MTEP17 MVP Triennial Review

A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio

September 2017

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Executive Summary

The MTEP17 Triennial Multi-Value Project (MVP) Review provides an update of the projected economic, public policy and qualitative benefits of the MVP Portfolio. The MTEP17 MVP Triennial Review's business case is on par with, if not better than, MTEP11, providing evidence that the MVP criteria and methodology works as expected. Analysis shows that projected MISO North and Central Region benefits provided by the MVP Portfolio have increased since MTEP11, the analysis from which the portfolio's business case was approved.

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

The MTEP17 results demonstrate the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.2 to 3.4; an increase from the 1.8 to 3.0 range calculated in MTEP11
- Creates $12.1 to $52.6 billion in net benefits over the next 20 to 40 years
- Enables 52.8 million MWh of wind energy to meet renewable energy mandates and goals through year 2031

Benefit increases are primarily congestion and fuel savings, largely driven by the changing MISO fleet, carbon costs and updated system landscape.

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

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

MISO conducted its second triennial MVP Portfolio review, per tariff requirement, for MTEP17. The MVP Review has no impact on the existing MVP Portfolio cost allocation and is performed solely for informational purposes. The intent of the MVP Review is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

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

The MVP Review uses stakeholder-vetted models and makes every effort to follow procedures and assumptions consistent with the MTEP11 analysis. Metrics that required any changes to the benefit valuation due to changing tariffs, procedures or conditions are highlighted. Consistent with MTEP11, the MTEP17 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in-service and those still in planning stages. Because the MVP Portfolio's costs are allocated solely to the MISO North and Central Regions, only MISO North and Central Region benefits are included in the MTEP17 MVP Triennial Review.

Public Policy Benefits

The MTEP17 MVP Review reconfirms the MVP Portfolio's ability to deliver wind generation, in a cost-effective manner, in support of MISO States' renewable energy mandates. Renewable Portfolio Standards assumptions[1] have only had minor changes since the MTEP11 analysis.

Updated analyses find that 11.3 GW of dispatched wind would be curtailed in lieu of the MVP Portfolio, which extrapolates to 60.5 percent of the 2031 full Renewable Portfolio Standard (RPS) energy. MTEP14 and MTEP11 analyses both showed a similar percentage of their full RPS energy would be curtailed without the installation of the MVP Portfolio. The minor differences between studies can be attributed to new transmission upgrades represented in the system models and the changes in actual physical locations of installed wind turbines.

In addition to allowing energy to not be curtailed, analyses determined that 5.1 GW of wind generation in excess of the 2031 requirements is enabled by the MVP Portfolio. For their respective models years, MTEP11 and MTEP14 analyses determined that 2.2 GW and 3.4 GW of additional generation could be sourced from the incremental energy zones.

When the results from the curtailment analyses and the wind-enabled analyses are combined, MTEP17 results show the MVP Portfolio enables a total of 52.8 million MWh of renewable energy to meet the renewable energy mandates through 2031. System wide, the MTEP17 wind enablement amount is substantively similar to 2014 and 2011 analyses — 43 million MWh and 41 million MWh, respectively.

Economic Benefits

MTEP17 analysis shows the Multi-Value Portfolio creates $22.1 to $74.8 billion in total benefits to MISO North and Central Region members (Figure E-1). Total portfolio costs have increased from $5.56 billion in MTEP11 to $6.65 billion in MTEP17. Even with the increased portfolio cost estimates, the increased MTEP17 congestion and fuel savings benefit forecasts result in portfolio benefit-to-cost ratios that have increased since MTEP11.

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

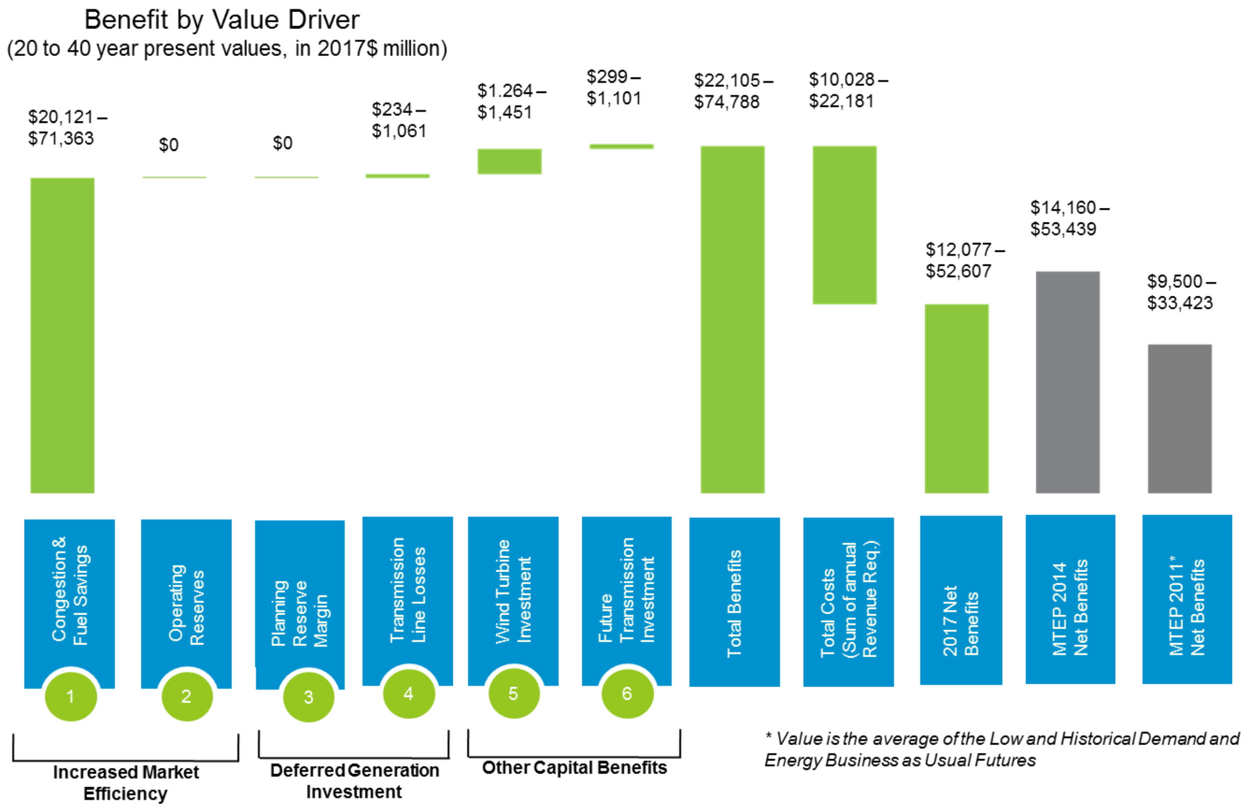

Figure E-1: MVP Portfolio Economic Benefits from MTEP17 MVP Triennial Review

Increased Market Efficiency

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. The MVP Review estimates that the MVP Portfolio will yield $20 to $71 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central regions.

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The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection highly correlated to the natural gas price assumption. A sensitivity applying the MTEP14 Business-as-Usual gas price assumptions to the MTEP17 MVP Triennial Review model showed a 27 percent reduction in the 20-year MTEP14 Present Value congestion and fuel savings benefits. Also, approximately 38 percent of the difference between the MTEP17 and MTEP14 present value congestion and fuel savings benefit is attributable to the carbon costs, wind enablement, coal retirements and topology changes (Figure E-2).

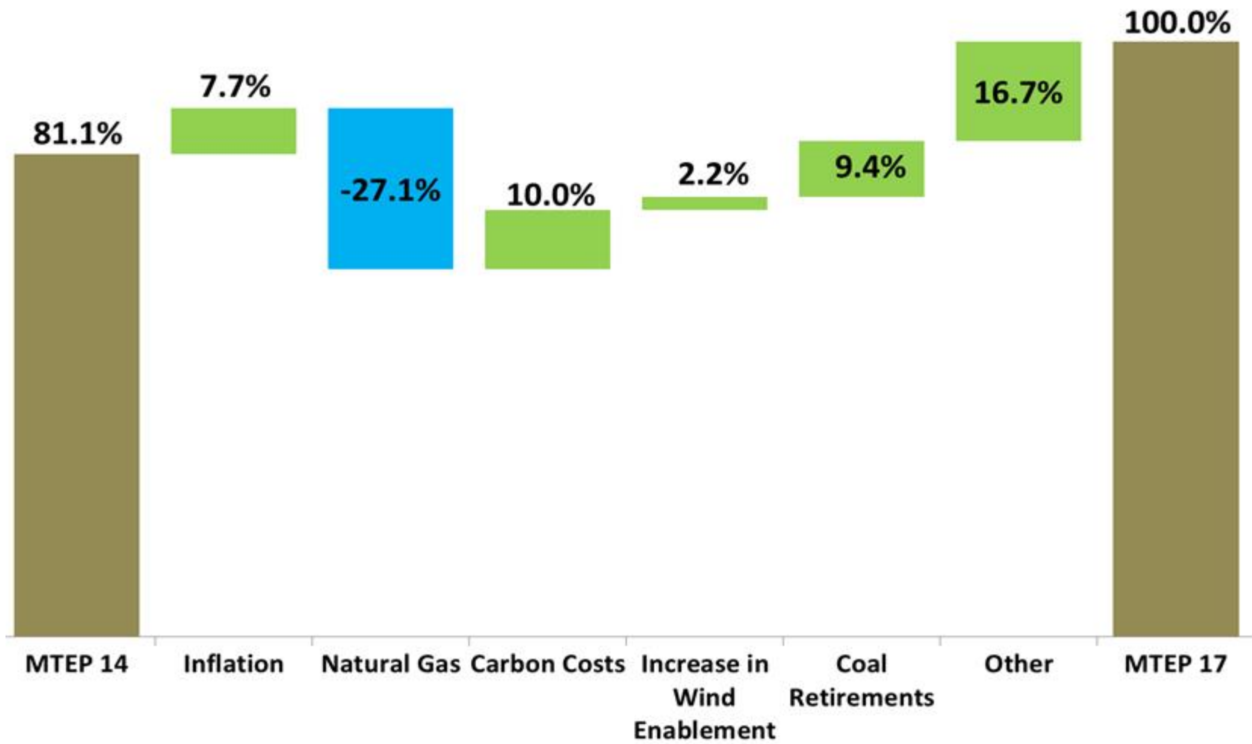

Figure E-2: Breakdown of Congestion and Fuel Savings Increase from MTEP14 to MTEP17

The MTEP17 Policy Regulation future's national CO_2 emissions were priced at $5.80/ton, which increased the congestion and fuel savings benefit by 10 percent relative to MTEP14. The MTEP14 model did not include carbon emission costs in the production cost calculation. The wind enabled through the MVP's offset more expensive generation, with carbon costs, to lead to the slight increase in MVP benefits.

Within the MTEP17 Policy Regulatory (PR) future assumptions MISO forecasted approximately 16 GW of coal retirements driven by both age and policy assumptions. The MTEP14 Triennial Review models included 12.6 GW of assumed coal retirements. The coal unit retirement assumption in MTEP17 PR future resulted in an increase in congestion and fuel savings of 9.4 percent. The additional 18.9 percent in increased benefits is driven by the increase in wind enabled by the MVPs as well as topology changes from MTEP14 to MTEP17.

In addition to the energy benefits quantified in the production cost analyses, the 2011 business case showed the MVP Portfolio also reduces operating reserve costs. The MVP Review does not estimate a reduced operating reserve benefit in 2017, as a conservative measure, because of the decreased number of days a reserve requirement was calculated since the MTEP11 analysis.

Deferred Generation Investment

The addition of the MVP Portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. Using current capital costs, the deferment from loss reduction equates to a MISO North and Central Regions' savings of $234 to $1,061 million — nearly double the MTEP11 values as a result of tighter reserve margins.

The previous MVP Triennial Review in MTEP14 estimated a deferred capacity value of $75.8 million due to the expected capacity shortage in Local Resource Zone (LRZ) 3 without the addition of the MVPs. With the refreshed analysis using updated system topology and expected capacity resources, MISO no longer expects a capacity shortfall in LRZ 3. As a result, the MVP Review does not estimate any deferred capacity benefits in the MTEP17 MVP Review.

Other Capital Benefits

The MTEP17 Triennial MVP Review found that the benefits from the optimization of wind generation siting to be $1.2 to $1.4 billion. These benefits are lower relative to MTEP11 and MTEP14 which is primarily due to a 40 percent decrease in the estimated wind capital costs.

Consistent with MTEP11, the MTEP17 MVP Triennial Review shows that the MVP Portfolio eliminates the need for $300 million in future baseline reliability upgrades. The magnitude of estimated benefits is in close proximity to the estimates from MTEP11 and MTEP14; however, the actual identified upgrades are different as a result of load growth, generation dispatch, wind levels and transmission upgrades.

Distribution of Economic Benefits

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to costs allocated to each LRZ (Figure E-3). The MVP Portfolio's benefits are at least 1.5 to 2.6 times the cost allocated to each zone. Differences in zonal distribution relative to MTEP11 and MTEP14 are a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), generation dispatch, wind siting and load levels.

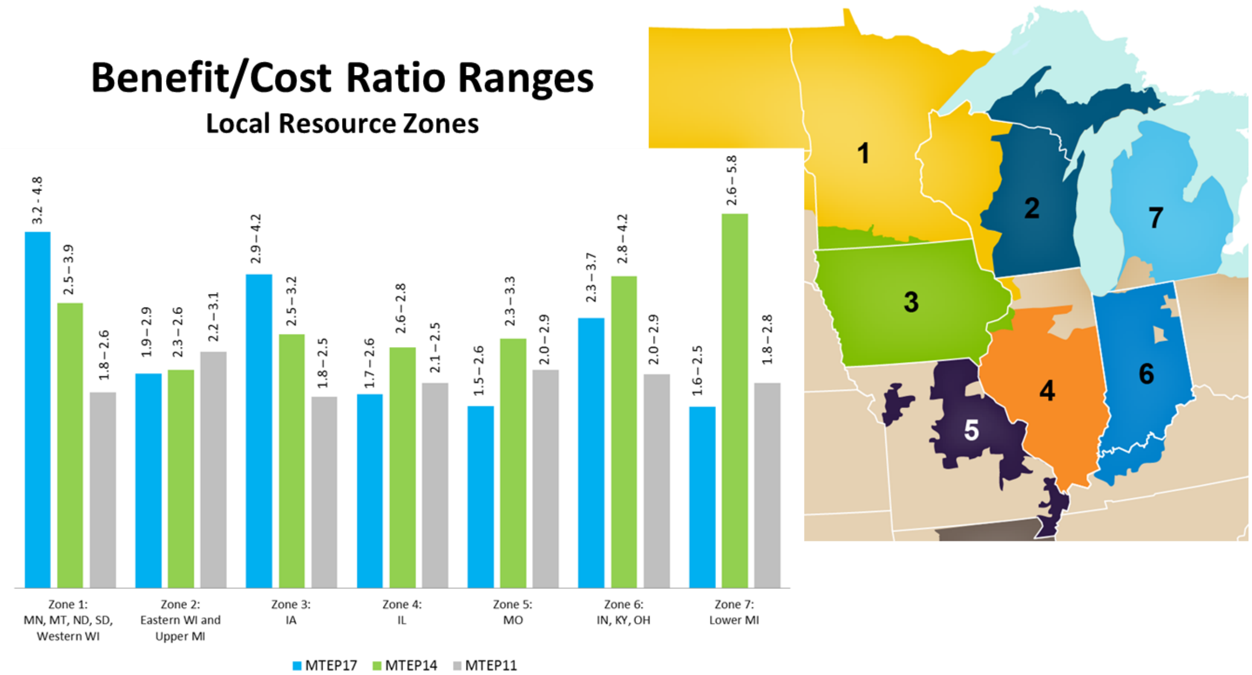

Figure E-3: MVP Portfolio Total Benefit Distribution

Qualitative and Social Benefits

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

- Enhances generation flexibility
- Creates a more robust regional transmission system that decreases the likelihood of future blackouts
- Increases the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time
- Supports the creation of thousands of local jobs and billions in local investment
- Reduces carbon emissions by 13 to 21 million tons annually

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

Historical Review

The MTEP17 MVP Review is the first cycle to provide a quantitative and qualitative look at how the in-service MVPs may have impacted certain historical market metrics. With only four of the 17 MVPs presently in service, no definitive conclusions could be made as a result of this analysis. However, correlations between congestion improvements on targeted flow gates and upward trends of wind resource interconnections and energy supplied were observed from the limited available data. As a larger statistical sample size becomes available in future reviews, a more detailed discussion on MVP impacts will be provided.

Going Forward

MTEP18 and MTEP19 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings using the latest portfolio costs and in-service dates. The next full triennial review will be performed in MTEP20.

1. Study Purpose and Drivers

The MVP Triennial Review has no impact on the existing Multi-Value Project Portfolio cost allocation. The study is performed solely for information purposes.

