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MINNESOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. E002, ET6675/CN-17-184

DIRECT TESTIMONY

OF

ZHENG ZHOU

Submitted on Behalf

of

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. (MISO)

September 6, 2018

Exhibit MISO - 1

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I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME, EMPLOYER, JOB TITLE, AND BUSINESS ADDRESS.

A. My name is Zheng Zhou. I am employed by the Midcontinent Independent System Operator, Inc. ("MISO") as its Manager of Economic Studies. My business address is 2985 Ames Crossing Road, Eagan, Minnesota 55121.

Q. WHAT IS MISO?

A. MISO is a not-for-profit, member-based, regional transmission organization ("RTO") providing reliability and market services over 65,800 miles of transmission lines in fifteen states and one Canadian province. MISO's regional area of operations stretches from the Ohio-Indiana line in the east to eastern Montana in the west, and south to New Orleans. MISO is governed by an independent ten-member Board of Directors.[1]

Q. WHAT ARE MISO'S RESPONSIBILITIES?

A. As an RTO, MISO is responsible for operational oversight and control, market operations, and planning of the transmission systems of its member Transmission Owners ("TOs"). Among many other responsibilities, MISO provides tariff administration for its Open Access Transmission, Energy and Operating Reserve

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[1] MISO has nine independent directors, and its CEO fills a tenth seat on the Board.

Markets Tariff ("Tariff").[2] Most relevant to these proceedings, MISO is responsible for ensuring that the transmission system is planned to reliably and efficiently provide for existing and forecasted electric usage. MISO is the Planning Coordinator for its regional area of operations and performs planning functions collaboratively with its TOs with stakeholder input throughout, while also providing an independent assessment and perspective of the needs of the transmission system overall.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a Ph.D. degree in Electrical Power Engineering in 2004 from Iowa State University. Prior to that, I received a Master's Degree in Electrical Engineering from Tsinghua University, located in China, in 2000 and Bachelor's degrees in electrical engineering and economics in 1997 from that same university.

Q. WHAT HAVE YOUR DUTIES AND RESPONSIBILITIES BEEN SINCE JOINING MISO?

A. I joined MISO as an engineer in its policy and economic studies team in 2004. I became a senior, then principal engineer respectively in 2008 and 2010 on this same team. I became a senior advisor in 2013, and supervised the loss of load expectation studies that support the calculation of planning reserve margin

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[2] The MISO Tariff is publicly available on the MISO website.

requirements for each load serving entity with the MISO footprint. In 2014, I became the Manager of Economic Transmission Planning. During my years in MISO as an engineer/advisor, I have been involved in many different aspect of power system planning functions that include power system economic planning, renewable energy integration, and loss of load expectation studies. I led and performed analyses for various notable transmission planning studies such as the Minnesota Wind Integration Study, Regional Generation Outlet Study, Multi-Value Project Portfolio Analysis, and the Manitoba Hydro Wind Synergy Study.

In 2014, I began my supervision of an engineering team that performed economic studies using, among other engineering tools, the ABB PROMOD Production Cost program to evaluate the economic impact of proposed transmission projects under various future scenarios. I supervised the planning study and stakeholder engagement associated with the first competitive bid Market Efficiency Project – the Duff-Coleman 345kV project and various alternatives – located in Southern Indiana. I also supervised the planning studies and stakeholder engagement for the other Market Efficiency Project located in Southern Minnesota, near the northern border of Iowa. That project was the Huntley-Wilmarth 345kV project, which is the subject of these proceedings. Both the Duff-Coleman and Huntley-Wilmarth projects are designed to provide strong economic benefits by reducing the nearby transmission system congestion while providing reliability support, operational flexibility, and opening opportunities to for future transmission system expansion.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the transmission owners' Application[3] to the Minnesota Public Utilities Commission for a Certificate of Need to permit ITC Midwest LLC ("ITC Midwest") and Northern States Power Company (Minnesota) ("NSP") to build and operate a 345 KV transmission line between the Huntley and Wilmarth substations and associated facilities. Together, these improvements are referred to in my testimony as the "Proposed Transmission Project."

My testimony explains the MISO planning process, including the relationship between the transmission planning group at MISO and transmission developers. My testimony summarizes MISO's results that show the electrical need for the Proposed Transmission Project.

[3] Application to the Minnesota Public Utilities Commission for a Certificate of Need for the Huntley-Wilmarth 345 kV Transmission Line Project, MPUC Docket No. E-002, ET6675/CN-17-184 (January 17, 2018) ("Application").

II. MISO TRANSMISSION PLANNING OBJECTIVES AND PROCESSES

Q. WHAT ARE THE PRINCIPLES OF THE MISO PLANNING PROCESS?

A. Regional planning at MISO is performed in accordance with several guiding documents. The Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation ("Transmission Owners Agreement" or "TOA") includes the planning framework that describes the planning responsibilities of MISO and its transmission owning members.[4] Responsibilities of MISO include the development of the MISO Transmission Expansion Plan ("MTEP") in collaboration with transmission owners and stakeholders based upon local, state, and federal (NERC) planning criteria.

MISO also adheres to the nine planning principles outlined in FERC Order No. 890[5] and reinforced in FERC Order 1000.[6] In so doing, MISO provides an open

[4] *See* MISO Transmission Owners Agreement, Appendix B, Section VI, which is publicly available on the MISO website as Rate Schedule 01.

[5] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009). "The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects." Order 890-B, Attachment K.

[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 66,051 (2011), *order on*

and transparent regional planning process that recommends transmission expansions that are reported in the MTEP.

Q. WHAT ARE THE OBJECTIVES OF THE MISO PLANNING PROCESS?

A. Consistent with the planning principles described above, the objectives of the MISO planning process are (i) to identify transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of MISO, (ii) to identify expansion that is critically needed to support the reliable and competitive supply of electric power by this system, and (iii) to identify expansion that is necessary to support energy policy mandates in effect within the MISO footprint.

Q. WHAT PLANNING PROCESS IS USED TO DEVELOP THE MTEP?

A. MISO uses a "bottom-up, top-down" approach in developing the MTEP plan. The "bottom-up" portion relies on the ongoing responsibilities of the individual transmission owners to continuously review and plan to reliably and efficiently meet the needs of their local systems. MISO then reviews these local planning activities with stakeholders and performs a "top-down" review of the adequacy of and appropriateness of the local plans in a coordinated fashion with all other local plans to most efficiently ensure that all of the needs are cost effectively met. In

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reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

addition, MISO, together with stakeholders, considers opportunities for improvements and expansions that would reduce consumer costs by providing access to new low cost resources that are consistent with and required by evolving legislative energy policies.

As part of the "top-down" review, MISO's planning process examines congestion that may limit access to the most efficient resources, and considers improvements that may be needed to meet forecasted energy requirements. Stakeholders from each MISO member sector, including state regulatory authorities, public consumer advocates, environmental representatives, end use customers, and independent power producers, among others, are engaged to develop a wide range of future system scenarios that are guided by assessments of possible future state and federal energy policy decisions. The possible future scenarios and energy polices ("Future Scenarios") form the basis for forecasts of resources and load that would be economical and consistent with policy. Transmission needs are then assessed and MTEP plans are developed to reliably and efficiently deliver the necessary energy from resources to load.

Q. WHAT DOES IT MEAN FOR A PROJECT TO BE APPROVED BY THE MISO BOARD OF DIRECTORS AS A PART OF THE MTEP?

A. The MTEP consists of the many individual projects or portfolios of projects that are recommended by the MISO staff to the MISO Board of Directors. In accordance with the TOA, approval of a MISO MTEP by the Board of Directors certifies the MTEP as MISO's plan for meeting the transmission needs of all stakeholders, subject to any required approvals by federal or state regulatory authorities.

Q. WHAT CONSIDERATIONS DOES MISO TAKE INTO ACCOUNT IN PREPARING THE MTEP REGIONAL PLANS?

A. There are numerous considerations in planning for a regional transmission system; however, two considerations are crucial. First, the security of the transmission system must be maintained. The transmission system must be able to withstand disturbances (generator and/or transmission facility outages) without interruption of service to load. This is achieved, in part, by assuring that disturbances do not lead to cascading loss of other generator and transmission facilities.

Second, the transmission system must be adequately planned to be able to accommodate load growth and/or changes in load and load growth patterns, as well as changes in generation and generation dispatch patterns without causing equipment to perform outside of its design capability. Additional considerations include addressing constraints that limit market efficiency and providing for expansions that enable energy policy mandates to be achieved.

