CARDINAL-HICKORY CREEK 345 kV
TRANSMISSION LINE PROJECT

ALTERNATIVES EVALUATION STUDY

<u>Submitted to</u>: United States Department of Agriculture's Rural Utilities Service (RUS)

<u>Applicant to RUS</u>: Dairyland Power Cooperative

Other participating utilities in the Cardinal-Hickory Creek Project:

- American Transmission Company LLC,
  by its corporate manager ATC Management Inc.
- ITC Midwest LLC

July 2016

DAIRYLAND POWER COOPERATIVE
A Touchstone Energy® Cooperative

ATC AMERICAN TRANSMISSION COMPANY®

ITC

TABLE OF CONTENTS

ABBREVIATIONS AND ACRONYMS

ACA	Alternative Crossings Analysis
AES	Alternatives Evaluation Study
ATC	together, American Transmission Company LLC by its corporate manager, ATC Management Inc.
CEQ	Council on Environmental Quality
CIL	Capacity Import Limit
CPP	Clean Power Plan
CWP	Construction Work Plan
Dairyland	Dairyland Power Cooperative
DC	Direct Current
DPP	Definitive Planning Phase
EA	Environmental Assessment
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Futures	Future Scenarios
GHG	Greenhouse Gas
IAs	Interconnection Agreements
ITC Midwest	ITC Midwest LLC
kV	Kilovolt
LOLE	Loss of Load Expectation
MCS	Macro-Corridor Study
MW	Megawatts
MWh	Megawatt-hour
MISO	Midcontinent Independent System Operator Inc.
MRO	Midwest Reliability Organization
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
MVP Portfolio	A Portfolio of 17 MVPs
NAA	No-Action Alternative
NEPA	National Environmental Policy Act

NERC	North American Electric Reliability Corporation
New Rules	81 Fed. Reg. 11032-11047
NTA	Non-Transmission Alternatives
NOI	Notice of Intent
Old Rules	7 C.F.R. § 1794
PJM	PJM Interconnection LLC
Portfolio	MVP Portfolio
Project	Cardinal-Hickory Creek Transmission Line Project
REAP	Rural Energy for America Program
Refuge	Upper Mississippi National Wildlife and Fish Refuge
RGOS	Regional Generation Outlet Study
RPSs	Renewable Portfolio Standards and Goals
ROW	Right-of-Way
RTO	Regional Transmission Organization
RUS	Rural Utilities Service
Tariff	MISO's Open Access Transmission Tariff
UMTDI	Upper Midwest Transmission Development Initiative
UMTDI Final Report	UMTDI Executive Committee Final Report
USACOE	United States Army Corps of Engineers
USFWS	United States Fish and Wildlife Service
USDA	United States Department of Agriculture
Utilities	collectively, Dairyland, ITC Midwest, & ATC

LIST OF FIGURES AND TABLES

1.0 INTRODUCTION

1.1 General Overview & Purpose of Document

Dairyland Power Cooperative ("Dairyland"), a cooperative organized under the laws of Wisconsin, ITC Midwest LLC ("ITC Midwest"), and American Transmission Company LLC by its corporate manager, ATC Management Inc., (together, "ATC") (all collectively, "Utilities") propose to construct and own the Cardinal–Hickory Creek Transmission Line Project ("Project"), a 345 kilovolt ("kV") transmission line connecting northeast Iowa and south-central Wisconsin. The Project meets multiple needs:

- Addresses reliability issues on the regional bulk transmission system;
- Cost-effectively increases transfer capacity to enable additional renewable generation needed to meet state renewable portfolio standards and support the nation's changing energy mix;
- Alleviates congestion on the transmission grid to reduce the overall cost of delivering energy; and
- Responds to public policy objectives aimed at enhancing the nation's transmission system and reducing carbon dioxide emissions.

On March 2, 2016, RUS published new rules, which included changes to its process under the National Environmental Policy Act ("NEPA"). See 81 Fed. Reg. 11032-11047 ("New Rules"). On April 1, 2016, RUS created a guidance ("New Guidance") requiring Dairyland to submit an Alternatives Evaluation Study ("AES") (RUS, 2016, Exhibit B) and a Macro-Corridor Study ("MCS") to RUS (RUS, 2016, Exhibit D).

According to this new guidance, the purpose of the AES is:

> The purpose of the AES is to provide the applicant's rationale for its proposal and why that proposal is the best means of solving the problem. Specifically, the AES will identify the applicant's purpose and need for action and the technological means to meet the purpose and need (i.e, building a new power plant, connecting a new transmission line to the grid to bring power from where it is generated to where it is needed, etc.). All of the technologies will be identified in the AES. The AES will not identify the specific

> locations on the ground where these technologies would be constructed.

(RUS, 2016, Exhibit B, § 1.1).

Consistent with these requirements, this AES will explain the need for the Project and describe other alternatives that were evaluated by the Utilities to meet that need. Each alternative will be described in sufficient detail so that the public and other stakeholders can understand and assess each alternative. This AES will also explain which alternative is best for fulfilling the need for the Project and why the other alternatives considered were rejected. This AES will also support preparation of the future EIS for the Project.

The purpose of the MCS is to identify potential corridors within which the proposed transmission line project could be sited. Dairyland will submit its MCS after the AES.

1.2 Environmental Review Requirements

Dairyland along with the other Utilities prepared this AES. Dairyland plans to request financial assistance from the Rural Utilities Service ("RUS"), an agency that administers the U.S. Department of Agriculture's Rural Utilities Programs, for Dairyland's anticipated ownership interest in the transmission-line portion of the Project, which will represent nine percent of the total Project investment. RUS has determined that its funding of Dairyland's ownership interest in the Project would be a federal action and is, therefore, subject to NEPA review. 42 U.S.C. § 4321 et seq. See also 7 C.F.R. § 1970.8(c). NEPA provides a general procedure for federal activities that may impact the environment. 42 U.S.C. § 4331, et. seq. If a federal action "significantly affect[s] the quality of the human environment" a "detailed statement" of such effects must be provided so that they may be considered in the decision-making process. 42 U.S.C. § 4332(C).

RUS is responsible for determining the appropriate level of environmental review and the adequacy of that review. 7 C.F.R. § 1970.10. RUS has determined that it will complete an Environmental Impact Statement ("EIS") to evaluate Dairyland's planned request for funding. 7 C.F.R. § 1970.9. RUS has agreed to be the lead agency in the preparation of the

EIS. 40 C.F.R. § 1501.5. The RUS has developed its own rules to implement NEPA requirements. 7 C.F.R. § 1970.1 -.157.

RUS, with the cooperation of other federal agencies involved in the NEPA review of this Project, will prepare an EIS in accordance with NEPA, the Council on Environmental Quality ("CEQ") rules and RUS rules. 40 C.F.R. §§ 1500-1508 and 7 C.F.R. § 1970. Agency and public input will be accepted throughout the process. Following issuance of the Final EIS, each federal agency will independently develop its own decision document.

1.3 Participating Utilities

Three separate entities would own the Project: Dairyland, ATC and ITC Midwest.

Dairyland is a not-for-profit generation and transmission cooperative headquartered in La Crosse, Wisconsin. Dairyland is owned by and provides the wholesale power requirements for 25 separate distribution cooperatives in southern Minnesota, western Wisconsin, northern Iowa, and northern Illinois and 15 municipal utilities in Wisconsin, Minnesota, and Iowa. Dairyland serves a population of approximately 600,000. Dairyland owns or has under contract generating units totaling approximately 1,252 megawatts ("MW") and owns approximately 3,200 miles of transmission line.

ATC began operations in 2001 as the nation's first multi-state, transmission-only utility. ATC owns and operates more than 9,500 miles of high-voltage transmission lines and 530 substations in portions of Wisconsin, Michigan, Minnesota, and Illinois. Since its formation, ATC has upgraded or built more than 2,300 miles of transmission lines and 175 substations. ATC is headquartered in Pewaukee, Wisconsin, and has offices in Madison, Cottage Grove, and De Pere, Wisconsin, and Kingsford, Michigan.

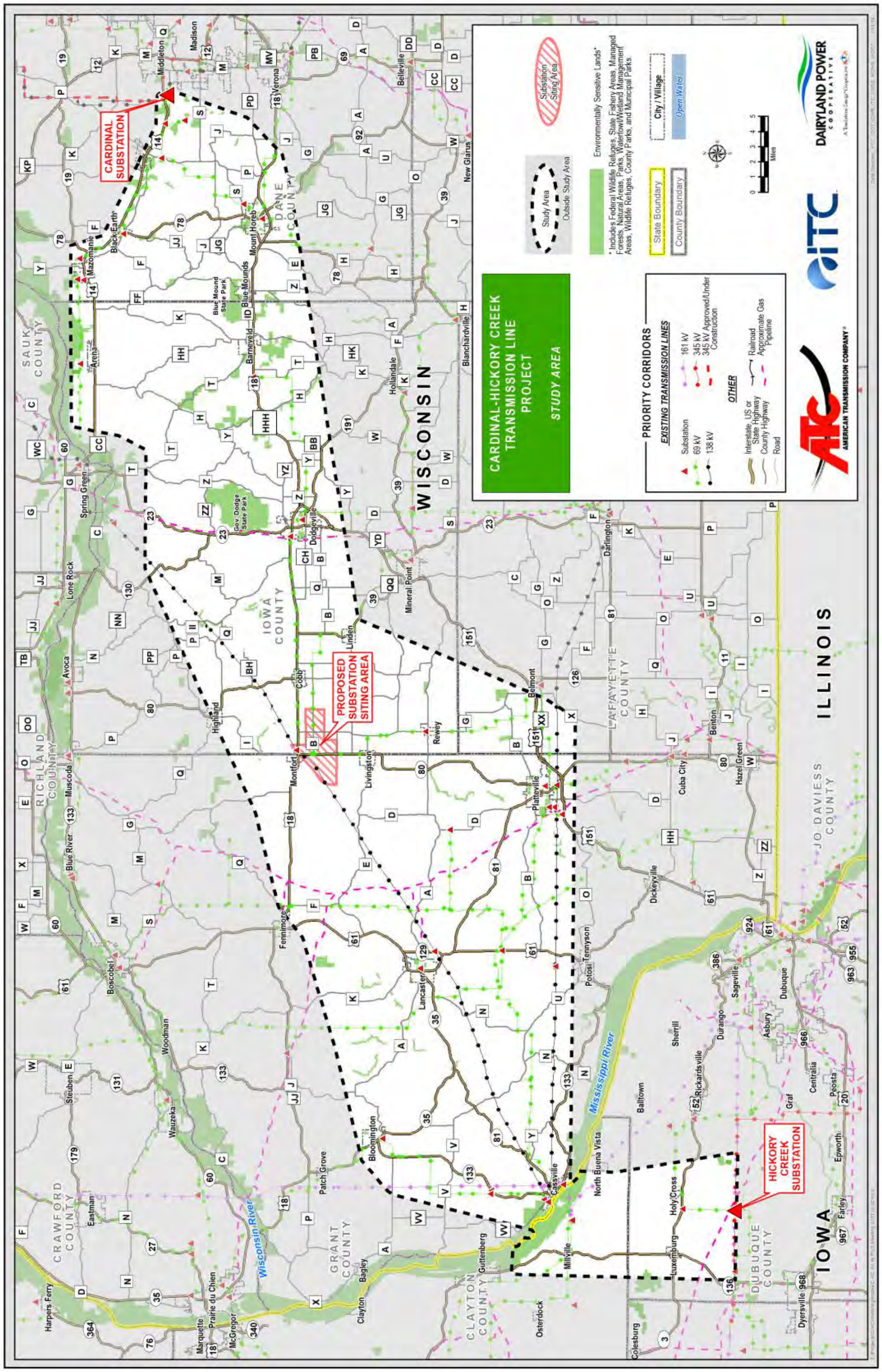
ITC Midwest is a wholly-owned subsidiary of ITC Holdings Corp., the nation's largest independent electric transmission company. ITC Midwest is headquartered in Cedar Rapids, Iowa, and maintains operating locations at Dubuque, Iowa City, and Perry, Iowa, as well as Albert Lea and Lakefield, Minnesota. ITC Midwest connects more than 700 communities with approximately 6,600 circuit miles of transmission line over roughly 54,000 square miles in Iowa, southern Minnesota, northeastern Missouri, and northwestern Illinois. ITC Midwest has also received a Certificate of Authority to operate as a public utility in Wisconsin.

1.4 Proposal Description

The Project proposal consists of a new transmission line and associated facilities in Iowa and Wisconsin. It has been approved by the regional transmission organization ("RTO"), namely the Midcontinent Independent System Operator Inc. ("MISO").[1] The Project will be approximately 125 miles long, depending on the final authorized route with the estimated costs of approximately $500 million (2023 dollars) and an in-service date of 2023. Figure 1-1 depicts the Cardinal-Hickory Creek Transmission Line Project Study Area.

[1] MISO is a non-profit regional transmission organization responsible for the independent planning and operation of the transmission grid and wholesale energy market across 15 states and the province of Manitoba. *See* MISO, https://www.misoenergy.org/Pages/Home.aspx. MISO oversees and coordinates regional transmission planning and regional transmission services and manages access to the transmission grid to facilitate fair and competitive wholesale electric markets. MISO became the first regional transmission organization to be approved by the Federal Energy Regulatory Commission (FERC) in 2001, and operates under a FERC-approved open-access transmission tariff.

Figure 1-1. Cardinal-Hickory Creek Transmission Line Project Study Area



The new 345 kV transmission line and associated facilities are proposed to meet these interconnection requirements are as follows:

- A new 345 kV terminal within the existing Hickory Creek Substation in Dubuque County, Iowa;
- A new intermediate 345/138 kV substation near the Village of Montfort in either Grant or Iowa County, Wisconsin;
- A new 345 kV terminal within the existing Cardinal Substation in the Town of Middleton in Dane County, Wisconsin;
- A new 45- to 65-mile (depending on the final route) 345 kV transmission line between the Hickory Creek Substation and the intermediate substation;
- A new 45- to 60-mile (depending on the final route) 345 kV transmission line between the intermediate substation and the existing Cardinal Substation;
- A rebuild of the Mississippi River Crossing at Cassville to accommodate a section of the 345 kV transmission line between Hickory Creek and the intermediate substation and Dairyland's 161 kV transmission line;
- A short, less than one-mile, 69 kV line in Iowa to enable the removal of the existing 69 kV line that crosses the Mississippi River at Cassville;
- Facility reinforcement needed in Iowa and Wisconsin due to the addition of the Hickory Creek Substation/Cardinal Substation 345 kV transmission line and the removal of the existing Mississippi River crossing at Cassville; and
- Rebuild of ITC Midwest's Turkey River Substation in Clayton County, Iowa with two 161/69 kV transformers, four 161 kV circuit breakers, and three 69 kV circuit breakers.

ITC Midwest owns the existing Hickory Creek Substation. ATC would own the new intermediate substation and owns the Cardinal Substation. Dairyland will own an undivided minority interest in all of the new 345 kV line. The majority interest in the new 345 kV line will be split by ITC Midwest and ATC. The Utilities are transmission-owning members of MISO.

The typical right-of-way (“ROW”) width for the Project would be 200 feet in Iowa and 150 feet in Wisconsin. For most of the Project, the Utilities propose to utilize single-pole structures that would have a typical height of approximately 150 feet. Depending on the final route, the new 345 kV line may be co-located with existing transmission lines. Typical spans between the transmission line structures would range from 500 to 1,100 feet. Additionally, there may be locations along the route that utilize different structure designs and/or ROW width for purposes of reducing potential impacts. Depictions of the typical structure types will be provided in the MCS.

The connection between the Hickory Creek Substation and the intermediate substation requires a crossing of the Mississippi River at a location that includes the United States Fish and Wildlife Service (“USFWS”)-managed Upper Mississippi National Wildlife and Fish Refuge (“Refuge”), the longest linear refuge in the United States. The Refuge extends north to south through Minnesota, Wisconsin, Iowa, and Illinois for approximately 260 river miles (USFWS, 2006, pp. 1-2). As requested by the USFWS, Dairyland and ITC Midwest have already submitted an Alternative Crossings Analysis (“ACA”) to the USFWS. (Copy available upon request.)

The Utilities are proposing to cross the Mississippi River and the Refuge at Cassville, Wisconsin. There are two existing transmission lines in this area: (1) Millville to Stoneman 69 kV, and (2) Turkey River to Stoneman 161 kV. The Project would eliminate the need for the existing Dairyland 69 kV line across the Refuge and the existing Dairyland 161 kV line would be double circuited with the new 345 kV line.

While the present needs are for the existing 161 kV line and the proposed 345 kV line at the river crossing, Dairyland and ITC Midwest are also presenting a design with 345 kV/345 kV specifications within the Refuge. The facilities would operate at 345 kV/161 kV for the foreseeable future, but be capable of operating at 345 kV/345 kV should future system conditions warrant it. Constructing the line in its ultimate configuration at this proposed crossing of a refuge and major river, is a prudent and cost-effective investment to accommodate future needs in a manner that avoids future impacts to the Refuge if a transmission system upgrade between Iowa and Wisconsin is needed. As with the other transmission features planned for the Refuge, the final design of the transmission facilities will be determined in consultation with the USFWS.

2.0 PURPOSE AND NEED

Under NEPA, the Project's purpose and need must be clearly specified so that federal agencies may properly evaluate it: "The [environmental impact] statement shall briefly specify the underlying purpose and need to which the agency is responding in proposing the alternatives including the proposed action." 40 C.F.R. § 1502.13. In addition to NEPA, RUS has two requirements addressing how to demonstrate the need for a project.

First, RUS requires that a prospective borrower include the project within its Construction Work Plan ("CWP"), which specifies the cooperative's plant requirements in the near term. 7 C.F.R. § 1710.250 and 7 C.F.R. 1970.6(a). On January 22, 2016, the Dairyland Board of Directors approved its 2016-2018 CWP, which includes the Project.

Second, RUS's New Guidance specifies "The purpose of the AES is to provide the applicant's rationale for its proposal and why that proposal is the best means of solving the problem. Specifically, the AES will identify the applicant's purpose and need for action and the technological means to meet the purpose and need" (RUS, 2016, Exhibit B, § 1.1).

Accordingly, the purpose and need for the Cardinal-Hickory Creek Project are set forth below.

2.1 Need Summary

Multiple study efforts beginning in 2008 and culminating in 2011 identified the Project as a necessary facility to ensure a reliable and efficient electric grid that keeps pace with energy and policy demands. Specifically, in its 2011 MISO Transmission Expansion Plan ("MTEP"), MISO designated a portfolio of 17 Multi-Value Projects ("MVP Portfolio" or "Portfolio") designed to create a backbone system to reliably and cost-effectively deliver renewable energy, primarily from high wind resource areas in the west and Midwest, to population centers to the east. This portfolio included the Project.

The Project would address multiple needs on the regional transmission system. First, it would address reliability issues by creating a tie between the 345 kV networks in Iowa and Wisconsin. Second, it would increase the transfer capability needed to accommodate additional renewable generation and respond to the nation's changing energy mix. Third, it would alleviate constraints on the regional transmission system needed to reduce energy costs and provide other economic benefits. Fourth, the Project responds to state renewable portfolio requirements and mandates, and would assist in addressing more recent public policy efforts, including federal plans and actions aimed at reducing greenhouse gas ("GHG") emissions, such as the U.S. Environmental Protection Agency's ("EPA") "Clean Power Plan" ("CPP"). 80 Fed. Reg. 64661 (October 23, 2015).

The Project will also provide specific benefits to Dairyland and its member cooperatives in addition to the regional benefits described above. Southwestern Wisconsin had several recent generation retirements at Stoneman (nameplate 40 MW) and Nelson Dewey (nameplate 220 MW), both in the Cassville, Wisconsin area. These generation retirements have increased the reliance on the local transmission system due to the need to bring energy to the area from more remote generation sources. This has increased power flow on the Turkey River-Stoneman 161 kV line. Dairyland and ITC Midwest each own a segment of Turkey River Stoneman 161 kV line. Power flow has also increased on the Dairyland owned Stoneman-Nelson Dewey 161 kV line. Power usually flows from the 345 kV transmission source at the Hickory Creek Substation near Dubuque towards Wisconsin on the 161 kV transmission lines causing high flows on these 161 kV lines. These lines could overload under certain contingencies. Without the Project, Dairyland would likely need to rebuild the Stoneman-Nelson Dewey 161 kV line to increase its capacity, and would likely need to replace equipment at the Stoneman Substation to increase the capacity for the Turkey River-Stoneman 161 kV line. The Project will likely allow Dairyland to avoid these transmission upgrades that would be necessary if the Project were not constructed.

The reliability benefits to the region outlined above should also reduce local transmission congestion. When congestion is present on the system, higher cost generation is dispatched from the east to reduce power flows from Iowa towards Wisconsin. The Project's new 345 kV transmission connection between Iowa and Wisconsin will add transmission capacity and alleviate congestion, allowing lower cost generation from the west to flow to Wisconsin. Reducing congestion in the area is a benefit to Dairyland by allowing a more efficient dispatch of generation, and by improving Dairyland's service to its member cooperatives' load in northeast Iowa, southwestern Wisconsin, and northwest Illinois.

Finally, Section 2.4.1.2 of the AES, below, describes the need to develop and implement local operating guides for the southwestern Wisconsin area to protect transmission lines from potential overload during high load times. A last resort in one of these operating guides is the potential for shedding load to maintain equipment loading under their maximum loading capabilities. This includes some Dairyland member load in southwestern Wisconsin. Once complete, the Project will allow for the retirement of the operating guides. The Project will add transmission capacity and improve system performance during peak load times. Completion of the Project will reduce the risk of potential loss of load to maintain adequate equipment loading during a contingency.

To summarize, Dairyland would share in the benefits provided by the Project to the regional transmission system. In addition, the Project would eliminate the likely need for Dairyland to rebuild the Stoneman-Nelson Dewey 161 kV line and the likely need to replace equipment at the Stoneman Substation; allow lower cost generation from the west to flow to Dairyland's service area by reducing congestion in the area, thereby allowing a more efficient dispatch of generation; and likely allow for the retirement of the operating guides instituted to maintain transmission system reliability after the retirements of local generation.

The following sections describe previous study efforts supporting the Project, MISO's designation of the MVP Portfolio, and the overall purpose and need for the Project.

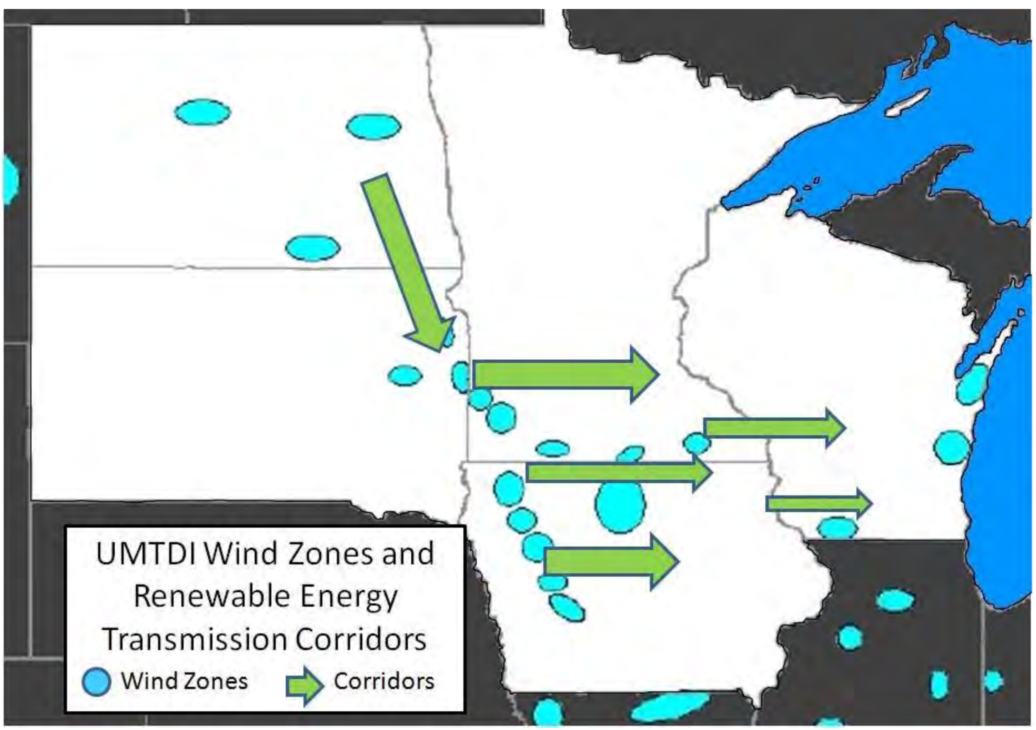
2.2 Study Efforts Supporting the Project

The need for additional capacity on the transmission system serving Midwest states to reliably and cost-effectively integrate renewable wind generation has been under study for more than a decade. As discussed in this and the next section, study efforts aimed at identifying solutions to address this need have focused on how to move wind-generated energy from high wind areas in Iowa, Minnesota, South Dakota, and North Dakota to load centers throughout the MISO footprint. As states have enacted renewable portfolio standards and goals ("RPSs") and the country shifts its energy mix to reduce carbon emissions, the need for additional renewable energy and the ability to transfer this energy has increased and is forecasted to continue to rise.