In 2017, MISO performed its second triennial review of the Multi-Value Project (MVP) Portfolio benefits. The MVP Portfolio was studied and approved in 2011 as a part of MISO's annual transmission expansion plan (MTEP), with a tariff requirement to conduct a full review every three years. The first triennial review was completed in 2014. The MTEP17 Triennial MVP Review provides an updated view into the projected economic, public policy and qualitative benefits of the MTEP11-approved MVP Portfolio.

The MVP Review has no impact on the existing MVP Portfolio cost allocation. Analysis is performed solely for information purposes. The intent of the MVP Reviews is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date. The MVP Reviews are intended to verify if the MVP criteria and methodology is working as expected.

The MVP Review uses stakeholder-vetted models and makes every effort to follow consistent procedures and assumptions as the Candidate MVP, also known as the MTEP11 analysis. Any metrics that required changes to the benefit valuation due to revised tariffs, procedures or conditions are highlighted throughout the report. Wherever practical, any differences between MTEP17, MTEP14 and MTEP11 assumptions are noted and the resulting differences quantified.

Consistent with MTEP11, the MTEP17 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in-service and those still being planned. The latest MVP cost estimates and in-service dates are used for all analyses.

2. Study Background

The MVP Portfolio (Figure 2-1 and Table 2-1) represents the culmination of more than eight years of planning efforts to find a cost-effective regional transmission solution that meets local energy and reliability needs.

In MTEP11, the MVP Portfolio was justified based its ability to:

- Provide benefits in excess of its costs under all scenarios studied, with its benefit-to-cost ratio ranging from 1.8 to 3.0
- Maintain system reliability by resolving reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigating 31 system instability conditions
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals
- Provide an average annual value of $1,279 million over the first 40 years of service, at an average annual revenue requirement of $624 million
- Support a variety of generation policies by using a set of energy zones that support wind, natural gas and other fuel sources

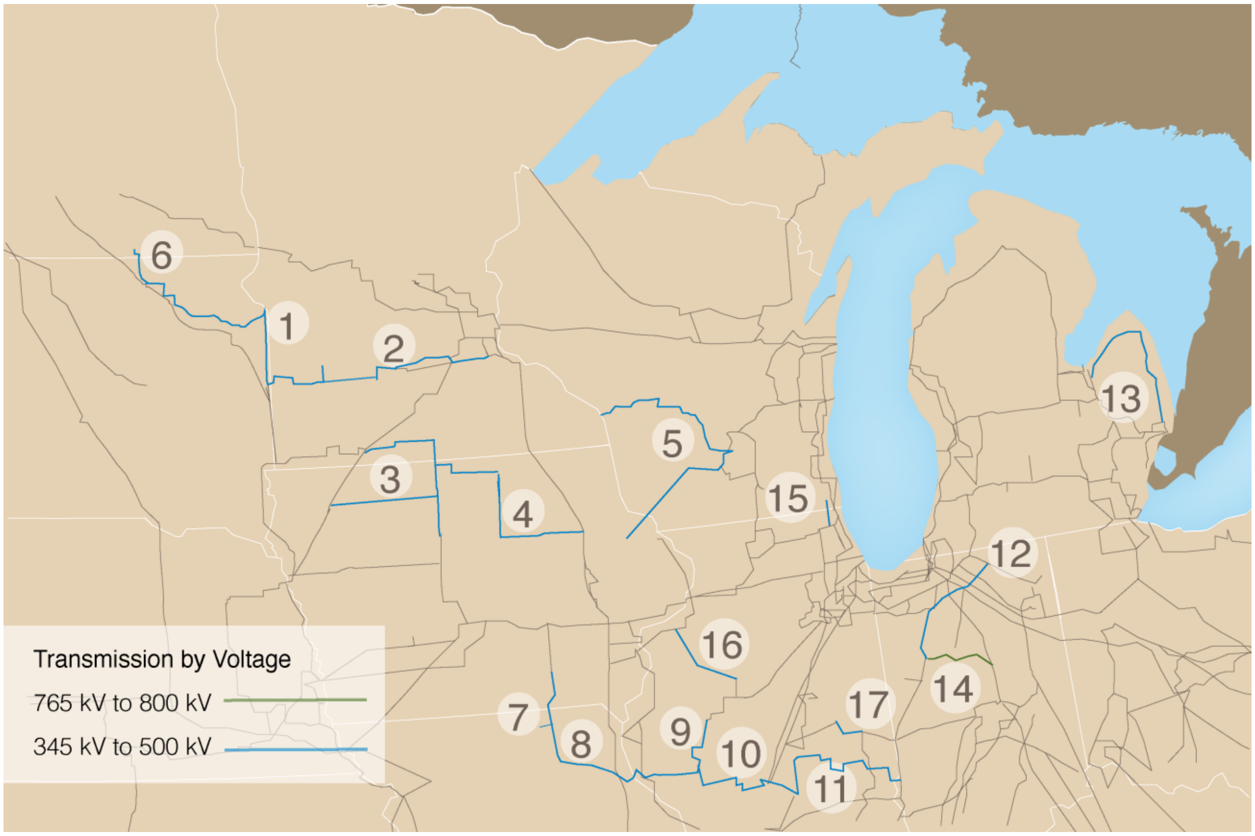

Figure 2-1: MVP Portfolio[2]

[2] Figure for illustrative purposes only. Final line routing may differ.

ID	Project	State	Voltage (kV)
1	Big Stone–Brookings	SD	345
2	Brookings, SD–SE Twin Cities	MN/SD	345
3	Lakefield Jct.–Winnebago–Winco–Burt Area & Sheldon–Burt Area–Webster	MN/IA	345
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345
5	LaCrosse–N. Madison–Cardinal & Dubuque Co–Spring Green–Cardinal	WI	345
6	Ellendale–Big Stone	ND/SD	345
7	Adair–Ottumwa	IA/MO	345
8	Adair–Palmyra Tap	MO/IL	345
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345
10	Pawnee–Pana	IL	345
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345
12	Reynolds–Burr Oak–Hiple	IN	345
13	Michigan Thumb Loop Expansion	MI	345
14	Reynolds–Greentown	IN	765
15	Pleasant Prairie–Zion Energy Center	WI/IL	345
16	Fargo-Galesburg–Oak Grove	IL	345
17	Sidney–Rising	IL	345

Table 2-1: MVP Portfolio

In 2008, the adoption of Renewable Portfolio Standards (RPS) (Figure 2-2) across the MISO footprint drove the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

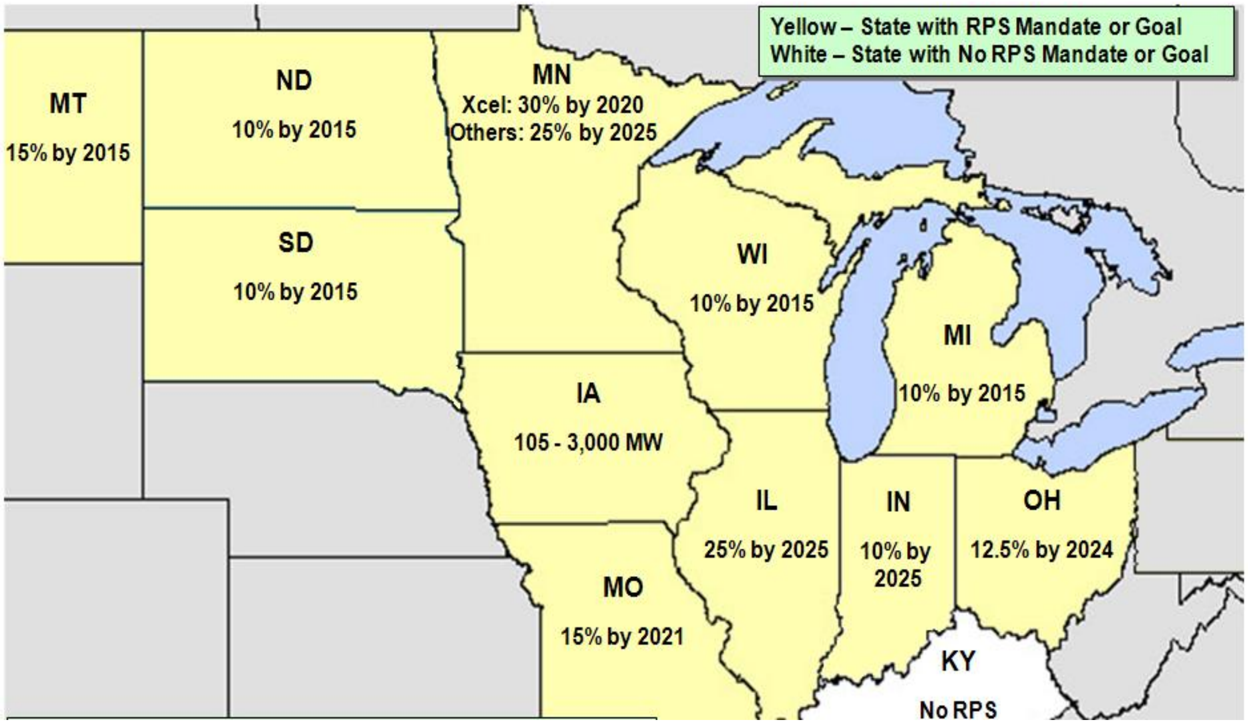

Figure 2-2: Renewable Portfolio Standards, 2011

Beginning with the MTEP 2003 Exploratory Studies, MISO and stakeholders began to explore how to best provide a value-added regional planning process to complement the local planning of MISO members. These explorations continued in later MTEP cycles and in specific targeted studies. In 2008, MISO began the Regional Generation Outlet Study (RGOS) to identify a set of value-based transmission projects necessary to enable Load Serving Entities (LSEs) to meet their RPS mandates. It accomplished this with the assistance of state regulators and industry stakeholders such as the Midwest Governor's Association (MGA), the Upper Midwest Transmission Development Initiative (UMTDI) and the Organization of MISO States (OMS).

While much consideration was given to wind capacity factors when developing the energy zones utilized in the RGOS and MVP Portfolio analyses, the zones were chosen with consideration of more factors than wind capacity. Existing infrastructure, such as transmission and natural gas pipelines, also influenced the selection of the zones. As such, although the energy zones were created to serve the renewable generation mandates, they could be used for a variety of different generation types to serve various future generation policies.

Common elements between the RGOS results and previous reliability, economic and generation interconnection analyses were identified to create the 2011 candidate MVP portfolio. This portfolio represented a set of "no regrets" projects that were believed to provide multiple kinds of reliability and economic benefits under all alternate futures studied. Over the course of the MVP Portfolio analysis, the Candidate MVP Portfolio was refined into the portfolio that was approved by the MISO Board of Directors in MTEP11.

The MVP Portfolio enables the delivery of the renewable energy required by public policy mandates in a manner more reliable and economical than without the associated transmission upgrades. Specifically, the portfolio mitigates approximately 650 reliability constraints under 6,700 different transmission outage conditions for steady state and transient conditions under both peak and shoulder load scenarios. Some of these conditions could be severe enough to cause cascading outages on the system. By mitigating these constraints, approximately 41 million MWh per year of renewable generation can be delivered to serve the MISO state renewable portfolio mandates.

Under all future policy scenarios studied, the MVP Portfolio delivered widespread regional benefits to the transmission system. To use conservative projections relating only to the state renewable portfolio mandates, only the Business as Usual future was used in developing the candidate MVP business case.

The projected benefits are spread across the system, in a manner commensurate with costs (Figure 2-3).

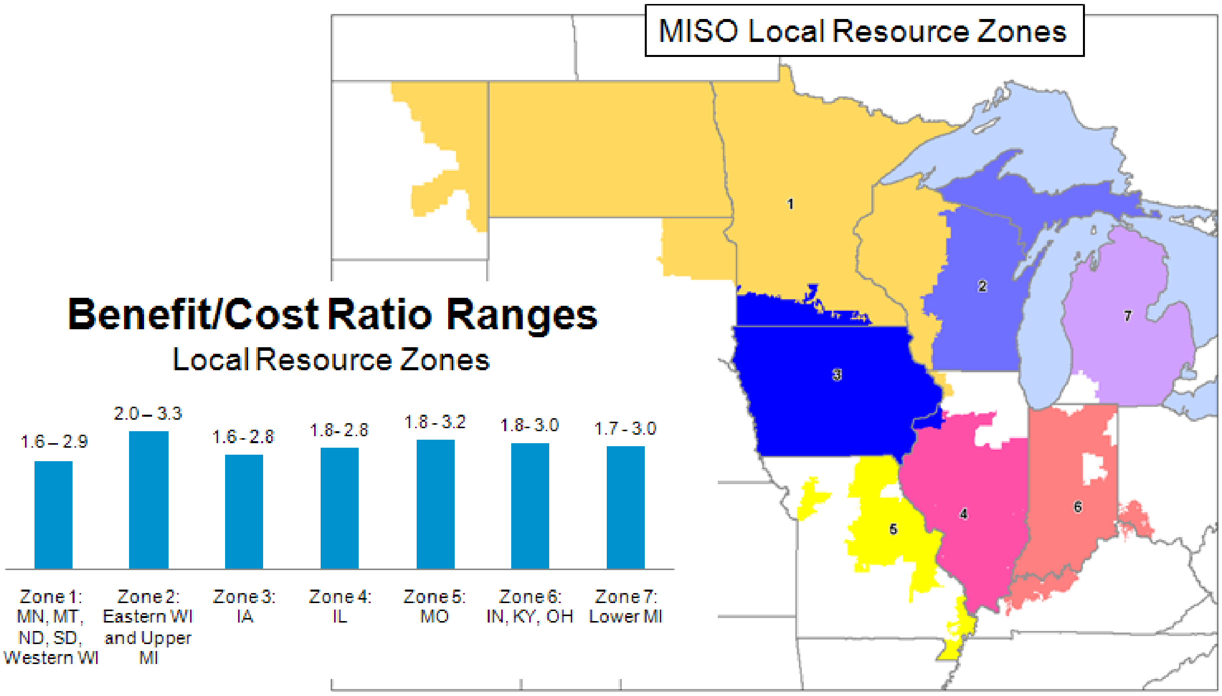

Figure 2-3: MTEP11 MVP Portfolio Benefit Spread

Taking into account the significant economic value created by the portfolio, the distribution of these value, and the ability of the portfolio to meet MVP criteria through its reliability and public policy benefits, the MVP Portfolio was approved by the MISO Board of Directors in MTEP11.

3. MTEP17 MVP Review Model Development

The MTEP17 MVP Triennial Review uses MTEP17 economic models as the basis for the analysis. The MTEP17 economic models were developed in 2016 with topology based on the MISO powerflow models from the MTEP16 reliability study. To maintain consistency between economic and reliability models, MVP Triennial Review wind curtailment and enablement analysis was performed with MTEP16 vintage powerflows.

MTEP17 economic models, developed in 2016, are the basis for the MTEP17 MVP Triennial Review.

The MTEP models were developed through an open stakeholder process and vetted through the appropriate MISO stakeholder committees, including MISO Planning Advisory Committee, Planning Subcommittee, Modeling Users Group and Economic Planning Users Group. The details of the economic and reliability models used in the MTEP17 MVP Triennial Review are described in the following sections. The MTEP models are available via the MISO FTP site with proper licenses and confidentiality agreements.

3.1 Economic Models

The MVP Benefit Review uses PROMOD IV as the primary tool to evaluate the economic benefits of the MVP Portfolio. The MTEP17 MISO North/Central economic models, stakeholder vetted in 2016, are used as the basis for the MTEP17 Review. The same economic models are used in the MTEP17 Market Congestion Planning Study.

In previous reviews, including MTEP11, MISO utilized a Business as Usual (BAU) future scenario to represent a status quo environment; generally including existing standards for renewable mandates and little or no change in environmental legislation. A BAU future was not developed for MTEP17. To replicate the MTEP11 MVP business case[3] as close as possible, the MTEP17 Review will rely on the Policy Regulation (PR) future.

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Similar to previous cycles' BAU futures, the MTEP17 PR future includes mid or base levels of demand and energy growth rates, fuel prices and uncertainty variables. The primary difference between the MTEP17 PR and previous cycles' BAU futures is the inclusion of a carbon reduction target in the MTEP17 PR. The MTEP17 Triennial Review was performed both with and without the carbon reduction target applied for comparability, but default values in the MTEP17 include the carbon constraint per the future definition.

MTEP11 analysis relied on two definitions of the BAU future — one with a slightly higher baseline growth rate and one with a slightly lower growth rate (Table 3-1), and MTEP14 utilized a single BAU future scenario in the previous review. As such, all MTEP17 Triennial MVP Review results in this report will be compared to the arithmetic mean of the MTEP11 Low BAU and High BAU results and MTEP14 BAU results (where applicable).

[3] The Candidate MVP Analysis provided results for information purposes under all MTEP11 future scenarios; however, the business case only used the Business as Usual futures.

