, $6.530 billion

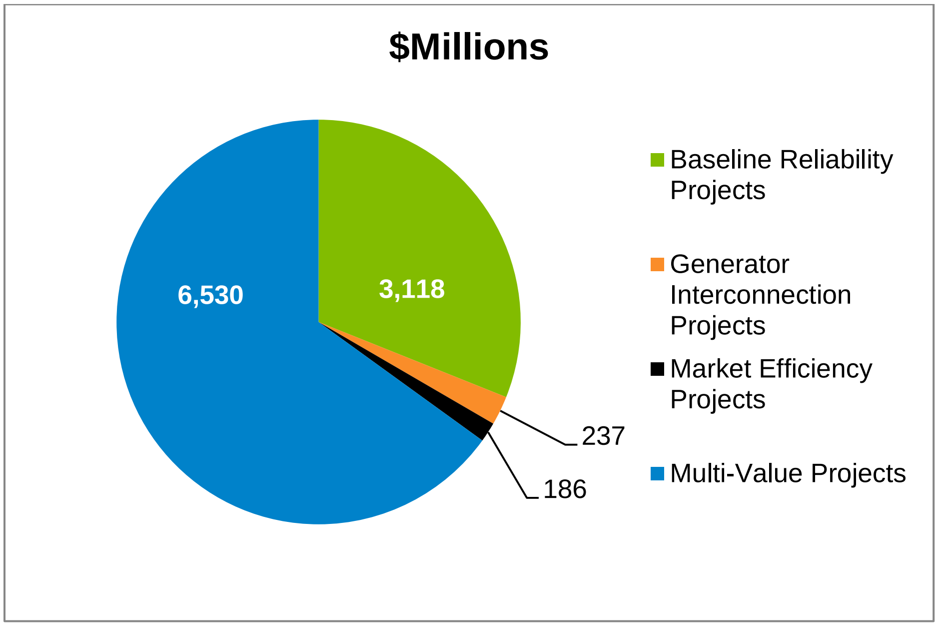


Figure 2.2-1: MTEP cumulative cost sharing by project type ($millions)

[5] 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 ($M)	GIP ($M)	MEP ($M)	MVP ($M)	Total ($M)
A in MTEP06	$672.8	$16.0	-	-	**$688.8**
A in MTEP07	$86.1	$16.6	-	-	**$102.7**
A in MTEP08	$1,288.0	$11.8	-	-	**$1,299.8**
A in MTEP09	$168.1	$64.1	$5.6	-	**$237.8**
A in MTEP10	$43.7	$1.2	-	$510.0	**$554.9**
A in MTEP11	$380.9	$46.6	-	$6,019.6	**$6,447.1**
A in MTEP12	$478.4	$26.3	$5.3	-	**$510.0**
A in MTEP13	-	$3.0	-	-	**$3.0**
A in MTEP14	-	$15.0	-	-	**$15.0**
A in MTEP15	-	$2.0	$67.4	-	**$69.4**
A in MTEP16	-	$31.2	$108	-	**$138.9**
Total	**$3,118.0**	**$233.8**	**$186.3**	**$6,529.6**	**$10,067.7**

Table 2.2-2: MTEP06 to MTEP16 cost-shared project costs by MTEP cycle and project type (shown in $millions)

Cost allocation methods vary depending on the classification of the project. BRPs, and GIPs are not subject to the competitive bid process; the majority of the costs are allocated to the pricing zone where the project is located.[6] Of the $3.5 billion in approved costs for these project types (not including MVPs), approximately 65.2 percent ($2.3 billion) is allocated to the pricing zone where the project is located. The remaining 34.8 percent ($1.2 billion) is allocated to neighboring pricing zones or to all pricing zones system-wide within the North/Central planning areas. Appendix A-2.3 shows a tabular summary of this information by Transmission Pricing Zone.

Approximately 65.2 percent ($2.3 billion) of BRP, GIP and MEP remains in the pricing zone where the project is located. The remaining 34.8 percent ($1.2 billion) is allocated to neighboring pricing zones or system-wide to all MISO North/Central planning area pricing zones

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

For the approved portfolio of MVPs, the costs are allocated 100 percent region-wide and recovered from customers through a monthly energy charge that is calculated using the applicable monthly MVP Usage Rate. The MVP charge applies to all MISO load, and export and through transactions sinking outside the MISO region. However, the MVP charge does not apply to load under grandfathered agreements.

For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.72 per month over the next 20 years

Indicative annual MVP Usage Rates[7] (dollar per MWh) are based on the approved MVP portfolio using current estimated project costs and in-service dates. The MVP usage rates have been calculated for the period 2017 to 2056 and are shown by the blue line (Figure 2.2-2).[8] The red and green lines represent an average of the estimated MVP Usage Rates over 20 and 40 year periods. For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.72 per month over the next 20 years.

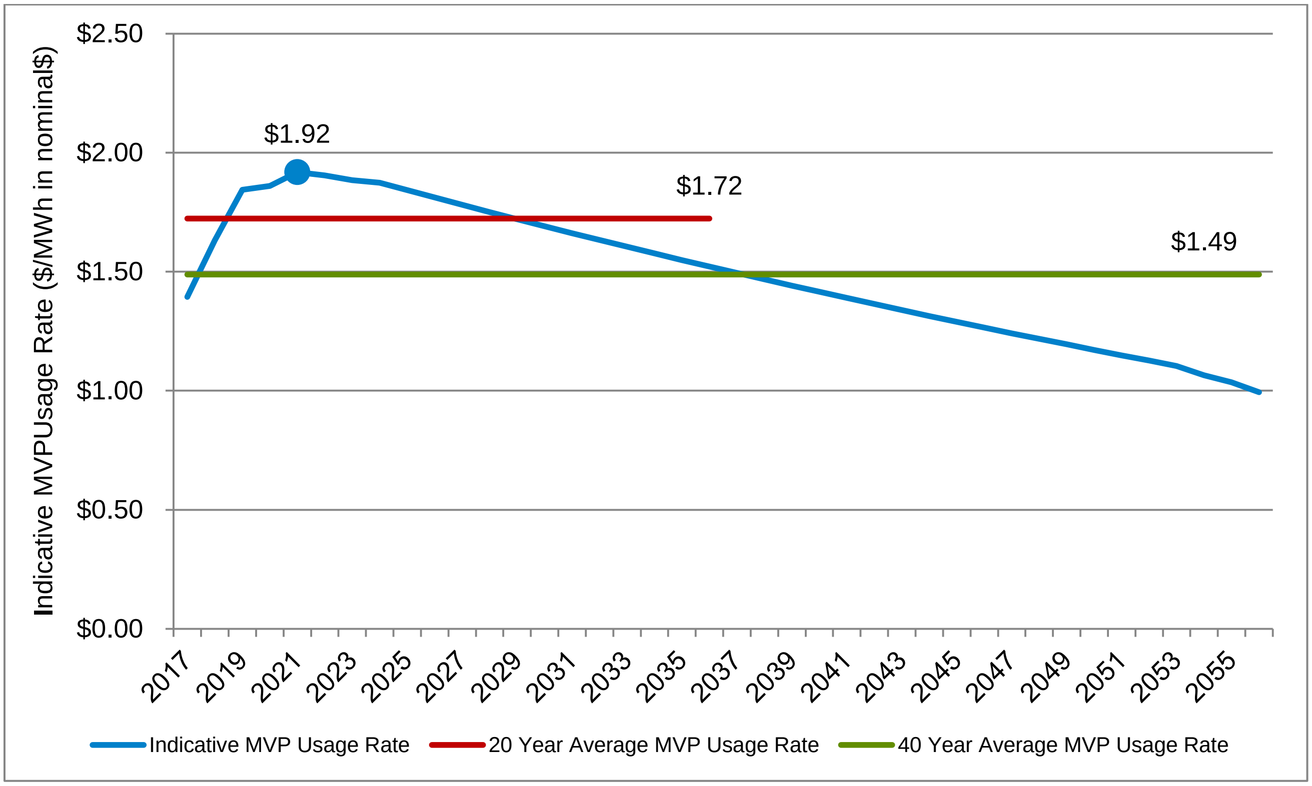
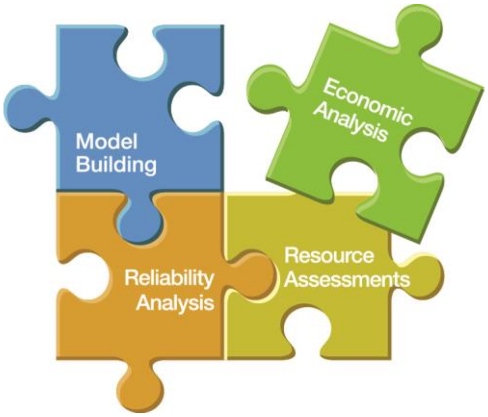


Figure 2.2-2: Indicative MVP usage rate for approved MVP portfolio from 2017 to 2056

[7] The MVP Usage Rate is charged via Schedule 26-A to: 1) Export and Through-Schedules; 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.

[8] The annual estimated MVP Usage Rates for 2017 to 2056 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

2.3 MTEP16 Process and Schedule



MTEP joins together individual pieces of the transmission puzzle to create a comprehensive plan for expansion. 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 2016 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, regional policy studies and interregional studies.

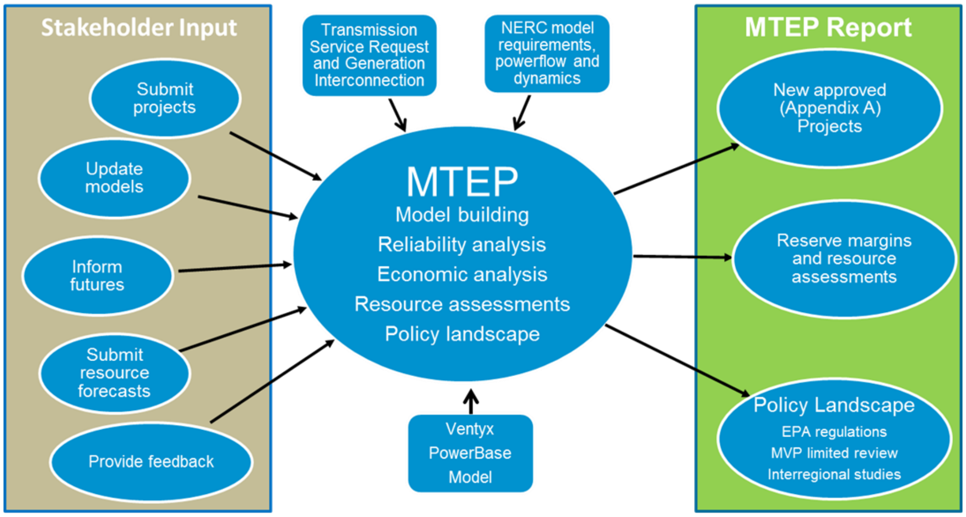


Figure 2.3-1: MTEP inputs and outputs

MTEP Planning Approach

MISO incorporates multiple perspectives by conducting reliability and economic analyses from the bottom up and top down. It evaluates long term transmission service requests (TSR) to move energy in, out, through or within the MISO market footprint, and 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

MTEP16 Workstreams

Completion of MTEP16 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.

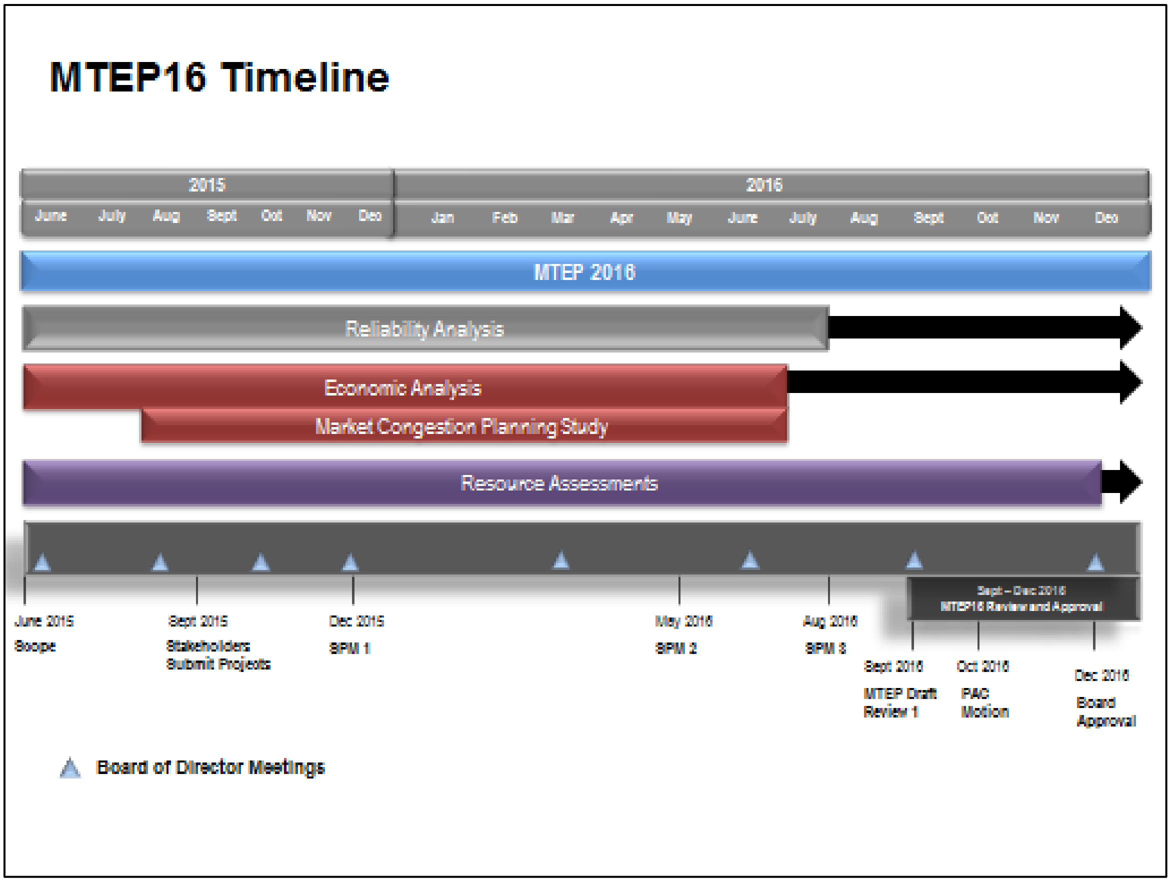


Figure 2.3-3: MTEP16 Timeline

Stakeholder Involvement in MTEP16

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 four 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). The SPMs report up to the Planning Subcommittee (PSC). The Planning Advisory Committee (PAC) reviews the full MTEP report in detail, and provides formal feedback to the System Planning Committee (SPC), which is made up of members of the MISO Board of Directors. The SPC makes its recommendations to the full board, which has final approval authority (Figure 2.3-4).

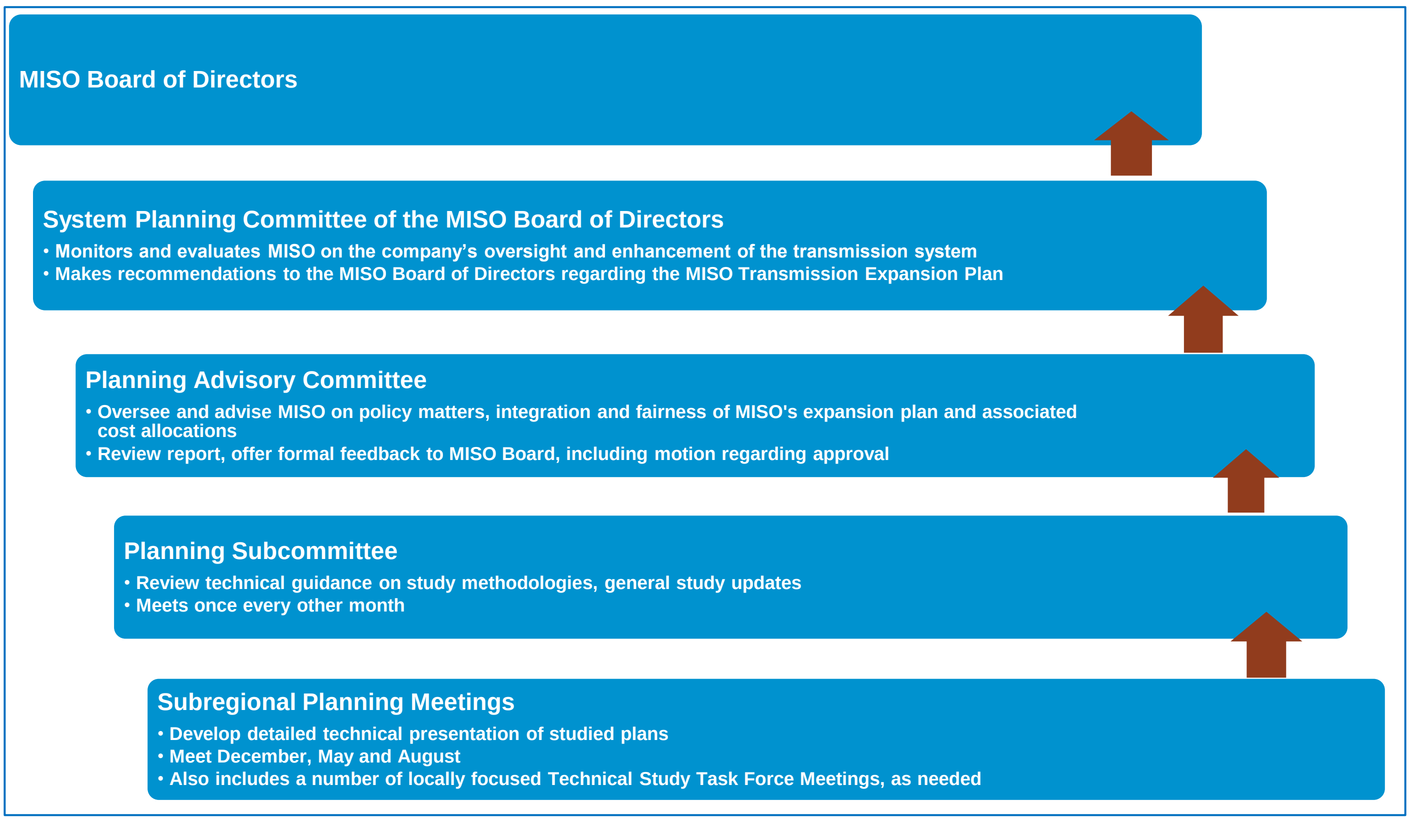


Figure 2.3-4: MTEP stakeholder forums

MTEP16 Schedule

Each MTEP cycle spans 18 months. MTEP16 began June 2015 and ends December 2016, with board approval consideration (Table 2.3-1).

Milestone	Date
Stakeholders submit proposed MTEP16 projects	September 2015
First round of Subregional Planning Meetings (SPM)	December 2015
Second round of Subregional Planning Meetings (SPM)	May 2016
MTEP16 Report first draft posted	August 2016
Third round of SPM meetings (8/15 to 8/25)	August 2016
Planning Advisory Committee final review and motion	October 2016
MISO Board System Planning Committee review	November 2016
MISO Board of Directors meeting to consider MTEP16 approval	December 2016

Table 2.3-1: MTEP16 schedule, major milestones

A Guide to MTEP Report Outputs

The MTEP16 report 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 Landscape. It summarizes regional studies and interregional studies.
- Book 4 presents additional regional energy information to show 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 projects vetted by MISO through the planning process. The appendices in the 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 that are not yet ready for execution. A move from Appendix B to Appendix A is the most common progression through the appendices; however projects may remain in Appendix B for a number of planning cycles.

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. Find the newest projects in the Appendix A spreadsheet by looking for “A in MTEP16” in the “Target Appendix” field.

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 - 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. 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 are generally classified in one of the following sub-types: Clearance, Condition, Distribution, Economic, Local Multiple Benefit, Metering, Operational, Performance, Reconfiguration, Relay, Reliability, Relocation, Replacement and Retirement.

Top-Down Projects

Top-down projects are 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)** meets 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, and are eligible for regional cost allocation. Projects qualify as MEPs based on cost and voltage thresholds and are developed to maximize benefit-to-cost ratios.

Externally Driven Projects

Externally driven projects are projects driven by needs identified through customer-initiated processes under the MISO 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.[9]

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards[10]. Others may be required for Generation Interconnection or Transmission Service. Some projects may be required for Regional Reliability Organization standards, while others may be required to provide distribution interconnections for load-serving entities. Appendix A projects may be required for economic reasons, to reduce market congestion or losses in a particular area. They may also decrease resource adequacy requirements through reduced losses during system peak or reduced planning reserve needs. Projects may be necessary to enable public policy requirements, such as current state renewable portfolio standards or Environmental Protection Agency standards. All projects in Appendix A address one or more MISO-documented transmission needs. Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff.

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

- Review the projects via an open stakeholder process at Subregional Planning Meetings
- Validate that the project addresses one or more transmission needs
- Consider and review alternatives
- Consider and review 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 MISO Board of Directors approval and inclusion in Appendix A, but can go through an expedited project review process.

[9] Projects with a Target Appendix A in the current MTEP cycle are not officially placed into Appendix A until Board of Directors approval in December of the cycle year.
[10] http://www.nerc.net/standardsreports/standardssummary.aspx

MTEP Appendix B

MTEP Appendix B contains all bottom-up projects validated by MISO as a solution to address an identified system need, but where it is prudent to defer the final recommendation of a solution to a subsequent MTEP cycle.

This generally occurs when the preferred project does not yet need a commitment based on anticipated lead time and there is still some uncertainty around the project drivers (such as changes in the projected conditions) or potential alternatives are still being considered.

MTEP Appendix B is limited to bottom-up projects only (Baseline Reliability Projects and Other Projects) and the projects will be reviewed by MISO in subsequent cycles to ensure the system needs still exist or a preferred solution is identified.

2.5 MTEP16 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.

Changes in the MTEP16 model-building process include data submission role additions per MOD-032-1 standard models

The MTEP16 model development process underwent some changes in data submission obligations per MOD-032-1 standard with inclusion of generator owners and load serving entities. In addition to TPL-001-4 standard requirements, MISO built a powerflow and dynamics model suite to support the Eastern Interconnection modeling process per MOD-032 requirements. Similar to MTEP15, there were two sets of models built. One model set contained approved future projects from MTEP15 Appendix A, and the other model set contained approved MTEP15 Appendix A projects and projects targeted for approval in MTEP16.

For MTEP studies, models for steady-state powerflow and dynamics stability reliability analyses are built to represent a planning horizon spanning the next 10 years; economic studies represent a 15-year planning horizon. The primary sources of information used to develop the models are:

- MISO's Model on Demand (MOD) powerflow database with future transmission, generator interconnection and transmission service related 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
- External model updates from neighboring planning entities

MTEP models are interdependent (Figure 2.5-1).

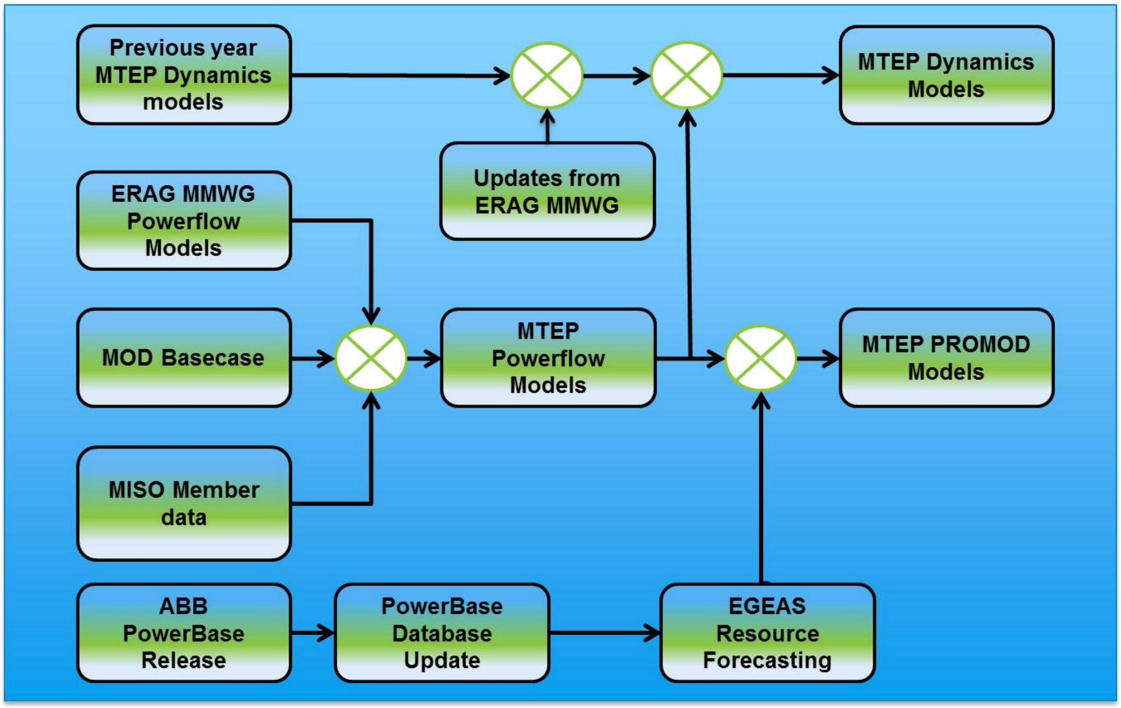


Figure 2.5-1: MTEP16 model relationships

Reliability Study Models

Powerflow Models

MISO developed regional powerflow models for MTEP16 as required by the TPL-001-4 standard and ERAG MMWG process (Table 2.5-1). Developed model base cases and sensitivity cases are listed with the corresponding TPL-001-4 requirement.

Model Year	Base case	Sensitivity
Year 2	2018 Summer Peak with wind at 15.6% (TPL requirement R2.1.1)	2018 Light Load (minimum load level) wind at 0% (TPL requirement R2.1.4)
Year 5	2021 Summer Peak with wind at 15.6% (TPL requirement R2.1.1)	2021 Summer Shoulder (70-85% peak) with wind at 90% (TPL requirement R2.1.4)
Year 5	2021 Summer Shoulder (70-85% peak) with wind at 40% (TPL requirement R2.1.2)	2021 Light Load (minimum load level) with wind up to 90% (TPL requirement R2.1.4)
Year 5	2021-2022 Winter Peak (Wind at 30%)	
Year 10	2026 Summer Peak (Wind at 15.6%) (TPL requirement R2.2.1.)	

