Exhibit No.:	
Issue:	Public Interest Transmission Planning
Witness:	Jameson T. Smith
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Midcontinent Independent System Operator, Inc.
Case No:	EA-2015-0146
Date Testimony Prepared:	November 16, 2015

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EA-2015-0146

SURREBUTTAL TESTIMONY

OF

JAMESON T. SMITH

SUBMITTED ON BEHALF

of

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. (MISO)

Kansas City, Missouri
November 16, 2015

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name, business address, and present position.

A. My name is Jameson Smith. I am employed by the Midcontinent Independent System Operator, Inc. ("MISO") as the Director of Policy Studies. My business address is Two Lakeway, 3860 N. Causeway Boulevard, Suite 442, Metairie, Louisiana 70002.

Q. What is MISO?

A. MISO is a not-for-profit, member-based, regional transmission organization ("RTO") providing reliability and market services over 65,700 miles of transmission lines in fifteen states and one Canadian province. MISO's regional area of operations stretches from the Ohio-Indiana line in the east to eastern Montana in the west, and south to New Orleans. MISO is governed by an independent Board of Directors.

MISO's responsibilities include the development of the MISO Transmission Expansion Plan ("MTEP") in collaboration with transmission owners and stakeholders. MISO adheres to the nine planning principles outlined in FERC Order No. 890.[1] In so doing, MISO provides an open and transparent regional planning process. FERC Order No. 1000 furthered the planning principles outlined in FERC

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

Order No. 890, and included the requirements to plan for public policy and for coordinated inter-regional planning and cost allocation.[2] The MTEP process (i) identifies transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of MISO, (ii) identifies expansion that is critically needed to support the reliable and competitive supply of electric power by this system, and (iii) identifies expansion that is necessary to support energy policy mandates.

Q. What are MISO's responsibilities?

A. As an RTO, MISO is responsible for operational oversight and control, market operations, and for coordination of the planning and expansion of the transmission systems that are under its control. Among many other responsibilities, MISO monitors and calculates Available Flowgate Capability and provides tariff administration for its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"),[3] which has been accepted by the Federal Energy Regulatory Commission.[4] MISO is the Reliability Coordinator for its regional area of operations, providing real-time operational monitoring and control of the transmission system. MISO operates real-time and a day-ahead energy markets based on

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[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 66,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

[3] MISO Tariff, available at: https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx

[4] MISO's Tariff was initially accepted by FERC in 1998, but was suspended until subsequently adopted in 2001. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,326 (2001); *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,033 (2001), *order on reh'g*, 98 FERC ¶ 61,141 (2002). MISO began providing transmission service under its Tariff in 2002.

Locational Marginal Prices ("LMPs") in which each market participant's offer to supply energy is matched to demand and is cleared based on a security constrained economic dispatch process – resources on the system are dispatched to minimize the cost of energy production while respecting the reliability limitations of the system. In addition, MISO operates a market for Financial Transmission Rights, which are used by market participants to hedge against congestion costs, and an ancillary services market, which provides for the services necessary to support transmission of capacity and energy from resources to load.

MISO is responsible for approving transmission service, new generation interconnections, and new transmission interconnections within the MISO's regional area of operations, and for ensuring that the system is planned to reliably and efficiently provide for existing and forecasted usage of the transmission system. MISO is the Planning Coordinator for its regional area of operations, which includes portions of Missouri, and performs planning functions collaboratively with transmission owners with stakeholder input – state regulatory authorities (the Organization of MISO States as well as individual authorities), public consumer advocates, environmental representatives, end-use customers, independent power producers, and others – throughout the process. MISO provides an independent assessment and perspective of the needs of the overall transmission system.

Q. What is your educational background?

A. I graduated from Mississippi State University with a Bachelor of Science degree in Electrical Engineering. I received a Master of Business Administration degree from Oklahoma State University.

Q. Are you a professional engineer?

A. Yes. I am a registered professional engineer in the State of Oklahoma, License No. PE22110.

Q. What is your professional experience?

A. In January 2001, I was employed by American Electric Power as a transmission planning engineer for its holdings located in the Southwest Power Pool. I performed transmission planning studies for four states, and conducted analyses for annual forward planning, generation interconnection, load interconnection, and voltage stability.

I have been employed by MISO since January 2006 when I became a resource forecasting engineer in MISO's Transmission Asset Management Division ("TAM"). In this role, I participated in the development of the economic planning processes performed today, and have run the resource expansion and production cost models utilized in that process. During my time in this group, I was also the project manager for the study that identified the candidate Multi Value Projects ("MVPs"), the final results from which are discussed in my testimony, for the MISO footprint as it existed in 2010.

In September 2010, I transitioned to the role of Manager of Policy Studies within TAM. My team was responsible for working with stakeholders to evaluate emerging economic and policy trends and their impacts on the bulk electric system. Most of these studies focus on the impact of renewable portfolio standard ("RPS")/renewable energy standard ("RES") and environmental rulemakings.

In August 2014, I undertook my current position as the Director of Policy Studies at MISO.

Q. What are your duties and responsibilities in your present position as Director of Policy Studies?

A. My current duties involve providing corporate direction to the Policy Studies management and team where the objective is to evaluate macroeconomic and public policy impacts on the bulk electric system. I am directly involved in MISO's review of the recent Clean Power Plan ("CPP") final rule recently adopted by the United States Environmental Protection Agency and the impacts of greater dependence on natural gas within areas where MISO operates. I am involved in execution of the economic planning processes connected with the annual evaluation of MISO Transmission Expansion Plan ("MTEP") projects.

Q. What is MTEP?

A. MISO reviews the local planning activities of individual transmission owners with stakeholders regarding the adequacy and appropriateness of the local plans in a coordinated fashion with all other local plans. MISO seeks to ensure that all of the needs are met cost effectively. MISO considers, together with stakeholders, opportunities for improvements and expansions that would reduce costs by providing electric suppliers access to new, low cost resources that are consistent with and required by legislative energy policies. MISO's planning process examines transmission congestion that may limit access to the most efficient resources, and considers improvements that are needed to meet forecasted energy requirements. Stakeholders from each MISO member sector – state regulatory authorities, public consumer advocates, environmental representatives, end-use customers, independent power producers, and others – are engaged to develop future system scenarios from assessments of possible future state and federal energy policy decisions.

II. PURPOSE AND SCOPE

Q. Are you familiar with the transmission project proposed in the Application filed by Ameren Transmission Company of Illinois ("ATXI")?

A. Yes. ATXI filed an Application in this docket seeking a certificate of public convenience and necessity. ATXI seeks authorization to construct, operate, and maintain the Mark Twain facilities (also referred to as the "Project"). The Mark Twain facilities include 95 miles of high voltage electric transmission lines and related facilities. The Project generally contains the following elements: high voltage 345 kV transmission facilities running generally from Palmyra, Missouri and extending westward to a new substation located near Kirksville, Missouri as well as a 345-kV transmission line running from the new substation north to the Iowa border.

Q. Have you reviewed the pre-filed rebuttal testimony of Neighbors United Against Ameren's Power Line ("Neighbors") witness William E. Powers?

A. Yes. I have reviewed the rebuttal testimony submitted by Neighbors witness Powers, as well as related testimony filed by Staff witnesses.

Q. What is the purpose of your testimony?

A. I respond to matters raised in the rebuttal testimony of Neighbors witness Powers. I address issues regarding the role played by renewables in MISO's transmission planning process as well as issues involving that process as it specifically relates to the MVP portfolio and the Mark Twain portion of that portfolio.

Q. Please elaborate on any special terminology that you will use in this testimony.

A. I will refer to the "MISO footprint" in my testimony. Unless otherwise specified, this footprint refers to MISO's regional area of operations at the time of the approval of the MVP portfolio in 2011.

Q. What analyses form the basis of your testimony?

A. The Mark Twain project is part of a MVP portfolio, a report concerning which ("Multi Value Portfolio Report") is attached as Schedule JTS-S-1 of my testimony in this case.[5] The portfolio was approved by the MISO Board of Directors on December 8, 2011 as part of MISO's MTEP 11.[6] This approval was based on a set of reliability, economic, and public policy analyses conducted in 2011 that documented the reliability benefits of the Mark Twain project and the combined reliability, economic, and public policy benefits of the full MVP portfolio. My testimony also includes as Schedule JTS-S-2 the results of the MTEP 14 MVP Triennial Review ("Triennial Review") of the economic and public policy benefits of the MVP portfolio that was conducted in 2014.[7] The Triennial Review was

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5 As examples, page 14 of the Powers rebuttal testimony cites the report, as does the rebuttal testimonies of Staff members Stahlman (page 3), and Lange (pages 6-8). A copy of the report is publicly available at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf.

6 *See* MTEP 2011 Report, publicly available at: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf.

7 A copy of MISO's publicly available MTEP 14 MVP Triennial Review (August 2014) ("Triennial Review") is also available at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/DRAFT_MTEP14%20MVP%20Triennial%20Review%20Report.docx.

conducted according to a Tariff requirement to conduct a full review of the MVP portfolio benefits on a triennial basis.

III. MISO REGIONAL TRANSMISSION PLANNING

A. Wind Development in the MISO Footprint

Q. Page 10 of Mr. Powers' rebuttal testimony contains a section entitled, "No Wind Projects Proposed in Northeast Missouri, that Have Completed the MISO Interconnection Study Process, Have Been Stalled by Lack of Transmission Capacity." Do you agree with this heading?

A. Not necessarily. At a bare minimum, the heading reflects an incomplete treatment of the topic

Q. Do you agree with the overall content of that same section (Section V., pages 10 through 13) of Mr. Powers' rebuttal testimony?

A. No. The overall message of that Section V. in Mr. Powers' rebuttal testimony seems to be that the Project is not needed to facilitate and deliver regionally-based, wind-powered renewable energy. That message conflicts with the basic purpose of the collaborative effort that developed the MVP portfolio of transmission projects.

Q. What was the goal underlying the MVP portfolio?

A. The overall purpose of the MVP analysis was to design a transmission portfolio to promote public policy goals by taking advantage of the linkages between local and regional economic and reliability benefits and by promoting a competitive and efficient electric market within MISO. The portfolio was designed using economic and reliability analyses, applying several future scenarios concerning such matters as future environmental restrictions on the generation of electricity to assist in the development of a portfolio of transmission projects that would be robust under a number of potential energy policies.

Q. Were wind power projects, the subject of Section V. of the Powers rebuttal testimony, important to MISO's MVP analyses?

A. Yes. The MVP portfolio is a group of transmission projects distributed across the MISO footprint that enable the reliable delivery of the requirements of state policies regarding renewable energy (oftentimes referred to as RPS or RES mandates). The MVP portfolio was planned to provide economic benefits in excess of costs to the MISO footprint, primarily by reducing generator production costs.

Q. Was an approximately 300 MW wind project located in Northeastern Missouri part of the MISO interconnection queue in 2007, as stated on page 10 of the Powers rebuttal testimony?

A. Yes.

Q. Did the Missouri wind project go into production?

A. No. This final result is correctly stated on page 12 of the Powers rebuttal testimony.

Q. How does this result compare with other experiences during the same time period for wind projects in the MISO footprint?

A. Unfortunately, this result was typical of the results for wind projects in the period before development of the MVP portfolio of transmission projects. Wind projects were proposed and entered the interconnection queue, only to be cancelled when faced with the interconnection and other costs mentioned on page 11 of the Powers rebuttal testimony. This includes approximately

1,200 MW of wind in Northeast Missouri. MISO studied this problem in collaboration with stakeholders from each MISO member sector, including state regulatory authorities, public consumer advocates, environmental representatives, end use customers, and independent power producers.

Q. What were the results of this collaboration?

A. MISO undertook a multi-year planning process aimed at addressing the regional transmission plans necessary to enable RPS mandates to be met at the lowest delivered wholesale energy cost. This effort was known as the Regional Generation Outlet Study ("RGOS"), and was conducted between 2008 and 2010.[8] The RGOS identified energy production zones in which mandated (renewable) energy production could locate, and indicative transmission options that would provide sufficient transmission capacity needed for the efficient and reliable delivery of new generation capacity to meet the combined renewable portfolio standards of the MISO region while providing value across the MISO footprint.

Zone selection involved MISO staff and extensive stakeholder interaction, including discussions with various state and regulatory agencies within the MISO footprint. These included the Midwest Governors Association, the Organization of MISO States, and the Upper Midwest Transmission Development Initiative. The indicative plans were further consolidated into a

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[8] *See* MISO's Regional Generation Outlet Study, publicly available at: https://www.misoenergy.org/Planning/Pages/RegionalGenerationOutletStudy.aspx.

candidate MVP portfolio and evaluated for effectiveness in meeting the RGOS objectives. The analysis balanced relative wind capacities with distances from natural gas pipelines and interconnection with the existing transmission infrastructure.

Q. Are the wind zones identified in the RGOS shown in Mr. Powers' testimony on page 14 the only areas from where wind generation could be sourced to bring renewable energy to Missouri?

A. No. MISO identified a number of zones throughout the MISO footprint that could be utilized to meet the energy requirements of the various renewable portfolio regulations. The MVP portfolio is designed to enable the utilization of regional and/or local renewable resources to mitigate total costs for meeting the policy requirements.

Q. Will the Mark Twain Project assist Missouri in meeting its renewable obligations, even if no wind generation is developed in the areas in Missouri shown on the RGOS map?

A. Yes. The Mark Twain Project, as part of the MVP portfolio, plays an important role in meeting the Missouri obligations. The Project allows for the development of local wind to take advantage of in-state incentives and for access to remote regions to take advantage of resources whose capacity factors are significantly higher than those in Missouri in order to reduce the overall cost for compliance with the portfolio requirement.

Q. What would be the impact on the MISO regional plan if the Mark Twain facilities are not constructed as planned?

A. The MTEP designs a complex system that will serve both short- and long-term needs of the bulk electrical grid in a coordinated manner. The inability to construct a key element of the regional expansion plan, especially a "backbone" element such as the one proposed in the Application that is designed for both reliability and its economic attributes, will result in the loss of the economic benefits provided by the project and the need to develop less optimal solutions to reliability concerns. A revised plan would not provide the same positive economic opportunities for customers in Missouri and elsewhere that are provided by the plan that includes the Mark Twain facilities.

B. <u>Reliability Benefits</u>

Q. Page 24 of Mr. Powers' rebuttal testimony states that "MISO assumes that the Adair-to-Novelty line has a rating of 167 MW" and Mr. Powers also states that "ATXI confirm[ed] that the rated capacity . . . is 285, or approximately 285 MW . . . ." Do these figures conflict with one another?

A. No, I have no reason to doubt either figure since they were stated for different time periods that are approximately five years apart from one another. The line rating from ATXI in discovery during this case appears to reflect the current (2015) rating for the line. The MISO studies were earlier in time, during the planning stage for the MVPs.

Q. Does your response mean that the Adair-to-Novelty line will not be overloaded as previously projected?

A. Not necessarily. The overload condition depends upon a number of factors, including the amount of generation that injects into the transmission system. Withdrawal of a single project from the interconnection queue in 2007, mentioned on pages 10-13 of

Mr. Powers' rebuttal testimony, does not mean that wind development will not occur in proximity of the Mark Twain facilities. MVP projects increase the attractiveness and feasibility of locating generation projects nearby. The MVP portfolio, including the Mark Twain project, enables 1,347 MW of potential resources in the Northeast Missouri region.

Q. What effect would elimination of the benefits discussed by MISO related to the potential overload on the Adair-to-Novelty line have on the benefits computed by MISO for the MVP portfolio?

A. The ATXI testimony supports reliability-related benefits for the Mark Twain facilities. One effect of the MVP upgrades is to support local transmission reliability. This effect pushes out the timing of reliability-based transmission projects. The reliability benefit is quantified in MISO's MVP studies under the category of deferred future transmission investment. However, as stated earlier in my testimony, the largest category of benefits from the MVP portfolio of projects is generator production cost reductions. The benefit from deferred transmission investment is a small portion of the quantified benefits of the MVP projects – \$226-\$794 million out of \$15,540-\$49,204 million from the Multi Value Project Portfolio Report in 2012 (page 49, 2011 constant dollars) and \$377-\$1,223 million out of \$21,451-\$66,816 million from the Triennial Review (page 25, 2014 constant dollars). Aside from the reliability benefits for the Project, the Mark Twain facilities are important to the delivery of net benefits by the entire MVP portfolio of transmission projects.

Q. Do you agree with Mr. Powers' assessment on page 25 of his rebuttal testimony that "[r]econductoring the AECI Adair-to-Novelty 161 kV line segment with

ACCC or ACCR conductor," rather than reliance upon the Mark Twain facilities, is a sound approach?

A. No. The problem with Mr. Powers' approach is that it is narrowly focused on a particular reliability situation. The Mark Twain facilities were planned differently, fundamentally justified as a backbone system to provide net benefits well in excess of costs,[9] and designed to serve public policy goals in the development of renewable generation resources while also being tied to local systems to serve local reliability needs. The MVP portfolio represents the holistic solution for delivering transmission improvements considering generation, transmission, and other factors under a range of future conditions.

Q. Would Mr. Powers' assessment of reliability situations in Northeastern Missouri sacrifice any benefits that are associated with the Mark Twain Project?

A. Yes. Mr. Powers' narrow focus on reliability does not recognize the MVP benefits obtained from the portfolio. MISO's Triennial Review identified benefits of $21,451-$66,816 million associated with the cost of $8,303-$17,192 million for the MVP portfolio (page 25, 2014 constant dollars). The majority of the benefits are found in reducing congestion-driven production costs, providing for more efficient dispatch of generators by using lowest cost generation throughout the MISO footprint. The Mark Twain project provides Missouri access to the regional, zero production cost of the

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[9] The costs considered in MISO's studies included compensation for the acquisition of land rights associated with transmission line routes. Staff witness Stahlman states that MISO's economic analysis did not "consider any offset for limitations in land use." Rebuttal Testimony of Michael L. Stahlman, page 4. MISO's economic analysis did consider such an offset.

renewable energy, and takes advantage of the efficiencies of participation in the multi-state energy trading construct

Additionally, the increase of transfer capability between states allows for Missouri residents to benefit from a broader resource pool for resource adequacy, reducing the need for investment in future generating resources through the management of resource reserve targets and reductions in losses on the system. The optionality produced by the MVP portfolio provides for balancing the cost of renewable resource investment by allowing states to develop resources locally or take advantage of higher capacity factor regions that reduce the capital investment necessary to meet the energy requirements of most renewable policy regulations, such as those in Missouri.

The MVP portfolio also allows for the deferral of other transmission investments such as those suggested by Mr. Powers that would be required for the reliability of the system in the absence of the Mark Twain and other MVP projects. In all, the MVP portfolio creates benefit to cost ratios of 1.8 to 3.0 as identified under MTEP 2011 assumptions, and 2.6 to 3.9 as identified under Triennial Review assumptions. The Missouri ratios are 2.0 to 2.9 and 2.3 to 3.3, respectively.

Q. **Page 9 of Mr. Powers' rebuttal testimony states that "[p]eak load is forecast to remain relatively constant . . ., 10 percent below the historic peak in 2007, until 2024." Does this statement concerning load growth argue against the benefits of the Project?**

A. No. As stated previously in this testimony, the MVP project type and portfolio investigated the regional transmission required to support the renewable energy mandates of the states in the MISO footprint, and was not driven by load growth and any related reliability concerns. The ATXI testimony supports reliability-related benefits for the Project, but the benefits provided by the Mark Twain facilities and the MVP portfolio are only minimally affected by even the absence of such reliability benefits that might be linked with growth in peak load.

C. <u>The Source of Renewable Power</u>

Q. Mr. Powers' rebuttal testimony on page 34 is critical of MISO's studies that he states are based upon "an article of faith that the overwhelming majority of RPS targets . . . will be met with remote wind power." Do you agree?

A. No. As stated earlier in this testimony, MISO undertook a multi-year planning process aimed at meeting RPS mandates. The RGOS effort, noted on page 34 of Mr. Powers' rebuttal testimony, was a collaborative effort by a variety of stakeholders who identified wind power as the source that would most economically meet the majority of renewable energy needs in the MISO footprint. In some instances, such as in Missouri,[10] a "carve out" was created for solar generation to require its use to satisfy renewable portfolio requirements in recognition of the difficulty in developing solar power against the more favorable economics for wind power.

Q. Do you agree with the economic comparison between wind and solar power that is stated on pages 34-38 of Mr. Powers' rebuttal testimony?

A. No. Mr. Powers' comparison between renewable resources mixes reports from different sources and different years. For example, page 36 of Mr. Powers' rebuttal

[10] Mo. Rev. Stat. § 393.1030.1 ("At least two percent of each portfolio requirement shall be derived from solar energy.").

testimony uses a projection from a 2014 report by the U.S. Department of Energy for the 2016 capital cost of solar power in a comparison with wind power costs in MISO's 2014 Triennial Review.

Mr. Powers refers to the U.S. Energy Information Administration's Assumptions to the Annual Energy Outlook 2015 on page 35 of his testimony. Of the three references for cost of renewable resources cited in Mr. Powers rebuttal testimony, this source is the only one that includes both a wind and solar capital cost. In Table 8.2 on page 106 of the document (attached as Schedule JTS-S-3), overnight construction costs in 2013 dollars for wind and photovoltaic are $1,980/kW and $3,279/kW, respectively. So even this source that is cited by Mr. Powers' conflicts with his conclusion on page 37 of his rebuttal testimony that the cost of production for wind and solar projects is currently about the same.

Regardless of the relative costs of the renewable resources, the MVPs benefits are driven overwhelmingly by the portfolio enhancing market access to the low cost production of the renewable energy. The benefits driven by optimizing renewable resource location build, which is dependent on the capital cost of the new renewable resource, are approximately 6.9 percent of the quantifiable benefits identified.

Q. What has been the experience of wind power versus solar power since completion of MISO's original studies?

A. There continues to be little interest in solar generation in the MISO footprint above the levels mandated in state RPS mandates. The ratio of wind to solar generation entering the most advanced stage of MISO's interconnection queue (the Definitive

Planning Phase) or has a generation interconnection agreement in progress as of the last week of October 2015 was 17 to 1, evidencing that it is wind power that is likely to meet RPS mandates and to facilitate compliance with the CPP.

Q. In its MVP process, what did MISO plan for that is related to the development of renewable generation sources?

A. MISO's transmission planning process provides a robust system that is able to accommodate changes in generation and generation dispatch patterns as well as changes in the level and pattern of customer demands without causing equipment to perform outside of its design capabilities. MISO's MVP planning process considered this need for robustness in its planning for the increased presence of renewable generation resources in the generation mix. For instance, MISO's sensitivity analyses considered scenarios where public policy would focus more on carbon emission control.

Since development of the MVP portfolio, Federal environmental regulatory efforts have become more refined regarding the treatment of carbon emissions, which may lead to the retirement of some coal-fired plants and the expansion of low carbon dioxide emitting generation resources (*e.g.* natural gas powered) and zero emitting generation resources (*e.g.* renewables). On August 3, 2015, the United States Environmental Protection Agency Administrator signed final CPP rules under the Clean Air Act Section 111 regarding the release of carbon dioxide. These rules include the use of building blocks to facilitate state compliance with lower carbon emission rates, such as the additional development of renewable generation. The MVP portfolio supports the development of renewable generation, and the proximity of the energy zones to natural gas pipelines allows for the potential utilization of the energy zones by new natural gas fired units.

The MVP portfolio, including the Mark Twain project, provides a robust transmission supply that will be available to provide needed support to maintain reliable service under changing needs.

IV. CONCLUSION

Q. Based upon the results of MISO planning studies, as well as your review and analyses, how would you summarize your response to Mr. Powers' rebuttal testimony in opposition to construction of the facilities contained in the ATXI Application?

A. The Mark Twain facilities proposed by ATXI would provide substantial benefits to Missouri as part of the MVP portfolio that serves the MISO footprint. Mr. Powers' opposition to the Project in the areas addressed by my testimony fails to recognize the broad scope of the MISO transmission planning process, and therefore fails to recognize the broad benefits that will result from construction and operation of the Mark Twain Project.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and Associated Substation near Kirksville, Missouri	) **File No. EA-2015-0146**

AFFIDAVIT OF JAMESON T. SMITH

STATE OF LOUISIANA)
) ss
PARISH OF JEFFERSON)

Jameson T. Smith, being first duly sworn on his oath, states:

1. My name is Jameson T. Smith. I work at Midcontinent Independent System Operator, Inc. ("MISO") as the Director of Policy Studies. My business address is Two Lakeway, 3860 N. Causeway Boulevard, Suite 442, Metairie, Louisiana 70002.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of MISO, consisting of 20 pages (including the cover page) and three attached schedules, having been prepared in written form for introduction into evidence in the above-captioned docket.

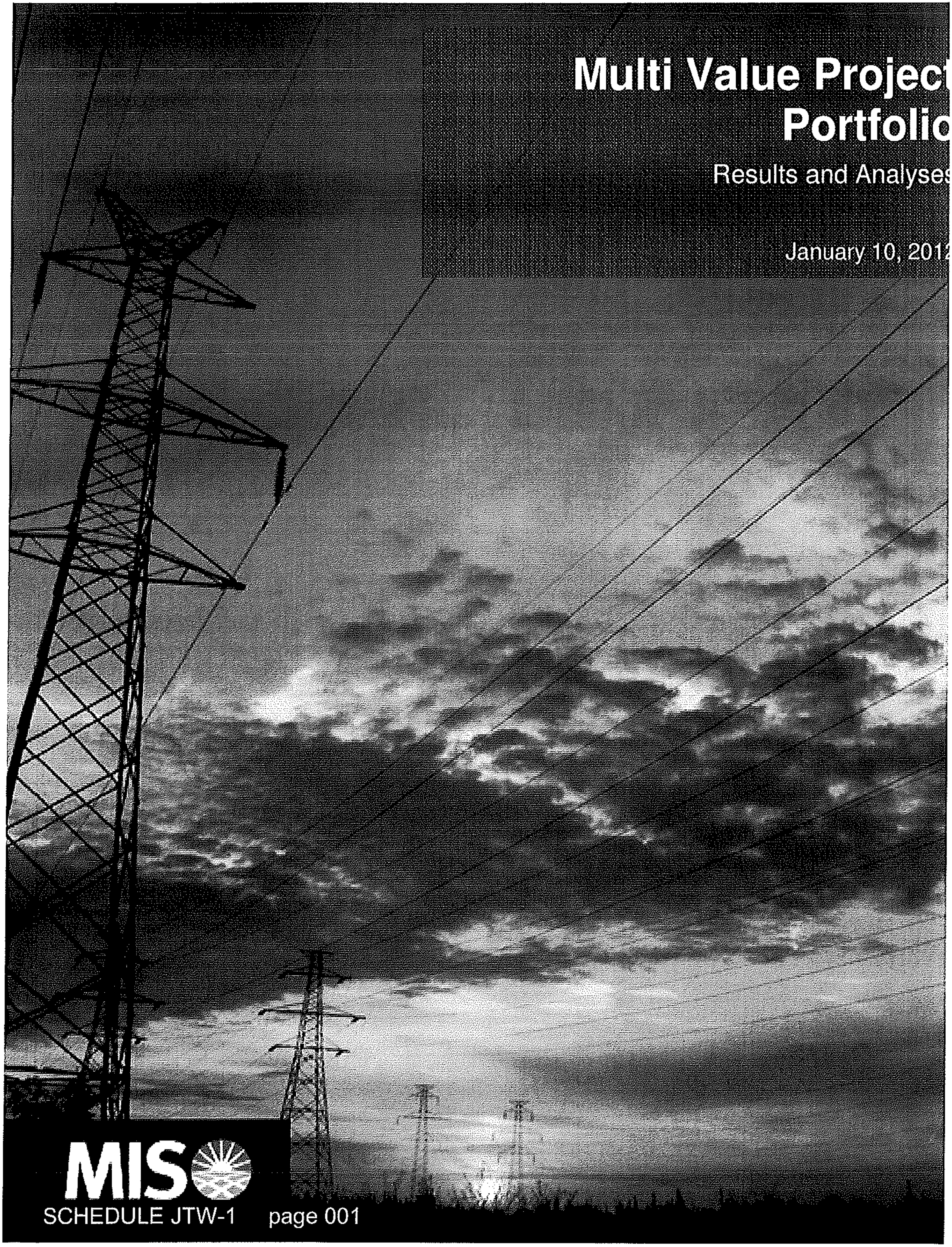
3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached Surrebuttal Testimony to the questions therein propounded, including the attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Jameson T. Smith

Subscribed and sworn before me this 16th day of November, 2015.