2.2.1 Upper Midwest Transmission Development Initiative

In 2008, the governors of Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin formed the Upper Midwest Transmission Development Initiative ("UMTDI") to "identify and resolve regional transmission planning and cost allocation issues" within the five-state area (UMTDI, 2010, p. 1). The UMTDI effort evaluated the need for an estimated 15,000 MW of wind energy and identified wind zones where wind resources would most likely develop. Working with MISO, UMTDI also identified potential transmission corridors. The wind resource zones and the transmission corridors are shown in Figure 2-1.

Figure 2-1. UMTDI Wind Zones and Renewable Energy Transmission Corridors



On September 29, 2010, UMTDI published its Executive Committee Final Report ("UMTDI Final Report") and identified five "no regrets" or "first mover" projects that would meet transmission needs under a variety of future scenarios (UMTDI, 2010, p. 9). The first mover projects included connections between La Crosse, Wisconsin, to Madison, Wisconsin, and connections between Dubuque, Iowa, to Spring Green, Wisconsin, and on to Madison, Wisconsin. The La Crosse to Madison connection is referred to as the Badger Coulee 345 kV Transmission Line Project which received approval from the Public Service Commission of Wisconsin in 2015 and is currently being constructed. The Dubuque-Spring Green-Madison connections became the Cardinal-Hickory Creek Transmission Line Project described in this AES. Subsequently, the intermediate substation location identified in the UMTDI Final Report for this Project changed from the original location of Spring Green to Montfort, Wisconsin, eliminating the need for the Project to cross the Wisconsin River twice and addressing planning, cost, routing, and siting concerns within the Spring Green area.

2.2.2 MISO Regional Generator Outlet Study

Also beginning in 2008, MISO, in conjunction with state utility regulators and industry stakeholders, initiated the Regional Generation Outlet Study (“RGOS”), a collaborative, multi-year effort to determine how to build the transmission facilities that would meet the significant renewable energy requirements within MISO at the lowest delivered per megawatt- hour (“MWh”) cost (MISO, 2010, p. 1).

Since its inception, MISO has conducted studies of the transmission system within the MISO footprint to identify and recommend construction of projects required to address network reliability issues. Pursuant to the directives in Federal Energy Regulatory Commission (“FERC”) Order Nos. 890 and 1000, MISO’s transmission planning process has broadened to identify and recommend those projects that increase system efficiency and reduce costs, as well as those projects that meet specific state and federal public policy objectives (Rauch Direct Testimony, 2014: 12r:5-10). MISO’s planning process evaluates transmission system congestion that may limit access to the most efficient energy resources, and analyzes potential improvements that could be implemented to meet forecasted energy requirements (Rauch Direct Testimony, 2014: 13r:19-21). MISO reports on its recommended transmission projects in its annual MTEP.

MISO uses a “bottom up, top down” approach in its transmission expansion planning process (Rauch Direct Testimony, 2014: 13r:8). In this approach, MISO first relies on individual transmission owners to identify and report the projects that they have determined are needed for their systems (Rauch Direct Testimony, 2014: 13r:9-11). MISO then reviews the various projects in relation to one another, and the MISO system as a whole, to prioritize projects based on their ability to effectively address system reliability, reduce consumer costs, and address evolving federal and state energy policy issues (Rauch Direct Testimony, 2014: 13r:12-18).

In the RGOS effort, with input from the state regulators, planning engineers first identified areas where wind generation would likely be sited in "wind zones" (Rauch Direct Testimony, 2014: 18r:7-12). RGOS then evaluated three transmission expansion scenarios to reliably integrate wind energy from the zones. The first was a "native" voltage overlay that does not introduce new voltages, such as 765 kV, in areas where they do not already exist. The second set was a 765 kV overlay throughout the study footprint. The third set was a native transmission overlay with the addition of direct current ("DC") transmission (MISO, 2010, p. 1).

Consistent with the UMTDI recommendations, the RGOS set of 18 candidate projects included 345 kV lines between North La Crosse and Madison and between Dubuque and Madison (MISO, 2010, p. 95). RGOS concluded: "The development of these corridors will provide for the continuation and extension of the west to east transmission path to provide more areas with greater access to the high wind areas within the Buffalo Ridge and beyond" (MISO, 2010, p. 95).

2.3 MISO MVP Portfolio Development

Approximately 11 months of intensive studies were performed on the candidate RGOS portfolio, with intense review and involvement by stakeholders, including the Organization of MISO States. MISO then selected projects for further evaluation that were common to all three RGOS scenarios and where previous reliability, economic, and generation interconnection analyses had been performed (MISO, 2010, p. 97). MISO developed the final MVP Portfolio according to the following criteria that were ultimately included in Attachment FF of MISO's Open Access Transmission Tariff ("Tariff"):

- Criterion 1: The MVP must enable the transmission system to deliver energy reliably and economically in support of documented federal or state energy policy mandates or laws.
- Criterion 2: The MVP must provide multiple types of economic value across multiple pricing zones with a total cost/benefit ratio prescribed in Attachment FF of the Tariff.
- Criterion 3: The MVP must address at least one transmission issue associated with a projected violation of a North American Electric Reliability Corporation ("NERC") or Regional Entity standard and at least one economic-based transmission issue that provides economic value across multiple pricing zones (MISO, 2012, § 3.1).

As stated in the MTEP-11, [2] the resulting 17-project MVP Portfolio:

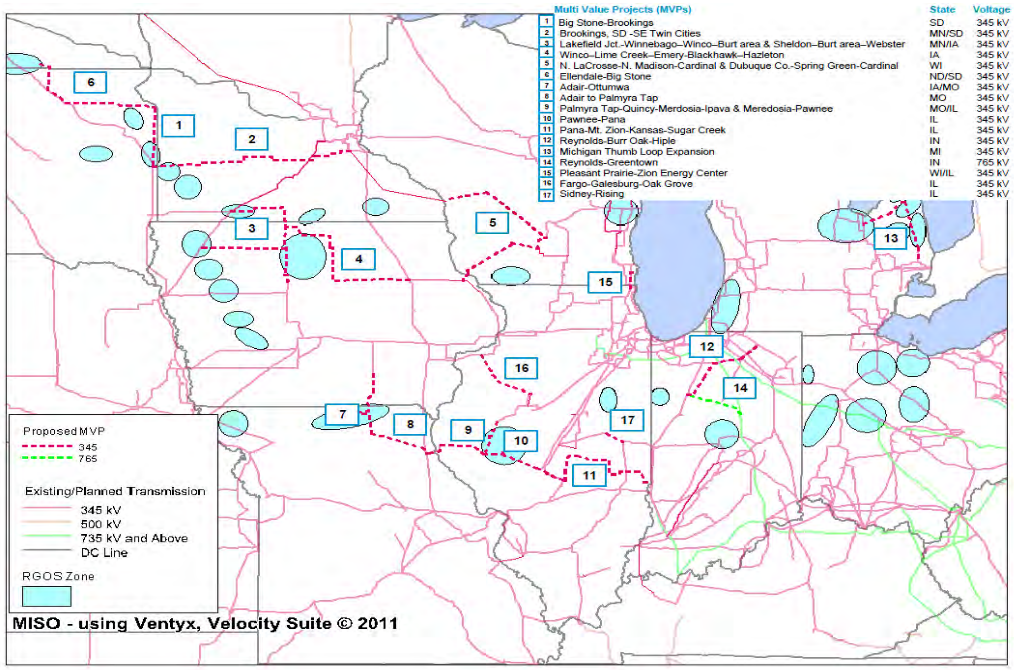
> …combines reliability, economic and public policy drivers to provide a transmission solution that provides benefits in excess of its costs throughout the MISO footprint. This portfolio, when integrated into the existing and planned transmission network, resolves about 650 reliability violations for more than 6,700 system conditions, enabling the delivery of 41 million MWh of renewable energy annually to load. The portfolio also provides strong economic benefits; all zones within the MISO footprint see benefits of at least 1.6 to 2.8[3] times their cost.

(MISO, 2011, p. 7). Importantly, the MVP Portfolio creates a transmission network that is able to respond to evolving reliability and generation needs within the MISO footprint (MISO, 2011, p. 8). As a result, the MVP Portfolio will be able to support a variety of different generation fuel sources that support a variety of generation policies (MISO, 2011, p. 8).

Figure 2-2 is a map showing the RGOS wind zones and the candidate MVP Portfolio of projects:

[2] The number after "MTEP" refers to the year the MTEP was approved by the MISO Board of Directors, generally in the month of December.
[3] The MTEP-11 Report contains two different benefit-cost ratios for the Portfolio: 1.6 to 2.8 and 1.8 to 3.0 (MISO, 2011, pp. 1 and 42 respectively). MISO's Triennial Review stated that MTEP-11 showed a ratio of 1.8 to 3.0.

Figure 2-2: RGOS Wind Zones



In 2011, MISO determined that the projects in the MVP Portfolio would reduce congestion, improve competition in wholesale markets, spread the benefits of low-cost generation, and enable the reliable delivery of renewable energy pursuant to states' RPSs (Rauch Direct Testimony, 2014: 17r:13-17, 20r:17-20 & 33r:1-3). In addition, MISO found that the MVP Portfolio: (1) "enhances generation flexibility;" (2) "creates a more robust regional transmission system that decreases the likelihood of future blackouts;" (3) "increases the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time;" (4) "supports the creation of thousands of local jobs and billions in local investment;" and (5) "reduces carbon emissions by 9 to 15 million tons annually" (MISO, 2014-1, p. 9). The Project's economic benefits include (1) enabling low-cost generation to displace higher-cost generation; (2) allowing more efficient dispatch of operating reserves; (3) reducing transmission line losses; (4) reducing future planning reserve margin requirements; and (5) avoiding costs for reliability projects that would otherwise need to be constructed.

Simultaneous to these three processes (UMTDI, RGOS, and MVP Portfolio) that culminated in the adoption of 17 MVP projects, MISO and the states within MISO convened two separate proceedings over 18 months to address who would pay for the MVPs. Because the portfolio of MVPs benefited every zone in MISO, most stakeholders agreed that the costs for each MVP should be shared by all. So, regardless of where the MVP would be located, every utility in MISO would pay a *pro rata* share for that project based on that utility's wholesale consumption of electric energy within MISO.[4] This agreement was premised on building all of the 17 projects so that every state shared in the benefits of the MVP Portfolio, and was accepted by FERC.[5]

2.4 The Purpose and Need of the Cardinal-Hickory Creek Project

The purpose and need of the Cardinal-Hickory Creek Project was specified by MISO through its multi-year process. Specifically, this Project is intended to support MISO's criteria of improving reliability, economics, and transfer capability between Iowa and Wisconsin as well as supporting energy policy mandates. The Project will provide many benefits to the regional transmission system, only some of which are documented in this AES.

2.4.1 Transmission System Reliability

The electric transmission system in the United States is comprised of a highly decentralized interconnected network of generating plants, high-voltage transmission lines, and distribution facilities. In many areas of the Midwest, including the Project endpoints in Dane County, Wisconsin and Dubuque County, Iowa, the transmission backbone system is comprised of 345 kV lines. This Project would add a 345 kV connection between Iowa and Wisconsin that would improve the reliability of the regional transmission system. Due to the location of the intermediate substation in Montfort, Wisconsin, the reliability improvement would also be local to southwestern Wisconsin where there is a presently a lack of connectivity to the regional 345 kV network.

[4] *Ill. Commerce Comm'n v. FERC,* No. 11-3421, slip op. at 7 (7th Cir. June 7, 2013).
[5] *Midwest Independent Transmission System Operator*, 133 FERC ¶ 61,221 (December 16, 2010).

2.4.1.1 The Cardinal-Hickory Creek Project Helps to Solve Regional Reliability Problems

MISO's studies found that construction of this Project would reduce the need for other lower voltage transmission line upgrades in Wisconsin and Iowa that would be required to maintain the future reliability of the transmission system absent this Project. In 2014, MISO conducted its tariff-required MVP Triennial Review (MISO, 2014-1). The Triennial Review listed 30 transmission projects that would be avoided by the MVPs (MISO, 2014-1, Table 6-13). The Project contributes to the elimination of 13 of those 30 avoided projects. Table 2-1 shows the 13 projects that would likely be partially or wholly avoided by this Project.

Table 2-1. Transmission Projects Eliminated through the Cardinal-Hickory Creek Project

Transmission Project	Length (miles)	Cost ($)
Salem 161 kV Bus Tie	N/A	1,000,000
Rock Creek 161 kV Bus Tie	N/A	1,000,000
Beaver Channel 161 kV Bus Tie	N/A	1,000,000
Maquoketa - Hillsie 161 kV	11.99	17,985,000
Lore - Kerper 161 kV	7.02	10,530,000
8th Street - Kerper 161 kV	2.60	3,900,000
East Calamus - Grand Mound 161 kV	2.56	3,840,000
Dundee - Coggon 161 kV	18.10	27,150,000
Sub 56 (Davenport) - Sub 85 161 kV	3.80	5,700,000
Vienna - North Madison 138 kV	0.21	315,000
Townline Road - Bass Creek 138 kV	11.82	17,730,000
Portage - Columbia 138 kV Ckt 2	5.70	8,550,000
Portage - Columbia 138 kV Ckt 1	5.70	8,550,000

Source: MISO, 2014-1, Table 6-13.[6]

The Triennial Review's identification of avoided-reliability projects in 2033 was based on MTEP-13 (MISO, 2014-1, § 3.3, page 18).[7] A more recent industry assessment of system

[6] MISO also included a rebuild of the Lore-Turkey River 161 kV line (19.64 miles). The line was rebuilt in 2015 and therefore removed from this list for the AES.

[7] For MTEP-13, while MISO was predicting the avoided projects for 2033 based on the load predicted for 2033, the model used the power flows expected during the summer peak of 2023. As a general rule, MISO's MTEPs are based on the grid that is anticipated 10 years in the future.

reliability during summer peak in the year 2020 demonstrates that this Project would eliminate projected reliability issues under a variety of contingencies[8] (ReliabilityFirst, 2015).

2.4.1.2 Additional Reliability Benefits

While the reliability benefits that MISO identified for the MVPs are sufficient to establish the purpose and need for this Project, additional anticipated reliability benefits have accrued since 2011. The reliability studies that MISO ran in 2011 included all generators that were expected to be running (i.e. generators who had not announced retirement). At that time, MISO assumed that the Nelson Dewey and Stoneman power plants would be running. But these two generators, both located in Cassville, Wisconsin, stopped operating by the end of 2015, after announcing closures in 2012 and 2015, respectively. These closures are changing the electricity flows on the regional grid in southwestern Wisconsin. ATC, Dairyland, and MISO are presently investigating an interim response to these changing flows. Specifically, the parties recently created MISO Operating Guides in southwestern Wisconsin to respond to multiple outages during high load levels.[9] These Operating Guides - which would protect the customers of Dairyland and other local utilities - would no longer be needed once the Project is constructed.[10]

In establishing the MVPs through various studies, MISO quantifiably demonstrated the reliability need for the entire Portfolio including the Cardinal-Hickory Creek Project. The MVPs also provide additional unquantified reliability benefits because they support future projects by providing a more robust regional transmission system that can better integrate new facilities. Also, since late 2011, the MVPs have been included in transmission planning models created for use in MISO, PJM Interconnection LLC (“PJM”), ReliabilityFirst,

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[8] A “contingency” is an event that could occur in the future and would negatively impact the operation of the transmission grid, such as an unexpected outage of a generation plant or a transmission line.

[9] An Operating Guide consists of pre-planned procedures which are initiated under pre-determined operating conditions of the transmission system to alleviate conditions such as line overloads. Operating Guides are normally used as interim measures and are not normally long-term solutions. In this case, Operating Guides may be implemented for the time between the retirements of these two generators and when the Project is placed in service.

[10] The Project will also reduce the frequency of implementation, or possibly eliminate, an existing Operating Guide for a long 69 kV path from the border of Iowa and Illinois to southwestern Wisconsin. This guide prevents the line from becoming overloaded during hot summer days.

Midwest Reliability Organization ("MRO"), and others. Developers in these areas are now proposing projects based on these models.[11] The impact of any additional generator or transmission line is evaluated with the MVPs as assumed facilities. The existence of the MVPs provides a reliability benefit by mitigating or obviating the need for certain additional upgrades to accommodate new transmission and generation. However, because the new facility is analyzed assuming the MVPs are in place, these reliability benefits are not separately identified or quantified.

In sum, the Cardinal-Hickory Creek Project addresses reliability concerns identified by MISO as part of development of the MVPs. In addition, the MVP Portfolio, including the Cardinal Hickory-Creek Project, provides reliability support for new generation and transmission additions to the regional grid.

2.4.2 Increased Economic Benefits

The addition of a 345 kV transmission line between Iowa and Wisconsin would provide a path for lower cost renewable energy to reach market, reducing overall energy costs. The Project was selected as one component of the overall MVP Portfolio because it, when combined with all of the other MVPs, fulfilled the economic benefit requirements specified by MISO. MISO applied the economic benefits test to the Portfolio as a whole, *i.e.* it did not evaluate the economic benefits of each component of the Portfolio.

The MVP Triennial Review provided updated insight into the MVP Portfolio's anticipated benefits relating to, among other things, economics (MISO, 2014-1, p. 2). Based on the MVP Triennial Review analysis, the collective MVP Portfolio is now estimated to provide a benefit-to-cost ratio ranging from 2.6 to 3.9 and result in $13.1 billion to $49.6 billion of net benefits over the next 20 to 40 years across the MISO footprint (MISO, 2014-1, p. 2). A part of those benefits derive from the avoided transmission projects that were discussed above in

[11] Because of the length of time it takes to plan, permit and construct a line, planning additions to the regional transmission grid face sequencing difficulties. It often takes seven to 15 years to construct a transmission line. Consequently, the planning and design of future projects must begin before a prior project is completed. The Cardinal-Hickory Creek Project was approved in 2011. MISO cannot wait for this Project to be permitted and built before determining which additional lines are required to maintain the reliability of the transmission grid seven to 15 years from today. It is this sequencing difficulty that places the Cardinal-Hickory Creek Project as a block in the foundation of our regional grid even before the project is permitted or built.

section 2.4.1.1. Based on MISO's information, eliminating the need for those projects would save approximately $151,710,000 (2014 dollars). The entirety of the MVP Portfolio's economic benefits analysis is contained in the MVP Triennial Review, which is attached as Appendix A.

When determining what new transmission projects should be built, MISO evaluates both the reliability and economic benefits of prospective projects. This Project, and the economic benefits that it brings, has been assumed in all recent, long-term economic planning models. Similar to the additional, unquantified benefits arising from subsequent reliability analyses described above, this Project also brings unquantified yet significant benefits relating to economic analyses: since 2011, the Cardinal-Hickory Creek Project has been an assumed component of the regional system when evaluating how to eliminate congestion. The existence of the MVPs provides an economic benefit by mitigating or obviating the need for certain additional upgrades to reduce congestion. However, because the new facility is analyzed assuming the MVPs are in place, these economic benefits are not separately identified or quantified.

Based on changes that have occurred since the MISO's initial MVP analysis, the MVP projects, including this Project, have shown increased value in MISO's MVP Triennial Review.

2.4.3 Increased Transfer Capability Between Iowa and Wisconsin

At the time of the MTEP-11 analysis, all but one of the 12 MISO states had enacted RPS mandates or goals. The RPSs are state specific, but generally started in 2010 and the amount of renewable energy required to be produced increases as energy usage increases. The MTEP-11 report recognized that the RPSs created "a great deal of uncertainty about how these goals will be achieved, including the location of future generation and the required transmission to enable renewable integration" (MISO, 2011, p. 31). However, MISO recognized that compliance would likely focus on capturing the wind resources present throughout the MISO footprint, which are most abundant in the upper Great Plains.

The Project creates a tie between the 345 kV network in east-central Iowa and the 345 kV network in south-central Wisconsin. This tie between these two 345 kV networks creates an additional wind outlet that brings power from the wind-rich areas of the upper Great Plains to the remainder of the MISO footprint. The Utilities estimate that the incremental increase in transfer capability created by the Project will be most significant during summer peak load when electricity demand is at its highest, and during the "shoulder months"—spring and fall—when wind generation is generally at its highest and electricity demand is more moderate.

The transmission lines within the MVP Portfolio, working together, will significantly increase transfer capability across the MISO footprint. MISO calculated that the entire MVP Portfolio will enable delivery of 41 million MWh of wind energy per year (MISO, 2014-1, 3). In contrast, if the MVP Portfolio were not constructed, MISO estimates that in 2023, up to 10,500 MW of potential wind generation energy would be curtailed (MISO, 2014-1, p. 3).

In the Triennial Review, MISO confirmed that the MVP Portfolio would support the existing RPSs. Additionally, MISO now estimates that the MVP Portfolio will enable 4,300 MW of wind generation beyond the amount needed to meet 2028 RPSs and does so in a more reliable and economic manner than without the associated transmission upgrades (MISO, 2014-1, p. 3).

In addition to the MVP documentation, other recent MISO reports demonstrate that this Project is needed to address limitations in the transfer of electricity between Iowa and Wisconsin. For example, the 2014 and 2015 MISO Loss of Load Expectation ("LOLE") Study Reports each identified a capacity import limit ("CIL") into Wisconsin from Iowa highlighting the limitations on the current system (MISO, 2014-2, p. 16; MISO, 2015-3, p. 14). The CIL is specified by MISO and represents the amount of electricity (in MW) that can be reliably imported into a specific local resource zone (MISO, 2015-4, § 4.3.8.4). In setting the CIL, MISO considers the import and export capabilities of the existing grid. In 2014, MISO established a CIL for the summer of 2015 limited by the Turkey River-Stoneman 161 kV line. While this specific facility was recently updated[12],, the transfer capability problems simply moved to an adjacent line, underscoring the problem in this area. Specifically, in 2015, the CIL identified for the summer of 2016 was the Stoneman-Nelson Dewey 161 kV line. The Cardinal-Hickory Creek Project is expected to eliminate the Stoneman-Nelson Dewey 161 kV CIL once it is constructed and it is unlikely that any CIL will be identified in the surrounding area.

Because of the existing limitations on transfer from Iowa to Wisconsin, the development of additional wind generation in Iowa is dependent on increasing transfer capability. Indeed, there are a number of wind generation projects in MISO that are explicitly dependent upon completion of the Project. MISO has informed these wind generators that they are only eligible for conditional interconnection agreements ("IAs") [13] until the Cardinal-Hickory Creek Project is built and operational. The following table lists the wind developments having conditional IAs due to the Project:

Table 2-2. Generation Interconnection Requests in MISO Conditional on the Cardinal-Hickory Creek Project being In-Service

Interconnection Request	Fuel Type	State	TO
G735	Wind	Iowa	ITC Midwest[14]
H008	Wind	Iowa	ITC Midwest[15]
H096	Wind	Iowa	ITC Midwest[16]

[12] The Lore-Turkey River-Stoneman- Nelson Dewey 161 kV path has been a historical constraint in many types of analysis since before MISO and the MISO market existed. Lore – Turkey River – Stoneman was rebuilt / uprated in the past couple of years so the constraint moved to the next element.

[13] Conditional Interconnection Agreements often have terms requiring the generator to limit its output to less than nameplate under certain conditions in order to maintain reliability.