		MTEP17 PR	MTEP14 BAU	MTEP11 Low BAU	MTEP11 High BAU
Demand and Energy	Demand Growth Rate	0.64%	1.06%	1.26%	1.86%
	Energy Growth Rate	0.65%	1.06%	1.26%	1.86%
Natural Gas Forecast[4]	Starting Point	2.26 $/MMBTU	3.75 $/MMBTU	5.38 $/MMBTU	5.38 $/MMBTU
	2021 Price	3.85 $/MMBTU	6.26 $/MMBTU	6.07 $/MMBTU	6.58 $/MMBTU
	2026 Price	4.45 $/MMBTU	8.36 $/MMBTU	6.62 $/MMBTU	7.59 $/MMBTU
	2031 Price	5.20 $/MMBTU	10.59 $/MMBTU	7.22 $/MMBTU	8.77 $/MMBTU
Fuel Cost (Starting Price)	Oil	Powerbase Default	Powerbase Default	Powerbase Default	Powerbase Default
	Coal	Powerbase Default	Powerbase Default	Powerbase Default	Powerbase Default
	Uranium	1.08 $/MMBTU	1.23 $/MMBTU	1.21 $/MMBTU	1.21 $/MMBTU
Fuel Escalation	Oil	2.50%	2.50%	1.74%	2.91%
	Coal	2.50%	2.50%	1.74%	2.91%
	Uranium	2.50%	2.50%	1.74%	2.91%
Other Variables	Inflation	2.50%	2.50%	1.74%	2.91%
	Retirements	Known + Historical Retirement Trend ~16,000 MW	Known + EPA Driven Forecast MISO ~12,600 MW	Known Retirements MISO ~400 MW	Known Retirements MISO ~400 MW
	Renewable Levels	State Mandates	State Mandates	State Mandates	State Mandates
MISO Footprint		Duke and FE in PJM; includes MISO South	Duke and FE in PJM; includes MISO South	MTEP11	MTEP11

Table 3-1: MTEP17, MTEP14 and MTEP11 Key PROMOD Model Assumptions

Models include all publically announced retirements as well as baseline generation retirements driven by economics.

MISO footprint changes since the MTEP11 analysis are modeled verbatim to current configurations, i.e. Duke Ohio/Kentucky and First Energy are modeled as part of PJM and the MISO pool includes the MISO South Region. While the MISO pool includes the South Region, only the MISO North and Central Region benefits are being included in the MTEP17 MVP Triennial Review's business case.

MTEP16 powerflow models for the year 2026 are used as the base transmission topology for the MVP Triennial Review. Because there are no significant transmission topology changes known between years 2026 and 2031, the 2031 production cost models use the same transmission topology as 2026.

PROMOD uses an "event file" to provide pre- and post-contingent ratings for monitored transmission lines. The latest MISO Book of Flowgates and the NERC Book of Flowgates are used to create the event file of transmission constraints in the hourly security constrained model. Ratings and configurations are updated for out-year models by taking into account all approved MTEP Appendix A projects for the model series.

[4] MTEP11 and MTEP13 use different natural gas escalation methodologies; all numbers from previous reviews inflated by 2.5% for comparability with MTEP17 model years

3.2 Capacity Expansion Models

The MTEP17 Triennial Review decreased transmission line losses benefit (Section 6.4) is monetized using the Electricity Generation Expansion Analysis System (EGEAS) model. EGEAS is designed by the Electric Power Research Institute to find the least-cost integrated resource supply plan given a demand level. EGEAS expansions include traditional supply-side resources, demand response and storage resources. The EGEAS model is used annually in MISO's MTEP process to identify future capacity needs beyond the typical five-year project-planning horizon.

The EGEAS optimization process is based on a dynamic programming method where all possible resource addition combinations that meet user-specified constraints are enumerated and evaluated. The EGEAS objective function minimizes the present value of revenue requirements. The revenue requirements include both carrying charges for capital investment and system operating costs.

MTEP17 Triennial MVP Review analysis was performed using the MTEP17 Policy Regulation future, developed in 2016. The capacity model shares the same input database and assumptions as the economic models (Section 3.1).

3.3 Reliability Models

To maintain consistency between economic and reliability models, MTEP16-vintage MISO powerflow models are used as the basis for the MTEP17 MVP Triennial Review reliability analysis. The MTEP17 economic models are developed with topology based on the MTEP16 MISO powerflow models. Siemens PTI Power System Simulator for Engineering (PSS/E) and Transmission Adequacy & Reliability Assessment (TARA) are utilized for the MTEP17 MVP Triennial Review analysis.

Powerflow models are built using MISO's Model on Demand (MOD) model data repository. Models include approved MTEP Appendix A projects (through MTEP16) and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) modeling for the external system. Load and generation profiles are seasonal dependent (Table 3-2). MTEP powerflow models have wind dispatched at 90 percent connected capacity in Shoulder models and at capacity credit level (approximately 15.6 percent) in the Summer Peak.

A 10-year Shoulder model was not required as a part of the MTEP16 reliability study. To create this sensitivity case, loads were proportionally scaled on the MTEP16 10-year Summer Peak model by comparing the existing MTEP16 five-year Summer Peak and Shoulder Peak load levels. Additional wind units were also added to the MTEP16 MVP Triennial Review cases to meet renewable portfolio standards.

Demand is grown in the Future Transmission Investment case using the extrapolated growth rate between the year 2021 MTEP16 Summer Peak case and the 2026 MTEP16 Summer Peak Case.

Analysis	Model(s)
Wind Curtailment	2026 MTEP16 Shoulder (90% Wind)
Wind Enabled	2026 MTEP16 Shoulder with Wind at 2031 Levels
Transmission Line Losses	2026 MTEP16 Summer Peak (15.6% Wind)
Future Transmission Investment	2026 MTEP16 Summer Peak with Demand and Wind at 2036 Levels

Table 3-2: Reliability Models by Analysis

3.4 Capacity Import Limit Models

The MTEP16 series of MISO powerflow models are used as the basis for the MTEP17 MVP Triennial Review capacity import limit analysis. Zonal Local Clearing Requirements are calculated using the capacity import limits identified through transfer analysis. The MTEP17 MVP Triennial Review incorporates capacity import limits calculated using a year 2026 model both with and without the MVP Portfolio. Single-element contingencies in MISO and seam areas are evaluated with subsystem files from MTEP16 reliability studies. The monitored file includes all facilities under MISO functional control and seam facilities 100 kV and above.

Additional details on the models used in the Planning Reserve Margin benefit estimation can be found in the 2017 Loss of Load Expectation Report.

3.5 Loss of Load Expectation Models

For the 2017 Planning Year, MISO utilized the General Electric-developed Multi-Area Reliability Simulation (MARS) program to calculate the Loss of Load Expectation. GE MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. GE MARS calculates the annual LOLE for the MISO system and each Local Resource Zone (LRZ) by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, load forecast uncertainty and external support.

Going forward, MISO will no longer use GE MARS for LOLE studies. Instead, Astrape Consulting's Strategic Energy & Risk Valuation Model (SERVM) will be used to calculate the Loss of Load Expectation for the applicable Planning Year. The 2017 Planning Year LOLE models, updated to include generation retirements, were the basis for the MTEP17 MVP Triennial Review models. Additional model details can be found in the 2017 Loss of Load Expectation Report.

4. Project Costs and In-Service Dates

The MTEP17 MVP Triennial Review cost and in-service data was updated in August 2017 through coordination with Transmission Owners (Figure 4-1). All cost and schedule updates are maintained in the MTEP project database, with reports provided regularly for stakeholders. Additional details on cost and schedule variation are available with the full MVP Dashboard posted on the MISO public website.

MVP No.	Project Name	State	Estimated In Service Date	State Regulatory Status	Construction	Estimated Cost ($M)
1	Big Stone - Brookings	SD	2017	●	Underway	$141
2	Brookings, SD - SE Twin Cities	MN/SD	2013-2015	●	Complete	$670
3	Lakefield Jct - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster	MN/IA	2015-2018	●	Underway	$651
4	Winco - Lime Creek - Emery - Black Hawk-Hazleton	IA	2015-2019	●	Underway	$564
5	N. LaCrosse - N. Madison - Cardinal (a/k/a Badger - Coulee Project)	WI	2018	●	Underway	$1,016
	Cardinal - Hickory Creek	WI/IA	2023	○	Pending	
6	Big Stone South - Ellendale	ND/SD	2019	●	Underway	$320
7	Ottumwa - Zachary	IA/MO	2018-2019	◐	Pending	$226
8	Zachary - Maywood	MO	2016-2019	◐	Pending	$172
9	Maywood - Herleman - Meredosia - Ipava & Meredosia - Austin	MO/IL	2016-2017	●	Underway	$723
10	Austin - Pana	IL	2016-2017	●	Underway	$135
11	Pana - Faraday - Kansas - Sugar Creek	IL/IN	2015-2019	●	Underway	$423
12	Reynolds - Burr Oak - Hiple	IN	2018	●	Underway	$388
13	Michigan Thumb Loop Expansion	MI	2012-2015	●	Complete	$504
14	Reynolds - Greentown	IN	2013-2018	●	Underway	$388
15	Pleasant Prairie - Zion Energy Center	WI	2013	●	Complete	$36
16	Fargo- Sandburg - Oak Grove	IL	2016-2018	●	Pending	$204
17	Sidney - Rising	IL	2016	●	Complete	$88
					Total	**$6,651**

State Regulatory Status Indicator Scale	
Pending	○
In regulatory process or partially complete	◐
Regulatory process complete or no regulatory process Requirements	●

Figure 4-1: MVP Cost and In-Service Dates August 2017[5]

For MTEP17, all benefit calculations start in year 2023, the first year when all projects are in service. For MTEP11, year 2021 was the first year when the MVP Portfolio was expected in service.

[5] Costs provided in nominal dollars unless otherwise specified; see facility level costs details in the MVP Triennial Review detailed business case.

The costs contained within the MTEP database are in nominal, as-spent, dollars unless otherwise specified. Consistent with previous analyses, and to simplify the benefit-to-cost ratio calculations, all MVP facilities are assumed to go into service in the portfolio in-service year, so nominal costs are escalated using a 2.5 percent inflation rate from the facility in-service date up to the year 2023.

A load ratio share was developed to allocate the benefit-to-cost ratios in each of the seven MISO North/Central local resource zones (LRZ). Load ratios are based off the actual 2016 energy withdrawals with the Policy Regulation (PR) future MTEP growth rate applied.

MTEP17 MVP Triennial Review benefit-to-cost calculations only include direct benefits to MISO North and Central members. MISO South Region benefits are excluded from all estimations. Export Revenue share, including PJM exports[6], are factored into the calculation at an estimate rate of 1.31 percent.

Total costs are annualized using the MISO North/Central-wide average Transmission Owner annual charge rate/revenue requirement. Consistent with the MTEP11 analysis and other Market Efficiency Projects, the MTEP17 MVP Triennial Review assumes that costs start in 2023, such as year one of the annual charge rate is 2023 and construction work in progress (CWIP) is excluded from the total costs.

[6] FERC's July 13, 2016 Order in ER10-1791 directed MISO to charge the MVP rate on exports to PJM

5. Portfolio Public Policy Assessment

The MTEP17 MVP Triennial Review redemonstrates the MVP Portfolio's ability to enable the renewable energy mandates of the footprint. Renewable Portfolio Standards assumptions[7] have only had minor changes since the MTEP11 analysis and any changes in capacity requirements are solely attributed to load forecast changes and the actual installation of wind turbines.

The MVP portfolio enables a total of 52.8 million MWh of renewable energy to meet the renewable energy mandates and goals through 2031.

This analysis took place in two parts. The first part demonstrated the wind needed to meet renewable energy mandates would be curtailed but for the approved MVP Portfolio. The second demonstrated the additional renewable energy, above the mandate, that will be enabled by the portfolio. This energy could be used to serve mandated renewable energy needs beyond 2031, as most of the mandates are indexed to grow with load.

5.1 Wind Curtailment

A wind curtailment analysis was performed to find the percentage of mandated renewable energy that could not be enabled but for the MVP Portfolio. A list of 277 monitored element/contingent element pairs (flowgates) that are resolved by MVP portfolio was prepared as the basis for calculating wind curtailment. These flowgates and a study case representing year 2026 shoulder scenario without MVPs modeled in it were fed into a security constrained re-dispatch routine. This re-dispatch algorithm then fetched the amount by which committed wind units and the RGOS energy zones need to be curtailed so as to relieve the overloaded flowgates.

Results of the re-dispatch algorithm found that 11,295 MW of year 2026 dispatched wind would be curtailed. As a connected capacity, 12,550 MW would be curtailed since wind is modeled at 90 percent of its nameplate in the shoulder case. The MTEP17 results are similar in magnitude to both MTEP14 and MTEP11, which found that 11,697 MW and 12,201 MW of connected wind would be curtailed, respectively.

The curtailed energy was calculated to be 37.6 million MWh from the connected capacity multiplied by the capacity factor times 8,760 hours per year. A MISO-wide per-unit capacity factor was averaged from the 2031 incremental wind zone capacities to 34.2 percent. Comparatively, the full 2031 RPS energy is 62.1 million MWh. As a percentage of the 2031 full RPS energy, 60.5 percent would be curtailed in lieu of the MVP Portfolio. MTEP14 and MTEP11 analysis both showed a similar percentage of full RPS energy would be curtailed without the installation of the MVP portfolio: 56.4 percent and 63 percent, respectively. The minor differences between studies can be attributed to new transmission upgrades represented in the system models and the changes in actual physical locations of installed wind turbines.

5.2 Wind Enabled

Additional analyses were performed to determine the incremental wind energy in excess of the RPS requirements enabled by the approved MVP Portfolio. This energy could be used to meet renewable energy mandates beyond 2031, as most of the state mandates are indexed to grow with load. An Optimal

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

Transfer Capability analyses were run on the Shoulder case model to determine how much the wind in each zone could be ramped up prior to additional reliability constraints occurring.

Transfers were sourced from the wind zones. All Bulk Electric System (BES) elements in the MISO system were monitored, with constraints being flagged at 100 percent of the applicable ratings. All single contingencies in the MISO footprint were evaluated during the transfer analysis. This transfer was sunk against MISO, PJM and SPP units (Table 5-1). More specifically, the power was sunk to the smallest units in each region, with the assumption that these small units would be the most expensive system generation.

Region	Sink
MISO	33 percent
PJM	44 percent
SPP	23 percent

Table 5-1: Transfer Sink Distribution

MTEP17 analysis determined that 5,123 MW of additional generation could be sourced from the incremental energy zones to serve future renewable energy mandates (Table 5-2). For their respective model years, MTEP14 and MTEP11 analysis determined that 4,335 MW and 2,230 MW of additional generation could be sourced from the incremental energy zones.

Wind Zone	Incremental Wind Enabled
IN-K	672
MI-B	989
MI-E	1,001
MI-F	727
MI-I	853
MO-C	31
WI-B	399
WI-D	451

Table 5-2: Incremental Wind Enabled Above 2031 Mandated Level, by Zone

Incremental wind-enabled numbers were calculated using a single optimal transfer pass technique, which implements a linear programming solver to come up with the maximum MW transfer that can be made without causing additional violations. When the results from the curtailment analyses and the wind-enabled analyses are combined, MTEP17 results show the MVP Portfolio enables a total of 52.8 million MWh of renewable energy to meet the renewable energy mandates through 2031. System wide, the MTEP17 wind enablement amount is substantively similar to 2014 and 2011 analyses — 43 million MWh and 41 million MWh, respectively. For individual zones however, this value can be heavily dependent on the details of the models — individual unit dispatches, load levels, area interchanges, topology changes, etc. In each case, market trade-offs (seen in the dispatch or unit commitment) have a big impact on what units can run. Because of these sensitivities the Wind Enablement optimization calculation is done only for the system as a whole, without looking to individual regions.

6. Portfolio Economic Analysis

The MTEP17 Triennial MVP Review estimates the MVP benefit-to-cost ratio has increased from 1.8 – 3.0 in MTEP11 to 2.2 – 3.4 in MTEP17.

MTEP17 estimates show the Multi-Value Portfolio creates $12 to $52.6 billion in net benefits to MISO North and Central Region members, an increase of 21 to 36 percent from MTEP11 (Figure 6-1). Differences between reviews are primarily driven by natural gas prices and retirements impacting congestion and fuel savings. Total portfolio costs have also increased from $5.56 billion in MTEP11 to $6.65 billion in MTEP17, decreasing the net benefits. Even with the increased portfolio cost estimates, the increased MTEP17 benefit estimation results in portfolio benefit-to-cost ratios that have increased from 1.8 to 3.0 in MTEP11 to 2.2 to 3.4 in MTEP17.