Notary Public
#35884

My commission expires: at death



Multi Value Project Portfolio

Results and Analyses

January 10, 2012

MISO

SCHEDULE JTW-1 page 001

1 Executive Summary

MISO staff recommends that the Multi Value Project (MVP) portfolio described in this report be approved by the MISO Board of Directors for inclusion into Appendix A of MTEP11. This recommendation is based on the strong reliability, public policy and economic benefits of the portfolio that are distributed across the MISO footprint in a manner that is commensurate with the portfolio's costs. In short, the proposed portfolio will:

- 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.

This report summarizes the key reliability, public policy and economic benefits of the recommended MVP portfolio, as well as the scope of the analyses used to determine these benefits.

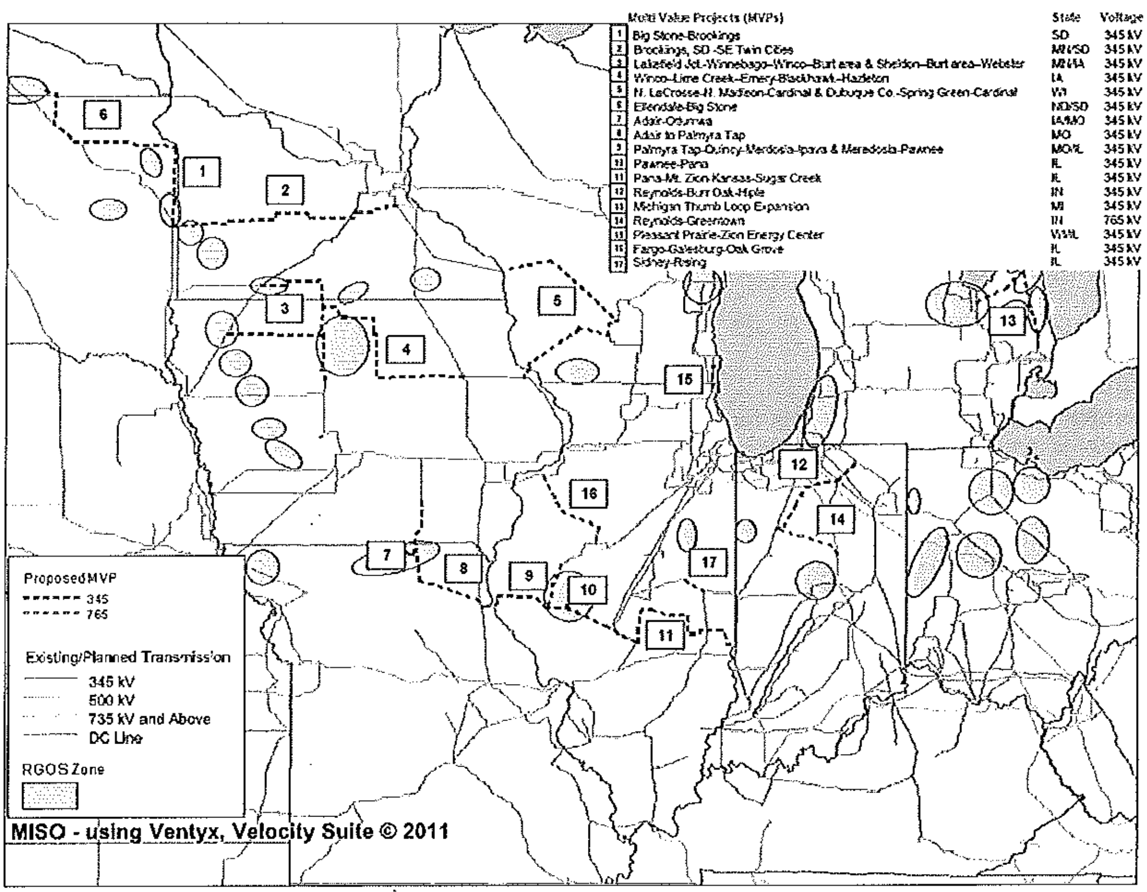


Figure 1.1: MVP portfolio[1]

[1] MVP line routing shown throughout the report is for illustrative purposes only and do not represent the final line routes.

The recommended MVP portfolio includes the Brookings Project, conditionally approved in June 2011, and the Michigan Thumb Loop project, approved in August 2010. It also includes 15 additional projects which, when integrated into the transmission system, provide multiple kinds of benefits under all future scenarios studied[2].

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[3]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. –Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co. –Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop Expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo-Galesburg–Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
	Total				$5,197

Table 1.1: MVP portfolio[4]

[2] More information on these scenarios may be found in the business case description.
[3] Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.
[4] In-service dates represent the best information available at the time of publication. These dates may shift as the projects progress through the state regulatory processes.

Public policy decisions over the last decade have driven changes in how the transmission system is planned. The recent adoption of Renewable Portfolio Standards (RPS) and clean energy goals across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

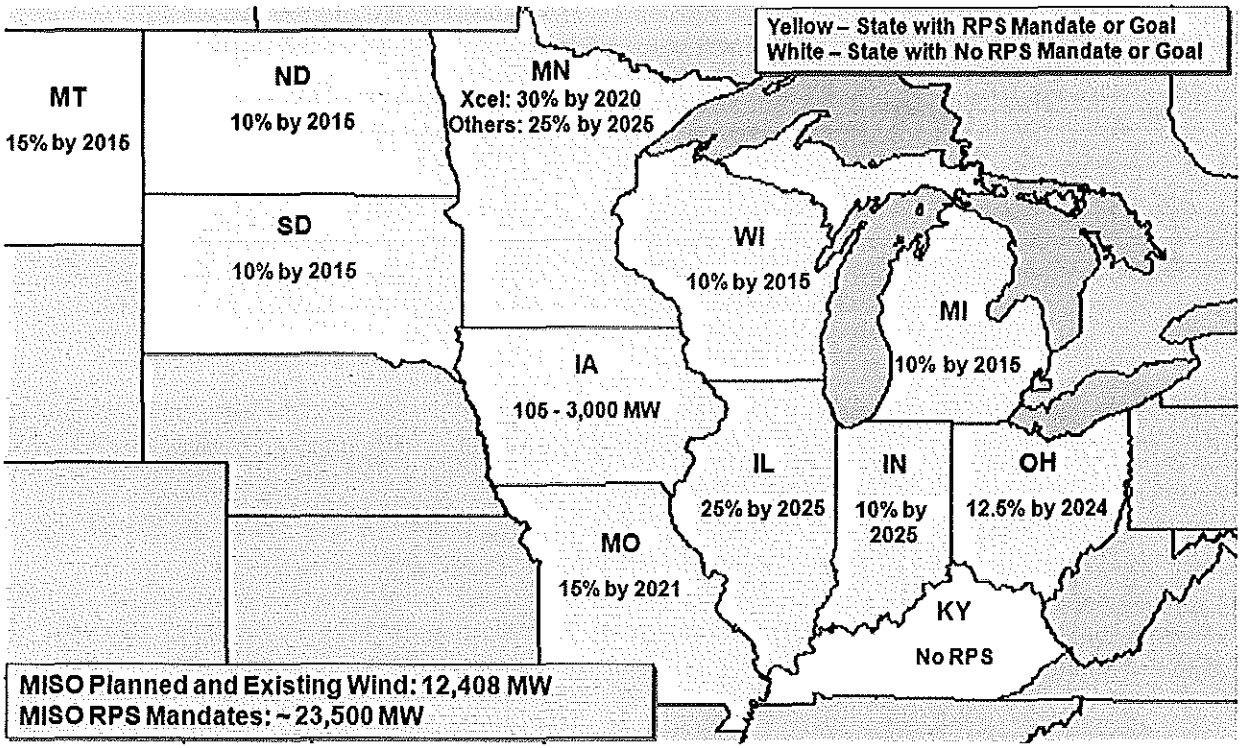


Figure 1.2: Renewable energy mandates and clean energy goals within the MISO footprint[5],[6]

Beginning with the MTEP03 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.

The recent adoption of Renewable Portfolio Standards (RPS) across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

The goal of the RGOS analysis was to design transmission portfolios that would enable RPS mandates to be met at the lowest delivered wholesale energy cost. The cost calculation combined the expenses of the new transmission portfolios with the capital costs of the new renewable generation, balancing

[5] Existing and planned wind as included in the MVP Portfolio analyses. State RPS mandates and goals include all policies signed into law by June 1, 2011.
[6] The higher number for Iowa's state RPS mandates and goals reflects the wind online rather than a statutory requirement.

the trade offs of a lower transmission investment to deliver wind from low wind availability areas, typically closer to large load centers; against a larger transmission investment to deliver wind from higher wind availability areas, typically located further from load centers.

> 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 zones.

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. Figure 1.3 depicts the correlation between the natural gas pipelines in the MISO footprint and the energy zones.

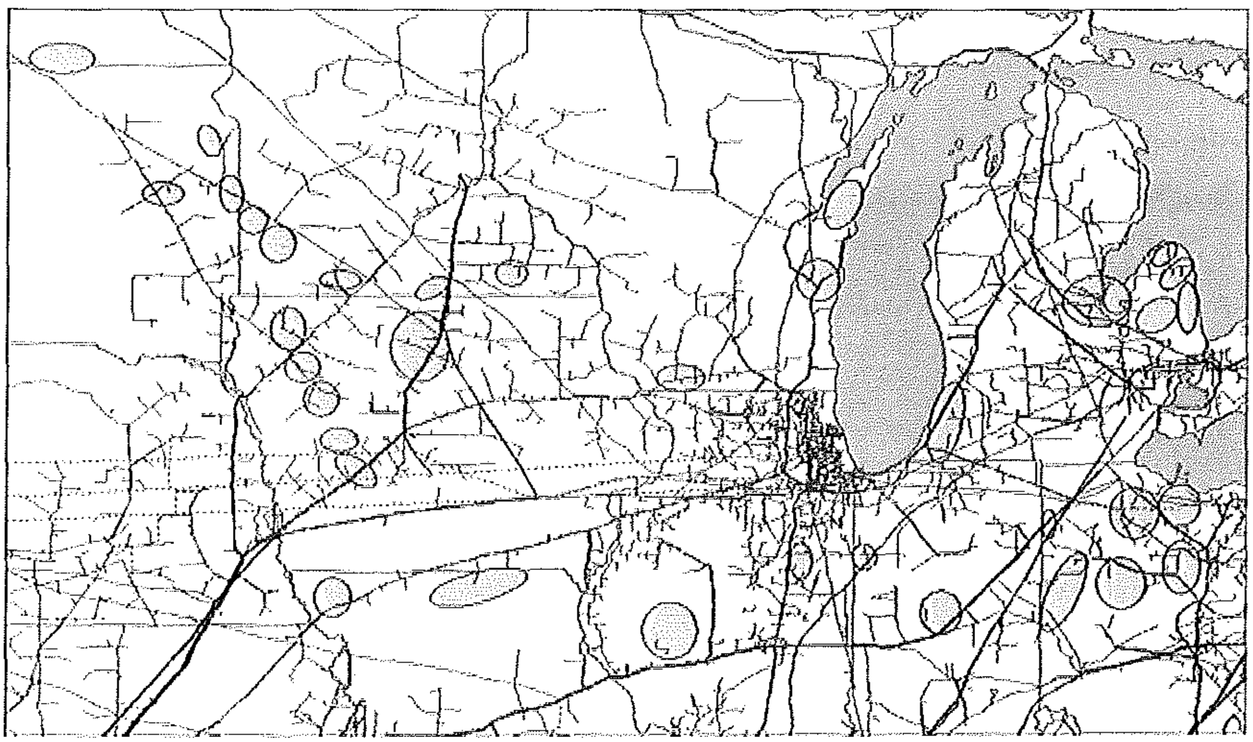


Figure 1.3: RGOS and MVP Analyses Incremental Energy Zones and natural gas pipelines

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 which were believed to provide multiple kinds of reliability and economic benefits under all alternate futures studied.

The output from the study, a recommended MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

The 2011 MVP portfolio analysis hypothesized that this set of candidate projects will create a high value transmission portfolio, enabling MISO states to meet their near term RPS mandates. The study evaluated the candidate MVP portfolio against the MVP cost allocation criteria to prove or disprove this hypothesis, as well as to confirm that the benefits of the portfolio would be widely distributed across the footprint. The output from the study, a recommended MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

Over the course of the MVP portfolio analysis, the candidate MVP portfolio was refined into the portfolio that is now recommended to the MISO Board of Directors for approval. The portfolio was refined to ensure that the portfolio as a group and each project contained within it was justified under the MVP criteria, discussed below, and to ensure that the portfolio benefit to cost ratio was optimized.

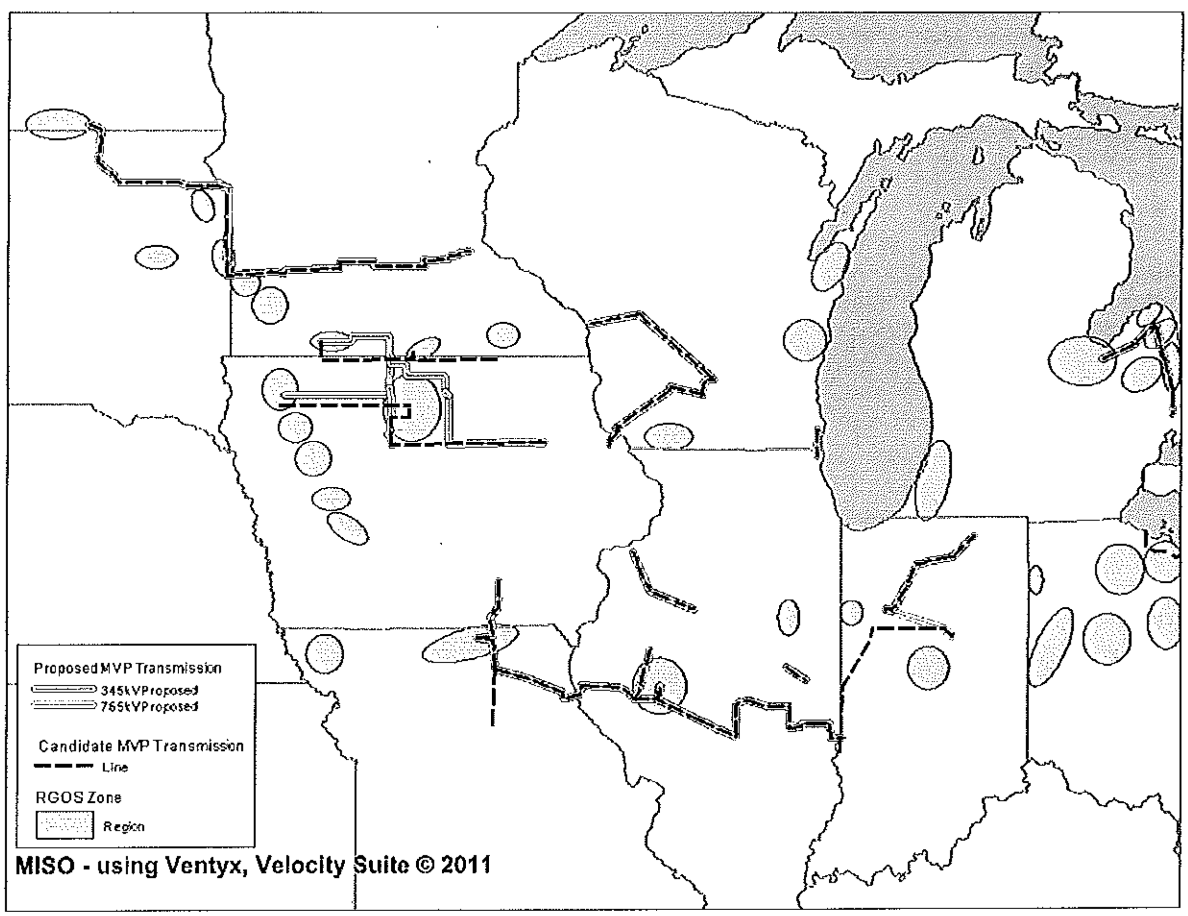


Figure 1.4: Candidate versus Recommended MVP Portfolios

The recommended MVP portfolio will enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be 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.

> The benefits created by the recommended MVP portfolio are spread across the system, in a manner commensurate with its costs.

Under all future policy scenarios studied, the recommended MVP portfolio delivers widespread regional benefits to the transmission system. For example, based on scenarios that did not consider new energy policies, the benefits of the proposed portfolio were shown to range from 1.8 to 3.0 times its total cost. These benefits are spread across the system, in a manner commensurate with their costs, as demonstrated in Figure 1.5.

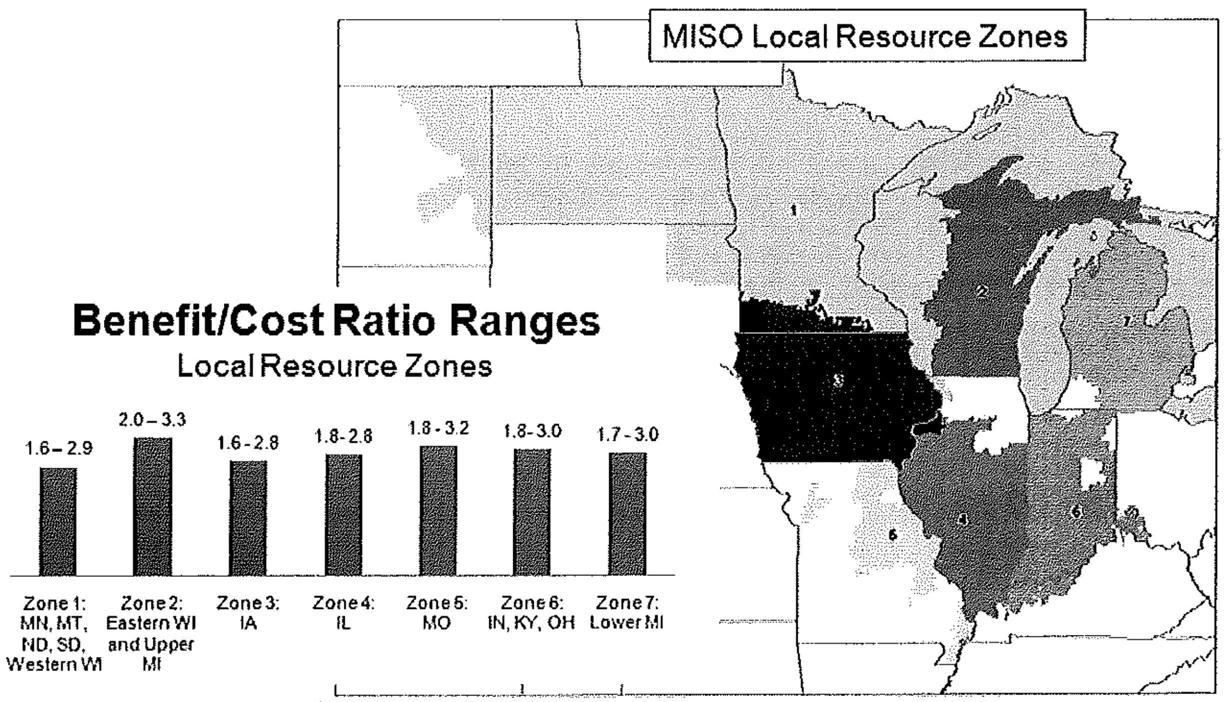


Figure 1.5: Recommended MVP portfolio benefits spread

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 criterion 1 through its reliability and public policy benefits, MISO staff recommended the 2011 MVP portfolio to the MISO Board of Directors for their review and approval.

2 MISO Planning Approach

The goal of the MISO planning process is to develop a comprehensive expansion plan that reflects a fully integrated view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons. This process is guided by a set of principles established by the MISO Board of Directors, adopted on August 18, 2005. The principles were created in an effort to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, modified and approved by the MISO Board of Directors System Planning Committee on May 16, 2011, are:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

A number of conditions must be met to build longer term transmission able to support future generation growth and accommodate new energy policies. These conditions are intertwined with the planning principles put forth by the MISO Board of Directors and supported by an integrated, inclusive transmission planning approach. The conditions that must be met to build transmission include:

- A robust business case that demonstrates value sufficient to support the construction of the transmission project.
- Increased consensus on current and future energy policies.
- A regional tariff that matches who benefits with who pays over time.
- Cost recovery mechanisms that reduce financial risk.

3 Multi Value Project portfolio drivers

The 2011 MVP portfolio analysis was based on the need to economically and reliably help states meet their public policy needs. The study identified a regional transmission portfolio that will enable the MISO Load Serving Entities (LSEs) to meet their Renewable Portfolio Standards (RPS). The analyses and their results describe a robust business case for the portfolio. This business case demonstrates that not only will the recommended MVP portfolio reliably enable Renewable Portfolio Standards to be met, but it will do so in a manner where its economic benefits exceed its costs.

While the study focused upon the RPS requirements, the transmission portfolio will ultimately have widespread benefits beyond the delivery of wind and other renewable energy. It will enhance system reliability and efficiency under a variety of different generation build outs. It will also open markets to competition, reducing congestion and spreading the benefits of low cost generation across the MISO footprint. The MVP portfolio analysis focused on identifying and increasing the benefits of the transmission portfolio, including the reliability, economic and public policy drivers.

3.1 Tariff requirements

The MVP portfolio analysis and the recommendation were premised on the MVP criteria described in Attachment FF of the MISO Tariff and shown below.

> Criterion 1
>
> A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the minimum or maximum amount of energy that can be generated. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.
>
> Criterion 2
>
> A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP benefit to cost ratio of 1.0 or higher, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.
>
> Criterion 3
>
> A Multi Value Project must address at least one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic based transmission issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.

The MVP cost allocation criteria requires evaluation of the portfolio on a reliability, economic and energy delivery basis. The scope of the analysis was designed to demonstrate this value, both on a project and portfolio basis. The projects in the MVP portfolio were evaluated against MVP criteria 1 and their ability to reliably enable the renewable energy mandates of the MISO states was quantified.

In addition, the Tariff identifies specific types of economic value which can be provided by Multi Value Projects. These values are:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.
- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.
- Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.
- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.

The full proposed portfolio was evaluated against the benefits defined in the Tariff for MVPs. In addition to the benefits described above, the operating reserve and wind siting benefits for the portfolio were quantified, as allowed under the last Tariff defined economic value. These benefits are described more fully in the economic benefit section later in the report.

3.2 Transmission strategy

A transmission strategy addressing both local needs and regional drivers allows the MISO system to realize significant economic and reliability benefits. Regional transmission, such as the transmission in the recommended MVP portfolio, increases reliability in the MISO footprint and opens the market to increased competition by providing access to low cost generation, regardless of fuel type. Development of a strong regional transmission backbone is analogous to the development of the U.S. Interstate Highway System. While developed for specific national security justifications, the system has realized significant additional benefits in subsequent years. Similarly, the recommended MVP portfolio will create reliability, economic and public policy benefits reaching beyond the immediate needs exhibited in this analysis.

The overall goal for the MVP portfolio analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system. The portfolio was designed using reliability and economic analyses, applying several futures scenarios to determine the robustness of the designed portfolio under a number of future potential energy policies.

3.3 Public policy needs

Twelve of thirteen states in the MISO footprint have enacted either RPS requirements or renewable energy goals which require or recommend varying amounts of load be served with energy from renewable energy resources. The MVP portfolio analysis focused on the transmission necessary to economically and reliably meet the state RPS mandates. Figure 3.1 provides additional details on these renewable energy requirements and goals.

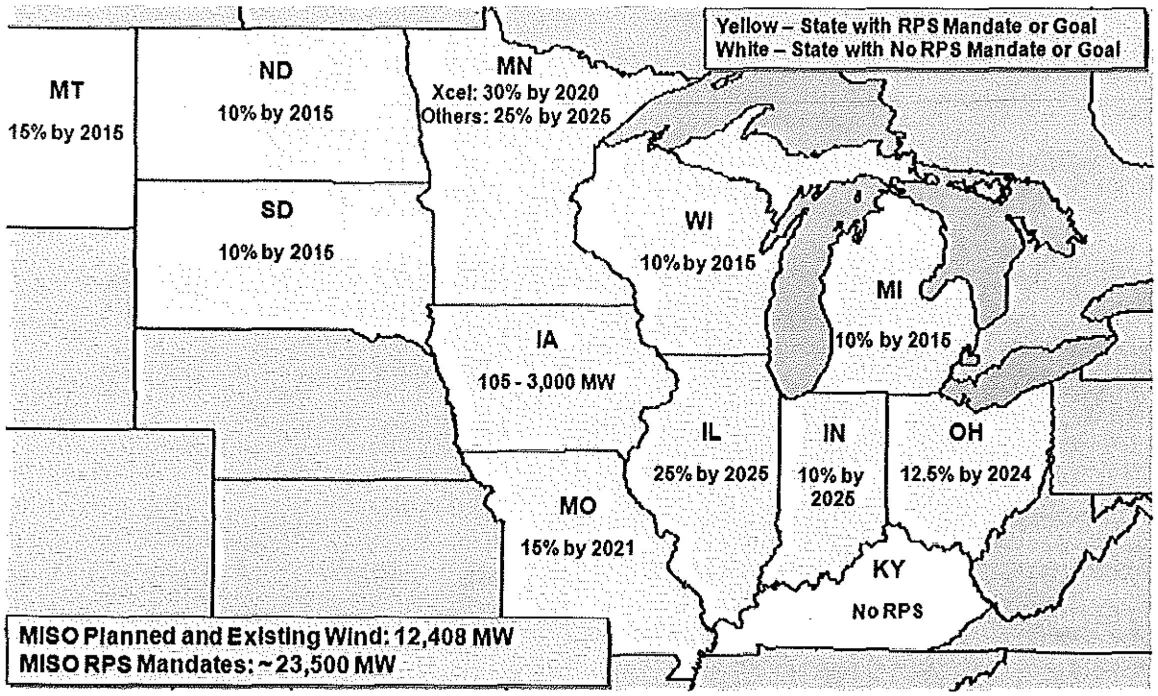


Figure 3.1: RPS mandates and goals within the MISO footprint[7]

RPS mandates vary from state to state in their specific requirement details and implementation timing, but they generally start in about 2010 and are indexed to increase with load growth. While state laws support a number of different types of renewable resources, and multiple types of renewable resources will play a role in meeting state RPS mandates, the majority of renewable energy resources installed in the foreseeable future will likely focus on harnessing the abundant wind resources throughout the MISO footprint.

> The goal of the MVP portfolio analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system.

3.4 Enhanced reliability and economic drivers

The ultimate goal of the MISO planning process is enable the reliable delivery of energy to load at the lowest possible cost. This requires a strategy premised upon a low cost approach to transmission and generation investment. This premise supports the overall constructability of the transmission portfolio, while reducing financial risk associated with overbuilding the system.

[7] The higher number for Iowa's state RPS mandates and goals reflects the wind online rather than a statutory requirement.

4 MVP Portfolio Development and Scope

The MVP portfolio was developed by considering regional system enhancements, from previous MISO analyses, that could potentially provide multiple types of value, including enhanced reliability, reduced congestion, increased market efficiency, reduced real power losses and the deferral of otherwise needed capital investments in transmission.

This portfolio was also based upon a set of energy zones, developed to provide a low-cost approach to wind siting when both generation and transmission capital costs are considered. Incremental wind necessary to meet the 2021 or 2026 renewable mandates for MISO stakeholders was added to these zones, as described in the following sections.

Finally, the MVP portfolio was intensively evaluated to ensure its composite projects, and the portfolio in total, are justified under the MVP cost allocation criterion. This analysis included an evaluation of each individual project justification against MVP criterion 1. It also included an evaluation of the full portfolio, both on a reliability and economic basis.

4.1 Development of the MVP Portfolio

MISO began to investigate the transmission required to integrate wind and provide the best value to consumers in 2002. The analyses continued through subsequent MTEP cycles, with exploratory and energy market analyses. As the demand for renewable energy grew, driven largely by an increasing level of renewable energy mandates or goals, additional regional studies were conducted to determine the transmission necessary to support these policy objectives. These studies included the Joint and Coordinated System Plan (JCSP), the Regional Generation Outlet Studies (RGOS), and analyses by the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP) group.