III. ECONOMIC PLANNING PROCESS

Q. WHAT MTEP PLANNING PROCESS WAS UTILIZED FOR EVALUATING THE PROPOSED TRANSMISSION PROJECT?

A. The Proposed Transmission Project was evaluated through the Market Congestion Planning Study ("MCPS") process in 2016 and approved as part of the 2016 MTEP. Reporting on the MCPS process was performed in the form of a 2016 MTEP Report, the most relevant portion of which is attached as Schedule 1.

Q. WHAT IS THE GOAL OF THE MCPS?

A. MCPS, which is part of the "top-down" approach of the MISO planning process, aims 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.

In order to develop a robust transmission plan under a wide variety of economic and policy conditions, MCPS utilizes a scenario based analysis, that serve as the basis for transmission evaluation. Stakeholders from each MISO member sector, including state regulatory authorities, public consumer advocates, environmental representatives, end use customers, and independent power producers, among others, are engaged to develop a wide range of "Future Scenarios" that are guided by assessments of possible future state and federal energy policy decisions.

Q. WHAT FUTURE SCENARIOS WERE DEVELOPED FOR THE MCPS PROCESS IN 2016?

A. The "Futures Scenarios" utilized in the MCPS in 2016, along with their key drivers, are described below:[7]

- The Business as Usual 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. Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted by the Load Serving Entities. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. To capture the expected effects of environmental regulations on the coal fleet, a total of 12.6 GW of coal unit retirements are modeled.
- The High Demand future is designed to capture 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. Similar to the Business as Usual

[7] This discussion is essentially a portion of Section 5.2 ("Futures Development") of the 2016 MTEP Report, adapted for purposes of presenting this testimony.

future, all current state-level RPS and EERS mandates are modeled; along with 12.6 GW of coal unit retirements. Additionally, 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.

- The Low Demand future is designed to capture 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 bound of the Load Forecast Uncertainty metric. Similar to the Business as Usual future, all current state-level RPS and EERS mandates are modeled; along with 12.6 GW of coal unit retirements. 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.
- The Regional Clean Power Plan (CPP) future focuses on several key items from a footprint wide level which 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 the following:
    - In addition to the 12.6 GW of coal unit retirements modeled in the previous three futures, another 14 GW of the oldest coal units are retired. Moreover, this future includes a $25/ton carbon cost, state mandates for renewables, and half of the Energy Efficiency (EE) annual growth used by the EPA.

- The same age-related retirements modeled in the High Demand and Low Demand future.
- An economic maturity curve with solar and wind to reflect declining costs over time.
- Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted by the Load Serving Entities.

- 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 following:
  - In addition to the 12.6 GW of coal unit retirements modeled in the previous three futures, another 20 GW of the oldest coal units are retired. Moreover, this future includes a $40/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA.
  - The same age-related retirements modeled in the High Demand and Regional Clean Power Plan.
  - An economic maturity curve with solar and wind to reflect declining costs over time.
  - Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted by the Load Serving Entities.

Q. HOW ARE TRANSMISSION PLANS DEVELOPED AND EVALUATED THROUGH THE MCPS PROCESS?

A. MCPS utilizes different "Futures Scenarios" developed to identify potential congestion issues that may cause inefficiencies in the market by limiting access to the efficient generation resources and meeting the forecasted energy requirements. With the congestion issues clearly defined, the study evaluates a wide variety of transmission ideas in an iterative fashion with both economic and reliability robustness considerations. The development of transmission solutions is performed using a two-phase approach: "Project Candidate Identification" phase which includes: screening analysis to pinpoint the solutions with the highest potential; and a "Robustness Analysis" phase where economic evaluations are performed over multiple years and futures to assess robustness, and reliability analyses are conducted to ensure the projects do not degrade system reliability.

Q. HOW IS THE PROJECT CANDIDATE IDENTIFICATION PHASE CONDUCTED?

A. In the Project Candidate Identification phase, a 2-staged approach to determine the transmission ideas that show high potential is utilized.

In the first stage, an initial screening test involving a one-year production cost analysis of the economic benefits resulting from the transmission idea for each future is performed. The ratio of weighted economic benefit across all the "Future

Scenarios" for that study year to the estimated transmission carrying charge for the particular year for each transmission idea is then estimated. All transmission ideas that result in ratios greater than or equal to 0.9 are considered for advancement to the next stage of analysis.

In the second stage, MISO performs a complete economic analysis of each transmission idea that includes a production cost analysis for all study years and futures. A weighted benefit-to-cost ratio is calculated for the first 20 years of project life for each transmission idea. The transmission ideas with a weighted benefit-to-cost ratio greater than or equal to 1.0 are deemed "Project Candidates."

Q. HOW IS THE ROBUSTNESS ANALYSIS PHASE CONDUCTED?

A. In the Robustness Analysis phase, all Project Candidates are analyzed to ensure that the study assumptions, such as the generation siting assumptions for future generation without signed Generation Interconnection Agreements and age-related retirement assumptions, have no significant impact on the benefits delivered by the transmission plan. Further, a reliability analysis is performed to ensure that any reliability harm caused by the transmission plan is addressed. 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. Sensitivity analyses are also performed as part of the robustness analysis on an as-needed basis, and include, among other factors, consideration of: (i) variations in amount, type, and location of future generation supplies as dictated by future scenarios developed with stakeholder input and guidance; (ii) alternative transmission proposals; (iii) impacts of variations in load growth; and (iv) effects of demand response resources on transmission benefits.

Q. WHAT WERE THE METRIC AND CRITERIA USED FOR THE SELECTION OF TRANSMISSION PROJECTS FROM THE MCPS IN 2016?

A. MISO utilized the Adjusted Production Cost ("APC") as the benefit metric to quantify the economic benefits resulting from a transmission project. The APC for an entity is defined as the sum of generation production cost[8] of all generation resources owned by the entity and cost of energy imported by the entity less the revenue generated from energy exports from the entity. For the MCPS Study in 2016, the reduction in APC for the MISO North/Central Region due to a transmission project was utilized as the annual economic benefit resulting from the transmission project.

A weighted benefit-to-cost ratio was calculated for each transmission project using the present value of the APC savings in the system for the first 20 years of

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8 Generation Production Cost includes fuel, start-up, variable operations and maintenance, and emissions costs.

project life and the 20-year present value of the estimated annual transmission carrying charge and the "Future Weights" for the "Future Scenarios." Transmission Projects with a benefit-to-cost ratio of 1.25 or higher are selected from the MCPS as the optimal economic transmission upgrades (best-fit solutions).

Q. WHAT WERE THE FUTURE WEIGHTS UTILIZED IN THE MCPS IN 2016?

A. The Future Weights for various Futures Scenarios utilized for transmission evaluation in 2016 are as follows: Business as Usual – 19 percent; High Demand – 10 percent; Low Demand – 16 percent; Regional CPP – 30 percent; and Sub-Regional CPP – 25 percent.[9] Future weights were developed by taking inputs from various stakeholders from each MISO member sector, including state regulatory authorities, public consumer advocates, environmental representatives, end use customers, and independent power producers, among others.

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9 A description of the weighting is contained on page 97 in the 2016 MTEP Report. Schedule 1 ("MISO Models and Futures").

IV. ECONOMIC EVALUATION OF THE PROPOSED TRANSMISSION PROJECT

Q. WERE ANY TRANSMISSION ISSUES IDENTIFIED DURING THE 2016 MCPS THAT WOULD BE RESOLVED BY THE PROPOSED TRANSMISSION PROJECT?

A. Yes. During the Transmission Issue identification phase of the MCPS study in 2016, eight transmission issues (also referred to as "Top Congested Flowgates" or "Transmission Needs" in the 2016 MTEP Report) were identified in the MISO North/Central Region. One of these transmission issues was resolved by the Proposed Transmission Project. This transmission issue was Huntley – Blue Earth 161kV, and is located in southern Minnesota. This transmission issue is located in the NSP and ITC Midwest service areas.

Q. HOW DID MISO CONDUCT THE TRANSMISSION DEVELOPMENT PHASE OF THE MCPS THAT RESULTED IN THE DEVELOPMENT OF THE PROPOSED TRANSMISSION PROJECT?

A. After the transmission issues were identified, MISO engaged in a collaboration process with its stakeholders – including the local transmission owning members, transmission developers, and other entities – to develop transmission solutions to address these issues. Fifty-seven potential transmission solutions were identified to relieve identified transmission issues in the MCPS study in 2016, including twenty-three potential solutions in the Iowa/Minnesota area.[10] A screening analysis, performed as part of the Project Candidate Identification phase of the MCPS, was conducted to determine whether these projects addressed the identified transmission issues. Twenty-three transmission solutions, including sixteen transmission solutions from the Iowa/Minnesota area, met the benefit-to-cost ratio criteria to be considered for evaluation for all years and futures. After further review of the screening analysis results, four of the sixteen transmission solutions were identified to be solutions for further evaluation based on the benefits they provided relative to their costs and their varied approaches in addressing the transmission issue. Three of these four transmission solutions had benefit-to-cost ratios of greater than 1.0 and were identified as Project Candidates. Of the three project candidates, the Proposed Transmission Project had the highest benefit-to-cost ratio, highest 20-year present value benefit, and was the only Project Candidate to fully relieve the transmission issue.