Table 2.5-1: MTEP16 Powerflow Models

Per TPL-001-4 requirement R1.1, the system model contains representations of the following:

- R1.1.1 Existing Facilities: MISO's Model on Demand (MOD) database is used to store modeling data for all the existing facilities. MOD is updated monthly in collaboration with MISO members.
- R1.1.2. Known Outages: MISO models any known outage(s) of generation or transmission facility with duration of at least six months using data from Control Room Operations Window (CROW) Outage Scheduling System and publicly known information.
- R1.1.3. New planned facilities and changes to existing facilities: MOD is also used to capture all the future transmission upgrades and changes to existing facilities, which go into models per their in-service date. To support MTEP study requirements, two sets of powerflow models were developed:
  - MTEP15 Appendix A, which includes only approved future transmission facilities first approved in MTEP15 and future projects approved in prior MTEP studies. Approved future transmission projects also include network upgrades associated with generator interconnection and transmission delivery service requests.
  - MTEP15 Appendix A plus MTEP16 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 MTEP16 planning cycle to verify their need and sufficiency in ensuring system reliability
- R1.1.4. Real and reactive Load forecasts: real and reactive load is modeled based on seasonal load projections provided by member companies to the MISO MOD.
- R1.1.5. Known commitments for Firm Transmission Service and Interchange: MISO models known commitments based on the information obtained from the transacting parties.
- R1.1.6. Resources (supply or demand side) required for Load: Resources are modeled based on seasonal projections submitted by members in MOD. All the existing generators are included. Planned generators with signed Generation Interconnection Agreements are included according to their expected in-service dates. Generator retirements that have completed the MISO Attachment Y retirement study process are modeled off-line when unit can be retired.

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. Network Resource dispatch includes some energy resources, such as wind, which is dispatched in models in support of renewable energy standards. Wind generation is dispatched at capacity credit level in summer peak models and at average and high levels in off-peak models. The system average wind capacity credit is 15.6 percent based on MISO's Loss of Load Expectation study. The percentage values for wind generation (Table 2.5-1), are based on the nameplate capacity.

- 15.6 percent represents the wind capacity credit value
- 40 percent represents the average wind output level
- 90 percent represents the high wind output level and transmission design target 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 operating guides 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, with the exception of wind resources.

During the model development process, preliminary powerflow models are posted for stakeholder review and comment. MISO planning staff produces a model data check and case summary documents, which are posted for stakeholder review. Stakeholders submit topology corrections back to MISO Model On Demand system for inclusion in subsequent versions of the models.

Generation, load and area interchange data is calculated for each MISO control area for 2018 summer and 2021 summer peak models (Table 2.5-2). Note that 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 contained within the MISO members' model control areas.

Area	2018SummerPeak (All numbers in MW)				2021SummerPeak (All numbers in MW)			
	GEN	Load	Losses	Area Interchange	GEN	Load	Losses	Area Interchange
HE	1,366	572	30	764	1,422	579	30	813
DEI	6,999	7,556	319	(882)	7,072	7,689	314	(937)
SIGE	1,917	1,952	27	(61)	1,965	1,949	25	(9)
IPL	3,353	3,100	83	166	3,351	3,010	81	257
NIPS	3,853	3,548	53	246	3,853	3,612	56	179
METC	11,344	10,215	349	780	11,473	10,307	351	814
ITCT	10,984	11,523	249	(788)	10,941	11,509	254	(822)
WEC	6,720	6,421	97	189	6,803	6,521	98	171
MIUP	535	615	23	(105)	537	621	22	(108)
BREC	1,544	1,596	16	(68)	1,610	1,614	17	(21)
EES-EMI	4,133	4,010	110	7	4,137	4,028	105	(3)
EES-EAI	9,413	7,745	173	1,493	9,083	7,883	158	1,040
LAGN	3,043	1,734	13	1,296	3,037	1,867	12	1,159
CWLD	234	389	2	(157)	251	406	2	(157)
SMEPA	1,294	851	21	422	1,339	881	20	438
EES	17,460	18,959	355	(1,858)	17,594	19,397	353	(2,161)
AMMO	8,630	7,942	187	500	8,740	7,917	190	633
AMIL	11,049	9,764	262	1,024	11,043	9,829	255	958
CWLP	721	489	4	228	686	482	3	201
SIPC	361	345	14	2	383	360	14	9
CLEC	3,633	3,062	72	499	3,724	3,166	66	493
LAFA	252	497	7	(252)	278	523	7	(252)
LEPA	-	229	0.1	(230)	6	240	0.1	(235)
XEL	9,601	10,538	246	(1,201)	9,631	10,743	227	(1,357)
MP	1,577	1,668	42	(135)	1,519	1,687	64	(234)
SMMPA	115	605	1	(492)	127	617	1	(492)
GRE	2,663	2,845	92	(277)	2,520	2,865	92	(440)
OTP	2,149	1,751	78	318	2,173	1,818	81	272

Area	2018SummerPeak (All numbers in MW)				2021SummerPeak (All numbers in MW)			
	GEN	Load	Losses	Area Interchange	GEN	Load	Losses	Area Interchange
ALTW	4,193	4,013	93	87	4,211	4,018	90	102
MPW	219	162	1	55	194	165	1	28
MEC	6,008	6,147	97	(237)	6,004	6,297	97	(391)
MDU	439	665	12	(238)	445	699	15	(269)
DPC	835	1,048	42	(255)	854	1,063	36	(245)
ALTE	3,634	2,865	76	688	3,712	2,957	76	674
WPS	2,167	2,634	53	(525)	2,180	2,651	50	(526)
MGE	381	767	10	(398)	349	785	10	(448)
UPPC	46	228	8	(190)	47	228	8	(190)
	142,859	**139,048**	**3,316**	**414**	**143,292**	**140,984**	**3,282**	**(1,056)**

Table 2.5-2: System conditions for 2018 and 2021 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. Stability models are required for the study of the TPL-001-4 standard (Table 2.5-3).

Model Year	Base case	Sensitivity
Year 5	2021 Summer Peak with wind at 15.6% (TPL requirement R2.4.1)	2021 Light Load (minimum load level) with wind up to 90% (TPL requirement R2.4.3)
Year 5	2021 Summer Shoulder (70-80% peak) with wind at 40% (TPL requirement R2.4.2)	2021 Summer Shoulder (70-80% peak) with wind at 90% (TPL requirement R2.4.3)

Table 2.5-3: MTEP16 dynamic stability models

The MTEP15 dynamics data is the starting point for MTEP16 dynamics model development. This data is reviewed and updated with stakeholder feedback. Additionally, the ERAG MMWG 2015 series dynamic stability models are reviewed and any improved modeling data in external areas is incorporated in the MTEP16 dynamics models.

Dynamic load modeling in MTEP16 dynamic models is driven by Requirement 2.4.1 of the TPL-001-4 standard. The dynamic 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. Test simulations are performed to enable a review of model performance. Charts showing simulation results are posted for stakeholder review.

Dynamic load models are a recent addition to stability models and improve model accuracy

During the MTEP16 dynamic models development process, 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 studies. These models are forward-looking, hourly models based on assumptions discussed and agreed upon through the stakeholder process. For MTEP16, the Planning Advisory Committee (PAC) approved the following future scenarios:[11]

- Business As Usual
- High Demand
- Low Demand
- Regional Clean Power Plant (CPP) Compliance
- Sub Regional CPP Compliance

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 MISO-specific updates.

Updates include data obtained from the following sources:

- MISO Commercial Model for verifying 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.

[11] For more details on these assumption scenarios, see Chapters 5.2: MTEP Future Development and 5.3: Market Congestion Planning Study.

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 its tier one neighbors as part of the model development process to accurately reflect neighboring systems. Highlights of this collaboration include extensive updates from PJM and Southwest Power Pool (SPP).

Chapter 3

Historical MTEP Plan Status

2016

3.0 Historical MTEP Plan Status

Since the first MTEP report in 2003, more than $12.9 billion in projects have been constructed in the MISO region. Not including withdrawn projects, there are currently $10.6 billion of previously approved projects in various stages of design, planning or construction as of September 2016.

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 MTEP15 Status Report

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

MISO's transmission planning responsibilities include the monitoring of previously approved MTEP Appendix A projects. MISO surveys all Transmission Owners and Selected Developers 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 report provides the status of MTEP15 Appendix A projects as of Quarter 1, 2016, and elaborates on the status of the Multi-Value Projects (MVP) approved in MTEP11.

Since the first MTEP report in 2003, a total of $25.6 billion in transmission projects have been approved. Of this approved investment, $12.9 billion have been constructed; $2.1 billion has been withdrawn; and the remaining $10.6 billion is in various stages of design, planning or construction through the third quarter of 2016.

Following the approval of a MTEP, MISO continues to provide transparency through its publication of project status updates. This monitoring of previously approved MTEP Appendix A projects ensures that a good-faith effort is being made to move projects forward, as prescribed in the Transmission Owners' Agreement. Transmission Owners and Selected Developers provide updated costs, in-service dates, and various other status updates as required by the MISO Tariff and BPM-020.

MISO summarized information regarding the status of previously approved MTEP Appendix A projects to present general trends and notable highlights. Since MTEP13, this information has been presented by summarizing the differences between the costs and schedules published in the respective MTEP reports from those costs and schedules provided to MISO by Transmission Owners and Selected Developers through their submitted status updates.

The cost and schedule trending analysis conducted on the projects approved in MTEP15 considers all active Appendix A projects that were not in service or otherwise withdrawn as of September 2016. Additionally, the MVPs are excluded from the trend analysis because of the significant amount of investment related to the MVPs approved in MTEP11 when compared to other projects included in Appendix A of a respective MTEP (Figures 3.1-1 and 3.1-2). This is addressed following the discussion on the non-MVP facilities (Figure 3.1-3).

Though this section focuses on projects that have experienced cost-increases or schedule delays, these projects do not represent the norm. The majority of MISO's previously approved projects have little to no deviations from the cost and schedules that were published in their respective MTEP reports.

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

As of the third quarter of 2016, MISO is tracking 565 active projects from MTEP15 Appendix A totaling $5.74 billion of approved investment. Of this total, 45 percent were approved in MTEP15 and the remaining 55 percent were approved in MTEP03 through MTEP14. All costs contained within this section are in nominal, as-spent dollars.

Non-MVP Project Cost Variation

The estimated total costs for the 565 active MTEP15 Appendix A projects have increased from the MTEP-approved $5.4 billion to $5.7 billion, a cost variance of 6 percent. 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, the number of projects with significant cost increases (with respect to the project size and scope) is small. The projects with the largest percentage deviation were generally projects with a small total cost. Currently, 85 percent of projects have increased by less than 25 percent of their original cost estimate; 68 percent of projects have no reported cost increase or have a decreased cost estimate.

The cost-shared projects of the MTEP15 Appendix A subset represent $680 million in approved MTEP investment. Of the 12 active (non-MVP) cost-shared projects, five projects' cost estimates have not increased since approval and only one projects' costs currently expected to increase by more than 25 percent of the original estimate. All projects with cost deviations are Baseline Reliability Projects or Generator Interconnection Projects, which are not justified based on economics (red line, Figure 3.1-1). The cost-shared trend has decreased over the last two quarters as projects go into service and the number of active cost-shared projects decreases. Also, fewer cost shared projects are approved each cycle due to a change in cost sharing methodology after MTEP13.

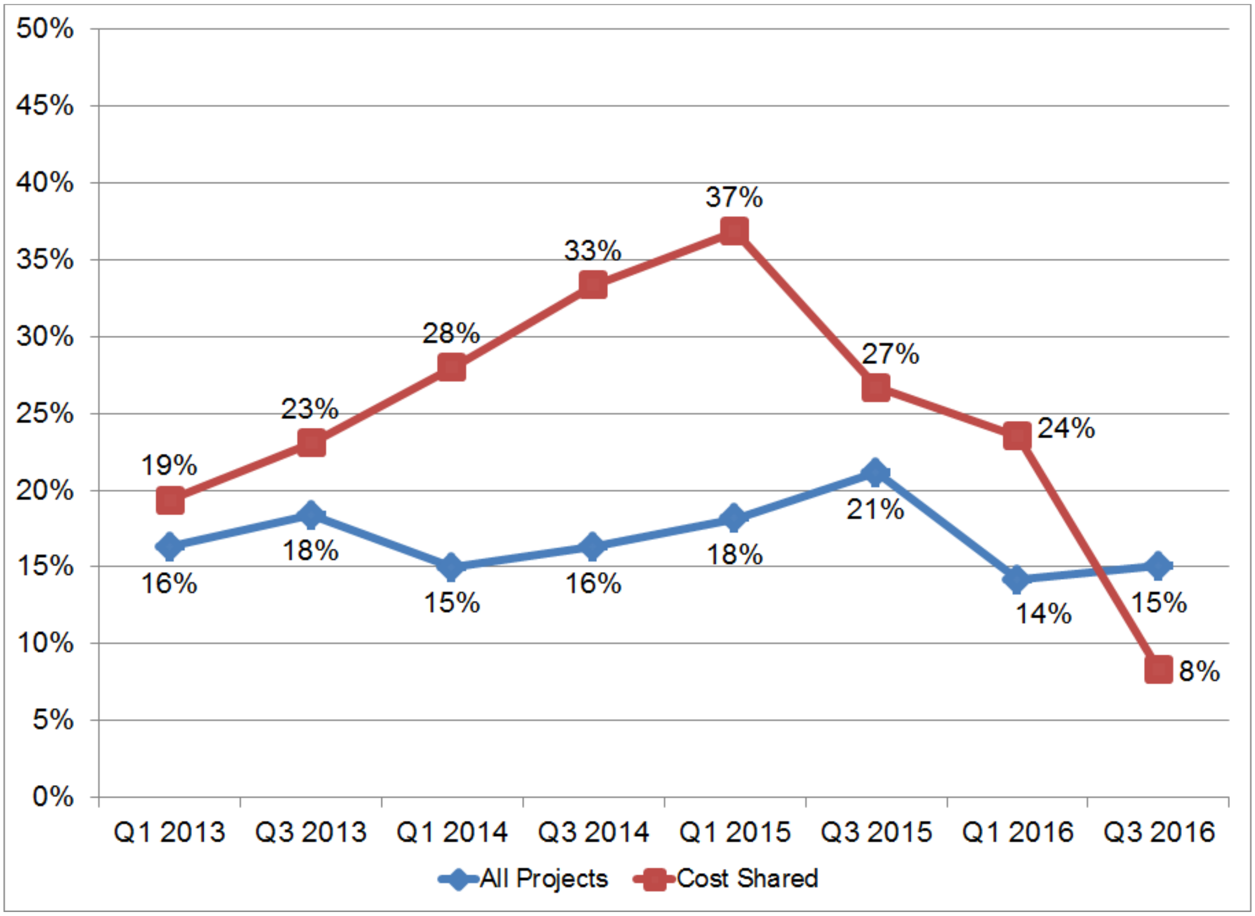


Figure 3.1-1: Percentage of active MTEP15 Appendix A Projects (non-MVP) that have deviated by more than 25 percent of their original cost estimate, through Q3 2016

Non-MVP Project Schedule Variation

The 565 MTEP15 Appendix A projects have, on average, delayed their in-service date by 14 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 39 percent of Active MTEP15 Appendix A projects have not extended beyond the MTEP-approved estimate. Projected in-service dates have extended beyond 12 months for 43 percent of the Active MTEP15 Appendix A projects (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 eight of the 12 cost-shared MTEP15 Appendix A projects (red line, Figure 3.1-2).

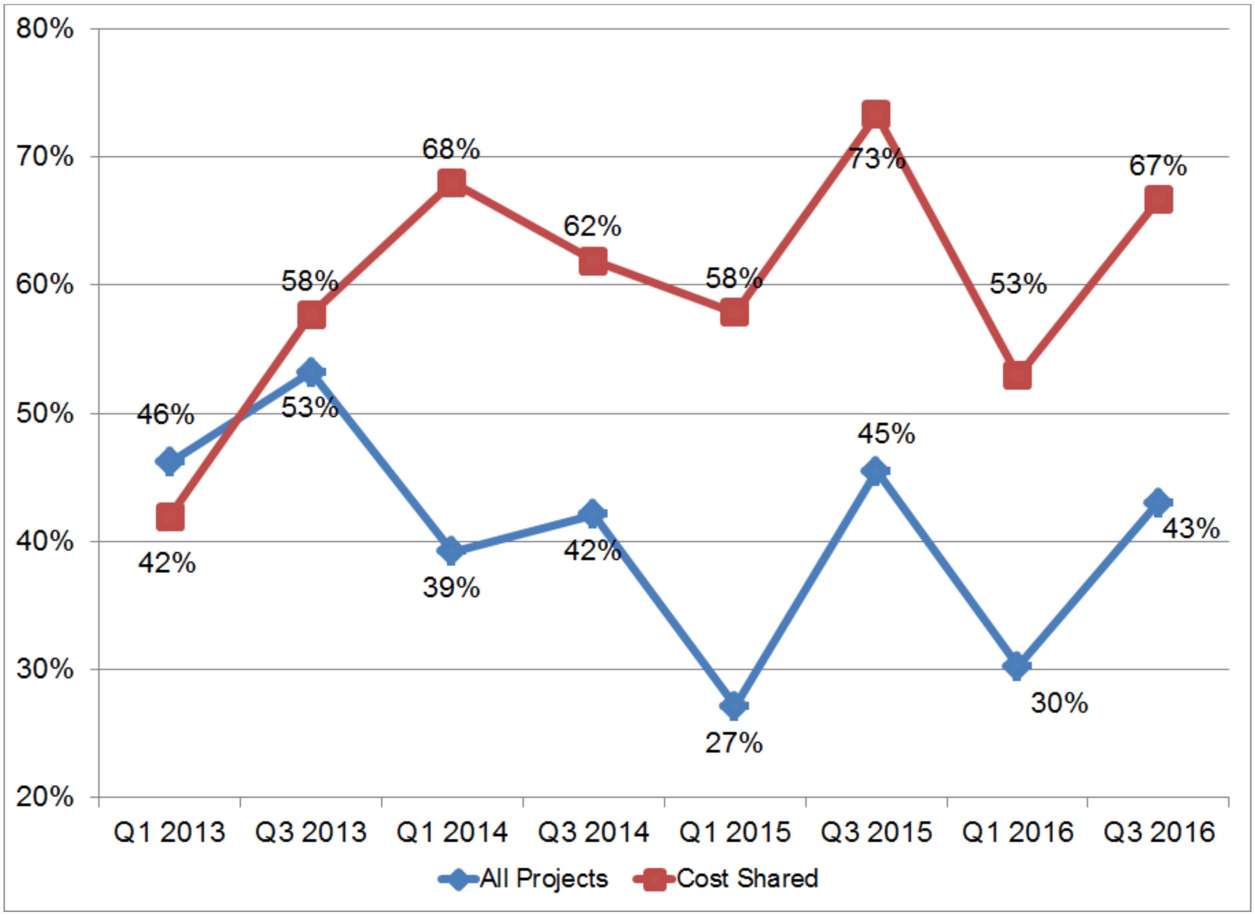


Figure 3.1-2: Percentage of active MTEP15 Appendix A Projects (non-MVP) that have a schedule delay of more than 12 months from the original expected in service date, through Q3 2016

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[12]:

- 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 September 2016, three projects are in service, six projects are at least partially under construction and the remainder are complete or are in progress with state regulatory approvals (Figure 3.1-3). Since the MTEP11 approval,

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

the total projected budget for the MVP Portfolio has increased by 18.8 percent, the result of longer-than-planned line routing, substation design changes and use of more developed construction estimates.

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

Multi-Value Project Status as of Q3 2016

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[1]	
			MTEP Approved	Q2 2016	State Regulatory Status	Construction	MTEP Approved	Q2 2016
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	672.4
3	Lakefield Jct. - Winnebago-Winco-Burt area & Sheldon-Burt Area-Webster	MN/IA	2015-2016	2016-2018	●	Underway	550.4	545.7
4	Winco-Lime Creek-Emery-Black Hawk-Hazelton	IA	2015	2015-2018	●	Underway	468.6	470.3
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project)	WI/IA	2018-2020	2018-2023	●	Pending	797.5	1046.1
	Cardinal-Hickory Creek	WI/IA	2018-2020	2018-2023	◑	Pending		
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	2016-2018	◑	Pending	112.8	153.4
9	Maywood-Herleman-Meredosia-Ipava & Meredosia-Austin	MO/IL	2016-2017	2016-2017	●	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	439.7
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Underway	271.0	388.0
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	510.0	510.0
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	387.5
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	219.3
17	Sidney-Rising	IL	2016	2016	●	Underway	83.2	90.6
						Totals:	***5,564***	***6,611***

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 September 2016

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 MTEP16 cycle, the MTEP report now represents 13 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.

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP16 cycle, is more than $26.2 billion (Figure 3.2-1). MTEP16 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, approximately $12.9 billion of cumulative approved projects have been constructed and are in service as of September 2016
- $3.1 billion of MTEP projects are expected to go into service in 2016

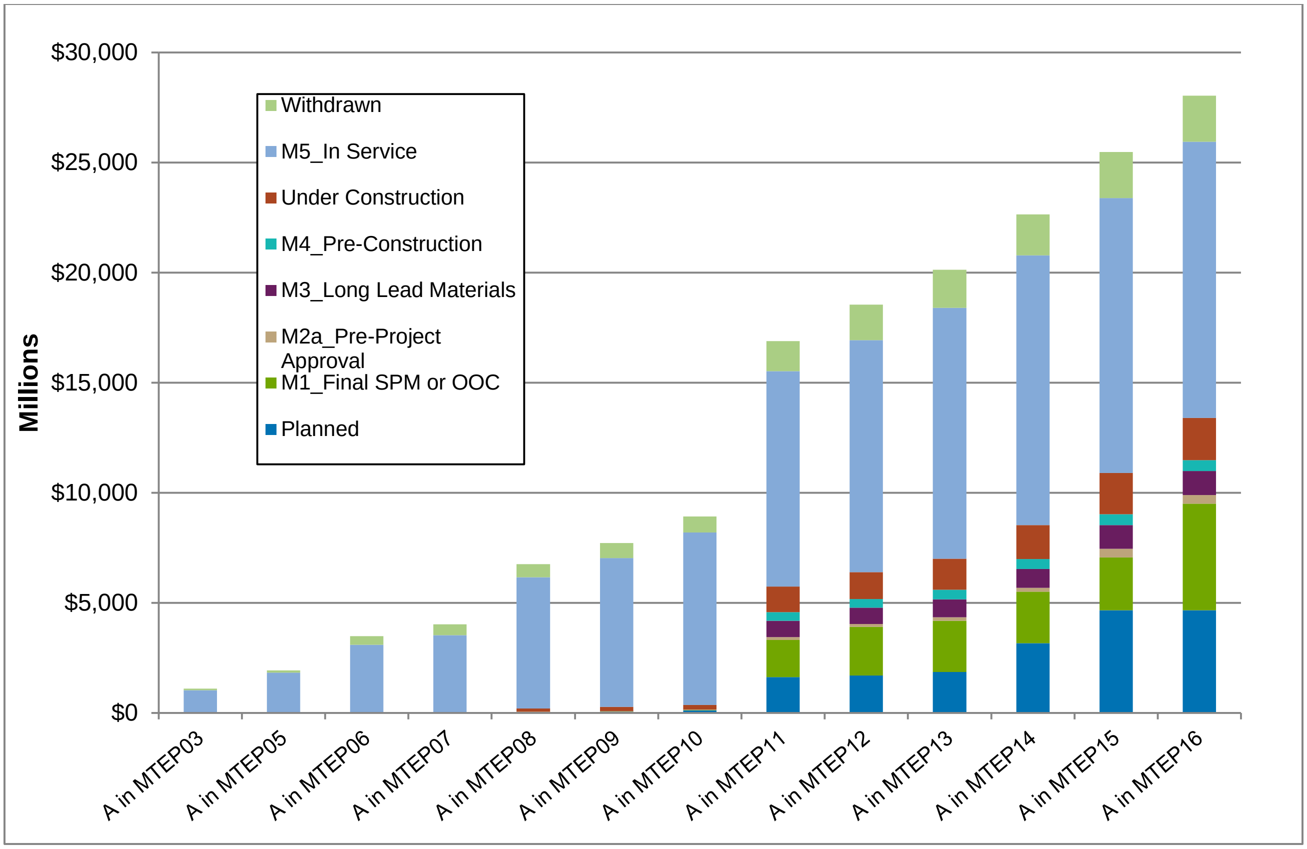


Figure 3.2-1: Cumulative Investment by Facility Status[13]

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 incremental value 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.

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

- 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.
- MTEP15 and 16 further reflect a continuation of a typical MTEP, primarily driven by reliability projects. Beginning in MTEP15, MTEP participants began planning to meet a series of new, more stringent NERC reliability standards.

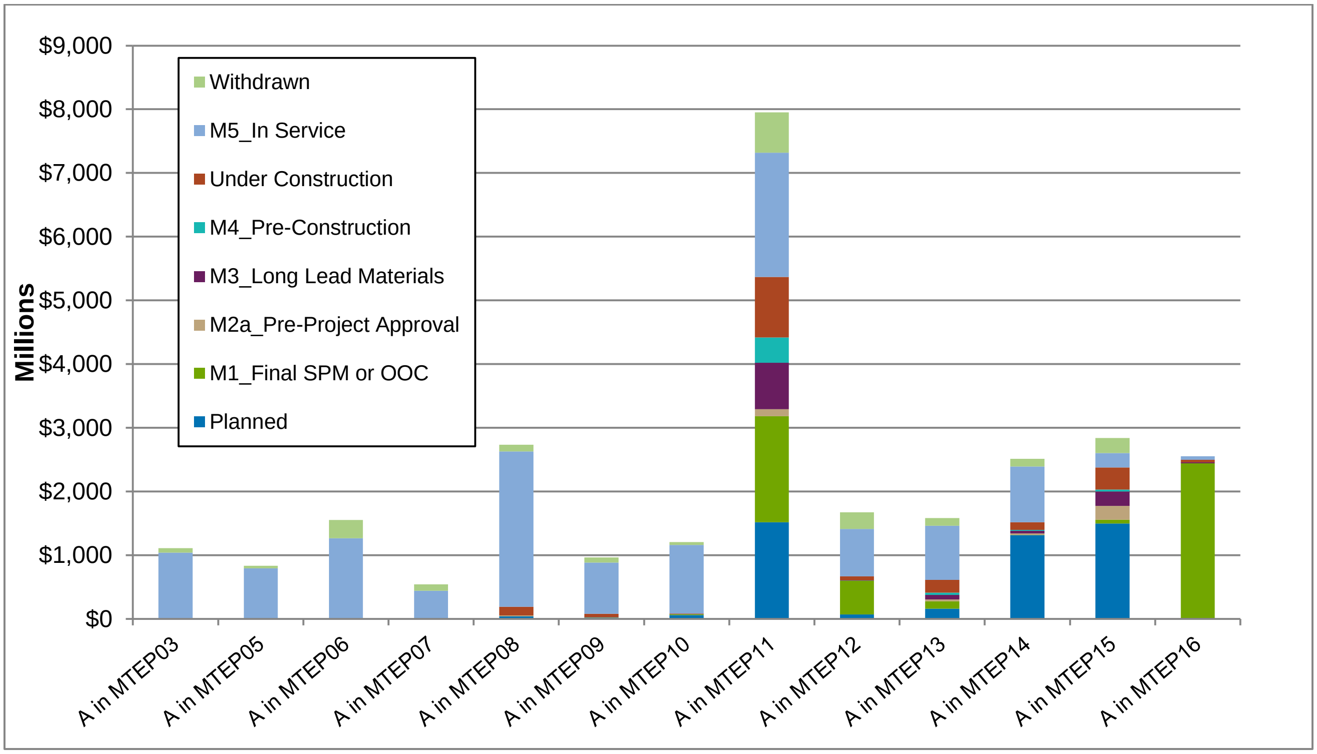


Figure 3.2-2: Approved Investment by MTEP Cycle[14]

Since MTEP03, approximately $2.1 billion in approved transmission investment has been withdrawn. Common reasons for a project 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

MISO documents all withdrawn projects and facilities to ensure the planning process addresses required system needs.