[14] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/ITC%20Midwest%20LLC-Crystal%20Lake%20Wind%20II%20GIA%20G735%201st%20Rev%20SA2144%20PUBLIC%20VER.pdf

[15] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/ITC%20Midwest%20LLC-Bethel%20Wind%20Energy%20LLC%20GIA%20H008%20SA2387%202nd%20Rev%20PUBLIC%20VER.pdf

[16] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/ITC%20Midwest%20LLC-Rippey%20Wind%20Energy%20LLC%20GIA%20H096%20SA2385%202nd%20Rev%20PUBLIC%20VER.pdf

Interconnection Request	Fuel Type	State	TO
J091	Wind	Iowa	ITC Midwest[17]
R39	Wind	Iowa	MidAmerican Energy Company[18]
G667	Wind	Minnesota	Great River Energy[19]
J278	Wind	Minnesota	Great River Energy[20]
G870	Wind	Minnesota	ITC Midwest[21]
G826	Wind	Minnesota	Northern States Power[22]
G858	Wind	Minnesota	Northern States Power[23]
H071	Wind	Minnesota	Northern States Power[24]
H081	Wind	Minnesota	Northern States Power[25]

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[17] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/ITC%20Midwest%20LLC-Crystal%20Lake%20Wind%20III,%20LLC%20GIA%20%20J091%201st%20Rev%20SA2146%20PUBLIC%20VER.pdf

[18] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/MidAmerican%20Energy%20Company-MidAmerican%20Energy%20Company%20GIA%20R39%20SA2682%20ER14-2598%20PUBLIC%20VER.pdf

[19] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/Great%20River%20Energy-South%20Fork%20Wind,%20LLC%20GIA%20G667%20SA2317%203rd%20Rev%20PUBLIC%20VER.pdf

[20] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/Great%20River%20Energy-South%20Fork%20Wind,%20LLC%20GIA%20G667%20SA2317%203rd%20Rev%20PUBLIC%20VER.pdf

[21] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/ITC%20Midwest%20LLC-Wisconsin%20Power%20and%20Light%20Company%20GIA%20G870%20SA2259%202nd%20Rev%20PUBLIC%20VER.pdf

[22] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/Northern%20States%20Power%20Company-Odell%20Wind%20Farm,%20LLC%20PGIA%20G826%20SA2707%202nd%20Rev%20ER15-1968.pdf

[23] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/Northern%20States%20Power%20Company-Black%20Oak%20Wind%20Farm,%20LLC%20GIA%203rd%20Rev%20G858-H071%20SA2693%20ER15-2296%20PUBLIC%20VER.pdf

[24] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/Northern%20States%20Power%20Company-Black%20Oak%20Wind%20Farm,%20LLC%20GIA%203rd%20Rev%20G858-H071%20SA2693%20ER15-2296%20PUBLIC%20VER.pdf

Moreover, the long-term planning models used for MISO's consideration of all generation interconnection requests in MISO, starting with the August 2012 Definitive Planning Phase ("DPP") cycle, have assumed that the Project will be built, meaning that the number of conditional IAs will continue to grow.

In sum, the Project will provide increased transfer capability between Iowa and Wisconsin.

2.4.4 National Public Policy Benefits

Access to renewable energy generation has become increasingly important as states have adopted RPSs and that is one of the reasons why the MVP Portfolio was created. MISO determined in 2011 that this Project was needed for conveying wind energy. If anything, that need has increased since 2011 due to federal actions including public policy initiatives to reduce carbon emissions. The MVPs will also increase the flexibility of the regional grid to accommodate new public policies.

2.4.4.1 Presidential Directives & New Laws

The Obama Administration has developed a wide range of initiatives that seek to reduce GHG emissions through policies that support increased renewable energy generation. In June 2013, President Obama announced the Climate Action Plan, a national plan for tackling climate change (Executive Office of the President, 2013). The plan, which is divided into three key pillars, outlines steps to cut carbon emissions in the United States. The three key pillars are: (1) cutting carbon emissions in the United States; (2) preparing the country for the impacts of climate change; and (3) leading international efforts to address global climate change. Part of the President's Climate Action Plan directed the EPA to establish the first ever restrictions on carbon emissions from power plants, the largest source of unregulated carbon emissions in the United States.[26] Also, the President's Climate Action Plan fast-

[25] https://www.misoenergy.org/Library/Repository/Contract%20Legal%20Regulatory/Interconnection%20Agreement/Northern%20States%20Power%20Company-Red%20Pine%20Wind%20Project,%20LLC%20GIA%20H081%202nd%20Rev%20SA2753%20ER15-2654.pdf

[26] The EPA published its final rule on October 23, 2015, which is discussed in greater detail in Section 2.4.4.3.

tracks permitting for renewable energy projects on public lands; focuses on streamlining the siting, permitting, and review process for all transmission projects; increases funding for clean energy technology and efficiency improvements; and seeks to improve efficiency standards for buildings and appliances, as well as heavy trucks.

One of the mechanisms that the Obama Administration has used to encourage greater use of renewable energy is to streamline the federal permitting process for infrastructure, such as high-voltage transmission projects, which are necessary to deliver utility-scale renewable energy.[27] On June 7, 2013, President Obama signed a Presidential Memorandum entitled *Transforming our Nation's Electric Grid Through Improved Siting, Permitting, and Review* that recognized the importance of investing in transmission infrastructure to meet the nation's energy needs:

> Our Nation's electric transmission grid is the backbone of our economy, a key factor in future economic growth, and a critical component of our energy security. Countries that harness the power of clean, renewable energy will be best positioned to thrive in the global economy while protecting the environment and increasing prosperity. In order to ensure the growth of America's clean energy economy and improve energy security, we must modernize and expand our electric transmission grid.

(Obama, 2013-2). The memorandum put forth initiatives to expedite the review of transmission projects on federal lands, to help develop principles for establishing energy corridors and encourage the use of such, and to improve the overall transmission siting, permitting, and review processes.

On December 4, 2015, President Obama signed into law new streamlining requirements that build on his prior Executive Orders and Presidential Memorandum. See § 41002 et. seq. of the Fixing America's Surface Transportation Act, Pub. L. No. 114-94, approved December 4, 2015. Among other things, this law requires that upon the request of a project applicant a

[27] See the President's May 17, 2013 memorandum, *Modernizing Federal Infrastructure Review and Permitting Regulations, Policies and Procedures*, which recognized that "[r]eliable, safe, and resilient infrastructure is the backbone of an economy built to last. Investing in our Nation's infrastructure serves as an engine for job creation and economic growth, while bringing immediate and long-term economic benefits to communities across the country" *Id.* (Obama, 2013-1). The memorandum further states that "[t]he quality of our infrastructure is critical to maintaining our Nation's competitive edge in a global economy and to securing our path to energy independence." *Id.*

coordinated project plan be developed for each project and that a permitting timeline be adopted by the lead agency and cooperating agencies, which may only be extended under specified circumstances. The Cardinal-Hickory Creek Project would qualify for the new streamlining process created by this law.

2.4.4.2 Department of Agriculture

Through its Rural Energy for America Program ("REAP"), the United States Department of Agriculture ("USDA") has been providing millions of dollars in grants and loans for the development of rural renewable energy. Secretary Vilsack stated that, "Investing in renewable energy and energy efficiency projects supports home-grown energy sources, creates jobs, reduces greenhouse gas pollution and helps usher in a more secure energy future for the nation" (USDA, 2015). REAP has already been used to fund wind generation in Iowa (USDA, 2015).

2.4.4.3 Environmental Protection Agency

Demonstrating the importance of wind generation in MISO, the EPA recently estimated that an additional 24,000 to 26,000 MW of wind would need to be built nationwide between now and 2025 to allow the states to comply with an interim target within the EPA's CPP (EPA, 2015-1, 2015-2). As of the writing of this AES, numerous parties—including the State of Wisconsin—have sued the EPA and, on February 9, 2016, the United States Supreme Court stayed the CPP pending disposition of the petitions for review in the United States Court of Appeals for the District of Columbia Circuit and disposition of petitions for a writ of certiorari. It is currently unknown whether the CPP will be upheld. Regardless of the CPP's legal status, given the long lead time for transmission infrastructure, it is important to continue to examine how the rule could impact the need for additional transmission facilities.

The EPA developed the CPP to address carbon dioxide emissions from existing coal- and gas-fired power plants. The EPA issued a proposed rule in June 2014, and on October 23, 2015 published its final rule. The final rule requires states to meet state-specific carbon emissions reduction goals; however, it provides states flexibility in determining how to achieve CPP compliance. 80 Fed. Reg. 64661, at 63-64 (October 23, 2015). Under the final rule, now stayed, states must submit a plan (“state plan” or “state implementation plan”) by 2018, begin reducing carbon dioxide emissions by 2022, and continue emission reductions through 2030. 80 Fed. Reg. 64661 at 64 (October 23, 2015).

NERC released a report on the reliability impacts of the CPP that had some notable findings:

- Even without the CPP (under NERC’s reference case), significant new wind generation will be built requiring new transmission. For example, NERC expects wind and solar to increase by 110 GW between 2016 and 2030 (NERC, 2016, pp. vii and 16). This increase in renewables is due primarily to state renewable portfolio standards, the extension of the production tax credits and technology improvements (NERC, 2016, p. 20);

- With the CPP, renewables-–especially wind and utility-scale solar—will expand by an additional 10-20 GW above the reference case. (NERC, 2016, p. vii); NERC notes that the majority of wind will be developed in MISO (NERC, 2016, pp. 28, 32, 41, and 42);[28]

- NERC noted that because transmission can take up to 15 years to build that states and utilities must be cognizant of the time constraints needed to build the infrastructure necessary to maintain reliability in the face of this substantial increase in renewables (regardless of whether the CPP is upheld) (NERC, 2016, pp. viii, 22, 23, 55, and 58).

In sum, NERC concluded that to maintain the bulk power system’s reliability, more transmission will be required regardless of whether the CPP is upheld and, if upheld, MISO will gain more new wind generation than any other region in the country requiring even more transmission.

MISO also analyzed the draft CPP and identified significant coal generation retirements, which would require substantial transmission system investments. MISO is in the process of completing a four-phase analysis of potential impacts of the draft and final CPP on the MISO system. Phases I to III of the study have been completed and were based on the draft rule; Phase IV will reflect the impacts of the final rule. Phases I and II, which focused on the economic analyses of compliance costs, indicated that the most cost-effective compliance with the draft CPP would likely lead to the retirement of 14,000 MW of coal generation

[28] In an earlier report, NERC identified that one of the necessary lines was an additional 345 kV transmission line between Iowa and Wisconsin. (NERC, 2014, p. 20).

(MISO, 2014-3. p. 3). The Phase III study concluded that a multi-billion dollar transmission build-out would be needed to comply with the CPP scenarios studied (MISO, 2015-5, p. 7). MISO recently completed their Mid-Term Analysis of EPA's Final Clean Power Plan and concluded that more transmission infrastructure will be required to move renewable energy throughout the Midwest when the CPP is fully implemented. (MISO, 2016-3, p. 18).

The EPA has issued its own projections regarding changes in the energy resource mix and renewable generation additions. The EPA stated that, under the final rule, between 23,000 and 29,000 MW of additional coal capacity nationwide is projected to become uneconomical by 2025, increasing to as much as 38,000 MW by 2030 (EPA, 2015-3, p. 3-30). This would exacerbate already declining reserve margins in the MISO region and require substantial new generation additions. Also, EPA estimates that the final rule will result in between 54,000 and 57,000 MW of renewable energy capacity additions by 2025, and between 91,000 and 94,000 MW by 2030 (EPA, 2015-3, Table 3-14). Some of these renewable resources – especially wind – will likely require heavy investments in new transmission capacity, as well as upgrades to existing transmission infrastructure.

EPA's analysis of the final rule demonstrates that projected changes to the energy resource mix will be dramatic under the final rule, and transmission infrastructure additions and updates will be critical to the states' compliance with the CPP if it is ultimately upheld. These additional infrastructure needs require utilities to start planning transmission infrastructure updates now, as transmission development requires long lead times—anywhere from seven to 15 years—to complete a new project.

As noted earlier, the MVP Portfolio, including the Project, would enable 41 million MWh of renewable energy to be used to meet the needs of electric customers in the MISO market, which would in turn displace other forms of generation, most significantly high-carbon generation. Once constructed, the MVP Portfolio would result in reducing carbon emissions by 9 million to 15 million tons annually (MISO, 2014-1, p. 9).

2.4.5 The Project Provides Flexibility

When developing its MVP Portfolio, MISO considered public policy that existed in 2011 and possible future public policy changes. However, when identifying the transmission needs for future public policies, MISO did not consider the CPP requirements because the CPP was not published until 2015, well after the initial MVP studies and the Triennial Review in 2014. Regardless of the outcome of the challenges to the CPP, the electric industry expects dramatic changes in the type and location of generators. While much is uncertain, the following is known:

- it typically takes seven to 15 years to develop a multi-state transmission line;
- numerous generators will be retired in the near term, sometimes with less than one year's notice;
- numerous new generators, many in new locations with good wind such as Iowa, will be built in the near term;
- additional public policies may be adopted or market forces may arise that would change the generation mix even further; and
- major transmission backbone additions, such as this Project, bolster the regional grid helping it to accommodate a variety of future conditions (they increase "flexibility").

Rather than being in the early stages of a seven-to-fifteen year process, this Project has matured to the point of seeking regulatory approvals and is projected to be in-service in seven years.

2.5 Conclusion on Purpose and Need

The Project is needed to enhance regional reliability, cost-effectively increase transfer capacity to support state RPSs, alleviate transmission congestion to reduce energy costs, and respond to essential public policy objectives to enhance the nation's transmission system and reduce carbon emissions. The purpose of the Project is to meet these reliability, transfer capability, congestion relief, and public policy needs. It provides the added benefit of improving flexibility at a time when the future is uncertain.

3.0 ALTERNATIVES EVALUATION

3.1 The Law

3.1.1 Required Contents of an AES

Under the New Guidance, the AES must accomplish the following:

> The AES should explain each technology alternative in sufficient detail so that interested agencies and the public can generally understand each alternative. The AES should explain which alternative is considered best for fulfilling the purpose and need for the project and clearly explain why certain alternatives are unacceptable or less than optimal.

RUS, 2016, Exhibit B, § 1.2.

3.1.2 RUS's Use of this AES in Preparing its NEPA Documents

RUS may use this AES to comply with its obligations under NEPA, *e.g.* in preparing its Notice of Intent ("NOI") and EIS. Accordingly, understanding what information RUS will need for its future documents highlights what information would be helpful (but not required) in an AES.

To comply with NEPA, an agency must consider in its EIS "reasonable alternatives" to the proposed action. The CEQ has rules specifying what alternatives must be considered within a federal EIS and what information must be provided about those alternatives:

> (a) Rigorously explore and objectively evaluate all reasonable alternatives, and for alternatives which were eliminated from detailed study, briefly discuss the reasons for their having been eliminated.
>
> (b) Devote substantial treatment to each alternative considered in detail including the proposed action so that reviewers may evaluate their comparative merits.
>
> (c) Include reasonable alternatives not with-in the jurisdiction of the lead agency.
>
> (d) Include the alternative of no action.

40 C.F.R. § 1502.14.

In a separate guidance, CEQ explains: "Reasonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense, rather than simply desirable from the standpoint of the applicant" (CEQ, 1981). In its New Rule, RUS specifically defers to the CEQ rules on EIS's. 7 C.F.R. § 1970.13.

Additionally, in its New Rule, RUS described what alternatives must be included within the EIS, as follows:

> Consideration of alternatives.
>
> The purpose of considering alternatives to a proposed action is to explore and evaluate whether there may be reasonable alternatives to that action that may have fewer or less significant negative environmental impacts. When considering whether the alternatives are reasonable, the Agency will take into account factors such as economic and technical feasibility. The extent of the analysis on each alternative will depend on the nature and complexity of the proposal. Environmental review documents must discuss the consideration of alternatives as follows:
>
> (a) For proposals subject to subpart C of this part, the environmental effects of the ''No Action'' alternative must be evaluated. All EAs must evaluate other reasonable alternatives whenever the proposal involves potential adverse effects to environmental resources.
>
> (b) For proposals subject to subpart D of this part [EISs], the Agency will follow the requirements in 40 CFR part 1502.

7 C.F.R. § 1970.13.

The New Rule also specifies that the alternatives RUS considers in its EIS must be directly tied to the purpose and need of the project: "As necessary, applicants must develop and document reasonable alternatives that meet their purpose and need while improving environmental outcomes." 7 C.F.R. § 1970.5(b)(3)(iii).

An AES does not need to satisfy the requirements for an EIS, but, when available, Dairyland has nevertheless provided information required for the EIS.

For transmission projects, there are two types of alternatives: alternative solutions to a specified transmission problem, and alternative siting locations. This AES evaluates what alternatives could meet the purpose and need for this Project. The MCS--which is currently being prepared--focuses on the siting alternatives.

3.2 The Proposed Action

The proposed Project is a 345 kV transmission line, approximately 125 miles in length, connecting the existing Hickory Creek Substation in Dubuque County, Iowa[29] with the existing Cardinal Substation in Middleton, Wisconsin, with a new intermediate 345/138 kV substation near Montfort, Wisconsin, and associated 69 kV facilities. As described in Chapter 2, the Project is one component of the MISO MVP Portfolio and therefore has multiple benefits including, but not limited to: enhancing regional reliability, increasing economic benefits through alleviating transmission congestion, increasing transfer capability between Iowa and Wisconsin to ensure compliance with existing RPSs, and increasing flexibility to address other public policies.

3.3 Transmission Alternatives

3.3.1 MISO's Modeling During the RGOS Process

As a precursor to the MVP discussion, MISO first conducted the RGOS. MISO used its well-honed transmission-planning process. First, MISO identified where generation would be located in the study area for a specific year (for the MVPs, it was 2021). Because one of the main purposes of the MVPs was compliance with RPSs, likely locations for new renewable resources within each state were identified. Those new generation locations were added to other generators (both existing and new) in the study area.

[29] The Hickory Creek Substation, with a 345 kV/161 kV transformer, was placed into service in the fall of 2015 to enable the retirement of the Nelson Dewey Generator Station.

Next MISO determined how best to reliably convey the electricity from those generators to customers. To obtain the most cost-effective solution to the RPSs, MISO ran a number of different scenarios. MISO, in one scenario, assumed each state built enough in-state renewables to comply with its respective RPSs and then built the attendant transmission, *i.e.* MISO placed lots of renewables within each state. In another scenario, MISO assumed that states would purchase the most economical renewables regardless of location and would build the required transmission. Through this iterative process, MISO tested whether local renewables alone were more or less expensive than a mix of local renewables with renewables from the wind-rich upper Great Plains.

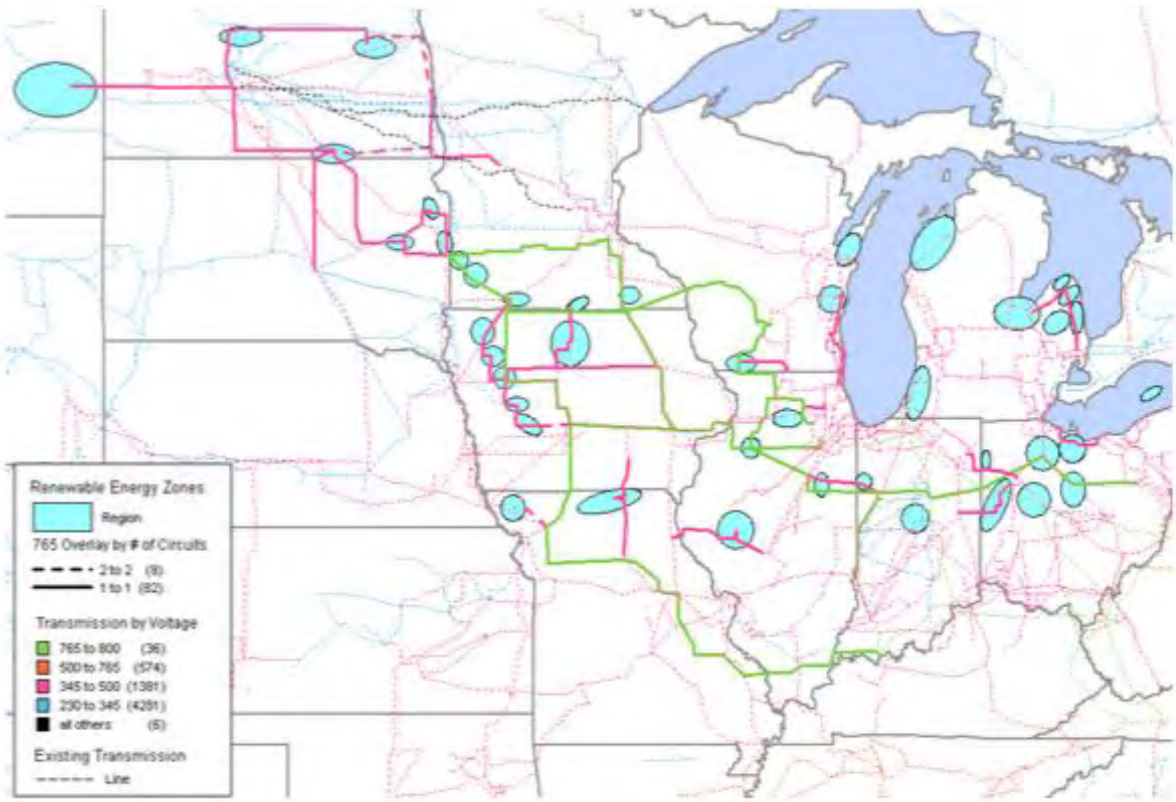
3.3.2 Three High-Voltage Alternative Portfolios Considered in the RGOS

During RGOS, the following three high-voltage portfolios (Figures 3-1, 3-2, and 3-3) were carried forward for formal discussion among all stakeholders: a native overlay of mostly 345 kV lines, an overlay of 765 kV lines and a number of DC lines:

Figure 3-1. MISO Native Overlay of Mostly 345 kV Lines

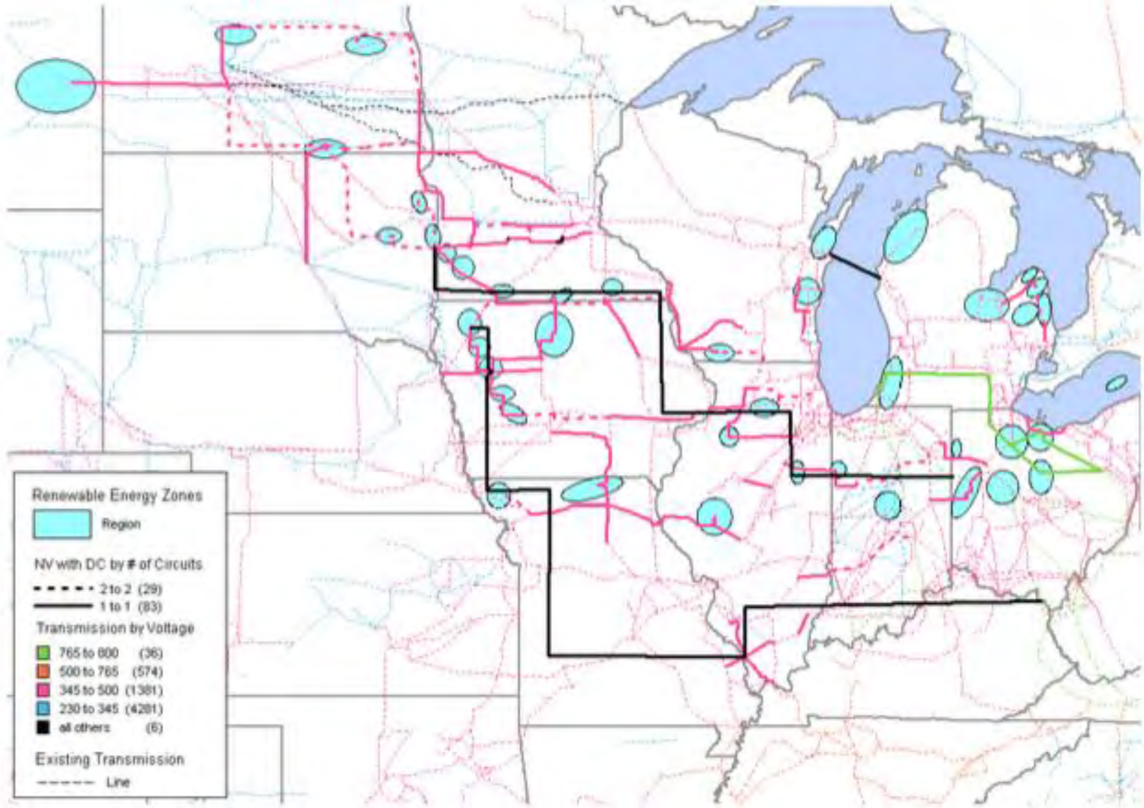
Source: MISO, 2010, Figure 1.2-3.

Figure 3-2. MISO 765 kV Transmission Line Overlay



Source: MISO, 2010, Figure 1.2-4.

Figure 3-3. MISO Direct-Current Transmission Line Overlay



Source: MISO, 2010, Figure 1.2-5.

Based on the results of RGOS, stakeholders selected the alternatives to be evaluated during the MVP process.

3.3.3 The High-Voltage Projects Evaluated as Part of the MVP Process

While the RGOS study focused on the ability to transmit renewables, MISO expanded its analysis during the MVP process to evaluate which lines, when considered with the whole portfolio, would provide reliability benefits to and reduce congestion on the regional grid.

MISO conducted the MVP analyses over the following four separate future scenarios ("Futures").

- Business as Usual with Mid-Low Demand and Energy Growth Rates;
- Business as Usual with Historic Demand and Energy Growth Rates;
- Carbon Constraint; and

- Combined Energy Policy.

(MISO, 2011, Executive Summary, p. 7.) Each Future had differing assumptions for each variable such as how quickly demand for electricity would grow and the price of natural gas. (The Triennial Review and annual MTEP studies also use this method of varied Futures.)