Various sensitivity analyses were performed as part of the Robustness Analysis to help inform the project's business case under different potential scenarios. These sensitivity tests evaluated the impact of:

- Retiring Sherco Units 1 and 2;
- Removing all assumed non-MISO future-forecasted wind unit capacity from Iowa and Minnesota;

[10] *See* 2016 MTEP Report, Schedule 1 on page 101.

- Removing all assumed future-forecasted wind unit capacity and instead modeling 100% of the wind unit capacity in the MISO queue with DPP or GIA-in-Progress for Iowa and Minnesota;[11]
- Removing all assumed future-forecasted wind unit capacity and instead modeling 75% of the wind unit capacity in the MISO queue with DPP or GIA-in-Progress for Iowa and Minnesota; and
- Removing all assumed future-forecasted wind unit capacity and instead modeling 50% of the wind unit capacity in the MISO queue with DPP or GIA-in-Progress for Iowa and Minnesota.

Under all of these sensitivities, the Proposed Transmission Project maintained a high weighted benefit-to-cost ratio.

Q. WHAT WERE THE BENEFIT-TO-COST RATIOS FOR THE PROPOSED TRANSMISSION PROJECT?

A. The Proposed Transmission Project has a range of cost estimates that depend on the line routing cost estimates and the scenario under consideration. As reported in the 2016 MTEP Report, the relevant part of which is shown in Schedule 1, the lower end of the range of cost estimates with recognition of MISO wind turbine interconnection request information provides a benefit-to-cost ratio of 2.28. On

[11] This wind sensitivity was used for the values reported in Table 5.3-1 of the 2016 MTEP Report, Schedule 1 on page 102, under the model designated as "Queue Wind Sensitivity." Under this sensitivity, the weighted benefit-to-cost ratio of the Proposed Transmission Project ranged from 1.86 to 2.28.

the higher end of the range of routing cost estimates and without recognition of MISO wind turbine interconnection request information, the Proposed Transmission Project provides a benefit-to-cost ratio of 1.51.[12] These benefit-to-cost ratios are well above the threshold of 1.25 to be considered an economically justified transmission upgrade (best-fit solution) from the MCPS.[13]

Q. HOW WAS THE PROPOSED TRANSMISSION PROJECT JUSTIFIED?

A. The Proposed Transmission Project was justified based on economic benefits it provides to the MISO North/Central Region under a variety of Future Scenarios.

Q. WHAT RESULTS FOLLOWED THE EVALUATION OF THE PROPOSED TRANSMISSION PROJECT?

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[12] These figures are shown on Table 5.3-1 of the 2016 MTEP Report, Schedule 1 on page 102. The line construction cost estimates, and corresponding benefit-to-cost ratios, reflect MISO study results and do not necessarily correspond to the discussion of alternatives in information filed by ITC Midwest and NSP in these dockets.

[13] Benefit-to-cost ratios near the 1.25 level result from using the highest line routing costs reported in the Application for these proceedings, even without recognition of MISO wind turbine interconnection request information. Application, Chapter 2 ("Project Description"), Table 2 on page 35 (total project costs for four proposed routes from $105.8 to $138.0 million). Applicants reported the results of an analysis of the benefit-to-cost ratio for the Project using updated models developed for MTEP17. *Id.*, Chapter 4 ("Need Analysis"). Table 17 reports benefit-to-cost results using a range of estimates based on construction costs. The direction of change for these results appear to be consistent with MISO-based analyses.

A. The MISO staff recommended the Proposed Transmission Project to the MISO Board as part of the 2016 MTEP based on the large net economic benefits. The MISO Board approved the Proposed Transmission Project as part of the 2016 MTEP. Approval of a MISO MTEP by the Board of Directors certifies MISO's plan for meeting the transmission needs of all stakeholders, subject to any required approvals by federal or state regulatory authorities.

V. RELIABILITY CONSIDERATIONS AND RESULTS

Q. WHAT OTHER PLANNING CONSIDERATIONS ARE TAKEN INTO ACCOUNT IN THE SELECTION OF TRANSMISSION PROJECTS FROM THE MCPS?

A. A reliability analysis is performed as part of the Robustness Analysis during the MCPS to ensure that the selected transmission projects do not degrade system reliability. The reliability analysis ensures that the transmission system has sufficient capacity to meet projected power flows while maintaining required voltage levels and system stability.

Q. HOW DO YOU DETERMINE IF A TRANSMISSION SYSTEM HAS CAPACITY SUFFICIENT TO MEET PROJECTED POWER FLOWS WHILE MAINTAINING REQUIRED VOLTAGE LEVELS?

A. This determination requires an engineering evaluation of the transmission system as a whole, as well as an evaluation of critical individual system components (transformers, lines, switchgear), under both normal and contingency conditions (conditions where one or more system components are out of service). Power system simulation models are developed for use in these analyses. Projected power flows for each major component are checked to ensure that rated capacities are not exceeded. Voltage levels are also checked to ensure that voltage levels are maintained within system limits to allow for safe operation of the system and adequate power delivery to customers.

Q. WHAT IS THE PROCESS FOR PERFORMING RELIABILITY ANALYSIS OF THE PROPOSED PROJECT?

A. A “No Harm Test” is performed, which compares two power flow models (with and without the candidate project) under a variety of system assumptions. Both models are assessed against applicable regional and NERC standards to determine if any new voltage or thermal reliability issues appear in the with-project models. The candidate project passes the no harm test if system reliability improves or remains the same.

Q. WHAT ASSUMPTIONS WENT INTO THE RELIABILITY ANALYSIS OF THE PROPOSED PROJECT

A. The analyses utilized the stakeholder-vetted series power flow models for the 2016 MTEP to assess system reliability. Because the proposed project is in a wind-rich location, analysis was performed using several different wind generation scenarios beyond the typical summer peak load conditions:

1) 2021 Summer Peak (Wind modeled at 15.6%)

2) 2021 Summer Shoulder (Wind modeled at 40%)

3) 2021 Summer Shoulder (Wind modeled at 90%)

Q. WHAT WERE THE RESULTS OF THE RELIABILITY ASSESSMENT PERFORMED WITH THE PROPOSED TRANSMISSION PROJECT?

A. The Proposed Transmission Project causes no harmful reliability impacts on the transmission system in the MISO footprint or neighboring transmission systems.

VI. <u>ANALYSIS OF ALTERNATIVES</u>

Q. WHAT ALTERNATIVE TRANSMISSION PROJECTS WERE CONSIDERED BY MISO?

A. After a comprehensive review through the MCPS to screen transmission solutions (*i.e.* the two-phase approach described above), five transmission projects (including the Proposed Transmission Project) emerged for additional analyses as cost-effective solutions to address the Huntley – Blue Earth 161kV transmission issues. The descriptions of the alternative projects to the Proposed Transmission Projects are as follows:

- Upgrade existing Huntley – Blue Earth – South Bend 161kV lines from 197 MVA to 362 MVA. Add a new 161kV line from South Bend to Wilmarth with an approximate length of 9 miles. Wilmarth would require a 161 kV substation addition, which would include a 345/161kV transformer and a new 161/115kV transformer as well as 161kV switch, breaker, bus bar, and communication/relay equipment. (Referred to as "Alternative Project 1.");
- A new 161kV line originating at existing Freeborn 161kV substation and terminating at existing West Owatonna 161kV substation, approximately 32 miles long. (Referred to as "Alternative Project 2."); and
- Two of the alternatives were mostly the same as the Proposed Transmission Project, but with additional upgrades on the nearby lower voltage system.
  - A new 345kV line from the existing Huntley substation to the existing Wilmarth substation, and an upgrade on the existing Wilmarth – Swan Lake – Ft Ridgeley 115kV line. (Referred to as "Alternative Project 3.")
  - A new 345kV line from the existing Huntley substation to the existing Wilmarth substation, an upgrade on the existing Wilmarth – Swan Lake – Ft Ridgeley 115kV line, a 2nd Helena – Scott County 345kV line, and an upgrade on the existing Scott Co – Scott Co Tap 115kV line. (Referred to as "Alternative Project 4.")