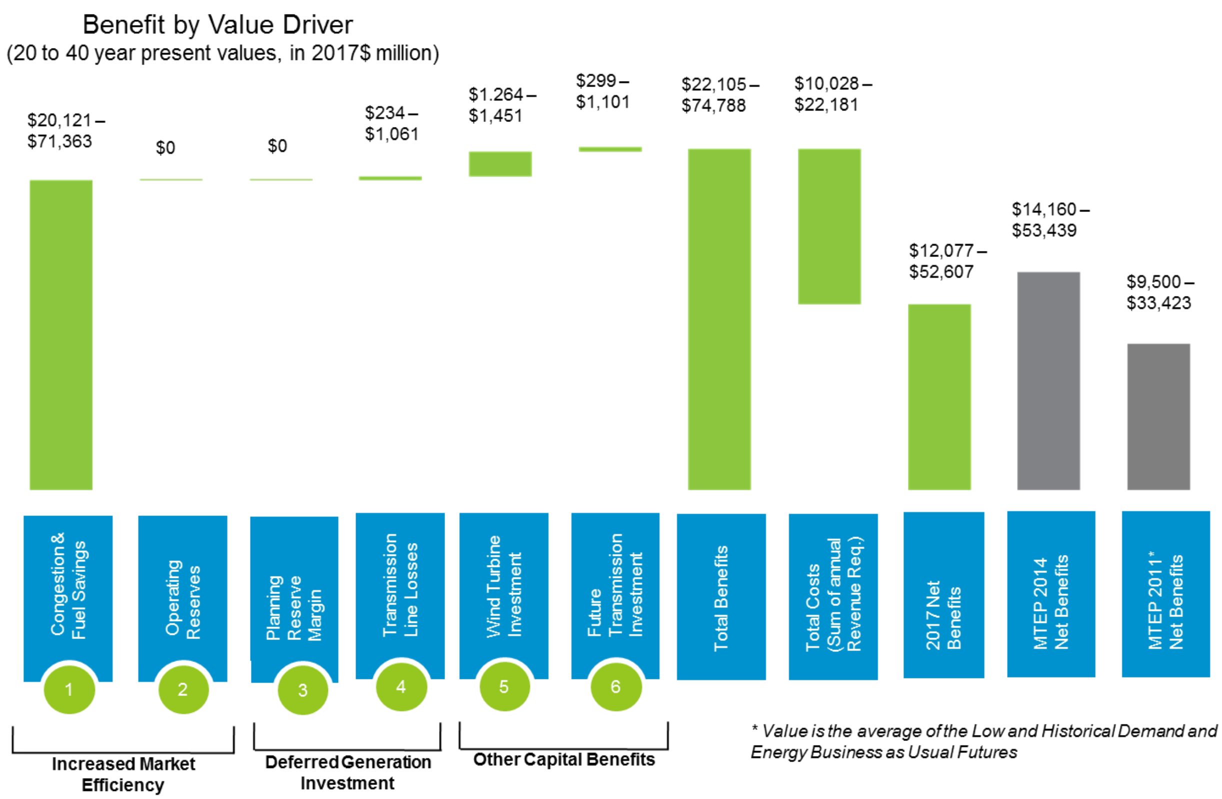

Figure 6-1: MVP Portfolio Economic Benefits from MTEP17 MVP Triennial Review

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to cost allocated to each North and Central Region local resource zones (Figure 6-2). MTEP17 MVP Triennial Review results continue to indicate benefit-to-cost ratios in excess of 1.5 to 2.6 for each zone. Zonal benefit distributions have changed since the MTEP11and MTEP14 business cases as a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), load growth, generation retirements and wind siting. As state demand and energy forecasts change and additional clarity is gained into the location of actual wind turbine installation, so does the siting of forecast wind.

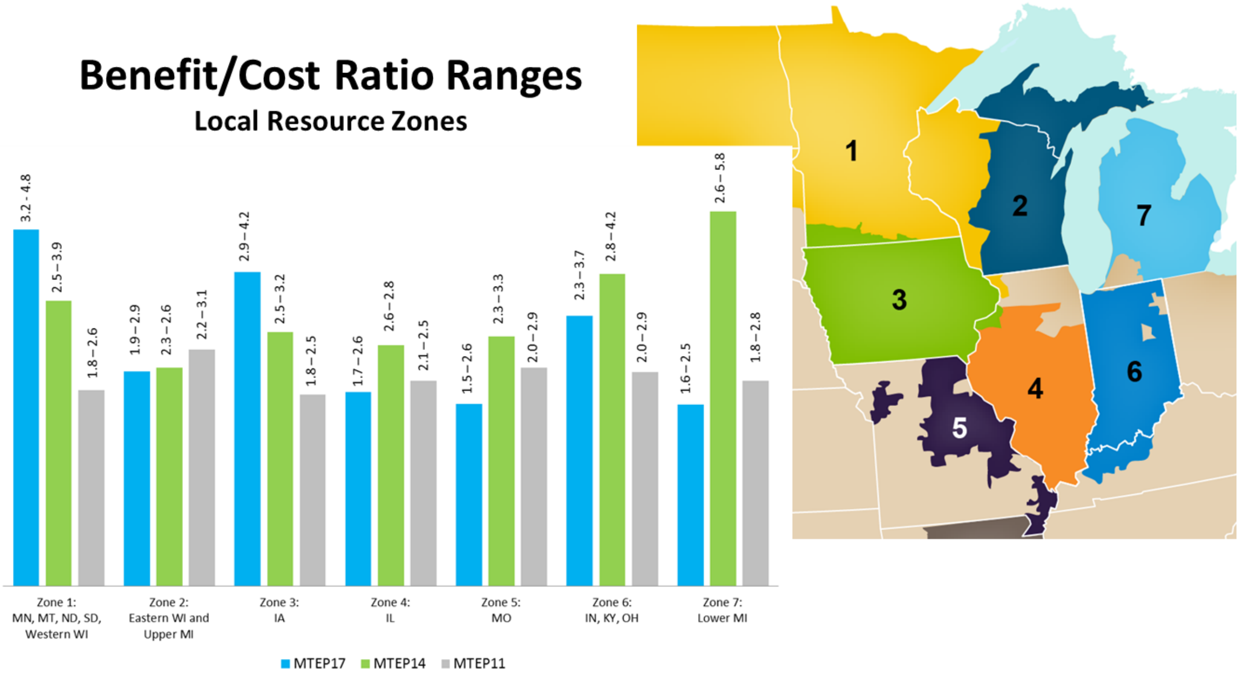

Figure 6-2: MVP Portfolio Production Cost Benefit Spread[8]

MVP Portfolio benefits in MTEP17 include a carbon cost component embedded with the future assumptions applied to the congestion and fuel savings analysis. This assumption is not included in the futures of MTEP11 and MTEP14, but sensitivity analysis shows only a marginal impact on the zonally distributed benefit-to-cost ratios in MTEP17 (Figure 6-3).

[8] Low – High B/C ratios are based on the 20 and 40 NPV with 3 percent and 8.2 percent discount rates applied. Values are represented graphically as the median of the B/C range.

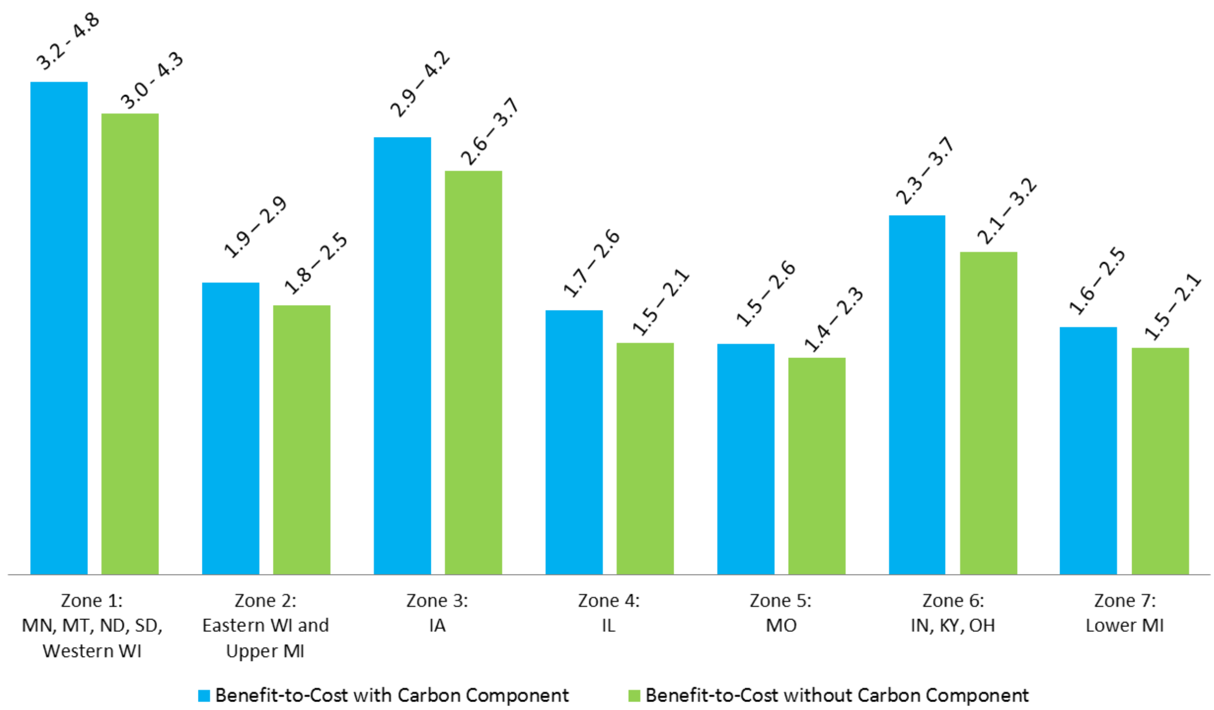

Figure 6-3: MTEP17 MVP Portfolio Production Cost Benefit with and without Carbon Cost Component

6.1 Congestion and Fuel Savings

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. These benefits were outlined through a series of production cost analyses, which capture the economic benefits of the MVP transmission and the wind it enables. These benefits reflect the savings achieved through the reduction of transmission congestion costs and through more efficient use of generation resources.

Changes due to projected unit retirements, carbon cost modeling, wind enablement and topology changes have increased the Congestion-Fuel savings in MTEP17.

Congestion and fuel savings is the most significant portion of the MVP benefits (Figure 6-1). The MTEP17 Triennial MVP Review estimates that the MVP Portfolio will yield $20 to $71 billion in 20- to 40-year present value adjusted production cost benefits, depending on the timeframe and discount rate assumptions. This value is up 32 percent to 60 percent from the original MTEP11 valuation and 5 percent to 11 percent from MTEP14 (Table 6-2).

	MTEP17	MTEP14	MTEP11
3% Discount Rate; 20 Year NPV	31,797	30,214	23,603
8% Discount Rate; 20 Year NPV	20,121	18,698	15,295
3% Discount Rate; 40 Year NPV	71,363	64,157	44,508
8% Discount Rate; 40 Year NPV	29,783	27,017	20,478

Table 6-2: Congestion and Fuel Savings Benefit ($M-2017)

The difference in congestion and fuel savings benefits relative to MTEP14 increased primarily due to carbon cost modeling, increase in wind enablement and topology changes (Figures 6-4, 6-5). Benefits decreased due to a reduction in the out-year natural gas price forecast assumptions, leading to a net increase of 19 percent on a 20-year present value basis. MTEP14 futures utilized a natural gas price escalation rate assumption sourced from a combination of the New York Mercantile Exchange (NYMEX) and Energy Information Administration (EIA) forecasts. MTEP17 assumed natural gas price escalation rate is approximately 2.5 percent per year[9], compared to 7.2 percent per year in MTEP14. The reduced escalation rate causes the assumed natural gas price to be 34 percent lower in MTEP17 than MTEP14 (Figure 6-4).

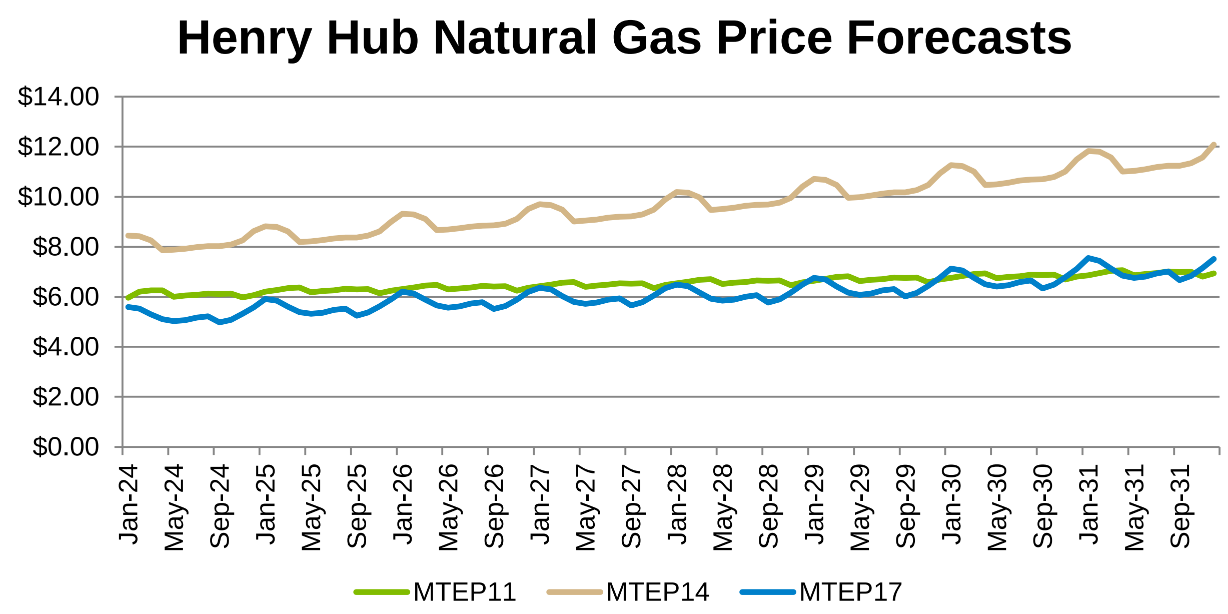

Figure 6-4: Natural Gas Price Forecast Comparison

[9] 2.5% of the assumed MTEP14 natural gas price escalation rate represents inflation . Inflation rate added to the NYMEX and EIA sourced growth rate.

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection highly correlated to the natural gas price assumption. A sensitivity applying the MTEP14 BAU gas price assumptions to the MTEP17 MVP Triennial Review model showed a 27 percent reduction in the 20 year MTEP14 Present Value congestion and fuel savings benefits (Figure 6-5). Also, approximately 38 percent of the difference between the MTEP17 and MTEP14 present value congestion and fuel savings benefit is attributable to the carbon costs, wind enablement, coal retirements and topology changes.

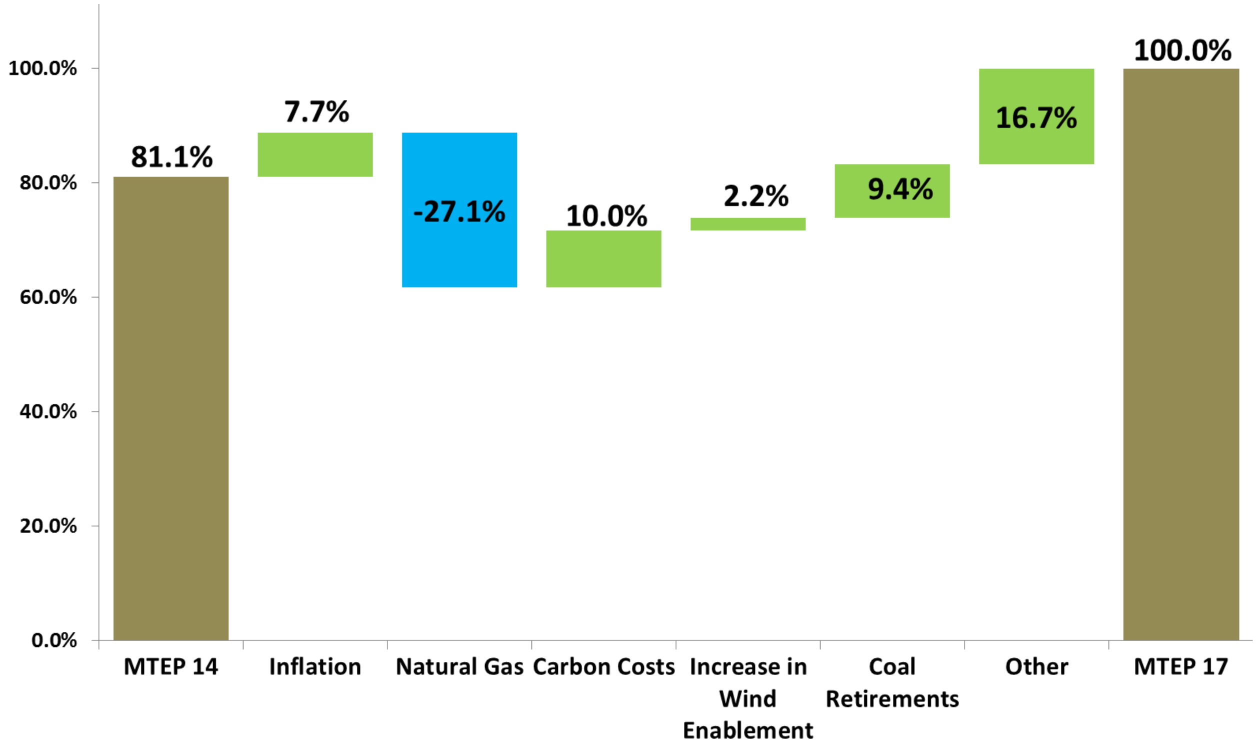

Figure 6-5: Breakdown of Net Present Value Congestion and Fuel Savings Benefit Increase from MTEP14 to MTEP17 – 20 Year NPV at 8.2 percent Discount Rate

MTEP17 Policy Regulation national CO_2 emissions were priced at $5.80/ton, which increased the congestion and fuel savings benefit by 10 percent relative to MTEP14. The MTEP14 model did not include carbon emission costs in the production cost calculation. The wind enabled through the MVP's offset more expensive generation, with carbon costs, to lead to the slight increase in MVP benefits.