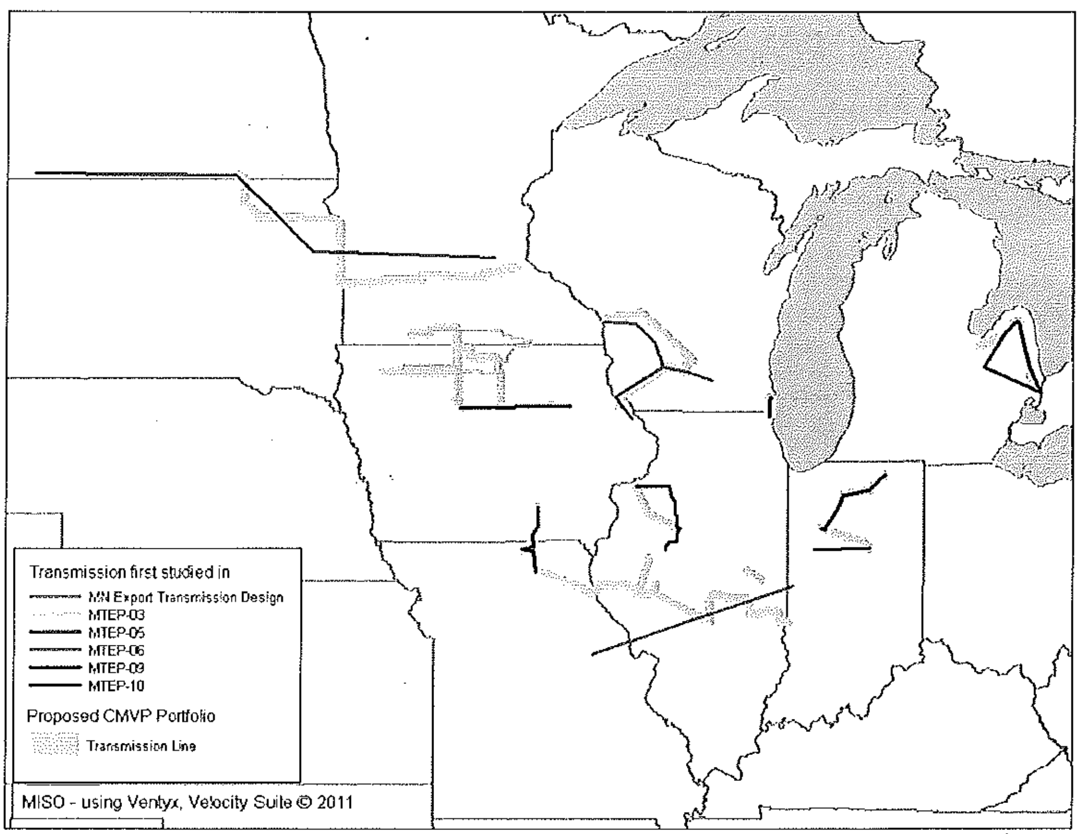


Figure 4.1: Summary of prior study input into recommended MVP portfolio

As analyses continued, the policy and economic drivers behind a regional transmission plan continued to grow. This growth was partly fueled by the development of the MISO energy and operating reserve market, which allows for regional transmission to provide regional benefits through increasing market efficiency, enabling low cost generation to be delivered to load. Simultaneously, an increase in state energy policy mandates drove the need for a robust regional transmission network, capable of responding to legislated changes in generation requirements.

It is worth noting that, although individual projects were identified beginning in MTEP03, these projects were not studied only in the year they were first identified. Subsequent MTEP analyses built on the analyses of previous years and culminated in the final recommendation of the recommended MVP portfolio.

4.1.1 MTEP03 high wind generation development scenario

In the first MISO Transmission Expansion Plan, MTEP03, the MISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal, wind and gas generation based on the interconnection queues at the time. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

More specifically, MTEP03 included a high wind development scenario, which included approximately 8,600 to 10,000 MW of new wind development. This scenario was used to evaluate several transmission scenarios on a conceptual level, including a set of high voltage lines in Iowa, running from Lakefield to Adams in southern Minnesota, then looping back to tap the line from Raun to Lakefield line in Iowa.

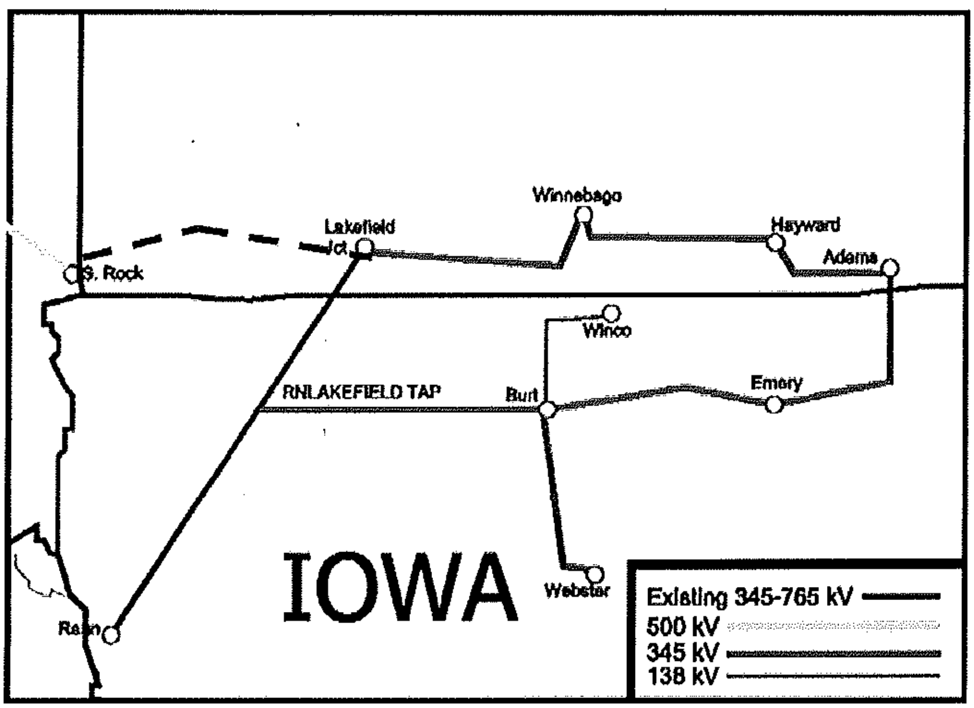


Figure 4.2: Iowa transmission identified in MTEP03

This line was studied in subsequent MTEP cycles, and it eventually led to the identification and incorporation of several Iowa lines into the MVP portfolio. MTEP03 also identified a potential upgrade of the Sidney-Rising line, as a conceptual transmission project.

4.1.2 MTEP05

MTEP05 continued the exploratory transmission analysis began in MTEP03, with two studies which focused in the area around the Dakotas and Northern Minnesota, along with the area around Iowa and Southern Minnesota. It was expected that high voltage transmission projects in these areas would provide additional access to existing base load generation, as well as future wind investment.

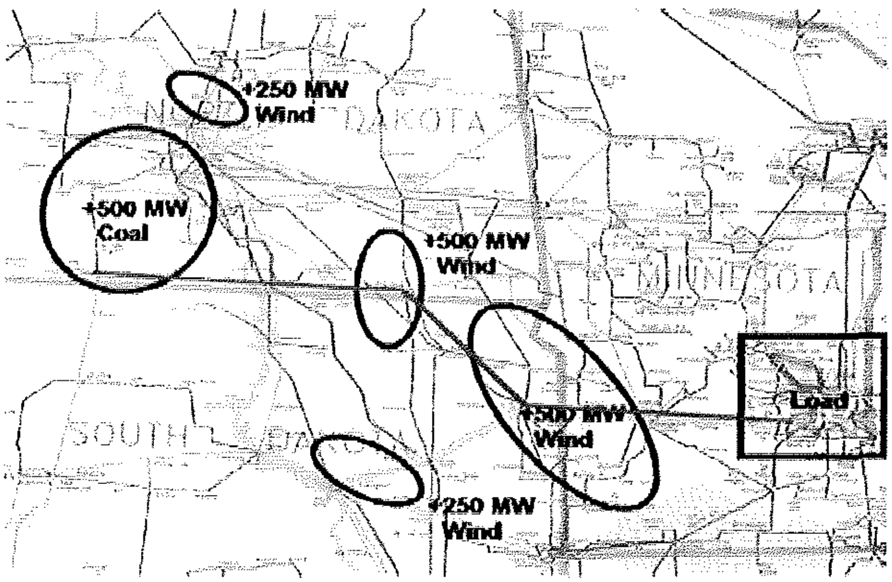


Figure 4.3: Northwest Transmission Option 2

The Northwest study identified the need for at least one, and potentially several, new transmission corridors between the Dakotas and to the Twin Cities of Minnesota. These lines were further studied through the MISO stakeholder CapX 2020 study effort, and they formed the basis of several lines included in the recommended MVP portfolio.

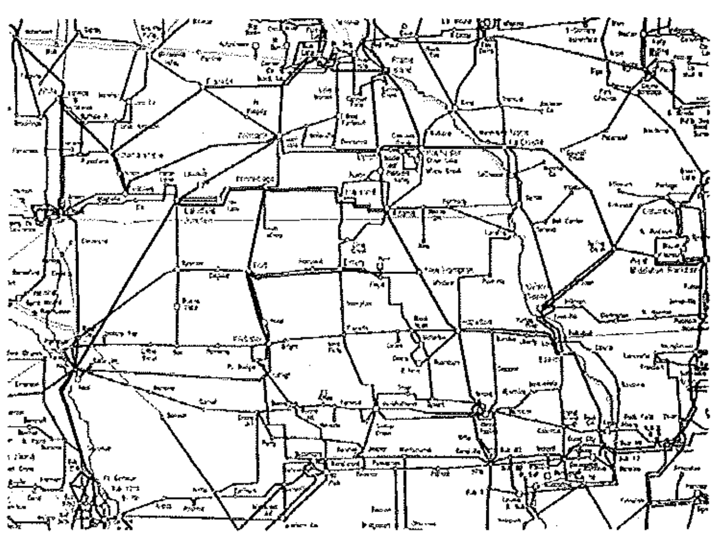


Figure 4.4: Iowa-Minnesota Transmission Scenario 2

The Iowa-Minnesota study further reinforced the need for transmission through southern Minnesota and Iowa. It also identified the need for transmission extending from Minnesota to the Spring Green area in Wisconsin, then from the Spring Green area southwest to the Dubuque area.

4.1.3 MTEP06

In MTEP06, the Vision Exploratory Study modeled scenario which included 20% wind energy for Minnesota and 10% wind energy for the other MISO states, for a total of 16 GW. This hypothetical generation scenario was used to evaluate additional high voltage transmission needs. Although this study focused on a 765 kV solution, it determined that transmission would be needed along many of the corridors identified in prior studies. Additionally, it identified that a transmission path would be required across south-central Illinois to efficiently deliver wind energy to load.

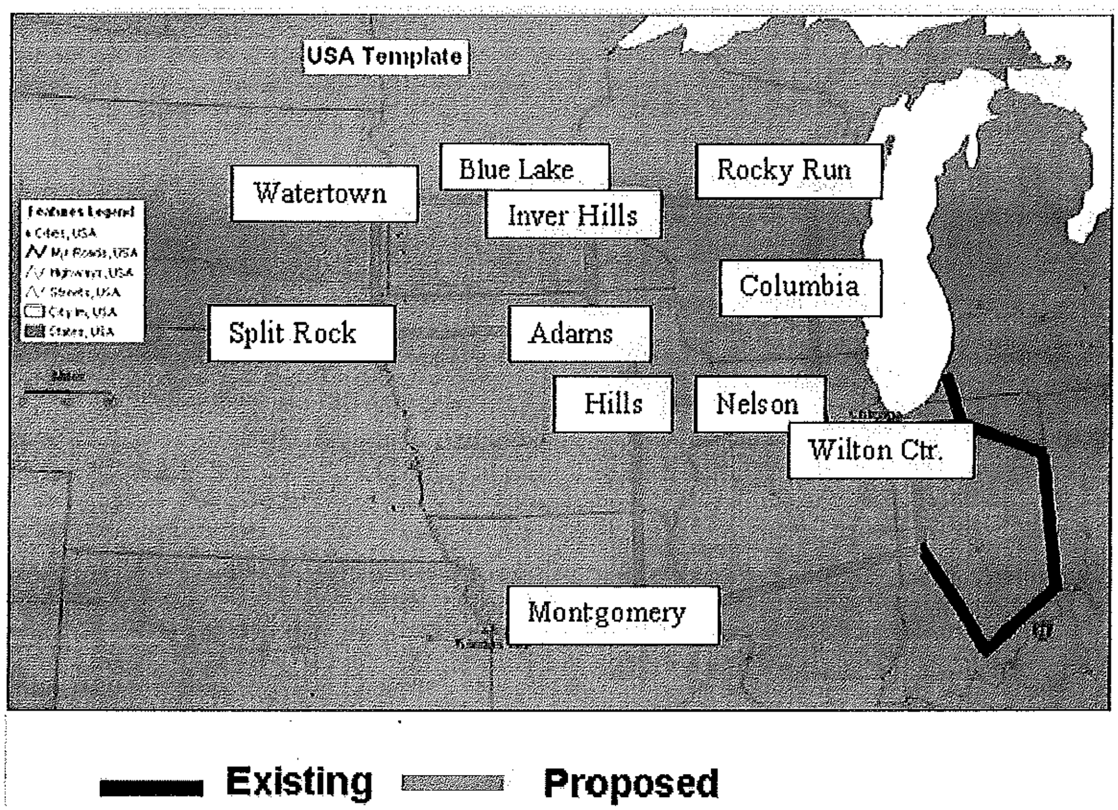


Figure 4.5: Proposed Vision Lines

4.1.4 Regional Generation Outlet Study (RGOS)

Beginning in MTEP09, MISO began the Regional Generation Outlet Study (RGOS). This study was intended, at a high level, to identify the transmission required to support the renewable mandates and goals of the MISO states, while minimizing the cost of energy delivered to the consumers. The study was conducted in two phases: Phase I focused on the western portion of the footprint, while Phase II focused on the full footprint.

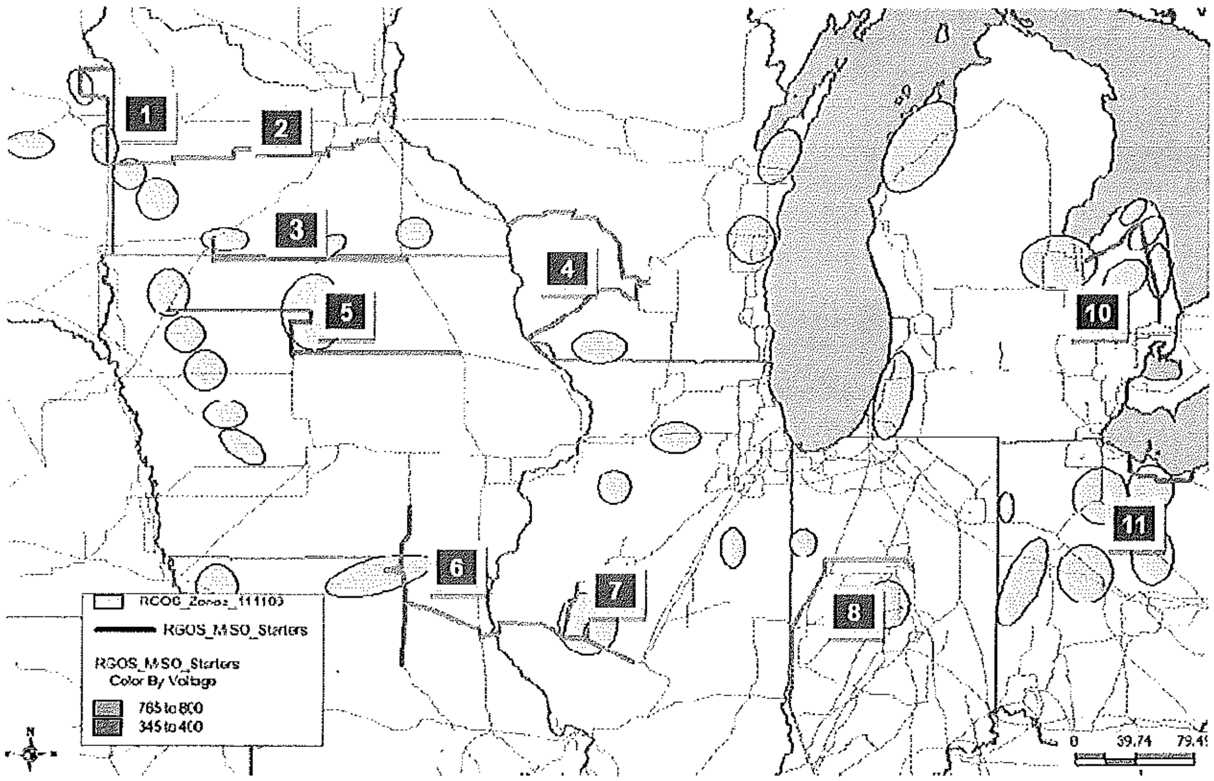


Figure 4.6: Regional Generator Outlet Study Input into MVP Portfolio

At the conclusion of the RGOS analyses, a set of three alternative expansion portfolios were identified. These portfolios, designed to meet the renewable energy mandates and goals of the full load for all the states in the MISO footprint, ranged in cost from $16 to $22 billion. They included transmission identified through the previous MTEP analyses, as highlighted earlier. Common transmission projects or corridors were identified between the three scenarios, and these projects formed transmission recommendations for the initial candidate MVP portfolio.

4.1.5 Candidate MVP Portfolio

The candidate MVP portfolio was created based on stakeholder feedback, as well as input from the analyses described in section 4.1. The portfolio was designed to meet the renewable energy mandates of all MISO load, and the projects in the portfolio were hypothesized to provide widespread benefits across the footprint. The projects selected as candidates for possible inclusion in the broader portfolio were then intensively evaluated in the MVP portfolio analysis to ensure they were justified and contributed to the portfolio business case.

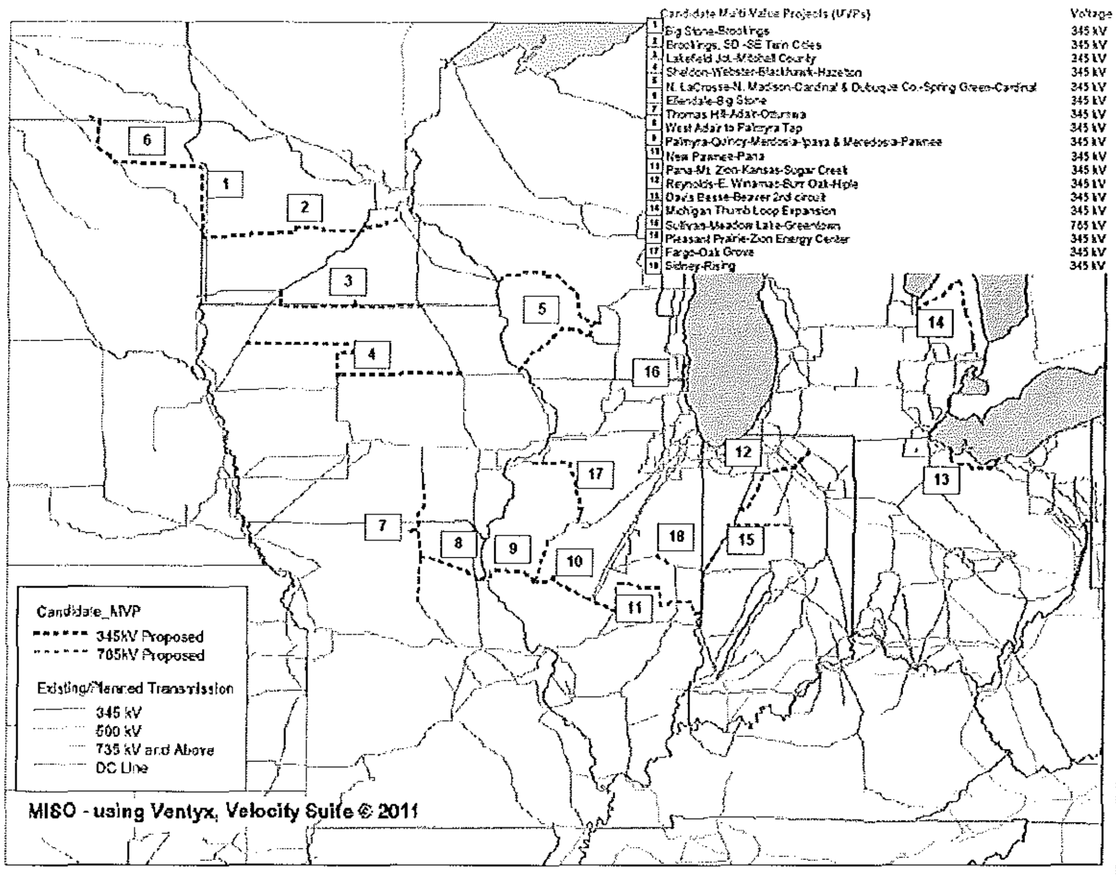


Figure 4.7: Initial Candidate MVP portfolio

4.2 Wind siting strategy

Key assumptions of the MVP portfolio study revolved around the amount and location of wind energy zones modeled within the study footprint. This energy zone development was based on stakeholder surveys focusing on expected renewable energy needs over the next 20 years and how much of that need is expected to be met with wind generation.

During the RGOS energy zone development, MISO staff evaluated multiple energy zone configurations to meet renewable energy requirements. In this process, study participants identified capital costs associated with generation capacity as well as capital costs associated with indicative transmission that would help deliver the energy to the system. It was determined that the most expensive energy delivery options were those options relying: 1) solely on the best regional wind source areas (with higher amounts of transmission needed) or 2) those options relying solely on the best local wind source areas (with higher amounts of generation capital required).

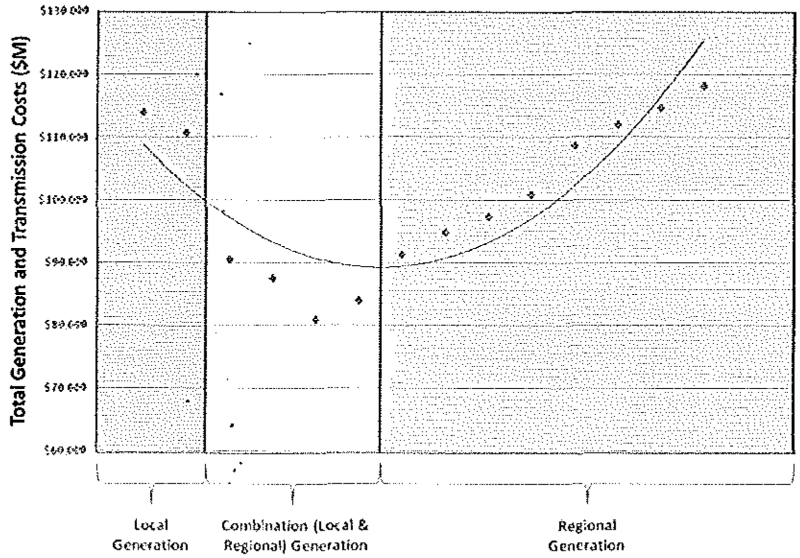


Figure 4.8: Generation and Transmission Capacity, by Energy Zone Location

As a result of RGOS energy zone development efforts as well as interaction with regulatory bodies such as the Upper Midwest Transmission Development Initiative (UMTDI) and various state agencies within the MISO, a set of energy zones was selected. These zones represent the intention of state governments to source some renewable energy locally while also using the higher wind potential areas within the MISO market footprint. Zone selection was based on a number of potential locations developed by MISO utilizing mesoscale wind data supplied by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. The analysis found wind zones distributed across the region resulted in the best method to meet renewable energy requirements at the least overall system cost.

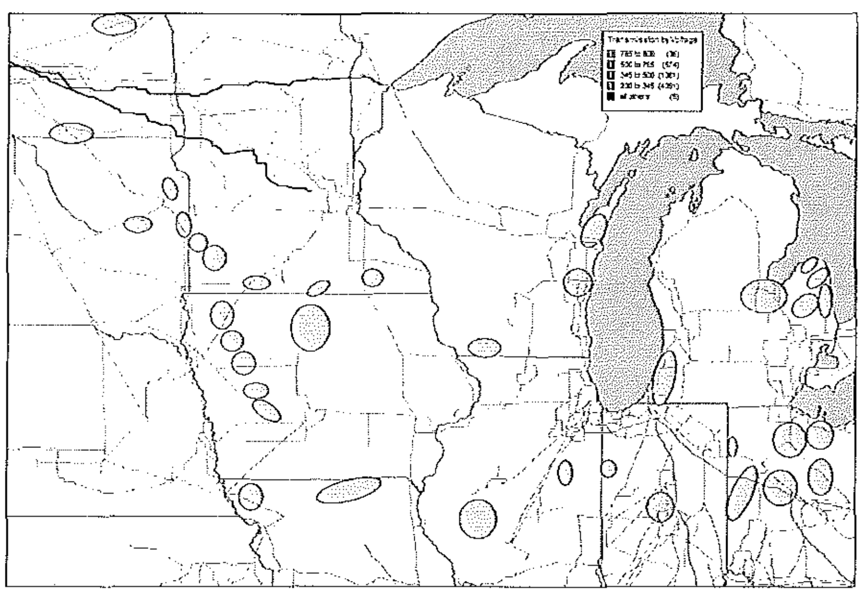


Figure 4.9::Energy Zone Locations

4.3 Incremental Generation Requirements

Once the location of the incremental wind generation was determined, through the low cost wind siting approach described above, additional analyses were required to determine how much incremental generation will be required to meet the renewable energy mandates of the MISO stakeholders. These analyses are based upon the 2009 retail sales for each area, as provided by the U.S. Energy Information Administration, a growth rate of 1.125% annually, and the specifics of each state's public policy requirements. Details on each state's public policy requirements may be found in Appendix A, while the calculations used to determine the total energy requirements may be found in Appendix B.

	2021 RPS Requirements (MWh)	2026 RPS Requirements (MWh)
IL - Ameren Illinois	3,072,047	4,274,713
IL - Alternative Retail Energy Suppliers in Ameren Illinois	2,016,516	3,046,465
MI - Total State of Michigan less AEP[8]	8,383,843	8,383,843
MN - Xcel Energy	10,535,661	11,141,777
MN - Total State of Minnesota less Xcel Energy	8,050,396	10,641,919
MO - Ameren Missouri	5,825,834	6,160,994
MO - Columbia Water and Light	122,809	194,812
MT - Montana-Dakota Utilities	113,581	120,115
OH - Duke Ohio[9]	2,099,315	2,921,169
WI - Total State of Wisconsin	7,682,829	8,124,821
TOTAL	**47,902,831**	**55,010,629**

Table 4.1: State Renewable Energy Mandates

Incremental wind generation was added to the model to satisfy these mandated needs. The amount of incremental generation for each zone was based on the capacity factor, the planned and proposed generation, and existing wind with power purchase agreements to serve non-MISO load ascribed to each zone. It was also based on a total wind buildout following the distributed, low-cost wind siting approach described in section 4.2.

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
IA-B	300	474
IA-F	292	462
IA-G	271	427
IA-H	215	339
IA-I	127	201
IA-J	18	28
IL-F	400	415
IL-K	449	449
IN-E	145	229

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
MN-L	0	0
MO-A	356	356
MO-C	500	500
MT-A	136	214
ND-G	199	313
ND-K	164	259
ND-M	59	94
OH-A	30	42
OH-B	30	42

[8] RPS requirement must be sourced entirely within Michigan
[9] Half of RPS requirement must be sourced from within Ohio.

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)	Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
IN-K	194	306	OH-C	30	42
MI-A	0	0	OH-D	30	42
MI-B	601	601	OH-E	30	42
MI-C	549	549	OH-F	30	42
MI-D	442	442	OH-I	30	42
MI-E	601	601	SD-H	300	474
MI-F	601	601	SD-J	292	461
MI-I	303	303	SD-L	300	474
MN-B	75	119	WI-B	234	370
MN-E	0	0	WI-D	257	405
MN-H	0	0	WI-F	0	0
MN-K	175	277			

Table 4.2: Incremental Generation Added to the MVP Portfolio Analysis Model

4.4 Analyses Performed

The MVP portfolio analysis combined the MISO Board of Director planning principles and the conditions precedent to transmission construction to develop a transmission portfolio that meets public policy, economic and reliability requirements. The analysis built a robust business case for the recommended transmission, using the newly created MVP cost allocation methodology approved by FERC. The candidate transmission was tested against a variety of potential policy futures. This maximized the value of the transmission portfolio and reduced potential negative risks associated with its construction due to changes in future demand and energy growth. The output of the study was a justified portfolio of recommended MVPs for inclusion in MTEP11 Appendix A and, if approved by the MISO Board of Directors, subsequent construction.

The MVP cost allocation criteria requires the evaluation of the portfolio on a reliability, economic and energy delivery basis. The analyses were designed to demonstrate this value, both on a project and portfolio basis. To this end, the MVP portfolio analysis included the studies and output shown in Table 4.3.

These analyses focused on three main areas. The project valuation analyses focused on justifying each individual MVP against the MVP criteria. The portfolio valuation analyses determined the benefits of the portfolio in aggregate, quantifying additional reliability and economic benefits. Finally, a series of system performance analyses were performed to ensure that the system reliability will be maintained with the recommended MVP portfolio in service.