[14] New Appendix A projects in the MTEP16 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 conditions 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.

Chapter 4

Reliability Analysis

2016

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 find 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 2015, May-June 2016 and August 2016. 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 MTEP16 reliability assessment are summarized in this chapter and the complete results are presented in Appendix D of this MTEP16 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

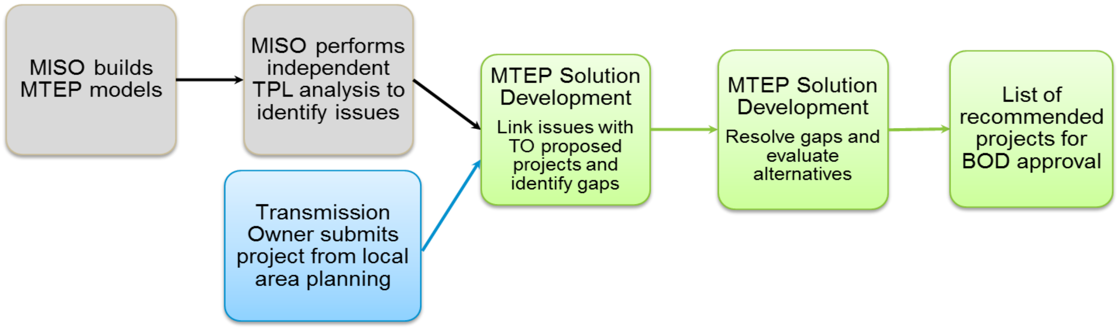


Figure 4.1-1: MTEP16 Reliability Study Process

Models

In MTEP16, MISO conducted regional studies using the following base cases and sensitivity cases developed collaboratively with our stakeholders:

- 2018 Summer Peak (wind at 14 percent)
- 2018 Light Load (wind at 0 percent)
- 2021 Summer Peak (wind at 14 percent)
- 2021 Shoulder Peak (wind at 40 percent)
- 2021 Shoulder Peak (wind at 90 percent)
- 2021 Light Load (wind at 90 percent)
- 2021 Winter Peak(wind at 30 percent)
- 2026 Summer Peak (wind at 14 percent)

Interchanges, generation, loads and losses are inputs into each planning model used in the MTEP16 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 2015 series Multiregional Modeling Working Group (MMWG) interchange.[15] 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

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

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 14 to 15.6 percent of nameplate in the summer peak case and 90 percent of nameplate in the shoulder cases. These wind dispatch levels were selected through the MISO planning stakeholder process. More information on the models may be found in Appendix D2 of this report.

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

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

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. Violations are mitigated via system reconfiguration, generation redispatch, implementation of an operating guide, or with a transmission upgrade, as appropriate and consistent with the requirements of the applicable reliability standards. Identified transmission upgrades to future system issues are investigated further in subsequent MTEP cycles.

MISO is currently engaging in discussions at the Planning Subcommittee meetings on how to better incorporate non-transmission alternatives in the reliability planning process. A business practice manual is under development.

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 MTEP16 2018 summer peak and shoulder peak models; the 2021 summer peak, shoulder peak, winter peak and light-load models; and the 2026 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 MTEP16 2021 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 four MISO planning subregions (Figure 4.1-2). The four MISO planning subregions are: Central (blue), East (green), South (orange) and West (red).

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
20-Nov-15	South TSTF Meeting	Web-ex/conf. call
4-Dec-15	East SPM No. 1	Detroit, Mich.
8-Dec-15	South SPM No. 1 (Miss., La., Texas, Ark.)	Metairie, La.
10-Dec-15	West SPM No. 1	Eagan, Minn.
14-Dec-15	Central SPM No. 1	Carmel, Ind.
17-Dec-15	South TSTF Meeting	Web-ex/conf. call
6-Jan-16	East TSTF Meeting	Web-ex/conf. call
8-Feb-16	West TSTF Meeting	Web-ex/conf. call
19-Feb-16	West TSTF Meeting	Web-ex/conf. call
11-Mar-16	Central TSTF Meeting	Web-ex/conf. call
22-Mar-16	Central TSTF Meeting	Web-ex/conf. call
31-Mar-16	East and West TSTF Meeting (closed)	Livonia, Mich.
6-May-16	East TSTF Meeting	Web-ex/conf. call
24-May-16	East SPM No. 2	Livonia, Mich.
26-May-16	Central SPM No. 2	Carmel, Ind.
2-Jun-16	South SPM No. 2 (Miss., La., Texas, Ark.)	Metairie, La.
3-Jun-16	West SPM No. 2	Eagan, Minn.
28-Jul-16	Michigan TSTF Meeting (closed)	Web-ex/conf. call
15-Aug-16	Central SPM No. 3	Carmel, Ind.
22-Aug-16	West SPM No. 3	Eagan, Minn.
24-Aug-16	East SPM No. 3	Cadillac, Mich.
25-Aug-16	South SPM No. 3 (Miss., La., Texas, Ark.)	Little Rock, Ark.
29-Sept-16	Michigan TSTF Meeting (closed)	Web-ex/conf. call
29-Sept-16	West TSTF Meeting	Eagan, Minn.

Table 4.1-1: MTEP16 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 MTEP16 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 MTEP16 report.

4.2 Generation Interconnection Projects

MISO provides safe, reliable, transparent, 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.

MTEP16 contains Target Appendix A GIPs totaling approximately $140 million (Table 4.2-1). These GIPs are associated with the generation interconnection requests (Table 4.2-2, Figure 4.2-1).

MTEP Project ID	Project Name	Submitting Company	Preliminary Share Status	Region	Estimated Cost ($)
10763	J392 Generation Upgrades	CETO	Not Shared	East	$874,000
10425	J340 Generation Interconnection	ITCT	Shared	East	$15,150,000
10743	Covert Gen Interconnection (PJM-T94)	METC	Shared	East	$3,605,000
10744	J392 Generation Interconnection	METC	Shared	East	$18,0872,200
11023	J392 Generator Interconnection	WPSC	Not Shared	East	$13,980,072
7944	J348 Generation Interconnection	EES-EAI	Not Shared	South	$2,526,158
10044	J348 Generation Interconnection	EES-EAI	Not Shared	South	$10,064,000
9957	J473 Generation Interconnection	SMEPA	Not Shared	South	$1,590,000
9969	J473 Generation Interconnection	SMEPA	Not Shared	South	$4,782,000
11383	J329 Network Upgrades	CFU-PMEU	Not Shared	West	$1,043,700
11463	C023 Stanton 31RB3	GRE	Not Shared	West	$33,033
9937	J233 Network Upgrades	ITCM	Not Shared	West	$17,740,415
9939	H009 Jasper -Aurora 69kV	ITCM	Not Shared	West	$3,720,000
9941	H021 Traer - Traer Tap 69 kV	ITCM	Not Shared	West	$293,449
10867	J285 interconnection Facilities	MEC	Shared	West	$3,000,000
10868	J411 interconnection Facilities (Ida Co. Substation)	MEC	Shared	West	$5,750,000

11103	Black Hawk: Install 2-69 kV Cap Banks	MEC	Not Shared	West	$1,180,000
11143	J274 Network Upgrades	MEC	Not Shared	West	$175,000
11144	R42 Network Upgrades Sub T(FD)	MEC	Not Shared	West	$88,000
11145	R42 Network Upgrades Sub T FD - Boone Jct 161 kV Line Uprate	MEC	Not Shared	West	$173,000
11146	J343 Network Upgrades Clarinda-Brooks 161 kV Uprate	MEC	Not Shared	West	$200,000
11283	J343 Network Upgrades Clarinda-Maryville 161 kV Uprate	MEC	Not Shared	West	$100,100
11284	J343 Network Upgrades Clarinda Substation	MEC	Not Shared	West	$80,500
11285	J344 Network Upgrades Beacon 161 kV Line Drops, Poweshiek	MEC	Not Shared	West	$25.000
11763	J344 Network Upgrades	ITCM	Not Shared	West	$5,537,540
11043	PJM Y1-069 Relay Modifications at Monroe to Accommodate PJM Y1-069 Lallendorf Generator Interconnection.	ITCT	Shared	East	250,000
11583	J301 Generation Interconnection.	ITCT	Shared	East	$9,497,000
11584	J308 Generation Interconnection	ITCT	Shared	East	$9,421,000.00
11603	J321 Generation Interconnection	ITCT	Shared	East	$9,366,000.00
11604	J419 Generation Interconnection	ITCT	Shared	East	$803,000
Total Estimated Cost					**$139,135,167**

Table 4.2-1 Generation Interconnection Projects in MTEP16 Target Appendix A[16]

[16] A detailed description how a shared project is determined is in Attachment FF, starting with Section II.C, page 57 of 499 of the Tariff.

GI Project No.	TO	County	ST	Study Cycle	Service Type	Point of Interconnection	Max Summer Output	Fuel Type	GIA
J392	METC	Otsego	MI	DPP-2015-FEB	NRIS	Livingston – Stover 138 kV Line	383.1	Gas	GIA
J340	ITCT	Huron	MI	DPP-2012-AUG	NRIS	Cosmo – Bad Axe 120 kV Line	100	Wind	GIA
PJM T94	METC	Van Buren	MI	N/A	N/A	Cook – Palisades 345 kV Line	1035	Gas	N/A
J348	EES-EAI	Arkansas	AR	DPP-2014-AUG	NRIS	Almyra -Stuttgart Ricuskey 115 kV Line	81	Solar	GIA
J473	SMEPA	Lamar	MS	DPP-2016-FEB	ERIS	Sumrall II 69 kV Substation	52	Solar	GIA
J329	CFU	Marion	IA	DPP-2014-AUG	NRIS	Pella West 69 kV Substation	55	Hydro	GIA
C023	GRE	Oliver	ND	02/04/16 Coordinated Study	N/A	Stanton 230 kV Substation	100	Wind	N/A
J233	ITCM	Marshall	IA	DPP-2013-AUG	NRIS	Marshalltown 161 kV Substation	635	Gas	GIA
H009	ITCM	Tama	IA	DPP-2012-AUG	ERIS	Trear – Marshalltown 161 kV Line	150	Wind	GIA
H021	ITCM	Grundy	IA	DPP-2012-AUG	NRIS	Wellsburg 115 kV Substation	138.6	Wind	GIA
J285	MEC	O'Brien	IA	DPP-2014-AUG	NRIS	O'Brien County 345 kV Substation	250	Wind	GIA
J411	MEC	Ida	IA	DPP-2015-FEB	NRIS	LeHigh – Raun 345 kV Line	300	Wind	GIA
G735	ITCM	Hancock	IA	DPP-2012-AUG	NRIS	Lime Creek 161 kV Substation	200	Wind	GIA
J274	MEC	Madison	IA	DPP-2013-AUG	NRIS	Winterset - Creston 161 kV Line	100	Wind	GIA
R42	MEC	Webster	IA	DPP-2012-AUG	NRIS	Lehigh 345 kV Substation	250	Wind	GIA
J343	MEC	Adams	IA	DPP-2014-AUG	NRIS	Creston - Clarinda 161 kV Line	150	Wind	GIA
J344	MEC	Mahaska	IA	DPP-2014-AUG	NRIS	Poweshiek – Oskaloosa 161 kV Line	169	Wind	GIA
PJM Y1-069	ITCT	Monroe	MI	N/A	N/A	Northern Ohio 345 kV	799	Gas	N/A
J301	ITCT	Tuscola	MI	DPP-2015-FEB	NRIS	Bauer – Rapson 354 kV Line	101	Wind	GIA
J308	ITCT	Sanilac	MI	DPP-2015-FEB	NRIS	Rapson – Banner 345 kV Line	301	Wind	GIA
J321	ITCT	Sanilac	MI	DPP-2015-FEB	NRIS	Rapson – Banner 345 kV Line	151.2	Wind	GIA
J419	ITCT	Washtenaw	MI	DPP-2015-FEB	NRIS	Milan 120 kV Substation	100	Solar	GIA

Table 4.2-2: Generation Interconnection Requests Associated with Target Appendix A

Figure 4.2-1: Generation Interconnection Requests Associated with MTEP16 Target Appendix A

MTEP16 Target Appendix A

Generation Interconnection Projects – Detail

MTEP Project 10763 – Consumers Energy Transmission Owner

- Perform Network Upgrades for J392 GIP
- J392 – 383.1 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: Livingston – Stover 138 kV Line
- Upgrade the Emmet 138 kV Sub Relaying
- Add a wavetrap to the Emmet – Livingston 138 kV Line to accommodate the addition of a dual-pilot relay scheme
- Completion date: June 17, 2016
- Actual cost: $874,000

MTEP Project 10425 – International Transmission Co. Transmission

- Perform Network Upgrades for J340 GIP
- J340 – 100 MW Wind Generator
- Point of interconnection: Cosmo – Bas Axe 120 kV Line
- Rebuild 5.3 miles of the existing 120 kV Cosmo Tap to Double Circuit steel poles
- Relocate the Harvest Wind Tap point
- String 954 ACSR to create the new J340 Harvest Wind-Grassmere 120 kV Line
- Expand the Grassmere Sub and install 1-345 kV Breaker, a 345/120 kV Transformer, and a 120 kV Breaker on the low side of the Transformer to tie in the new line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $15,150,000

MTEP Project 10743 – Michigan Electric Transmission Co.

- Perform Network Upgrades for PJM-T94 – Covert GIP
- PJM-T94 – 1,035 MW Gas Generation
- Point of interconnection: Cook – Palisades (Covert) 345 kV Line
- Construct a new control house at Palisades Sub and replace the relaying associated with positions RH25 and FH27
- Install OPGW on the new Palisades - Segreto #1 345 kV Line and remove the METC SCADA equipment at the new Covert 345 kV Sub
- Completion date: September 30, 2015
- Actual Cost: $3,605,000

MTEP Project 10744 – Michigan Electric Transmission Co.

- Perform Network Upgrades determined in the FEB2015 DPP for J392 GIP
- J392 – 383.1 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: Livingston – Stover 138 kV Line
- Wolverine to construct the following:
    - New 4 row, 11 Breaker, 138 kV Van Tyle Breaker and a half Sub (Ownership will be transferred to METC upon completion)

    - Loop the 138 kV Livingston - Stover Line into Van Tyle 138 kV Sub, and rebuild the new Livingston - Van Tyle line to double circuit structures with OPGW being added to the new poles
    - 1431 ACSR conductor will be installed on both sides of the new structures to create Livingston - Van Tyle #1 and #2 Lines
    - A dual pilot relaying scheme will be installed on the Livingston - Emmet 138 kV line and the Livingston Sub will be expanded to include 2 new rows, and 5 additional Breakers on the 138 kV Breaker and a half Sub
    - Relaying upgrades at Gaylord Sub
- Completion date: June 11, 2016
- Actual Cost: $18,087,200

MTEP Project 11023 – Wolverine Power Supply Cooperative

- Perform Network Upgrades determined in the FEB2015 DPP for J392 GIP
- J392 – 383.1 MW Combustion Turbine (Simple Cycle) Gas Generator
- Point of interconnection: Livingston – Stover 138 kV Line
- Wolverine to construct the following:
    - Advance 138 kV Sub and 138/69 kV Transformers
    - Gaylord 138 kV 4 Breaker ring bus to accommodate a 3rd line into the station (2016)
    - Gaylord 138 kV 6 Breaker ring bus and 2nd 138/69 kV Transformer (2018)
    - Upgrades to Elmira, Deer Lake and Alpine distribution Subs from 69 kV to 138 kV
    - Conversion of existing Gaylord - Advance 69 kV Line to 138kV, new lines will be Gaylord - Van Tyle and Van Tyle to Advance
    - Rebuild the Gaylord - Livingston 138 kV Line with 795 ACSS
- Completion date: April 30, 2016
- Actual Cost: $13,989,072

MTEP Project 7944 – Entergy - Arkansas

- Perform Network Upgrades for J348 GIP
- J348 - 81 MW Solar Generator
- Point of interconnection: P Stuttgart Ricuskey - Stuttgart Ind.115 kV Line
- Upgrade the Stuttgart Ricuskey - Stuttgart Ind.115 kV Line to 176 MVA
- Anticipated completion date: January 30, 2018
- Anticipated cost: $2,526,158

MTEP Project 10044 – Entergy - Arkansas

- Perform Network Upgrades for J348 GIP
- J348 - 81 MW Solar Generator
- Point of interconnection: Stuttgart Ricuskey - Almyra 115 kV Line
- New 115 kV 3 Breaker ring bus Switching Station named Goodwin Road on the Stuttgart Ricuskey - Almyra 115 kV Line
- Anticipated completion date: January 30, 2018
- Anticipated cost: $10,064,000

MTEP Project 9957 – Southern Mississippi Electric Power Association

- Perform Network Upgrades for J473 GIP Origis Solar Project - Sub
- J473 – 52 MW Solar Generator.

- Point of interconnection: Sumrall – Rawls 69 kV Line
- New 69 kV Switching Station with a 69/26.4 kV GSU
- The Origis Energy solar plant will tap the existing SMEPA 69 kV Line 42 (Sumrall - Rawls Springs) approximately 5.6 miles from Sumrall 69 kV Sub
- The generation interconnection project is contingent upon the following injection upgrades:
    - Line 42 and 43 (Columbia - Sumrall) will be uprated to a higher conductor temperature via structural change outs to support the generation addition
    - OPGW will also be installed for communications
- Anticipated completion date: March 23, 2017
- Anticipated cost: $1,590,000

MTEP Project 9969 – Southern Mississippi Electric Power Association

- Perform Network Upgrades for J473 GIP Origis Solar Project - Transmission
- J473 – 52 MW Solar Generator.
- Point of interconnection: Sumrall – Rawls 69 kV Line
- New 69 kV Switching Station with a 69/26.4 kV GSU
- The Origis Energy solar plant will tap the existing SMEPA 69 kV Line 42 (Sumrall - Rawls Springs) approximately 5.6 miles from Sumrall Sub
- The generation interconnection project is contingent upon the following injection upgrades:
    - Line 42 and 43 (Columbia - Sumrall) will be uprated to a higher conductor temperature via structural change outs to support the generation addition
    - OPGW will also be installed for communications
- Anticipated completion date: March 22, 2017
- Anticipated cost: $4,782,000

MTEP Project 11383 – Cedar Falls Utilities

- Perform Network Upgrades for J329 GIP on Subs in Pella, Iowa.
- J329 - 55 MW Hydro Generator
- Point of interconnection: Pella West 69 kV Sub
- Anticipated completion date: August 1, 2017
- Anticipated cost: $1,043,700

MTEP Project 11463 – Great River Energy

- Perform Network Upgrades for C023 GIP
- C023 – 100 MW Wind Generator
- Point of interconnection: Stanton 230 kV Sub
- Jumper replacement inside Stanton Sub at 230 kV Breaker 31RB3
- Anticipated completion date: November 1, 2016
- Anticipated cost: $33,033

MTEP Project 9937 – International Transmission Co. Transmission Midwest

- Perform Network Upgrades for J233 GIP
- J233 - 635 MW CT Combined-Cycle Combustion Turbine Generator
- Point of interconnection: Marshalltown (Sutherland) 161 kV Sub
- Replace existing 161/69 kV Transformers with 150 MVA units at Fernald, Jasper and Newton Subs
- Uprate the Marshalltown - Blairstown Junction 115 kV line to 90 MVA

- Uprate the Jasper - Laurel 161 kV to 361 MVA
- Remove sag limit from Jasper - Newton 161 kV Line to allow operation at 276 MVA
- Rebuild the ITCM portion of the Newton - Prairie City 69 kV Line with T2-4/0 ACSR to allow operation at the MEC rating of 40 MVA
- Anticipated Completion date: March 30, 2017
- Anticipated Cost: $17,740,415

MTEP Project 9939 – International Transmission Co. Transmission Midwest

- Perform Network Upgrades for H009 GIP
- H009 – 150 MW Wind Generator
- Point of interconnection: Jasper - Aurora Heights 69 kV Line
- Rebuild Jasper - Aurora Heights 69 kV Line with T2-477 ACSR
- Anticipated completion date: December 31, 2016
- Anticipated cost: $3,720,000

MTEP Project 9941 – International Transmission Co. Transmission Midwest

- Perform Network Upgrades for H021 GIP
- H021 – 138.6 MW Wind Generator
- Point of interconnection: Trear – Trear Tap 69 kV Line
- Upgrade the Traer - Trear Tap 69 kV Line
- Completion date: June 1, 2016
- Actual Cost: $293,449

MTEP Project 10867 – MidAmerican Energy Co.

- Perform Network Upgrades for J285 GIP
- J285 – 250 MW Wind Generator
- Point of interconnection: O'Brien County 345 kV Sub
- Add one 345 kV circuit breaker position at the Obrien County Sub 345 kV ring bus
- Completion date: August 15, 2016
- Actual cost: $3,000,000

MTEP Project 10868 – MidAmerican Energy Co.

- Perform Network Upgrades for J411 GIP
- J411 – 250 MW Wind Generator
- Point of interconnection: Raun – Lehigh 345 kV Line
- New 3-terminal 345 kV ring bus Sub (Ida County Sub), bisecting the Raun - Lehigh 345 kV Line
- Install new transposition structures for the Raun - Ida County and Ida County - Lehigh 345 kV Lines (ITCM will have an ownership share of the network transmission facilities)
- Completion date: July 15, 2016
- Actual Cost: $5,750,000

MTEP Project 11103 – MidAmerican Energy Co.

- Install two 69 kV Capacitor Banks at the Black Hawk Sub
- G735 – 200 MW Wind Generator
- Point of interconnection: Lime Creek 161 kV Line
- Add two 69kV, 15 MVAR Capacitor Banks at the Black Hawk 69 kV Sub

- Anticipated completion date: November 15, 2016
- Anticipated cost: $1,180,000

MTEP Project 11143 – MidAmerican Energy Co.

- Perform Network Upgrades on the Creston - Macksburg 161 kV Line
- J274 – 100 MW Wind Generator
- Point of interconnection: Winterset – Creston 161 kV Line
- Structure replacements on the Creston-Macksburg 161 kV Line
- Anticipated completion date: December 1, 2016
- Anticipated cost: $175,000

MTEP Project 11144 – MidAmerican Energy Co.

- Perform Network Upgrades on the Sub T(FD) 161 kV Sw 11-817
- R42 – 250 MW Wind Generator
- Point of interconnection: Lehigh 345 kV Sub
- Replace 161 kV Switch 11-817 at the 161 kV Sub T(FD)
- Completion date: June 24, 2016
- Actual Cost: $88,000

MTEP Project 11145 – MidAmerican Energy Co.

- Perform Network Upgrades on the Sub T FD - Boone Jct 161 kV Line
- R42 – 250 MW Wind Generator
- Point of interconnection: Lehigh 345 kV Sub
- Structure replacements on the Sub T(FD) – Boone Jct 161 kV Line
- Completion date: June 30, 2016
- Actual Cost: $173,000

MTEP Project 11146 – MidAmerican Energy Co.

- Perform Network Upgraders on the Clarinda - Brooks 161 kV Line
- J343 – 150 MW Wind Generator
- Point of interconnection: Creston – Clarinda 161 kV Line
- Structure replacements on the Clarinda - Brooks 161 kV Line
- Anticipated completion date: June 1, 2017
- Anticipated cost: $200,000

MTEP Project 11283 – MidAmerican Energy Co.

- Perform Network Upgrades on the Clarinda - Maryville 161 kV Line
- J343 – 150 MW Wind Generator
- Point of interconnection: Creston – Clarinda 161 kV Line
- Three structure replacements on the Clarinda - Maryville 161 kV Line
- Anticipated completion date: June 1, 2017
- Anticipated cost: $100,100

MTEP Project 11284 – MidAmerican Energy Co.

- Replace 161 kV Switch 803L at the Clarinda 161 kV Sub
- J343 – 150 MW Wind Generator

- Point of interconnection: Creston – Clarinda 161 kV Line
- Install a new 161 kV line disconnect switch at Clarinda 161 kV Sub on the line terminal to Maryville
- Replace associated line drops and jumpers, remove existing switch
- Anticipated completion date: June 1, 2017
- Anticipated cost: $80,500

MTEP Project 11285 – MidAmerican Energy Co.

- Perform Network Upgrades - Beacon 161 kV Sub
- J344 – 169 MW Wind Generator
- Point of interconnection: Poweshiek - Oskaloosa 161 kV Line
- Replace the line drops at the Beacon 161 kV Sub on the Beacon – Poweshiek 161 kV Line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $25,000

MTEP Project 11763 – International Transmission Co. - Midwest

- Perform Network Upgrades – Irvine Switch
- J344 – 169 MW Wind Generator
- Point of interconnection: Poweshiek - Oskaloosa 161 kV Line
- New 3-Terminal, 3-Breaker Irvine ring bus Sub on the Poweshiek – Beacon 161 kV Line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $5,537,540

MTEP Project 11043 – International Transmission Co. - Transmission

- Perform modifications at Monroe for the Lallendorf GIP
- PJM-Y1-069 799 MW Gas Generator in First Energy
- Point of interconnection: Northern Ohio 345 kV Line
- Perform relay modifications and install a new wave trap at Monroe
- Completion date: April 1, 2016
- Actual cost: $250,000

MTEP Project 11583 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J308 GIP
- J301 – 101 MW Wind Generator
- Point of interconnection: Bauer – Rapson 345 kV Line
- New 345kV, 3 Breaker Sub fed by Looping the Bauer – Ringle 345 kV Line
- Anticipated completion date: September 1, 2017
- Anticipated cost: $9,497,000

MTEP Project 11584 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J308 GIP
- J308 – 301 MW Wind Generator
- Point of interconnection: Rapson – Banner 345 kV Line
- New 345kV, 3 Breaker Sub with Relay Upgrades
- 0.1 Miles of Double Circuit 345 kV Line to the new Sub, tapping Greenwood – Rapson 345 kV Line

- Anticipated completion date: September 1, 2017
- Anticipated cost: $9,421,000

MTEP Project 11603 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J321 GIP
- J321 – 151.2 MW Wind Generator
- Point of interconnection: Rapson – Banner 345 kV Line
- New 345kV, 3 Breaker Sub in a Ring Bus configuration
- Loop Greenwood – Rapson #2 345 kV Line into the new Sub
- Anticipated completion date: September 1, 2017
- Anticipated cost: $9,366,000

MTEP Project 11604 – International Transmission Co. - Transmission

- Perform Network Upgrades and TOIFs for J419 GIP
- J419 – 100 MW Solar Generator
- Point of interconnection: Milan 120 kV Substation
- Install a 120 kV Breaker with associated disconnects at Milan Substation
- Extend bus 103
- Anticipated completion date: June 30, 2018
- Anticipated cost: $803,000

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).