Within the MTEP17 Policy Regulatory future assumptions MISO forecasted approximately 16 GW of coal retirements driven by both age and policy assumptions. The MTEP14 Triennial Review models included 12.6 GW of assumed coal retirements. The coal unit retirement assumption in MTEP17 PR future resulted in an increase in congestion and fuel savings of 9.4 percent.

The additional 18.9 percent in increased benefits is driven by the increase in wind enabled by the MVPs as well as a combination of "Other" differencesfrom MTEP14 to MTEP17. The Other category represents changes between study models such as topology upgrades, generation siting, demand and energy values as well as the compounding/synergic effects of all categories together.

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

The MTEP17 MVP Triennial Review economic analysis was performed with 2026 and 2031 Policy Regulation production cost models, with wind curtailments considered for 2026, 2031 and 2036. The 2036 case was used as a proxy case to determine the additional benefits from wind enabled above and beyond that mandated by the year 2031.

6.2 Operating Reserves

In addition to the energy benefits quantified in the production cost analyses, the 2011 business case showed the MVP Portfolio also reduces operating reserve costs. The 2011 business case showed that the MVP Portfolio decreases congestion on the system, increasing the transfer capability into several areas that would otherwise have to hold additional operating reserves under certain system conditions.

Consistent with MTEP14, as a conservative measure, the MVP Triennial Review does not estimate a reduced operating reserve benefit in MTEP17.

Reserve zones are established to ensure that operating reserves are dispersed in a manner that prevents adverse operating conditions that affect the reliability of the transmission system. Minimum operating reserve requirements by operating zone are typically calculated to be zero. Only a limited number of days have had non-zero minimum operating reserve requirements since MTEP11 (Table 6-4). As a conservative measure, and consistent with MTEP14, this MVP Triennial Review does not estimate a reduced operating reserve benefit in MTEP17.

Zone	MTEP11 (June 2010 – May 2011)			MTEP14 (January 2013 – December 2013)			MTEP17 (January 2016 – December 2016)		
	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)
Missouri/ Illinois	95	1	95.1	0	0	0	0	0	0
Indiana	14,966	53	282.4	0	0	0	0	0	0
Northern Ohio	9,147	15	609.8	N/A	N/A	N/A	N/A	N/A	N/A
Michigan	4,915	17	289.1	0	0	0	0	0	0
Wisconsin	227	2	113.4	0	0	0	0	0	0
Minnesota	376	1	376.3	32	2	16	0	0	0

Table 6-4: Historic Operating Requirements

6.3 Planning Reserve Margin Requirements

The MTEP14 Review estimated a deferred capacity value of $75.8 million due to the expected capacity shortage in Local Resource Zone (LRZ) 3 without the addition of the MVPs. With the refreshed analysis on updated system topology and expected capacity resources, MISO no longer expects a capacity shortfall in LRZ 3. As a result, the MVP Review does not estimate any deferred capacity benefits as a product of the MVPs.

With the refreshed analysis on updated system topology, MISO no longer expects a capacity shortfall in LRZ 3. As a result, the MVP Review does not estimate any deferred capacity benefits as a product of the MVPs.

In the 2013/2014 Planning Year MISO improved the methodology[10] that establishes the Planning Reserve Margin Requirement (PRMR), so beginning in 2014 the benefit analysis for the MVP Review was updated to align with the current process to include zonal capacity transfer limits. MISO now performs loss of load expectation (LOLE) analysis to determine zonal capacity import limits with and without the MVPs to calculate the impact on local clearing requirements (the amount of generation capacity required to be physically within a LRZ). In MTEP14 this analysis estimated an 852 MW of capacity shortfall in LRZ 3 without the MVP portfolio, which translated to $946-$2,746 million of deferred capacity expansion costs. Refreshing this analysis in MTEP17 no longer estimates a capacity shortfall in LRZ 3, and therefore, no deferred capacity benefits are expected.

Three primary variables determine if an LRZ will be short or long on capacity:

- **Local Reliability Requirement (LRR):** The expected load requirements (MW) of the LRZ
- **Unforced Capacity (UCAP):** The expected available generation (MW) in the LRZ
- **Capacity Import Limit:** The limit that sets the amount of resources outside of the LRZ that can serve the zone's load

All of these variables have changed since the triennial analysis of 2014: The LRR in the recent analysis is marginally smaller, the UCAP is higher due to the addition of new generation, and the CIL has increased. The UCAP MW and LRR MW changes all but remove the need to import to support LRZ 3's demand. The increase in CIL is due to multiple factors, including transmission system changes since 2014 and study methodology improvements.

Specific system changes include rating upgrades that have impacted the constraints from both scenarios, with and without MVP, studied in 2014. Increases to the ratings have contributed to these constraints no longer binding resulting in higher limits in recent analysis. Additionally, non-MVP projects coming into service have also driven current limit higher. When combined with the decreased LRR and increased UCAP MW, LRZ 3 is no longer expected to be short on capacity.

[10] Prior to 2013 the MISO-wide PRMR included an embedded congestion component, which has since been replaced by a more granular zonal PRMR and local clearing requirement. The MTEP11 MVP analsysis showed that the MVP portfolio reduced congestion, which would thus reduce the congestion component of the PRMR and allow MISO to reliably carry a decreased PRMR

6.4 Transmission Line Losses

The addition of the MVP Portfolio to the transmission network reduces overall system losses, which also reduces the generation needed to serve the combined load and transmission line losses. The energy value of these loss reductions is considered in the congestion and fuel savings benefits, but the loss reduction also helps to reduce future generation capacity needs.

The MTEP17 Review found that system losses decrease by 127.6 MW with the inclusion of the MVP Portfolio.

The MTEP17 Review found that system losses decrease by 127.6 MW with the inclusion of the MVP Portfolio. MTEP14 and MTEP11 estimated that the MVPs reduced losses by 122 MW and 150 MW respectively. The decrease between MTEP17 and MTEP14, relative to MTEP11 can be attributed to changes in system demand, the MISO North and Central Regions membership changes, and transmission topology upgrades in the base model.

Comparatively to MTEP11, tightening reserve margins have increased the value of deferred capacity from transmission losses in both the MTEP14 and MTEP17 reviews. In MTEP11, baseload additions were not required in the 20-year capacity expansion forecast to maintain planning reserve requirements so the decreased transmission losses from the MVP Portfolio allowed the deferment of a single combustion turbine. In MTEP17, the decreased losses cause a large shift in the proportion of baseload combined cycle units and peaking combustion turbines in the capacity expansion forecast.

The estimated benefits from reduced transmission line losses are substantively similar to MTEP14, and more than double compared to the MTEP11 values (Table 6-9) as a result of tighter reserve margins. Using current capital costs, the deferment equates to a savings of $234 to $1,061 million, excluding the impacts of any potential future policies.

	MTEP17	MTEP14	MTEP11
3% Discount Rate; 20 Year NPV	711	790	244
8% Discount Rate; 20 Year NPV	234	313	309
3% Discount Rate; 40 Year NPV	1,061	1,162	339
8% Discount Rate; 40 Year NPV	383	432	352

Table 6-9: Transmission Line Losses Benefit ($M-2017)

The benefit valuation methodology used in the MTEP17 Review is similar to that used in MTEP11. The transmission loss reduction was calculated by comparing the transmission line losses in the 2026 summer peak powerflow model both with and without the MVP Portfolio. This value was then used to extrapolate the transmission line losses for 2016 through 2023, assuming escalation at the Policy Regulation base demand growth rate. The change in required system capacity expansion due to the impact of the MVP Portfolio was calculated through a series of EGEAS simulations. In these simulations, the total system generation requirement was set to the system PRMR multiplied by the system load plus the system losses (Generation Requirements = (1+PRMR)*(Load + Losses)). To isolate the impact of the transmission line loss benefit, all variables in these simulations were held constant, except system losses.

The difference in capital fixed charges and fixed operation and maintenance costs in the no-MVP case and the post-MVP case is equal to the capacity benefit from transmission loss reduction, due to the addition of the MVP portfolio to the transmission system.

6.5 Wind Turbine Investment

The lower expected benefits in the MTEP17 results compared to MTEP11 and MTEP14 can primarily be attributed to a 40 percent decrease in the expected wind capital costs.

During the RGOS, the pre-cursor to the Candidate MVP Study, MISO developed a wind siting approach that results in a low-cost solution when transmission and generation capital costs are considered. This approach sources generation in a combination of local and regional locations, placing wind local to load, where less transmission is required; and regionally, where the wind is the strongest (Figure 6-7). However, this strategy depends on a strong regional transmission system to deliver the wind energy. Without this regional transmission backbone, the wind generation has to be sited close to load, requiring the construction of significantly larger amounts of wind capacity to produce the renewable energy mandated by public policy.

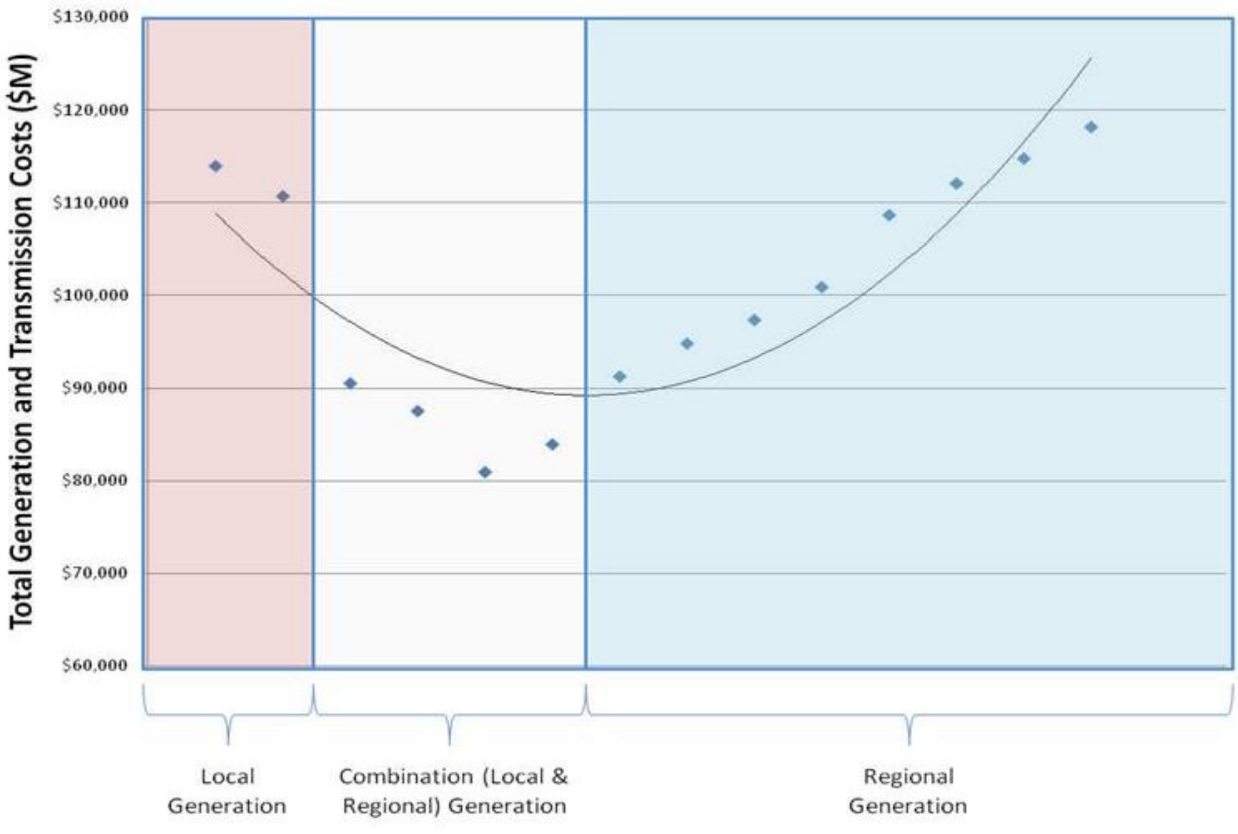

Figure 6-7: Local versus Combination Wind Siting

The MTEP17 Triennial MVP Review found that the benefits from the optimization of wind generation siting are lower in magnitude when compared with MTEP11 and MTEP14 (Table 6-10). The lower expected benefits in the MTEP17 results compared to MTEP11 and MTEP14 can primarily be attributed to a 40 percent decrease in the expected wind capital costs.

	MTEP17	MTEP14	MTEP11
3% Discount Rate; 20 Year NPV	1,264	2,361	1,992
8% Discount Rate; 20 Year NPV	1,451	2,717	2,393
3% Discount Rate; 40 Year NPV	1,264	2,361	1,992
8% Discount Rate; 40 Year NPV	1,451	2,717	2,393

Table 6-10: Wind Turbine Investment Benefit ($M-2017)

In the RGOS study, it was determined that 11 percent less wind would need to be built to meet renewable energy mandates in a combination local/regional methodology relative to a local only approach. This change in generation was applied to energy required by the renewable energy mandates, as well as the total wind energy enabled by the MVP Portfolio (Section 5). This resulted in a total of 3.4 GW of avoided wind generation (Table 6-11).

Year	MVP Portfolio Enabled Wind (MW)	Equivalent Local Wind Generation (MW)	Incremental Cumulative Wind Benefit (MW)
Pre-2021	15,949	17,741	1,792
2021	21,139	23,514	2,375
2026	24,612	27,377	2,765
2031	25,689	28,575	2,886
Full Wind Enabled	30,812	34,273	3,461

Table 6-11: Renewable Energy Requirements, Combination versus Local Approach

The incremental wind benefits were monetized by applying a value of $1.2 to $2 million/MW, based on the NREL Annual Technology Baseline report that estimates of the capital costs to build onshore wind[11]. The total wind-enabled benefits were then spread over the expected life of a wind turbine. Consistent with the MTEP11 and MTEP14 business case that avoids overstating the benefits of the combination wind siting, a transmission cost differential of approximately $1.5 billion was subtracted from the overall wind turbine capital savings to represent the expected lower transmission costs required by a local-only siting strategy.

[11] Updated in 2016

6.6 Future Transmission Investment

Consistent with MTEP11, the MTEP17 MVP Triennial Review shows that the MVP Portfolio eliminates the need for approximately $300 million in future baseline reliability upgrades (Table 6-12). The magnitude of estimated benefits is in close proximity to the estimates from MTEP11 and MTEP14; however, the actual identified upgrades are different due to differences in bus-level load growth, generation dispatch, wind levels and transmission upgrades.

MTEP17 analysis shows the MVP Portfolio eliminates the need for approximately $300 million in future baseline reliability upgrades.

	MTEP17	MTEP14	MTEP11
3% Discount Rate; 20 Year NPV	615	726	561
8% Discount Rate; 20 Year NPV	299	352	308
3% Discount Rate; 40 Year NPV	1,101	1,317	1,003
8% Discount Rate; 40 Year NPV	410	487	424

Table 6-12: Future Transmission Investment Benefits ($M-2017)

Reflective of the post-Order 1000 Baseline Reliability Project cost allocation methodology, capital cost deferment benefits were fully distributed to the LRZ in which the avoided investment is physically located; a change from the MTEP11 business case that distributed 20 percent of the costs regionally and 80 percent locally.

A model simulating 2036 summer peak load conditions was created by growing the load in the 2026 summer peak model. The 2036 model was run both with and without the MVP Portfolio to determine which out-year reliability violations are eliminated with the inclusion of the MVP Portfolio (Table 6-13).