This process took hundreds of hours of high-powered computer time and months of working with stakeholders. Indeed, for the combined RGOS and MVP processes, MISO spent approximately 35,000 hours of staff time and convened more than 200 stakeholder meetings. (Rauch, Direct Testimony, p. 19r:18-22.)

In 2011, MISO and stakeholders selected (by near consensus) the 345 kV option; stakeholders agreed the 17 MVPs were "no regrets" projects, namely, they provided a robust solution to a number of challenges. MISO recently reconfirmed this robustness in its Triennial Review of the MVP Portfolio.

The three high-voltage RGOS portfolios are presented above only to demonstrate MISO's exhaustive process for evaluating ways to meet the purpose and need. When RUS conducts its alternatives analysis, it will be considering only the alternatives to this specific Project, not the entire Portfolio. Fourteen of the other projects within the MVP Portfolio have been or are in the process of being built. Selecting a different portfolio is not an alternative to be considered.

3.3.4 High-Voltage Transmission System Alternatives to this Project

The Cardinal-Hickory Creek Project is one leg of the overall portfolio of MVPs, all of which work independently and collectively. Any high-voltage alternative to this Project must stand in the shoes of this Project independently and in the context of the overall Portfolio. MISO approved a line connecting the Hickory Creek 345 kV substation on the Salem–Hazelton 345 kV transmission line in Iowa to the Cardinal Substation in Wisconsin because of the dominant west-to-east flows of renewable energy across the footprint. This MVP is a wind outlet to load centers like Madison and Milwaukee. In combination with other MVPs, it enables additional transfer capability while offloading heavily congested paths near the Quad Cities on the Iowa-Illinois border. In order to route power around the Quad Cities, a connection between northeast Iowa and south-central Wisconsin was utilized. There are limited connection points to the regional grid in northeast Iowa and southwestern and south-central Wisconsin. Because the proposed Project takes a route that is relatively direct between the available connection points, any other high-voltage alternative connecting northeast Iowa to south-central Wisconsin would necessarily be longer and would still have to traverse the Mississippi River. Because it would be longer, this alternative would likely be more expensive than this Project.

3.3.5 Low-Voltage Transmission Alternatives to this Project

Alternatives considered in the MVP process had to meet MISO's purpose and need: reliability reinforcement, congestion relief, increased transfer capability for RPS compliance and meeting public policy needs. RPS compliance was not only a requirement, it was the primary purpose for starting the MVP process. Accordingly, MISO only studied an alternative if it allowed the MISO states to meet their RPSs. A portfolio of low-voltage alternatives simply could not meet this fundamental requirement; therefore, MISO did not study an entire portfolio of low-voltage alternatives during the MVP process.

While MISO did not consider an entire portfolio of low-voltage alternatives, it did consider whether portions of the MVP Portfolio could be low-voltage. In relation to this Project, MISO considered whether rebuilding the overloaded 138 kV lines between northeastern Iowa and southwestern Wisconsin would be better than a 345 kV line (MISO, 2012, p. 29). MISO rejected this low-voltage alternative because the estimated cost was greater than the Project and it would not provide the same level of benefits.

The remainder of this section discusses the limitations of a conceptual low-voltage alternative between northeastern Iowa and southwestern Wisconsin. Evaluating a low-voltage alternative on a conceptual level demonstrates why any Iowa-Wisconsin low-voltage alternative to the Project cannot cost-effectively meet the purpose and need set forth by MISO.

First, as discussed above in Section 2.4.1.2, the recent development of Operating Guides for multiple element outages highlights the need for a new high-voltage connection into southwestern Wisconsin. If a new high-voltage connection is not built, multiple facility improvements would be required to avoid loss of load in addition to any combination of low-voltage lines.

Second, a low-voltage alternative would not provide the same level of economic benefits as the Project. Low-voltage lines have higher line losses than the Project and are, therefore, less economically efficient.

Third, a low-voltage alternative was not defined as an MVP by MISO so it would not be cost-shared across the MISO footprint such that the costs to local ratepayers would be higher than this Project.

Fourth, as discussed in Table 2.2, twelve wind developments in Iowa and Minnesota list the Project as a conditional project. While further study would be required, it is likely that the number of conditional projects would grow under any low-voltage alternative. In other words, it is likely that, in addition to a low-voltage alternative, additional transmission lines (new or rebuilt) would be required to convey wind from Iowa and Minnesota to the rest of MISO, including Wisconsin.

Lastly, a low-voltage alternative would provide less flexibility than the Project for supporting emerging public policy initiatives. Lower voltage lines have lower ratings and higher impedances, which means less flexibility to accommodate new public policy requirements that rely on the ability to move large amounts of renewable energy from one geographic area to another.

3.3.6 Conclusion on Transmission Alternatives

After multiple years of study by teams of regional transmission-planning experts, the MVPs were selected as the best alternatives to meet the objectives defined by MISO. The Cardinal-Hickory Creek Project, as a part of the entire MVP Portfolio, was selected as the best project to fulfill the purpose and need between Iowa and Wisconsin and for the region as a whole.

3.4 NON-TRANSMISSION ALTERNATIVES

This section introduces different types of non-transmission alternatives ("NTA") and evaluates whether they are feasible alternatives to the Cardinal-Hickory Creek Project. Typical NTAs include centralized generation, distributed generation, energy storage, energy efficiency, and demand response.

Centralized generation is a utility-scale power plant that is fueled by renewable or fossil energy. Distributed generation--such as residential solar--are smaller generating units connected to the electric distribution system. Energy storage can be utility scale or distributed. Utility-scale energy storage includes pumped hydro, compressed air, molten salt, and electric battery installations. Distributed energy storage includes thermal and electric battery installations at commercial sites and possibly residential sites. Energy efficiency, in this context, includes end-user facility improvements that reduce overall energy consumption. For example, more efficient lighting could be installed at a commercial site that would reduce energy consumption throughout the year but especially during system peak. Demand response is curtailment of energy consumption in exchange for some incentive. Demand response includes temporary load reduction, typically in response to high summer peak demand, and load shifting from regular periods of high demand to periods of lower demand often based on time-of-use pricing.

3.4.1 Evaluation of the Non-Transmission Alternatives

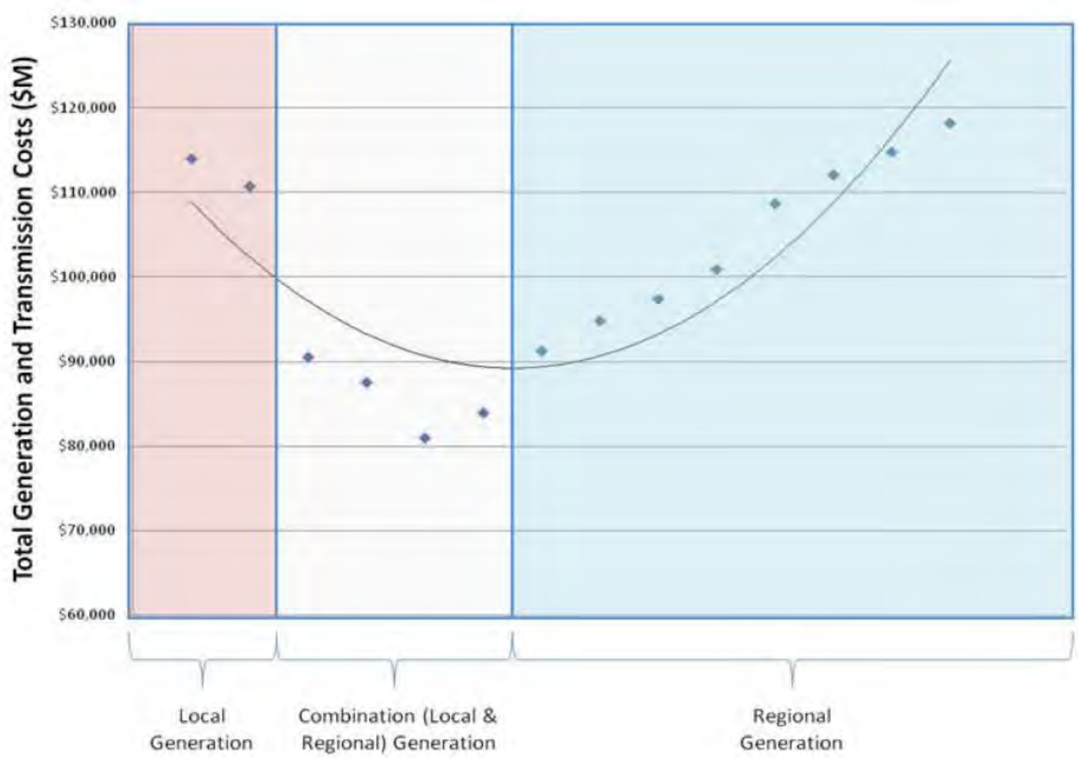
One of the main objectives of this Project is to support the transfer of renewable energy from Iowa to Wisconsin through increasing the transfer capability between the two states. Put simply: only transmission can provide a permanent increase in transfer capability between Iowa and Wisconsin. Because NTAs cannot meet the objectives specified by MISO, MISO did not evaluate NTAs during the MVP process. The only alternatives considered by MISO were alternative locations for wind generation (local, regional, and mixed) for the specific purpose of RPS compliance. Nevertheless, by law, Dairyland and the RUS must consider NTAs and that evaluation is provided below.

3.4.1.1 Generation

3.4.1.1.1 Utility-Scale Generation

During the MVP study process, MISO evaluated whether utility-scale renewable generation within each state would be more cost effective than purchasing renewables from the wind-rich upper Great Plains. MISO concluded that local generation is more expensive than a combination of local and regional generation when all costs are considered, including the cost of new transmission. Figure 3-4 displays that the "low cost approach to wind generation siting, when both generation and transmission capital costs are considered, is a combination of local and regional wind generation locations" (MISO, 2011, p. 55).

Figure 3-4. MISO's Analysis of the Cost of Local vs. Regional Wind



Source: MISO, 2011, Figure 4.1-9.

These results are driven by the following:

- In western MISO, including Iowa, the wind blows harder and more often, *i.e.* the wind capacity factors are higher;
- States with lower wind capacity factors -- like Wisconsin -- can benefit by importing renewable energy from neighboring states where the cost is lower; and
- Building the transmission required to transport wind energy from far away adds to the cost of that energy.

MISO selected the “sweet spot” of a mix of local and regional renewables. Consequently, MISO rejected the NTA of in-state generation as it was not cost-effective for Wisconsin and the other MISO states to comply with their RPSs by using only in-state renewable generation.

3.4.1.1.2 Distributed Generation

As with utility-scale generation, distributed generation cannot meet the purpose and need of this MVP. As discussed above, MISO found that using local renewable resources was not cost-effective and MISO only evaluated local utility-scale renewables. If MISO had evaluated local distributed renewables, the economics would have been even worse. (Economies-of-scale are lost when installing distributed generation as opposed to utility-scale generation.) Distributed generation would also fail to provide reliability benefits and congestion relief because it is typically installed on a piecemeal basis by a variety of owners. For distributed generation to be considered a valid solution to system reliability and congestion issues, among other things, it must have the same level of contractual obligation as utility-scale generation.

3.4.1.2 Storage

Energy storage also is not a feasible alternative to this Project. One of the Project’s primary purposes is RPS compliance through increasing the transfer capability between Iowa and Wisconsin. Energy storage could increase transfer capability by charging or discharging energy, depending on the storage location, when additional transfer capability is required. But a tremendous amount of storage would be required to replace the increased transfer capability that would be provided by this Project. That volume of storage could only be provided by pumped hydro, compressed air or molten salt, none of which is available in Wisconsin due to Wisconsin's geographic features. To provide similar levels of transfer capability and the economic and reliability support of this Project, multiple storage installations at a variety of locations would be necessary. Widespread utility-scale energy storage projects by means of electric batteries are still too expensive to consider as a reasonable alternative to the Cardinal-Hickory Creek Project.[30] In sum, storage is not a reasonable NTA to this Project.

3.4.1.3 Energy Efficiency

The four Futures studied by MISO all included reasonable increases in energy efficiency but still found a need for the MVP Portfolio. For energy efficiency to replace this Project, energy efficiency efforts would have to eliminate demand to a level that all the RPSs would be met with existing renewable resources and the reliability and congestion benefits would be achieved through a dramatic reduction in flows on the regional grid. Such an increase in energy efficiency is simply not possible. Given that this Project is intended to deliver renewable energy from Iowa to Wisconsin and the entire region, energy efficiency is not a reasonable alternative.

3.4.1.4 Demand Response

As with energy efficiency, load reduction and load shifting result in a decreased need for electricity. Demand response would not provide the reliability benefits of the Cardinal-Hickory Creek Project. Neither load reduction nor load shifting would directly increase the transfer capability between Iowa and Wisconsin to allow for additional renewable energy transfer. If load reduction were contracted to respond to real-time market signals, it could provide some congestion relief. However, the scope of this Project would require an amount of price responsive demand that is not known to exist. In sum, demand response is not an

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[30] While the capital cost of electric batteries is enough to eliminate them as a reasonable NTA, the following make them even more uneconomic:

- existing interconnection requirements could result in the application of local transmission costs; and
- Energy losses for a battery would be higher than that of an extra-high-voltage line. All forms of storage result in lost energy. There would be additional energy losses from the low-voltage lines used to transport the energy to the batteries.

alternative to this Project.

3.4.2 Conclusion on NTAs

None of the NTAs could meet the purpose and need of this Project: bolstering reliability, increasing economic benefits, increasing transfer capability between Iowa and Wisconsin to ensure compliance with existing RPSs, and increasing flexibility to address emerging public policies. For these reasons, there is not a feasible NTA to this Project.

3.5 No Action Alternative

The no-action alternative ("NAA") is to do nothing. Under the NAA, the Applicants would construct neither the Project nor any alternative.

The MVP portfolio development process began at the request of a number of Midwestern Governors, requesting help from MISO to meet their respective RPSs. MISO established the MVP objectives to meet that need and others. Simply doing nothing – the NAA – would not fulfill the purpose and need of enhancing regional reliability, providing economic benefits through alleviating transmission congestion, increasing transfer capability between Iowa and Wisconsin to ensure compliance with existing RPSs, and increasing flexibility to address other public policies.

The purpose and need of the Project simply cannot be met by a no-action alternative.

3.6 Conclusion on the Alternatives Evaluation

Over several years, MISO completed hundreds of computer modeling runs to determine the best alternatives to achieve the specified purpose and need. MISO selected the 345 kV MVP Portfolio because it was shown to "more reliably enable the delivery of wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner" (MISO, 2012, p. 87). The Project is one component of a Portfolio that was designed assuming all of the components would be built and work together as a whole. Because this Portfolio benefitted all of the MISO states, the states agreed to share in the costs of building the Portfolio.

The Cardinal-Hickory Creek Project, among other things, was designed to increase the transfer capability between Iowa and Wisconsin, facilitating compliance with the RPSs. As a part of the MVP Portfolio, it was also designed to enhance regional reliability, decrease congestion, and provide flexibility in meeting emerging public policy requirements. Any reasonable alternative to the Project must meet these needs, and none do for the following reasons:

- a high-voltage alternative between Iowa and south-central Wisconsin would be longer than this Project and, therefore, more expensive;
- a low-voltage alternative would be more costly than this Project and would not provide the same level of benefits;
- non-transmission alternatives, among other things, do not increase the transfer capability between Iowa and Wisconsin and, therefore, are not feasible alternatives to this Project; and
- a no-action alternative does not meet the Project purpose and need objectives.

Finally, the MVP Portfolio was designed assuming all individual components would be constructed. Selecting any alternative other than this Project would result in reduced benefits to the entire MISO region and would undermine the grand bargain struck by the MISO states.

4.0 REQUIRED PERMITS AND APPROVALS

The Utilities are required to obtain approvals from a variety of federal and state agencies for the Project. Tables 4-1, 4-2, and 4-3 list the expected permits, studies, consultations and regulatory requirements for the Project.

Table 4-1. Federal Permits and Other Compliance that May be Required for Project

Agency	Permits or Other Compliance
U.S. Department of Agriculture, Rural Utilities Service	NEPA compliance as lead agency, including National Historic Preservation Act – Section 106, tribal consultation.

Agency	Permits or Other Compliance
U.S. Fish and Wildlife Service	Use authorization if right-of-way required on National Wildlife Refuge or Wetland Management District lands) and Special Use Permit if crossing National Wildlife Refuge. Incidental Take or Non-Purposeful Take Permit under Section 7 of Endangered Species Act of 1973. Non-Purposeful Take Permit under the Bald and Golden Eagle Protection Act.
U.S. Army Corps of Engineers (USACOE)	Section 10 Permit of the Rivers and Harbors Act of 1899. Nationwide permit or individual permit under Section 401 and404 of the Clean Water Act of 1977. If USACOE land is crossed, an easement will be required and a permit under Section 14 of the Rivers and Harbors Act of 1899, codified in 33 USC 408 (commonly referred to as “Section 408”) may also be required.
U.S. Coast Guard	Permit for Structures or Work in or Affecting Navigable Waters of the United States.
Federal Aviation Administration	Form 7460-1 Objects Affecting Navigable Airspace.
Federal Highway Administration	Permit required to cross federal highways and interstate highways (usually coordinated through state department of transportation).
U.S. Environmental Protection Agency	A spill prevention, control, and countermeasure (SPCC) plan.
National Park Service (NPS)	Possibly a need to obtain an easement on lands that have been funded in part by the Land and Water Conservation Act
Natural Resources Conservation Service (NRCS)	May need permission for easement on property encumbered by NRCS obtained/managed conservation easement

Table 4-2. State of Wisconsin and Other Compliance that May be Required for Project

Agency	Permits or Other Compliance
Public Service Commission of Wisconsin	Certificate of Public Convenience and Necessity
Wisconsin Department of Natural Resources	Construction Site Erosion Control and Stormwater Discharge Permit Endangered/Threatened Species Incidental Take Authorization Wisconsin Pollutant Discharge Elimination System (WPDES) Permit General Utility Crossings Permit Section 401 Water Quality Certification (if Section 404 permit is required by the U.S. Army Corps of Engineers) Chapter 30 permit to place temporary bridges in or adjacent to navigable waters, pursuant to Wis. Stat. § 30.123 and Wis. Admin. Code ch. 320; Chapter 30 permit to place miscellaneous structures within navigable waterways, pursuant to Wis. Stat. § 30.12 and Wis. Admin. Code ch. 329; Chapter 30 permit for grading on the bank of a navigable waterway, pursuant to Wis. Stat. § 30.19 and Wis. Admin. Code ch. 341; Wetland Individual permit, pursuant to Wis. Stat. § 281.36 and Wis. Admin. Code chs. NR 103 and 299.
Wisconsin Department of Transportation	Application to Construct and Operate Utility Facilities on Highway Rights-of-Way (Form DT1553)

Agency	Permits or Other Compliance
	Application for Access Driveway Permit Application for Drainage Permit Form Road Crossing Authorization Oversize Loads or Excessive Weights on Highways
Wisconsin Historical Society/Office of Preservation Planning	National Historic Preservation Act, Section 106 consultation
Wisconsin Department of Agriculture, Trade, and Consumer Protection	Agricultural Impact Statement

Table 4-3. State of Iowa Permits and Other Compliance that May be Required for Project

Agency	Permits or Other Compliance
Iowa Utilities Board and/or Iowa Municipality	Electric Transmission Franchise
Iowa Department of Natural Resources	Clean Water Act, Section 401 Water Quality Certification (if Section 404 permit is required by the U.S. Army Corps of Engineers) National Pollutant Discharge Elimination System (NPDES) Permit Flood Plain Development Permit Sovereign Land Construction Permit
Iowa Department of Transportation	Utility Accommodation Permit Work within Right-of-Way Permit

5.0 CONCLUSION

The purpose and need for this Project is to improve reliability, provide economic benefits through reduced congestion, increase transfer capability between Iowa and Wisconsin as well as support energy policy mandates. MISO determined that the best alternative for meeting this purpose and need is the Cardinal-Hickory Creek Project. No other high or low-voltage transmission alternative will be as cost-effective as this Project in connecting northwestern Iowa with southeastern and south-central Wisconsin. Non-transmission alternatives are neither feasible nor cost effective and a no-action alternative could not meet the important purpose and need. The Cardinal-Hickory Creek Project, alone and as part of the MVP Portfolio, will bring numerous reliability, economic and public policy benefits to Wisconsin, Iowa and the region.

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APPENDIX A

MTEP14 MVP Triennial Review

A 2014 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio

September 2014

Contents

Executive Summary

The MTEP14 Triennial Multi-Value Project (MVP) Review provides an updated view into the projected economic, public policy, and qualitative benefits of the MVP Portfolio. The MTEP14 MVP Triennial Review's business case is on par with, if not stronger 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 MTEP14 results demonstrate the MVP Portfolio:

- Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.6 to 3.9; an increase from the 1.8 to 3.0 range calculated in MTEP11
- Creates \$13.1 to \$49.6 billion in net benefits over the next 20 to 40 years, an increase of approximately 50 percent from MTEP11
- Enables 43 million MWh of wind energy to meet renewable energy mandates and goals through year 2028, an additional 2 million MWh from the MTEP11 year 2026 forecast
- Provides additional benefits to each local resource zone relative to MTEP11

Benefit increases are primarily congestion and fuel savings largely driven by natural gas price assumptions.

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 Multi Value Projects (MVPs), meet one or more of three goals:

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

MISO conducted its first triennial MVP Portfolio review, per tariff requirement, for MTEP14. The MVP Review has no impact on the existing MVP Portfolio cost allocation. MTEP14 Review analysis is performed solely for informational purposes. The intent of the MVP Review is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

The 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 MTEP14 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 MTEP14 MVP Review assesses the benefits of the entire MVP Portfolio and does not differentiate between facilities currently in-service and those still being planned. Because the MVP Portfolio's costs are allocated solely to the MISO North and Central Regions, only MISO North and Central Region benefits are included in the MTEP14 MVP Triennial Review.

Public Policy Benefits

The MTEP14 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 not changed since the MTEP11 analysis.

Updated analyses find that 10.5 GW of year 2023 dispatched wind would be curtailed in lieu of the MVP Portfolio, which extrapolates to 56 percent of the 2028 full RPS energy. MTEP11 analysis showed that 63 percent of the year 2026 full RPS energy would be curtailed without the installation of the MVP Portfolio. The MTEP14 calculated reduction in curtailment as a percentage of RPS has decreased since MTEP11, primarily because post-MTEP11 transmission upgrades are represented and the actual physical location of installed wind turbines has changed slightly since the 2011 forecast.

In addition to allowing energy to not be curtailed, analyses determined that 4.3 GW of wind generation in excess of the 2028 requirements is enabled by the MVP Portfolio. MTEP11 analysis determined that 2.2 GW of additional year 2026 generation could be sourced from the incremental energy zones. The results are the essentially the same for both analyses as the increase in wind enabled from MTEP 2011 is primarily attributed to additional load growth. The MTEP 2011 analysis was performed on a year 2026 model and MTEP 2014 on year 2028.

When the results from the curtailment analyses and the wind enabled analyses are combined, MTEP 2014 results show the MVP Portfolio enables a total of 43 million MWh of renewable energy to meet the renewable energy mandates through 2028. MTEP 2011 showed the MVP Portfolio enabled a similar level renewable energy mandates – 41 million MWh through 2026.

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

Economic Benefits

MTEP14 analysis shows the Multi-Value Portfolio creates $21.5 to $66.8 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 $5.86 billion in MTEP14. Even with the increased portfolio cost estimates, the increased MTEP14 congestion and fuel savings and transmission line losses benefit forecasts result in portfolio benefit-to-cost ratios that have increased since MTEP11.