Analysis Type	Analysis Output	Purpose
Steady state	List of thermal overloads mitigated by each project in the MVP portfolio	Project valuation
Alternatives	Relative value of each MVP against a stakeholder or MISO identified alternative Can include steady state and production cost analyses	Project valuation
Underbuild requirements	Incremental transmission required to mitigate constraints created by the addition of the recommended MVP portfolio	System performance
Short circuit	Incremental upgrades required to mitigate any short circuit / breaker duty violations	System performance
Stability	List of violations mitigated by the recommended MVP portfolio Includes both transient and voltage stability analysis	System performance Portfolio valuation
Generation enabled	Wind enabled by the MVP portfolio	Portfolio valuation
Production cost	Adjusted Production Cost (APC) benefits of the entire MVP portfolio	Portfolio valuation
Robustness testing	Quantification of MVP portfolio benefits under various policy futures or transmission conditions	Portfolio valuation
Operating reserves Impact	Impact of the MVP portfolio on existing operating reserve zones and quantification of this benefit	Portfolio valuation
Planning Reserve Margin (PRM) benefits	Capacity savings due to reductions in the system-wide Planning Reserve Margin caused by the addition of the MVP portfolio to the transmission system	Portfolio valuation
Transmission loss reductions	Capacity losses savings caused by the addition of the MVP portfolio to the transmission system, where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour	Portfolio valuation
Wind generation capital investment	Quantification of the incremental wind generator capital cost savings enabled by the wind siting methodology supported by the MVP portfolio	Portfolio valuation
Avoided capital investment (transmission)	Future baseline transmission investment that may be avoided due to the installation of the MVP portfolio	Portfolio valuation

Table 4.3: MVP Portfolio Analyses and Output

4.5 Stakeholder involvement

Stakeholders reviewed and contributed to the development of the recommended MVP portfolio throughout the study process. A Technical Study Task Force (TSTF), composed of regulators, transmission owners, renewable energy developers, and market participants, met at least monthly with MISO engineers to provide input, feedback, and guidance throughout the MVP study processes. Also, regular updates were given to the MISO Planning Advisory Committee (PAC) and Planning Subcommittee (PSC). Finally, all study results were available for stakeholder review Feedback or analyses requested throughout the study process were incorporated into the MVP portfolio scope.

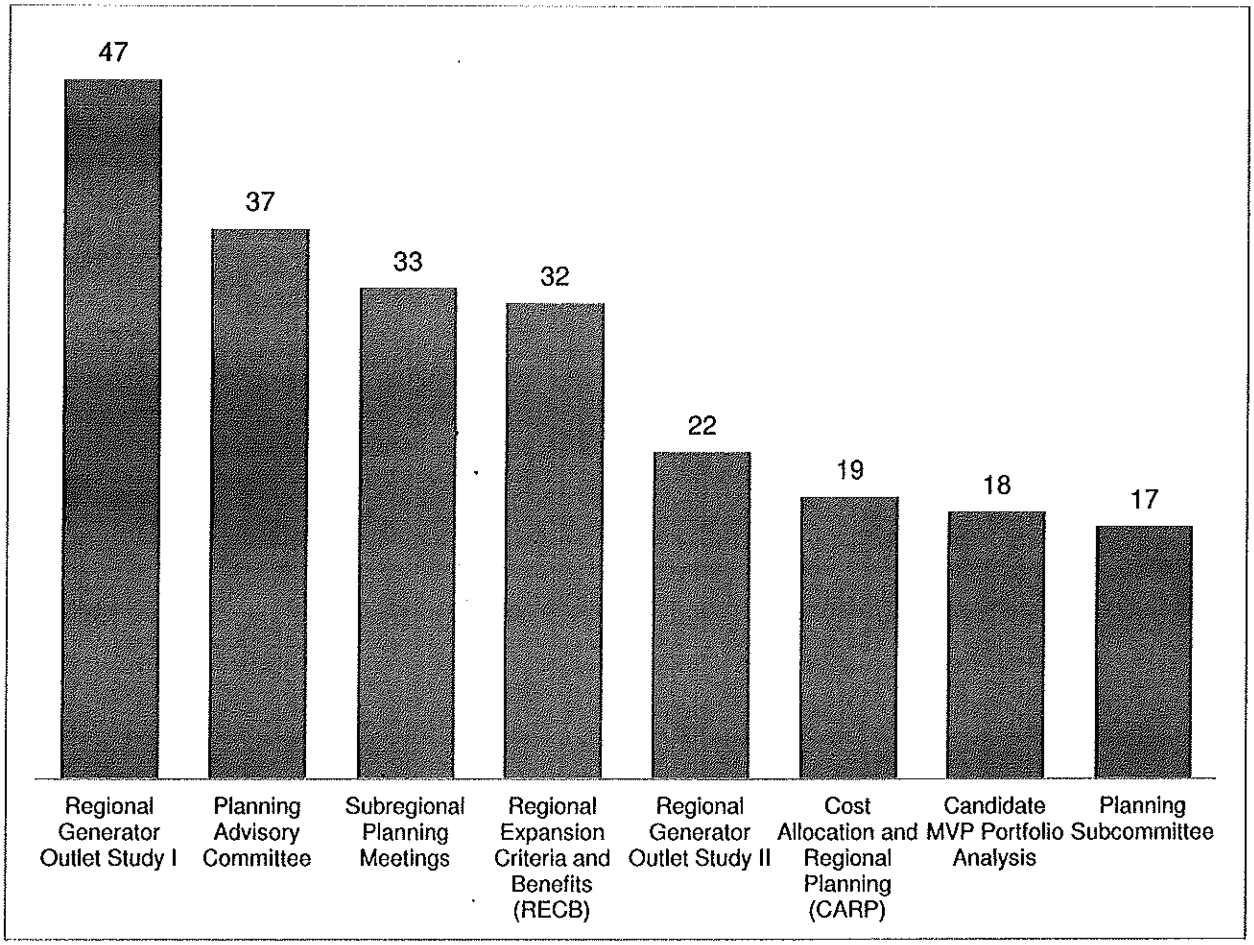


Figure 4.10: Regional Planning Stakeholder Meetings, 2008 - 2011

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5 Project justification and alternatives assessment

Each project in the MVP portfolio was analyzed to ensure that the project is justified against MVP cost allocation criterion 1, and to determine if any relevant alternatives exist to the proposed projects. The projects listed below constitute the final projects, which are recommended to the MISO Board of Directors.

5.1 Big Stone to Brookings County 345 kV Line

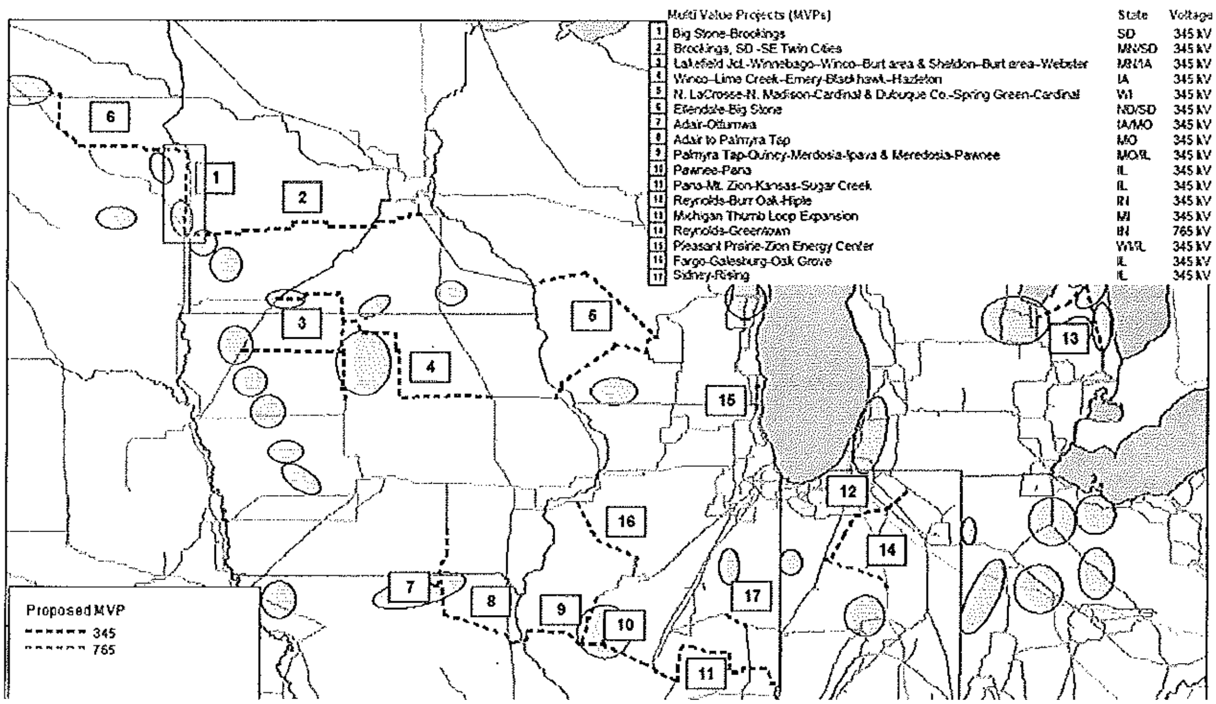

Figure 5.1: Big Stone to Brookings County

Project(s): 2221

Transmission Owner(s): OTP, XEL

Project Description: This project creates a new 345 kV path on the border of South Dakota and Minnesota by connecting XEL's Brookings County and OTP's Big Stone. Approximately 69 miles of new 345 kV transmission will be installed between these two substations along with a new 345 kV terminal at Big Stone and two 345/230 kV, 672 MVA transformers. The total estimated cost of this project is $191 million[10]. The expected in service date for this project is December 2017.

Project Justification: The new 345 kV outlet from Big Stone removes overloads on the 230 kV paths from Big Stone to Blair and Hankinson to Wahpeton along with 115 kV paths from Johnson to Morris , Big Stone to Highway 12 to Ortonville, Pipestone to Buffalo Ridge and Canby to Granite Falls. The overloaded Watertown 345/230 kV is also alleviated. Along with project 2220, this project reliably moves mandated renewable energy from the Dakotas to major 345 kV transmission hubs and load centers.

Alternatives Considered: An alternative to build a new 345 kV from Big Stone to Canby to Granite Falls to Minnesota Valley and rebuild the 230 kV or build a new 345 kV to Morris could provide an

[10] In 2011 dollars.

alternative outlet for Big Stone wind. The cost of this alternative is higher than the 345 kV path to Brookings County.

5.2 Brookings County to Southeast Twin Cities 345 kV Line

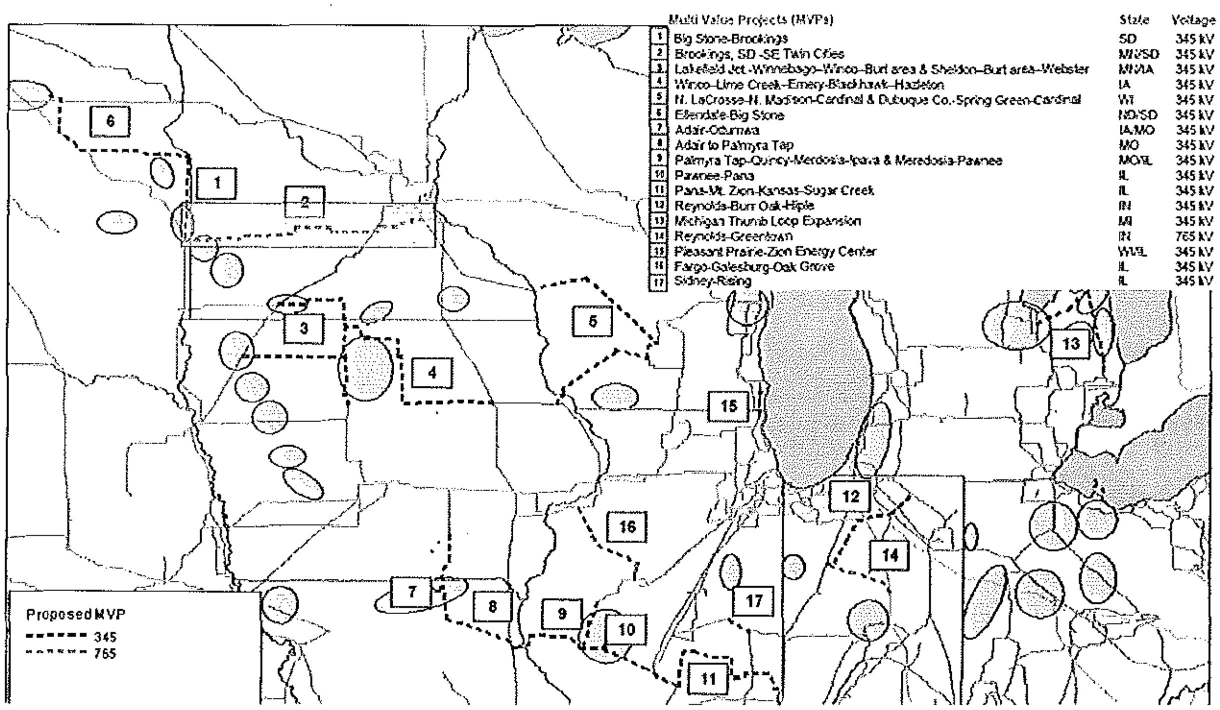

Figure 5.2: Brookings County to Southeast Twin Cities

Project(s): 1203

Transmission Owner(s): XEL, GRE

Project Description:
This project creates a new 345 kV path through southern Minnesota, by connecting XEL's Brookings County substation to the Twin Cities. Single circuit 345 kV transmission will be constructed from Brookings County to Lyon County, from Helena to Lake Marion to Hampton Corner, and from Lyon County to Hazel Creek to Minnesota Valley. The Hazel Creek to Minnesota Valley section will be operated at 230 kV initially. Double circuit 345 kV transmission will be constructed from Lyon Count to Cedar Mountain to Helena. A 115 kV line will be built between the new Cedar Mountain and the existing Franklin substations. The project includes one 345/230 kV, 336 MVA transformer at Hazel Creek, three 345/115 kV, 448 MVA transformers at Lyon County, Lake Marion and Cedar Mountain, one upgraded 115/69 kV, 140 MVA transformer at Lake Marion and two upgraded 115/69 kV, 70 MVA transformers at Franklin. A new breaker and deadend structure is planned at Lake Marion and the Arlington to Green Isle 69 kV line will be upgraded to 477 ACSR. The project adds a total of 351 miles of new 345 kV, 5 miles of new 115 kV and 5.8 miles of rebuilt 69 kV lines. The total estimated cost of this project is $695 million[11]. The expected in service dates for these projects are:

- June 2013 (Cedar Mountain 345/115 kV transformer)
- August 2013 (Cedar Mountain to Helena 345 kV double circuit line and Arlington to Green Isle 69 kV rebuild)

[11] In 2011 dollars

- October 2013 (Lyon County 345/115 kV transformer)
- November 2013 (Lyon County to Cedar Mountain 345 kV double circuit line)
- January 2014 (Franklin 115/69 kV transformers)
- February 2014 (Cedar Mountain to Franklin 115 kV line)
- March 2014 (Lake Marion 345/115 kV and 115/69 kV transformers and station work)
- April 2014 (Helena to Lake Marion 345 kV line)
- June 2014 (Lake Marion to Hampton Corner 345 kV line)
- January 2015 (Brookings to Lyon County 345 kV line and Hazel Creek 345/230 kV transformer)
- February 2015 (Lyon County to Hazel Creek to Minnesota Valley 345 kV line)

Project Justification:
Without the Brookings County to Twin Cities 345 kV line, the loss of Split Rock to White 345 kV leaves only the 230kV system to feed load to the East. This overloads the Watertown 345/230 kV transformer without the parallel 345 kV path from Brookings County. Not having the project also impacts the 115 kV network in southern Minnesota which is connected on both sides by 230 kV. The loss of either 230kV source causes multiple overloads in the surrounding 115 kV network without this project. The loss of any segment of the Wilmarth-Helena-Blue Lake 345 kV line in southeast Minnesota leads to overloads on the underlying 115 kV network. Without this project, the power flowing west to east is forced through the 115 kV system, overloading the underlying 115 kV lines. The Wilmarth to Eastwood and Wilmarth to Swan Lake 115 kV lines are overloaded without the additional 345kV support to the north that is included with project 1203. At the Minnesota/Wisconsin interface, the loss of 345 kV lines at Blue Lake, Prairie Island, Red Rock, Coon Creek and Chisago substations overload the Prairie Island 345/161 kV transformer, particularly for any NERC Category C5 outages involving lines between the aforementioned substations. The Brookings County to Twin Cities project would bring an additional 345 kV source into this area to reduce loading along the path into Wisconsin. There are also 115 kV overloads in this area which are mitigated by this project.

Alternatives Considered:
With the existing 345 kV outlets out of Brookings County thermally constrained and with most of the 230 and 115 kV paths between Brookings County and the Twin Cities overloaded, mitigating all these constraints through underlying line rebuilds would be infeasible and costlier compared to this project.

5.3 Lakefield Junction to Winnebago to Winnco to Burt area; Sheldon to Burt area to Webster 345 kV Lines

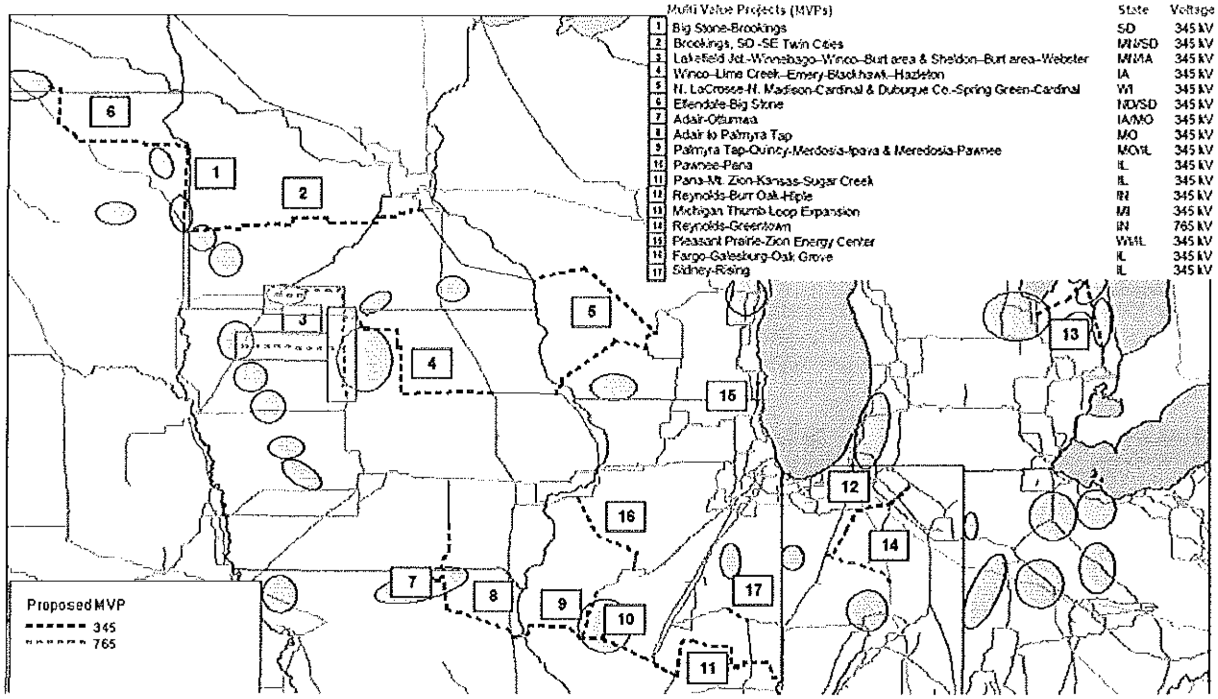

Figure 5.3: Lakefield Jct to Winnebago to Winnco to Burt area; Sheldon to Burt area to Webster

Project(s): 3205

Transmission Owner(s): MEC, ITCM

Project Description:
Designed to connect with project 3213, this project creates a double circuit 345/161 kV path through the border of Minnesota and Iowa. New 345 kV transmission will be built from Lakefield Junction to Winnebago to Winnco to Burt and from Sheldon to Burt to Webster. Rebuilt 161 kV transmission will be on the same towers and go from Lakefield to Fox Lake to Rutland to Winnebago to Winnco and Wisdom to Osgood to Burt to Hope to Webster. Winnebago, Winnco, Sheldon and Burt are all new 345 kV stations. Sheldon will be a tap on the existing Raun to Lakefield 345 kV line. A 345/161 kV, 450 MVA transformer will be installed at Winnebago. This project adds 218 miles of new 345 kV and 92 miles of rebuilt 161 kV transmission. The total estimated cost of this project is \$506 million[12]. The expected in service dates for these projects are:

- December 2015 (All Lakefield Junction to Burt work)
- December 2016 (All Sheldon to Webster work)

Project Justification:
The new 345 kV path through southern Minnesota and northern Iowa effectively mitigates the Fox Lake – Rutland – Winnebago 161 kV constraint. Existing wind in the Winnebago and Wisdom areas are benefitted by 345 kV transmission moving generation out of these constrained areas. Working in tandem with project 3213, this project reliably moves mandated renewable energy from western and

[12] In 2011 dollars

northern Iowa along with existing wind at the Winnebago, Wisdom and Lime Creek/Emery areas to major 345 kV transmission hubs.

Alternatives Considered:
An Iowa alternative of Lakefield Junction to Mitchell County and Sheldon to Burt to Webster to Black Hawk to Hazleton 345 kV was analyzed but was not effective in collecting Lime Creek/Emery area wind or lowering congestion on the Mitchell County to Hazleton 345 kV line. It had similar cost to the combined Iowa projects 3205 and 3213.

5.4 Winco to Lime Creek to Emery to Black Hawk to Hazleton 345 kV Line

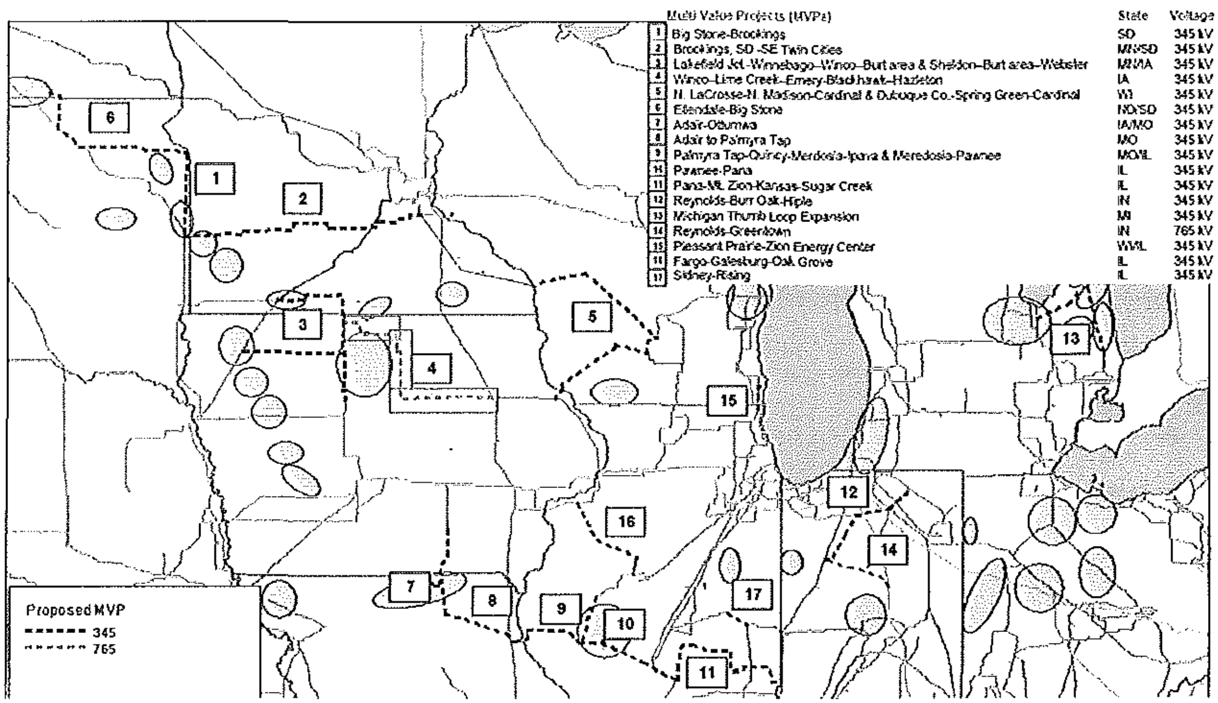

Figure 5.4: Winnco to Lime Creek to Emery to Black Hawk to Hazleton 345 kV line

Project(s): 3213

Transmission Owner(s): MEC, ITCM

Project Description:
Designed to connect with project 3205, this project creates a double circuit 345/161 kV path through northern Iowa. New 345 kV transmission will be built from the new Winnco substation to Lime Creek to Emery to Black Hawk to Hazleton. Rebuilt 161 kV transmission will be on the same towers as the 345 kV and will go from Lime Creek to Emery to Hampton to Franklin to Union Tap to Black Hawk to Hazleton. A 345/161 kV, 450 MVA transformer will be installed at Lime Creek, Emery and Black Hawk. This project adds 206 miles of new 345 kV, 23 miles of new 161 and 149 miles of rebuilt 161 kV transmission. The total estimated cost of this project is $480 million[13]. The expected in service date of the project is December 2015.

Project Justification:

[13] In 2011 dollars

The new 345 kV path through Iowa mitigates constraints seen on the Lime Creek – Emery – Floyd – Bremer – Black Hawk 161 kV line. The 345/161 kV transformers at Lime Creek and Emery are effectively acting as step-up transformers for wind and lowering congestion on the lower voltages. The additional 345 kV path into Hazleton significantly increases the transfer capability of the Mitchell County – Hazleton 345 kV line. Working in tandem with project 3205, this project reliably moves mandated renewable energy from western and northern Iowa along with existing wind at the Winnebago, Wisdom and Lime Creek/Emery areas to major 345 kV transmission hubs.

Alternatives Considered:
An Iowa alternative of Lakefield Junction to Mitchell County and Sheldon to Burt to Webster to Black Hawk to Hazleton 345 kV was analyzed but was not effective in collecting Lime Creek/Emery area wind or lowering congestion on the Mitchell County to Hazleton 345 kV line. It had similar cost to the combined Iowa projects 3205 and 3213.

5.5 North LaCrosse to North Madison to Cardinal 345 kV Line

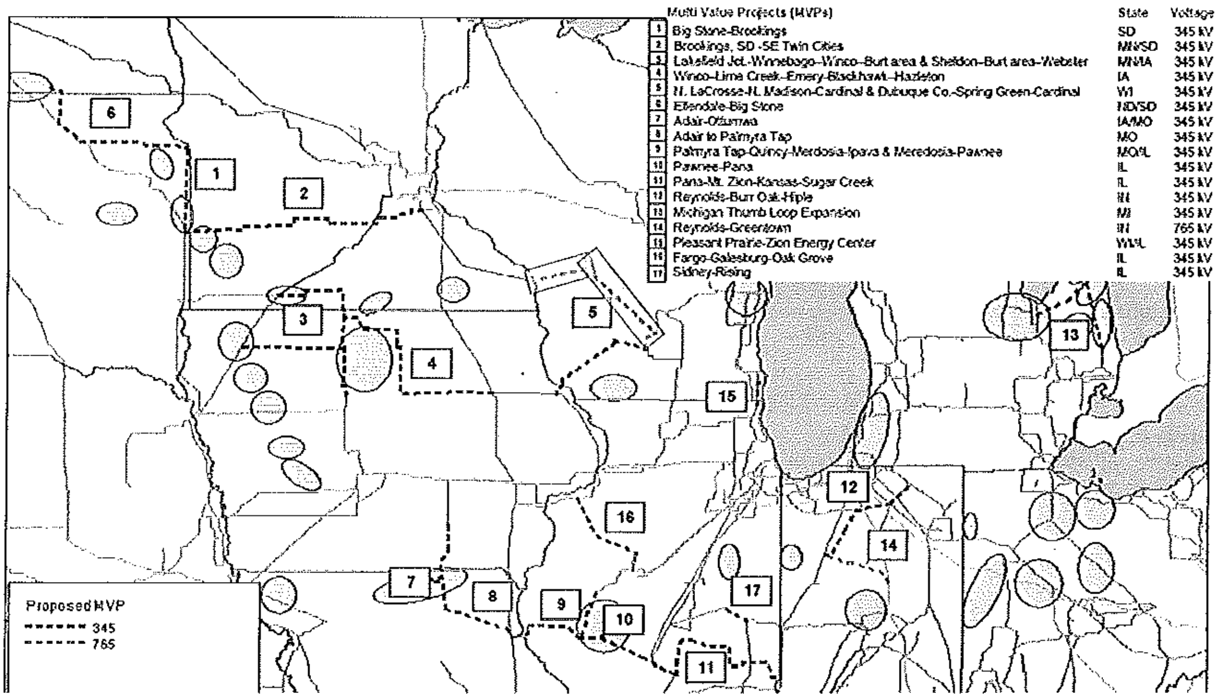

Figure 5.5: North LaCrosse to North Madison to Cardinal

Project(s): 3127

Transmission Owner(s): ATC, XEL

Description: This creates a 345 kV line from the North LaCrosse (Briggs Road) substation, to the North Madison substation, to the Cardinal substation, through southwestern Wisconsin. A 448 MVA, 345/161 kV transformer will be installed at Briggs Road, and approximately 20 miles of 138 kV line between the North Madison and Cardinal substations will be reconductored. The new 345 kV line will be approximately 157 miles long. The estimated cost is $390 million[14]. The expected in service date is December 2018.