Avoided Investment	Element	kV	Upgrade Required	Miles
BIGSTON4-BROWNSV4	Line	230	Transmission line, < 345 kV	36.71
ARROWHD7-GRE-BERGNTP7	Line	115	Transmission line, < 345 kV	1
17REYNOLDS-17MAGNET	Line	138	Transmission line, < 345 kV	0.77
08LAFCIN-08PURDUE	Line	138	Transmission line, < 345 kV	1.29
BIGSTON7-HIWY12 7	Line	115	Transmission line, < 345 kV	2
TRK RIV5-STONEMAN	Line	161	Transmission line, < 345 kV	2.71
4OREANA-4ADM NORTH	Line	138	Transmission line, < 345 kV	3.23
4OREANA-4ADM NORTH	Line	138	Transmission line, < 345 kV	3.91
HIWY12 7-ORTONVL7	Line	115	Transmission line, < 345 kV	4.5
INVRGRV7-GRE-PILOTKB7	Line	115	Transmission line, < 345 kV	5.6
NOM 138-ALB 138	Line	138	Transmission line, < 345 kV	9.21
08WAB R-08WTR ST	Line	138	Transmission line, < 345 kV	9.55
ALB 138-BASSCRK	Line	138	Transmission line, < 345 kV	11.88
08HORTVL-08WHITST	Line	345	Transmission line, 345 kV	14.35
SHEYNNE7-MAPLTN 7	Line	115	Transmission line, < 345 kV	14.78
08CAYUGA-08VDSBRG	Line	230	Transmission line, < 345 kV	18.4
HANKSON4-WAHPETN4	Line	230	Transmission line, < 345 kV	25.55
BIGSTON4-BLAIR 4	Line	230	Transmission line, < 345 kV	33.13
BROWNSV4-HANKSON4	Line	230	Transmission line, < 345 kV	33.46
CANBY 7-GRANITF7	Line	115	Transmission line, < 345 kV	39.22
08DRESSR-08DRESSR	Transformer	345/138	Transformer	
16THOMPS-16THOMPS	Transformer	345/138	Transformer	
7PALMYRA-5PALMYRA	Transformer	345/161	Transformer	
RUTLAND5-WINBAGO5	Transformer	161/161	Transformer	
BIGSTON7	Transformer	230/115	Transformer	
08PER SE	Transformer	230/69/13.8	Transformer	

Table 6-13: Avoided Transmission Investment

The cost of this avoided investment was valued using generic transmission costs, as estimated from projects in the MTEP database and recent transmission planning studies (Table 6-14). Generic estimates, in nominal dollars, are unchanged from those used in the MTEP11 and MTEP14 analysis. Transmission investment costs were assumed to be spread between 2031 and 2035. To represent potential production cost benefits that may be missed by avoiding this transmission investment, the 345 kV transmission line savings was reduced by half.

Avoided Transmission Investment	Estimated Upgrade Cost
Bus Tie	$1,000,000
Transformer	$5,000,000
Transmission lines (per mile, for voltages under 345 kV)	$1,500,000
Transmission lines (per mile, for 345 kV)	$2,500,000

Table 6-14: Generic Transmission Costs

7. Qualitative and Social Benefits

Aside from widespread economic and public policy benefits, the MVP Portfolio also provides benefits based on qualitative or social values. Consistent with the MTEP11 analysis, these benefits are excluded from the business case. The quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the MVP Portfolio.

7.1 Enhanced Generation Flexibility

The MVP Portfolio also provides benefits based on qualitative or social values, which suggests that the quantified values from the economic analysis may be conservative because they do not account for the full benefit potential.

The MVP Portfolio is primarily evaluated on its ability to reliably deliver energy required by renewable energy mandates. However, the MVP Portfolio also provides value under a variety of different generation policies. The energy zones, which were a key input into the MVP Portfolio analysis, were created to support multiple generation fuel types. For example, the correlation of the energy zones to the existing transmission lines and natural gas pipelines were a major factor considered in the design of the zones (Figure 7-1).

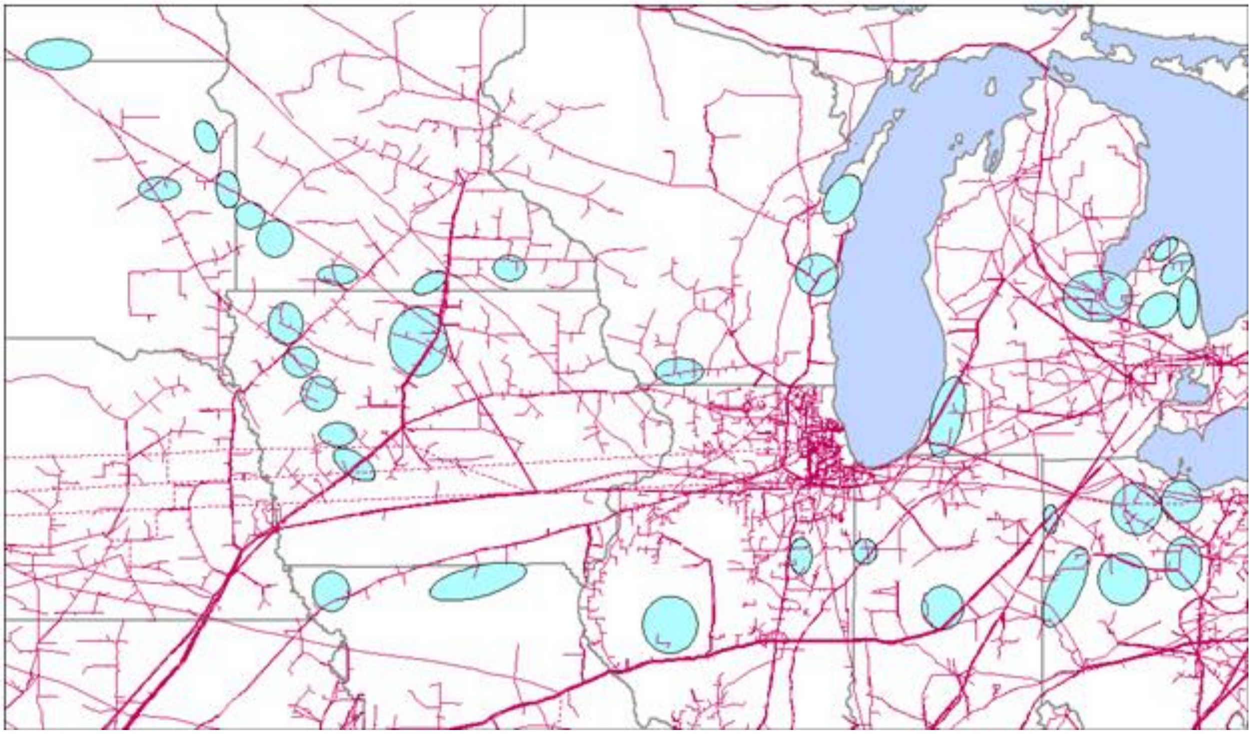

Figure 7-1: Energy Zone Correlation with Natural Gas Pipelines

7.2 Increased System Robustness

A transmission system blackout, or similar event, can have widespread repercussions and result in billions of dollars of damage. The blackout of the Eastern and Midwestern United States in August 2003 affected more than 50 million people and had an estimated economic impact of between $4 and $10 billion.

The MVP Portfolio creates a more robust regional transmission system that decreases the likelihood of future blackouts by:

- Strengthening the overall transmission system by decreasing the impacts of transmission outages
- Increasing access to additional generation under contingent events
- Enabling additional transfers of energy across the system during severe conditions

7.3 Decreased Natural Gas Risk

Natural gas prices vary widely (Figure 7-2) causing corresponding fluctuations in the cost of energy from natural gas. In addition, recent and pending U.S. Environmental Protection Agency regulations limiting the emissions permissible from power plants will likely lead to more natural gas generation. This may cause the cost of natural gas to increase along with demand. The MVP Portfolio can partially offset the natural gas price risk by providing additional access to generation that uses fuels other than natural gas (such as nuclear, wind, solar and coal) during periods with high natural gas prices.

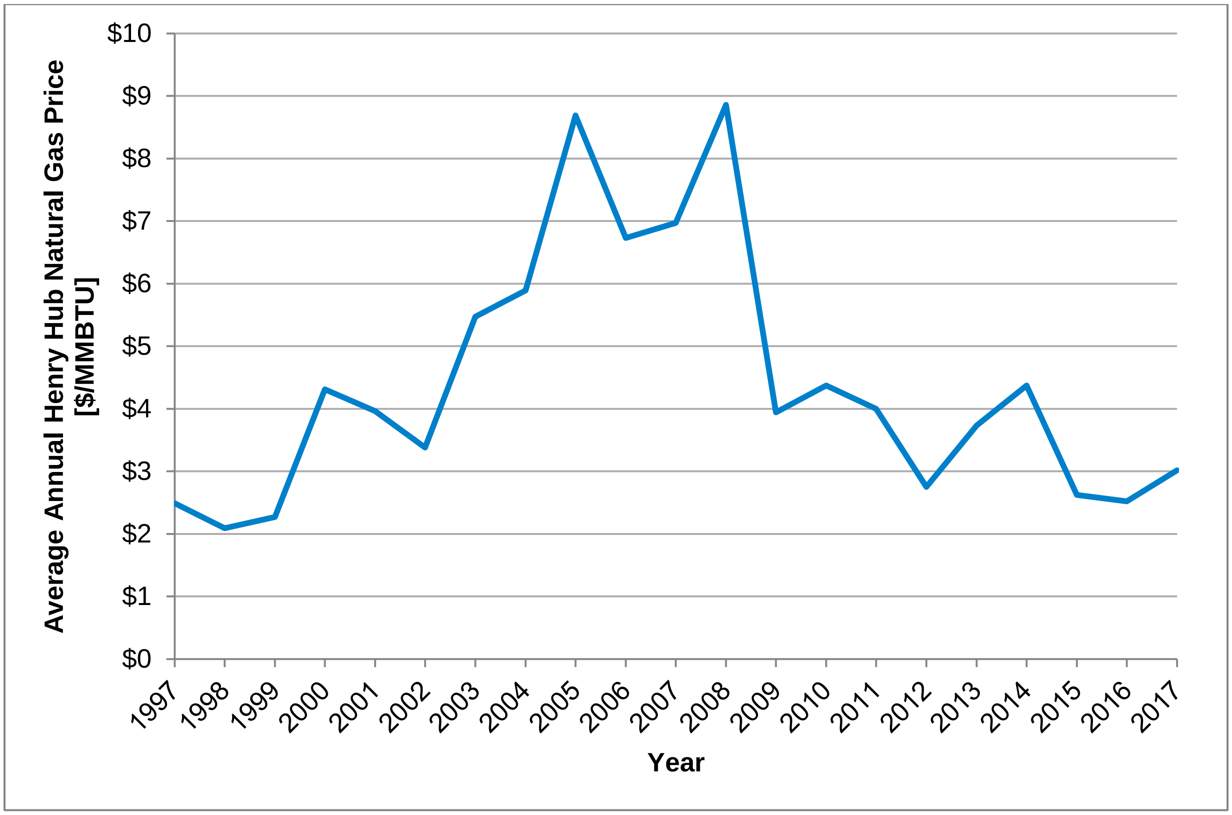

Figure 7-2: Historic Henry Hub Natural Gas Prices

A set of sensitivity analyses were performed to quantify the impact of changes in natural gas prices. The sensitivity cases maintained the same modeling assumptions from the base business case analyses, except for the gas prices. The gas prices were tested at ±25 percent $/MMBTU as well as studied with the MTEP 14 natural gas price, which is 57 percent higher than the gas prices in MTEP17.

The system production cost is driven by many variables, including fuel prices, carbon emission regulations, variable operations, management costs and renewable energy mandates. The decrease in natural gas prices lowers fuel costs on the system, which in turn produced lower production cost benefits due to the inclusion of the MVP Portfolio. These decreased benefits are offset by carbon costs, coal unit retirements, increased wind enablement and topology changes that led to the efficient usage of renewable and low-cost generation resources (Figure 7-3).

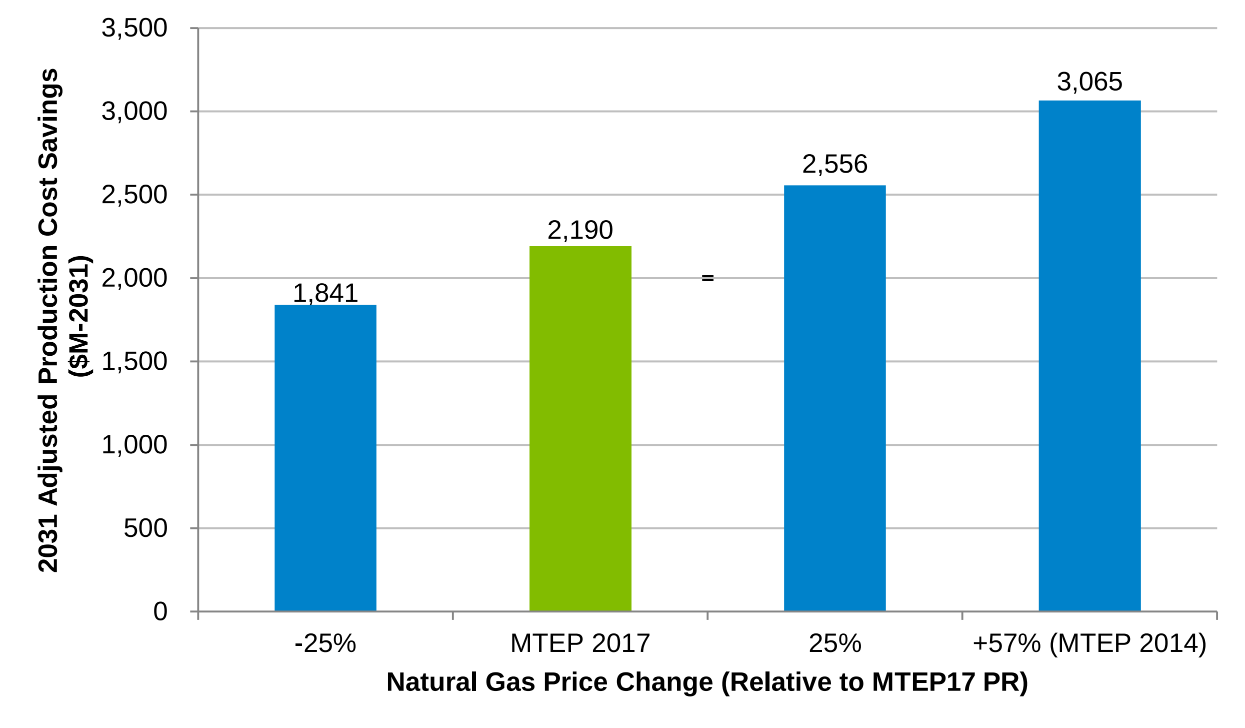

Figure 7-3: MVP Portfolio Adjusted Production Cost Savings by Natural Gas Price

7.4 Decreased Wind Generation Volatility

As the geographical distance between wind generators increases, the correlation in the wind output decreases (Figure 7-4). This relationship leads to a higher average output from wind for a geographically diverse set of wind plants, relative to a closely clustered group of wind plants. The MVP Portfolio will increase the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time.

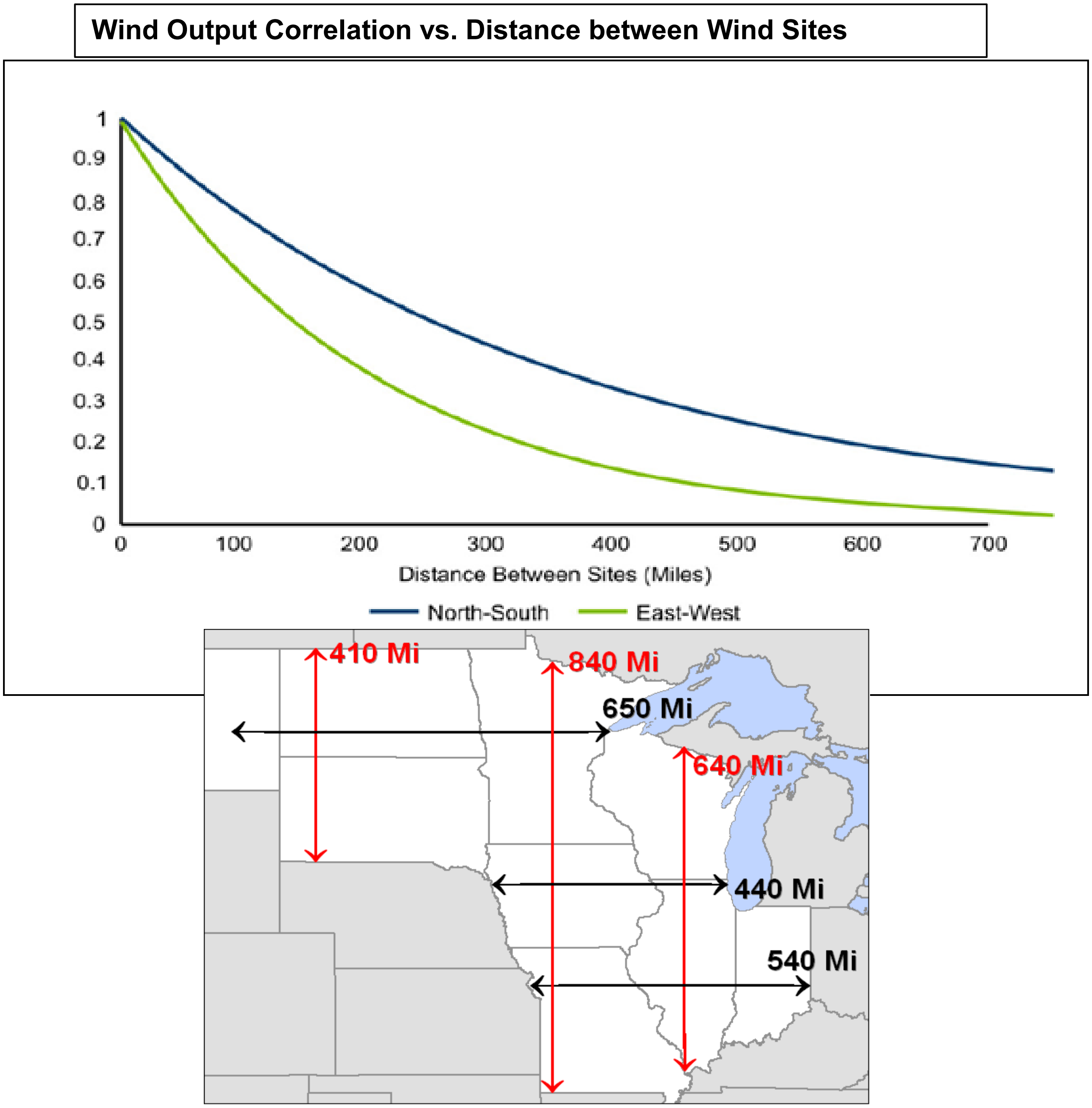

Figure 7-4: Wind Output Correlation to Distance between Wind Sites

7.5 Local Investment and Jobs Creation

In addition to the direct benefits of the MVP Portfolio, studies performed by the State Commissions have shown the indirect economic benefits of the MVP transmission investment. The MVP Portfolio supports thousands of local jobs and creates billions in local investment. In MTEP11, it was estimated that the MVP Portfolio supports between 17,000 and 39,800 local jobs, as well as $1.1 to $9.2 billion in local investment.