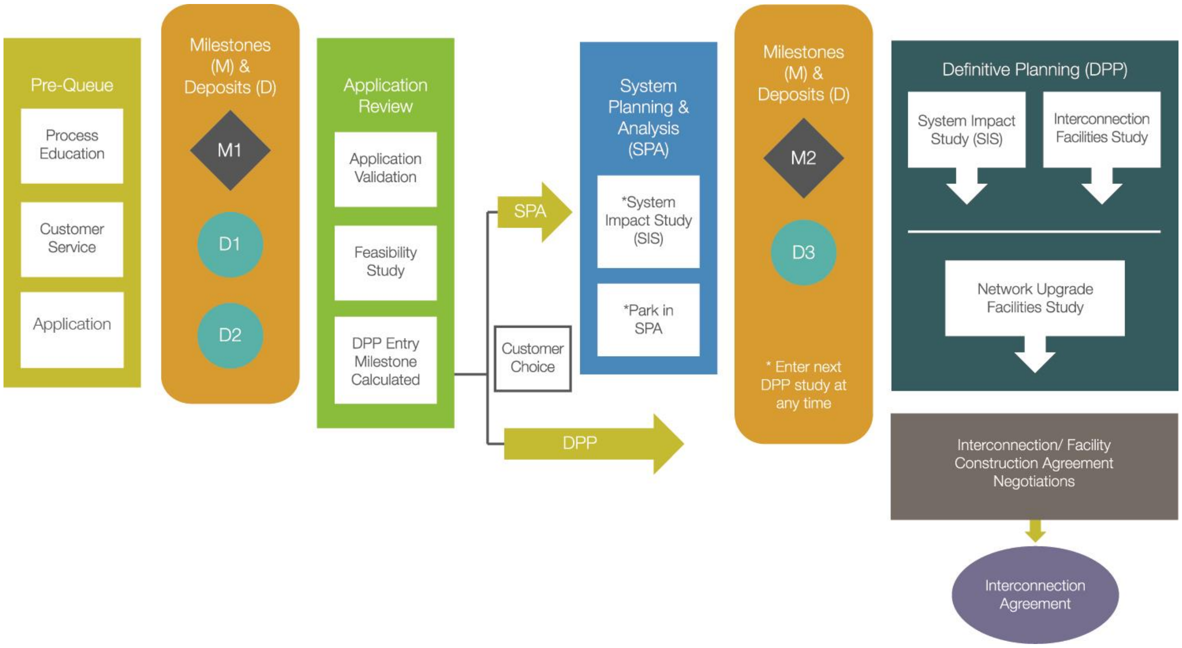


Figure 4.2-2: Generator Interconnection Queue Process

Since the beginning of the queue process, MISO and its Transmission Owners have received approximately 1,734 generator interconnection requests totaling 343GW (Figures 4.2-3 and 4.2-4). Among them, 56 GW out of the 343 GW or 16 percent 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.

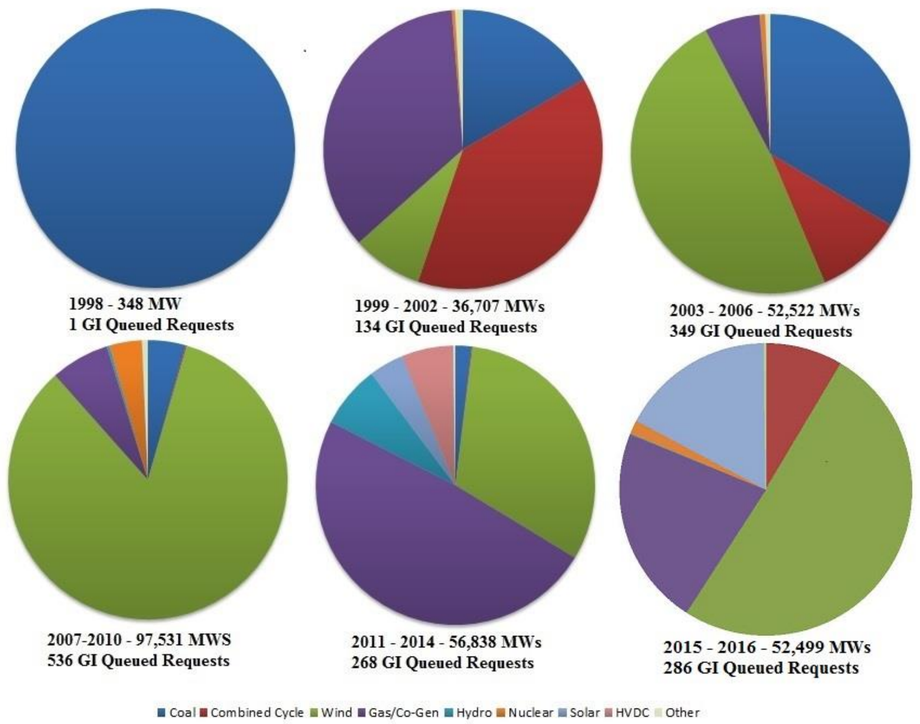


Figure 4.2-3: Queue trends

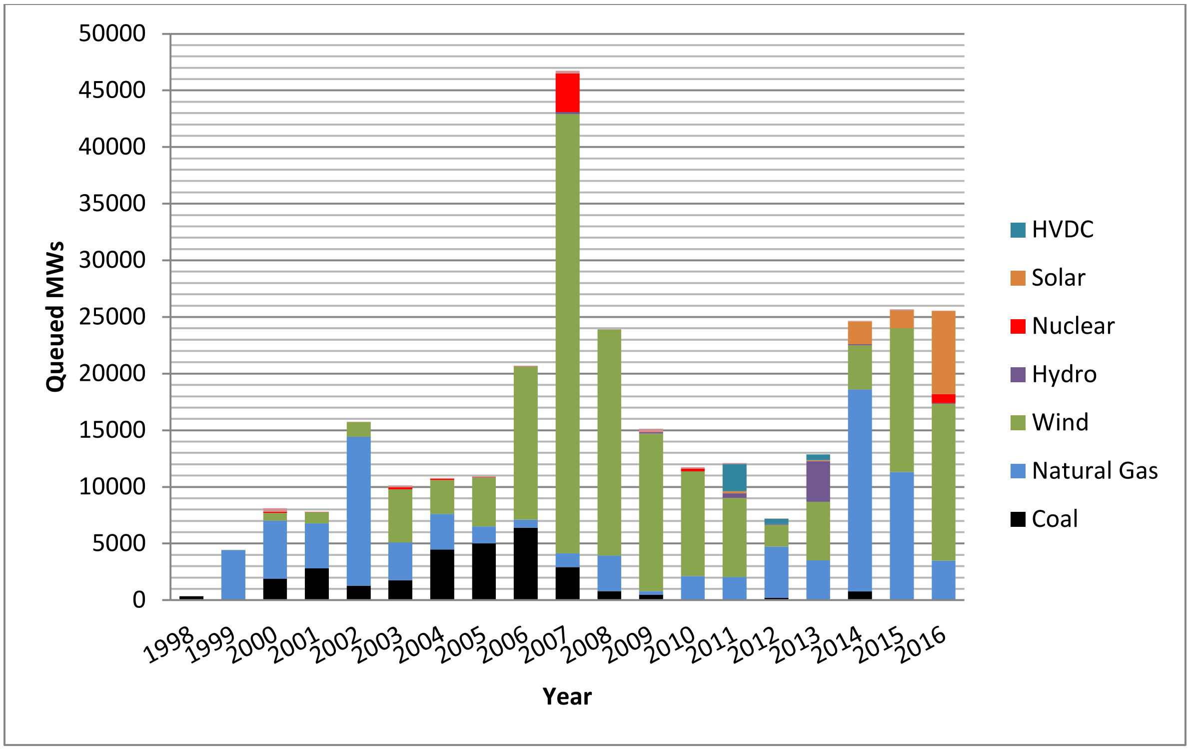


Figure 4.2- 4: Queue Trends

Renewable Portfolio Standards (RPS) have become more common since the late 1990s. Although there is no RPS program in place at the national level, 29 states and the District of Columbia had enforceable RPS or other mandated renewable capacity policies. In addition, eight states adopted voluntary renewable energy standards. Between 2005 and 2008, 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).

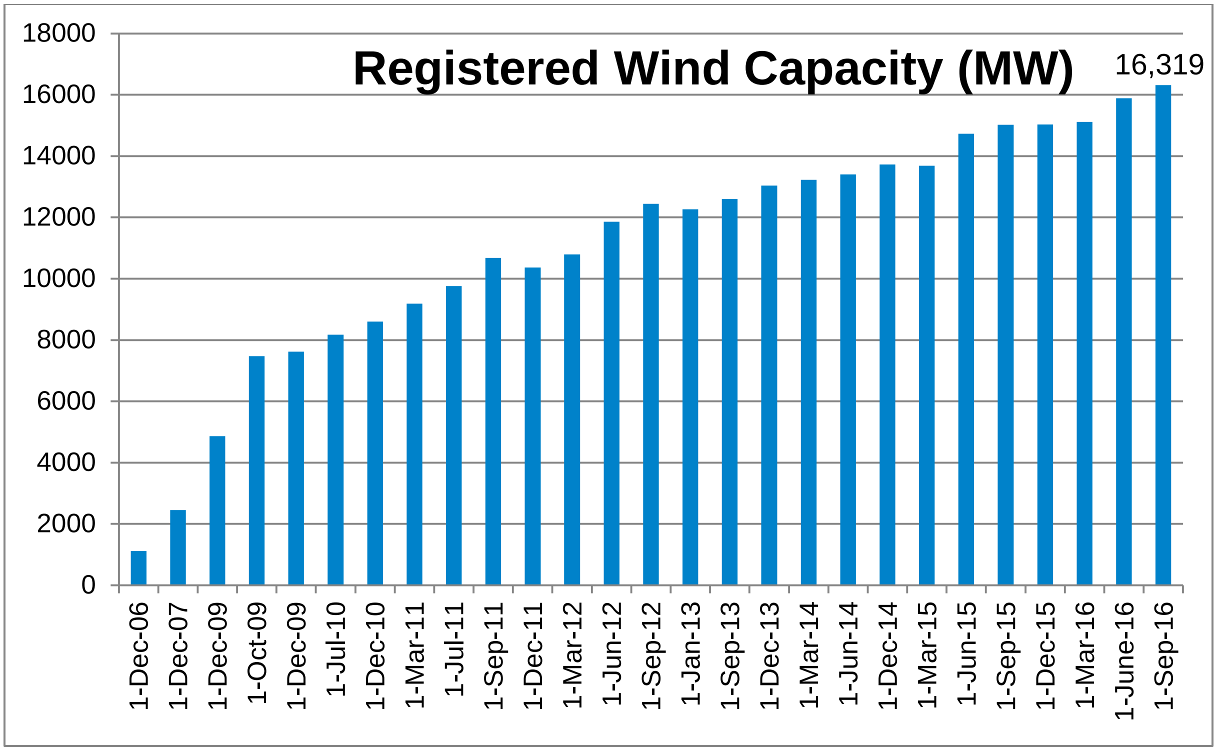


Figure 4.2-5: Nameplate Wind Capacity Registered for MISO

As a result of the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) and its compliance requirements, MISO's generator interconnection queue has seen fluctuating in natural gas interconnection requests (Table 4.2-3). Data corresponding to year 2016 only includes natural gas requests for the first three quarters.

Year	Gas Requests (MW)	% Of All New Requests
2016	4,472*	4.2%
2015	9,076	35%
2014	9,424	58%
2013	3,835	30%
2012	4,509	63%

*Natural Gas MW requested as of October 2016

Table 4.2-3: Recent-year Natural Gas Requests

Furthermore, there are about 2.5 GW of solar generation interconnection in definitive planning phase (DPP) as of August 2016. This could be the result of recent federal energy legislation and the economic stimulus package, and lower prices of solar photovoltaic (PV) modules.

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 Interconnection 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 TPL-001-4 standards
- Consistency in the planning model
- Attachment Y process coordination
- Interconnection study timeline improvement
- Seams coordination
- Continuing to streamline the 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. 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 to system reliability taking into account the deliverability of network resources in the MISO footprint. Short-term TSRs (less than one year) are evaluated based on the real-time AFC values 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 July 2015 to June 2016, MISO Transmission Service Planning processed 219 long-term TSRs (Figure 4.3-1) and completed 16 System Impact Studies for a total of 17 TSRs. Of these System Impact Studies, five TSRs were confirmed, one was refused, none executed a Facilities Study Agreement and 11 await the completion of a corresponding external Affected System Impact Studies. Remainders of TSRs were either rollover TSRs or had the same point-of-receipt/point-of-delivery Local Balancing Authority, which don't require a system impact study.

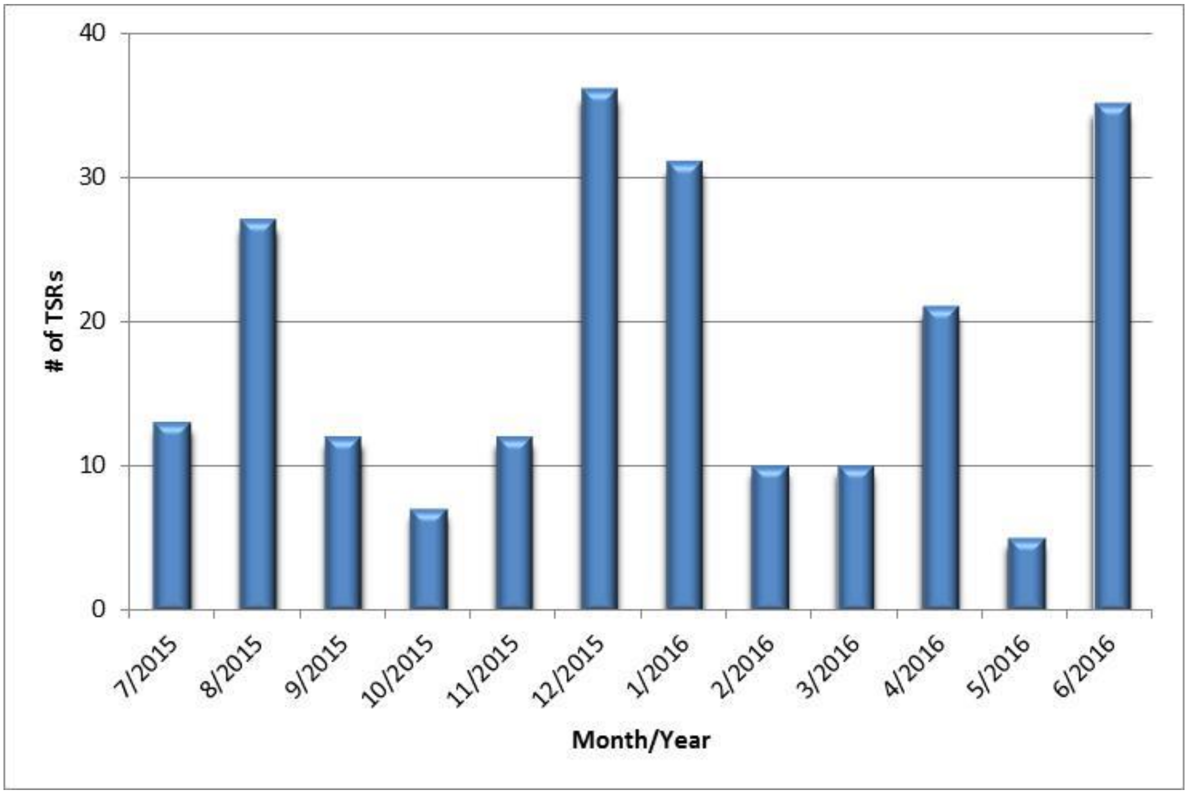


Figure 4.3-1: MISO Long-Term TSRs processed from July 2015 through June 2016

Long-term TSRs processed and evaluated by MISO planning staff are either Firm Point-to-Point or Network Transmission Service. 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 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 have a term of less than one year and can be firm or non-firm. Established MISO tools review 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.

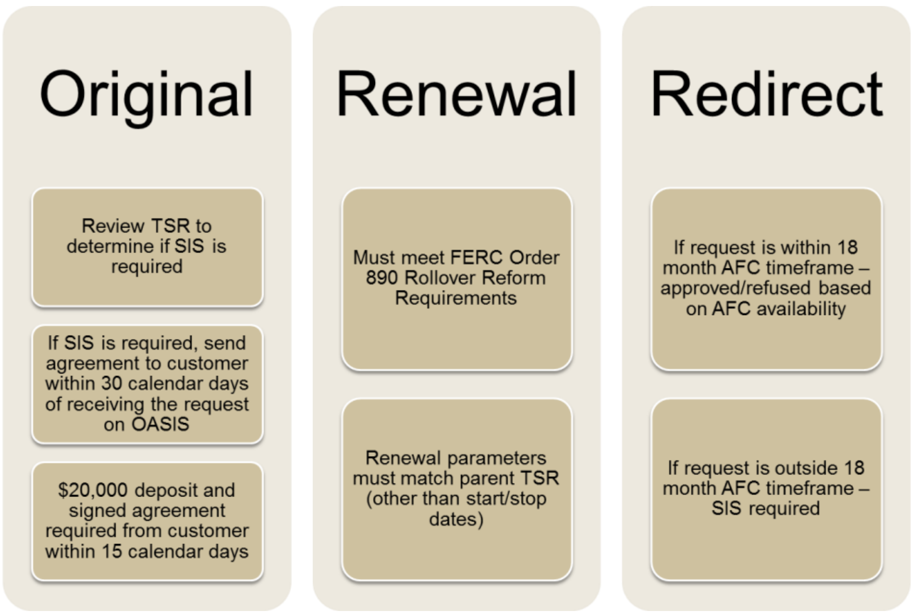


Figure 4.3-2: TSR Triage Phase Processing

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 and the customer choses to move forward with the TSR.

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, SPP and Joint Parties reached a settlement that was subsequently filed with FERC in October 2015. The settlement provisions regulate the firm and non-firm utilization of the MISO North – MISO South contractual path from the date of acceptance of the settlement by FERC. The settlement was accepted by FERC in January 2016.

MISO instituted a contract path limit in TSR studies (in addition to the flow-based limitations) for the TSRs going across the MISO South-MISO North interface in both directions. An OASIS document has been posted to list out the latest contract path limit and the source sink combinations that are restricted. This document will be updated as/when the contract path rating is updated in future.

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 provides a mechanism to ensure Transmission System reliability in response to the retirement or suspension of a generation resource.

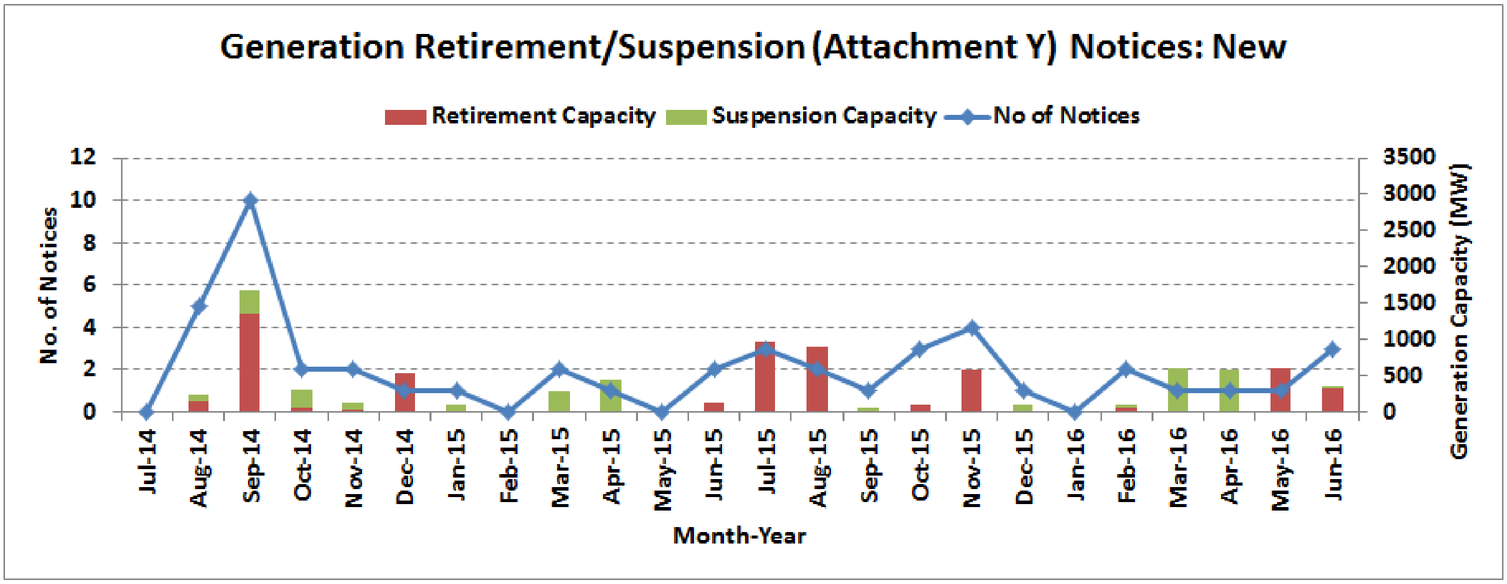
The MISO Attachment Y provides a mechanism to ensure Transmission System reliability in response to the retirement or suspension of a generation resource

Under the Tariff provisions, MISO may require the asset 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 or 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 received eight Attachment Y Notices (2,288 MW) for unit retirement/suspension during the first six months of 2016 (Figure 4.4-1). In the same period (January-June) in 2015 MISO received six Attachment Y retirement/suspension notices (964 MW) (Figure 4.4-1). MISO completed assessments and resolved nine Attachment Y Notices (2,081 MW) for unit retirement/suspension in the first six months of 2016 (Fig 4.4-2).

Attachment Y activity remains fairly consistent over the year as asset owners move forward in the face of economic and pending regulatory pressures despite uncertainty in policy implementation. The activity is expected to continue at a regular pace as implementation plans become more clearly defined.



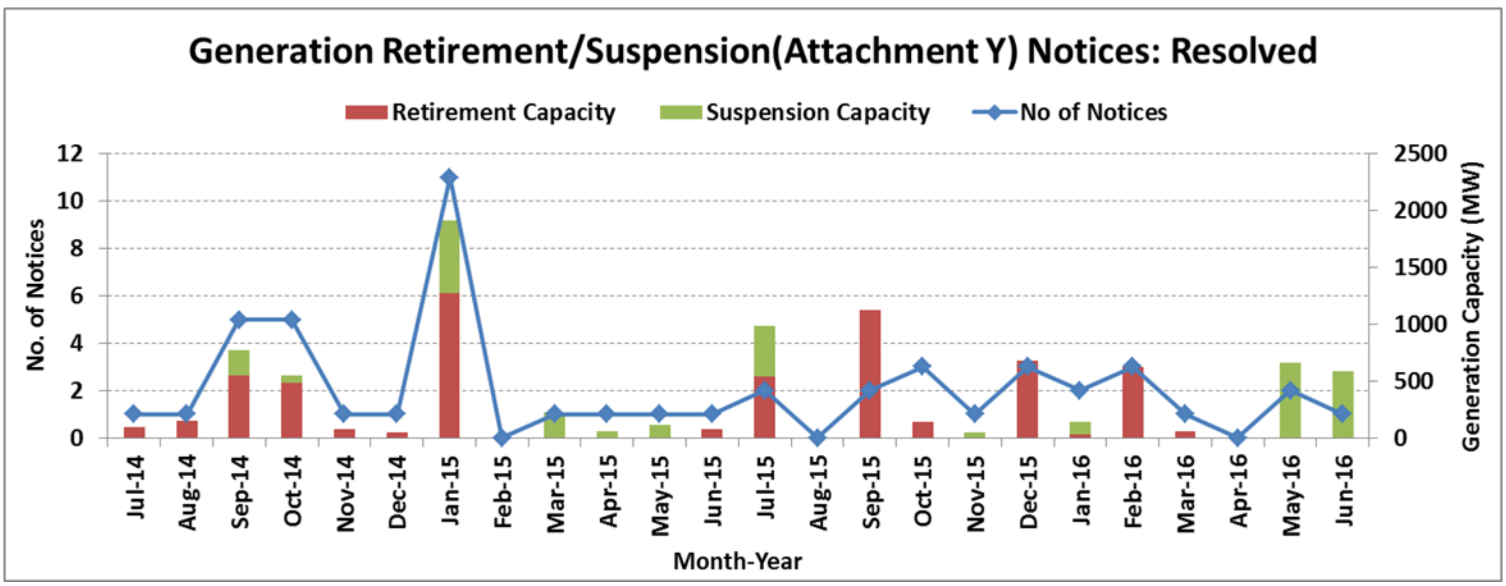


Figure 4.4-1: Generation Retirement/Suspension (Attachment Y) Notices – new and resolved

Overall, 4,847 MW of generation capacity is retiring in 2016 and an additional 69 MW of generation capacity will retire in 2017 (Figure 4.4-2). This includes 3,068 MW of coal generation, 1,722 MW of gas generation and 57 MW of diesel/biomass generation that is approved for retirement in 2016 and 69 MW of coal generation in 2017. The data suggests that majority of retirements in 2016 are related to compliance with the Mercury and Air Toxics Standards.

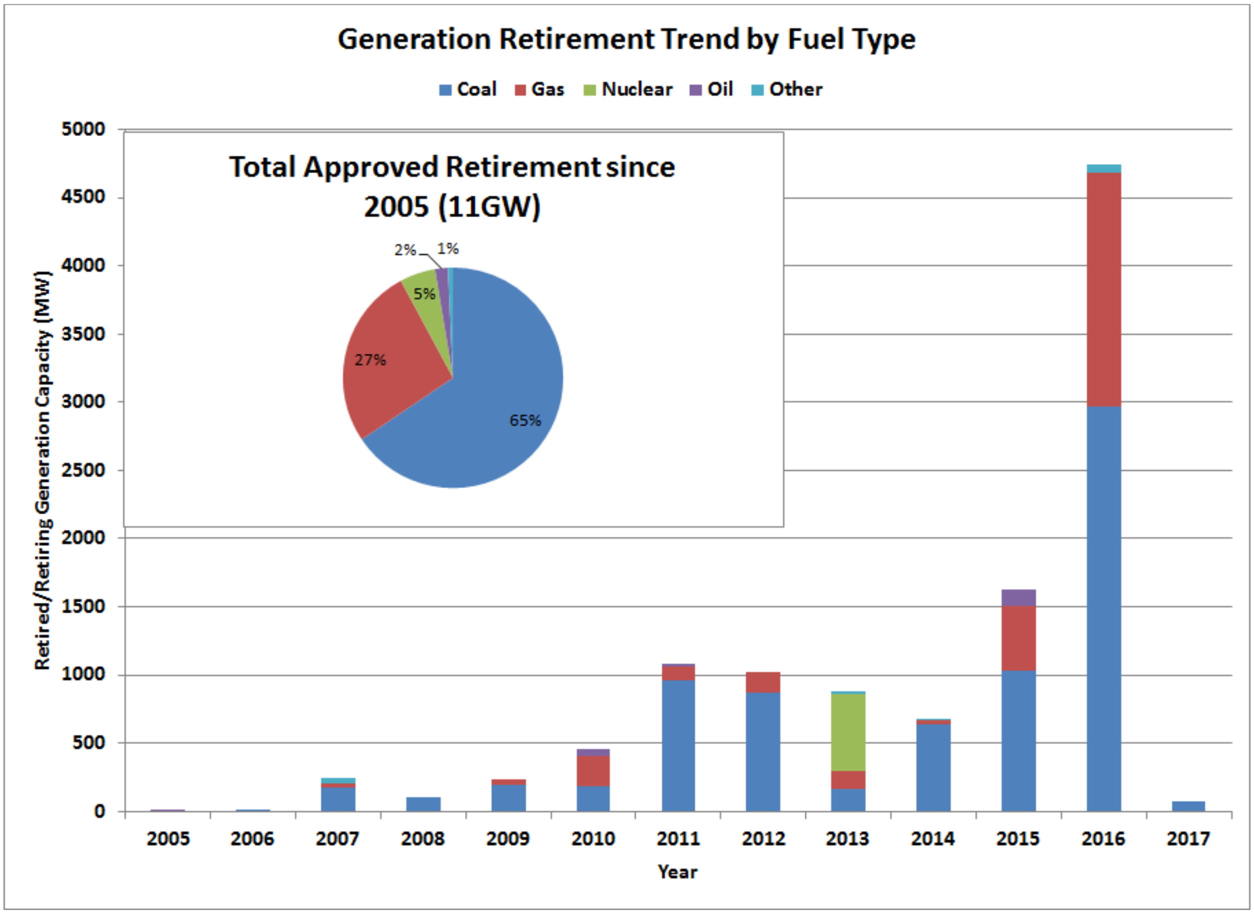


Figure 4.4-2: Generation capacity (aggregate MW) approved for retirement

2016 FERC Order on Cost Allocation

In May 2016, FERC issued an order accepting the new cost allocation method developed by MISO that assigns cost responsibility to the load-serving entities (LSE) whose loads benefit from the operation of the SSR unit. FERC directed MISO to file a plan to re-allocate costs previously assigned under the SSR Agreements for Escanaba 1 & 2, Presque Isle 5-9, White Pine 1 and White Pine 2.