[14] In 2011 dollars

Justification: The 345 kV line from North LaCrosse to North Madison creates a tie between the 345kV network in western Wisconsin to the 345 kV network in southeastern Wisconsin. This creates an additional wind outlet path across the state; pushing power into southern Wisconsin, where it can go east into Milwaukee, or south to Illinois, providing access to less expensive wind power in two major load centers. With the Brookings project, the wind coming into North LaCrosse needs an outlet, and the line to North Madison is the best option studied. From a reliability perspective, the addition of the North LaCrosse to North Madison to Cardinal 345 kV path helps relieve constraints on the 345 kV system parallel to the project to the north and south of the new line. The 138 and 161 kV system in southwest Wisconsin and nearby in Iowa are also overloaded during certain contingent events, and the new line relieves those constraints. This project will mitigate twelve bulk electric system (BES) NERC Category B thermal constraints and eight NERC Category C constraints. It will also relieve 30 non-BES NERC Category B and 36 NERC Category C constraints.

Alternatives Considered:
Rebuilding the overloaded 138 and 161 kV lines, along with adding transformers or upgrading the existing units to handle the increased loading, was the only other alternative considered. This was not a viable alternative, because the cost is greater than the proposed project. The proposed project also provides the most benefit to the transmission grid in the future.

5.6 Dubuque to Spring Green to Cardinal 345 kV Line

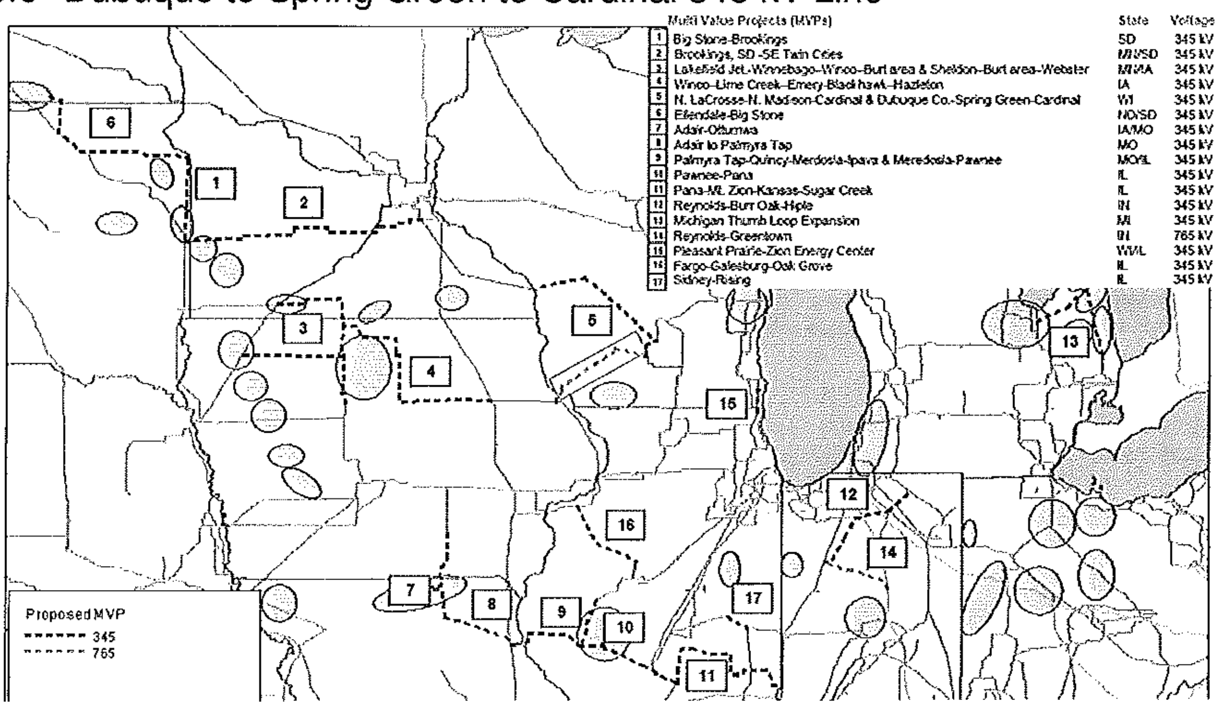

Figure 5.6: Dubuque to Spring Green to Cardinal

Project(s): 3127

Transmission Owner(s): ATC, ITCM

Description: A 345 kV line is created from the Dubuque substation in Iowa, to the Spring Green substation to the Cardinal substation through southwestern Wisconsin. A new Dubuque County 345 kV switching station will be created, and the Spring Green substation will be upgraded to accommodate the new connections. A new 500 MVA, 345/138 kV transformer will be added. To accommodate the new 345 kV connections from Spring Green and North Madison, the Cardinal substation will be upgraded. There are also upgrades to the 69 kV system, which is being converted to operate at 138 kV, in the Mazomanie – Black Earth – Stagecoach area. The new 345 kV line is approximately 136 miles long. The estimated cost is $324 million[15]. The expected in service date is December 2020.

Justification: The 345 kV line from Dubuque to Spring Green to Cardinal creates a tie between the 345kV network in Iowa to the 345 kV network in southcentral Wisconsin. This expansion creates an additional wind outlet path across the state; bringing power from Iowa into southern Wisconsin, where it can then go east into Milwaukee or south toward Chicago providing access to less expensive wind power in two major load centers. In combination with another Multi Value Project, the Oak Grove – Galesburg – Fargo 345 kV line, this project enables 1,100 MW of wind power transfer capability. This new path will help offload the lines that feed the Quad City (Iowa) area by bringing power flow to the north. From a reliability perspective, the addition of the Dubuque – Spring Green – Cardinal 345 kV path helps relieve constraints on the 345 kV system parallel to the project to the north and south of the new line, as well as 138 kV system constraints in the aforementioned areas and to the west of the new line. The 138 kV system in southwest Wisconsin and nearby in Iowa is also overloaded during certain contingent events, and the new line relieves those constraints. Those overloaded facilities that are not relieved by the 345 kV project are relieved by upgrades to the lower voltage transmission system, including converting part of the 69 kV system to operate at 138 kV. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and ten NERC Category C constraints. It will also relieve two non-BES NERC Category B and two NERC Category C constraints.

Alternatives Considered: An alternative to the proposed project would be to rebuild the 138 kV lines that were overloaded. The cost of this alternative would be more than the proposed project, without providing benefits of the proposed project.

[15] In 2011 dollars

5.7 Ellendale to Big Stone 345 kV Line

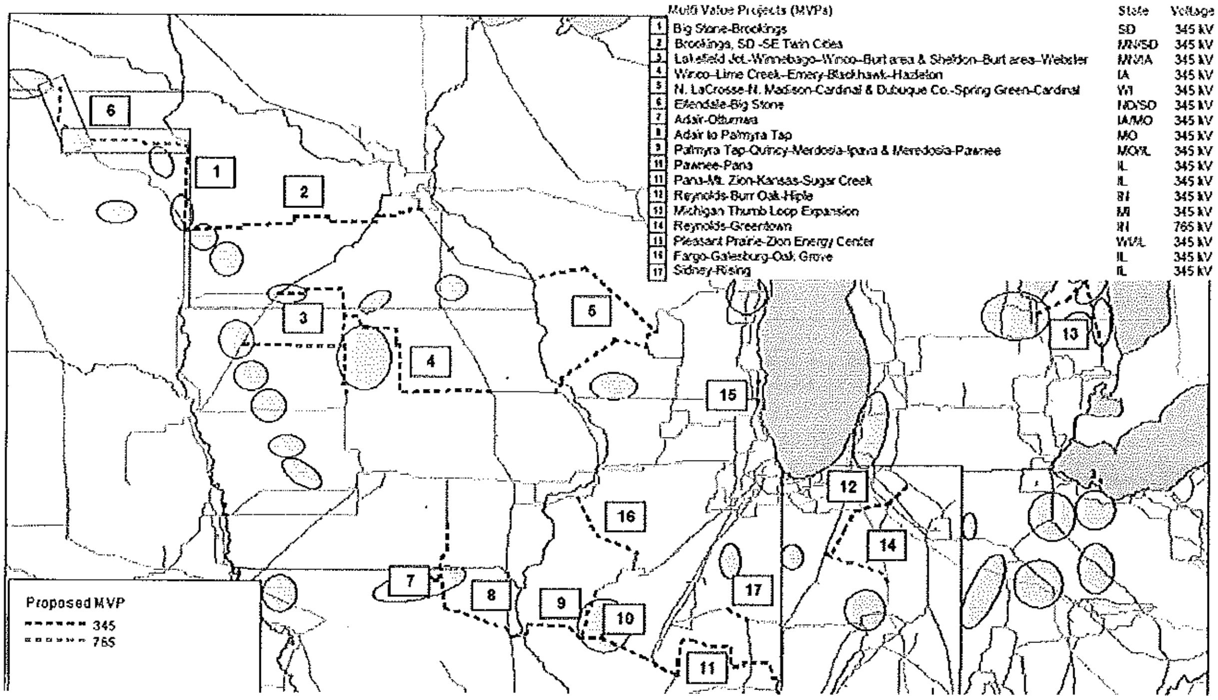

Figure 5.7: Ellendale to Big Stone

Project(s): 2220

Transmission Owner(s): OTP, MDU

Project Description:
This project creates a new 345 kV path through the border of the Dakotas by connecting OTP's Big Stone and MDU's Ellendale substations. Approximately 145 miles of new 345 kV transmission will be installed between these substations along with a new 345kV terminal at Ellendale and a 345/230 kV, 500 MVA transformer. The total estimated cost of this project is $261 million[16]. The expected in service date for this project is December 2019.

Project Justification:
The new 345 kV outlet from Ellendale removes overloads on the 230 kV path from Ellendale to Oakes to Forman and the 115 kV path from Ellendale to Aberdeen. Overloads on the 230/115 kV transformers at Ellendale, Forman and Heskett are also alleviated. Along with project 2221, this project reliably moves mandated renewable energy from the Dakotas to major 345 kV transmission hubs and load centers.

Alternatives Considered:
An alternative to convert the 115 kV path from Ellendale to Huron could alleviate the southern path constraints out of Ellendale but downstream transmission may also need to be rebuilt to accommodate wind injection delivered through a lower impedance line. The eastern 230 kV path out of Ellendale would need to be rebuilt to 345 kV up to Fergus Falls. The cost of this alternative is higher than a 345 kV path to Big Stone.

[16] In 2011 dollars

5.8 Ottumwa to Adair to Palmyra Tap 345 kV Line

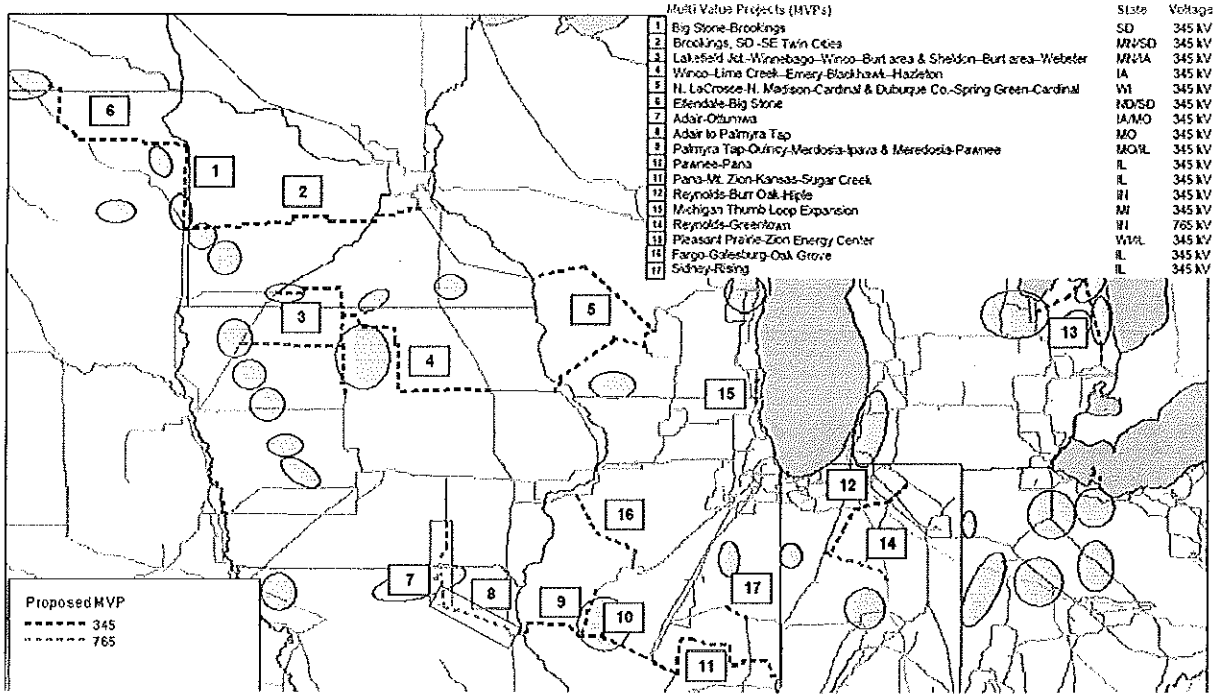

Figure 5.8: Ottumwa to Adair to Palmyra Tap

Project(s): 2248, 3170

Transmission Owner(s): Ameren Missouri, MEC, ITCM

Project Description:
This creates a 345 kV path through central/eastern Missouri by connecting Iowa's Ottumwa substation to Ameren Missouri's West Adair substation (P2248). It then extends 345 kV from West Adair to Ameren Missouri's Palmyra substation Tap (P3370), near the Missouri/Illinois border. Approximately 88 miles of new and rebuilt 345 kV line will be installed between Ottumwa and Adair, along with a 345kV terminal at Adair and a 345/161 kV, 560 MVA step down transformer. Sixty-three miles of new 345 kV line will be built between West Adair and the Palmyra Tap, where a new 345 kV switching station will be established. The estimated cost is $250 million[17]. The New Palmyra Tap substation will be ready by November 2016. The Ottumwa to West Adair 345 kV line and West Adair substation work will be ready by June 2017. The West Adair to Palmyra 345 kV line and West Adair 345/161 kV transformer will be ready by November 2018.

Project Justification:
The new 345 kV lines from Ottumwa to West Adair to Palmyra will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. In addition to providing a wind outlet, the new lines will provide reliability benefits by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformer at West Adair is especially effective in resolving 161 kV line overloads on the lines out of West Adair and preventing the loss of the generation at West Adair during certain NERC Category C events. This project will mitigate two bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints. It will also relieve three non-BES NERC Category B and two NERC Category C constraints.

[17] In 2011 dollars

Alternatives Considered:
An alternative was to incorporate an additional 345 kV line from West Adair to Thomas Hill. While improving reliability in the area, the addition would not improve the distribution of benefits within MISO. Thus the alternative was removed, and the proposed project was recommended.

5.9 Palmyra Tap to Quincy to Meredosia to Pawnee; Meredosia to Ipava 345kV Line

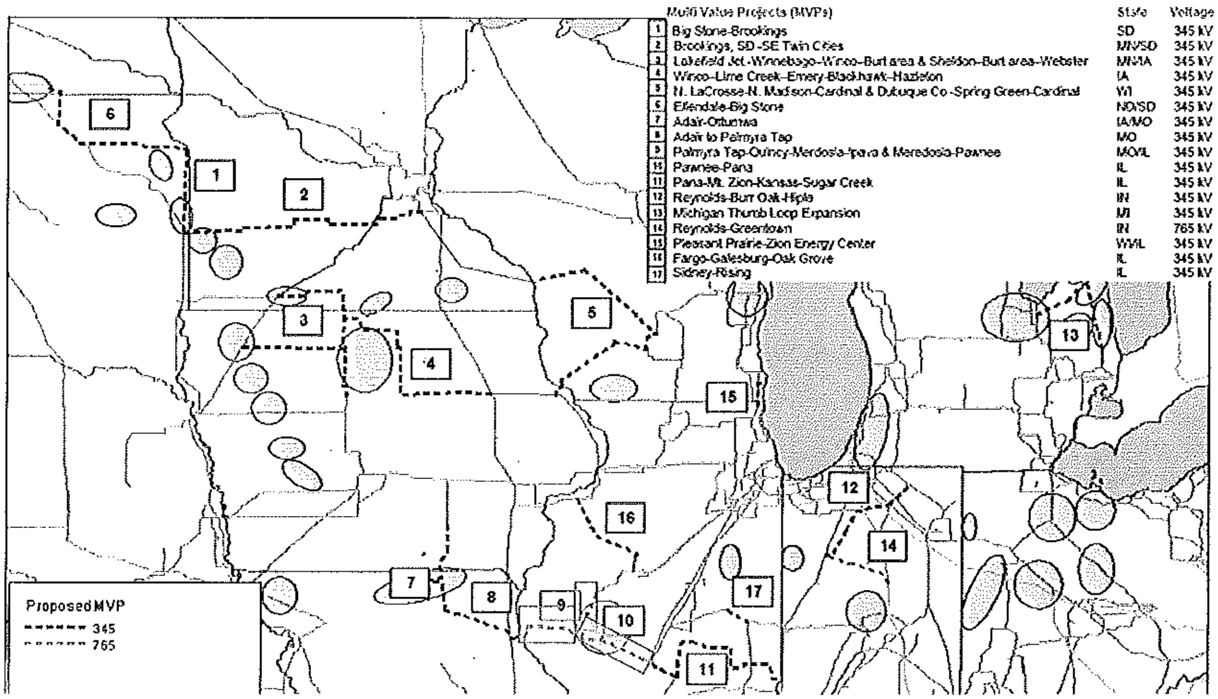

Figure 5.9: Palmyra Tap to Quincy to Meredosia to Pawnee; Meredosia to Ipava

Project(s): 3017

Transmission Owner(s): Ameren

Description: This creates a 345 kV path through western/central Illinois by construction of 345 kV lines between the new Palmyra Tap switching station to Quincy, Meredosia and Pawnee. Another 345 kV line would go from Meredosia north to the Ipava substation. A total of 116 miles of new 345 kV line will be built between the Palmyra switching station and Pawnee, with new 345/138 kV, 560 MVA transformers at Quincy and Pawnee. The new 345 kV line from Meredosia to Ipava would be 41 miles long. The estimated cost is $392 million[18]. The New Palmyra Tap switching station will be ready by June 2016. The Palmyra Tap switching station to Quincy to Meredosia 345 kV line and the Quincy and Pawnee 345/138kV transformers will be ready by November 2016. The Ipava substation upgrades for new 345 kV connection from Meredosia will be ready by June 2017. The Meredosia to Ipava and Meredosia to Pawnee 345 kV lines will be ready by November 2017.

Justification: The 345 kV lines from the Palmyra switching station to Pawnee and from Meredosia to Ipava will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. In addition to providing a wind outlet, the new lines will

[18] In 2011 dollars

provide reliability benefits by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformers in this project will keep the power flow on the 345 kV system. Otherwise, it would be, injected into the lower voltage transmission networks if the 345 kV additions are not made, which causes a number of lower voltage network constraints to be alleviated. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and three NERC Category C constraints.

Alternatives Considered: A 345 kV connection between Palmyra and Sioux would alleviate some constraints, but would not affect constraints in the Tazewell area, which would also need a 345 kV connection to Palmyra. The alternative would not provide regional distribution of benefits with the multi value project, as it would constrain the 345 kV path from St. Louis across southern Illinois and into Indiana. Therefore the proposed project is recommended for the greatest benefit.

5.10 Pawnee to Pana to Mt. Zion to Kansas to Sugar Creek 345kV Line

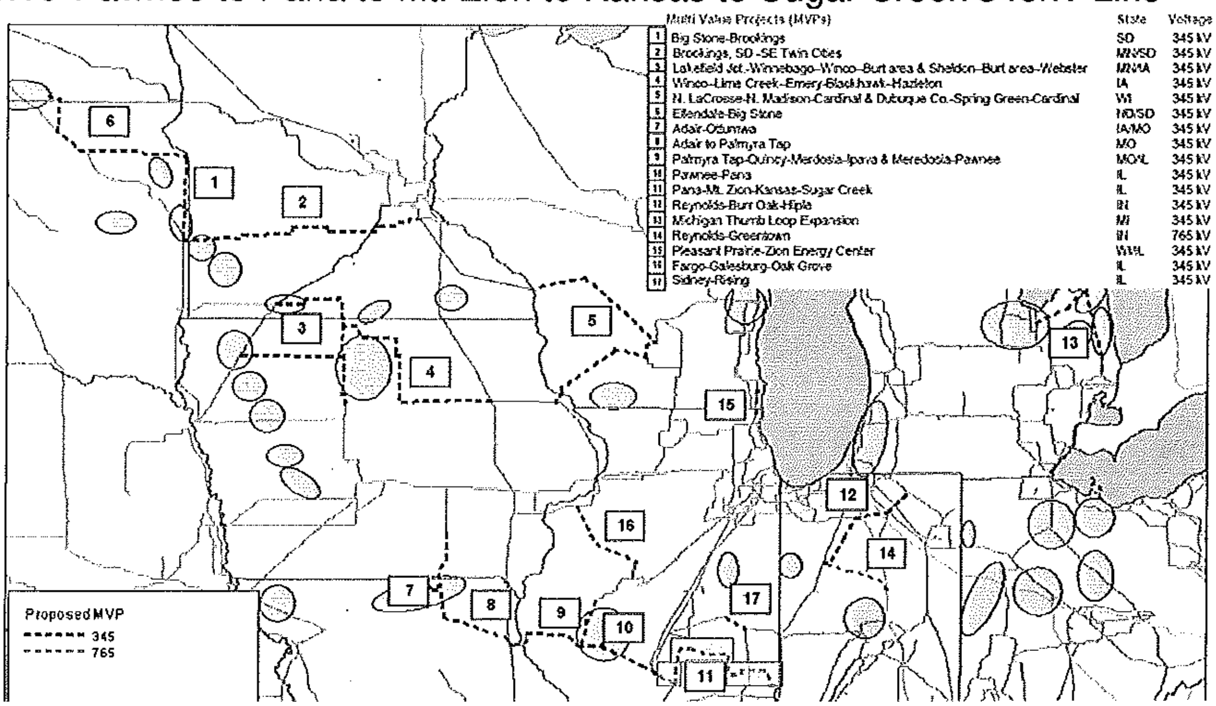

Figure 5.10: Pawnee to Pana to Mt. Zion to Kansas to Sugar Creek

Project(s): 2237, 3169

Transmission Owner(s): Ameren

Description: This creates a 345 kV path through eastern/central Illinois by building 345 kV lines between the Pawnee substation to Pana, Mt. Zion, Kansas and Sugar Creek (Indiana). A total of 146 miles of new 345 kV line will be constructed between the Pawnee substation and Sugar Creek substation on the eastern Illinois/Indiana border, with new 345/138 kV, transformers at Mt. Zion, Pana (both transformers are 560 MVA) and Kansas (448 MVA transformer). The estimated cost is $372 million[19] All components will be in service by November 2018, except the new Kansas to Sugar Creek 345 kV Line, which will be ready by November 2019.

[19] In 2011 dollars

Justification: The 345 kV lines from the Pawnee to Sugar Creek in western Indiana will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. This 345 kV extension creates another 345 kV path across central Illinois to connect to the existing 345 kV network in Indiana at Sugar Creek. This provides access wind generation to all of Indiana, and supplies major load centers such as Indianapolis and the Chicago suburbs in northern Indiana. The new lines will provide a wind outlet and reliability benefits, by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformers in this project will keep the power flow on the 345 kV system. Otherwise, it would be injected into the lower voltage transmission networks in Illinois if the 345kV additions are not made, which causes a number of lower voltage network constraints to be alleviated. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and 12 NERC Category C constraints.

Alternatives Considered: An alternative to the proposed project was a parallel 345 kV path to the north, which would have built a 345 kV line through Bloomington into Brokaw, through Gilman and to the Reynolds Substation in northwest Indiana. Although the benefits of taking this northern path were similar to the southern route, there were fewer benefits gained by going with the northern path. It also cost more than the recommended project.

5.11 Reynolds to Burr Oak to Hiple 345 kV line

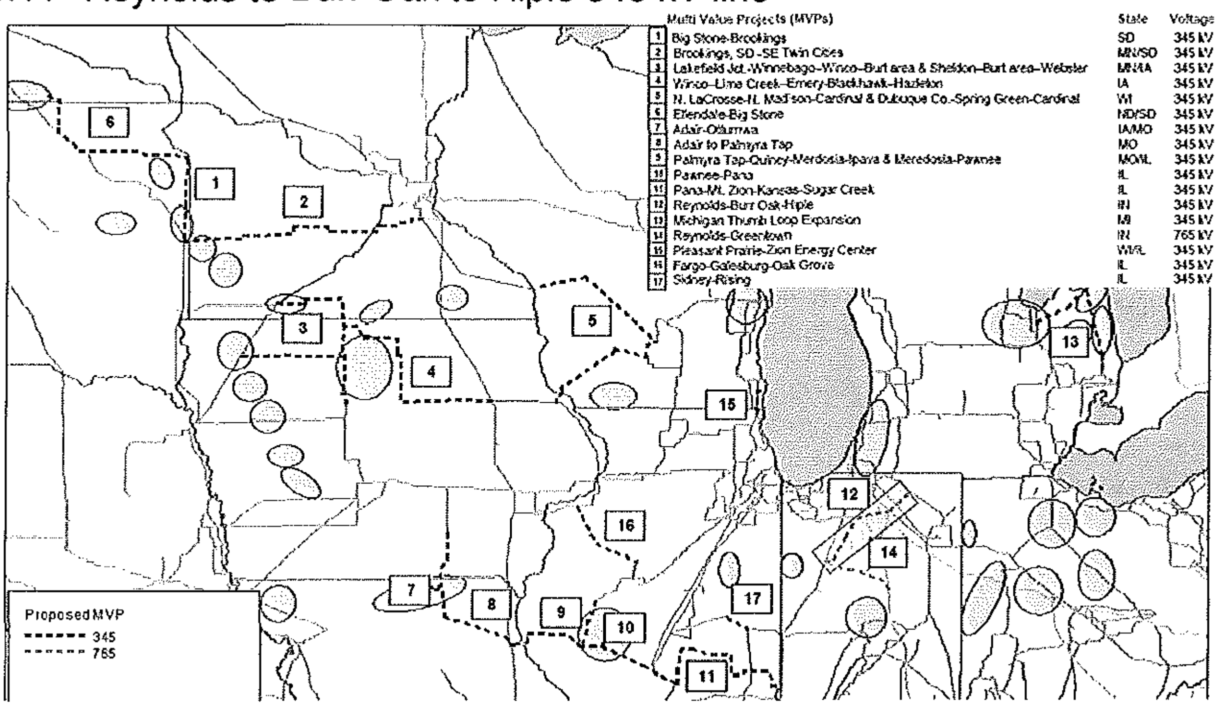

Figure 5.11: Reynolds to Burr Oak to Hiple

Project(s): 3203

Transmission Owner(s): NIPSCo

Description: This creates a 345 kV line from Reynolds substation to Burr Oak to Hiple through northern Indiana. At the Reynolds and Hiple stations, it creates a tie to 345kV lines routed near those two stations but do not connect electrically at those points. The 345 kV line is approximately 100 miles long, along with the substation upgrades at Reynolds and Hiple necessary to accommodate the new 345 kV line connections. The estimated cost of this project is $284 million[20]. The expected in service date is December 2019.

Justification: The project from Reynolds to Burr Oak to Hiple through northern Indiana will create a 345 kV path across the northern portion of Indiana toward Michigan, with the new tie at Hiple connecting an existing 345 kV line to the Argenta Station in southern Michigan. This path will provide an additional 345 kV path to move wind energy across Indiana, and closer to the east coast, bringing less expensive wind generation into areas where the expense to generate power can be considerably greater. The line will relieve overloads on the 138 kV system along a parallel path as well as the 138 kV network in the Lafayette, IN, area. The additional ties at Reynolds and Hiple also reduce loading on the existing 345 kV lines and creates a second path for power flow in this area, enhancing system reliability. This project will mitigate five bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints.