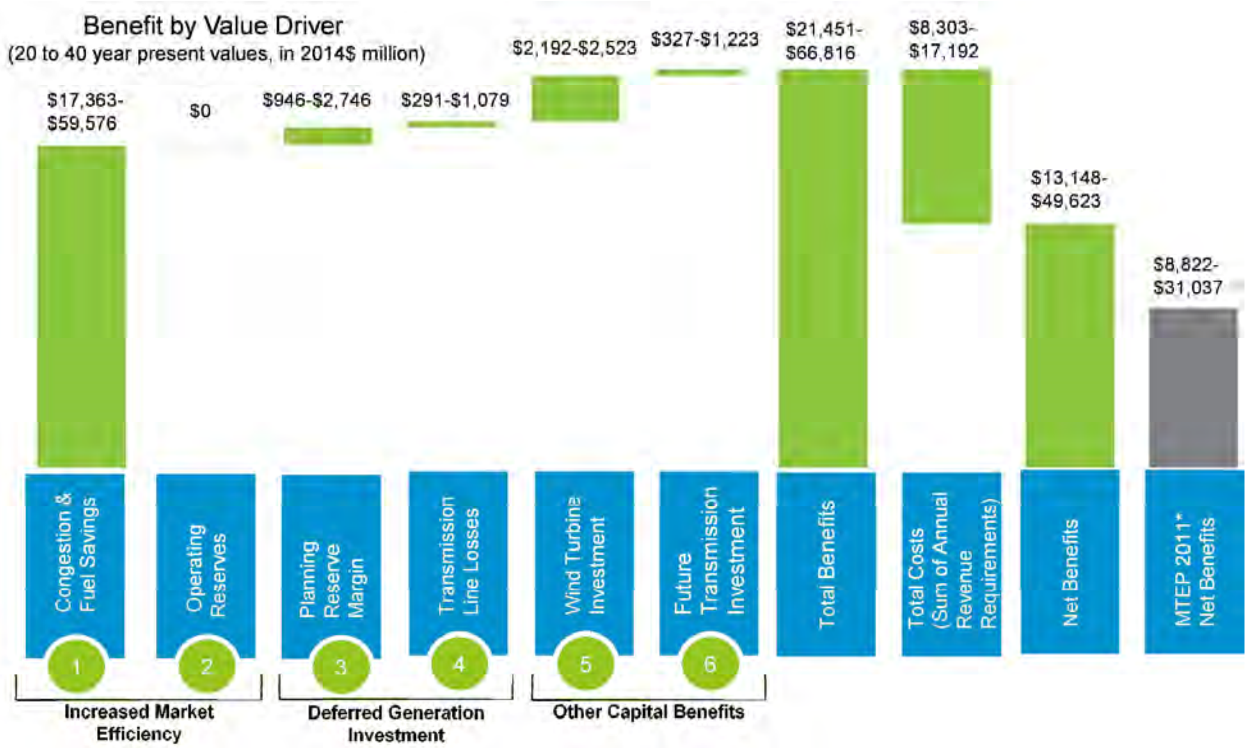

Figure E-1: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

The bulk of the increase in benefits is due to an increase in the assumed natural gas price forecast in MTEP14 compared to MTEP11. In addition, the MTEP15 natural gas assumptions, which will be used in the MTEP15 MVP Portfolio Limited Review, are lower than the MTEP14 forecast. Under each of the natural gas price assumption sensitivities, the MVP Portfolio is projected to provide economic benefits in excess of costs (Table E-1).

Natural Gas Forecast Assumption	Total NPV Portfolio Benefits ($M-2014)	Total Portfolio Benefit to Cost Ratio
MTEP14 – MVP Triennial Review	21,451 – 66,816	2.6 – 3.9
MTEP11	17,875 – 54,186	2.2 – 3.2
MTEP15	18,472 – 56,670	2.2 – 3.3

Table E-1: MVP Portfolio Economic Benefits - Natural Gas Price Sensitivities[2]

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 $17 to $60 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central Regions – an increase of up to 40 percent from the MTEP11 net present value.

An increase in the natural gas price escalation rate, increases congestion and fuel savings benefits by approximately 30 percent in MTEP14 compared to MTEP11

The increase in congestion and fuel savings benefits relative to MTEP11 is primarily due to an increase in the out-year natural gas price forecast assumptions (Figures E-2). The increased escalation rate causes the assumed natural gas price to be higher in MTEP14 compared to MTEP11 in years 2023 and 2028 - the two years from which the congestion and fuel savings results are based (Figure E-2).

The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. A sensitivity applying the MTEP11 Low BAU gas prices assumption to the MTEP14 MVP Triennial Review model showed a 29.3 percent reduction in the annual year 2028 MTEP14 congestion and fuel savings benefits (Figure E-2).

Post MTEP14 natural gas price forecast assumptions are more closely aligned with those of MTEP11 (Figure E-2). A sensitivity applying the MTEP15 BAU natural gas prices to the MTEP14 analysis showed a 21.7 percent reduction in year 2028 MTEP14 adjusted production cost savings.

2 Sensitivity performed applying MTEP11/MTEP15 natural gas price to the MTEP14 congestion and fuel savings model. All other benefit valuations unchanged from the MTEP14 MVP Triennial Review.

MISO membership changes have little net effect on benefit-to-cost ratios. The exclusion of Duke Ohio/Kentucky and First Energy from the MISO pool decreases benefits by 7.4 percent relative to the MTEP14 total benefits; however, per Schedule 39, 6.3 percent of the total portfolio costs are allocated to Duke Ohio/Kentucky and First Energy, thus there is a minimal net effect to the benefit-to-cost ratio.

The MVP Portfolio is solely located in the MISO North and Central Regions and therefore, the inclusion of the MISO South Region to the MISO dispatch pool has little effect on MVP-related production cost savings (Figure E-2).

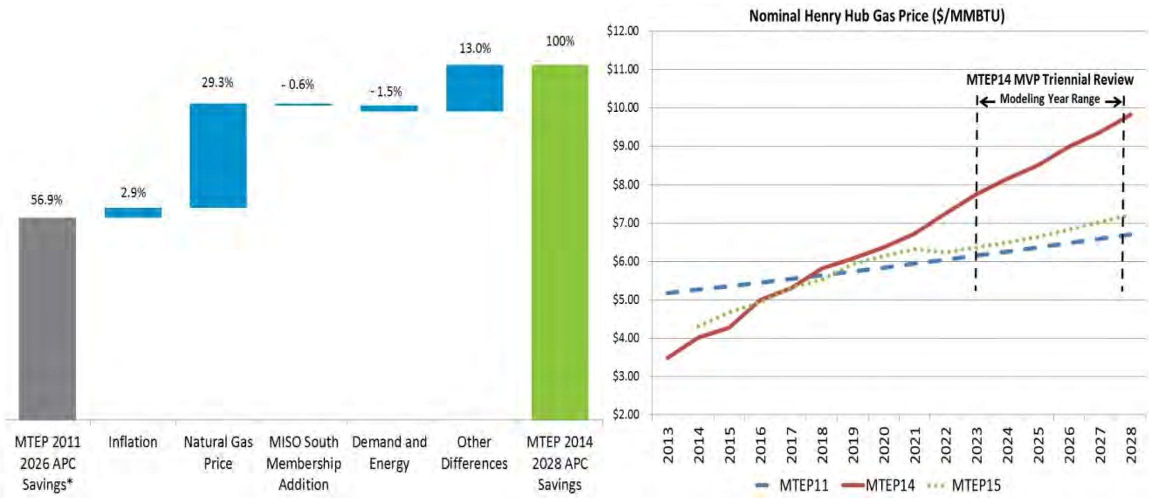

Figure E-2: Breakdown of Congestion and Fuel Savings Increase from MTEP11 to MTEP14

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 2014, 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 $291 to $1,079 million - nearly double the MTEP11 values. Tightening reserve margins, from an additional approximate 12 GW of expected coal generation retirements, have increased the value of deferred capacity from transmission losses in MTEP14. In addition to the tighter reserve margins, a one year shift forward in MVP Portfolio in-service dates since MTEP11 has increased benefits by an additional 30 percent.

The MTEP14 MVP Review estimates the MVPs annually defer more than $900 million in future capacity expansion by increasing capacity import limits, thus reducing the local clearing requirements of the system planning reserve margin requirement. In the 2013 planning year, MISO and the Loss of Load Expectation Working Group improved the methodology that establishes the MISO Planning Reserve Margin Requirement (PRMR). Previously, and in the MTEP11 analysis, MISO developed a MISO-wide

PRMR with an embedded congestion component. The post 2013 planning year methodology no longer uses a congestion component, but rather calculates a more granular zonal PRMR and a local clearing requirement based on the zonal capacity import limit. While terminology and methods have changed between MTEP11 and MTEP14, both calculations capture the same benefit of increased capacity sharing across the MISO region provided by the MVPs; as such, MTEP14 and MTEP11 provide benefit estimates of similar magnitudes.

Other Capital Benefits

Benefits from the optimization of wind generation siting and the elimination of need for some future baseline reliability upgrades remain at similar levels to those estimated in MTEP11. A slight increase in MTEP14 wind turbine investment benefits relative to MTEP11 benefits is from an update to the wind requirement forecast and wind enabled calculations.

Consistent with MTEP11, the MTEP14 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 estimate from MTEP11; however, the actual identified upgrades have some differences because 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 local resource zone (Figure E-3). The MVP Portfolio's benefits are at least 2.3 to 2.8 times the cost allocated to each zone. As a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), load growth, and wind siting, zonal benefit distributions have changed slightly since MTEP11.

Benefit-to-cost ratios have increased in all zones since MTEP11

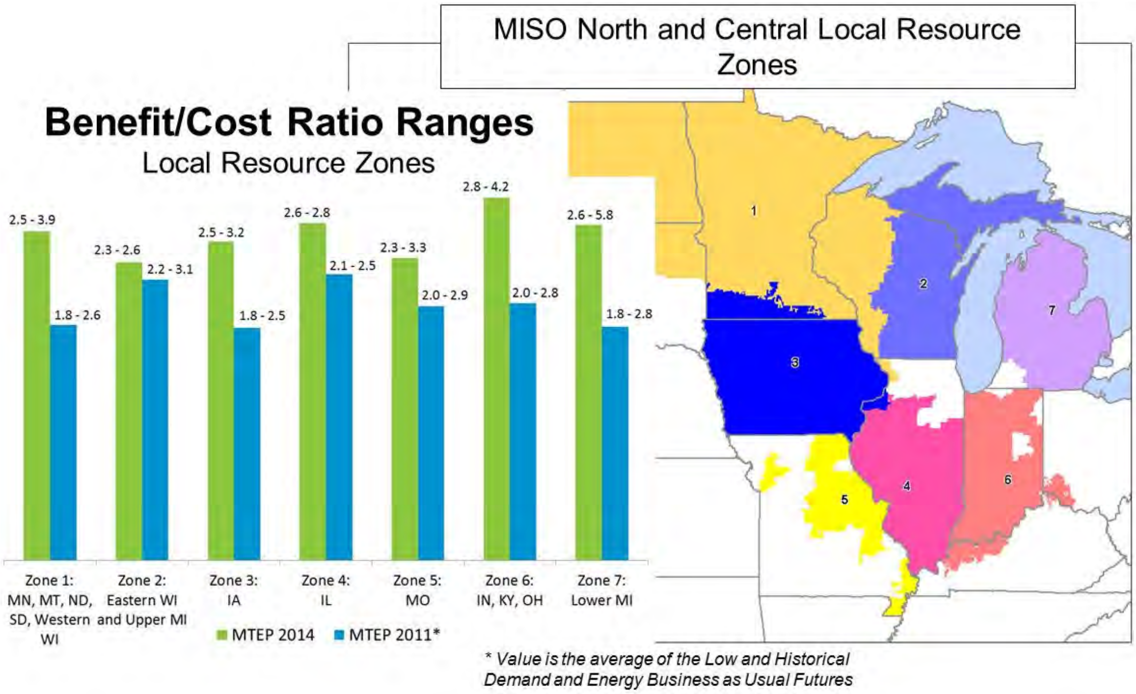

Figure E-3: MVP Portfolio Total Benefit Distribution

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 9 to 15 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.

Going Forward

MTEP15 and MTEP16 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings using the latest portfolio costs and in-service dates. Beginning in MTEP17, in addition to the Full Triennial Review, MISO will perform an assessment of the congestion costs, energy prices, fuel costs, planning reserve margin requirements, resource interconnections and energy supply consumption based on historical data.

1. Study Purpose and Drivers

Beginning in MISO Transmission Expansion Plan (MTEP) 2014, MISO has a triennial tariff requirement to conduct a full review of the Multi-Value Project (MVP) Portfolio benefits. The MTEP14 Triennial MVP Review provides an updated view into the projected economic, public policy and qualitative benefits of the MTEP11 approved MVP Portfolio.

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

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 MTEP14 and MTEP11 assumptions are highlighted and the resulting differences quantified.

Consistent with MTEP11, the MTEP14 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 which support wind, natural gas and other fuel sources.

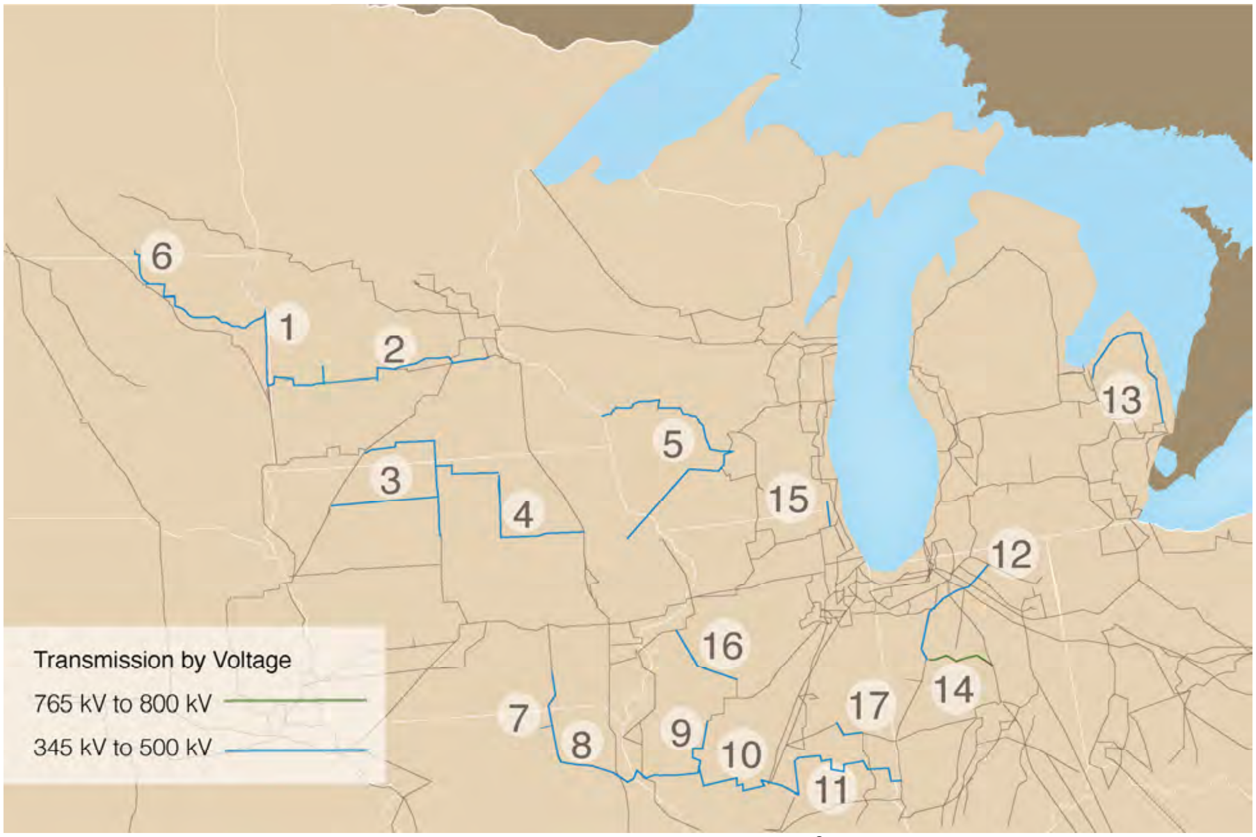

Figure 2-1: MVP Portfolio[3]

[3] 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.

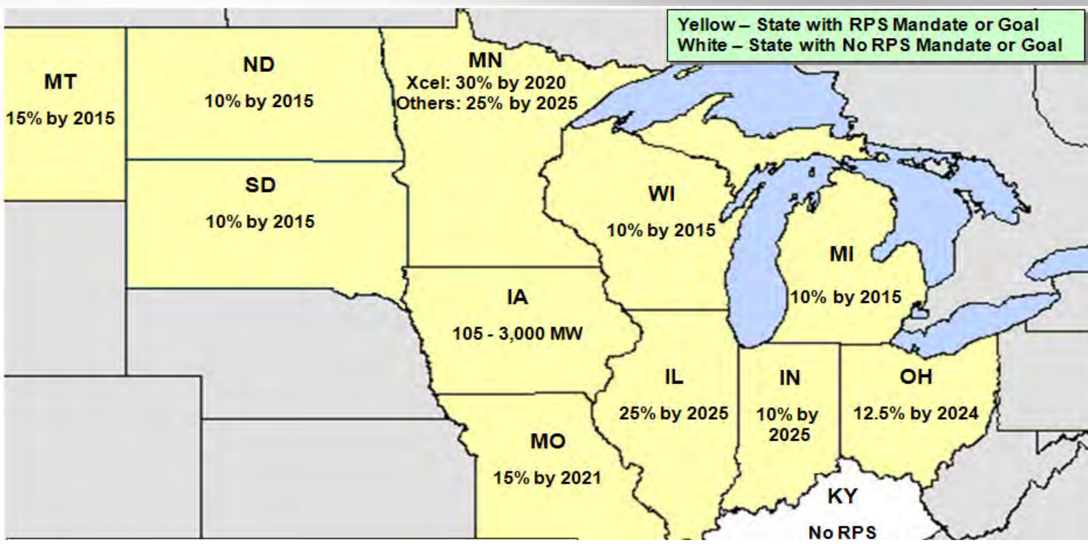

Figure 2-2: Renewable Portfolio Standards - 2011

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, 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), 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.

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).

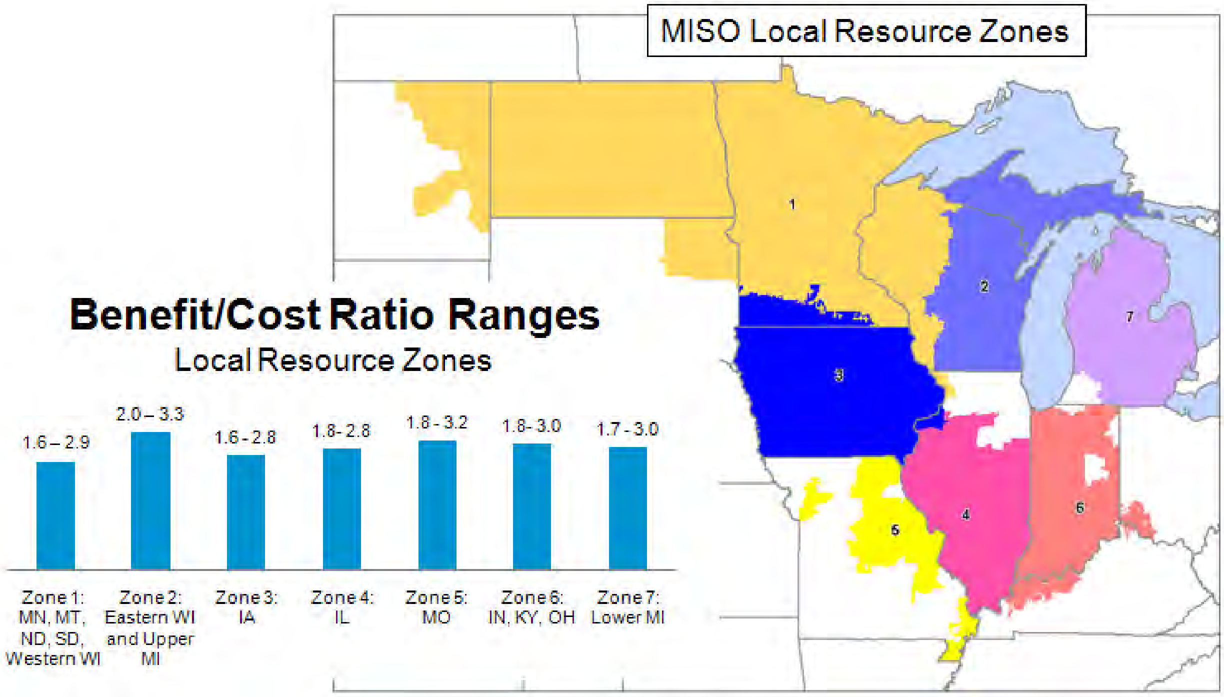

Figure 2-3: MTEP11 MVP Portfolio Benefit Spread

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. MTEP14 Review Model Development

The MTEP14 MVP Triennial Review uses MTEP14 economic models as the basis for the analysis. The MTEP14 economic models were developed in 2012 and 2013 with topology based on the MTEP13 series MISO powerflow models. To maintain consistency between economic and reliability models, MVP Triennial Review reliability analysis was performed with MTEP13 vintage powerflows.

MTEP14 economic models, developed in 2013, are the basis for the MTEP14 MVP Triennial Review.

The MTEP models were developed through an open stakeholder process and vetted through the MISO Planning Advisory Committee. The details of the economic and reliability models used in the MTEP14 MVP Triennial Review are described in the following sections. The MTEP models are publically 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 MTEP14 MISO North/Central economic models, stakeholder vetted in 2013, are used as the basis for the MTEP14 Review. The same economic models are used in the MTEP14 North/Central Market Congestion Planning Study, formerly known as the Market Efficiency Planning Study.

Consistent with the MTEP11 MVP business case[4], the MTEP14 Review relies solely on the Business as Usual (BAU) future.

The MTEP14 BAU future is most representative of the average of the MTEP11 Low and High BAU futures

The MTEP14 BAU future is defined as: A *status quo environment that assumes a slow recovery from the economic downturn and its impact on demand and energy projections. This scenario assumes existing standards for renewable mandates and little or no change in environmental legislation.*

MTEP11 had two definitions of the BAU future – a typical MTEP Planning Advisory Committee defined future and a slightly modified version from the Cost Allocation and Regional Planning (CARP) process. For the purposes of this report the two MTEP11 BAU futures are identified by their load growth rates – one with a slightly higher baseline growth rate and one with a slightly lower growth rate (Table 3-1). Based on current definitions, the MTEP14 BAU future's demand and energy growth rate is closest to the MTEP11 BAU-Low Demand and Energy, but the natural gas price is closest to the MTEP11 BAU-High Demand and Energy (Table 3-1). The MTEP14 BAU future is most representative of the average of the MTEP11 Low and High BAU futures; as such, all MTEP14 Triennial MVP Review results in this report will be compared to the arithmetic mean of the MTEP11 Low BAU and High BAU results.

[4] 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.

		MTEP14 BAU	MTEP11 Low BAU	MTEP11 High BAU
Demand and Energy	**Demand Growth Rate**	1.06 percent	1.26 percent	1.86 percent
	Energy Growth Rate	1.06 percent	1.26 percent	1.86 percent
Natural Gas Forecast[5]	**Starting Point**	3.48 $/MMBTU	5 $/MMBTU	5 $/MMBTU
	2018 Price	5.81 $/MMBTU	5.64 $/MMBTU	6.11 $/MMBTU
	2023 Price	7.76 $/MMBTU	6.15 $/MMBTU	7.05 $/MMBTU
	2028 Price	9.83 $/MMBTU	6.70 $/MMBTU	8.14 $/MMBTU
Fuel Cost (Starting Price)	**Oil**	Powerbase Default	Powerbase Default	Powerbase Default
	Coal	Powerbase Default	Powerbase Default	Powerbase Default
	Uranium	1.14 $/MMBTU	1.12 $/MMBTU	1.12 $/MMBTU
Fuel Escalations	**Oil**	2.50 percent	1.74 percent	2.91 percent
	Coal	2.50 percent	1.74 percent	2.91 percent
	Uranium	2.50 percent	1.74 percent	2.91 percent
Emission Costs	**SO2**	0	0	0
	NOx	0	0	0
	CO2	0	0	0
Other Variables	**Inflation**	2.50 percent	1.74 percent	2.91 percent
	Retirements	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
MISO Footprint		Duke and FE in PJM; includes MISO South	MTEP11	MTEP11

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

Models include all publically announced retirements as well as 12,600 MW of baseline generation retirements driven by environmental regulations. Unit-specific retirements are based on a MISO Planning Advisory Committee vetted generic process as the results of the MISO Asset Owner EPA Survey are confidential.

MISO footprint changes since the MTEP11 analysis are modeled verbatim to current[6] 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 MTEP14 MVP Triennial Review's business case.

[5] MTEP11 and MTEP13 use different natural gas escalation methodologies
[6] As of July 2014

MTEP13 powerflow models for the year 2023 are used as the base transmission topology for the MVP Triennial Review. Because there are no significant transmission topology changes known between years 2023 and 2028, the 2028 production cost models use the same transmission topology as 2023.

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.

3.2 Capacity Expansion Models

The MTEP14 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.

MTEP14 Triennial MVP Review analysis was performed using the MTEP14 BAU future, developed in 2012 and 2013. 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, MTEP13 vintage MISO powerflow models are used as the basis for the MTEP14 MVP Triennial Review reliability analysis. The MTEP14 economic models are developed with topology based on the MTEP13 MISO powerflow models. Siemens PTI Power System Simulator for Engineering (PSS E) and Power System Simulator for Managing and Utilizing System Transmission (PSS MUST) is utilized for the MTEP14 MVP Triennial Review.

Powerflow models are built using MISO's Model on Demand (MOD) model data repository. Models include approved MTEP Appendix A projects 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 20 percent in the Summer Peak.

Additional wind units were added to the MTEP14 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 2018 MTEP13 Summer Peak case and the 2023 MTEP13 Summer Peak Case.