SSR Agreement Activity

Since the inception of the SSR program in 2005, MISO has implemented nine SSR Agreements with only one agreement remaining active for White Pine Unit 1.

White Pine 1 (20 MW) – The owner of the White Pine plant in the Upper Peninsula of Michigan requested to retire Unit 1 on April 16, 2014, and MISO determined that White Pine Unit 1 is needed as an SSR unit until projects are implemented in the 2019 to 2022 timeframe. The initial term of the SSR Agreement was established for April 16, 2014, to April 15, 2015 and recently was renewed for a third term from April 16, 2016 to April 15, 2017. In July 2016, a transmission reconfiguration plan was proposed as an alternative to the SSR Agreement and determined to be an acceptable solution to allow the retirement of White Pine Unit 1. MISO filed with FERC to terminate the White Pine Unit 1 SSR Agreement effective November 26, 2016.

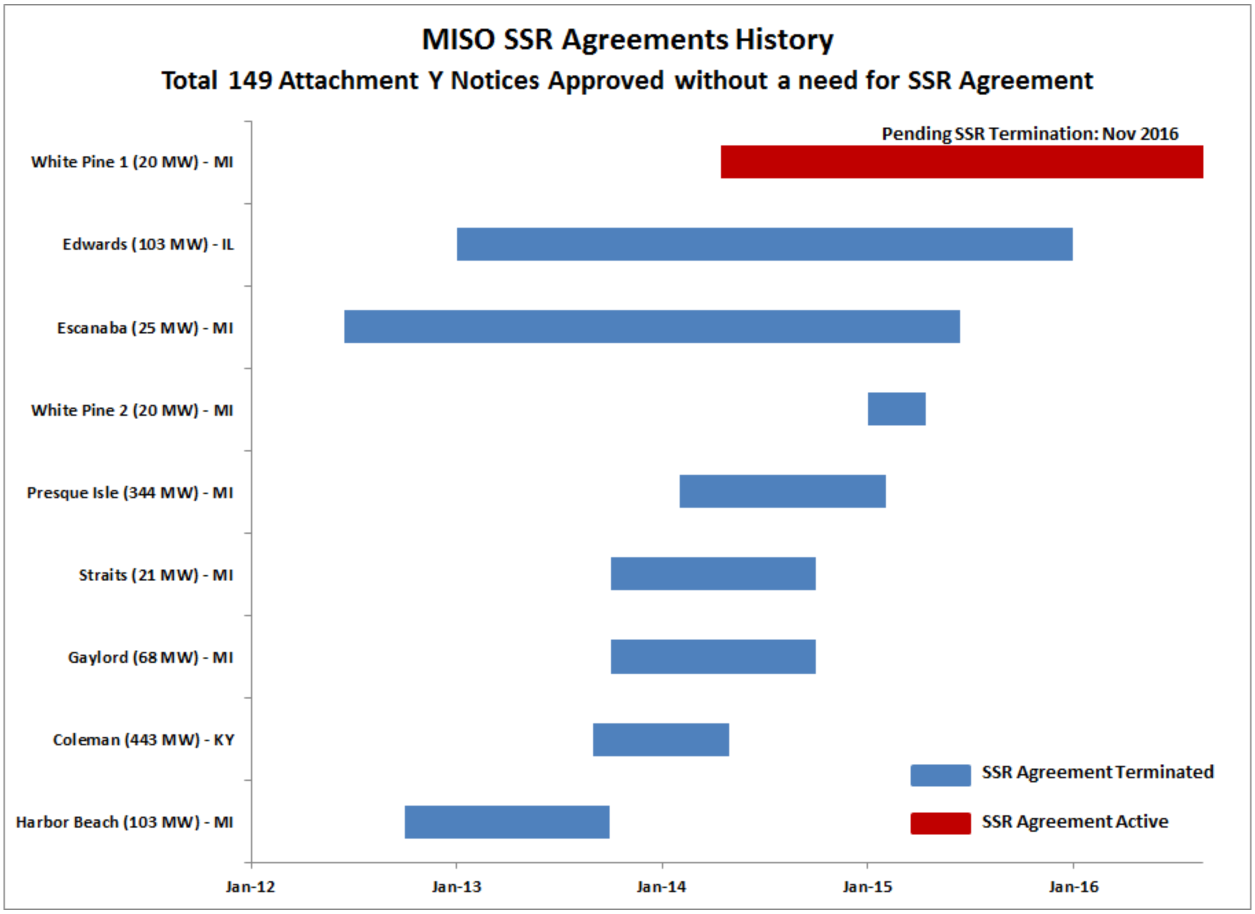


Figure 4.4-3: SSR History

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 4.4-4). 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 Y 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 violations of reliability criteria that require the need for the SSR Unit., 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 or the owner has otherwise publicly disclosed the information.

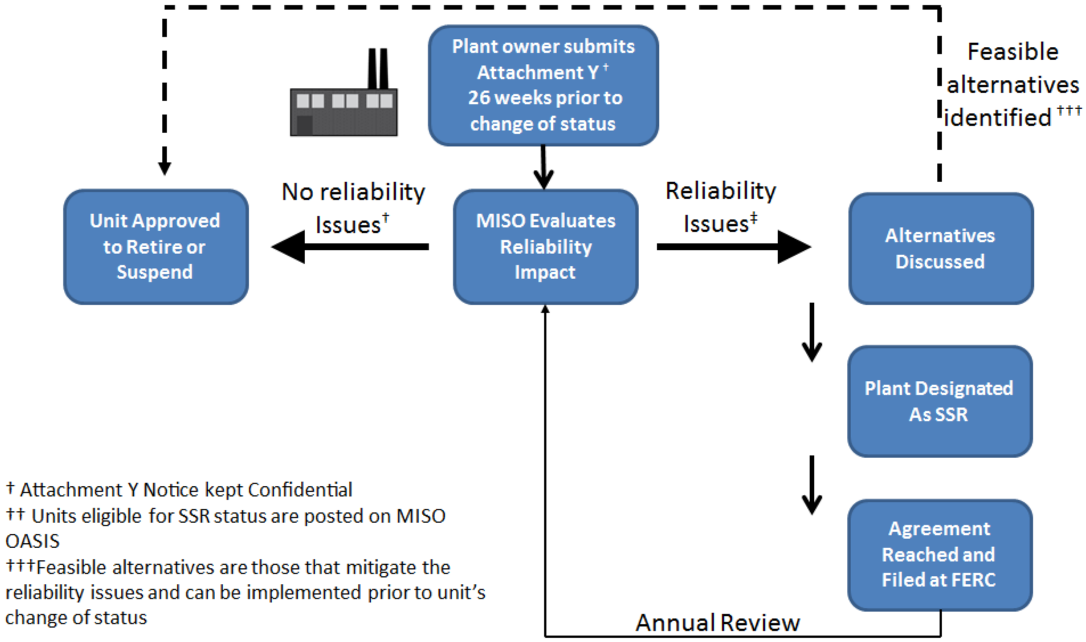


Figure 4.4-4: MISO Attachment Y process

4.5 Generator Deliverability Analysis

MISO performs generator deliverability analysis as a part of the MTEP16 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 4,400 MW of deliverability is restricted due to constraints in the MTEP16 near-term scenario. This level is reduced to about 1,800 MW when longer term planned solutions through 2026 are considered. Constraints observed that are restricting generation beyond the established network resource amounts will be mitigated, with constraints with identified mitigation (Figure 4.5-1).

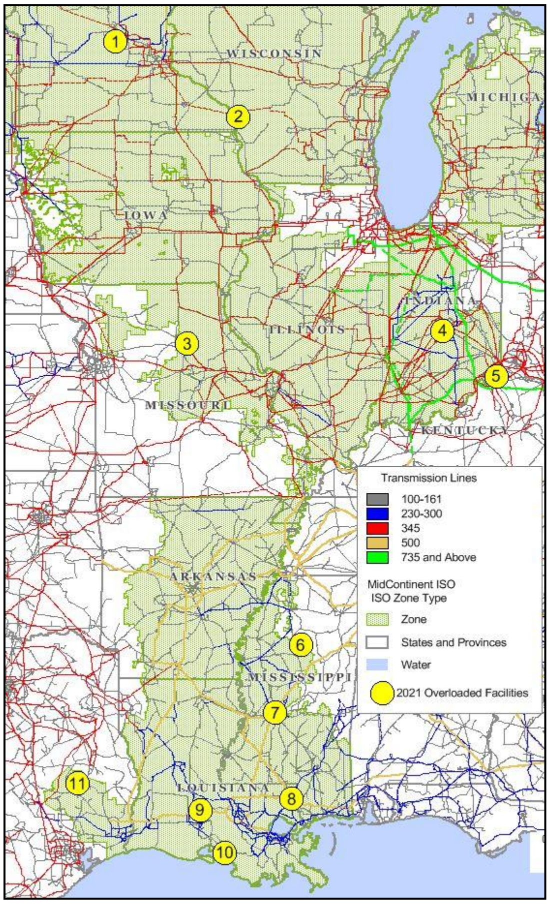


Figure 4.5-1: MTEP16 2021 generator deliverability constraints with defined mitigation

This analysis revealed 18 constraints that restrict existing deliverable amounts (Table 4.5-1) in the 2021 scenario with four constraints with identified mitigation. Mitigation for other constraints are being identified and will be included in MTEP17, as appropriate. 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
Markland 138 kV - He Belle Terra 138 kV	DEI	5	Yes	10.6
Stout CT 138 kV - Stout North 138 kV	IPL	4	Yes	12.08
Ray Braswell SES 500 kV - Franklin 500 kV	EES-EMI	7		3065.67
Miami Street 115 kV - Monument Street 115 kV	EES-EMI	7		36.19
Rex Brown 115 kV - Monument Street 115 kV	EES-EMI	7		197.66
Grenada South 115 kV - Elliot 115 kV	EES-EMI	6		106.44
Magnolia Groveton 138 kV - Staley 138 kV	EES	11		99
Bogalusa 500 kV - Adams Creek 230 kV	EES	8		2224.65
Horner 69 kV - Sinnock 69 kV	AMMO	3		1.07
Bayou Sale 138 kV - WaxLake 138 kV	CLEC	10		169.91
Coughlin 138 kV - Plaisance 138 kV	CLEC	9	Yes	511.83
Teche 138 kV - Bayou Sale 138 kV	CLEC	10		277.25
WaxLake 138 kV - El Paso Tap 138 kV	CLEC	10		65.02
La Crosse 69.0 kV - West Salem 69.0 kV	XEL	2	Yes	31.13
Franklin 500 kV - Bogalusa 500 kV	EES-EMI	8		4684.58
Plaisance 138 kV - Champagne 138 kV	EES-CLEC	9		42.97
Maple Lake 69 kV - Annandale 69 kV	GRE	1		3.96
Lakeover 500 kV - Lakeover 115 kV	EES-EMI	7		120.22

Table 4.5-1: MTEP16 Near-term constraints that limit deliverability of about 4,400 MW of network resources

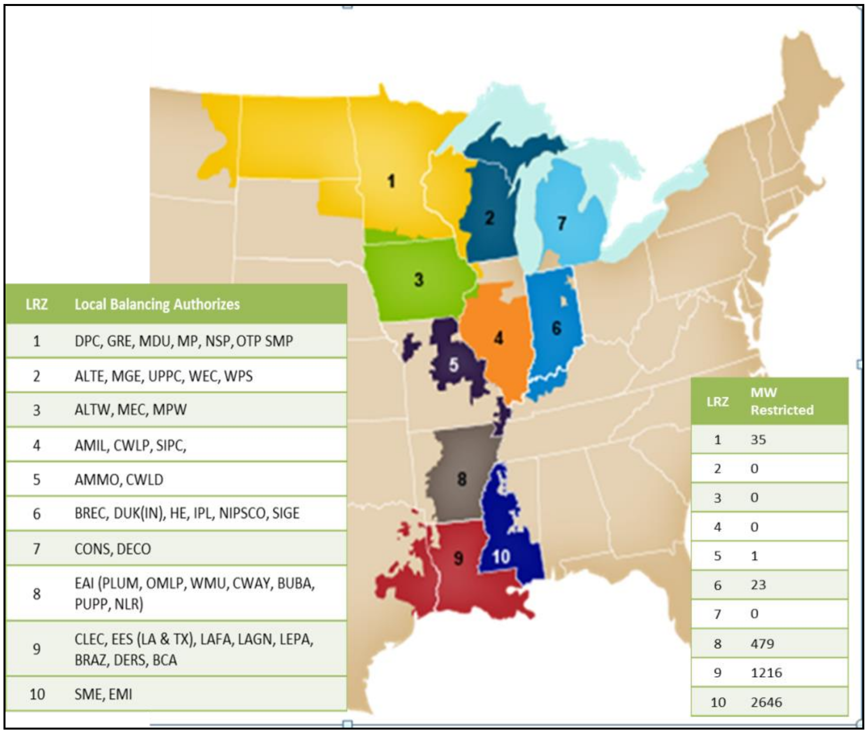
Additional 2026 constraints will be monitored in future MTEP studies to determine if mitigation is required through the MTEP generator deliverability process. Appendix D6 lists detailed results for the 2026 constraints and impacted NRIS projects.

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[17] 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 recognized as needing mitigation were identified in the near-term 2021 planning scenarios, or as a recurring constraint in the long-term planning scenario. Deliverability was tested only up to the granted network resource levels of the existing and future network resource units modeled in the MTEP16 2021 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.

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



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	MW Restricted
1	35
2	0
3	0
4	0
5	1
6	23
7	0
8	479
9	1216
10	2646

Figure 4.5-3: Local Resource Zones (LRZ)

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

Since MTEP09, MISO has performed annual generator deliverability studies to better monitor the restricted megawatts and Network Resources. The 4,400 MW of restricted deliverability from MTEP16 compares to 4,100 MW in MTEP15, 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).

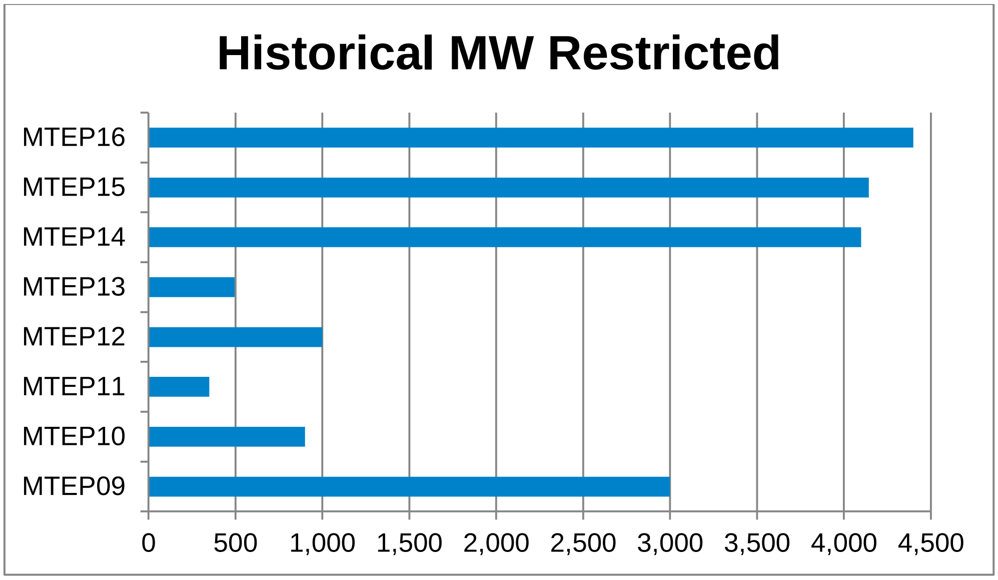


Figure 4.5-4: Restricted MW identified through MTEP cycles

The analysis of the 2026 scenario revealed 48 constraints that restrict existing deliverable amounts (Table 4.5-2) with 10 constraints requiring mitigation. Six of the 10 constraints were observed in the near-term 2021 scenario, in which mitigation was requested. The other four constraints are observed in last year's long-term (10-year-out) scenario, and therefore would require mitigation to resolve this repetitive overload. MTEP projects will be created for the mitigation required to alleviate the constraints identified.

To understand Table 4.5-2:

- "Area Name" is the Transmission Owner of the facility
- "Overload Branch" is caused by bottling-up of aggregate deliverable generation
- "2021 Constraint" shows if the overloaded branch also existed in MTEP16 near-term (five-year) results
- "Mitigation Identified" represents constraints with identified mitigation. Mitigation will also be evaluated for the remaining 2021 constraints shown in the table

Area Name	Overload Branch	2021 Constraint	Mitigation Identified
DEI	Markland 138 kV - He Belle Terra 138 kV	Yes	Yes
IPL	Stout CT 138 kV - Stout North 138 kV	Yes	Yes
EES-EMI	Ray Braswell SES 500 kV - Franklin 500 kV	Yes	
EES-EMI	Miami Street 115 kV - Monument Street 115 kV	Yes	
EES-EMI	Rex Brown 115 kV - Monument Street 115 kV	Yes	

Area Name	Overload Branch	2021 Constraint	Mitigation Identified
EES-EMI	Grenada South 115 kV - Elliot 115 kV	Yes	
EES	Magnolia Groveton 138 kV - Staley 138 kV	Yes	
EES	Bogalusa 500 kV - Adams Creek 230 kV	Yes	
AMMO	Horner 69 kV - Sinnock 69 kV	Yes	
CLEC	Bayou Sale 138 kV - WaxLake 138 kV	Yes	
CLEC	Coughlin 138 kV - Plaisance 138 kV	Yes	Yes
CLEC	Teche 138 kV - Bayou Sale 138 kV	Yes	
CLEC	WaxLake 138 kV - El Paso Tap 138 kV	Yes	
XEL	La Crosse 69.0 kV - West Salem 69.0 kV	Yes	Yes
EES-EMI	Franklin 500 kV - Bogalusa 500 kV	Yes	
EES-CLEC	Plaisance 138 kV - Champagne 138 kV	Yes	
GRE	Maple Lake 69 kV - Annandale 69 kV	Yes	
EES-EMI	Lakeover 500 kV- Lakeover 115 kV	Yes	
DEO&K	Todd Hunter 345 kV - Todd Hunter 138 kV (15)	No	
DPC	Lublin Tap 69 kV - Lakehead 69 kV	No	
DPC	Rochester 161 kV - Wabaco 161 kV	No	
EES	Little Gypsy 115 kV - Claytonia 161 kV	No	
EES-EMI	Batesville 230 kV - Batesville 115 kV	No	
LGEE	Ghent 138 kV - North American Stainless 138 kV	No	
METC	Campbell 138 kV - Northern Fibre 138 kV	No	
METC	Lewiston 69.0 kV - Atlanta Distribution 69.0 kV	No	
METC	Gaylord OCB 69.0 kV - Johannesburg Jct 69.0 kV	No	
METC	Johannesburg Jct 69.0 kV - Lewiston 69.0 kV	No	
MP	Substation 16L Tap 115 kV - Cotton Tap 115 kV	No	
MP	Cotton Tap 115 kV - Bergen Lake Tap 115 kV	No	
SIGE	Northwest 69 kV - Pigeon Creek 69 kV	No	
SIPC	Grassy 69.0 kV - Hastings 69.0 kV	No	
SIPC	Marion Power Plant 69.0 kV - Grassy 69.0 kV	No	
SIPC	Marion Power Plant 69.0 kV -	No	
SIPC	Marion Power Plant 69.0 kV - Double Circuit 69.0 kV	No	
SIPC	Double Circuit 69.0 kV - Creal Springs 69.0 kV	No	
SMEPA	Prentiss 161 kV - Prentiss 69 kV	No	
TVA	Batesville 115 kV - Star 115 kV	No	
TVA	Star 115 kV - Batesville 161 kV	No	
UPPC	Victoria Falls 69 kV - Rockland Jct 2	No	
UPPC	Victoria Falls 69 kV - Rockland Jct 1	No	
UPPC	Rockland Jct 2 69 kV - Rockland 69 kV	No	
UPPC	Rockland Jct 1 69 kV - UPPS Co 69 kV	No	
UPPC/MIUP	Rockland 69 kV - MASS 69 kV	No	

Area Name	Overload Branch	2021 Constraint	Mitigation Identified
XEL	Black Dog 115 kV - Wilson Tap 115 kV	No	
XEL	Henderson 69 kV - Jessen Land 69 kV	No	
XEL	Winthrop 69.0 kV - Winthrop 69.0 kV	No	
XEL	Eagle Lake 69.0 kV - Jamestown Tap 69.0 kV	No	
XEL	Kelso Switching Station 69.0 kV - Henderson 69.0 kV	No	
XEL	Fort Ridgly 69 kV - Schiling Tap 69 kV	No	
XEL	Johnson Tap 69 kV - Penelope 69 kV	No	
XEL	Eagle Lake 69.0 kV - Eagle Lake 69.0 kV	No	
XEL	Traverse 69 kV - New Sweden Tap 69 kV	No	
XEL	Lake Marion Tap 69 kV - ELKO 69 kV	No	
ALTW	Burlington - South Burlington 69 kV	No	
ALTW	4th Street - Agency 69 kV	No	
ALTW	South Burlington - 4th Street 69 kV	No	
CE	Wemple Town 345 - Wemple town 138 kV	No	
CE	Wemple Town 138 - Wemple town 138 kV	No	

Table 4.5-2: MTEP16 long-term constraints that limit deliverability of about 1,800 MW of Network Resources

MTEP16 Mitigation

MTEP16 near-term (five-year) summer peak deliverability analysis results showed four constraints that require mitigation as previously seen in table 4.5-1. Mitigation was submitted for each of these constraint to alleviate limitation. Table 4.5-3 shows the project provided for each of the four constraints requiring mitigation.

Overloaded Branch	Area	Mitigation Required	MW Restricted	Mitigation (MTEP ID)
Markland 138 kV - He Belle Terra 138 kV	DEI	Yes	10.6	7961
Stout CT 138 kV - Stout North 138 kV	IPL	Yes	12.08	11523
Coughlin 138 kV - Plaisance 138 kV	CLEC	Yes	511.83	9716
La Crosse 69.0 kV - West Salem 69.0 kV	XEL	Yes	31.13	TBD

Table 4.5-3: MTEP16 projects submitted to alleviate constraints that limit deliverability of Network Resources[18]

.

[18] **Note:** Any mitigation stated as (TBD), already has verbal mitigation submitted and its project submission is pending at this moment

MTEP15 Mitigation

MTEP15 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.

Table 4.5-4 shows projects submitted to alleviate constraints observed in MTEP15 results.

Overloaded Branch	Area	MW Restricted	Mitigation (MTEP ID)
Nelson – Michigan 230 kV	351 EES	1034.8	10008
Verdine – PPG 230 kV	351 EES	1034.8	10008
Grimes – Mt. Zion 138 kV	351 EES	98.19	9852
Grimes 345/138 kV transformer - 2	351 EES	93.88	9852
Grimes 345/138 kV transformer - 1	351 EES	84.69	9852
Mt. Zion – Line 558 Tap 138 kV	351 EES	28.71	9852
Tubular – Dobbin 138 kV	351 EES	22.73	9821
Grimes – Bentwater 138 kV	351 EES	15.11	9852
Cahokia 345 kV Bus 1 – Cahokia 138 kV Bus 4	357 AMIL	257.88	9719

Table 4.5-4: MTEP15 projects submitted to alleviate constraints that limit deliverability of Network Resources

Proposed Changes for MTEP17

MTEP17 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.

Changes proposed for MTEP17 are:

- 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 MTEP16 and previous years the TSRs were included in the base case. Mitigation was not directly identified within Baseline Generator Deliverability process. In MTEP17 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 a 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 MTEP16, 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 MTEP17 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 are dispatched in merit order to serve LBA network load. The base dispatch will be adjusted to model all Network Resources at the same percentage of output, to the extent that all of the Network Resources are not dispatched in the starting case. 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 evaluates 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 to resolve this infeasibility.

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

MISO details the financial uplift associated with infeasible LTTRs for its 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.

For 2016-2017 planning year, the total LTTR payment is $351 million. The LTTR infeasibility uplift ratio is 3.97 percent (Table 4.6-1).