Alternatives Considered: There is no viable alternative to the proposed plan. The proposed project runs parallel to the constraints identified and is the most effective at relieving them.

5.12 MI Thumb Loop Expansion

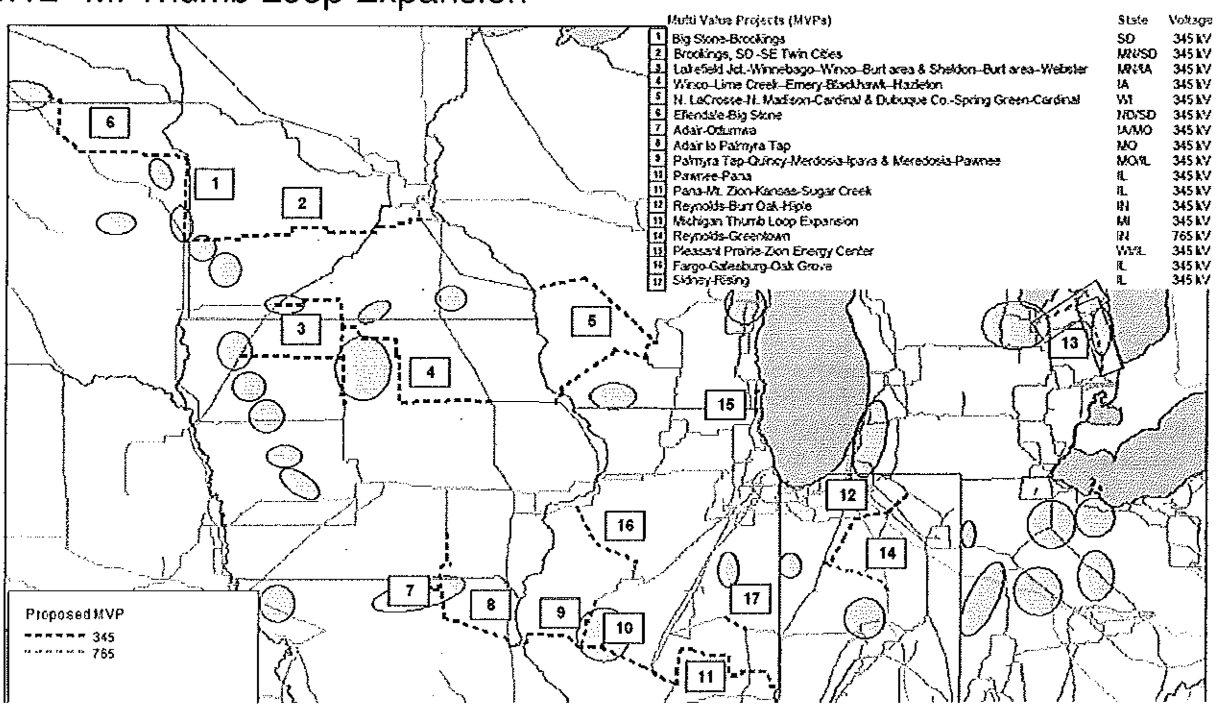

Figure 5.12: Michigan Thumb Loop Expansion

Project(s): 3168

Transmission Owner(s): ITC

Description: The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be

[20] In 2011 dollars

located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station, two 345 kV circuits will extend down the east side of the Thumb to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the sites that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area. The cost of this project is $510 million[21].

Justification: This project was needed pursuant to the directives of the Michigan Public Service Commission' and the Final Report of the Michigan Wind Energy Resource Zone Board ("Board"). This project is necessary to deliver wind mandate in Region 4, the primary wind zone region in Michigan (the Thumb). Reliability analysis tested 13 different system conditions involving Ludington pumped storage scenarios and Ontario interface transfers. Without mitigations, overloads were up to 155% and instability may happen for some multiple contingencies. With the existing system and alternative designs tested, NERC reliability standards cannot be met when renewable sufficient to deliver the wind mandates are connected.

Alternative 1 Considered: Replace the existing single circuit 120 kV loop from Tuscola up to Wyatt and down to Lee with two new 230 kV circuits on a 230 kV double circuit tower line that will extend from a new 230 kV station at or near the existing 120 kV Wyatt station southwest to a new 345/230 kV station southwest of the existing Atlanta 138/120 kV station and two more 230 kV circuits on a 230 kV double circuit tower line that will extend from the new 230 kV station at or near the Wyatt station down around to the existing Greenwood 345 kV station utilizing high temperature 1431 ACSR conductor (or an equivalently rated conductor) and 230 kV double circuit tower (or steel pole) construction, existing ROW as available and new ROW where necessary. Also, add two new 230 kV circuits (on new ROW) on a 230 kV double circuit tower line that will extend from the new station at or near the Wyatt station down around the west side of the Thumb to the new station south west of the Atlanta 138/120 kV station and two new 230 kV circuits on a 230 kV double circuit tower line that will extend from the Wyatt station down to the Greenwood station along the east side of the Thumb utilizing a similar conductor/tower configuration as the "inner loop". Continue south from the Greenwood 345 kV station with a new 345 kV double circuit tower line containing two new 345 kV circuits toward a new 345 kV station at a site due south of the existing Greenwood station and just north of the point where the three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The two new 345 kV circuits from Greenwood to this new station south of Greenwood would parallel the existing 345 kV circuit along that same path. These routes would utilize existing ROW to the extent possible.

Total Project Cost Estimate: $740, 000,000

Alternative 2 Considered: Replace the existing single circuit 120 kV loop from Tuscola up to Wyatt and down to Lee with two new 230 kV circuits on a 230 kV double circuit tower line that will extend from a new 230 kV station at or near the existing 120 kV Wyatt station southwest to a new 345/230 kV station southwest of the existing Atlanta 138/120 kV station and two more 230 kV circuits on a 230 kV double circuit tower line that will extend from the new 230 kV station at or near the Wyatt station down around to the existing Greenwood 345 kV station utilizing high temperature 1431 ACSR conductor (or an equivalently rated conductor) and 230 kV double circuit tower (or steel pole) construction, existing ROW

[21] In 2011 dollars

as available and new ROW where necessary. Also, add two new 230 kV circuits (on new ROW) on a 230 kV double circuit tower line that will extend from the new station at or near the Wyatt station down around the west side of the Thumb to the new station south west of the Atlanta 138/120 kV station utilizing a similar conductor/tower configuration as the "inner loop". Then continue south from the Greenwood 345 kV station with a new 345 kV double circuit tower line containing two new 345 kV circuits toward a new 345 kV station at a site due south of the existing Greenwood station and just north of the point where the three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The two new 345 kV circuits from Greenwood to this new station south of Greenwood would parallel the existing 345 kV circuit along that same path. These routes would utilize existing ROW to the extent possible.

Total Project Cost Estimate: $560,000,000

5.13 Reynolds to Greentown 765 kV line

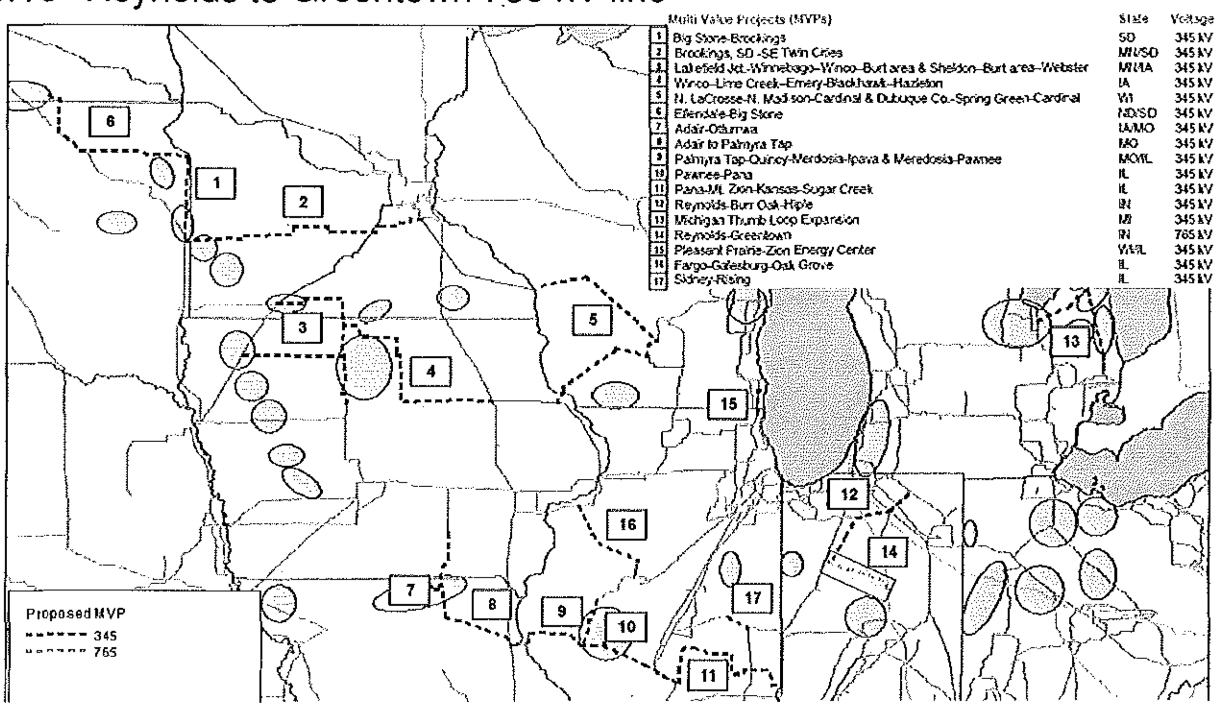

Figure 5.13: Reynolds to Greentown

Project(s): 2202

Transmission Owner(s): NIPSCO, Duke

Description: This project creates a 765 kV line from the Reynolds substation to the Greentown substation through Indiana, north of the Lafayette area. A 765/345 kV transformer/substation will also be installed at the Reynolds substation. The length of 765 kV line is approximately 66 miles, along with the 765 kV substation terminal upgrades at Greentown necessary to accommodate the 765 kV line connection. The estimated cost of this project is $245 million[22]. The 765 kV line project will be ready by June 2018. The 765/345 kV substation upgrade/construction will be ready by August 2018.

Justification: The 765 kV line from Reynolds to Greentown path across central Indiana will create an additional wind outlet path across the state, pushing power closer to the east coast, bringing less expensive wind generation into areas where the generation of power can be considerably more expensive. There are constraints on reliability on the 345 kV system to the north going toward

[22] In 2011 dollars

Chicago and Michigan, and to the south, crossing the Illinois/Indiana border and down into southwestern Indiana. These are mitigated with the new 765 kV line. The system flows attempt to bring power back to the Greentown substation, which cause numerous overloads for contingent scenarios that can be mitigated with the proposed 765 kV line. The line will also relieve constraints on the 138 kV system along a parallel path in the Lafayette, Indiana, area as well as the 138 kV line to the south between Dresser and Bedford. This 765 kV line will provide reliability benefits throughout Indiana. This project will mitigate seven bulk electric system (BES) NERC Category B thermal constraints and 21 NERC Category C constraints. It also relieves four non-BES NERC Category C constraints.

Alternatives Considered: Alternatives to the proposed project would be building lines to bypass the Lafayette area, which would relieve the constraints identified in this analysis, but load up the 230 and 138kV systems beyond the Lafayette area. The 345 kV in the Cayuga area is also heavily loaded, and upgrading would not be recommended. The proposed project is effective in alleviating all these constraints, without creating new ones, and provides a reduction of loadings on the existing lines.

5.14 Pleasant Prairie to Zion Energy Center 345 kV line

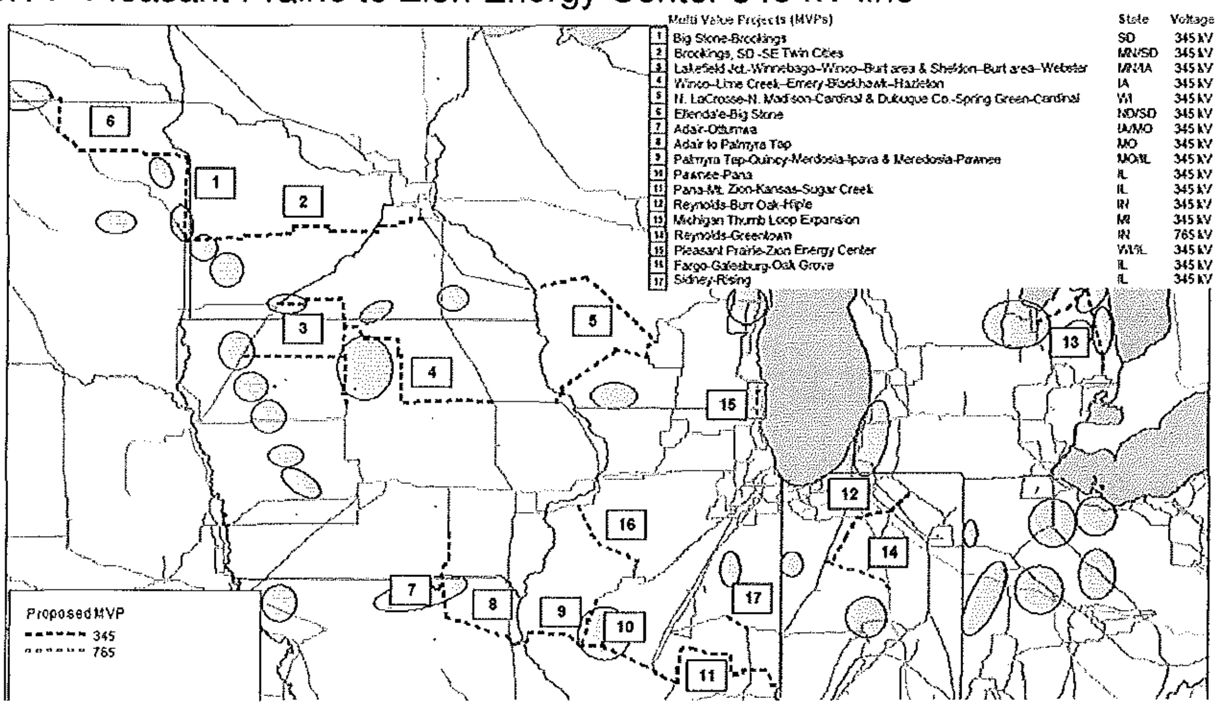

Figure 5.14: Pleasant Prairie to Zion Energy Center

Project(s): 2844

Transmission Owner(s): ATC

Description: A 345 kV line will be created from the Pleasant Prairie substation in Wisconsin to the Zion Energy Center substation in Illinois. The line will be approximately 5.3 miles long. The estimated cost is $26 million[23]. The expected in service date is March 2014.

Justification: The 345 kV line from Pleasant Prairie to Zion Energy Center creates an additional 345kV tie between these two stations, allowing more power to flow from the north down into Illinois.

[23] In 2011 dollars

That will bring wind energy from the north and west into this area. From a reliability perspective, the addition of the path relieves constraints on the 138 kV system adjacent to the project as well as 138 kV system constraints to the west of the new line. This project will mitigate seven bulk electric system (BES) NERC Category B thermal constraints and four NERC Category C constraints.

Alternatives Considered: No viable alternatives to this project were identified. The proposed project, which creates a parallel path to the existing constrained line, is the most effective solution.

5.15 Oak Grove to Galesburg to Fargo 345 kV line

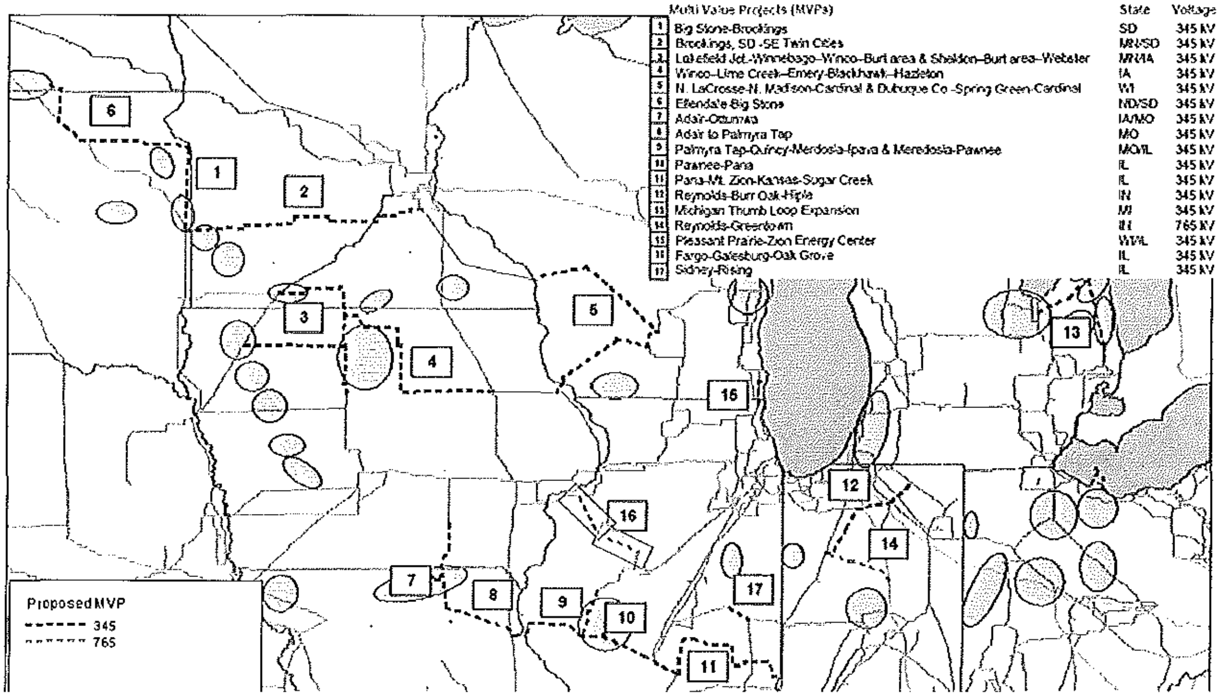

Figure 5.15: Oak Grove to Galesburg to Fargo 345 kV line

Project(s): 3022

Transmission Owner(s): Ameren, MEC

Description: This creates a 345 kV line from the MEC's Oak Grove substation to Ameren's Galesburg substation and to the Fargo substation through central Illinois. A new 560 MVA, 345/138 kV transformer will be installed at the Galesburg substation in addition to terminal additions/upgrades at all three substations. The 345 kV line is approximately 70 miles long, along with 40 miles of reconductor/rebuild at 345 kV and 138 kV to complete the project. The estimated cost is $193 million[24]. The Oak Grove – Galesburg 345 kV line and the Oak Grove 345 kV substation upgrades are expected to be ready by December 2016. The Fargo – Oak Grove 345 kV Line and Galesburg transformer addition are expected to be ready by November 2018. The Fargo substation upgrades are expected to be in service in 2018.

Justification: The new 345 kV line from Oak Grove to Galesburg to Fargo creates a path from western Illinois near the Iowa/Illinois border to central Illinois. This expansion creates an additional wind outlet path across the state, pushing power into central Illinois. In combination with another MVP, Dubuque – Spring Green – Cardinal 345 kV line, this enables 1,100 MW of wind power transfer

[24] In 2011 dollars

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capability. From a reliability perspective, the addition of the Oak Grove to Fargo 345 kV path helps relieve constraints on the 345 kV system to the north. The 138kV system in the same area is also overloaded during certain contingent events. With the MVPs proposed in Wisconsin, Oak Grove to Fargo is needed to provide an outlet for the power coming from the west. It will keep that power on the 345 kV transmission system, rather than forcing it through the 138 kV system, requiring significant upgrades to carry the increased power flow.

Analysis also shows that the north ties from ATC to ComEd will remain constrained despite a new MVP from Pleasant Prairie to Zion, if the Oak-Grove Fargo 345 kV line is not built. This is because both outlets, Dubuque-Cardinal and Oak Grove-Fargo, are needed to effectively mitigate constraints on the transmission network supplying the Chicago area. This project will mitigate six bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints.

Alternatives Considered: Alternatives to the proposed project would be upgrading the 345 and 138 kV lines that are overloaded going toward Chicago. Upgrading the overloaded lines would likely lead to more overloads to the east, by injecting the additional power into an already constrained 345 kV path through Com Ed's Silver Lake area. The proposed project provides the greatest benefit to the transmission system.

5.16 Sidney to Rising 345kV Line

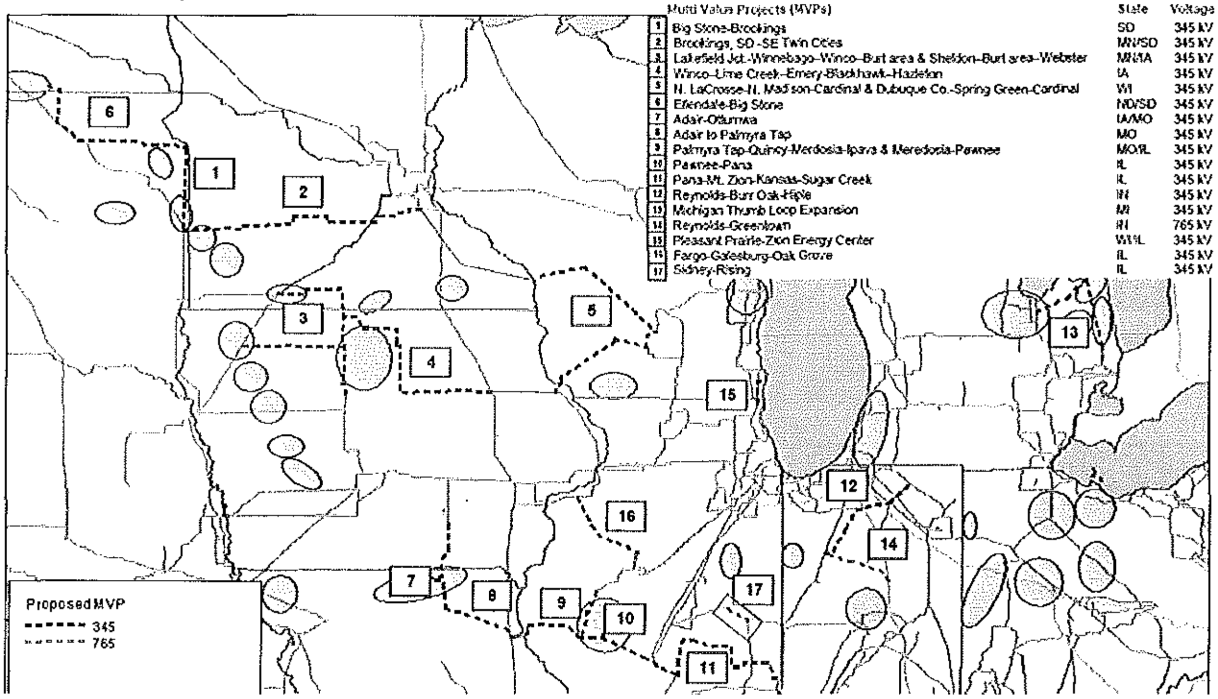


Figure 5.16: Sidney to Rising 345 kV line

Project(s): 2239

Transmission Owner(s): Ameren

Description: This builds a 345 kV line between the Sidney and Rising substation through eastern/central Illinois. That would create approximately 27 miles of 345 kV line, along with the substation upgrades at Sidney and Rising needed to accommodate the new line. The estimated cost of this project is $90 million[25]. The Sidney and Rising substation upgrades are expected to be ready by June 2016, and the 345 kV line should be ready by November 2016.

Justification: The 345 kV line from Rising to Sidney in Illinois will connect a gap in the 345 kV network in the area, promoting wind generation moving from the west to the east into Indiana. It will mitigate constraints by keeping the power on the 345 kV system, rather than pushing it into the 138 kV network at Rising. That causes overloads on the Rising transformer and on nearby 138 kV lines fed from Rising. This project will mitigate one bulk electric system (BES) NERC Category A thermal constraint, one NERC Category B constraint and three NERC Category C constraints.

Alternatives Considered: Upgrading the transformer at Rising and the 138 kV lines are a possible alternative, but that transformer was upgraded recently. Analysis shows that the power flow is being forced into the 138 kV system between Sidney and Rising to step back up to the 345 kV system. Completing the short connection between Sidney and Rising is the most effective recommendation for a long term solution.

[25] In 2011 dollars

6 Portfolio reliability analyses

In addition to the individual project justification, the MVP portfolio analysis also included an evaluation of the complete recommended MVP portfolio to ensure that system reliability is maintained. The recommended MVP portfolio maintains system reliability by resolving violations on approximately 650 transmission elements for more than 6,700 system conditions. It also mitigates 31 system instability conditions. More information on the constraints for each individual project may be found in Section 6 of this report.

6.1 Steady state

6.1.1 Reliability Planning Methodology Overview

The reliability assessment performed for the MVP portfolio analysis tested the transmission system using appropriate North American Electric Reliability Corporation (NERC) Table 1 events to determine if the system, as planned, meets Transmission Planning (TPL) standards. Any violation of these standards was identified, and the components of the portfolio were tested to determine their effectiveness in addressing the identified issues. In addition secondary transmission upgrades were developed to mitigate any unresolved issues. The performance of the mitigation plan was tested to ensure it alleviates the identified issues and does not create additional issues.

6.1.2 Planning Criteria and Monitored Elements

In accordance with the MISO Transmission Owners Agreement, the MISO Transmission System is to be planned to meet local, regional and NERC planning standards. The MVP portfolio analysis, performed by MISO staff, tested the performance of the system against the NERC Standards when applicable Renewable Portfolio Standards (RPS) were applied. Compliance with local requirements, where the local requirements exceed NERC standards, was not evaluated. This analysis will be performed by the responsible Transmission Owners. All system elements that were loaded at 95% or higher were flagged as transmission issues for Category A, B and C events. Elements under Category C3 contingencies were flagged as transmission issues at loadings of 125% and higher.

All system elements, 100 kV and above, within the MISO Planning regions, as well as tie lines to neighboring systems, were monitored. Elements 69 kV and above were monitored in select MISO Planning regions per Transmission Owner planning standards. Some non-MISO member systems were monitored if they were within the MISO Reliability Coordination Area.

6.1.3 Baseline Modeling Methodology

The MVP portfolio analysis powerflow models were developed to represent various system conditions in the planning horizon. 2021 Summer Peak and 2021 Shoulder Peak powerflow models were developed. MISO coordinated with external seam regions, including TVA, SPP, MAPP and PJM, to reflect the latest topology of the corresponding regions. For all other areas, modeling data from the 2020 Eastern Interconnection Planning Collaborative (EIPC) model was applied.

6.1.4 Contingencies Examined

Regional contingency files were developed by MISO staff collaboratively with Transmission Owners and regional study group input. NERC Category A, B and C contingency events on the transmission system under MISO functional control were analyzed. In general, contingencies on the MISO members' transmission system at 100 kV and above were analyzed, although some 69 kV transmission was also analyzed. The MTEP10 MRO contingency files were used with updates from MISO Transmission Owners. Automated single contingencies and bus double contingencies were also performed on the new MVP and surrounding transmission.

6.1.5 Results

A total of 384 thermal overloads were mitigated by the recommended MVP portfolio under shoulder peak conditions, for approximately 4,600 system conditions. In addition, approximately 100 additional thermal overloads and 150 voltage violations were mitigated by the recommended MVP portfolio in the summer peak analysis.

6.2 Transient stability

The purpose of performing transient stability analysis is to identify loss of synchronism, sometimes referred to as 'out of step' conditions for existing and proposed generation under severe fault conditions required by NERC and regional reliability standards. For the MVP portfolio transient stability analysis, two scenarios were studied.

Tasks of the two studies were evaluation of the impact of major fault conditions on the ability of the generators to remain synchronized to the electric system without any voltage or damping criteria violations.

6.2.1 Methodology and base case creation

Transient stability analysis was performed on two cases representing the shoulder peak conditions, in 2021, after the addition of RGOS wind zones and the 17 MVP portfolio lines. The following two cases were created for comparative analysis. These models were based upon the MTEP11 powerflow models utilized for the steady state analysis, as described in the previous section.

1. A base case, or the "No MVP portfolio case," was developed by adding all the incremental wind zones, without the portfolio, to the MTEP11 case.
2. A study case, or the "With MVP portfolio case," was developed by adding all the incremental wind zones, with the portfolio, to the MTEP11 case.

The corresponding dynamic files, for the power flow cases mentioned above, were created by adding the GE 1.5 MW turbines (GEWTG1- Type 3 model) to represent each wind zone. It was assumed that all new wind turbines would have a +/-0.95 power factor range. The machine data for all existing units was unchanged because it had been reviewed by the Transmission Owners during the MTEP10 review process. For all external models where the data was not available, machines were modeled with a classical machine model (GENCLS).