Q. WHY WERE THESE ALTERNATIVE PROJECTS NOT SELECTED?

A. The Proposed Transmission Project was selected for recommendation to the MISO Board in the 2016 MTEP over the alternative projects for the following reasons:

- The Proposed Transmission Project has the highest benefit-to-cost threshold of 1.5 to 1.9 based on the range of its cost estimates.[14] Alternative Project 2 does not meet the benefit-to-cost threshold with a ratio of 1.25.
- The Proposed Transmission Project fully relieves the congestion on the Huntley – Blue Earth transmission line identified in southern Minnesota. Alternative Project 1 and Alternative Project 2 provide only partial congestion relief on the identified transmission element.
- The incremental benefit provided by the upgrades included in Alternative Project 3 and Alternative Project 4 were not economically justifiable due to the size of their incremental costs.

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14 These figures are shown in Table 5.3-1 in the 2016 MTEP Report. Schedule 1 ("Huntley to Wilmarth 345 kV options sensitivity analysis results") on page 102.

VII. CONCLUSION

Q. WHAT IS YOUR CONCLUSION?

A. The Proposed Transmission Project would provide economic benefits and causes no reliability concerns for the transmission system owned and operated by NSP and ITC Midwest, and does not cause reliability concerns in the surrounding region. As a result, MISO included the Proposed Transmission Project in the 2016 MTEP. I support approval of the Proposed Transmission Project by the Minnesota Public Service Commission for a Certificate of Need.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Schedule 1

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

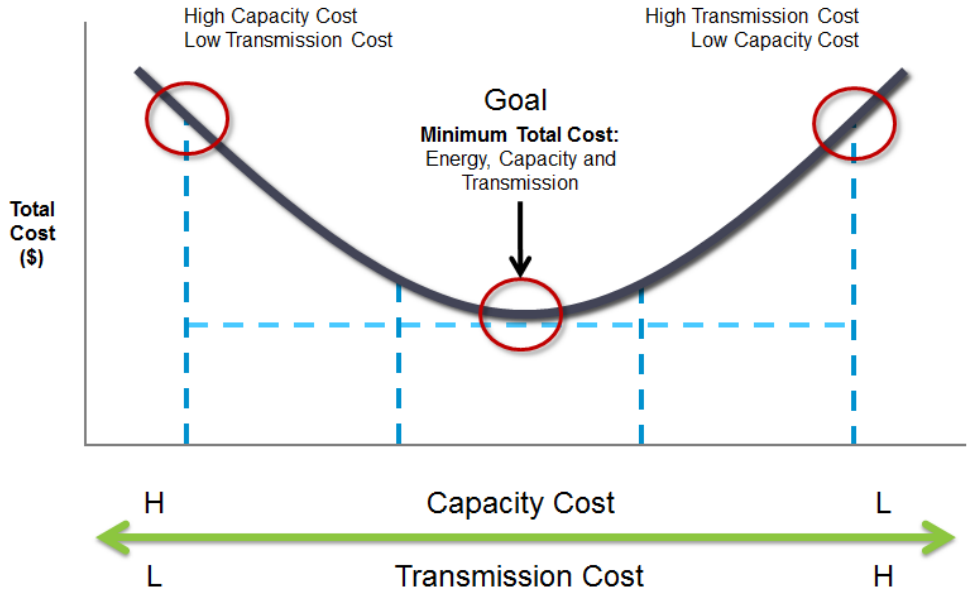

Figure 5.1-1: The goal of the MISO Value-Based Planning Process

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.

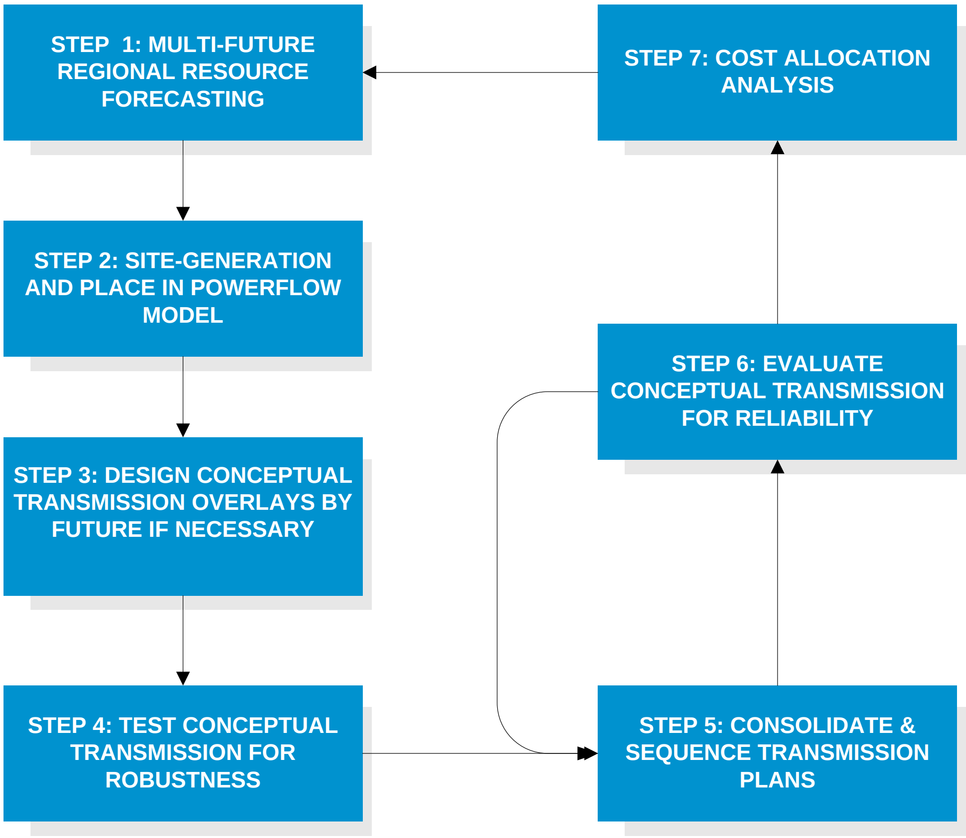

Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

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.

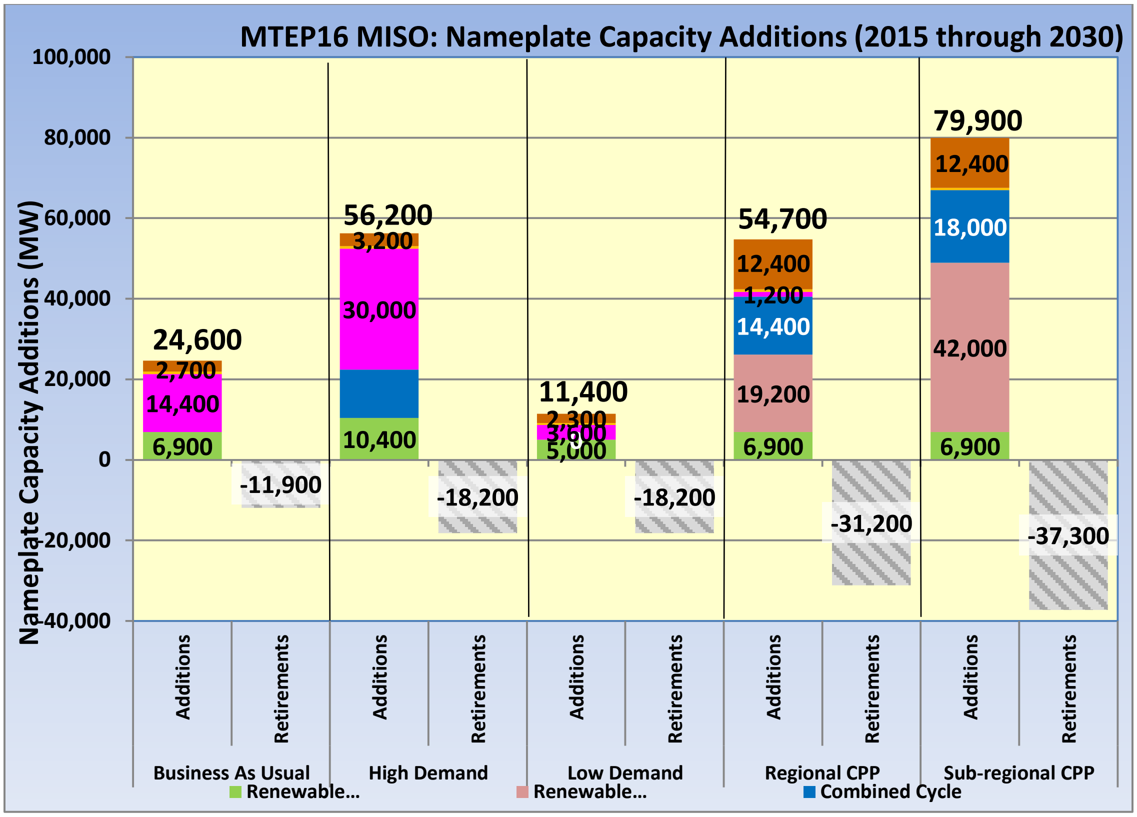

Figure 5.2-1: MISO nameplate capacity additions by future (2015-2030 EGEAS Model)[21]

[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.