Analysis	Model(s)
Wind Curtailment	2023 MTEP13 Shoulder
Wind Enabled	2023 MTEP13 Shoulder with Wind at 2028 Levels
Transmission Line Losses	2023 MTEP13 Summer Peak
Future Transmission Investment	2023 MTEP13 Summer Peak with Demand and Wind at 2033 Levels

Table 3-2: Reliability Models by Analysis

3.4 Capacity Import Limit Models

The MTEP13 series of MISO powerflow models updated for the 2014 Loss of Load Expectations (LOLE) study are used as the basis for the MTEP14 MVP Triennial Review capacity import limit analysis. Siemens Power Technology International Power System Simulator for Engineering (PSS E) and Power System Simulator for Managing and Utilizing System Transmission (PSS MUST) were utilized for the LOLE analyses, which produced results used in the MTEP14 MVP Triennial Review analysis.

Wind modeling and dispatch assumptions for LOLE studies were updated since completion of the 2014 LOLE analysis. These changes were applied to the MVP Triennial Review models so the Triennial analysis is using the up-to-date LOLE study methodology. Consistent with the current LOLE methodology, MISO wind dispatch was set at the wind capacity credit level. Applicable updates to generation retirements or suspensions were applied to the MTEP14 Triennial Review Models.

Zonal Local Clearing Requirements are calculated using the capacity import limits that are identified using PSS MUST transfer analysis. The MTEP14 MVP Triennial Review incorporates capacity import limits calculated using a year 2023 model both with and without the MVP Portfolio.

PSS MUST contingency files from Coordinated Seasonal Assessment (CSA) and MTEP[7] reliability assessment studies were used in the MTEP14 MVP Review (Table 3-3). Single-element contingencies in MISO and seam areas were evaluated in addition to submitted files.

Model	Contingency files used
2014-15 Planning Year	2013 Summer CSA
5-year-out peak	MTEP13 study

Table 3-3: Contingency files per model

PSS MUST subsystem files include source and sink definitions. The PSS MUST 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 2014 Loss of Load Expectation Report.

3.5 Loss of Load Expectation Models

MISO utilizes the General Electric-developed Multi-Area Reliability Simulation (MARS) program to calculate the loss of load expectation for the applicable planning year. 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.

The 2014 planning year LOLE models, updated to include generation retirements, were the basis for the MTEP14 MVP Triennial Review models. Additional model details can be found in the 2014 Loss of Load Expectation Report.

[7] Refer to sections 4.3.4 and 4.3.6 of the Transmission Planning BPM for more information regarding MTEP PSS MUST input files. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

4. Project Costs and In-Service Dates

The MTEP14 MVP Triennial Review cost and in-service data is referenced from the MTEP Quarter One 2014 Report – dated April 11, 2014 (Figure 4-1).

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[1]	
			MTEP Approved	Q1 2014	State Regulatory Status	Construction	MTEP Approved	Q1 2014
1	Big Stone-Brookings	SD	2017	2017	●	Pending	226.7	226.7
2	Brookings, SD-SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Underway	738.4	640.9
3	Lakefield Jct. - Winnebago-Winco-Burt area & Sheldon-Burt Area-Webster	MN/IA	2015-2016	2016-2018	◑	Pending	550.4	541.1
4	Winco-Lime Creek-Emery-Black Hawk-Hazelton	IA	2015	2015-2018	◑	Pending	468.6	464.3
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project) & Dubuque Co.-Spring Green-Cardinal	WI/IA	2018-2020	2013-2018	◑	Pending	797.5	879.0
6	Big Stone South - Ellendale	ND/SD	2019	2019	◑	Pending	330.7	395.7
7	Adair-Ottumwa	IA/MO	2017-2020	2017-2018	○	Pending	152.3	178.2
8	Adair-Palmyra Tap	MO	2016-2018	2016-2018	○	Pending	112.8	108.1
9	Palmyra Tap-Quincy-Merdosia-Ipava & Meredosia-Pawnee	MO/IL	2016-2017	2016-2017	●	Pending	432.2	524.2
10	Pawnee-Pana	IL	2018	2016-2018	●	Pending	99.4	108.6
11	Pana-Mt. Zion-Kansas-Sugar Creek	IL/IN	2018-2019	2016-2019	●	Pending	318.4	356.2
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Pending	271.0	271.0
13	Michigan Thumb Loop Expansion	MI	2013-2015	2013-2015	●	Underway	510.0	510.0
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	328.7
15	Pleasant Prairie-Zion Energy Center	WI	2014	2013	●	Complete	28.8	33.0
16	Fargo-Galesburg-Oak Grove	IL	2014-2019	2016-2018	○	Pending	199.0	225.5
17	Sidney-Rising	IL	2016	2016	●	Pending	83.2	66.3
						Totals:	***5,564***	***5,858***

Figure 4-1: MVP Cost and In-Service Dates – MTEP11 version MTEP14[8]

For MTEP14, all benefit calculations start in year 2020, 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.

The costs contained within the MTEP database are in nominal, as spent, dollars. Nominal dollars are converted to real dollars for net present value benefit cost calculations using the facility level in-service dates. To obtain a real value in 2020 dollars from the nominal values in the MTEP database each facility's cost escalates using a 2.5 percent inflation rate from in-service year to 2020.

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 2010 energy withdrawals with an applied Business as Usual (BAU) MTEP growth rate applied.

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[8] All costs in nominal dollars.

MTEP14 MVP Triennial Review benefit-to-cost calculations only include direct benefits to MISO North and Central members. Therefore it is necessary to exclude costs paid by parties outside of MISO via exports and costs paid by Duke Ohio/Kentucky and First Energy pursuant to Schedule 39. Consistent with MTEP11, export revenue is estimated as 1.94 percent of the total MVP Portfolio costs. Schedule 39 is estimated as 6.24 percent of the total portfolio costs. MISO South Region benefits are excluded from all estimations.

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 MTEP14 MVP Triennial Review assumes that costs start in 2020, such as year one of the annual charge rate is 2020 and construction work in progress (CWIP) is excluded from the total costs.

5. Portfolio Public Policy Assessment

The MTEP14 MVP Triennial Review redemonstrates the MVP Portfolio's ability to enable the renewable energy mandates of the footprint. Renewable Portfolio Standards assumptions[9] have not changed 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 43 million MWh of renewable energy to meet the renewable energy mandates and goals through 2028.

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 2028, 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.
The shift factors for all wind machines were calculated on the worst NERC Category B and C contingency constraints of each monitored element identified in 2011 as mitigated by the MVP Portfolio. The 488 monitored element/contingent element pairs (flowgates) consisted of 233 Category B and 255 Category C contingency events. These constraints were taken from a blend of projected 2023 and 2028 wind levels with the final calculations based on the projected 2028 wind levels.

Since the majority of the MISO West Region MVP justification was based on 2023 wind levels, it was assumed that any incremental increase to reach the 2028 renewable energy mandated levels would be curtailed. A transfer of the 279 wind units, sourced from both committed wind units and the Regional Generation Outlet Study (RGOS) energy zones to the system sink, Browns Ferry in the Tennessee Valley Authority, was used to develop the shift factors on the flowgates.

Linear optimization logic was used to minimize the amount of wind curtailed while reducing loadings to within line capacities. Similar to the MTEP11 justifications, a target loading of less than or equal to 95 percent was used. Fifty-four of the 488 flowgates could not achieve the target loading reduction, and their targets were relaxed in order to find a solution.

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

The algorithm found that 9,315 MW of year 2023 dispatched wind would be curtailed. It was also assumed that any additional wind in the West to meet Renewable Portfolio Standard (RPS) levels would be curtailed. This equated to 1,212 MW of dispatched wind. As a connected capacity, 11,697 MW would be curtailed, as the wind is modeled at 90 percent of its nameplate. The MTEP14 results are similar in magnitude to MTEP11, which found that 12,201 MW of connected wind would be curtailed through 2026.

The curtailed energy was calculated to be 32,176,153 MWh from the connected capacity multiplied by the capacity factor times 8,760 hours of the year. A MISO-wide per-unit capacity factor was averaged from the 2028 incremental wind zone capacities to 31.4 percent. Comparatively, the full 2028 RPS energy is 57,019,978 MWh. As a percentage of the 2028 full RPS energy, 56.4 percent would be curtailed in lieu of the MVP Portfolio. MTEP11 analysis showed that 63 percent of the year 2026 full RPS energy would be curtailed without the installation of the MVP Portfolio. The MTEP14 calculated reduction in curtailment as a percentage of RPS has decreased since MTEP11, primarily because post-MTEP11 transmission upgrades are represented and the actual physical location of installed wind turbines has changed slightly since the 2011 forecast.

5.2 Wind Enabled

Additional analyses were performed to determine the incremental wind energy in excess of the 2028 requirements enabled by the approved MVP Portfolio. This energy could be used to meet renewable energy mandates beyond 2028, as most of the state mandates are indexed to grow with load. A set of three First Contingency Incremental Transfer Capability (FCITC) analyses were run on the 2028 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 in proportion to their 2028 maximum output. 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

MTEP14 analysis determined that 4,335 MW of additional year 2028 generation could be sourced from the incremental energy zones to serve future renewable energy mandates (Table 5-2). MTEP11 analysis determined that 2,230 MW of additional year 2026 generation could be sourced from the incremental energy zones. The results are the essentially the same for both analyses as the increase in wind enabled from MTEP11 is primarily attributed to additional load growth. MTEP11 analysis was performed on a year 2026 model and MTEP14 on year 2028.

Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled
MI-B	250	IL-K	465
MI-C	238	IN-K	70
MI-D	318	WI-B	491
MI-E	264	WI-D	452
MI-F	320	WI-F	144
MI-I	210	MO-C	347
IL-F	167	MO-A	599

Table 5-2: Incremental Wind Enabled Above 2028 Mandated Level, by Zone

Consistent with the MTEP11 analysis, incremental wind enabled was calculated using a multiple pass technique – a first pass where wind is sourced from all wind zones, and a second where wind is sourced from just wind zones east of the Mississippi River. System-wide transfers from west to east across this boundary have historically been limited, and the first transfer limitations are seen along this corridor.

In the MTEP14 Review, no additional wind was enabled in much of the West. The MTEP14 Review power flow model had significantly stronger base dispatch flows from the Western portion of the system compared to the MTEP11 analysis. A first transfer including all zones east of the Mississippi as well as those from Missouri enabled the addition of 2,334 MW nameplate wind, at which point the wind zones in Michigan began meeting system limits. That wind was added to the model, and the analysis repeated for a second pass. The second transfer sourced wind from the Eastern wind zones minus those in Michigan, allowing an addition of 584 MW of nameplate wind, at which point a wind zone in Missouri met a local limit. The last transfer was performed leaving out the Missouri zone, and 1,416 MW of additional nameplate wind was enabled, before meeting a transfer limit in West-Central Illinois.

When the results from the curtailment analyses and the wind enabled analyses are combined, MTEP14 results show the MVP Portfolio enables a total of 43 million MWh of renewable energy to meet the renewable energy mandates through 2028. MTEP11 showed the MVP Portfolio enabled a similar level renewable energy mandates – 41 million MWh through 2026.

6. Portfolio Economic Analysis

MTEP14 estimates show the Multi-Value Portfolio creates $13.1 to $49.6 billion in net benefits to MISO North and Central Region members, an increase of approximately 50 percent from MTEP11 (Figure 6-1). Increases are primarily congestion and fuel savings driven by natural gas prices. Total portfolio costs have increased from $5.56 billion in MTEP11 to $5.86 billion in MTEP14. Even with the increased portfolio cost estimates, the increased MTEP14 benefit estimation results in portfolio benefit-to-cost ratios that have increased from 1.8 to 3.0 in MTEP11 to 2.6 to 3.9 in MTEP14.

The MTEP14 Triennial MVP Review estimates the MVP benefit-to-cost ratio has increased from 1.8 – 3.0 in MTEP11 to 2.6 – 3.9.

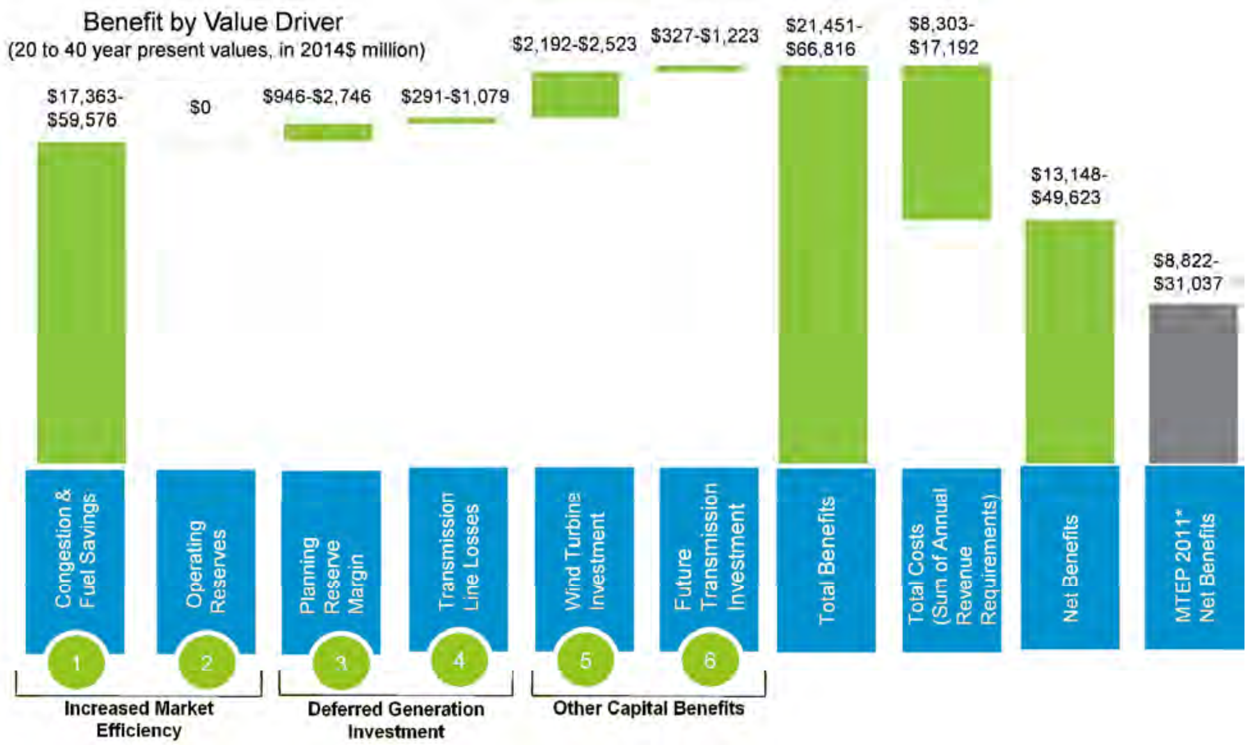

Figure 6-1: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

The bulk of the increase in benefits is due to an increase in the assumed natural gas price forecast in MTEP14 compared to MTEP11. In addition, the MTEP15 natural gas assumptions, which will be used in the MTEP15 MVP Portfolio Limited Review, are lower than the MTEP14 forecast. Under each of the natural gas price assumption sensitivities, the MVP Portfolio is projected to provide economic benefits in excess of costs (Table 6-1).

Natural Gas Forecast Assumption	Total NPV Portfolio Benefits ($M-2014)	Total Portfolio Benefit to Cost Ratio
MTEP14 – MVP Triennial Review	21,451 – 66,816	2.6 – 3.9
MTEP11	17,875 – 54,186	2.2 – 3.2
MTEP15	18,472 – 56,670	2.2 – 3.3

Table 6-1: MVP Portfolio Economic Benefits - Natural Gas Price Sensitivities[10]

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). MTEP14 MVP Triennial Review results indicate that benefit-to-cost ratios have increased in all zones since MTEP11. Portfolio's benefits are at least 2.3 to 2.8 times the cost allocated to each zone. Zonal benefit distributions have changed slightly since the MTEP11 business case as a result of changing tariffs/business practices (planning reserve margin requirement and baseline reliability project cost allocation), load growth, and wind siting. As state demand and energy forecasts change and additional clarity is gained in to the location of actual wind turbine installation so does the siting of forecast wind.

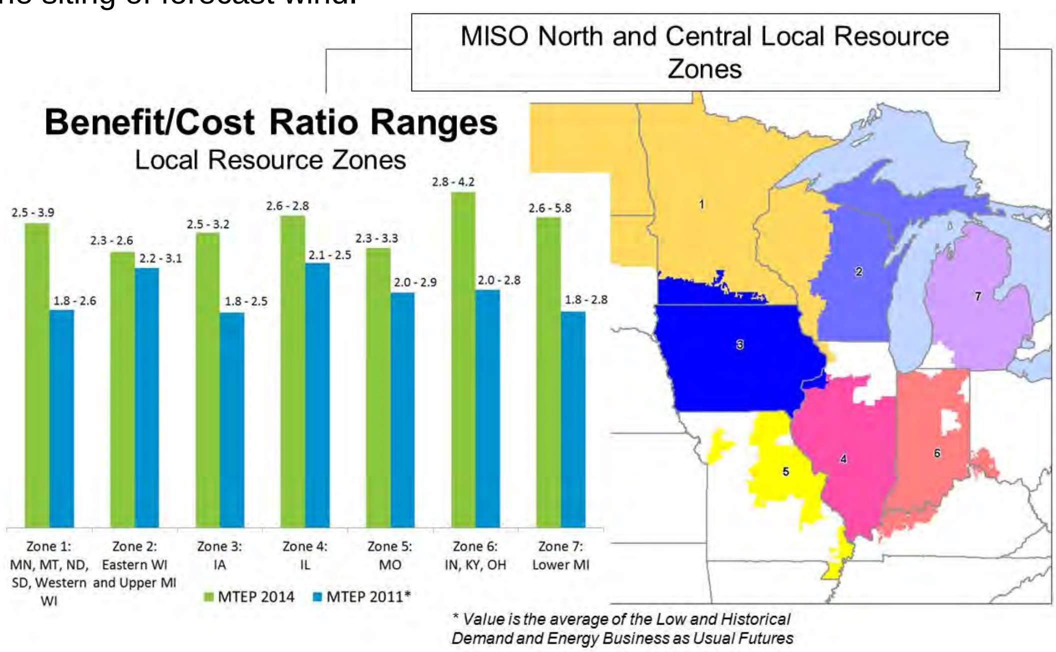

Figure 6-2: MVP Portfolio Production Cost Benefit Spread

10 Sensitivity performed applying MTEP11/MTEP15 natural gas price to the MTEP14 congestion and fuel savings model. All other benefit valuations unchanged from the MTEP14 MVP Triennial Review.

MVP Portfolio benefits under lower natural gas price sensitivities are at least 1.9 to 2.5 times the cost allocated to each zone (Figure 6-3). Under each natural gas price sensitivity benefits are zonally distributed in a manner roughly equivalent to the zonal cost allocation.

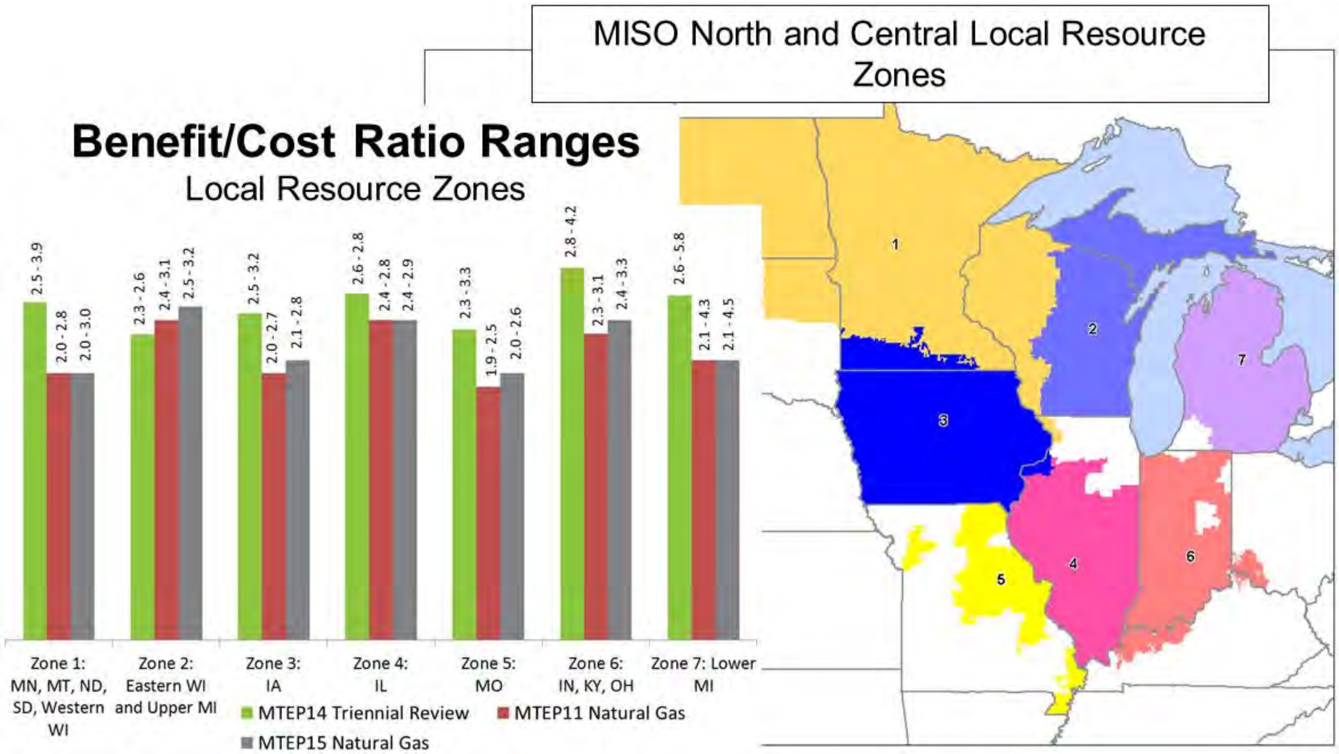

Figure 6-3: MVP Portfolio Production Cost Benefit Spread – Natural Gas Price Sensitivities[11]

[11] Sensitivity performed applying MTEP11/MTEP15 natural gas price to the MTEP14 congestion and fuel savings model. All other benefit valuations unchanged from the MTEP14 MVP Triennial Review.

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.

Primarily because of an increase in natural gas price forecast assumptions, congestion and fuel savings have increased by approximately 40 percent since MTEP11

Congestion and fuel savings is the most significant portion of the MVP benefits (Figure 6-1). The MTEP14 Triennial MVP Review estimates that the MVP Portfolio will yield $17 to $60 billion in 20- to 40-year present value adjusted production cost benefits, depending on the timeframe and discount rate assumptions. This value is up 22 percent to 44 percent from the original MTEP11 valuation (Table 6-2).

	MTEP14	MTEP11[12]
3 percent Discount Rate; 20 Year Net Present Value	28,057	21,918
8 percent Discount Rate; 20 Year Net Present Value	17,363	14,203
3 percent Discount Rate; 40 Year Net Present Value	59,576	41,330
8 percent Discount Rate; 40 Year Net Present Value	25,088	19,016

Table 6-2: Congestion and Fuel Savings Benefit ($M-2014)

The increase in congestion and fuel savings benefits relative to MTEP11 is primarily from an increase in the out-year natural gas price forecast assumptions (Figures 6-4, 6-5, and 6-6). In 2013, as part of the futures development, the MISO Planning Advisory Committee adopted a natural gas price escalation rate assumption sourced from a combination of the New York Mercantile Exchange (NYMEX) and Energy Information Administration (EIA) forecasts. The MTEP14 assumed natural gas price escalation rate is approximately 7.2% per year[13], compared to 1.74% per year in MTEP11. The increased escalation rate causes the assumed natural gas price to be $1.61/MMBTU higher in MTEP14 than MTEP11 in year 2023 and $3.13/MMBTU higher in year 2028 - the two years from which congestion and fuel savings results are based.

[12] Average of the High and Low MTEP11 BAU Futures

[13] 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[14], which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. A sensitivity applying the MTEP11 Low BAU gas prices assumption to the MTEP14 MVP Triennial Review model showed a 29.3 percent reduction in the annual year 2028 MTEP14 congestion and fuel savings benefits (Figure 6-5). Approximately 68% of the difference between the MTEP11 and MTEP14 congestion and fuel savings benefit is attributable to the natural gas price escalation rate assumed in MTEP14 (Figure 6-6).

Post MTEP14 natural gas price forecast assumptions are more closely aligned with those of MTEP11 (Figure 6-4). A sensitivity applying the MTEP15 BAU natural gas prices to the MTEP14 analysis showed a 21.7 percent reduction in year 2028 MTEP14 adjusted production cost savings.