6.2.2 Monitored facilities

For evaluating the transient stability performance under fault conditions, the rotor angle, active power output, terminal voltage and the reactive power output for each machine was monitored. For evaluating the transient voltage violations under fault conditions, 345kV bus voltages in each MISO control area were monitored. The list of monitored bus voltages can be seen in Appendix C of this report.

6.2.3 Fault analysis and assumptions

All faults that were analyzed during the MTEP10 stability analysis review were used as the starting point for the stability analysis. In addition, several three phase faults and single line to ground faults (SLG) were developed to simulate fault conditions on the MVP portfolio lines. All these faults were reviewed by the Technical Study Task Force in the first quarter of 2011.

A two cycle margin was added to the fault clearing times to determine if system reliability would be maintained under more stressed conditions. Generally, when the fault clearing times are increased, the probability of having an unstable condition is also increased. Therefore, it was important to determine whether the existing MTEP10 faults would cause system instability; with a two cycle embedded margin to account for modeling errors that can mask underlying reliability issues if the clearing times are close to the critical clearing times. This analysis was not required to comply with any NERC reliability criteria, but was performed to check the strength of the power system with increased wind generation and transmission under the 2021 conditions.

At the time this fault analysis was conducted, short circuit data was not available to model SLG fault conditions for the CMVP faults. NERC Category C6, C7, C8 and C9 reliability criteria requires the system to be stable under SLG faults cleared under delayed clearing such as a stuck breaker condition. NERC Category D1, D2, D3 and D4 reliability criteria, which is a lot more stringent, requires the system to be stable under three phase fault conditions with delayed clearing. Typically, a three phase fault is a lot more severe than a SLG fault and is a lot easier to simulate due to the absence of zero sequence fault currents. Therefore, SLG faults with delayed clearing on the MVP portfolio lines were simulated as three phase faults with delayed clearing.

The rationale for choosing this approach was simple. If the Three Phase faults were stable under delayed clearing conditions, then it could be reasonably assumed that the same faults would also be stable under SLG with delayed clearing. However, if the analysis revealed that a few faults caused instability, then only those faults would then be re-analyzed with correct fault impedance.

6.2.4 Results

The transient stability analysis revealed that the addition of the MVP portfolio to the transmission system made the system more stable under several fault conditions and 2021 shoulder peak conditions. There were a few fault conditions, which required the addition of minor reactive support devices at a couple of 345kv buses in the western region of the MISO transmission system. The evaluation of optimized reactive support locations under these fault conditions will be studied during the regular MTEP12 reliability analysis, which requires additional stakeholder input and more detailed analysis. The results of the transient stability analysis are under Appendix C of this report.

6.3 Voltage stability

Voltage stability analysis was performed to identify voltage collapse conditions under high energy transfer conditions from major generation resources to major load sinks. For this analysis, high transfer conditions were analyzed, from the wind rich west region of the MISO footprint to major load centers such as Minneapolis-St. Paul, Madison, St Louis and Des Moines. The idea was to evaluate the incremental transfer capability, between the generation resources and the load sinks, that is created by the addition of the MVP portfolio under 2021 summer peak conditions.

6.3.1 Methodology and base case creation

The evaluation of the MVP portfolio's incremental transfer capability benefits can only be quantified when the results are compared to identical system conditions without the MVP lines. Therefore, two different power flow cases were created for 2021 summer peak conditions, shown below.

1. A base case or the "No MVP portfolio case" was developed by adding all the incremental wind zones without the portfolio.

2. A study case or the "With MVP portfolio case" was developed by adding all the incremental wind zones with the portfolio.

For each of the two cases mentioned above, four different transfers were modeled by increasing the generation in the source areas and reducing the generation in the load areas. The idea is to transmit maximum megawatts over the transmission system before a voltage collapse condition occurs due to the contingency loss of a major transmission line. For each simulated transfer, an interface consisting of major import transmission lines into the load centers was created and monitored for each contingency.

The voltage stability transfer analysis was simulated under several contingency conditions to identify the worst contingency and the corresponding maximum megawatt transfer levels over the defined interface. This method was repeated for each transfer and for both the 2021 summer peak load cases as described above.

6.3.2 Results

The comparative analysis summary below shows that the addition of the MVP lines boosted transfer capabilities from wind rich regions to major load centers within the MISO footprint. The details of the voltage stability analysis showing the PV plots and reactive reserve margins for each transfer, under both scenarios, can be viewed in Appendix C of this report.

Voltage Stability Transfer Analyzed	Without Multi Value Project Portfolio (MW)	With Multi Value Project Portfolio (MW)	Incremental Transfer enabled by the MVPs (MW)	Incremental Transfer enabled by the MVPs (percent)
MISO West - Twin Cities	3399	5240	1841	54 percent
MISO West - Madison	1720	3160	1440	84 percent
MISO West - Des Moines	2000	3100	1100	55 percent
MISO West - St Louis	3700	4660	960	26 percent

Table 6.1: Transfer capabilities under high transfer conditions

6.4 Short circuit

The reliability analysis component of the MVP portfolio study included a short-circuit analysis. The goal was to determine whether the installation of the MVP transmission facilities would cause certain existing circuit breakers to exceed their short-circuit fault interrupting capability.

Per the Tariff, should the installation of one or more MVPs cause an electrical issue on a facility, the resolution can be included in the scope of the MVP. The costs can then be shared using the same regional cost allocation mechanism applicable to the base MVPs, as long as the electrical issue is associated with a facility that is owned by a MISO Transmission Owner and classified as a transmission plant. While many electrical issues resulting from MVPs are loading or voltage related, it is also possible for the MVPs to raise the available short-circuit fault current at specific buses.

When the available short-circuit fault current increases beyond the capability of one or more circuit breakers to interrupt the fault current, the situation must be remedied. Typical remedies include replacing the affected circuit breaker with those with higher short circuit fault interrupting capabilities. In some situations, it may be necessary to reconfigure the topology of the system (e.g., splitting buses, etc.) if the available short-circuit fault currents exceed the capabilities of available circuit breakers.

To perform the short-circuit analysis, MISO developed default criteria to govern the short-circuit study. MISO then requested each Transmission Owner to conduct a short-circuit analysis on their own circuit breakers, using either their own internal criteria or MISO's default criteria, to determine if there are fault duty issues with any circuit breakers caused by the installation of one or more MVPs. Most Transmission Owners elected to use the default MISO criteria. The Transmission Owners then submitted results to MISO, including any recommendations to be added to the scope of existing MVPs. The default MISO criteria for the short-circuit analysis follows.

6.4.1 Default criteria for worst case fault current interruption exposure

This default criteria will establish the worst case fault current interruption exposure for each circuit breaker when there is no established criteria for worst case fault current interruption exposure for a specific Transmission Owner:

- Three-phase, phase-to-ground and double phase-to-ground faults will be evaluated. Phase-to-phase faults will not be evaluated.

- Faults will be simulated with zero fault impedance.
- Fault currents will be calculated in accordance with IEEE/ANSI Standard C37.010-1999 using the X/R multiplying factors.
- Faults will be simulated with all generation on-line with the sub transient reactance or equivalent modeled for all generators.
- Faults will be simulated with all network buses and branches in their normal configuration.
- For branch faults, fault locations will be simulated at the branch-side terminals of the circuit breaker in question.
- For branch and bus faults, faults current circuit breaker flows will be determined assuming all other circuit breakers protecting the branch or bus are open. While this results in a lower total fault current, this typically represents the highest fault current exposure for a specific circuit breaker.
- For each circuit breaker, simulations will be made to determine the worst case fault current interruption exposure for primary and backup zones of protection, where backup zones of protection are covered by a specific circuit breaker under the failure of a different circuit breaker.

6.4.2 Default criteria for circuit breaker fault duty calculations

The following default criteria will be used to establish the fault duty for each circuit breaker when there is no established criteria for circuit breaker fault duty calculations for a specific Transmission Owner:

- For each circuit breaker, the interrupting capability of the circuit breaker must be greater than the worst case fault current interrupting exposure of the circuit breaker, plus a safety margin of 2.5 percent
- When specific circuit breakers must be derated for reclosing duty, the Transmission Owner will inform MISO about the specific derates and the associated zones of protection where they apply for each circuit breaker. These derates will be applied in determining the fault duty for the circuit breaker.

6.4.3 Results

The results of the short-circuit analysis indicated the need for only nine circuit breaker replacements, representing an estimated capital cost of about $2.2 million, or less than 0.1 percent of the recommended MVP portfolio. The circuit breaker replacements represented lower voltage circuit breakers exposed to higher fault current levels due the installation of nearby MVP facilities. The recommended circuit breaker replacements are shown in the table below:

Substation	Voltage	Number of Breaker Replacements	Driving MVP
Blount	69 kV	3	N. Lacrosse – Cardinal - Dubuque
Lakefield	161 kV	1	Lakefield - Hazleton
Winnebago	161 kV	3	Lakefield – Hazleton
Lime Creek	161 kV	1	Lakefield – Hazleton
Hazleton	161 kV	1	Lakefield – Hazleton

Table 6.2: Circuit breaker replacements

7 Portfolio Public Policy Assessment

The projects in the proposed Multi Value Project portfolio were evaluated against criterion 1, which require the projects to reliably or economically enable energy policy mandates. To demonstrate the ability of the portfolio to enable the renewable energy mandates of the footprint, a set of analyses were conducted to quantify the renewable energy enabled by the footprint.

This analysis took part in two parts. The first part demonstrated the wind needed to meet the 2026 renewable energy mandates that would be curtailed but for the recommended MVP portfolio. The second part demonstrated the additional renewable energy, above the 2026 mandate, that will be enabled by the portfolio. This energy could be used to serve mandated renewable energy needs beyond 2026, as most of the mandates are indexed to grow with load.

7.1 Wind Curtailment

A wind curtailment analysis was performed to find the percentage of mandated renewable energy which could not be enabled but for the recommended 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 as mitigated by the recommended MVP portfolio. The 429 monitored element/contingent element pairs (flowgates) consisted of 205 Category B and 224 Category C contingency events. These constraints were taken from a blend of 2021 and 2026 wind levels with the final calculations based on the 2026 wind levels.

Since the majority of the western region MVP justification was based on 2021 wind levels, it was assumed that any incremental increase to reach the 2026 renewable energy mandated levels would be curtailed. A transfer of the 193 wind units, sourced from both committed wind units and the RGOS energy zones, to the system sink, Browns Ferry in TVA, 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 Multi Value Project justifications, a target loading of less than or equal to 95% was used. 24 of the 429 flowgates could not achieve the target loading reduction, and their targets were relaxed in order to find a solution.

The algorithm found that 10,885 MW of dispatched wind would be curtailed. As a connected capacity, this equates to 12,095 MW as the wind is modeled at 90% of its nameplate. A MISO-wide per-unit capacity factor was averaged from the 2026 incremental wind zone capacities to 32.8%.

The curtailed energy was calculated to be 34,711,578 MWHr from the connected capacity times the capacity factor times 8,760 hours of the year. Comparatively, the full 2026 RPS energy is 55,010,629 MWHr. As a percentage of the 2026 full RPS energy, 63% would be curtailed in lieu of the MVP portfolio.

7.2 Wind Enabled

Additional analyses were performed to determine any incremental wind energy, in excess of the 2026 requirements, enabled by the recommended MVP portfolio. This energy could be used to meet renewable energy mandates beyond 2026, as most of the state mandates are indexed to grow with load. A set of two First Contingency Incremental Transfer Capability (FCITC) analyses were run on the 2026 model to determine how much the wind in each zone could be ramped up prior to additional reliability constraints occurring.

First, a transfer was sourced from all the wind zones in proportion to their 2026 maximum output. All the Bulk Electric System (BES) elements in the MISO system were monitored, with constraints being flagged at 100% 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, in the proportions below. 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 7.1: Transfer Sink Distribution

As a result of this analysis, it was determined that an additional 981 MW could be reliably sourced from the energy zones. Because of regional transfer limits, no additional western wind could be increased beyond this level. The output levels of the wind zones were updated in the model and a second transfer analysis was performed to determine any incremental wind that could be sourced from the Central and East wind zones. This analysis was performed with the same methodology and sink as the first analysis, but all the western wind zones were excluded from the transfer source. This analysis determined that 1,249 MW of additional generation could be sourced from the Central and Eastern wind zones.

Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled
IA-BF	22.5	IN-E	144.9	MT-A	15.4
IA-GH1	27.4	IN-K	483.0	ND-M	2.4
IA-H2	76.0	MN-B	109.5	SD-HJ	130.1
IA-J	5.1	MN-H	254.7	SD-L	15.4
IL-F	678.6	MN-K	34.8	WI-B	230.4

Table 7.2: Incremental Wind Enabled Above 2026 Mandated Level, by Zone

In total, it was determined that 2,230 MW of additional generation could be sourced from the incremental energy zones to serve future renewable energy mandates. When the results from the curtailment analyses and the wind enabled analyses are combined, the recommended MVP portfolio enables a total of 41 million MWhs of renewable energy to meet the renewable energy mandates.

8 Portfolio economic benefits analyses

Multi Value Projects represent the next step in the evolution of the MISO transmission system: a regional network that, when combined with the existing system, provides value in excess of its costs under a variety of future policy and economic conditions. These benefits are discussed below, as well as the analyses used to determine them.

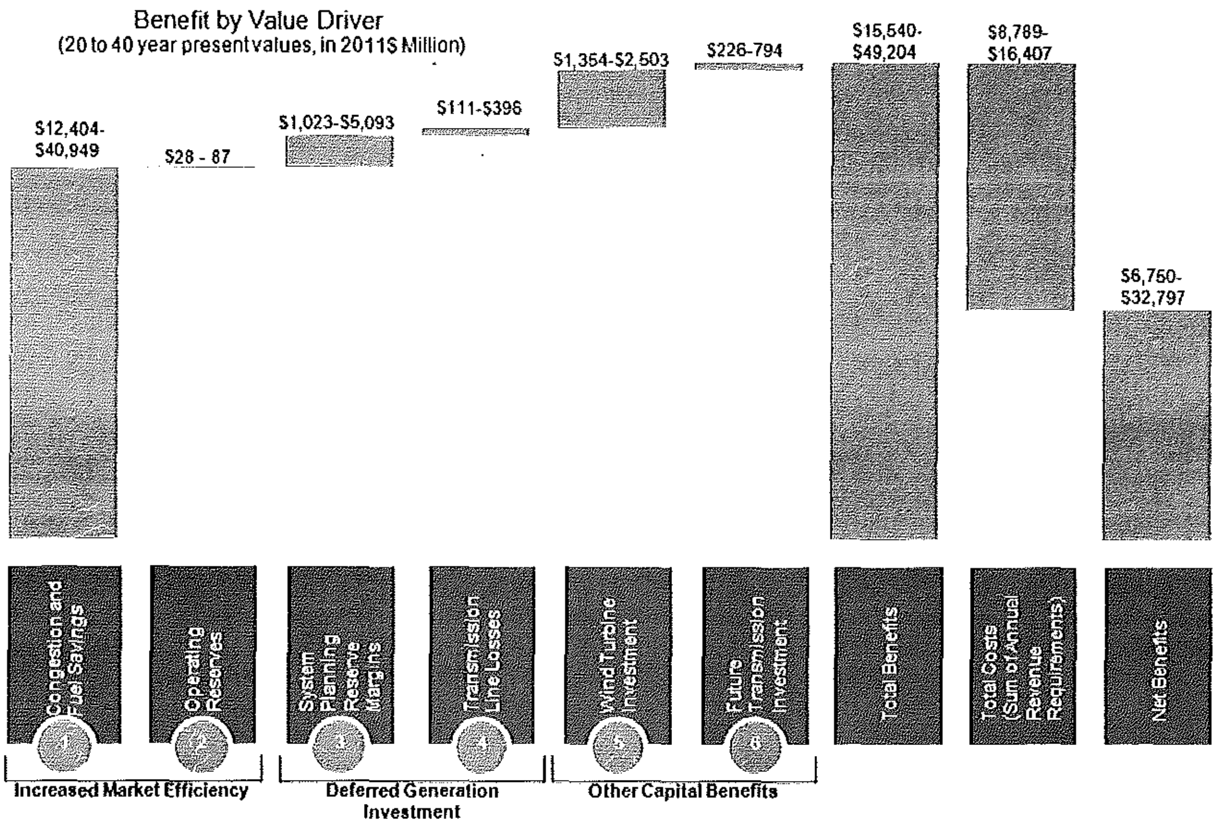


Figure 8.1: Recommended MVP portfolio economic benefits

8.1 Congestion and fuel savings

The recommended 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 captured the economic benefits of the recommended 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.

The future scenarios without any new energy policy requirements provide a baseline of the recommended MVP portfolio's benefits under current policy conditions. Additionally, the evaluation of the Carbon Constrained and Combined Policy future scenarios provide "bookends," helping to show the full range of benefits that may be provided by the portfolio. Looking at the "Business as Usual" future scenarios with no new energy policies, the recommended MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year present value adjusted production cost benefits, depending on the timeframe, discounts and growth rates of energy and demand. This benefit increases to a maximum present value of $91.7 billion under the Combined Policy future scenario.

8.1.1 Production cost model development

PROMOD IV® is an integrated electric generation and transmission market simulation system, and was the primary tool used to support economic assessment of the recommended MVP portfolio. It incorporates details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions and market system operations. It performs an 8,760-hour centralized security constrained unit commitment and economic dispatch, recognizing generation and transmission impacts at the nodal level. It uses an hourly chronological dispatch algorithm that minimizes cost, while recognizing a variety of operating constraints.

These include generating unit characteristics, transmission limits, fuel and environmental considerations, reserve requirements and customer demand. It provides a wide spectrum of forecasts on hourly energy prices, unit generation, fuel consumption, energy market prices at bus level, regional energy interchanges, transmission flows and congestion prices.

To be able to perform a credible economic assessment on the recommended MVP portfolio, production cost models require detailed model input assumptions on generation, fuel, demand and energy, transmission topology and system configuration, described below.

8.1.2 Models

The primary economic analysis was performed with 2021 and 2026 production cost models, with incremental wind mandates considered for 2021, 2026 and 2031, respectively. Three various levels of wind mandates and loads were modeled: 2021 RPS mandates and load levels, 2026 RPS mandates and load levels and 2026 load levels, plus all generation enabled by the recommended MVP portfolio used to estimate benefits in year 2031.

The transmission topology was taken from the 2021 summer peak power flow model developed through the MTEP11 planning process. The 2026 production cost models used the same transmission topology as 2021. The PROMOD study footprint included the majority of the Eastern Interconnection with ISO-New England, Eastern Canada and Florida excluded. Although these regions have very limited impact on the study results, fixed transactions were modeled to capture the influence of these regions on the rest of the study footprint.

8.1.3 Event file

Production cost models use an "event file" to capture a set of transmission constraints. The constraints ensure system reliability by performing hourly security constrained unit commitment and economic dispatch. The event file was developed based on the latest Book of Flowgates from MISO and NERC, updated to incorporate rating and configuration changes from concurrent studies in the MTEP11 planning cycle. In addition, MUST AC analyses and PROMOD Analysis Tool (PAT) contingency screening analyses were performed to identify a number of additional monitored/contingencies to ensure the most severe limiters of the transmission system are captured in the event file. As an integral part of the study, stakeholders and interested parties were extensively involved in the review of the event file.

8.1.4 Benefit measure

Comprised of 17 projects spread across the MISO footprint, the recommended MVP portfolio enables the renewable energy delivery required by public policy mandates that could not otherwise be realized. To determine the economic benefits of the recommended MVP portfolio, two production cost model simulations were performed with and without the combination of the recommended MVP portfolio and the wind it enables. The difference between these two cases provides measurable benefits associated with the recommended MVP portfolio, focusing on Adjusted Production Cost savings according to the tariff provisions. Adjusted Production Cost is the annual generation fleet production costs, including fuel, variable operations and maintenance, start up cost and emissions, adjusted with off-system purchases and sales. Adjusted Production Cost savings are achieved through reduction of transmission congestion costs and more efficient use of generation resources across the system.

8.1.5 Policy driven future scenarios

To account for out-year public policy and economic uncertainties, MISO collaborated with its stakeholders to refresh available future policy scenarios to better align them with potential policy outcomes taking place. The future scenarios were designed to bookend the potential range of future policy outcomes, ensuring that all of the most likely future policy scenarios and their impacts were within the range bounded by the results. Four futures were refreshed and analyzed:

- Business As Usual with Continued Low Demand and Energy Growth (BAULDE) assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.
- Business As Usual with Historic Demand and Energy Growth (BAUHDE) assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates.
- Carbon Constrained assumes that current energy policies will be continued, with the addition of a carbon cap modeled on the Waxman-Markey Bill.
- Combined Energy Policy assumes multiple energy policies are enacted, including a 20 percent federal RPS, a carbon cap modeled on the Waxman-Markey Bill, implementation of a smart grid and widespread adoption of electric vehicles.

The various input assumptions and uncertain variables defined for each policy driven future dictate a unique set of generation expansion plans on a least cost basis to meet regional Resource Adequacy Requirements, detailed in Table 8.1.

Future Scenarios	Wind Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price	Carbon Cost / Reduction Target
BAULDE	State RPS	0.78 percent	0.79 percent	$5	None
BAUHDE	State RPS	1.28 percent	1.42 percent	$5	None
Combined Energy Policy	20 percent Federal RPS by 2025	0.52 percent	0.68 percent	$8	$50/ton (42 percent by 2033)
Carbon Constrained	State RPS	0.03 percent	0.05 percent	$8	$50/ton (42 percent by 2033)

Table 8.1: MTEP11 Future Scenario Assumptions

8.1.6 Economic analysis results

A holistic economic assessment for the recommended MVP portfolio was performed against a wide range of future policy driven scenarios. This was done to minimize the risk imposed by the uncertainties around potential policy decisions. The future scenarios without any new energy policy mandates provide a baseline of the recommended MVP portfolio's benefits under current policy conditions. The evaluation of the Carbon Constrained and Combined Energy Policy future scenarios also provide "bookends" which help show the full range of benefits that may be provided by the portfolio.

8.1.7 Adjusted Production Cost savings and benefit spread

With the recommended MVP portfolio providing access to the lowest electric energy costs and relieving transmission congestion across the MISO footprint, the portfolio brought a wide range of adjusted production cost savings, from an estimated $12.4 to $28.3 billion in 20 year present value terms under the four selected future scenarios, as shown in Figure 8.2.

The recommended MVP portfolio also collects renewable energy from a distributed set of wind energy zones, enables the wind delivery and provides widespread regional benefits across the MISO footprint, regardless of future policy outcomes.

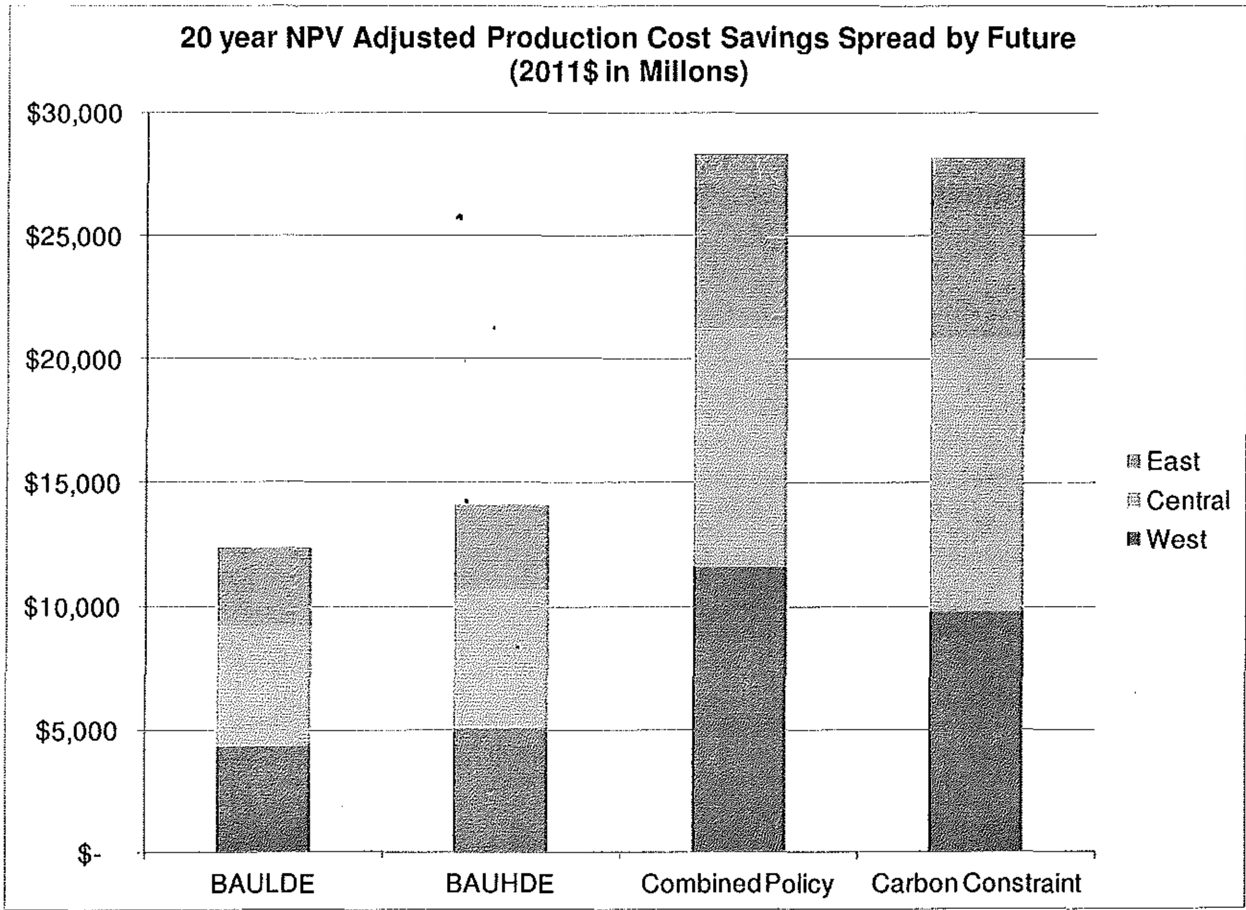


Figure 8.2: Adjusted Production Cost Savings spread by future

8.1.8 Generation displacement

Figure 8.3 summarizes the 2021 annual energy production changes between the base case and the change case. The recommended MVP portfolio enables the delivery of renewable energy to meet the near term RPS mandates of MISO states in a more reliable and economic manner, causing higher cost units to be displaced by the wind resources enabled by the proposed portfolio across the MISO footprint. Moreover, the recommended MVP portfolio allows low cost energy in the western regions to reach a wider footprint. It leads to a more efficient usage of generation resource across the entire study footprint, with some level of generation displacement occurring in external regions, particularly in PJM and SERC.