Region	Total Stage1A (GW)	Total LTTR Payment ($M) (including infeasible uplift)	Total Infeasible Uplift ($M)	Uplift Ratio
MISO-wide	440.6	$351	$13.9	3.97%

Table 4.6-1: Uplift costs associated with infeasible LTTR in the 2016 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 MTEP16 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

Constraint	Summer 2016	Fall 2016	Winter 2016	Spring 2017	Grand Total	Planned Mitigation
ANO-PLEASANT HILLS 500 FLO ANO-MABELVALE 500	$175,232.84	$193,371.55	$286,966.89	$644,074.33	$1,299,645.61	P8041: Upgrade Terminal Equipment; ISD May 10, 2017
SHRAM TAP-MIDWAY 138 FLO KINCAID-PANA-COFFEEN 345+KINCAID UNIT 1-SPS	$178,756.93	$283,092.69	$137,608.28	$198,315.15	$797,773.05	P7846, MTEP16 Target B; ISD June 2018
Bush-Lafayette 138 FLO WESTWOOD-CONCORD-SOUTHEAST 138	$-	$-	$112,419.02	$602,281.87	$714,700.89	
MARBLEHEAD N 161/138 kV T1 FLO MEPPEN-S QUINCY 138	$231,718.31	$421,243.83	$-	$-	$652,962.14	
REYNOLDS-MAGNET 138 kV FLO DEQUINE-WESTWOOD 345 1	$-	$563,339.29	$-	$-	$563,339.29	
NEWTON-ROBINSON 138 FLO NEWTON-CASEY W 345	$453,431.24	$-	$-	$-	$453,431.24	P7800, MTEP15 Appendix A; ISD December 2015
E QUINCY-HAMILTON 138 FLO PALMYRA - MARBLEHEAD N 161	$192,186.54	$141,958.86	$46,256.61	$42,375.22	$422,777.23	P9736, MTEP16 Target A; ISD May 2016
NEWTON 345/138 kV TR 1 FLO NEWTON-CASEY W 345	$-	$-	$365,348.01	$-	$365,348.01	P9724, Appendix B; ISD June 2018

Constraint	Summer 2016	Fall 2016	Winter 2016	Spring 2017	Grand Total	Planned Mitigation
LAYFIELD - HARTBURG 500 FLO GRIMES - CROCKET 345	$182,589.25	$93,491.89	$807.28	$27,099.91	$303,988.33	Stability limit increased to 1,525 MVA in March 2016
EUGENE - CAYUGA 345 FLO ROCKPORT-JEFFERSON 765	$-	$-	$-	$230,381.09	$230,381.09	
GRIMES - MT ZION 138 FLO ELDORADO - MT OLIVE 500	$55,995.24	$-	$14,523.58	$129,600.30	$200,119.12	10487: Western Region Economic Project; ISD June 2020

Table 4.6-2: Infeasible Uplift Breakdown by Binding Constraints from the 2016 Annual FTR Auction

Chapter 5

Economic Analysis

2016

5.1 Economic Analysis Introduction

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 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 per year to meet renewable energy mandates and goals.[19]

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).

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

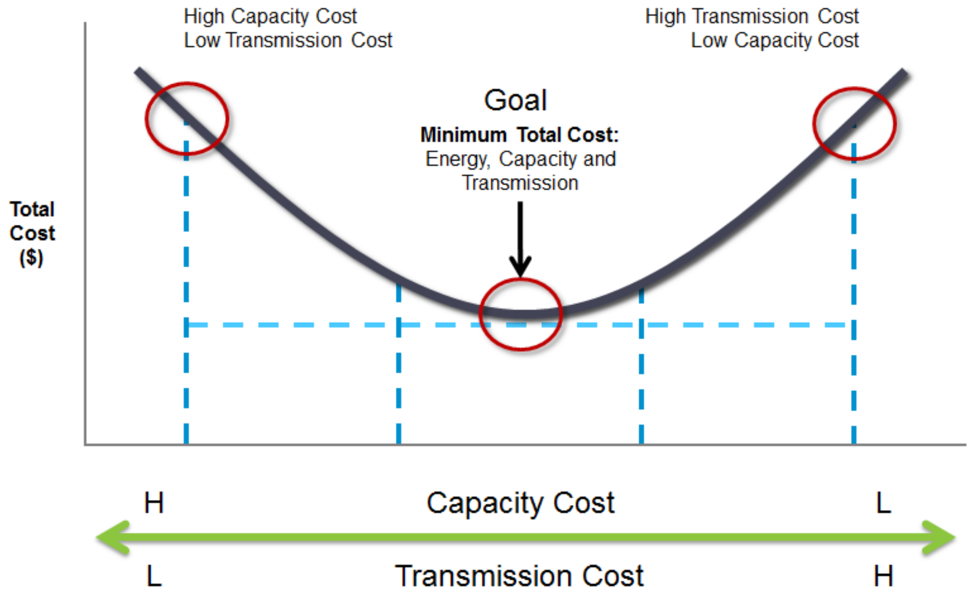


Figure 5.1-1: The goal of the MISO Value-Based Planning Process

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 the 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 common 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
- Resource 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 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.

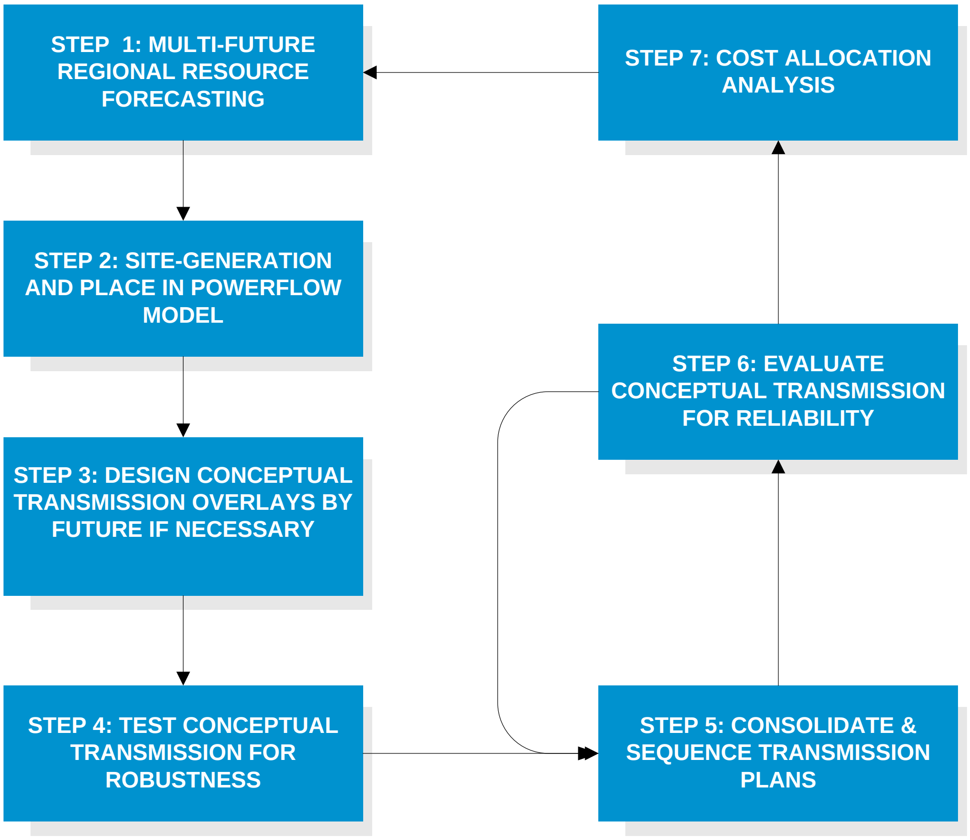


Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

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

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

A more detailed discussion of the assumptions and methodology around the MTEP16 future scenarios is in Chapter 5.2: MTEP Future Development.

Step 2: Siting of Regional Resource Forecast Units

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 resource 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 resources. 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 MTEP16 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 resources 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 resources 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) Working Group.

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

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 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 form to document and track solutions
- Development of an integrated transmission development process to categorize issues identified, screen solution ideas, refine solution ideas and formulate most-cost-effective projects

In MTEP16, MISO’s Value-Based Planning Process is exemplified in the MTEP Future Development (Chapter 5.2), and Market Congestion Planning Study (Chapter 5.3).

5.2 Futures Development

The MTEP16 generation expansion results created in 2015 cover both the North/Central and South regions. MISO completed this assessment of generation using the Electric Generation Expansion Analysis System (EGEAS) model in 2015. Using assumptions developed in coordination with the Planning Advisory Committee (PAC), 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.

Detailed MTEP16 capacity expansion results are presented in Appendix E2[20].

Capacity Expansion Results

The study determined the aggregated, least-cost capacity expansions for each defined future scenario through the 2030 study year (Figure 5.2-1). This added capacity is required to maintain planning reliability targets for each region as well as identify other economic generation. This iteration of MTEP show a long-term drive toward economically selected renewables in carbon cost futures and an increase in retirements and gas consumption. The reliability targets for MISO are defined in the Module E Resource Adequacy Assessment described in Book 2.

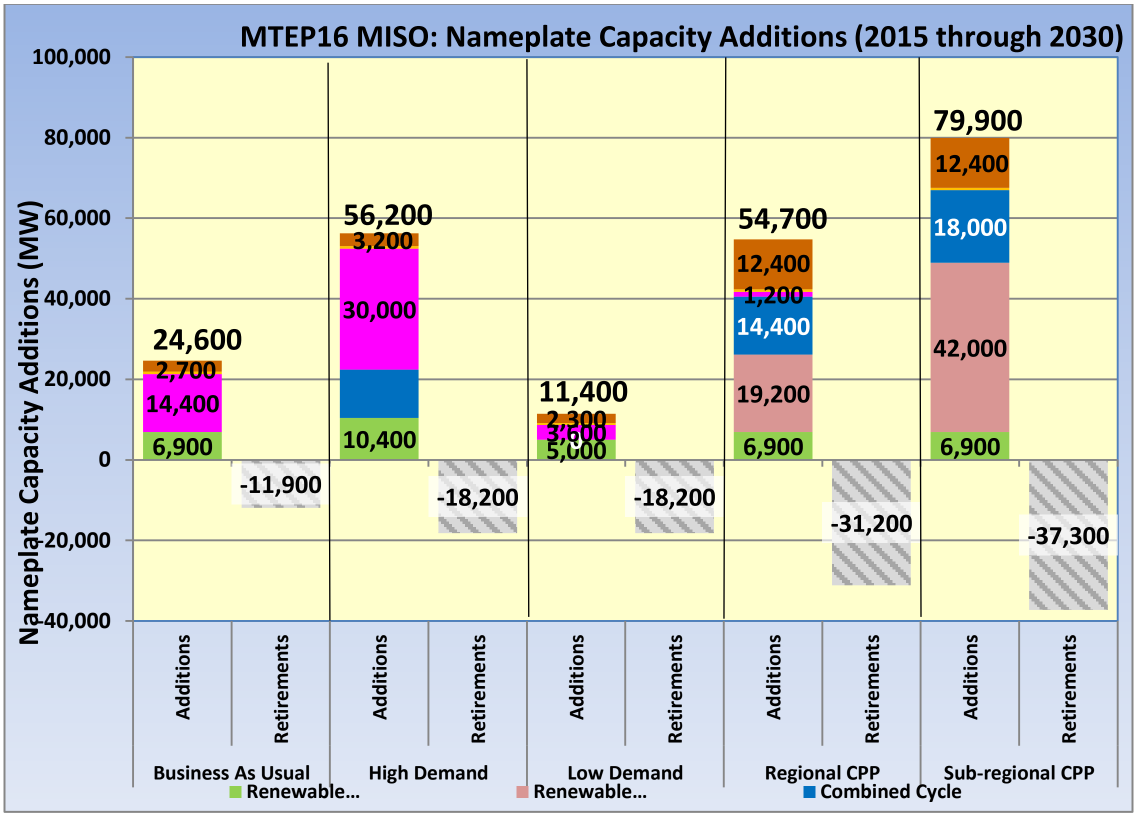


Figure 5.2-1: MISO nameplate capacity additions by future (2015-2030 EGEAS Model)[21]

[20] Futures were developed prior to the stay of the clean power plan. Futures under development for MTEP 17 will reflect a broader range of portfolio changes not specifically tied to the Clean Power Plan.

The Business As Usual future projects 24.6 GW of additional capacity to maintain system reserves and replace retired capacity between 2015 and 2030. MISO, with advice from the PAC, models 12.6 GW of coal retirements as a minimum in all future scenarios[22] to represent the projected effects of EPA regulations, specifically, Mercury and Air Toxics Standards (MATS). The High Demand and Low Demand futures include additional age-related retirements of non-coal and non-nuclear resources. On top of the age-related and 12.6 GW of coal retirements, the Regional and Sub-Regional Clean Power Plan (CPP) futures include an additional 14 GW and 20 GW of coal retirements respectively. Future capacity expansions include demand response (DR) and energy efficiency (EE) programs, as well as natural gas combustion turbines, natural gas combined cycle units, wind and solar.

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 are regularly developed 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. Previously, future scenario definitions were developed annually; however, several prior iterations of MTEP saw very similar futures with gas price and load growth variations year over year. Rather than continue to develop similar futures, MISO will implement a new futures process beginning with MTEP17[23]. Under the new process, futures will be evaluated annually and a decision made with input from stakeholders as to whether futures need to be wholly redesigned or merely updated with current fuel and demand forecasts.

Five narratives describe the MTEP16 future scenarios and their key drivers:

- The baseline, or 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 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

[21] Due to coal plant retirements that have already occurred, only the additional amounts 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.
[23] See September 9th PAC meeting materials process discussion: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=207650

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 Demand future captures the effects of increased economic growth resulting in higher energy costs and medium-high gas prices. The magnitude of demand and energy growth is determined by using the upper bound of the Load Forecast Uncertainty metric and also includes forecasted load increases in the South region. All current state-level RPS and EERS mandates are modeled. All existing EPA regulations governing electric power generation, transmission and distribution are incorporated. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including retired units or announced retirements. Additional age-related retirements are captured using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.
- The Low Demand future captures the effects of reduced economic growth resulting in lower energy costs and medium-low gas prices. The magnitude of demand and energy growth is determined by using the lower band of the Load Forecast Uncertainty metric. All current state-level RPS and EERS mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including retired units or announced retirements. Additional, age-related retirements are captured using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.
- The Regional Clean Power Plan future focuses on several key items from a footprint-wide level that, in combination, result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include:
    - Capturing expected effects of existing environmental regulations on the coal fleet, with 12.6 GW of coal unit retirements modeled, including known or announced retirements
    - 14 GW of additional coal unit retirements, coupled with a $25/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, to result in significant carbon emissions reduction by 2030
    - Additional, age-related retirements using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric
    - An economic maturity curve with solar and wind to reflect declining costs over time
    - Demand and energy growth rates modeled at levels as reported in Module E
- The Sub-Regional Clean Power Plan future focuses on several key items from a zonal or state level, which combine to result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include:
    - The capture of expected effects of existing environmental regulations on the coal fleet, with 12.6 GW of coal unit retirements are modeled, including existing or announced retirements
    - 20 GW of additional coal unit retirements, coupled with a $40/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, to result in a significant reduction in carbon emissions by 2030
        - These increased retirements and carbon cost levels from the Regional CPP Future are consistent with regional/sub-regional CPP assessments performed by MISO and other organizations since the CPP's introduction

- Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.
- An economic maturity curve with solar and wind to reflect declining costs over time.
- Demand and energy growth rates modeled at levels as reported in Module E

These future scenarios were developed and approved prior to the current 111(d) rule. The EPA finalized this rule on October 23, 2015[24] and it was stayed by the U.S. Supreme Court in on February 9, 2016.

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 MTEP16, 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, MISO nets out only the impact of the energy efficiency programs from the baseline demand and energy growth rates. The resulting growth rates for the various futures range from 0 percent to 1.43 percent for demand and 0.11 percent to 1.53 percent for energy (Table 5.2-1). Demand response programs are modeled within the production cost 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	**0.75%**	**0.82%**	**0.65%**	**0.76%**
High Demand	**1.55%**	**1.61%**	**1.43%**	**1.53%**
Low Demand	**0.11%**	**0.19%**	**0.00%**	**0.11%**
Regional CPP	**0.75%**	**0.82%**	**0.27%**	**0.46%**
Sub-Regional CPP	**0.75%**	**0.82%**	**0.27%**	**0.46%**

Table 5.2-1: MTEP16 effective demand and energy growth rates

Production and Capital Costs

EGEAS capacity expansion data provides the present value of production and capital costs for the study period through 2030 (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

[24] https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf

compared to a Business as Usual-type scenario. Production costs include fuel; variable and fixed operations and maintenance; and emissions costs (where applicable). As stated, EGEAS does not model congestion, therefore does not capture those costs or costs for transmission expansion. Gas line expansion is also outside of this analysis. Capital costs represent the annual revenue needed for new capacity. Each future scenario has a unique set of input assumptions, such as demand and energy growth rates, fuel prices, carbon costs and RPS requirements that drive the future capacity expansion capital investments and total production costs.

Due to the significantly higher production costs in the CPP futures, it should be noted that approximately $64 billion of the total $348 billion in production costs are due to the $25/ton carbon tax modeled in the Regional CPP future, while in the Sub-Regional CPP future approximately $90 billion of the total $431 billion in production costs are due to the $40/ton carbon tax modeled. Also, the retirement of an additional 14 GW and 20 GW of coal units on top of the 12.6 GW leads to higher production costs resulting from higher capacity factors of gas-fired generation, which has a higher-modeled fuel price than coal.

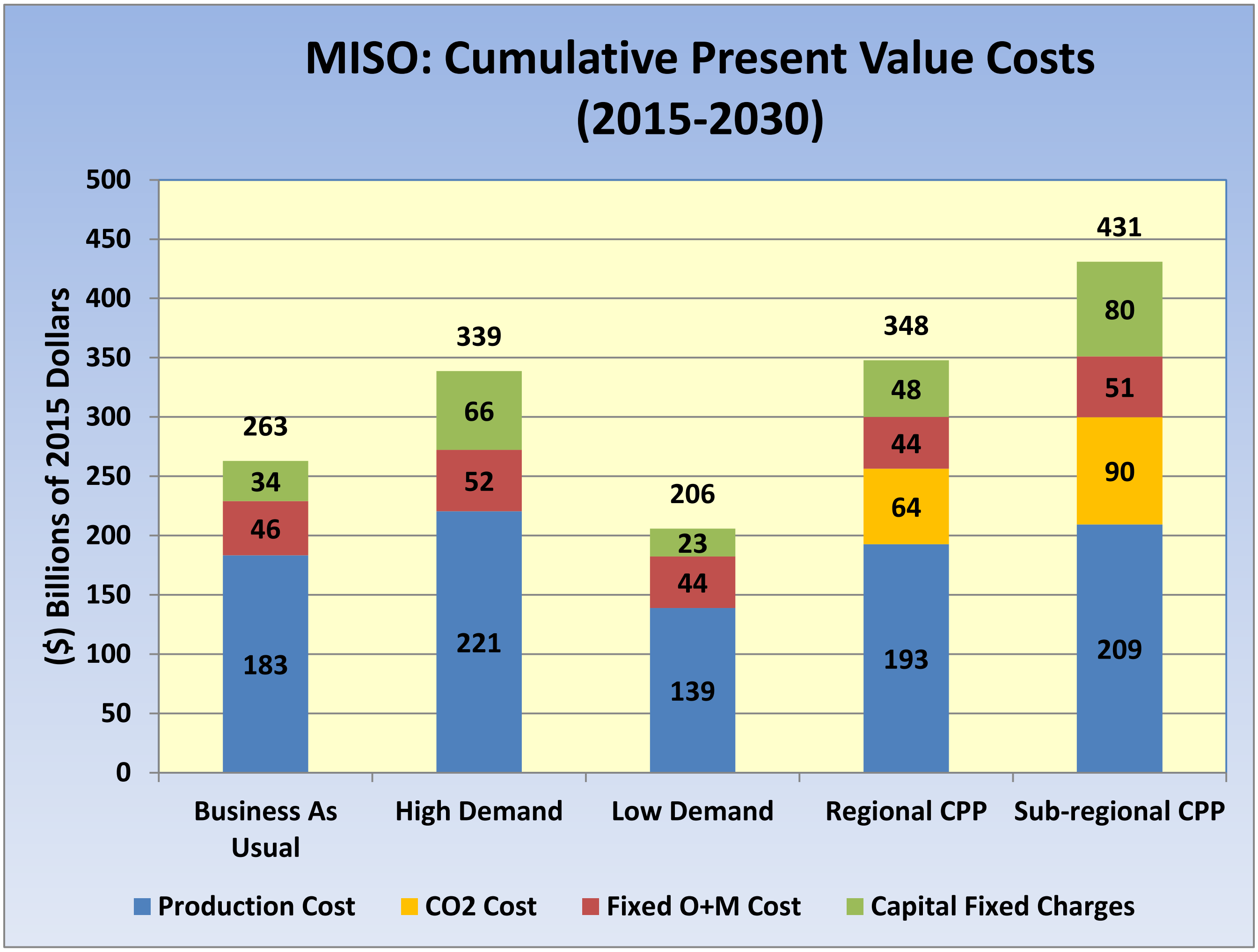


Figure 5.2-2: MISO present value of cumulative costs in 2015 U.S. dollars

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, prices have reached well over $10/MMBtu as recently as 2008. Therefore, it is important to capture a wide range of forecasts to account for potential volatility. For MTEP16, MISO utilized a natural gas forecast developed by Bentek[25] as a baseline. High and low forecasts were developed by adding or subtracting 20 percent from the baseline. The five scenario-specific MTEP16 natural gas forecasts are shown in nominal dollars per MMBtu (Figure 5.2-3).

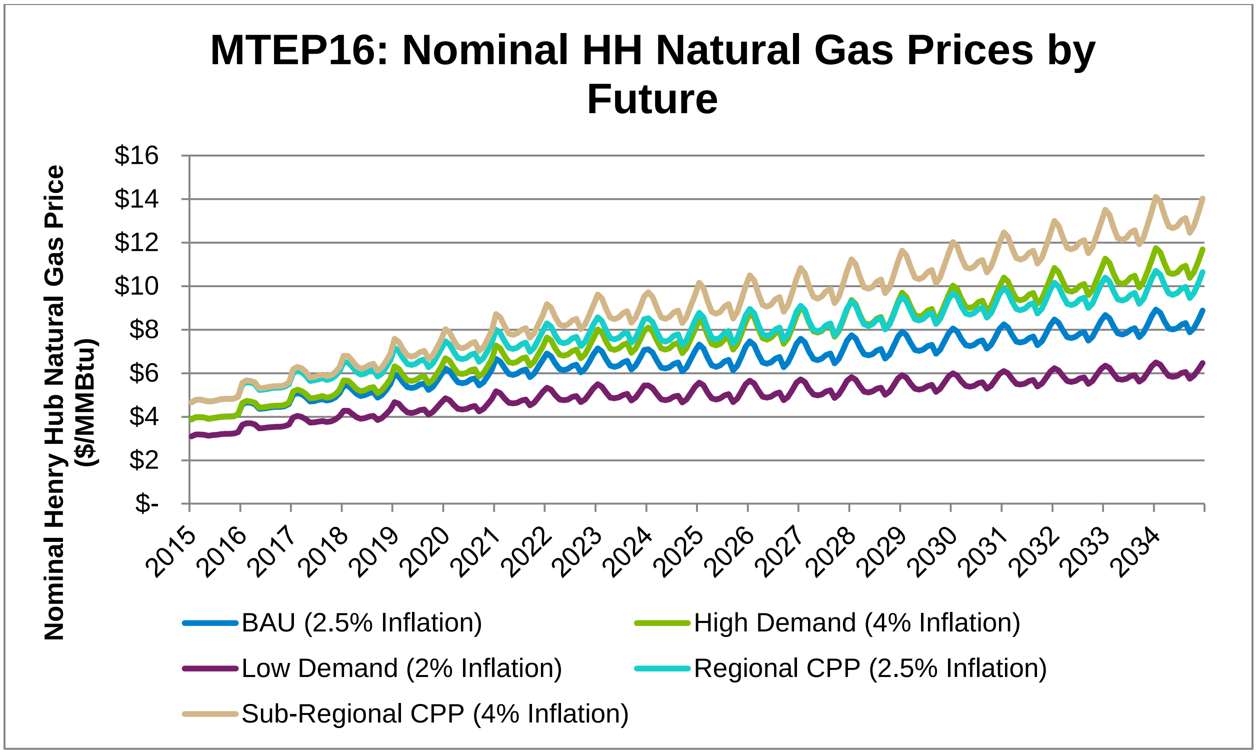


Figure 5.2-3: Natural gas forecasts by future

Renewable Portfolio Standards

Several states in the MISO footprint have some form of state mandate or goal to provide a specified amount of future energy from renewable resources. The Department of Energy's Database of State Incentives for Renewables and Efficiency (DSIRE) provides a breakdown of each state's mandate or goal. MISO uses the DSIRE information to calculate future penetrations of renewables, which are assumed to be primarily wind and solar, in each of the MTEP futures (Table 5.2-2). The MTEP16 Business as Usual, High Demand and Low Demand futures model state-mandated wind and solar only. In addition to modeling a minimum of state-mandated wind and solar, the Regional CPP and Sub-Regional CPP futures model renewable maturity cost curves, with solar declining at a rate of 10 percent per year for five years and wind declining at a rate of 1 percent per year for five years.

[25] 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

Future Scenario	MISO Incremental Wind Penetration	MISO Incremental Solar Penetration	Percentage of Energy from All Renewable Resources in 2030
Business As Usual	5,400 MW	1,500 MW	12%
High Demand	8,700 MW	1,700 MW	12%
Limited Demand	3,600 MW	1,375 MW	12%
Regional CPP	5,400 MW	20,700 MW	16%
Sub-Regional CPP	25,800 MW	23,100 MW	26%

Table 5.2-2: MISO wind and solar penetrations (including those with signed generation Interconnection Agreements through 2030)

Carbon Emissions

Each future scenario includes a different resource mix and thus produces a different carbon dioxide output (Figure 5.2-4). For all futures, with the exception of the High Demand future, total CO_2 emissions decline or remain flat between 2015 and 2030. Coal plant retirements, in combination with increased levels of renewables and demand-side management programs, are key factors in allowing carbon emissions to decline.

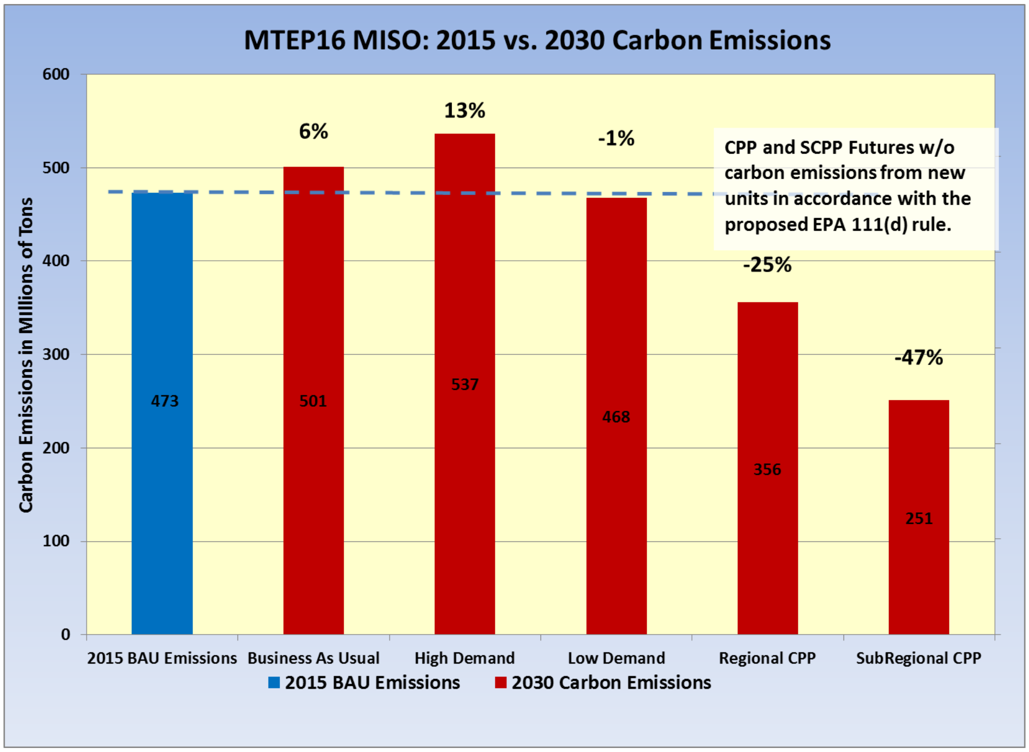


Figure 5.2-4: MISO carbon dioxide production

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 Regional CPP and SubRegional CPP Futures, which analyze the highest amount of coal unit retirements.