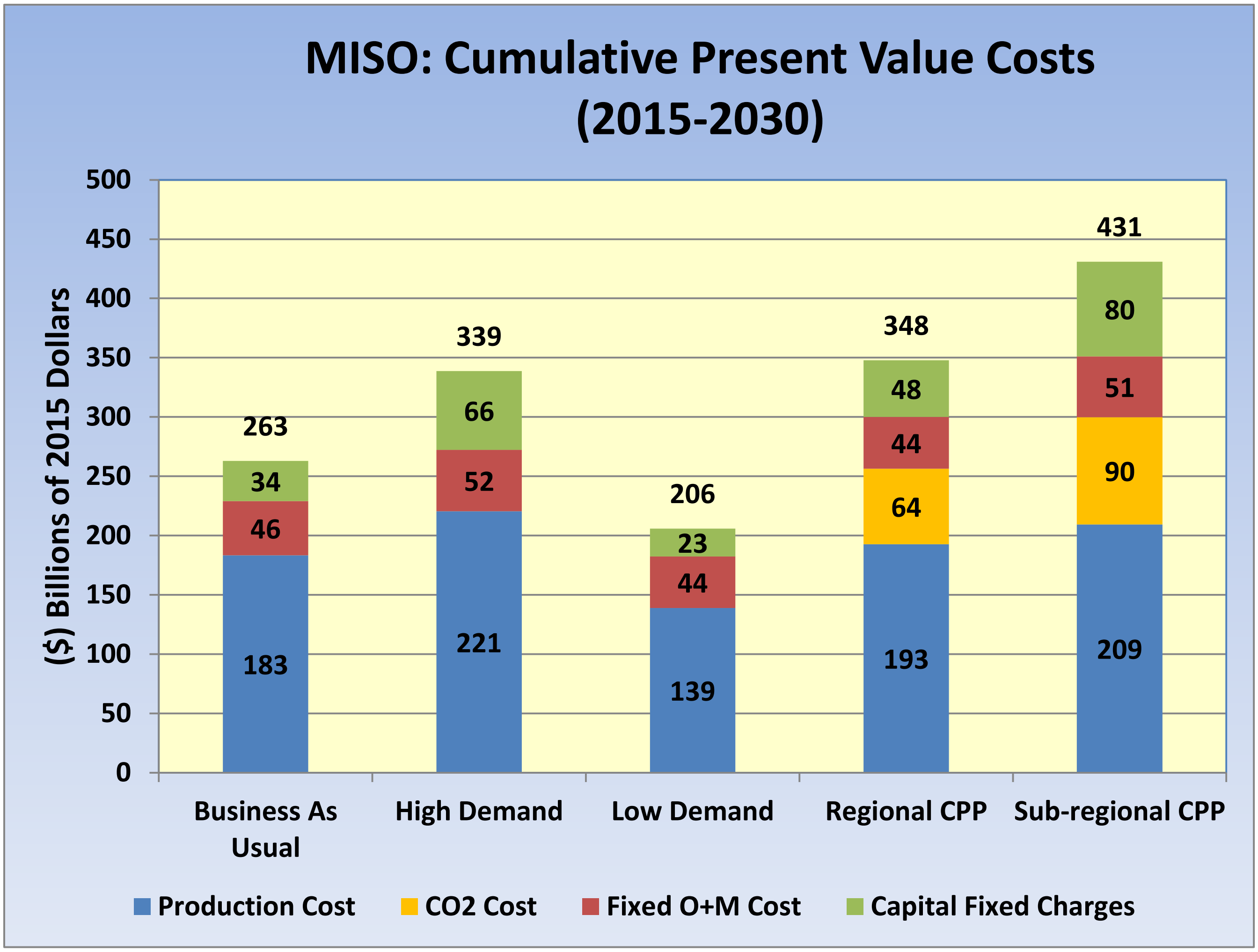

Figure 5.2-2: MISO present value of cumulative costs in 2015 U.S. dollars

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).

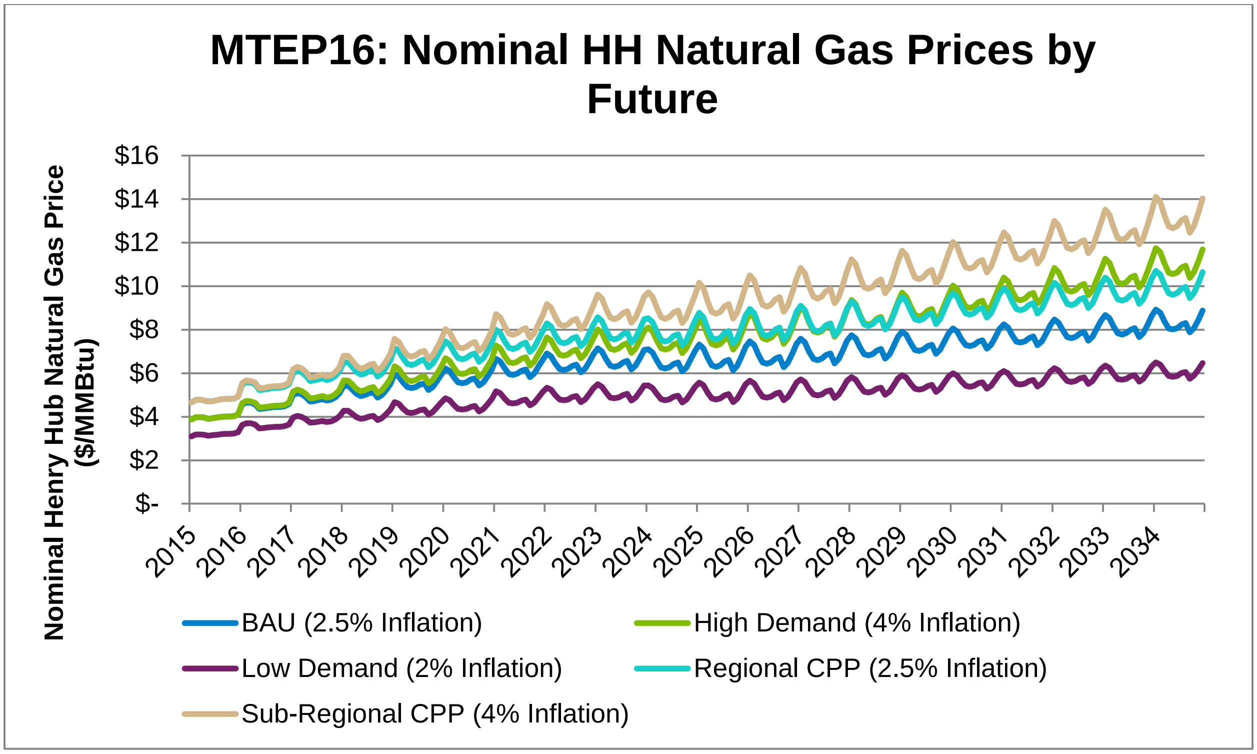

Figure 5.2-3: Natural gas forecasts by future

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.