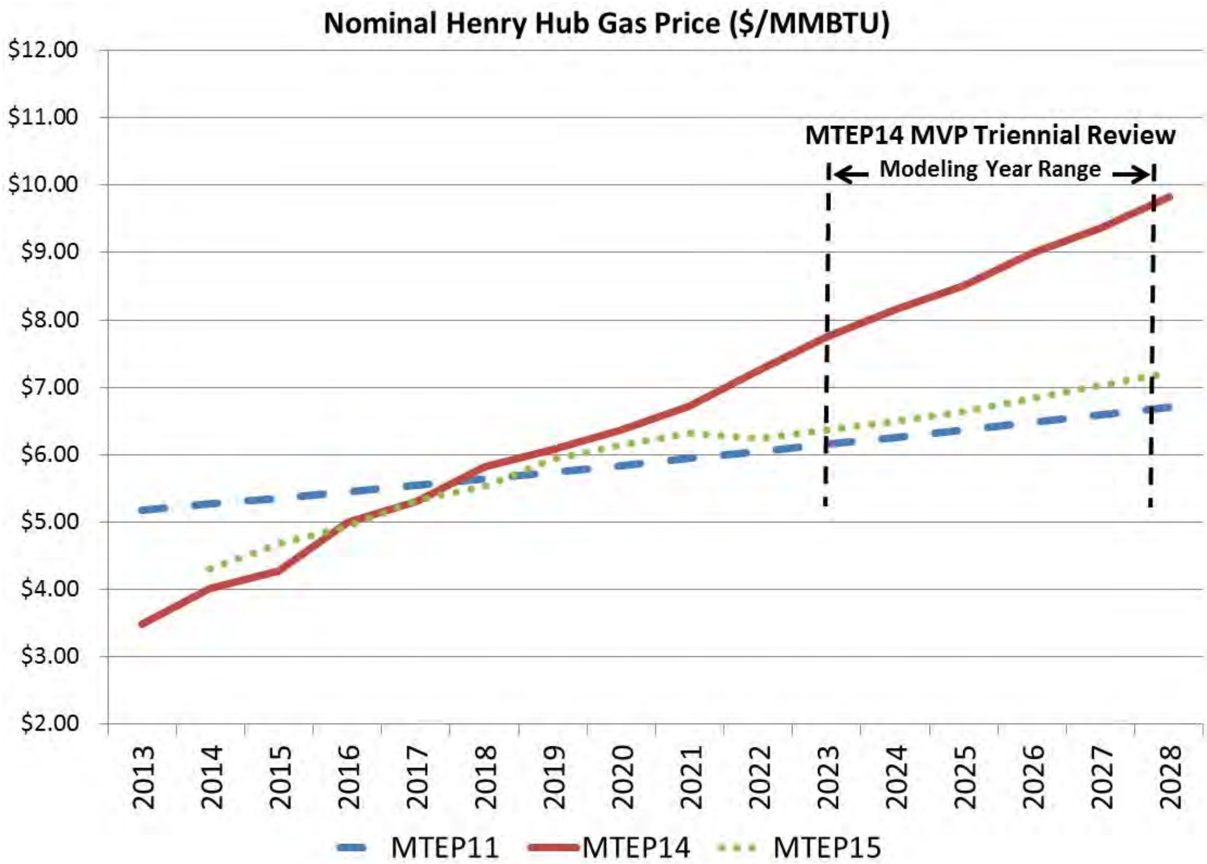

Figure 6-4: Natural Gas Price Forecast Comparison

MISO membership changes have little net effect on benefit-to-cost ratios. For example if Duke Ohio/Kentucky and First Energy's benefits and costs are either both included or excluded the benefit-to-cost ratio calculation yields similar results. The exclusion of Duke Ohio/Kentucky and First Energy from the MISO pool decreases benefits by 7.4

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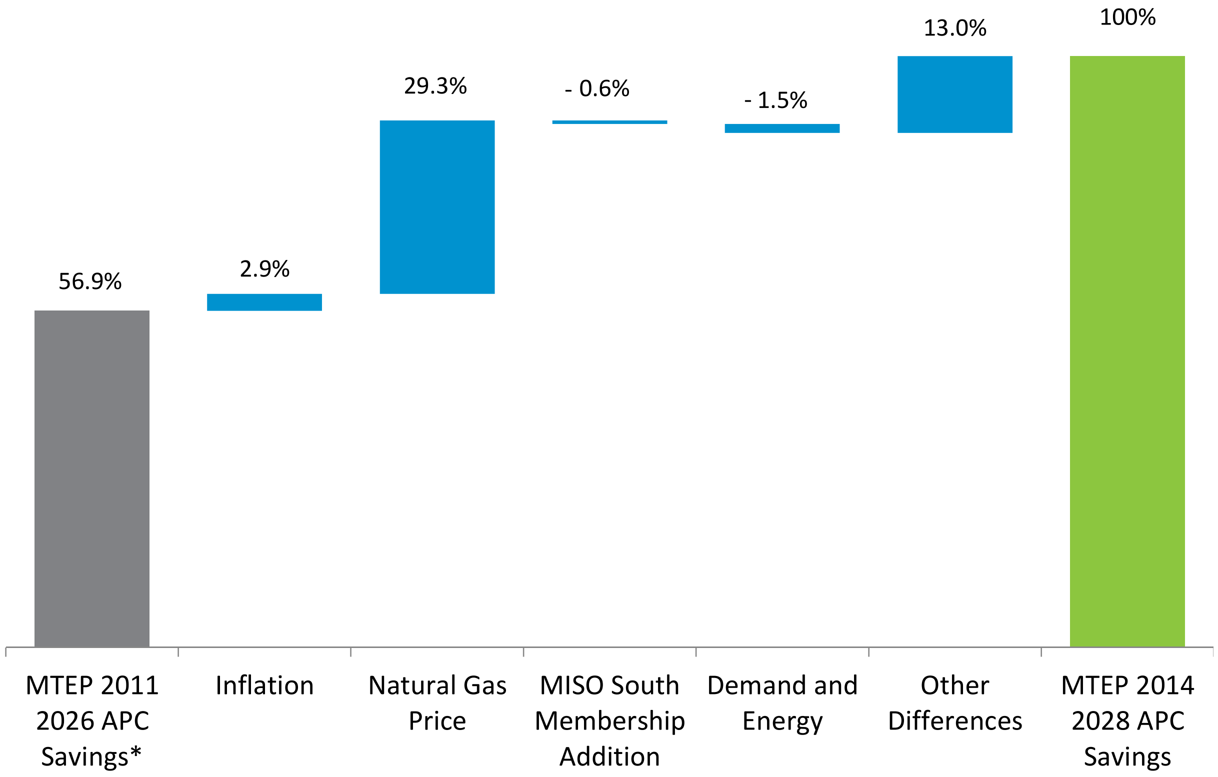
14 In the year 2028 simulation, the MVP enabled wind replaced 66% natural gas, 33% coal, and 1% other fueled units in the dispatch

percent relative to the MTEP14 total benefits; however, per Schedule 39, 6.3 percent of the total portfolio costs are allocated to Duke Ohio/Kentucky and First Energy, thus there is a minimal net effect to the benefit-to-cost ratio.

The MVP Portfolio is solely located in the MISO North and Central Regions and therefore, the inclusion of the South Region to the MISO dispatch pool has little effect on MVP related production cost savings (Figure 6-5).

Because demand and energy levels are similar between the MTEP11 Low BAU and MTEP14 cases, the updated demand and energy assumptions have little relative effect. Other Differences is calculated as the remaining difference between the MTEP14 saving and the sum of MTEP11 2026 APC Savings, Inflation, Natural Gas Prices, Footprint Changes, and Demand and Energy values. The largest modeling assumption differences in the Other Differences category is Environmental Protection Agency driven generation retirements, forecast generation siting, and topology upgrades. Other Differences also includes the compounding/synergic effects of all categories together.



**Excludes Duke Ohio/Kentucky - MTEP 2011 Business Case included Duke Ohio/Kentucky but excluded First Energy*

Figure 6-5: Breakdown of Annual Congestion and Fuel Savings Benefit Increase from MTEP11 to MTEP14 – Values a percentage of MTEP14 year 2028 Adjusted Production Cost (APC) Savings

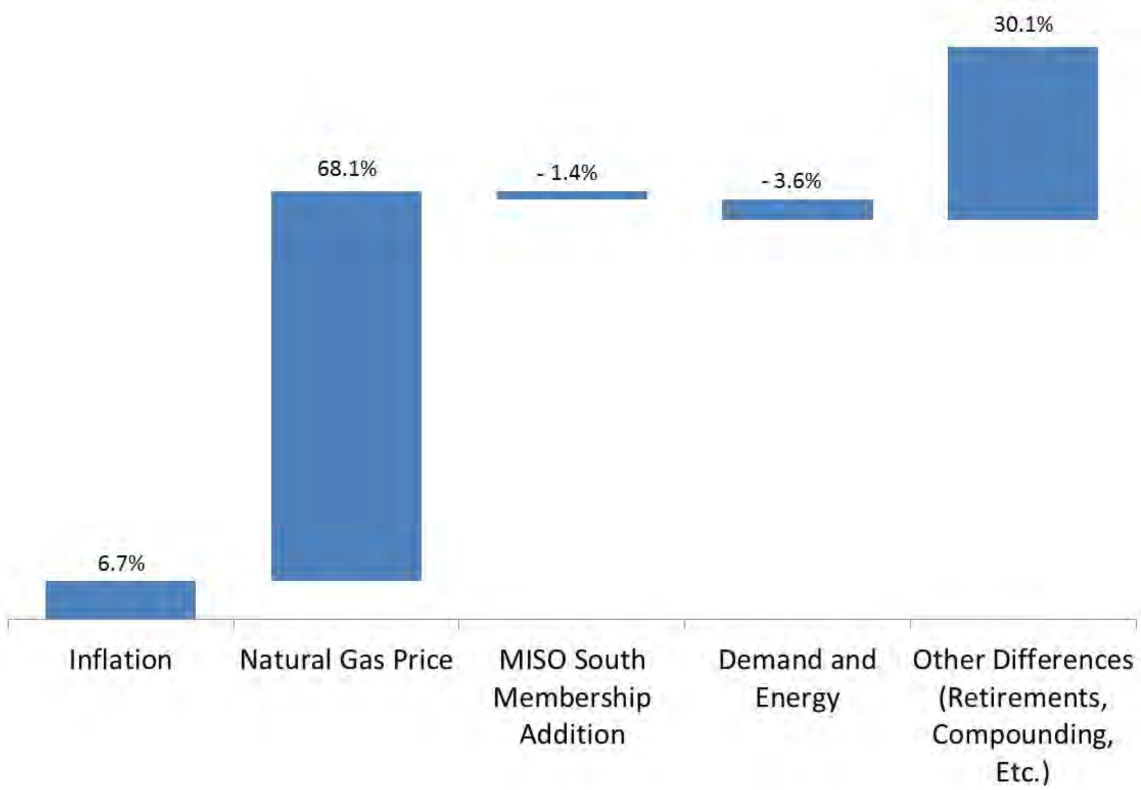


Figure 6-6: Breakdown of Annual Congestion and Fuel Savings Benefit Increase from MTEP11 to MTEP14 – Values a percentage of difference between MTEP14 year 2028 and MTEP11 year 2026 Adjusted Production Cost (APC) Savings

The MTEP14 MVP Triennial Review economic analysis was performed with 2023 and 2028 BAU future production cost models, with incremental wind mandates considered for 2023, 2028 and 2033. The 2033 case was used as a proxy case to determine the additional benefits from wind enabled above and beyond that mandated by the year 2028 (Section 5.2).

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 reduce 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. While MTEP14 analysis shows the MVP Portfolio improves flows on the flowgates for which the reserves are calculated (Table 6-3), as a conservative measure, the MTEP14 Triennial MVP Review is not estimating a reduced operating reserve benefit. Since MTEP11, a reserve requirement has been calculated only a limited number of days (Table 6-4).

As a conservative measure, the MVP Triennial Review does not estimate a reduced operating reserve benefit in MTEP14.

Zone	Limiter	Contingency	Change in Flows
Indiana	Bunsonville - Eugene 345	Casey - Breed 345	-15.0 percent
Indiana	Crete - St. Johns Tap 345	Dumont-Wilton Center 765	3.0 percent
Michigan	Benton Harbor - Palisades 345	Cook - Palisades 345	-9.4 percent
Wisconsin	MWEX	N/A	-11.6 percent
Minnesota	Arnold-Hazleton 345	N/A	23.9 percent

Table 6-3: Change in Transfers; Pre-MVP minus Post-MVP

Zone	MTEP11 (June 2010 – May 2011)			MTEP14 (January 2013 – December 2013)		
	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)
Missouri/Illinois[15]	95	1	95.1	0	0	0
Indiana	14966	53	282.4	0	0	0
Northern Ohio	9147	15	609.8	N/A	N/A	N/A
Michigan	4915	17	289.1	0	0	0
Wisconsin	227	2	113.4	0	0	0
Minnesota	376	1	376.3	32	2	16

Table 6-4: Historic Operating Requirements

MTEP11 MVP analysis concluded that the addition of the MVP Portfolio eliminated the need for the Indiana operating reserve zone and the reduction by half of additional system reserves held in other zones across the footprint. This created the opportunity to locate an average of 690,000 MWh of operating reserves annually where it would be most economical to do so, as opposed to holding these reserves in prescribed zones. MTEP11 estimated benefits from reduced operating reserves of $33 to $82 million in 20 to 40 year present value terms (Table 6-5).

	MTEP14	MTEP11[16]
3 percent Discount Rate; 20 Year Net Present Value	-	50
8 percent Discount Rate; 20 Year Net Present Value	-	34
3 percent Discount Rate; 40 Year Net Present Value	-	84
8 percent Discount Rate; 40 Year Net Present Value	-	42

Table 6-5: Reduction in Operating Reserves Benefit ($M-2014)

As operating reserve zones are determined on an ongoing basis, by monitoring the energy flowing through flowgates across the system, the benefit valuation in future MVP Triennial Reviews may provide a different result.

15 The Missouri Reserve Zone was changed to Illinois in 2012. The Illinois Reserve Zone was eliminated in September 2013

16 Average of the High and Low MTEP11 BAU Futures

6.3 Planning Reserve Margin Requirements

The MVPs increase capacity sharing between local resource zones which defers more than $900 million in future capacity expansion

MTEP14 MVP Triennial Review analysis estimates the MVPs annually defer more than 800 MW in capacity expansion by increasing capacity import limits thus reducing the local clearing requirements of the planning reserve margin requirement. Local clearing requirements are the amount of capacity that must be physically located within a resource zone to meet resource adequacy standards. The MTEP14 Review estimates that the MVPs increase capacity sharing between local resource zones (LRZ), which defers $946 to $2,746 million in future capacity expansion (Table 6-7).

In the 2013 planning year, MISO and the Loss of Load Expectation Working Group improved the methodology that establishes the MISO Planning Reserve Margin Requirement (PRMR). Previously, and in the MTEP11 analysis, MISO developed a MISO-wide PRMR with an embedded congestion component. The Candidate MVP Analysis showed the MVP Portfolio reduces total system congestion and thus reduces the congestion component of the PRMR. The MVP Portfolio allows MISO to carry a decreased PRMR while maintaining the same system reliability. The post-2013 planning year methodology no longer uses a single congestion component, but instead calculates a more granular zonal PRMR and a local clearing requirement based on the zonal capacity import limit. While terminology and methods have changed between MTEP11 and MTEP14, both calculations are capturing the same benefit of increased capacity sharing across the MISO region provided by the MVPs; as such, MTEP14 and MTEP11 provide benefit estimates of similar magnitudes (Table 6-6).

	MTEP14	MTEP11[17]
3 percent Discount Rate; 20 Year Net Present Value	1,440	2,846
8 percent Discount Rate; 20 Year Net Present Value	946	1,237
3 percent Discount Rate; 40 Year Net Present Value	2,746	3,760
8 percent Discount Rate; 40 Year Net Present Value	1,266	1,421

Table 6-6: Local Clearing Requirement Benefit ($M-2014)

[17] Average of the High and Low MTEP11 BAU Futures

Loss of load expectation (LOLE) analysis was performed to show the decrease in the local clearing requirement of the planning reserve margin requirement due to MVP Portfolio. This analysis used the 2014-2015 Planning Reserve Margin (PRM) 10-year out (2023) case. Capacity import limit increases from the MVPs were captured by comparing the zonal capacity import limits of a case with the MVP Portfolio to a case without inclusion of the MVP Portfolio. The 2023 Local Reliability Requirement (LRR) for each LRZ was determined by running GE MARS. Local clearing requirements were calculated for both the "with" and "without" MVP cases by subtracting the CIL values from the LRR values (Table 6-7).

Local Resource Zone	1	2	3	4	5	6	7	Formula Key
2023 Unforced Capacity (MW)	17,583	14,592	9,646	10,664	8,135	19,735	24,833	[A]
2023 Local Reliability Requirement Unforced Capacity (MW)	21,515	15,737	11,696	12,754	10,998	21,222	25,793	[B]
No MVP Capacity Import Limit (CIL) (MW)	5,326	2,958	1,198	4,632	5,398	5,328	3,589	[C]
MVP Capacity Import Limit (MW)	5,576	3,387	2,925	9,534	4,328	5,761	3,648	[D]
No MVP CIL Local Clearing Requirement (MW)	16,189	12,779	10,498	8,122	5,600	15,894	22,204	[E]=[B]-[C]
With MVP CIL Local Clearing Requirement (MW)	15,939	12,351	8,771	3,220	6,670	15,461	22,145	[F]=[B]-[D]
Excess capacity after LCR with No MVP CIL (MW)	1,394	1,813	-852	2,542	2,535	3,841	2,629	[G]=[A]-[E]
Excess capacity after LCR with MVP CIL (MW)	1,644	2,242	875	7,444	1,465	4,274	2,688	[H]=[A]-[F]
Deferred Capacity Value ($M-2014)			$75.8					[I]=[G]*CONE

Table 6-7: Deferred Capacity Value Calculation

The MTEP14 MVP Triennial Review analysis shows the MVP Portfolio allows 852 MW of capacity expansion deferral in LRZ 3. The deferred capacity benefit is valued using the Cost of New Entry (CONE) (Table 6-8). It's important to note that the capacity expansion deferral benefit may or may not be realized due to future market design changes around external resource capacity qualification.

The MTEP14 MVP Triennial Review methodology does not capture the MVP benefit to the capacity import of LRZ 5. This limitation is driven by the selection of generation used to perform import studies. MISO's LOLE methodology defines the selection of generation used as the source for a transfer study based on a zone's Local Balancing Area (LBA) ties. Based on its LBA ties, import studies indicate LRZ 5 primarily uses generation from the MISO South Region since its LBA ties in the North and Central Regions have very limited available capacity. The MVP facilities are not used to transfer power from the South Region so a benefit for LRZ 5 is not quantified.

Local Resource Zone	Cost of New Entry ($/MW-year)
1	89,500
2	90,320
3	88,450
4	89,890
5	91,610
6	89,670
7	90,100

Table 6-8: Cost of New Entry for Planning Year 2014/15[18]

[18] From MISO Business Practice Manual 011 Resource Adequacy – January 2014

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.

Reflective of MISO's tighter reserve margins, the value of MTEP14 capacity deferment benefits from reduced losses has increased

The MTEP14 Review found that system losses decrease by 122 MW with the inclusion of the MVP Portfolio. MTEP11 estimates that the MVPs reduced losses by 150 MW. The difference between MTEP11 and MTEP14 results is attributed to decreased system demand, the MISO North and Central Regions membership changes, and transmission topology upgrades in the base model.

Tightening reserve margins, from an additional approximate 12 GW of expected generation retirements due mostly to emissions compliance restrictions, have increased the value of deferred capacity from transmission losses in MTEP14. In MTEP11, baseload additions were not required in the 20-year capacity expansion forecast to maintain planning reserve requirements. In MTEP11, the decreased transmission losses from the MVP Portfolio allowed the deferment of a single combustion turbine. In MTEP14, the decreased losses cause a large shift in the proportion of baseload combined cycle units and peaking combustion turbines in the capacity expansion forecast.

In addition to the tighter reserve margins, a one-year shift forward in the MVP Portfolio expected in-service date relative to MTEP11, has increased benefits by approximately 30 percent. In MTEP11, the MVP Portfolio's expected in-service date was year 2021. In MTEP14, the MVP's Portfolio's expected in-service date has shifted to year 2020. Given current reserve margins, additional capacity is needed as soon as year 2016 to maintain out-year reserve requirements. The in-service date shift forward allows earlier access to the 122 MW of reduced losses which allows earlier and less discounted deferment of capacity expansions.

The combined result of the tighter reserve margins and in-service date shift has caused the estimated benefits from reduced transmission line losses to more than double compared to the MTEP11 values (Table 6-9). Using current capital costs, the deferment equates to a savings of $291 to $1,079 million ($-2014), excluding the impacts of any potential future policies.

	MTEP14	MTEP11[19]
3 percent Discount Rate; 20 Year Net Present Value	734	227
8 percent Discount Rate; 20 Year Net Present Value	291	287
3 percent Discount Rate; 40 Year Net Present Value	1,079	315
8 percent Discount Rate; 40 Year Net Present Value	401	327

Table 6-9: Transmission Line Losses Benefit ($M-2014)

The benefit valuation methodology used in the MTEP14 Review is identical to that used in MTEP11. The transmission loss reduction was calculated by comparing the transmission line losses in the 2023 summer peak powerflow model both with and without the MVP Portfolio. This value was then used to extrapolate the transmission line losses for 2018 through 2023, assuming escalation at the business as usual 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.

MVP benefits from the optimization of wind generation siting remain similar in magnitude since MTEP11

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

During the Regional Generator Outlet Study (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.

[19] Average of the High and Low MTEP11 BAU Futures

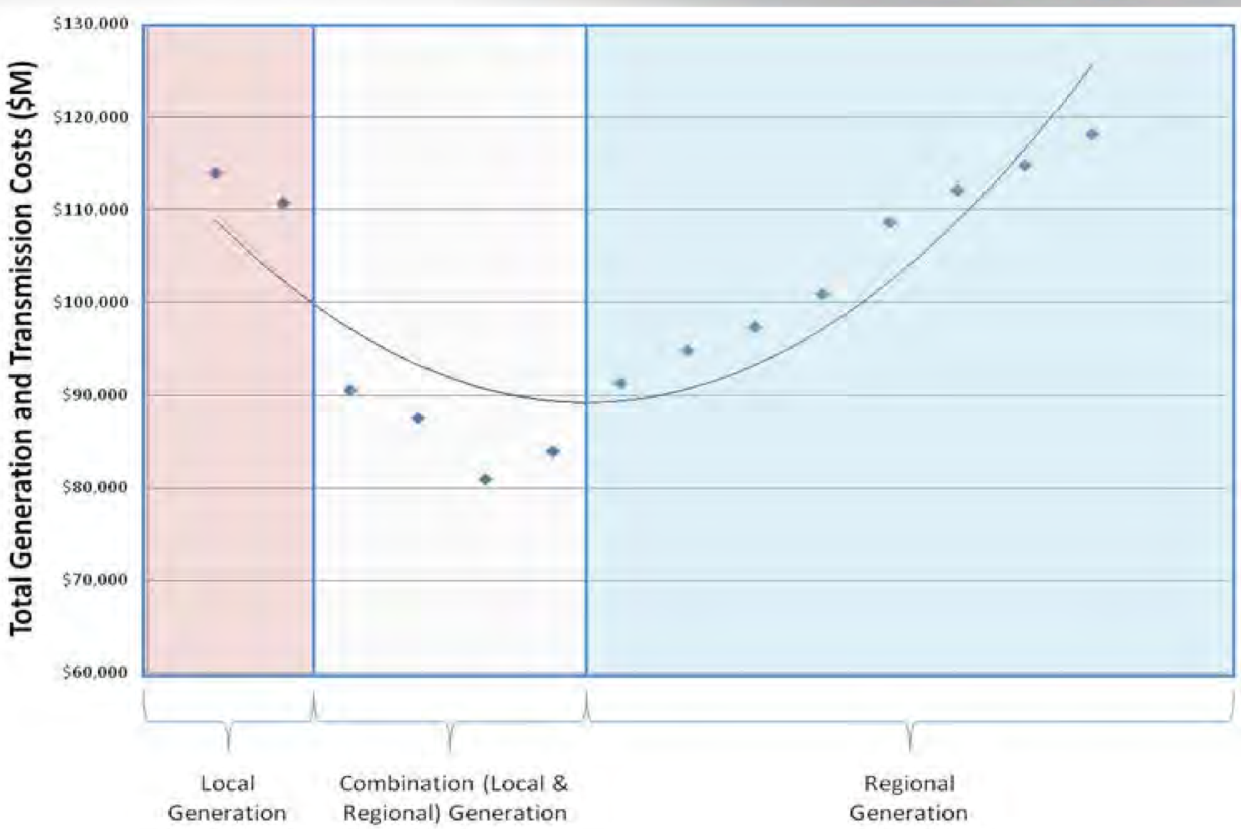


Figure 6-7: Local versus Combination Wind Siting

The MTEP14 Triennial MVP Review found that the benefits from the optimization of wind generation siting remain similar in magnitude since MTEP11 (Table 6-10). The slight increase in MTEP14 benefits relative to MTEP11 is from an update to the wind requirement forecast and wind enabled calculations. The MTEP14 Review found that the MVPs reduce turbine capital investments by 3,262 MW through 2028, compared to 2,884 MW through 2026 in MTEP11.