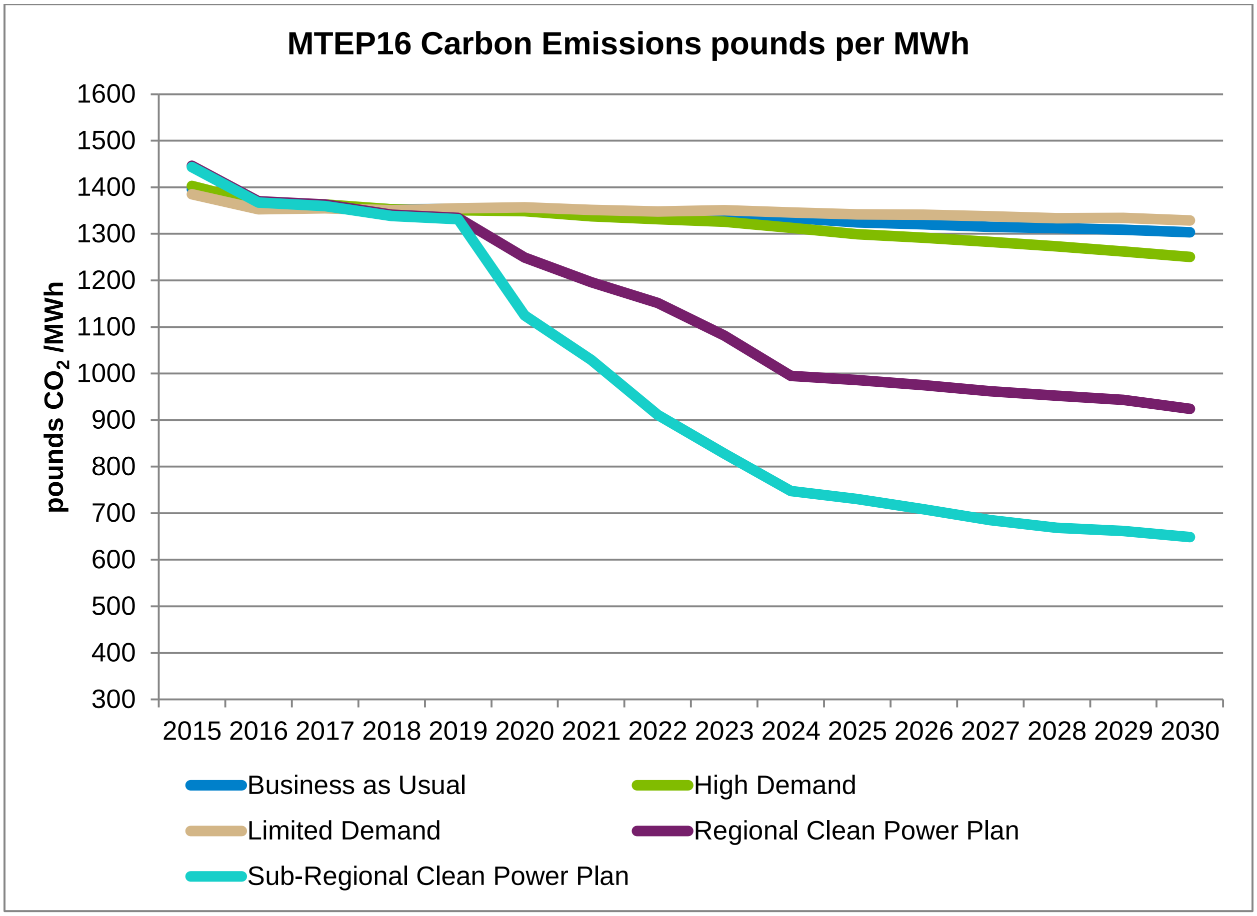


Figure 5.2-5: Carbon emissions per megawatt hour

Siting Of Capacity

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

DR programs are sited at the top 10 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.

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 Economic 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.

A consolidated economic planning effort has been undertaken for the MISO North/Central and South regions in MTEP16 in order to better align the study process across the MISO footprint.

Study Summary: MCPS North/Central Region

The 2016 MCPS study effort for the North/Central region identifies various congested flowgates and evaluates corresponding applicable transmission solutions. By building on the MCPS 2015 analysis, the 2016 cycle focuses on three specific areas that show the highest congestion: Iowa/Minnesota, Illinois, and Northern Indiana. In MTEP15, Duff to Coleman 345 kV was approved as a Market Efficiency Project (MEP) and addresses congestion near southern Indiana. Thus, southern Indiana did not have significant congestion and was not a focus area in MTEP16. Ultimately, the area with the most congestion, and therefore highest potential benefit, is on the border of Iowa and Minnesota.

MISO staff and stakeholders collaborated on the development of several solutions to mitigate congestion in various parts of the footprint. The solutions were tested for their robustness to address system needs under a wide variety of scenarios, embodied by the MTEP16 futures. Ultimately, solution I-2, a new Huntley to Wilmarth 345 kV circuit with an estimated cost range from $88 to $108 million, was found to offer the best value. This project completely mitigates the congestion on Huntley to Blue Earth 161 kV and strengthens the high-voltage power delivery system; thus, allowing for greater utilization of lower-cost generation to serve load. Furthermore, the project is found to be robust under all sensitivity analyses, including when wind projects in the MISO Generation Interconnection queue with a DPP or GIA-in-Progress status are modeled instead of RGOS/RRF wind in Iowa and Minnesota.

Subsequently, MISO recommends the Huntley to Wilmarth 345 kV project to the MISO Board of Directors for approval as a Market Efficiency Project (MEP) in MTEP16.

Study Summary: MCPS South Region

Since integration, the MISO Board of Directors has approved significant transmission investments in the MISO South region leading to a reduction in congestion. The 2016 MCPS study effort for the South region is built on the progress made during the MTEP15 cycle, which identified several congested flowgates and evaluated the applicable transmission solutions. The 2016 cycle focuses on five specific areas in MISO South: Amite South/Downstream of Gypsy (DSG), West of the Atchafalaya Basin (WOTAB)/Western, Local Resource Zone (LRZ) 8 (Arkansas), LRZ10 (Mississippi) and Remainder of LRZ9 (Rest of Louisiana).

In the MTEP16 MCPS study effort, 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 MTEP16 futures. Ultimately, four projects were selected to address system needs observed in Amite South/DSG, Remainder of LRZ9 (Rest of Louisiana), LRZ10 (Mississippi), and LRZ8 (Arkansas). The following four project candidates are recommended as economic Other Projects to Board of Directors for MTEP16 approval.

- First economic Other Project geographically located in Southeast Louisiana is to construct a new 230 kV substation south of the existing Ninemile substation called Churchill and construct a new 230 kV transmission line connecting the existing Waterford 230 kV substation to Churchill 230 kV substation. Additionally, re-configuring the existing Ninemile to Estelle 230 kV and Ninemile to Waterford 230 kV lines into the Churchill 230 kV substation and out to Ninemile 230 kV substation. This economic Other Project provides additional benefits to Amite South and Down Stream of Gypsy (DSG) load pockets. This project provides an outlet and improves the import capability by 650 MW into the DSG load pocket. Also, it provides operational flexibility in the region during planned transmission and generation outages as well as accommodating the system for any future retirements. The project will also provide enhanced resilience to the area during extreme events such as hurricanes. The estimated cost of the project is $87.7 million. Note that, the new 230 kV substation and re-configuration of the existing 230 kV transmission facilities are also part of an existing MTEP16 Appendix B reliability project with MTEPID 10587.
- Upgrade the terminal equipment on the Minden to Sarepta 115 kV line with an estimated cost of $1.9 million
- Relocate the existing McAdams 500/230 kV autotransformer to Lakeover with an estimated cost of $6.7 million
- Rebuilding the existing Trumann to Trumann West 161 kV line with an estimated cost of $7.6 million. Note that, the rebuild of Trumann to Trumann West 161 kV is also identified as a baseline reliability project and is recommended as a reliability project for approval in MTEP16.

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 2016, 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 assess 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.

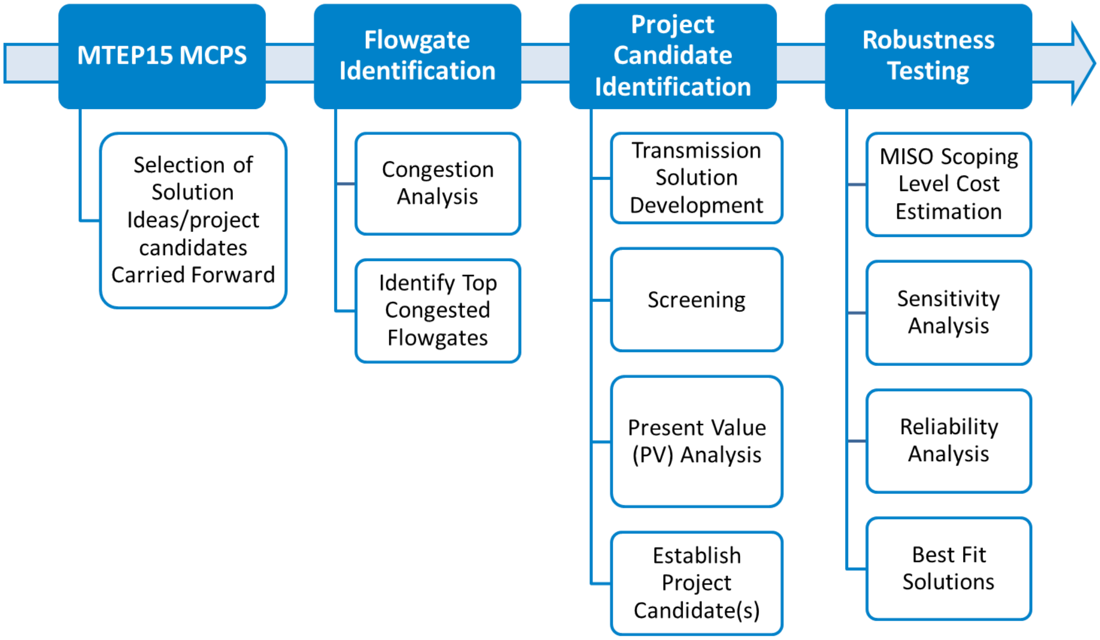


Figure 5.3-1: MCPS process overview

MISO 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 MTEP16 MCPS study are:

- Business as Usual (BAU): 19 percent
- High Demand (HD): 10 percent
- Low Demand (LD): 16 percent
- Regional CPP (RCPP): 30 percent
- Sub-Regional CPP (SRCPP): 25 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).

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).

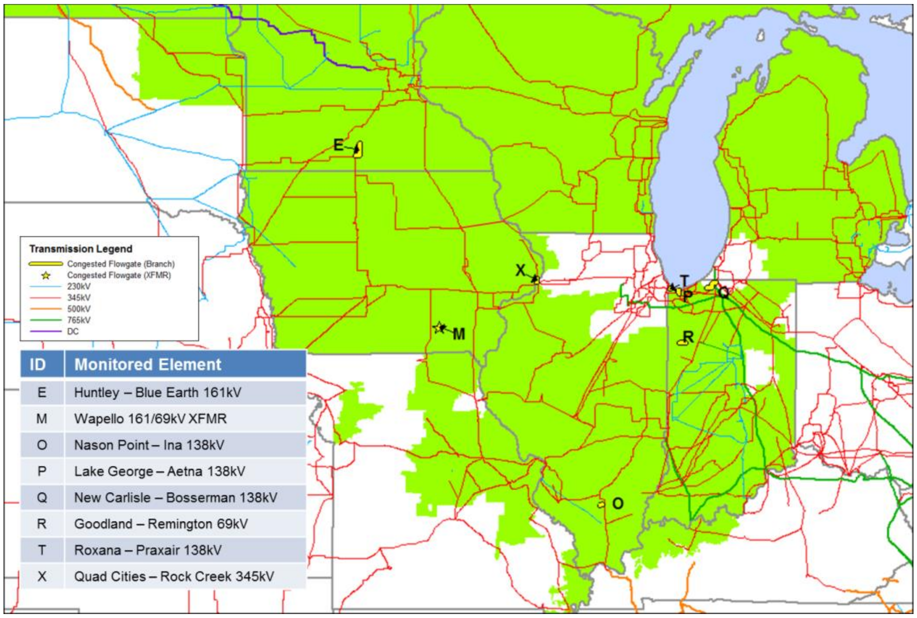


Figure 5.3-2: Projected Top Congested Flowgates in MISO North/Central Region

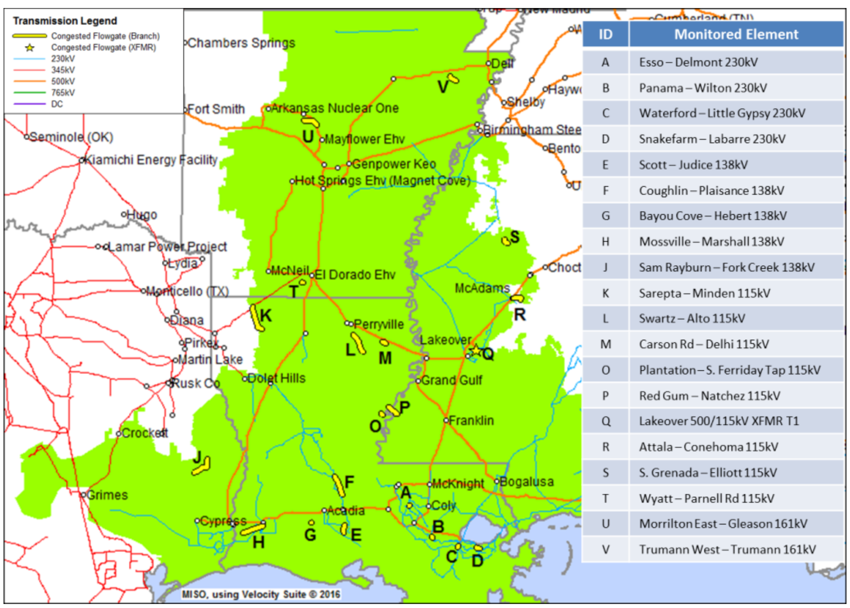


Figure 5.3-3: Projected Top Congested Flowgates in MISO South Region

The flowgates of interest are those with historical congestion and are projected to limit 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 partnership between MISO and stakeholders 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 economic 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 the most cost-effective solutions to 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 the 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 index threshold 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 five-year transition period following MISO South integration in 2013, the benefits for each project are counted only for the relevant MISO sub-region, North/Central or South. Data from three simulation years (2020, 2025 and 2030) 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 (PV) 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 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 the following cases:

- Five-year-out Summer Peak
- Five-year-out Shoulder Peak with 40 percent wind
- Five-year-out Shoulder Peak with 90 percent wind (for North/Central region project candidates only)
- 10-year-out Summer Peak (for South region project candidates only)

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

Iowa/Minnesota

A significant amount of congestion was identified on Huntley to Blue Earth 161 kV (Figure 5.3-8), which is near the border of Iowa and Minnesota. There are multiple factors contributing to the congestion on this line - one of which is the large amount of wind capacity and low-cost coal generation in northern Iowa. Further worsening congestion is the increase in wind capacity in Iowa that is assumed over the next 15 years. Finally, expected coal retirements near the Minneapolis/Saint Paul area such as Sherco 1, Sherco 2, and Clay Boswell 3 tend to increase the need for power to flow from northern Iowa to the Twin Cities via the Lakefield to Wilmarth 345 kV path. As a result, for the loss of this high-voltage transmission path, the low-voltage parallel path of Huntley to Blue Earth 161 kV becomes congested.

Congestion is also identified on the Wapello 161/69 kV transformer (Figure 5.3-8). Similar to Huntley to Blue Earth 161 kV, this transformer congests as a result of wind and coal in southern Iowa attempting to serve load centers near the border of Iowa and Illinois.

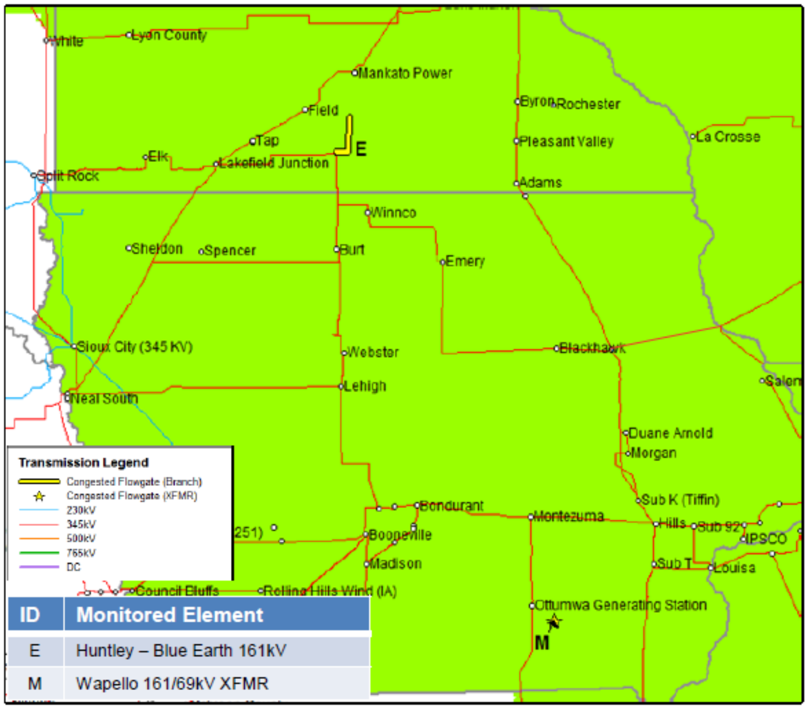


Figure 5.3-8: Iowa/Minnesota Top Congested Flowgates

Twenty-three solutions were evaluated in the Iowa/Minnesota area and 16 of those passed the screening analysis. All solutions that passed screening sought to address the congestion on Huntley to Blue Earth 161 kV and overlapped in their design elements. These solutions were divided into four groups based on similarities in their voltage level and the approach used in relieving congestion. Four solutions, one from each group, were selected for PV analysis due to their high screening index values. These solutions were:

- I-2: Huntley to Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)
- I-12: Huntley to NROC 345 kV new circuit
- I-15: Huntley to South Bend 161 kV reconductor, South Bend to Wilmarth 161 kV new circuit; Wilmarth substation 161 kV expansion with a 345/161 kV and a 161/115 kV XFMR
- I-19: Freeborn to West Owatonna 161 kV new circuit

Of the four solutions, I-2 had the highest benefit-to-cost ratio, largest 20-year PV benefit, and fully relieved the congestion on Huntley to Blue Earth 161 kV. I-12, I-15, and I-19 had lower benefit-to-cost ratios, lower 20-year PV benefits, and were unable to fully relieve Huntley to Blue Earth 161 kV. Therefore, I-2 was moved forward for further robustness testing and analysis to help inform the project recommendation decision for I-2.

Contingency analyses were performed to identify additional flowgates to monitor what could be impacted as a result of Huntley to Wilmarth 345 kV going into service. Some of these additional flowgates did bind due to I-2, and therefore, a refinement of the solution was considered to see if any additions or modifications to the project would be appropriate. Thus, two additional options were considered: I-2b, which consisted of Huntley to Wilmarth 345 kV and an upgrade on Wilmarth to Swan Lake to Ft Ridgley 115 kV; and I-2d, which is the same as I-2b plus a second Helena to Scott 345 kV circuit and an upgrade on Scott Co to Scott Co Tap 115 kV. Reliability analysis on all three of these options - I-2, I-2b and I-2d - revealed that none of these solutions caused additional voltage or thermal violations.

Also, various sensitivity analyses were performed to help inform the project's business case under different potential scenarios. These sensitivity tests evaluated the impact of future Sherco units' retirements, the removal of external RRF wind from Iowa and Minnesota, and modeling wind units in the queue with DPP or GIA-in-Progress status instead of RGOS/RRF wind units in Iowa and Minnesota. Under all of these sensitivities, Huntley to Wilmarth 345 kV was shown to be robust and maintain a benefit-to-cost ratio over 1.25. The results of the queue wind sensitivity in particular compared with the results of the base MTEP16 model can be seen in Table 5.3-1.

ID	Transmission Solution	Model	Cost Estimate (2016 $M)	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
				BAU	HD	LD	RCPP	SRCPP	Weighted	
I-2	Huntley – Wilmarth 345 kV new circuit	Base	88-108	0.43-0.52	1.16-1.42	0.10-0.13	1.32-1.62	3.63-4.45	1.51-1.86	210
		Queue Wind Sensitivity		1.39-1.71	2.40-2.95	0.69-0.85	2.45-3.01	2.03-2.49	1.86-2.28	251
I-2b	Huntley – Wilmarth 345 kV new circuit, Wilmarth to Swan Lake – Ft Ridgeley 115 kV upgrade	Base	113.3-133.3	0.37-0.43	1.12-1.31	0.09-0.10	1.15-1.35	3.31-3.90	1.36-1.60	234
		Queue Wind Sensitivity		1.13-1.33	2.08-2.45	0.55-0.65	2.02-2.39	1.73-2.03	1.55-1.83	259
I-2d	Huntley – Wilmarth 345 kV new circuit, Wilmarth – Swan Lake – Ft Ridgeley 115 kV upgrade Add 2nd Helena – Scott County 345 kV circuit, Scott Co – Scott Co Tap 115 kV upgrade	Base	154.8-174.8	0.27-0.31	0.92-1.04	0.08-0.10	0.98-1.11	3.03-3.43	1.21-1.36	272
		Queue Wind Sensitivity		0.86-0.97	1.74-1.97	0.44-0.50	1.68-1.90	1.55-1.76	1.30-1.47	285

Table 5.3-1: Huntley to Wilmarth 345 kV options sensitivity analysis results

Further investigating the incremental benefits among the three project alternatives in Table 5.3-1, MISO found that the additional upgrades included as part of I-2b and I-2d would not be economically justifiable, as the benefit yielded by these upgrades would not outweigh their incremental cost.

MISO also evaluated the robustness of Huntley to Wilmarth 345 kV under varying levels of future wind additions. The Queue Wind Sensitivity, which was performed in May 2016, utilized the capacity and locations of the queue wind units in Iowa/Minnesota with a DPP or GIA-in-Progress status at that time. The capacity of queue wind units with a SPA status was not included in this analysis.

Based on the analysis results and stakeholder feedback, MISO recommends the Huntley to Wilmarth 345 kV project to MISO Board of Directors for approval as a Market Efficiency Project (MEP) in MTEP16.

Illinois

Two top flowgates are identified in this region (Figure 5.3-9). A large amount of economical nuclear, coal and wind generation is sited in northern Illinois (mainly PJM COMED resources) and tends to serve nearby MISO and PJM loads. The Fargo to Oak Grove 345 kV line is a high-voltage flow path located in this area and allows COMED generation to serve load centers in the Minneapolis/St. Paul, Davenport and Chicago. The flow transfer on this line also increases flow on lines nearby, leading to congestion on Quad Cities to Rock Creek 345 kV. The congestion on Quad Cities to Rock Creek 345 kV also increases significantly when large amounts of future PJM wind generation are sited in northern Illinois in out-year models, particularly in the 10- and 15-year-out models.

Additionally, there is a generation pocket in southern Illinois that contains more than 1,000 MW of coal generation that is limited by transmission outlet capacity. The generation located within this pocket is transferred out through the West Mt Vernon to East West Frankfort 345 kV line or the underlying 138 kV transmission path. Under loss of this 345 kV line, flows shift to the lower voltage system causing heavy congestion.

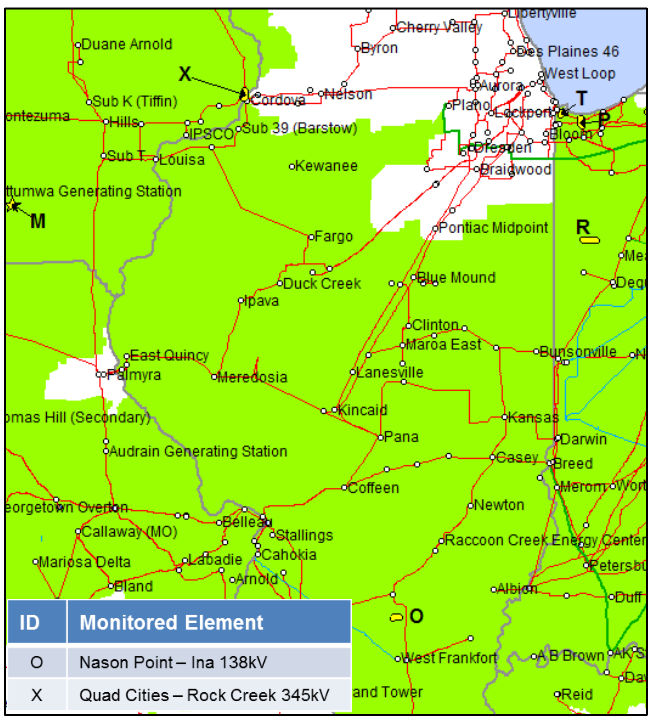


Figure 5.3-9: Illinois Top Congested Flowgates

Of the nine solutions studied in the Illinois area, two passed the initial screening analysis:

- Quad Cities to Rock Creek 345 kV Reconductor
- Quad Cities to Rock Creek 345 kV Second Circuit

Both solutions were designed to address the congestion seen on the Quad Cities to Rock Creek 345 kV line. However, it was determined that the congestion on this constraint was largely driven by the assumed additions of future wind generation in COMED, which was present in MISO's MTEP model but not PJM's RTEP model, a result of a difference in planning assumptions between MISO and PJM. As a result of these findings along with stakeholder feedback, these two solutions were not further evaluated as part of the MTEP16 MCPS.

In southern Illinois, none of the solutions to address congestion on Nason Point to Ina 138 kV line passed the screening, since a terminal equipment upgrade at the Ina substation (targeting for Appendix A in MTEP17) can relieve about 90 percent of the congestion.

Northern Indiana

Congestion is identified in northern Indiana on four different flowgates (Figure 5.3-10). The congestion in this area is primarily driven by the high levels of west-to-east flows across the high voltage lines. This leads to heavy congestion on the lower-voltage system under the outage of these high-voltage lines. In addition, congestion in this area is driven by the flows associated with serving the industrial and non-industrial load pockets along the southern border of Lake Michigan. This is exacerbated by the retirements of Bailly units 7 and 8 in the out-year models, thus increasing the need to transport power to various load centers along the southern border of Lake Michigan. These congestion drivers mainly apply to Lake George to Aetna 138 kV, New Carlisle to Bosserman 138 kV and Roxana to Praxair 138 kV.