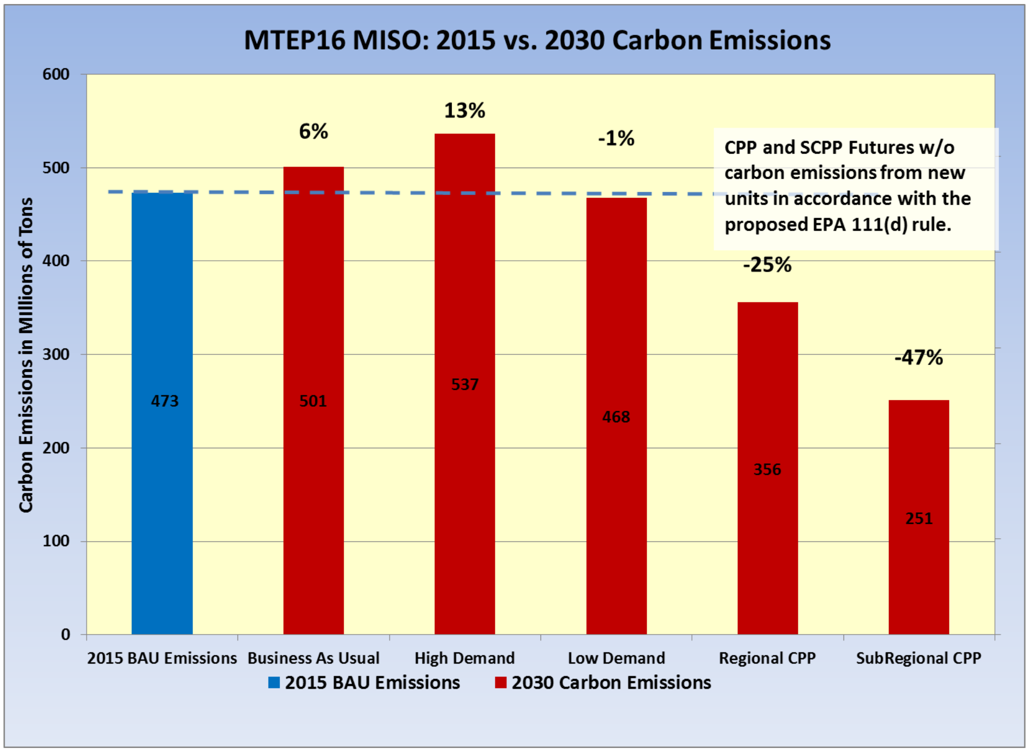

Figure 5.2-4: MISO carbon dioxide production

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.

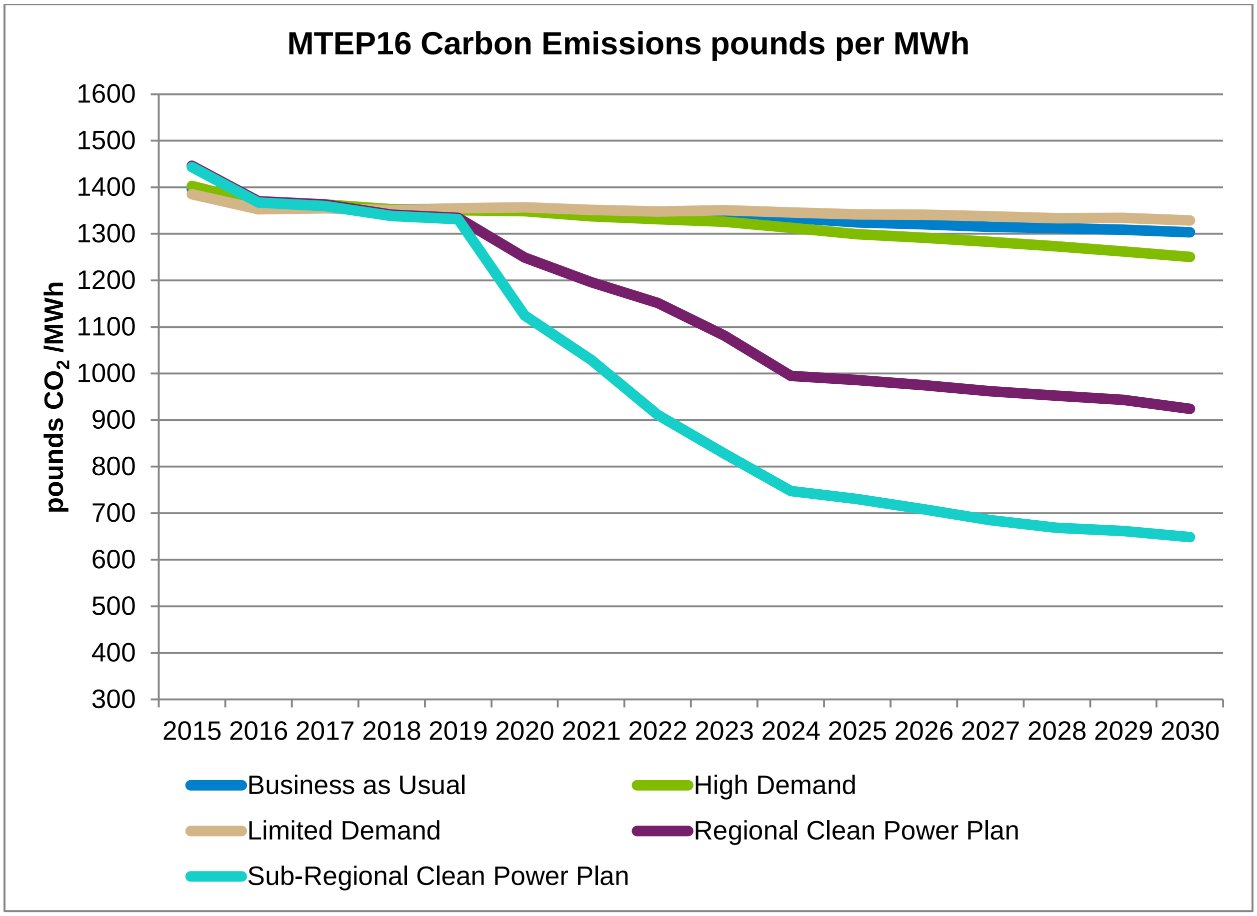

Figure 5.2-5: Carbon emissions per megawatt hour

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.

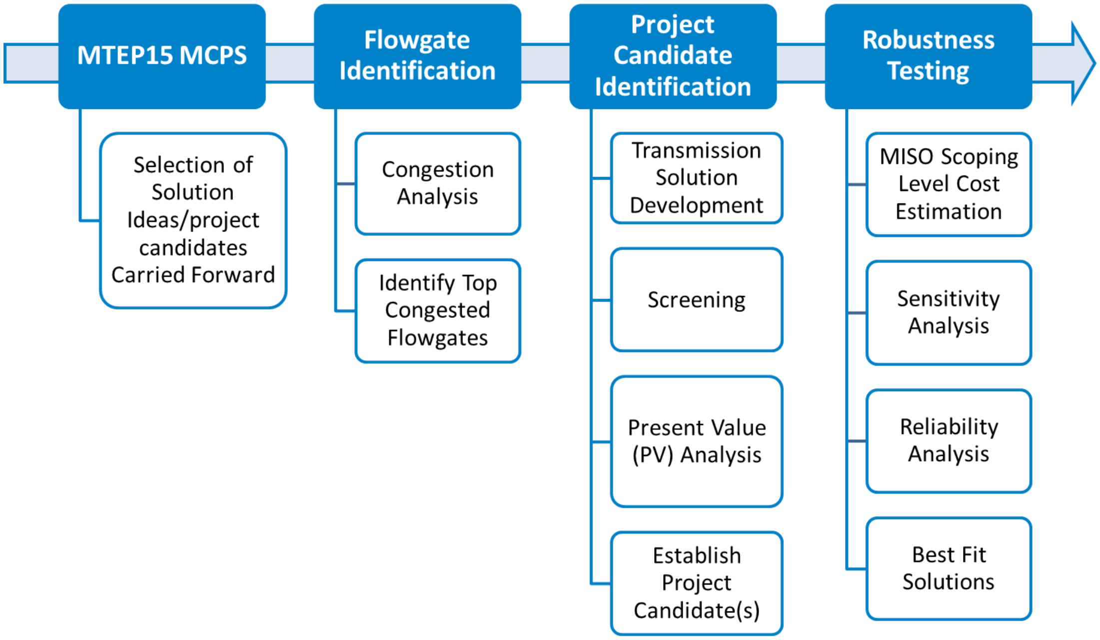

Figure 5.3-1: MCPS process overview

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).