7.6 Carbon Reduction

The MVP Portfolio reduces carbon emissions by 13 to 21 million tons annually (Figure 7-5).

The MVP Portfolio enables the delivery of significant amounts of wind energy across MISO and neighboring regions, which reduces carbon emissions.

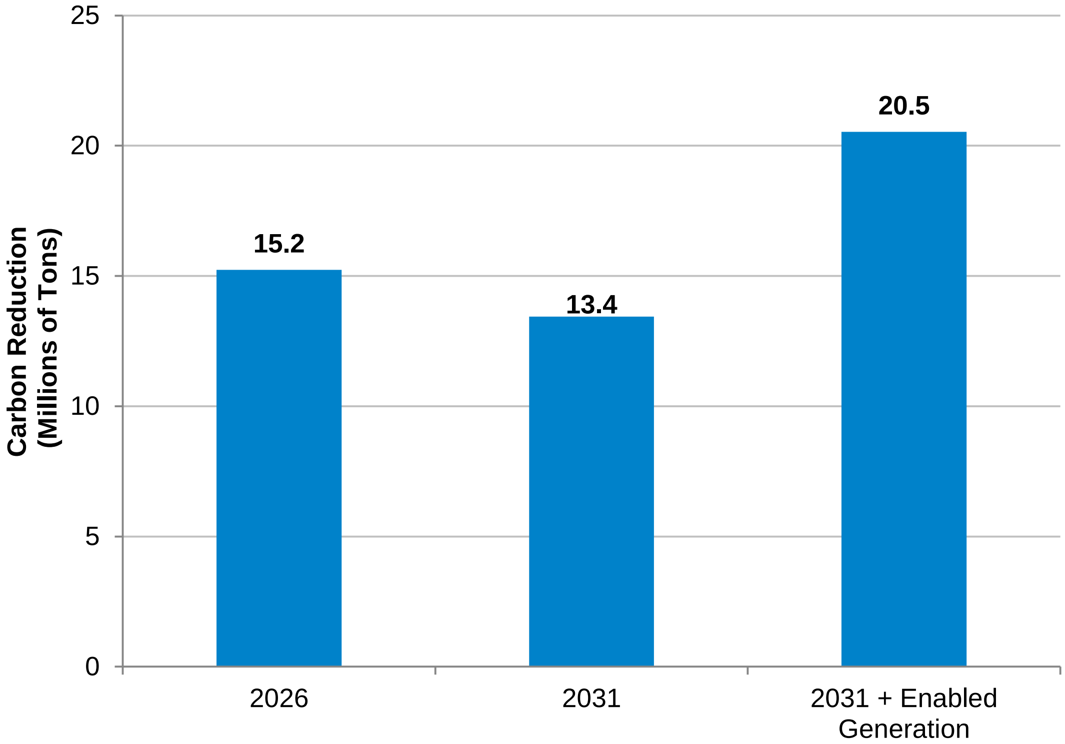

Figure 7-5: Forecasted Carbon Reduction from the MVP Portfolio by Year

8. Historical Data Review

8.1 Introduction

MTEP17 marks the first cycle in which the MVP Review will provision available historical market data for trend analysis. In accordance with Attachment FF the review will take a quantitative and qualitative look into how the in-service MVPs impact certain tariff-defined metrics:

- Congestion Costs
- Energy Prices
- Fuel Costs
- Planning Reserve Margin
- Newly Interconnected Resources
- Share of Energy Supplied

The prospective benefits quantified in previous chapters of this review assume the entire MVP portfolio is in-service over 20- and 40-year time-frames. As of the second quarter of 2017, only four of the 17 MVPs have gone into service, all of which have less than four years of historical market data (Table 8-1).

MVP #	Project Name	In-Service Date	MTEP Project ID
2	Brookings - Twin Cities	3/26/2015	1203
15	Pleasant Prairie – Zion Energy Center	12/6/2013	2844
17	Sidney – Rising	9/21/2016	2239
13	Michigan Thumb Loop	12/31/2015	3168

Table 8-1: In-Service MVPs as of the second quarter 2017

In breaking down the results of each metric, several positive correlations between targeted congestion areas and increasing renewable energy integration trends are observed, but without a larger statistical sample size, no definitive conclusions can be made from the limited available data. Once the entire MVP portfolio is energized, additional clarity can be provided around the realized MVP system impacts.

Where available, data regarding each benefit metric for the previous five years[12] has been provided, along with contextual and qualitative discussion regarding the collection process, data sources and in-service MVP impact.

8.2 Congestion Costs and Energy Prices

Congestion and fuel savings provide a significant portion of the prospective system-wide benefits over a 20- to 40-year time frame (see section 6.1). With only a small portion of the entire MVP portfolio in service, the MVP impact on congestion costs can be difficult to isolate on a system-wide review. To better capture this impact for the limited in-service portfolio, a targeted review of each project was performed using operational and planning experience to identify Day-Ahead (DA) binding constraints.

To evaluate congestion costs, the number of binding hours per year was collected from the Hourly MISO DA market database for each identified constraint during the sample period (January 2012 – July 2017). These DA congestion hours were then matched with the congestion dollar amounts and congestion savings are quantified, by constraint and year, for each project. Where congestion was present after the

[12] Sample period encompasses January 1, 2012-July 31, 2017

MVP in-service date, values are provided as negative. If no year is listed for a given constraint it means the binding constraint was not seen in the DA binding constraint database for that year.

Day-Ahead Locational Marginal Price (LMP) is the most common measure of energy prices, but because changes in DA LMPs are driven to a large extent by variations in fuel prices (particularly natural gas prices), this is not a reliable metric for evaluating the impact of the MVP projects. Instead, the binding constraints identified in the congestion cost analysis were evaluated for impact on energy price.

A binding constraint increases the prices at the raise-help nodes (where injecting power mitigates the flows creating congestion) by contributing to the Marginal Congestion Component (MCC). Each constraint and contingency was matched to the DA constraint and impacted Pnodes. DA shift factors for the significantly impacted (i.e. sensitivity of at least 5 percent) Pnodes were obtained along with Shadow Price of the constraints, and the energy price impact was calculated using the formula:

Average Price Impact for Most Significant Raise Help nodes = Average {Shift Factor * Shadow Price}

Finally, price impacts are compared before versus after the associated MVP in-service date.

MVP 15: Pleasant Prairie – Zion Energy Center (In Service December 6, 2013):

The Pleasant Prairie – Zion Energy Center MVP was designed to address congestion on the southeast Wisconsin-Illinois border by adding a third 345 kV line across the interface. The expected result was that less-expensive Wisconsin generation would be able to export during shoulder peak times (though this interface could overload in both directions depending on the scenario). Specific constraints in this region include the Lakeview - Zion 138 kV, which also required an operational Special Protection Scheme (SPS), and Pleasant Prairie – Zion 345 kV, which was binding in the Day Ahead market for different contingent scenarios.

With MVP 15 going into service in December 2013, the Pleasant Prairie – Zion 345 kV and Lakeview - Zion 138 kV constraints were significantly relieved (the new limiting element is now the MVP itself) with additional benefit of allowing the Lakeview SPS to retire. This is indicated by the limited number of binding hours occurring after the MVP in-service date, including no identified binding hours identified after 2014 (Table 8-2, 8-3).

Year	Binding Hours	DA Congestion Dollars
Zion-Arcadian FLO Pleasant Prairie - Zion + Lakeview SPS		
2012	60	$208,309
2013	233	$536,373
Zion - Lakeview 138kV FLO Pleasant Prairie-Zion 345kV		
2012	64	$102,706
2014		
Vortex period[13]	-8	-$175,996
Non-Vortex period	-52	-$317,278
Pleasant Prairie-Zion 345kV BASE		
2013	178	$891,141
Pleasant Prairie-Zion 345kV FLO Zion-Arcadian 345kV		
2012	65	$445,902
2014	-3	-$2,785
Total	**537**	**$1,688,372**

Table 8-2: Congestion Totals by Constraint for MVP 15 for years 2012 – 2017

Constraint	Average MCC Impact ($/MWh)	Max Nodes Impacted	Average MCC Impact ($/MWh)	Max Nodes Impacted
	Before ISD: 12/1/2012 - 12/6/2013		After ISD: 12/6/2013 - 7/31/2017	
Zion-Arcadian FLO Pleasant Prairie - Zion + Lakeview SPS	0.611	906	0	0
Zion - Lakeview 138kV FLO Pleasant Prairie-Zion 345kV	0.445	922	0.092	1110
Pleasant Prairie-Zion 345kV BASE	0.611	906	0	0
Pleasant Prairie-Zion 345kV FLO Zion-Arcadian 345kV	0.088	151	0	0

Table 8-3: Average Energy Price Impact by Constraint for MVP 15 before and after In-Service Date

MVP 2: Brookings – Twin Cities (In Service March 26, 2015):

Brookings – Twin Cities MVP 2, in conjunction with MVP 1 and 6, was designed to reliably transfer wind energy from the Dakotas and southwestern Minnesota to the Minneapolis-St Paul load center. Two targeted constraints on this west to east path — Brookings to White and Wilmarth to Swan Lake — were identified as potentially impacted by the in-service MVP, with generation in southwestern Minnesota and Iowa having limited 345 kV outlets, potentially causing binding during contingent scenarios. All binding hours and associated congestion dollars identified in the sample period occurred before the MVP in-service date (Table 8-4, 8-5), indicating the constraints were relieved as expected.

[13] To highlight the impact of high natural gas prices during the Polar Vortex weather event, the binding hours identified in 2014 are further broken up into the "Vortex period," which includes January 2 – March 31, 2014.

Year	Binding Hours	DA Congestion Dollars
Brookings - White		
2012	3	$17,277
2013	121	$864,064
2014	55	$371,960
2015	85	$749,853
Wilmarth - Swan Lake		
2014	53	$391,611
Total	**317**	**$2,394,765**

Table 8-4: Congestion Totals by Constraint for MVP 2 for years 2012 – 2017

Constraint	Average MCC Impact ($/MWh)	Max Nodes Impacted	Average MCC Impact ($/MWh)	Max Nodes Impacted
	Before ISD: 12/1/2012 – 3/26/2015		After ISD: 3/27/2016 - 7/31/2017	
Brookings - White	4.61	10	0	0
Wilmarth - Swan Lake	11.199	24	0	0

Table 8-5: Average Energy Price Impact by Constraint for MVP 2 before and after In-Service Date

One additional constraint, Fox Lake – Rutland, was originally identified as potentially impacted since it is electrically close to MVP2. This constraint was not included for analysis after operational experience indicated the line only binds during outages, and the on-going construction of MVP3 impacts several substations in the corridor, potentially contributing to outage related DA binding hours.

MVP 13: Michigan Thumb Loop (In Service December 31, 2015):

The Michigan Thumb Loop MVP, by design, was not focused on congestion relief but rather, to provide the infrastructure necessary to accommodate significant wind generation (originally estimated 2300-4200 MW of wind production[14]) in the Michigan Thumb region. One notable constraint identified in the area prior to the MVP completion was the Lee – Sandusky 138 kV line. With the addition of the MVP, this line was able to reliably de-energize and thus, eliminate binding (Table 8-6, 8-7).

[14] Michigan Public Service Commission Order U-15899 and the Final Report of the Michigan Wind Energy Resource Zone Board directed the development of transmission infrastructure needed to deliver the estimated minimum 2,367 MW and maximum 4,236 MW of wind production potential

Year	Binding hours	DA Congestion Dollars
Lee - Sandusky		
2012	2	$2,492
2013	758	$2,464,428
2014	162	$606,348
Total	922	$3,073,268

Table 8-6: Congestion Totals by Constraint for MVP 13 for years 2012 – 2017

Constraint	Average MCC Impact ($/MWh)	Max Nodes Impacted	Average MCC Impact ($/MWh)	Max Nodes Impacted
	Before ISD: 12/1/2012 - 12/31/2015		After ISD: 1/1/2016 - 7/31/2017	
Lee - Sandusky	4.188	19	0	0

Table 8-7: Average Energy Price Impact by Constraint for MVP 13 before and after In-Service Date

An additional impact of this MVP, beyond the congestion and wind integration, was that the Harbor Beach coal-fired power station (121 MW) was able to fully retire. The unit had planned to retire in 2013 but was required to remain active as a System Support Resource (SSR) unit for reliability needs in the area. Quantifying SSR savings and benefits goes beyond the scope of this review.

MVP 17: Sidney – Rising (In Service September 2016):

The Sidney-Rising MVP, in conjunction with MVPs nine through 11, was designed to help alleviate historical West to East congestion through the State of Illinois. MVP 17 is primarily expected to help congestion in the region by creating better outlet for the Clinton generating station. Because less than one year of post in-service data is available, analysis of MVP 17 congestion relief is not included in this report. Specific constraints expected to be relieved in future reviews include the Rising transformer, Casey-Sullivan and Newton-Casey lines.

8.3 Fuel Costs

The fuel price indices associated with conventional generation in the MISO North/Central region are the Chicago Citygates natural gas and Illinois Basin coal prices. No direct correlation is observed between the limited MVP data and historic fuel prices (Figure 8-1).

The main drivers for natural gas price changes are weather related. Sustained hot summer weather drives up demand for electric generators and sustained cold winter weather drives up demand for heating. The weather influence can be best observed with the massive price spike in the winter of 2014 due to the Polar Vortex weather phenomena. This event created record setting gas demand both from electric generators as well as from residential and commercial users of natural gas (for space heating), significantly driving up fuel prices.

Steady decreases in gas prices from mid-2014 through 2015 are due to increases in production related to shale gas, coupled with mild weather across the country in the 2015-2016 winter. Slight increases in gas prices over the course of 2016 are due to decreases in production, as some suppliers (responding to low price signals) left the market.

Coal prices are more closely tied to electric power generation than gas; however, price fluctuation is still impacted by a number of external factors not related to transmission. The coal power generation life cycle from mine to generator has recently been affected by competition, regulation, and financial and future expectation stability, resulting in restructured business models and lower commodity prices. With added costs and the competitive pressure of low gas prices, coal production and transportation has experienced a decrease in demand and price. This correlation can be observed in 2015 where coal prices at Illinois Basin begin a slight downward trend in-line with a dip in gas prices over the same period. While a complete MVP portfolio could potentially contribute to price pressures, the in-service MVPs on their own have most likely not resulted in any coal price influence.