The remaining constraint, Goodland to Remington 69 kV, is primarily congested due to the significant amount of wind located near the border of Illinois and Indiana.

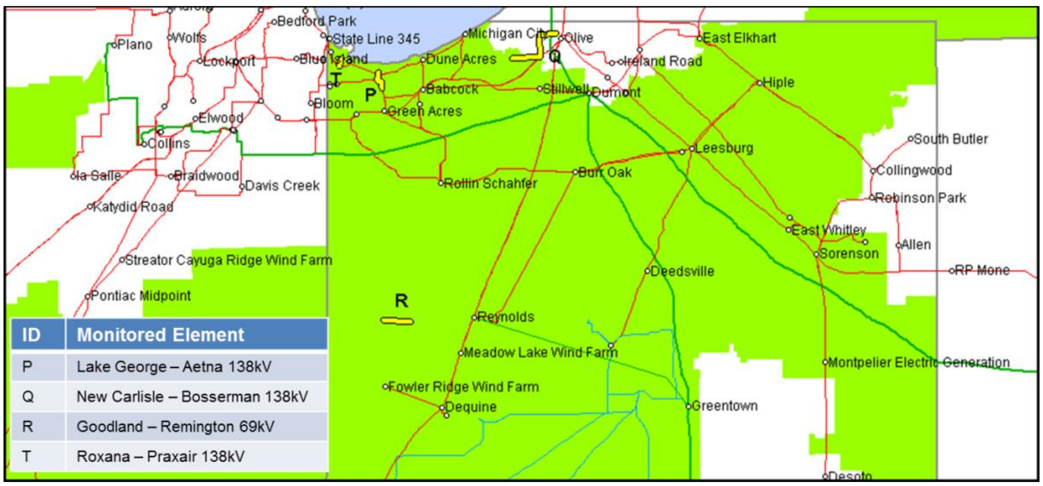


Figure 5.3-10: North Indiana Top Congested Flowgates

The assumed retirement of Bailly 7 and 8 had a large impact in this area by increasing congestion levels on the top flowgates identified in out-year simulations. However, MISO further investigated this congestion and found a standing operating guide that states whenever Bailly 7 and 8 are out of service, the Dune Acres transformer can be restored to service. Because some years/futures assume the retirement of Bailly 7 and 8, the Dune Acres transformer should be modeled as in-service for those respective years and futures. By closing this transformer, congestion on these constraints decreases substantially. Specifically, the congestion on Lake George to Aetna 138 kV, New Carlisle to Bosserman 138 kV and Roxana to Praxair 138 kV decreases between 33 percent and 90 percent.

Since screening is performed utilizing only 2030, it was decided that for the purposes of the screening the Dune Acres transformer would be modeled as out of service so as to not prematurely exclude any solutions that could end up performing well when considering all years. Therefore, of the 25 solutions submitted for evaluation in this area, six passed the screening analysis.

As part of the PV analysis, the Dune Acres transformer was modeled to reflect the impact of the operating guideline details for each year and future (Table 5.3-2).

	BAU/HD/LD Assumptions			RCPP/SRCPP Assumptions		
	Baily 7	Baily 8	Dune Acres XFMR	Baily 7	Baily 8	Dune Acres XFMR
2020	Online	Online	Open	Online	Online	Open
2025	Retired	Online	Open	Retired	Retired	Closed
2030	Retired	Retired	Closed	Retired	Retired	Closed

Table 5.3-2: Dune Acres Transformer Modeling Assumptions for PV Analysis

As a result, the benefits of the five solutions targeting Lake George to Aetna 138 kV, New Carlisle to Bosserman 138 kV, or Roxana to Praxair 138 kV reduced and the solutions were not considered as project candidates (Table 5.3-2). The lone solution targeting Goodland to Remington 69 kV that passed screening had a relatively higher benefit-to-cost ratio but was also too low to be considered as a project candidate. Based on the results, no project candidates were identified in Northern Indiana for further analysis.

ID	Transmission Solution	Cost Estimate (2016 $M)	Benefit to Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-20	SE Gary – Aetna 345 kV, tap Gary Ave – Dune Acres 345 kV and Lake George – Munster 345 kV lines into SE Gary*	48.3	0.09	0.17	0.08	0.19	0.36	0.19	12.90
I-26	New Sub* – Aetna 345 kV, Aetna 345/138 kV XFMR, tap Dune Acres – Gary 345 kV into New Sub*	27.3	0.01	-0.01	0.13	0.31	0.27	0.18	6.48
I-35	Thayer – Morrison 138 kV	35	0.56	0.63	0.25	1.05	1.44	0.89	42.02
I-40	Tap Gary – Dune Acres 345 kV into Burns Ditch South	17	0.38	0.11	0.27	0.51	0.56	0.42	9.27
I-50	New Carlisle – Liquid Carbonics 138 kV and Northern Indiana Upgrades	25.2	0.11	0.00	0.06	0.37	1.13	0.42	15.42
I-58	Lake George – Aetna 345 kV, Aetna 345/138 kV XFMR	36.7	0.11	0.00	0.14	0.24	0.21	0.17	7.97

Table 5.3-3: North Indiana PV Analysis Results

Amite South/DSG

A significant amount of congestion was identified in the Amite South and DSG load pockets, particularly on the import lines into the load pockets (Figure 5.3-11). In the event that an import line into either the Amite South or DSG load pocket is outaged (N-1) along with the loss of a generator (G-1) inside the load pocket, flows shift to the remaining import lines. This causes heavy congestion as well as Voltage and Local Reliability (VLR) commitments in the Amite South and DSG load pockets. Further aggravating the congestion are the import limitations of the transmission system as well as the limited economic generation resources available inside the Amite South and DSG load pockets. Construction of additional import lines into Amite South or DSG would therefore help to alleviate congestion as well as VLR issues in this area and can provide easy access to economic generation in these load pockets.

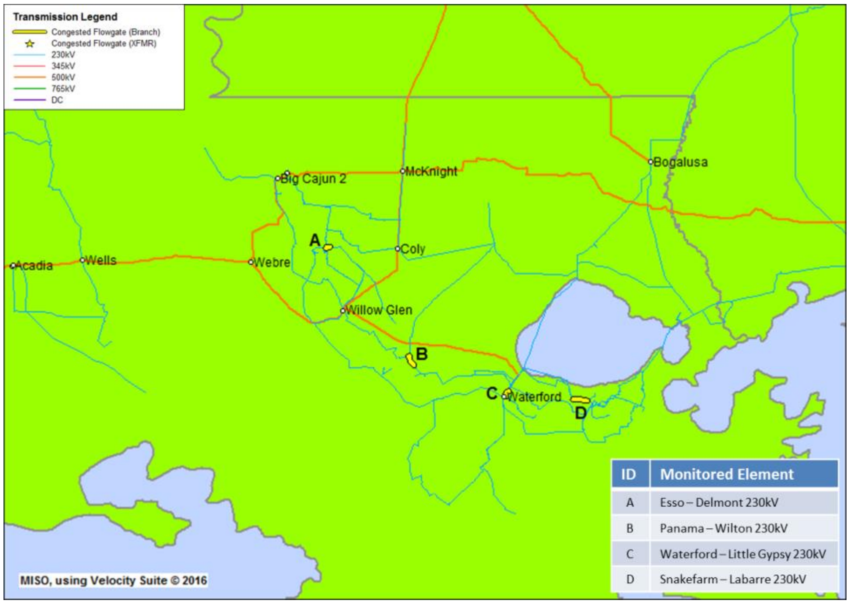


Figure 5.3-11: Amite South/DSG Top Congested Flowgates

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).

Scenario	Name	Siting Location	In-Service Year by Future				
			BAU	HD	LD	RCPP	SRCPP
1	RRF MISO CC:20	Little Gypsy 230 kV		2021		2020	2020
	RRF MISO CT:47	Michoud 230 kV		2029			
2	RRF MISO CC:20	White Bluff 500 kV		2021		2020	2020
	RRF MISO CT:47	Big Cajun 500 kV		2029			
3	Scen3 MISO CC:1	Little Gypsy 230 kV	2020	2020	2020	2020	2020
	Scen3 MISO CT:1	Michoud 230 kV		2029			

Table 5.3-4: Amite South/DSG Generation Scenarios

In Table 5.3-4 Generation Scenario 1 refers to the base Regional Resource Forecast (RRF) siting agreed upon by stakeholders as part of the model development for MTEP16. Scenario 2 was developed to reflect the potential future condition of all future RRF units being sited outside of the MISO South load pockets, while Scenario 3 was proposed by stakeholders to capture the potential impacts of Entergy's Request for Proposal (RFP) generation. In order better quantify the potential impacts of Scenario 3 network upgrades identified during the Generation Interconnection J396 study were included as a base case assumption. One important difference between the scenarios is the size of the future units added to the model. In Scenario 1 and Scenario 2 the RRF units are sized at 600 MW, while in Scenario 3 the Combined Cycle (CC) units are sized at 900 MW and the Combustion Turbine (CT) units are sized at 250 MW.

Twenty-two projects were submitted to address congestion in Amite South and DSG load pockets. These projects aimed to address issues of increased transfer capabilities into the Amite South and DSG load pockets, as well as alleviating congestion within the load pockets. After the completion of screening and refinement, three projects were identified as potential solutions to address congestion within the Amite South and DSG load pockets (Table 5.3-5 and Table 5.3-6).

Transmission Solution	Project Description
Amite South/DSG Alternative 2	• Reconductor existing facilities: ➢ Snakefarm to Labarre 230 kV ➢ Prospect to Goodhope 230 kV • Rebuild Existing facilities: ➢ Panama - Wilton to Romeville to Convent 230 kV ➢ St. Gabriel to AAC Corp to Licar 230 kV ➢ Evergreen to Donaldsonville to Bayou Verret 230 kV • Re-energize Little Gypsy to Luling 115 kV to 230 kV and tap into Waterford • Add two new Waterford 500/230 kV XFMRs
DSG Alternative 2	• Reconductor existing facilities: ➢ Snakefarm to Labarre 230 kV ➢ Prospect to Goodhope 230 kV • Re-energize Little Gypsy to Luling 115 kV to 230 kV and tap into Waterford
DSG Alternative 6	• Construction of new 230 kV substation called Churchill (new substation to south of Nine Mile) • Construction a new Waterford to Churchill 230 kV line • Re-configuring the existing Ninemile to Estelle 230 kV and Ninemile to Waterford 230 kV lines into the Churchill 230 kV substation and out to Ninemile 230 kV substation

Table 5.3-5: Amite South/DSG project alternative descriptions

Transmission Solution	Cost ($M)	ISD*	Weighted Benefit-to-Cost Ratios			Weighted Benefits (2016 $M)		
			Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Amite South/DSG Alternative 2	134.1	2020	2.34	2.20	1.35	443	417	256
DSG Alternative 2	22.0	2020	12.08	8.62	7.27	376	269	226
DSG Alternative 6	87.7	2022	3.42	2.08	1.96	390	238	223

***In Service Date**

Table 5.3-6: Amite South/DSG project PV analysis results

In addition these three project alternatives were subject to additional robustness analysis to quantify the impacts of the 55-year age-related retirement assumption of the MTEP17 futures applied to Nine Mile: 4 and Nine Mile: 5 in the DSG load pocket. This sensitivity analysis was performed both with and without generation replacement at the Nine Mile substation; a 900 MW CCGT was used as a replacement sensitivity and assumed to be sited at Nine Mile.

In comparing Amite South/DSG Alternative 2 to DSG Alternative 2, the robustness analysis showed minimal incremental benefits for rebuilding Amite South in Scenario 3. However, in the case that Nine Mile:4 and Nine Mile:5 are retired and not replaced by new CCGT generation, DSG Alternative 6 potentially provides significantly more benefits in Scenario 3 compared to DSG Alternative 2 (Table 5.3-7).

Transmission Solution	Case	Weighted Benefit-to-Cost Ratios			Weighted Benefits (2016 $M)		
		Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Amite South/DSG Alternative 2	Base Case	2.34	2.20	1.35	443	417	256
	Retire Nine Mile	12.16	12.04	5.71	2,280	2,262	1,075
	Replace Nine Mile	3.56	4.92	1.30	670	930	247
DSG Alternative 2	Base Case	12.08	8.62	7.27	376	269	226
	Retire Nine Mile	69.58	56.97	33.47	2,142	1,755	1,034
	Replace Nine Mile	20.46	26.27	7.42	631	815	230
DSG Alternative 6	Base Case	3.42	2.08	1.96	390	238	223
	Retire Nine Mile	22.14	16.75	13.35	2,481	1,877	1,501
	Replace Nine Mile	5.84	6.89	2.20	656	781	249

Table 5.3-7: Amite South/DSG project alternatives robustness analysis

Additionally, a reliability analysis was performed to determine the import capability of the competing alternatives into the Down Stream of Gypsy (DSG) load pocket. In comparing all three alternatives, DSG Alternative 6 increases the import capability into the DSG load pocket by 650 MW (Table 5.3-8).

Transmission Solution	DSG Load Pocket Import Capability (MW)	Maximum Load Serving Capability (MW)	Constraining Element
Base Case	1,645	3,618	Prospect to Good Hope 230 kV FTLO Waterford to Ninemile 230 kV
Amite South/DSG Alternative 2	1,520	3,375	Little Gypsy to Claytonia 115 kV FTLO Little Gypsy – Wesco 230 kV
DSG Alternative 2	1,520	3,375	Little Gypsy to Claytonia 115 kV FTLO Little Gypsy – Wesco 230 kV
DSG Alternative 6	2,295	3918	Prospect to Good Hope 230 kV FTLO Waterford to Ninemile 230 kV

Table 5.3-8: Amite South/DSG project alternative import and load serving capability

DG Alternative 6, located in Southeast Louisiana, is to construct a new 230 kV substation south of the existing Ninemile substation called Churchill and construct a new 230 kV transmission line connecting the existing Waterford 230 kV substation to Churchill 230 kV substation. Additionally, re-configuring the existing Ninemile to Estelle 230 kV and Ninemile to Waterford 230 kV lines into the Churchill 230 kV substation and out to Ninemile 230 kV substation. This economic Other Project provides additional benefits to Amite South and Down Stream of Gypsy (DSG) load pockets. This project provides an outlet and improves the import capability by 650 MW into the DSG load pocket. Also, it provides operational flexibility in the region during planned transmission outages as well as accommodating the system for any future retirements. MISO recommends this project to the Board of Directors as an economic Other Project for approval in MTEP16.

WOTAB/Western

The WOTAB and Western load pockets in MISO South have historically seen significant amounts of congestion due to import limitations. The import limitations in both the WOTAB and Western regions require the VLR commitments of units within these load pockets at specific limits in order to maintain system reliability. In order to replicate these VLR commitments, MISO utilizes N-1, G-1 conditions as part of the economic analysis.

The 2016 MCPS study for the South region identified that the majority of the congestion in this focus area is on import lines into the WOTAB load pocket (Figure 5.3-12). In the event that one of the import lines, most notably the 500 kV lines, into the WOTAB load pocket is outaged and a generator is lost inside of the WOTAB load, pocket flows shift to the remaining import lines.

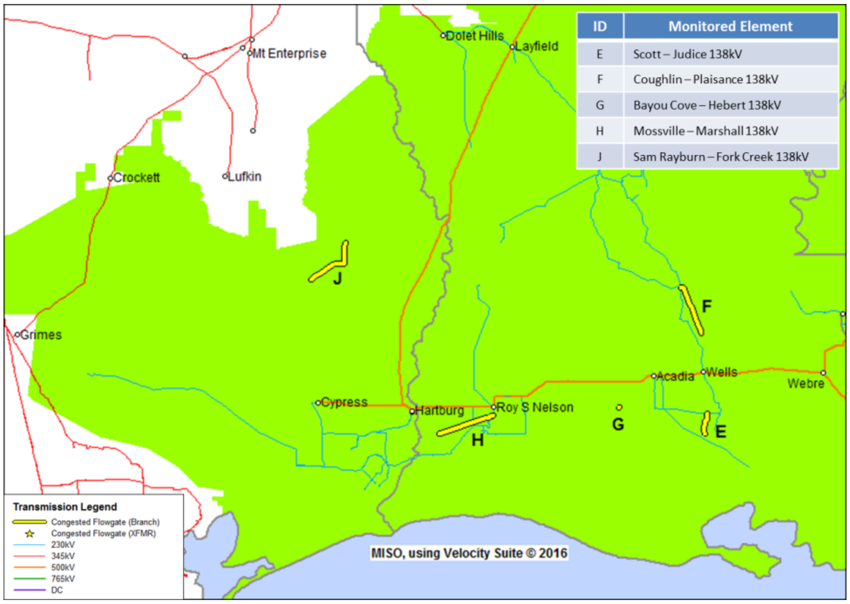


Figure 5.3-12: WOTAB/Western Top Congested Flowgates

Eighteen projects were submitted to address congestion in the WOTAB and Western load pockets. These projects were designed to provide increased transfer capabilities into the WOTAB and Western load pockets, as well as alleviating internal congestion within the load pockets. After the completion of screening, none of the submitted projects produced adequate benefits to pass the screening criteria.

Since integration, the MISO Board has approved significant transmission investments in the WOTAB and Western load pockets. These transmission expansions led to a reduction in congestion and the remaining congestion in the area is not sufficient to justify robust and cost effective transmission solutions. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

Remainder of LRZ9 (Rest of Louisiana)

The identified congestion in the Remainder of LRZ9 (Rest of Louisiana) spreads across the footprint with the majority of congestion on the Minden to Sarepta 115 kV line in northwest Louisiana, and on the Red Gum to Natchez 115 kV line on the border of Louisiana and Mississippi (Figure 5.3-13).

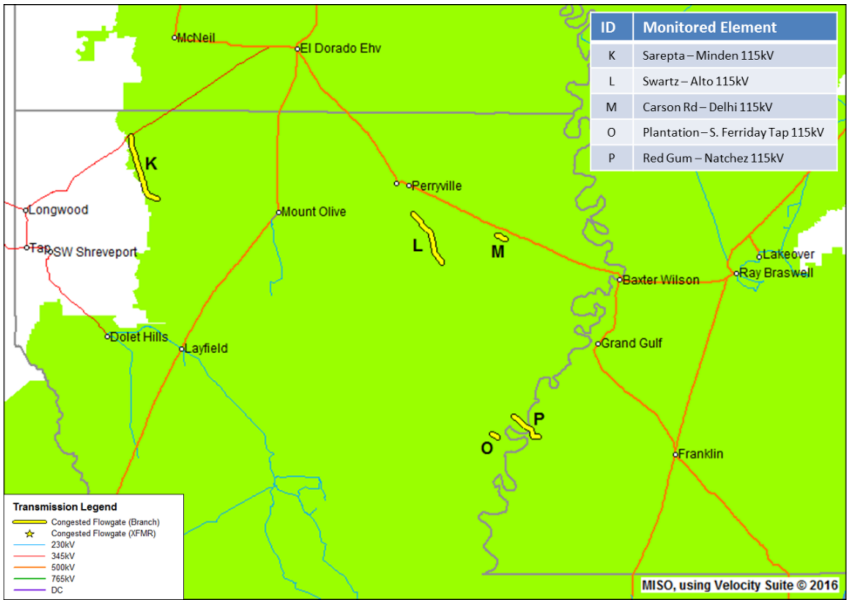


Figure 5.3-13: Remainder of LRZ9 (Rest of Louisiana) Top Congested Flowgates

A total of 17 projects were submitted to address the congestion in the Remainder of LRZ9 (Rest of Louisiana). After the completion of screening and refinement, two projects were selected for further evaluation.

One of the two projects, New Murray Tap to S. Natchez 115 kV, mitigated the congestion seen on the Red Gum to Natchez 115 kV and Plantation to S. Feriday Tap 115 kV lines. The robustness analysis determined that benefits of the project are reduced by re-siting the MISO PV Solar (RRF) in the RCPP and SRCPP futures. This sensitivity analysis leads to a reduction in the congestion seen on the Red Gum to Natchez 115 kV constraint, thus reducing the weighted benefit-to-cost ratio below the 1.25 threshold. This congestion will continue to be studied as part of future planning cycles.

The remaining project selected for further evaluation in this area upgrades the terminal equipment on the existing Minden to Sarepta 115 kV line. This project is identified as the best-fit solution to mitigate the congestion observed on this constraint and produces benefits that exceed the costs (Table 5.3-9).

MISO recommends the upgrade of the Minden to Sarepta 115 kV terminal equipment to the board as an economic Other Project in MTEP16.

Transmission Solution	Cost ($M)	ISD*	Benefit to Cost Ratios					
			BAU	HD	LD	RCPP	SRCPP	Weighted
Upgrade Minden to Sarepta 115 kV Terminal Equipment	$1.9	2020	(0.29)	2.59	0.57	0.88	5.06	**1.83**

***In Service Date**

Table 5.3-9: Upgrade Minden to Sarepta 115 kV terminal equipment PV analysis results

LRZ10 (Mississippi)

The majority of the identified congestion in LRZ10 is localized on the Lakeover 500/115 kV autotransformer for the loss of the Lakeover to Ray Braswell 500 kV line (Figure 5.3-14).

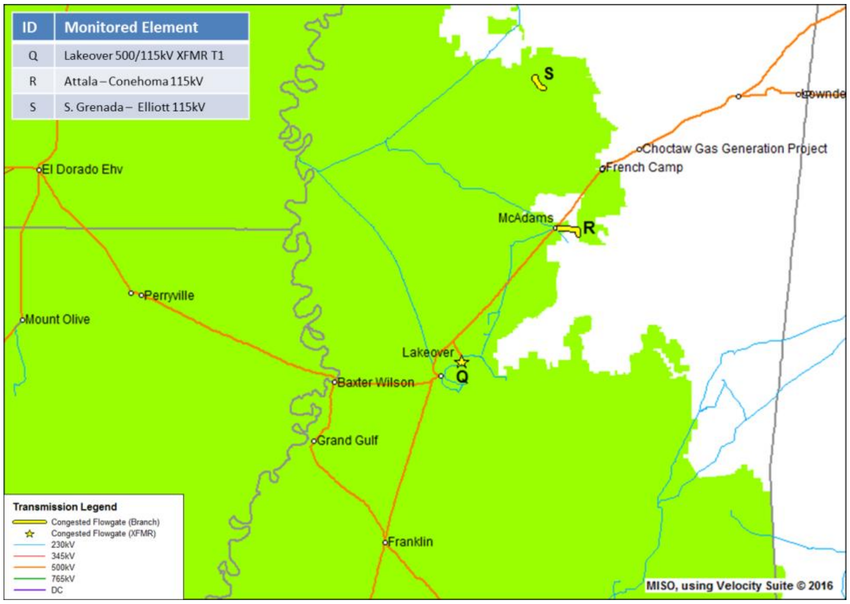


Figure 5.3-14: LRZ10 (Mississippi) Top Congested Flowgates

A total of 10 projects were submitted to address the congestion in LRZ10. After the completion of screening and refinement it became apparent that an adequate benefit-to-cost ratio is dependent on the ability to relocate the existing 500/230 kV autotransformer at McAdams to the Lakeover substation (Table 5.3-10).

MISO recommends the relocation of the existing 500/230 kV autotransformer at McAdams to the Lakeover substation to the Board as an economic Other Project in MTEP16.

Transmission Solution	Cost ($M)	ISD*	Benefit-to-Cost Ratios					
			BAU	HD	LD	RCPP	SRCPP	Weighted
Lakeover 500/230 kV XFMR	$6.7	2020	2.63	1.80	0.93	2.05	(0.06)	**1.43**

***In Service Date**

Table 5.3-10: Lakeover 500/230 kV XFMR PV analysis results

LRZ8 (Arkansas)

The identified congestion in LRZ8 was spread across the footprint with the majority of congestion showing on the Morrilton East to Gleason 161 kV line in central Arkansas, and on the Trumann to Trumann West 161 kV line in northeast Arkansas (Figure 5.3-15).

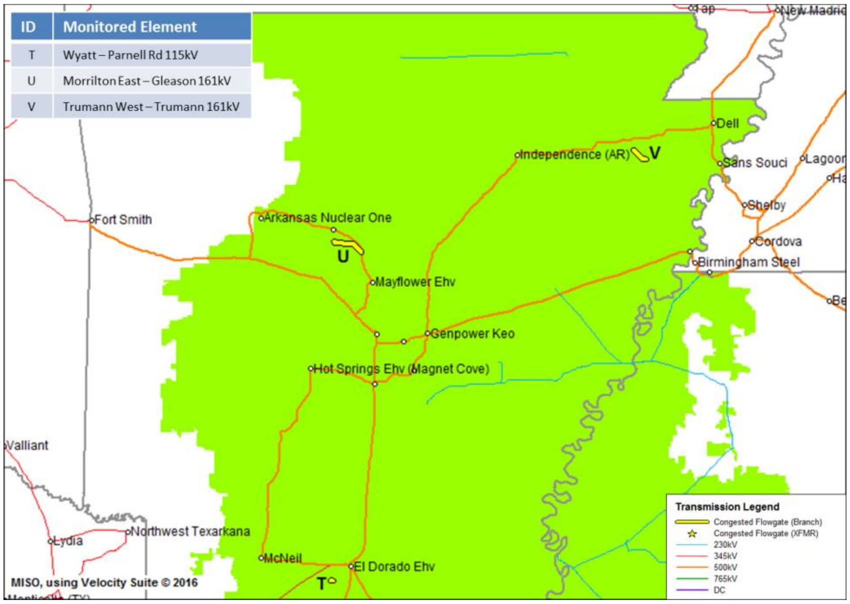


Figure 5.3-15: LRZ8 (Arkansas) Top Congested Flowgates

A total of 10 projects were submitted to address the congestion in LRZ8. After the completion of screening and refinement, two projects were selected for further evaluation.

One of the two projects, Rebuild Morrilton East to Tyler 161 kV, mitigated the congestion seen on the Morrilton East to Gleason 161 kV line. The robustness analysis determined that the benefits of the project are significantly impacted by the SERC wind that is sited in SPP footprint. A sensitivity study was performed, which deactivated this SERC wind in order to quantify the impact to the weighted benefit-to-cost ratio. This sensitivity resulted in the weighted benefit-to-cost ratio dropping significantly below the 1.25 threshold. This congestion will continue to be studied as part of future planning cycles.

The remaining project selected for further evaluation in this area rebuilds the existing Trumann to Trumann West 161 kV line. This project is identified as the best-fit solution to mitigate the congestion observed on the Trumann to Trumann West 161 kV line and produces benefits that well exceed the costs (Table 5.3-11).

The rebuild of Trumann to Trumann West 161 kV is recommended to the Board as part of MTEP16.

Transmission Solution	Cost ($M)	ISD*	Benefit to Cost Ratios					
			BAU	HD	LD	RCPP	SRCPP	Weighted
Rebuild Trumann to Trumann West 161 kV	$7.6	2018	12.69	3.06	19.72	15.29	11.60	**13.36**

***In Service Date**

Table 5.3-11: Rebuild Trumann to Trumann West 161 kV PV analysis results