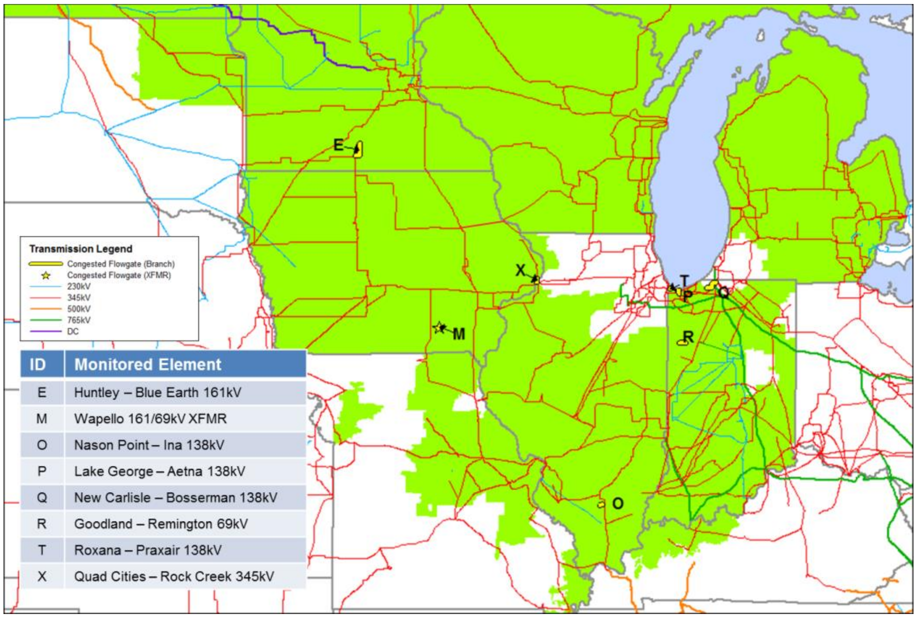

Figure 5.3-2: Projected Top Congested Flowgates in MISO North/Central Region

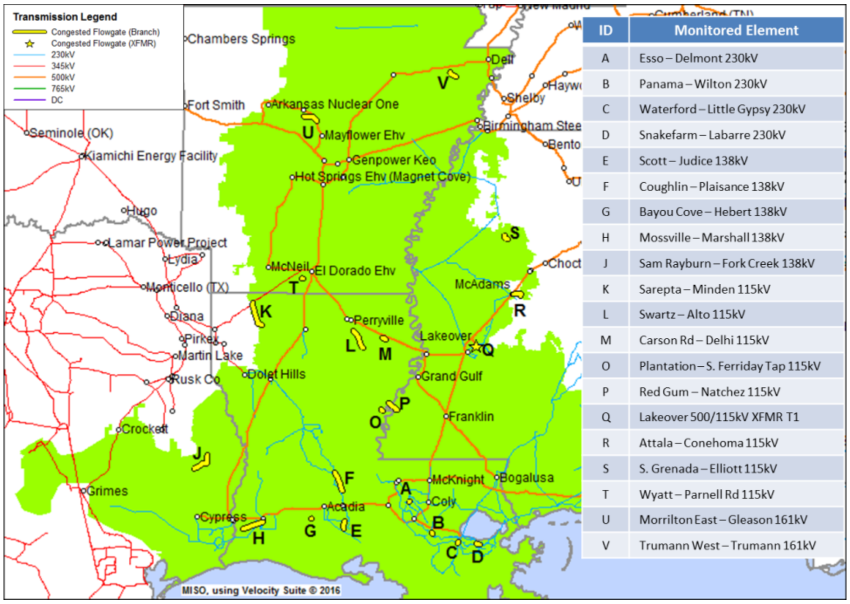

Figure 5.3-3: Projected Top Congested Flowgates in MISO South Region

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.

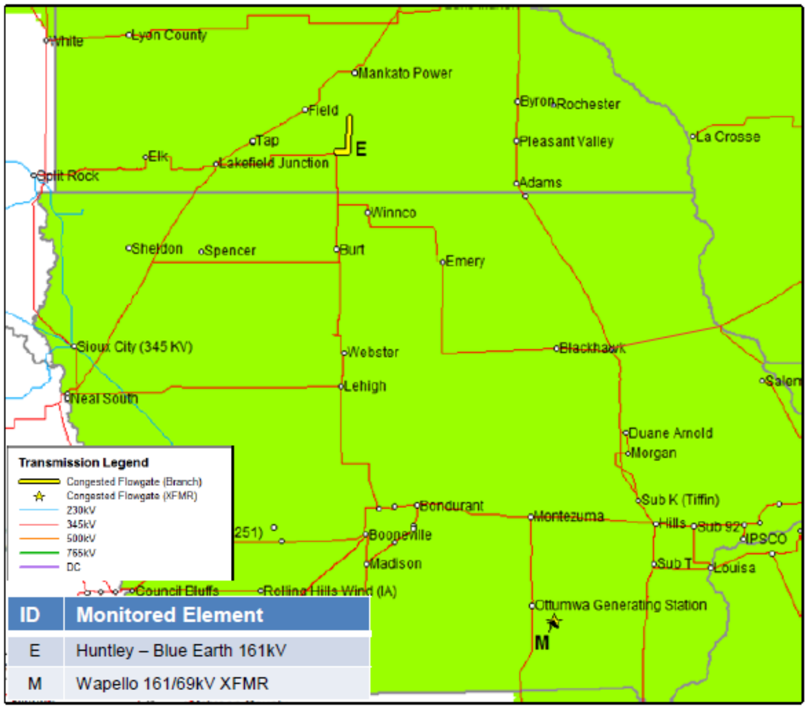

Figure 5.3-8: Iowa/Minnesota Top Congested Flowgates

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.

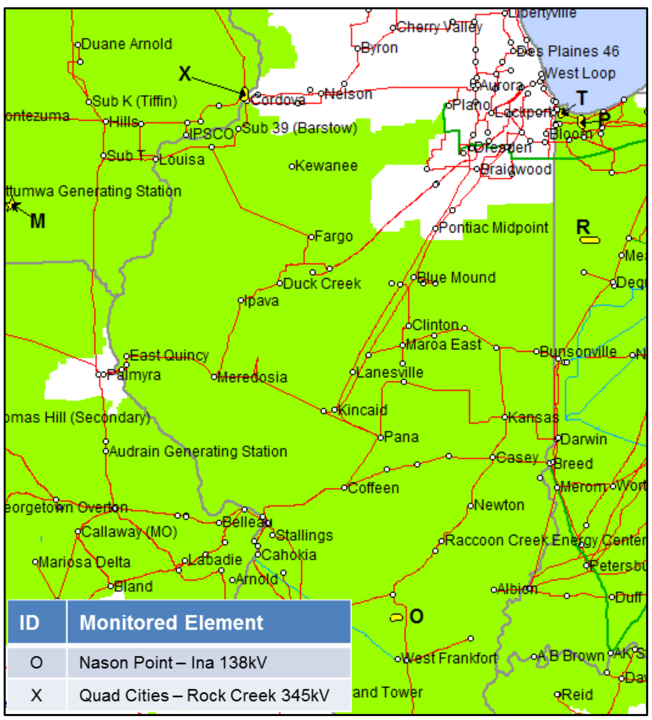

Figure 5.3-9: Illinois Top Congested Flowgates

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.

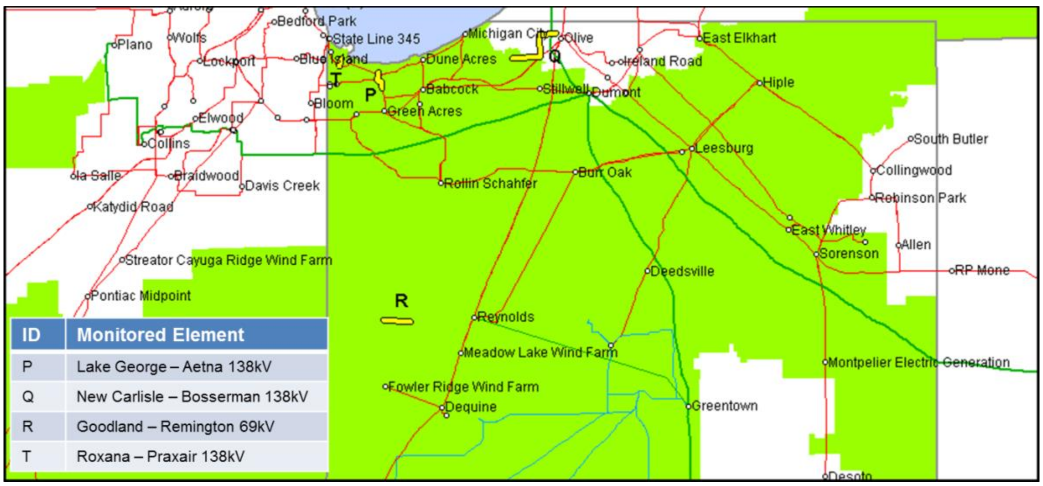

Figure 5.3-10: North Indiana Top Congested Flowgates

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.