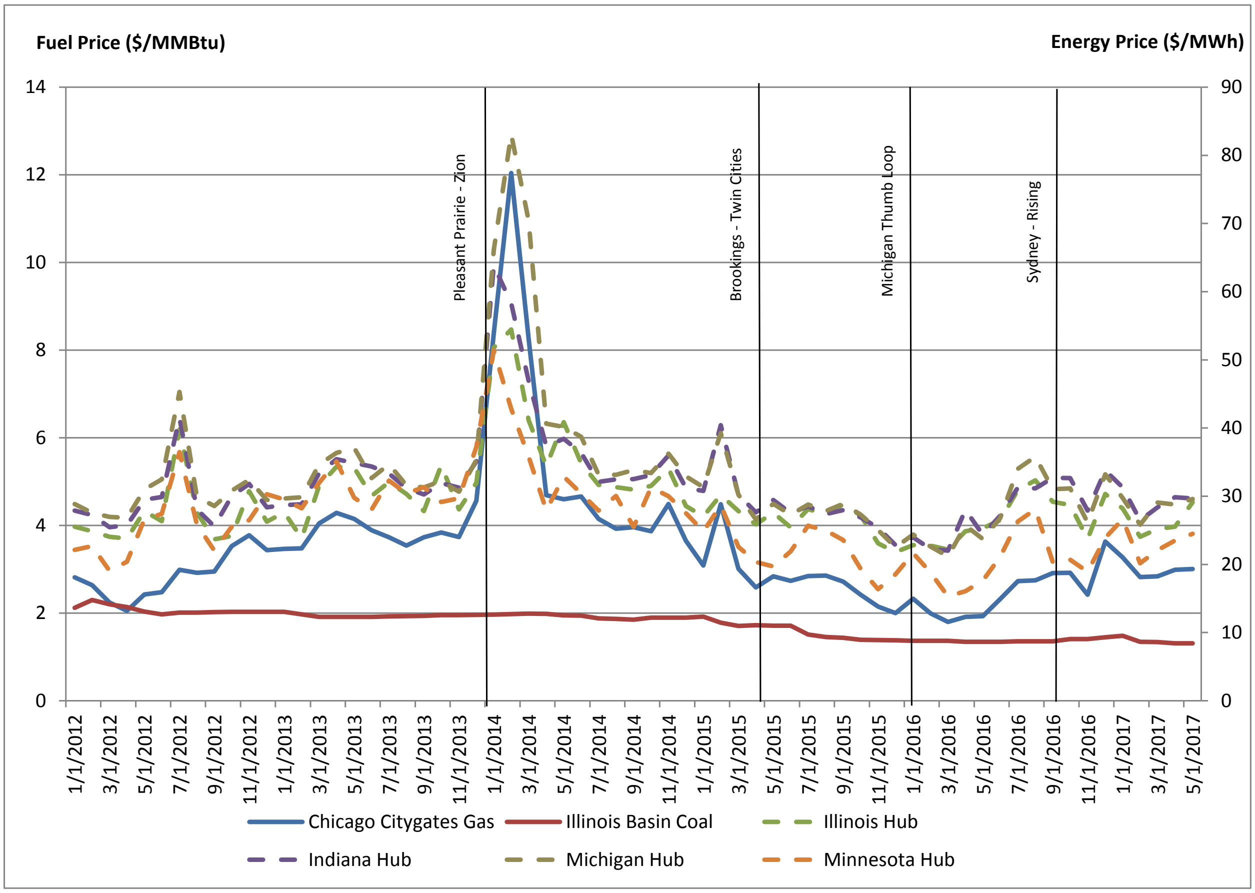

Figure 8-1: Fuel Prices 2012 – 2017 with MVP In-Service Dates

8.4 Planning Reserve Margin Requirements

The methodology for Planning Reserve Margin Requirements (PRMR) was improved in 2013 to calculate a more granular zonal PRMR, but removed the congestion component from the equation (see section 6.3). Without the congestion component as a factor in the calculation, changes in the transmission system topology (such as completed MVPs) will have no impact on the historical PRMR values.

As an alternative measure to PRMR, section 6.3 instead considers the impact of MVPs on Capacity Import Limits (CIL) to determine deferred investment savings. As the MISO footprint has yet to reach the point where any resource adequacy zones are short of capacity to take advantage of this benefit, a retrospective look at historical import limits cannot yet be quantified into hypothetical deferred investment. Details on PRMR and CIL calculations are available in the annual Loss of Load Expectation (LOLE) analysis.

8.5 Newly Interconnected Resources

A primary component of the MVP business case is the ability to reliably deliver wind energy to meet state renewable energy policy goals. To measure progress toward this objective, the aggregated totals of executed Generator Interconnection Agreement (GIA) Projects in MISO by fuel type were collected and analyzed. Over the five-year sample period, more than 6,000 MW of wind has been added to the MISO North/Central region (Table 8-8).

Fuel Type	2012	2013	2014	2015	2016	2017[15]	Total
Nuclear	-	-	-	84	-	-	84
Coal	2,960	111	144	-	-	-	3,215
Gas	225	-	83	-	423	677	1,408
Wind	2,149	251	685	1,342	1,493	150	6,070
Other Renewable	14	-	-	70	258	151	493
Other	26	5	-	-	-	-	31
Total	**5,374**	**367**	**912**	**1,495**	**2,174**	**978**	**11,300**

Table 8-8: Executed GIA Projects (MW) by Commercial Operating Date (MISO North/Central)

[15] 2017 data is through 4/30/2017

Additionally, the MVP Portfolio was designed to provide outlet for expected wind capacity in RGOS zones. A geospatial overlay of new wind projects in the North/Central region observes a correlation to actual wind siting and the original identified RGOS zones (Figure 8-2).

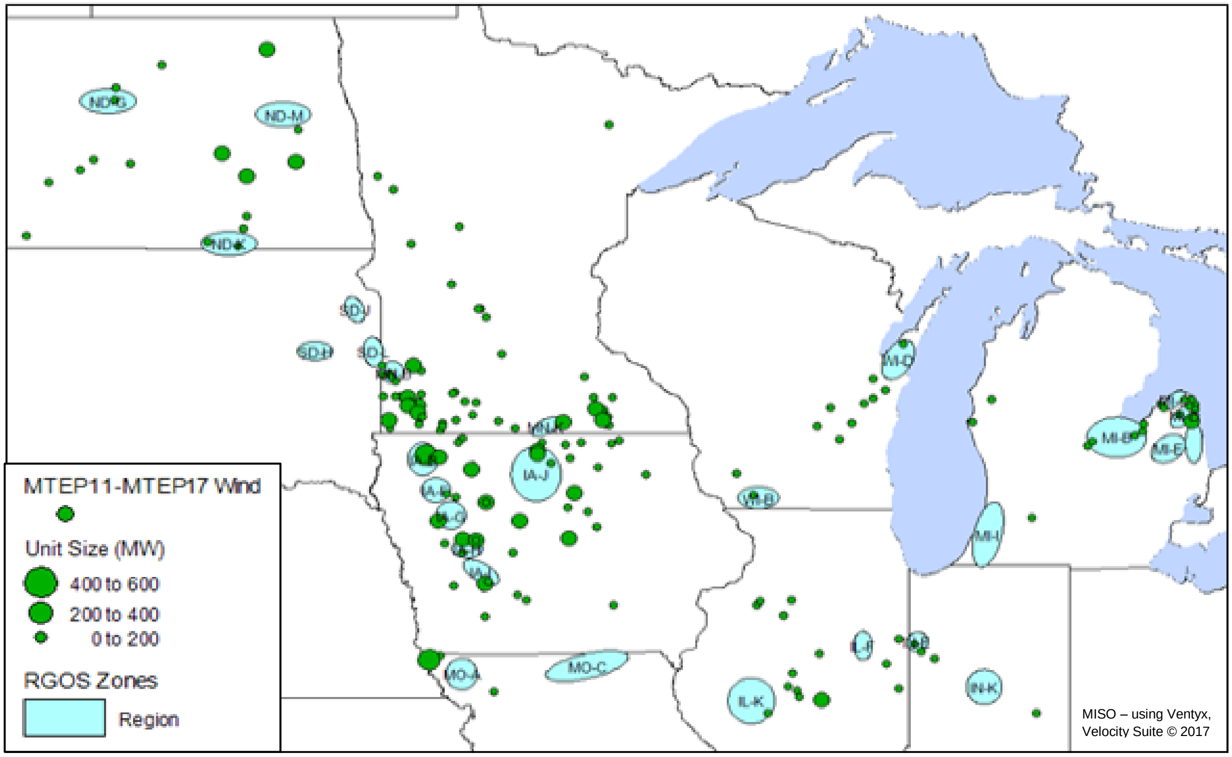

Figure 8-2: Wind Installations in MISO North/Central and RGOS Zones

8.6 Share of Energy Supplied

In addition to looking at what types of generation resources have been added to the MISO system, the share of energy supplied by resource type can also be measured using Real-Time settled generation market data (Figure 8-3). Some observed trends include a steady decline of coal from 2013-2016, while wind trends upward in each sample year correlating to more wind being added to the system (see section 8.4). The settled gas generation largely correlates with gas price fluctuations discussed in section 8.2, while the remaining resource types stay generally level. Figure 8-4 utilizes the same data set but displays the supplied energy as a percentage of MISO North/Central region energy mix for each sample year.

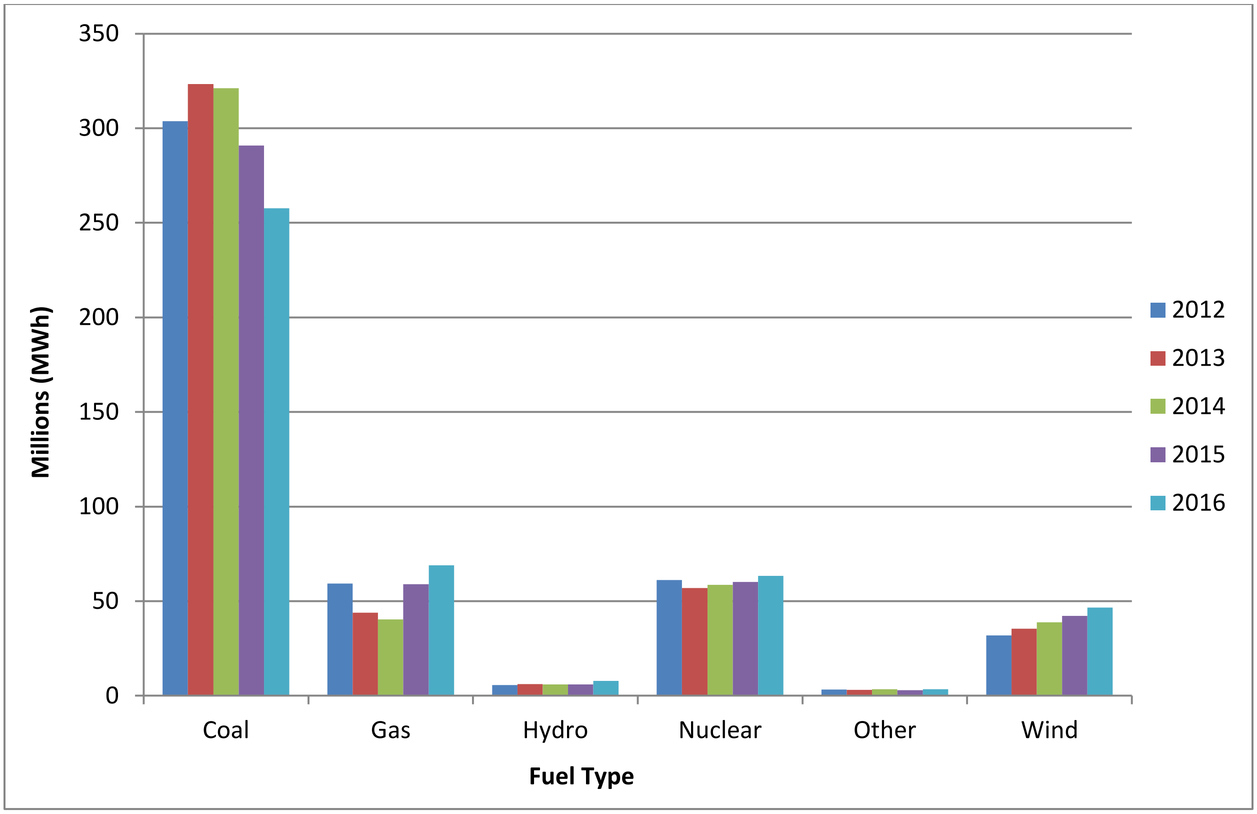

Figure 8-3: Sum of Real-Time Hourly Settled Generation by Year (MISO North/Central)

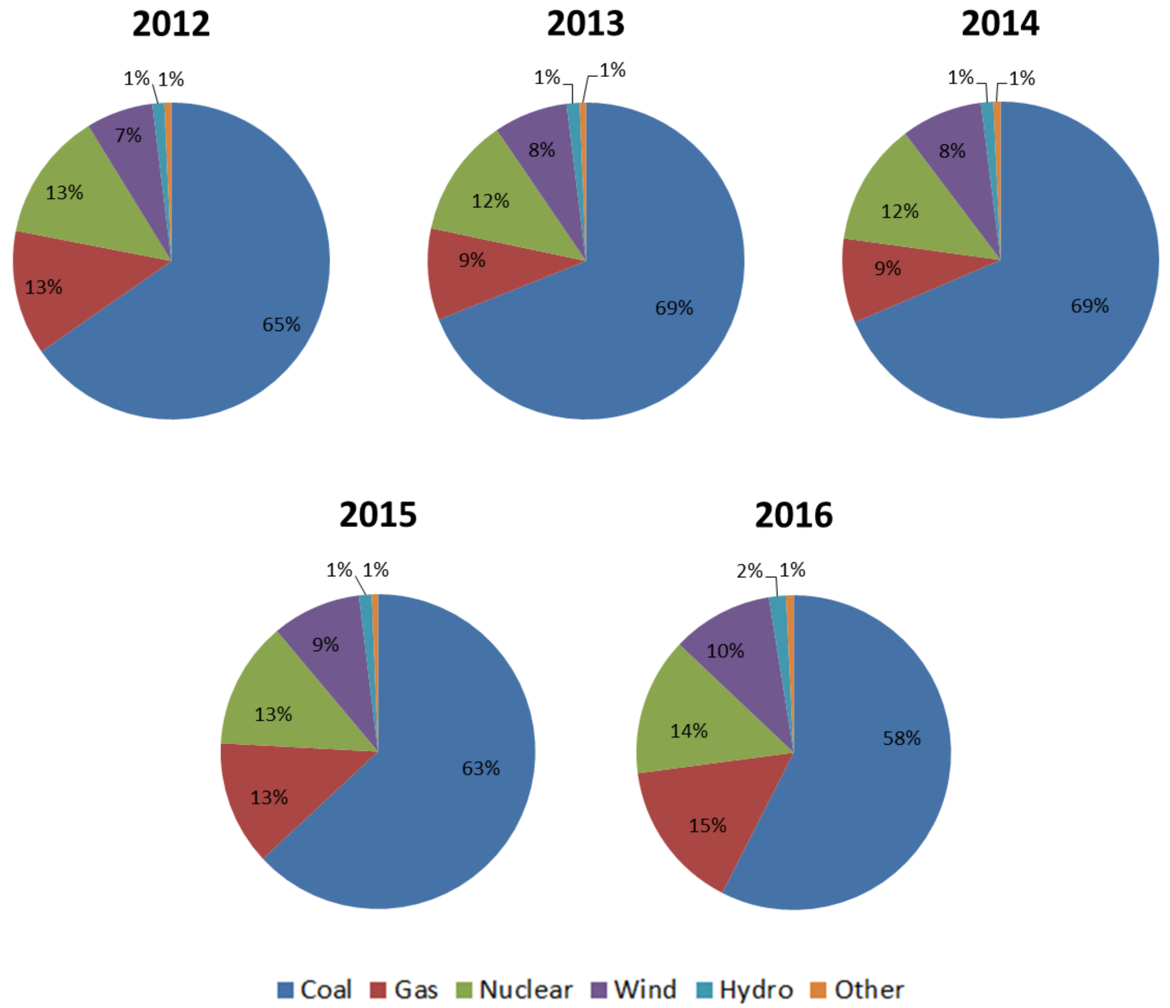

Figure 8-4: Percentage of Real-Time Hourly Settled Generation by Year (MISO North/Central)

8.7 Conclusions

All benefits assessed in the previous chapters of this review, and in the original MVP business case, are based on the MVP portfolio in its entirety, without differentiating between individual projects. In the MTEP17 review of historical market data, the results indicate some correlations between the MVPs and targeted congestion savings, as well as increasing trends of renewable energy supplied and installed. Because the in-service MVPs represent only a small portion of the entire portfolio (over a short time period), the tariff-required metrics discussed in this report may not yet be a reliable measure of MVP impacts. In future triennial reviews, when a larger statistical sample of data becomes available, a more detailed analysis on the correlation between MVP system impacts and realized benefits can be performed.

9. Conclusions and Going Forward

The MTEP17 Triennial MVP Review provides an updated view into the projected economic, public policy and qualitative benefits of the MTEP11 MVP Portfolio. With the second iteration of the full MVP review, the Multi-Value Projects continue to show benefits in excess of cost, showing benefit-to-cost ratios of 2.2 to 3.4. Differences between previous analyses are primarily driven by natural gas prices, changing generation fleet and changes to model dispatch and topology.

The MTEP17 MVP Triennial Review's business case continues to be on par with MTEP11, providing confidence that the MVP criteria and methodology are working as expected. While the economic cost savings provide a quantifiable benefit, the updated MTEP17 assessment also corroborates the MVP Portfolio's ability to reliably deliver wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner.

Results prepared through the MTEP17 Triennial Review are for information purposes only and have no effect on the existing MVP Portfolio status or cost allocation.

MTEP18 and MTEP19 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings (Section 6.1) using the latest portfolio costs and in-service dates. The next full Triennial Review will be featured in MTEP20.