	MTEP14	MTEP11[20]
3 percent Discount Rate; 20 Year Net Present Value	2,192	1,850
8 percent Discount Rate; 20 Year Net Present Value	2,523	2,222
3 percent Discount Rate; 40 Year Net Present Value	2,192	1,850
8 percent Discount Rate; 40 Year Net Present Value	2,523	2,222

Table 6-10: Wind Turbine Investment Benefit ($M-2014)

[20] Average of the High and Low MTEP11 BAU Futures

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 3.2 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-2018	16,403	18,246	1,843
2018	20,289	22,568	2,279
2023	22,946	25,524	2,578
2028	24,702	27,477	2,775
Full Wind Enabled	29,037	32,299	3,262

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

The incremental wind benefits were monetized by applying a value of $2 to $2.8 million/MW, based on the U.S. Energy Information Administration's estimates of the capital costs to build onshore wind[21]. The total wind enabled benefits were then spread over the expected life of a wind turbine. Consistent with the MTEP11 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.

[21] Value as of November 2013

6.6 Future Transmission Investment

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

MTEP14 analysis shows the MVP Portfolio eliminates the need for $300 million in future baseline reliability upgrades.

	MTEP14	MTEP11[22]
3 percent Discount Rate; 20 Year Net Present Value	674	521
8 percent Discount Rate; 20 Year Net Present Value	327	286
3 percent Discount Rate; 40 Year Net Present Value	1,223	931
8 percent Discount Rate; 40 Year Net Present Value	452	394

Table 6-12: Future Transmission Investment Benefits ($M-2014)

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 2033 summer peak load conditions was created by growing the load in the 2023 summer peak model by approximately 8 GW. The 2033 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).

[22] Average of the High and Low MTEP11 BAU Futures

Avoided Investment	Upgrade Required	Miles
New Carlisle - Olive 138 kV	Transmission line, < 345 kV	2.0
Reynolds 345/138 kV Transformer	Transformer	N/A
Lee - Lake Huron Pumping Tap 120 kV	Transmission line, < 345 kV	8.5
Waterman - Detroit Water 120 kV	Transmission line, < 345 kV	2.9
Dresden - Electric Junction 345 kV	Transmission line, 345 kV	31.1
Dresden - Goose Lake 138 kV	Transmission line, < 345 kV	5.8
Golf Mill - Niles Tap 138 kV	Transmission line, < 345 kV	2.5
Boy Branch - Saint Francois 138 kV	Transmission line, < 345 kV	7.1
Newton - Robinson Marathon 138 kV	Transmission line, < 345 kV	34.3
Weedman - North Leroy 138 kV	Transmission line, < 345 kV	3.6
Wilmarth - Eastwood 115 kV	Transmission line, < 345 kV	4.6
Swan Lake - Fort Ridgely 115 kV	Transmission line, < 345 kV	13.2
Black Dog - Pilot Knob 115 kV	Transmission line, < 345 kV	10.3
Lake Marion - Kenrick 115 kV	Transmission line, < 345 kV	3.5
Johnson Junction - Ortonville 115 kV	Transmission line, < 345 kV	24.7
Maquoketa - Hillsie 161 kV	Transmission line, < 345 kV	12.0
New Iowa Wind - Lime Creek 161 kV	Transmission line, < 345 kV	10
Lore - Turkey River 161 kV	Transmission line, < 345 kV	19.6
Lore - Kerper 161 kV	Transmission line, < 345 kV	7.0
Salem 161 kV Bus Tie	Bus Tie	N/A
8th Street - Kerper 161 kV	Transmission line, < 345 kV	2.6
Rock Creek 161 kV Bus Tie	Bus Tie	N/A
Beaver Channel 161 kV Bus Tie	Bus Tie	N/A
East Calamus - Grand Mound 161 kV	Transmission line, < 345 kV	2.6
Dundee - Coggon 161 kV	Transmission line, < 345 kV	18.1
Sub 56 (Davenport) - Sub 85 161 kV	Transmission line, < 345 kV	3.8
Vienna - North Madison 138 kV	Transmission line, < 345 kV	0.2
Townline Road - Bass Creek 138 kV	Transmission line, < 345 kV	11.8
Portage - Columbia 138 kV Ckt 2	Transmission line, < 345 kV	5.7
Portage - Columbia 138 kV Ckt 1	Transmission line, < 345 kV	5.7

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 since the MTEP11 analysis. Transmission investment costs were assumed to be spread between 2029 and 2033. 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.

> 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.

7.1 Enhanced Generation Flexibility

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).

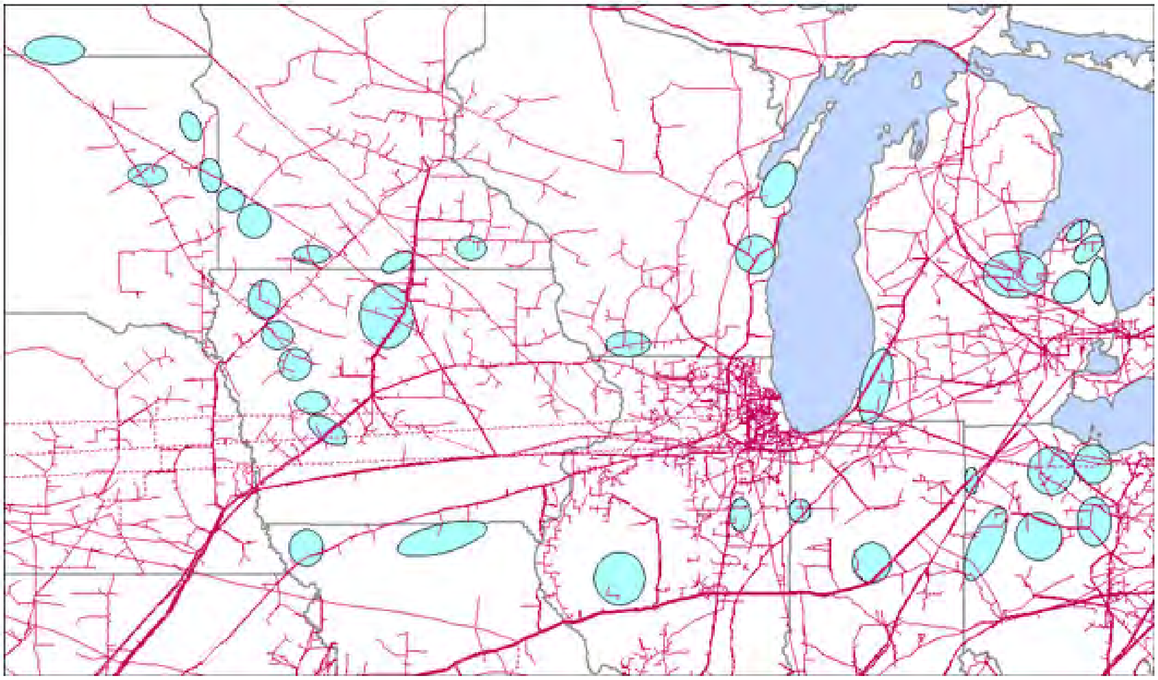


Figure 7-1: Energy Zone Correlation with Natural Gas Pipelines

7.2 Increased System Robustness

A transmission system blackout, or similar event, can have wide spread 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. Assuming a natural gas price increase of 25 percent to 50 percent, 2014 analysis shows the MVP Portfolio provides approximately a 24 to 45 percent higher adjusted production cost benefits.

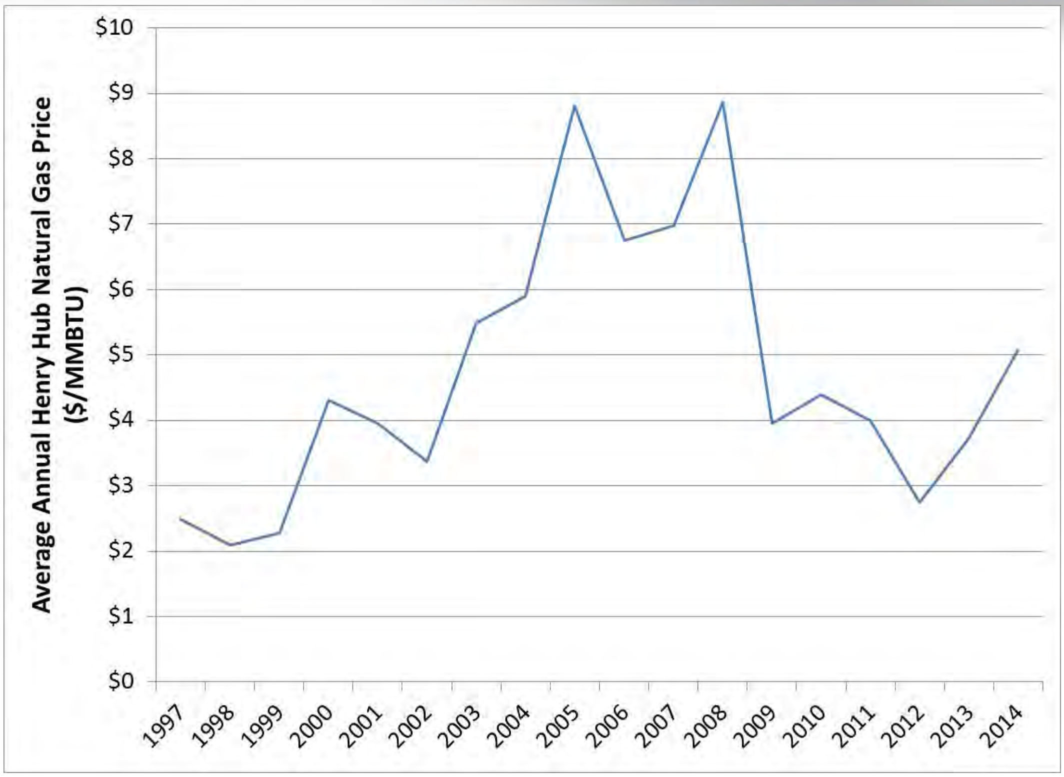


Figure 7-2: Historic Henry Hub Natural Gas Prices

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 increased from $3.50 to $4.35 and $5.22/MMBTU and then escalated to year 2028 using MTEP14 rates.

The system production cost is driven by many variables, including fuel prices, carbon emission regulations, variable operations, management costs and renewable energy mandates. The increase in natural gas prices imposed additional fuel costs on the system, which in turn produced greater production cost benefits due to the inclusion of the MVP Portfolio. These increased benefits were driven by the efficient usage of renewable and low cost generation resources (Figure 7-3).

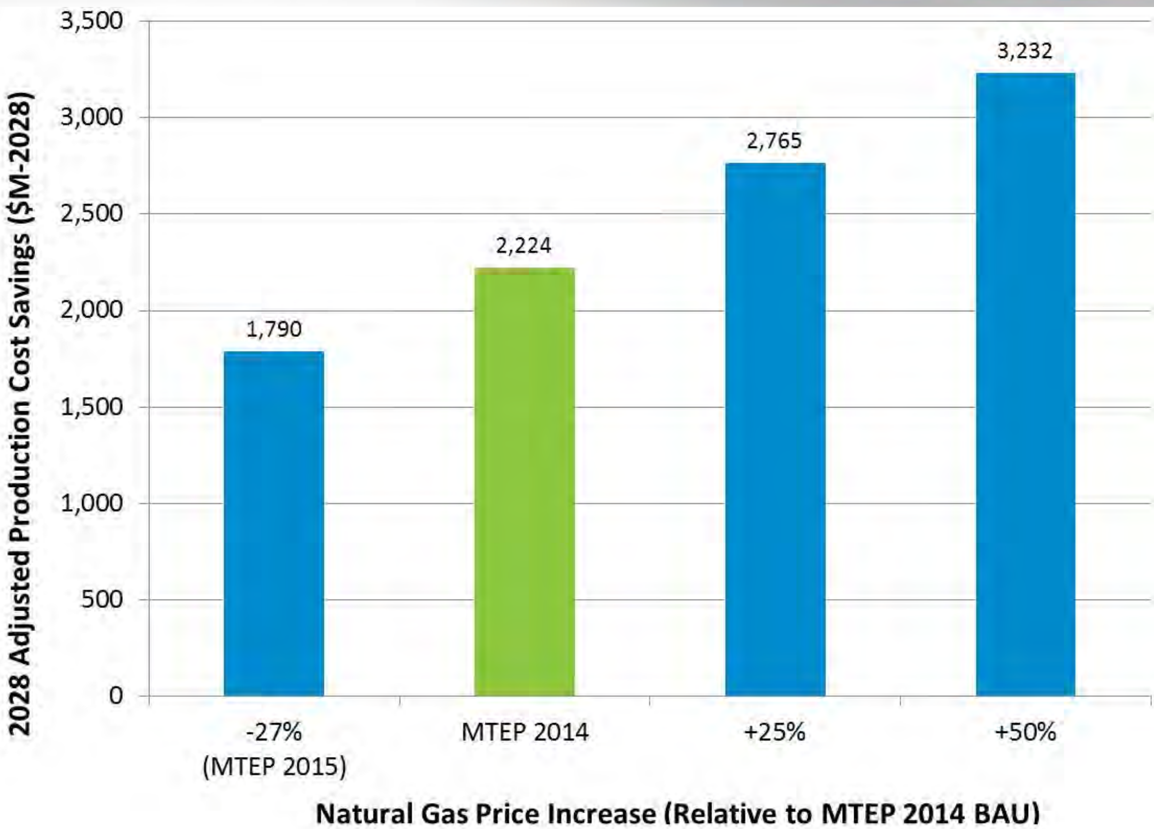


Figure 7-3: MVP Portfolio Adjusted Production Cost Savings by Natural Gas Price

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.

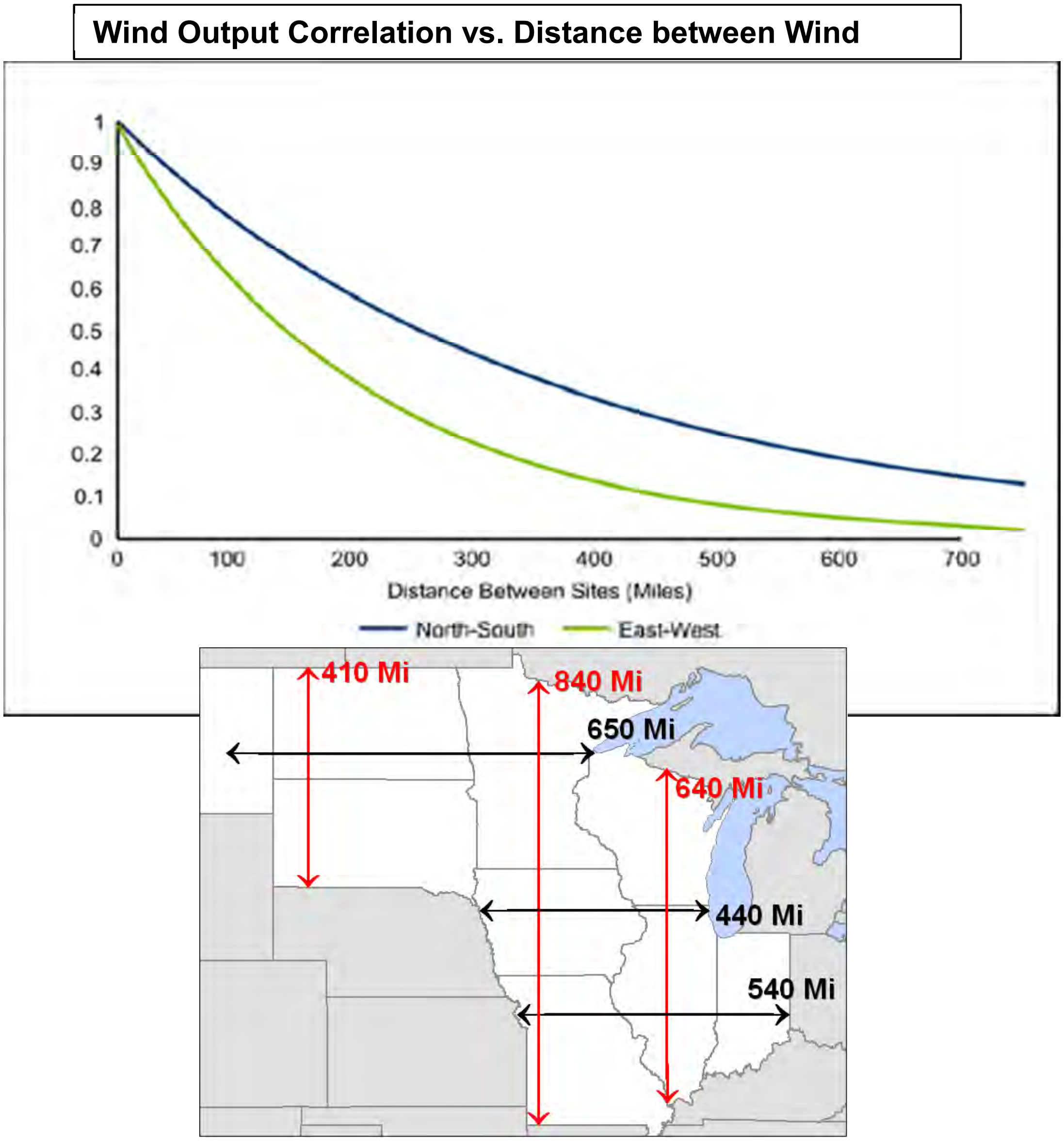


Figure 7-4: Wind Output Correlation to Distance between Wind Sites

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. Going forward, MISO is exploring the use of the IMPLAN model to quantify the direct, indirect, and induced effects on jobs and income related to transmission construction.

7.6 Carbon Reduction

The MVP Portfolio reduces carbon emissions by 9 to 15 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.

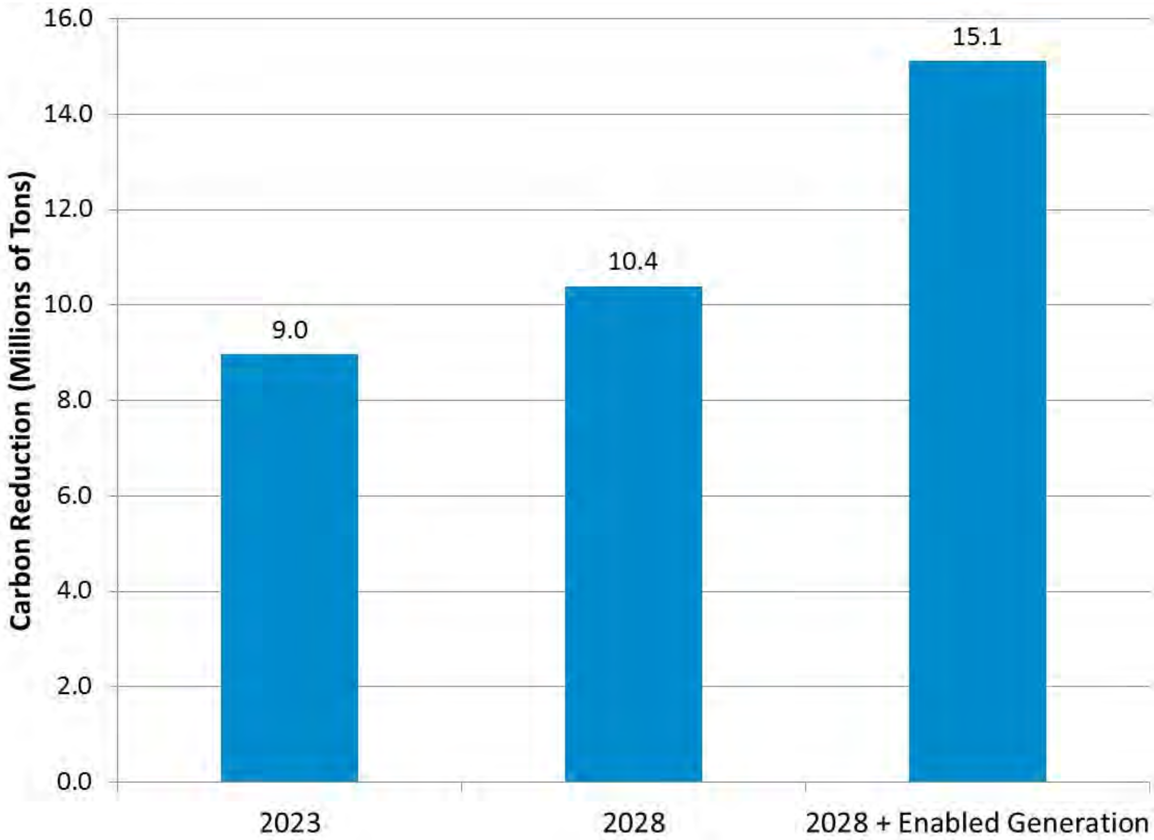


Figure 7-5: Forecasted Carbon Reduction from the MVP Portfolio by Year

8. Conclusions and Going Forward

The MTEP14 Triennial MVP Review provides an updated view into the projected economic, public policy and qualitative benefits of the MTEP11 MVP Portfolio. Analysis shows Multi-Value Project benefit-to-cost ratios have increased from 1.8 to 3.0 to a range of 2.6 to 3.9 since the MTEP11 analysis. Benefit increases are primarily congestion and fuel savings largely driven by natural gas prices.

The MTEP14 MVP Triennial Review's business case is on par with, if not stronger than, MTEP11 providing proof that the MVP criteria and methodology is working as expected. While the economic cost savings provide further benefit, the updated MTEP14 assessment corroborates the MVP Portfolio's ability to enable the delivery of wind generation in support of the renewable energy mandates of the MISO states in a cost effective manner.

Results prepared through the MTEP14 Triennial Review are for information purposes only and have no effect on the existing MVP Portfolio status or cost allocation.

MTEP15 and MTEP16 will feature a Limited Review of the MVP Portfolio benefits. Each Limited Review will provide an updated assessment of the congestion and fuel savings (Section 6.1) using the latest portfolio costs and in-service dates. Beginning in MTEP17, in addition to the Full Triennial Review, MISO will perform an assessment of the congestion costs, energy prices, fuel costs, planning reserve margin requirements, resource interconnections and energy supply consumption based on historical operations data.

Appendix

Detailed Transfer Analysis Results

LRZ	FCITC	Import Limit (CIL in MW)	Monitored Element	Contingency
1	-209	5,576	631115 OTTUMWA5 161 631116 BRDGPRT5 161 1	C:631115 OTTUMWA5 161 631134 TRICNTY5 161 1
2	-146	3,387	270810 LOCKPORT; B 345 274702 KENDALL; BU 345 1	C:270811 LOCKPORT; R 345 274703 KENDALL; RU 345 1
3	810	2,925	630388 WINCOR 8 69.0 630395 WNTRSET8 69.0 1	C:635631 BOONVIL5 161 635632 EARLHAM5 161 1
4	9,913	9,534	Limited by generation in tiers 1 and 2 - resulting limit considering Tier 1 and 2 available capacity and base interchange	
5	3,027	4,328	337651 8WHT BLUFF percent 500 337957 8KEO percent 500 1	C:P1_2-1312
6	2,002	5,761	243212 05BENTON 345 243250 05BENTON 138 1	C:P1_2_EXT_31
7	987	3,648	256290 18TITBAW 138 256542 18REDSTONE 138 1	C:b|18BULOCK-18SUMRTN 138-1

Table A-1: With MVP Capacity Import Limits

LRZ	FCITC	Import Limit (CIL in MW)	Monitored Element	Contingency
1	-204	5,326	699211 PT BCH3 345 699630 KEWAUNEE 345 1	C:ATC_B2_NAPL121
2	-237	2,958	270810 LOCKPORT; B 345 274702 KENDALL; BU 345 1	C:345-L10806_R-S
3	-564	1,198	300049 7THOMHL 345 300120 5THMHIL 161 1	C:345088 7MCCREDIE 345 345408 7OVERTON 345 1
4	4,429	4,632	256026 18THETFD 345 264580 19JEWEL 345 1	C:b|19BAUER-19PONTC 345-1
5	3,917	5,398	337651 8WHT BLUFF percent 500 337957 8KEO percent 500 1	C:P1_2-1312
6	1,277	5,328	256026 18THETFD 345 264580 19JEWEL 345 1	C:b|19BAUER-19PONTC 345-1
7	470	3,589	264522 19MENLO1 120 264947 19BUNCE2 120 1	C:x|19GRNEC 345-120-1

Table A-2: Without MVP Capacity Import Limits