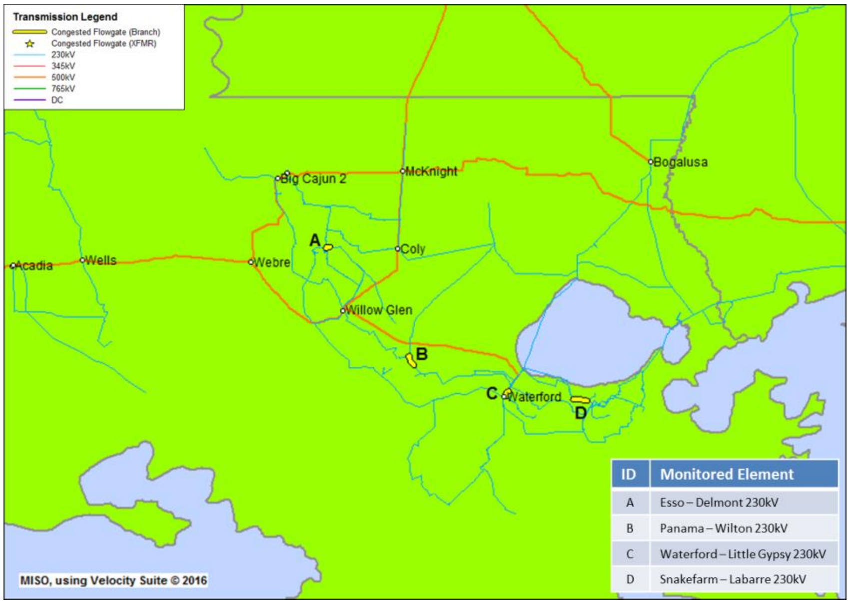

Figure 5.3-11: Amite South/DSG Top Congested Flowgates

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.

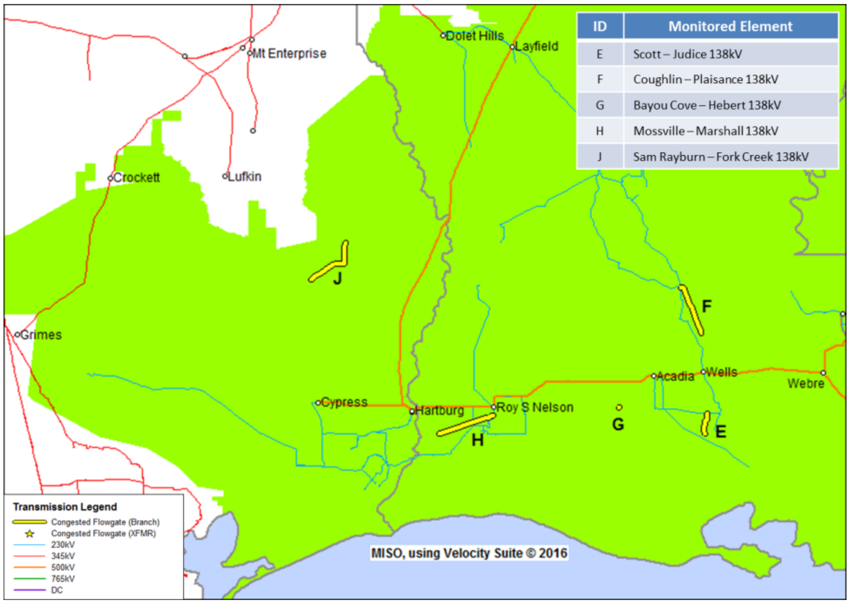

Figure 5.3-12: WOTAB/Western Top Congested Flowgates

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).

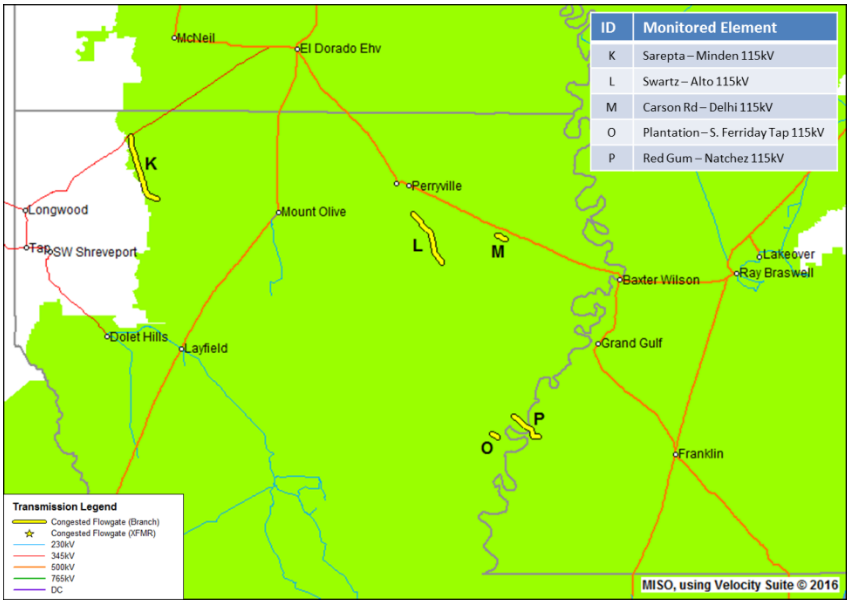

Figure 5.3-13: Remainder of LRZ9 (Rest of Louisiana) Top Congested Flowgates

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).

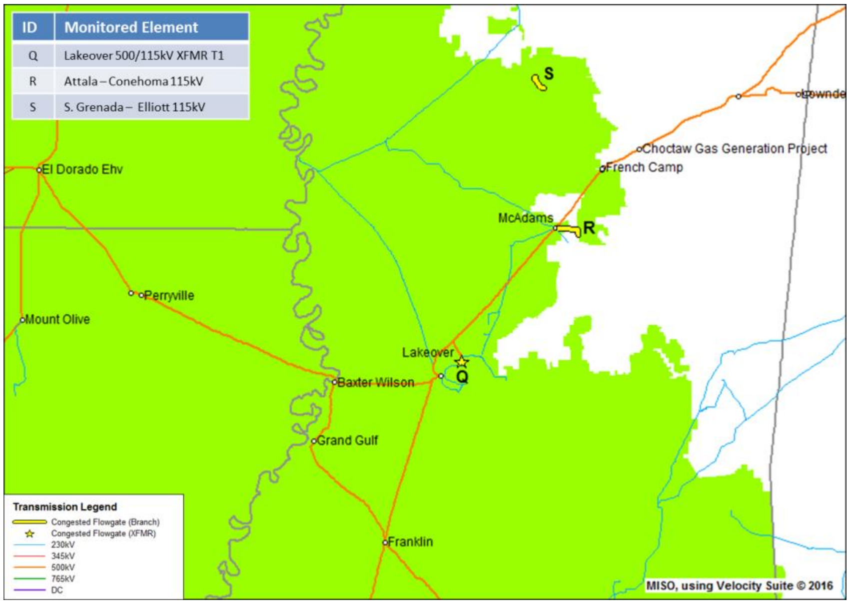

Figure 5.3-14: LRZ10 (Mississippi) Top Congested Flowgates

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).

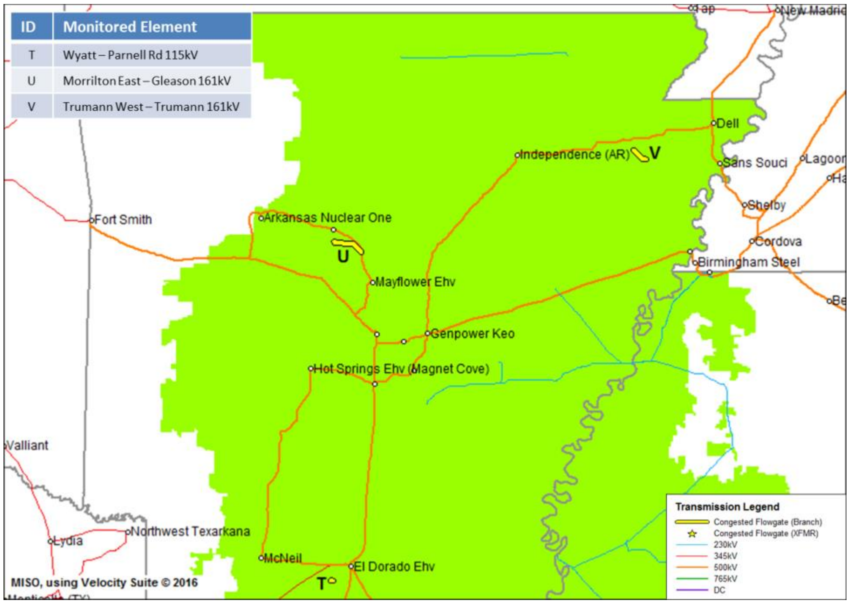

Figure 5.3-15: LRZ8 (Arkansas) Top Congested Flowgates

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

CERTIFICATE OF SERVICE

I, JoAnna M. Joachim, do hereby certify that a copy of the foregoing document was served upon each person designated on the official service list in these proceedings.

Dated this 6th day of September 2018.

/s/ JoAnna M. Joachim

JoAnna M. Joachim
720 City Center Drive
Carmel, Indiana 46320
(317) 249-5400