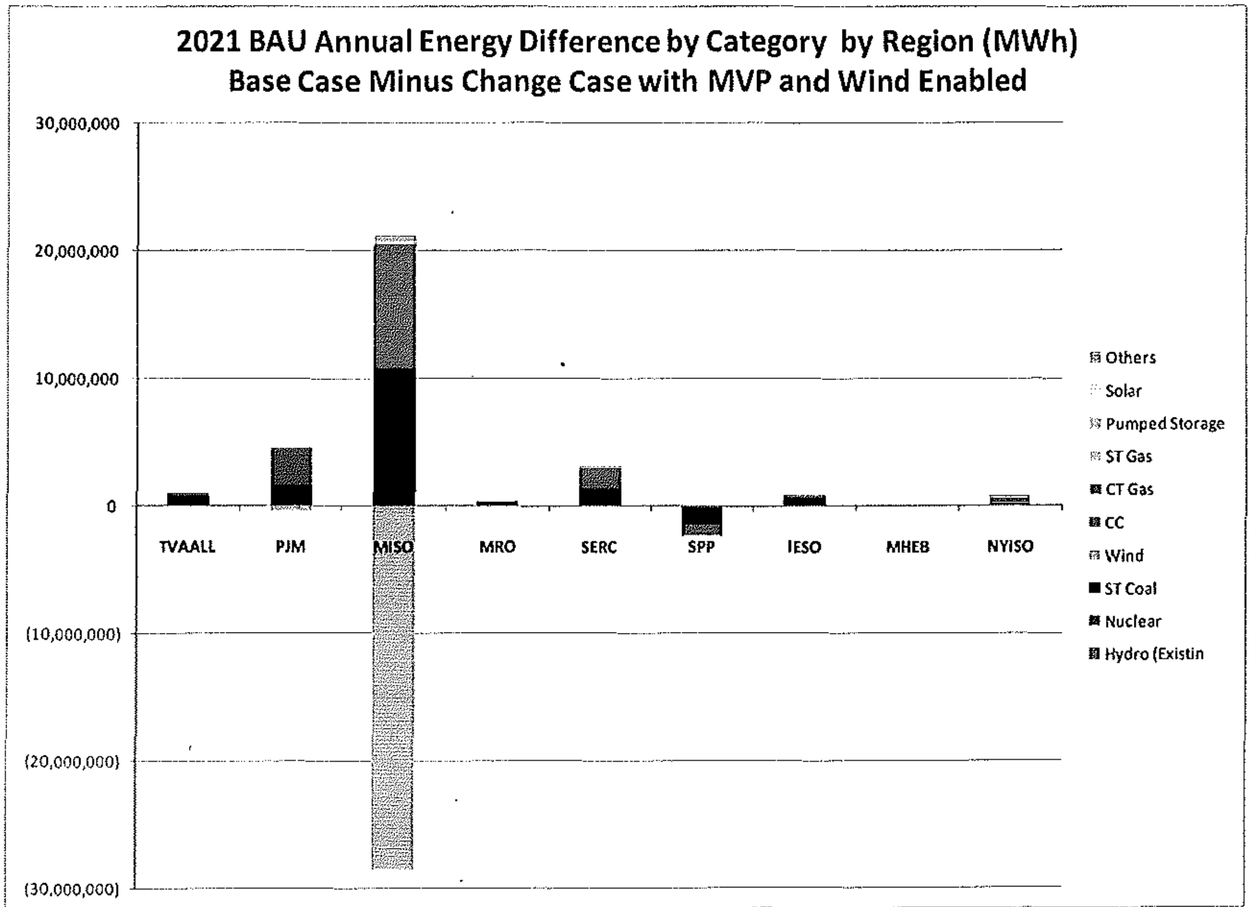


Figure 8.3: Generation displacement by region

8.1.9 Economic Variable Impact

The projected benefits of the recommended MVP portfolio depend on projections of future policy and economic variables. Figure 8.4 shows the impacts of economic variable assumptions on the projected economic benefits achieved by the recommended MVP portfolio, with the primary focus on the time of present value calculations and discount rate.

Considering solely the 'Business as Usual' future scenarios with no new energy policies, the recommended MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year present value adjusted production cost savings, depending on the time, discount rates and rate of energy and demand growth. This benefit would increase to a maximum present value of $91.7 billion under the Combined Energy Policy future scenario.

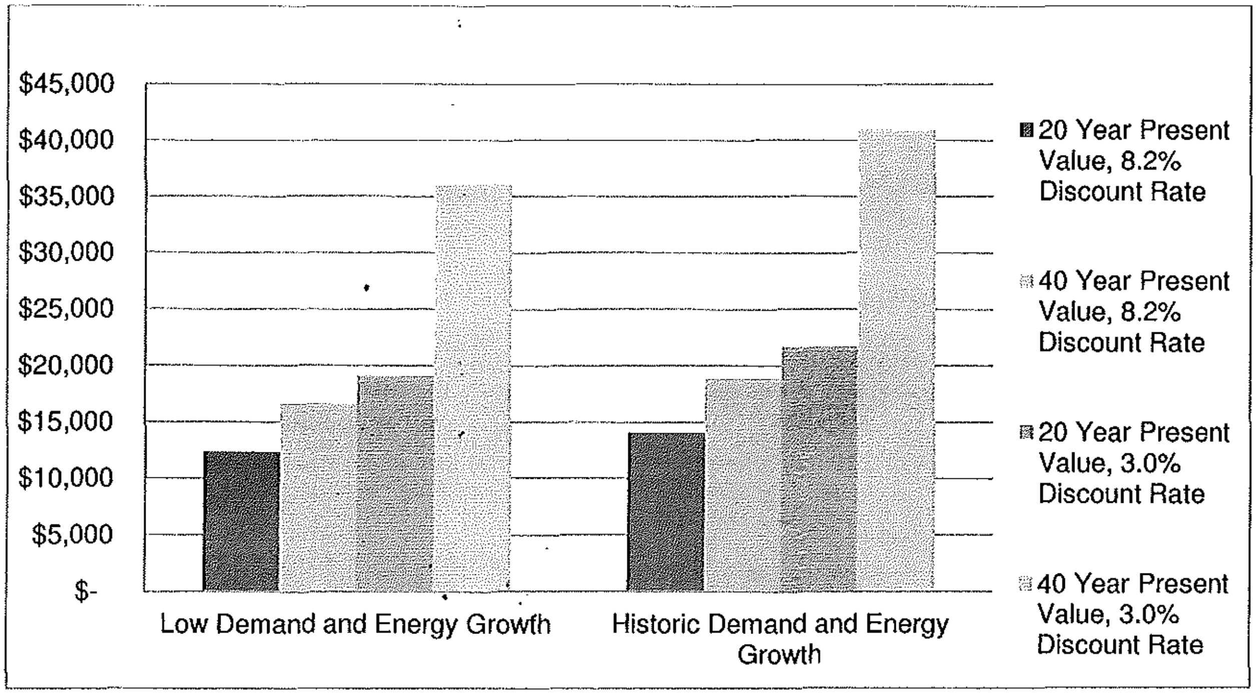


Figure 8.4: Adjusted Production Cost Benefits from recommended MVP portfolio

8.2 Operating reserves

In addition to the energy benefits quantified in the production cost analyses, the recommended MVP portfolio will also reduce operating reserve costs. The recommended MVP portfolio decreases congestion on the system, increasing the transfer capability into several key areas that would otherwise have to hold additional operating reserves under certain system conditions.

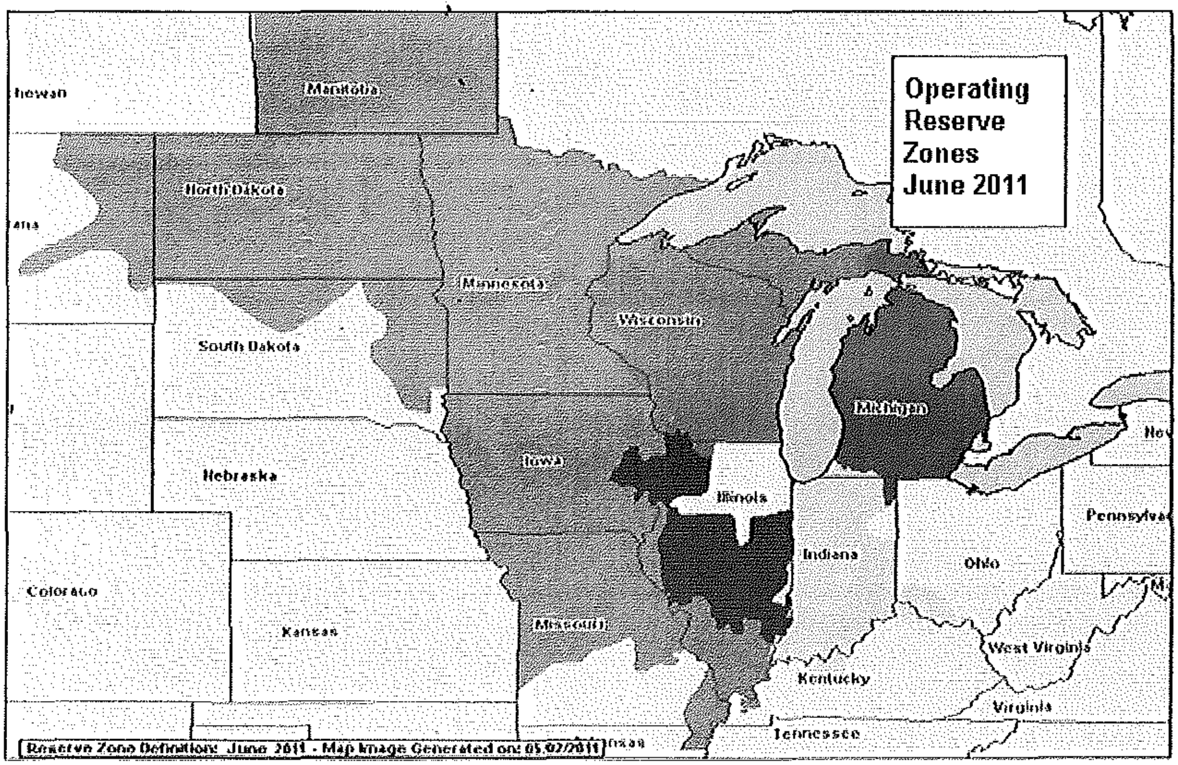


Figure 8.5: Operating reserve zones

MISO determined that the addition of the recommended MVP portfolio will eliminate the need for the Indiana operating reserve zone, as shown in Figure 8.5, and the need for additional system reserves to be held in other zones across the footprint would be reduced by half. This creates 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, creating benefits of $28 to $87 million in 20 to 40 year present value terms.

8.2.1 Analyses

Operating reserve zones are determined, on an ongoing basis, by monitoring the energy flowing through certain flowgates across the system. The zonal operating reserve requirements, based on the actual conditions from June 2010 through May 2011, are shown below in Table 8.2.

Zone	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)
Missouri	95	1	95.1
Indiana	14966	53	282.4
N-Ohio	9147	15	609.8
Michigan	4915	17	289.1
Wisconsin	227	2	113.4
Minnesota	376	1	376.3

Table 8.2: Historic operating requirements

Transfer analyses were performed to determine the changes in flows due to the addition of the recommended MVP portfolio to the system. These analyses were performed on both the most recent model used to create the operating reserve limitations, as well as on the 2021 MTEP11 power flow model.

Zone	Limiter	Contingency	Operating Model Change in Flows	MTEP11 Model Change in Flows
Missouri	Coffeen - Roxford 345	Newton-Xenia 345	-0.8%	-18.5%
Indiana	Bunsonville-Eugene 345	Casey-Breed 345	-17.5%	-87.2%
Indiana	Crete-St. Johns Tap 345	Dumont-Wilton Center 765	-4.5%	-9.4%
Michigan	Benton Harbor - Palisades 345	Cook - Palisades 345	-10.8%	-4.6%
Wisconsin	MWEX	N/A	-20.2%	-2.3%
Minnesota	Arnold-Hazleton 345	N/A	-60.9%	15.9%

Table 8.3: Change in transfers, pre-MVP minus post-MVP

As a result of these transfer analyses, it was determined that the need for the Indiana operating zone would be eliminated by the addition of the recommended MVP portfolio to the transmission system. Also, it was determined that the need for operating reserve requirements in other zones throughout the MISO footprint would be reduced by half.

The ability to locate reserves at the least-cost location, rather than in a specific zone, will drive a benefit equal to between \$5/MWh and \$7/MWh. These benefits were assumed to grow with load growth, at roughly 1% per year. As a result, the recommended MVP portfolio will create $33 to $116 million in present value benefits.

IN Operating Reserve, no-MVP (MWh)	IN Operating Reserves, with MVP (MWh)	Other Zonal Operating Reserve, no-MVP (MWh)	Other Zonal Operating Reserves, with MVP (MWh)	Total Zonal Operating Reserves, no-MVP	Total Zonal Operating Reserves, with MVP	Nominal Benefits - Low ($M)	Nominal Benefits - High ($M)
359,195	0	354,252	177,126	713,446	177,126	$2.68	$3.75

Table 8.4: 2011 operating reserve reductions and quantification

8.3 System Planning Reserve Margin

The system planning reserve is calculated by determining the amount of generation required to maintain a one day in 10 years Loss of Load Expectation (LOLE). The reserve margin requirement is calculated through summing two components: the unconstrained system Planning Reserve Margin (PRM) and a congestion contribution. The recommended MVP portfolio reduces transmission congestion across MISO, thereby reducing the system PRM and decreasing the amount of generation required to meet the PRM. By reducing the PRM, the recommended MVP portfolio defers new generation, creating present value benefits equal to $1.0 to $5.1 billion in 2011 dollars under business as usual conditions. Results for each set of future scenarios and business case assumptions are shown in Table 8.5.

	20 year NPV		40 year NPV	
	3%	8.20%	3%	8.20%
Business As Usual with Continued Low Demand and Energy Growth	$1,460	$1,023	$1,869	$1,151
Business As Usual with Historic Demand and Energy Growth	$3,811	$1,281	$5,093	$1,496
Combined Energy Policy	$1,610	$971	$2,222	$1,167
Carbon Constraint	$2,145	$1,159	$2,747	$1,309

Table 8.5: Planning Reserve Margin Capacity Reduction

8.3.1 Congestion Impact

Additional transmission investment may ease congestion in the system, reducing the congestion component used to calculate the system PRM and reducing the future capacity required to meet system load. The reduction in system congestion, as calculated through the production cost models as the reduction in congestion costs, was determined to be 21%.

In the 2011 Planning Year LOLE Study Report, it was determined that the system Planning Reserve Margin would begin to increase due to congestion in 2016. Congestion was found to increase by 0.3 percent annually, rising to 1.5 percent by 2020[26] and 4.5 percent by 2030.

The recommended MVP portfolio will decrease this congestion by 21 percent, when the entire portfolio is in-service. The reduction was phased-in to account for the different in-service dates of the various projects in the portfolio, with the congestion reduction starting at 3.5 percent in 2016 and growing linearly to 21 percent by 2021. This congestion reduction was multiplied by the pre-MVP congestion to find the total impact of the recommended MVP portfolio. This resulted in the congestion components shown in Table 8.6.

Year	Pre-MVP Congestion Component [1]	MVP Congestion Reduction Percentage [2]	MVP Congestion Reduction Impact [3]=[1]*[2]	Post-MVP Congestion Component [4]=[1]-[3]
2011	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2012	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2013	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2014	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2015	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2016	0.3 percent	3.5 percent	0.0 percent	0.3 percent
2017	0.6 percent	7.0 percent	0.0 percent	0.6 percent
2018	0.9 percent	10.5 percent	0.1 percent	0.8 percent
2019	1.2 percent	14.0 percent	0.2 percent	1.0 percent
2020	1.5 percent	17.5 percent	0.3 percent	1.2 percent
2021	1.8 percent	21.0 percent	0.4 percent	1.4 percent
2022	2.1 percent	21.0 percent	0.4 percent	1.7 percent
2023	2.4 percent	21.0 percent	0.5 percent	1.9 percent
2024	2.7 percent	21.0 percent	0.6 percent	2.1 percent
2025	3.0 percent	21.0 percent	0.6 percent	2.4 percent
2026	3.3 percent	21.0 percent	0.7 percent	2.6 percent
2027	3.6 percent	21.0 percent	0.8 percent	3.0 percent
2028	3.9 percent	21.0 percent	0.8 percent	3.1 percent
2029	4.2 percent	21.0 percent	0.9 percent	3.3 percent
2030	4.5 percent	21.0 percent	0.9 percent	3.6 percent

Table 8.6: Planning Reserve Margins Congestion Component

[26]For more information, refer to table 5.1 in the Planning Year 2011 LOLE Study Report, at the link below: https://www.misoenergy.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf

8.3.2 Planning Reserve Margin Reduction

The uncongested Planning Reserve Margin was set to 17.4 percent for the full study period. This margin was summed with the congestion component, as calculated above, to find the full Planning Reserve Margin Requirement, both with and without the recommended MVP portfolio. Figure 8.6 shows the expected system PRM for 2011 through 2030 accounting for congestion and system PRM relief from the recommended MVP portfolio.

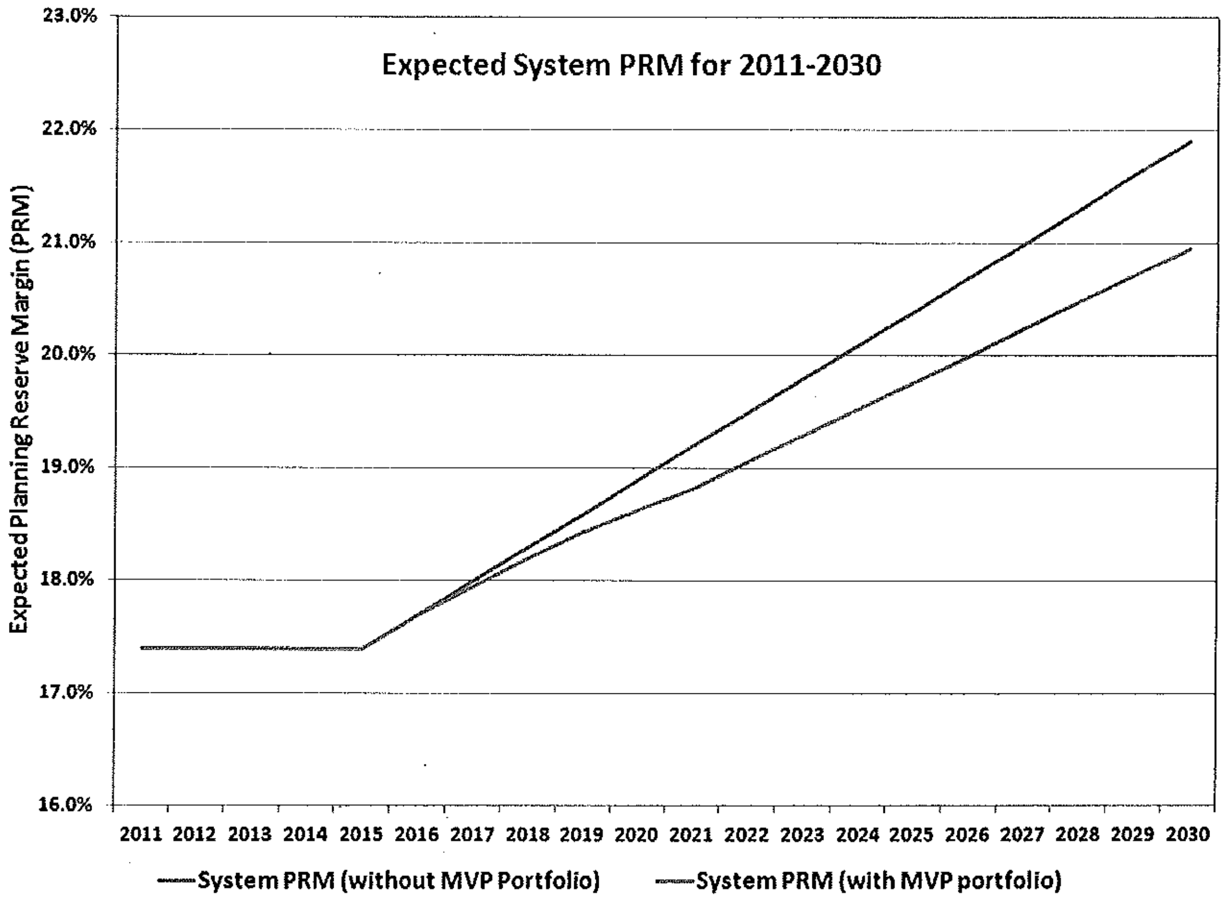


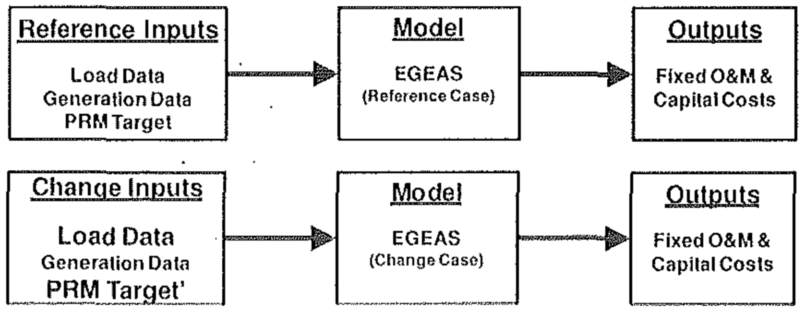
Figure 8.6: Expected System PRM, with and without the recommended MVP portfolio

8.3.3 Deferred Capacity Calculation

Sufficient generation must be built to ensure that, as the system Planning Reserve Margin increases, enough capacity is available to meet the system load and Planning Reserve Margin requirements. A lower PRM will require less future generation investment, resulting in a reduction in required capital outlays.

Electric Power Research Institute (EPRI's) Electric Generation Expansion Analysis System (EGEAS) was used to calculate the capacity benefits from PRM reduction due to transmission investment. The EGEAS model requires load forecast data, existing generation data, planned generation capacity and Planning Reserve Margin target as inputs.

Two series of analyses were run. The first set of analyses, representing the pre-MVP case, contained higher Planning Reserve Margins. The second set of analyses held all the variables constant except for the Planning Reserve Margin, modeling the lower Planning Reserve Margin created by the proposed Multi Value Project portfolio. The difference in the required capacity expansion between the two models is a benefit of the recommended MVP portfolio.



$$\text{Capacity Cost Savings} = \text{Cost}_{\text{Reference Case}} - \text{Cost}_{\text{Change Case}}$$

Figure 8.7: Capacity cost savings will be calculated by running two EGEAS cases.

EGEAS accurately captures the type and timing of resource additions that would occur with and without the Planning Reserve Margin (PRM) congestion relief. EGEAS outputs unit-by-unit capital fixed charge reports for each of these new capacity additions by year from 2011 through 2030. The capital cost of these capacity projections were then calculated as the 20-year or 40-year present values figures. These benefits include the reduction in annual fixed operations and maintenance charges from deferred capacity, as well as the capital charges from the reduced capacity requirements.

As can be seen in Figure 8.8 below, 400 MW of CT would be deferred by the additional of the recommended MVP portfolio in 2020, and 200 MW would be deferred in 2024. These results were documented for the Business as Usual with continued low demand growth rate future. Similar results were documented for the other futures.

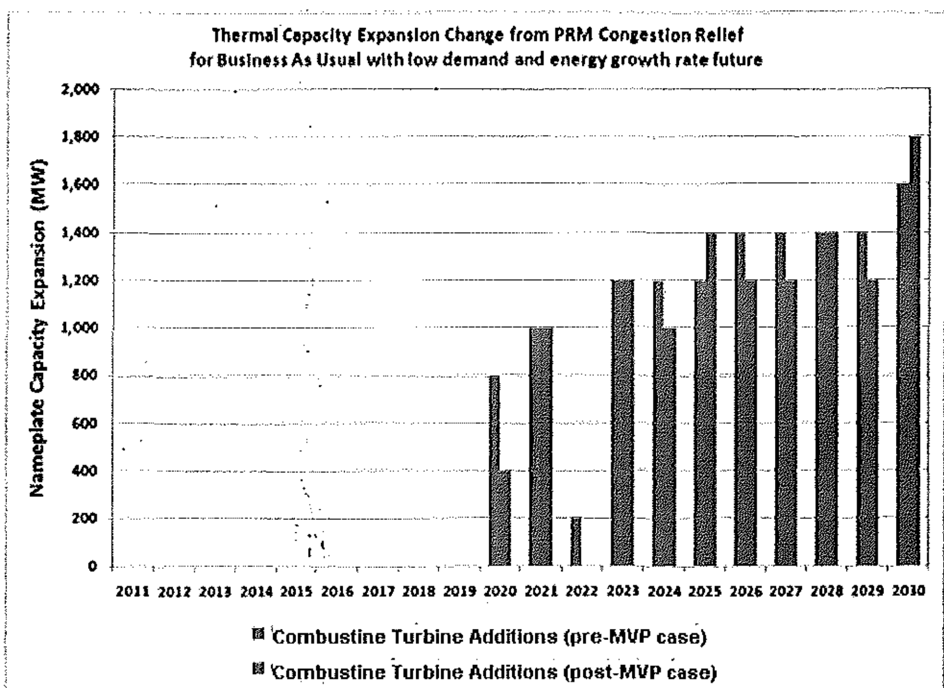


Figure 8.8: Business as Usual capacity expansion results, PRM benefit

8.4 Transmission line losses

The addition of the recommended 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. Specifically, when installed generation capacity is just sufficient to meet peak system load plus the planning reserve margin, a reduction in transmission losses reduces the amount of generation that must be built. This saves $111 million to $396 million in 2011 dollars, excluding the impacts of any potential future policies. Table 8.7 shows the capacity deferral results, depending on the timeline of the present value calculations, the discount rate and future scenarios analyzed.

	20 year NPV		40 year NPV	
	3%	8.20%	3%	8.20%
Business As Usual with Continued Low Demand and Energy Growth	$317	$229	$396	$251
Business As Usual with Historic Demand and Energy Growth	$111	$305	$196	$358
Combined Energy Policy	$655	$525	$834	$532
Carbon Constraint	$737	$229	$749	$248

Table 8.7: Transmission Line Losses Capacity Deferral

8.4.1 Transmission Losses Reduction

The transmission loss reduction was calculated through the PSS/E model. More specifically, the transmission line losses in the MTEP11 2021 summer peak models were compared, both with and without the recommended MVP transmission. This value was then used to extrapolate the transmission line losses for 2016 through 2021, assuming escalation at the normal demand growth rate.

8.4.2 Capacity Deferral Simulations

The change in required system capacity expansion due to the impact of the recommended MVP portfolio was calculated through a series of EGEAS simulations. In these simulations, the total system generation requirement was set to the system Planning Reserve Margin multiplied by the system load plus the system losses (Generation Requirements = (1+PRM)*(Load + Losses)). To isolate the impact of the transmission line loss benefit, all variables in these simulations were held constant, except for the system losses.

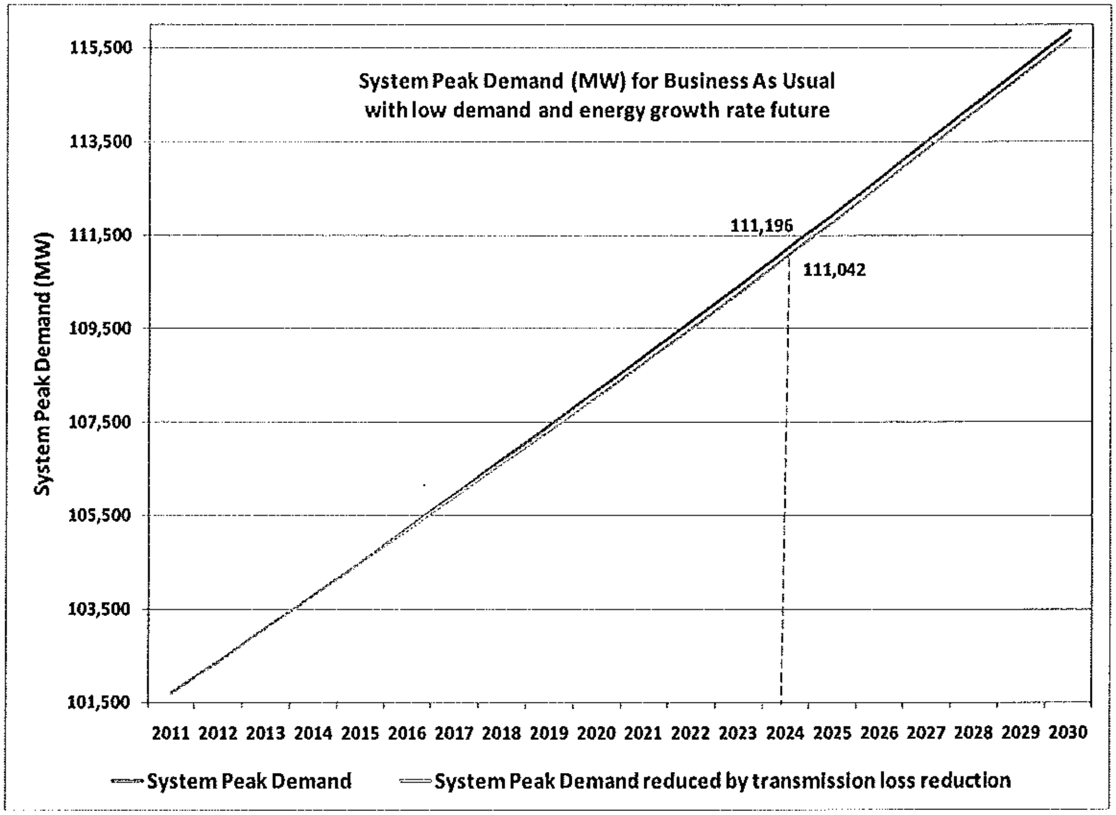


Figure 8.9: System peak demand, with and without the recommended MVP portfolio

The difference in capital fixed charges and fixed operation and maintenance costs in the reference, or pre-MVP case, and the post-MVP case is equal to the capacity benefit from transmission loss reduction, due to the addition of the recommended MVP portfolio to the transmission system. This capacity benefit was studied for the four MTEP11 future scenarios and observed during the study period (2011-2030). The capital impact of the change in capacity was then captured between 2021-2040 for a 20-year benefit value, and 2021-2060 for a 40-year capacity benefit value. As can be seen in Figure 8.10, 200 MW of CT is deferred in 2020 in the Business As Usual with a Low Demand and Energy Future at 8.2 percent discount rate.

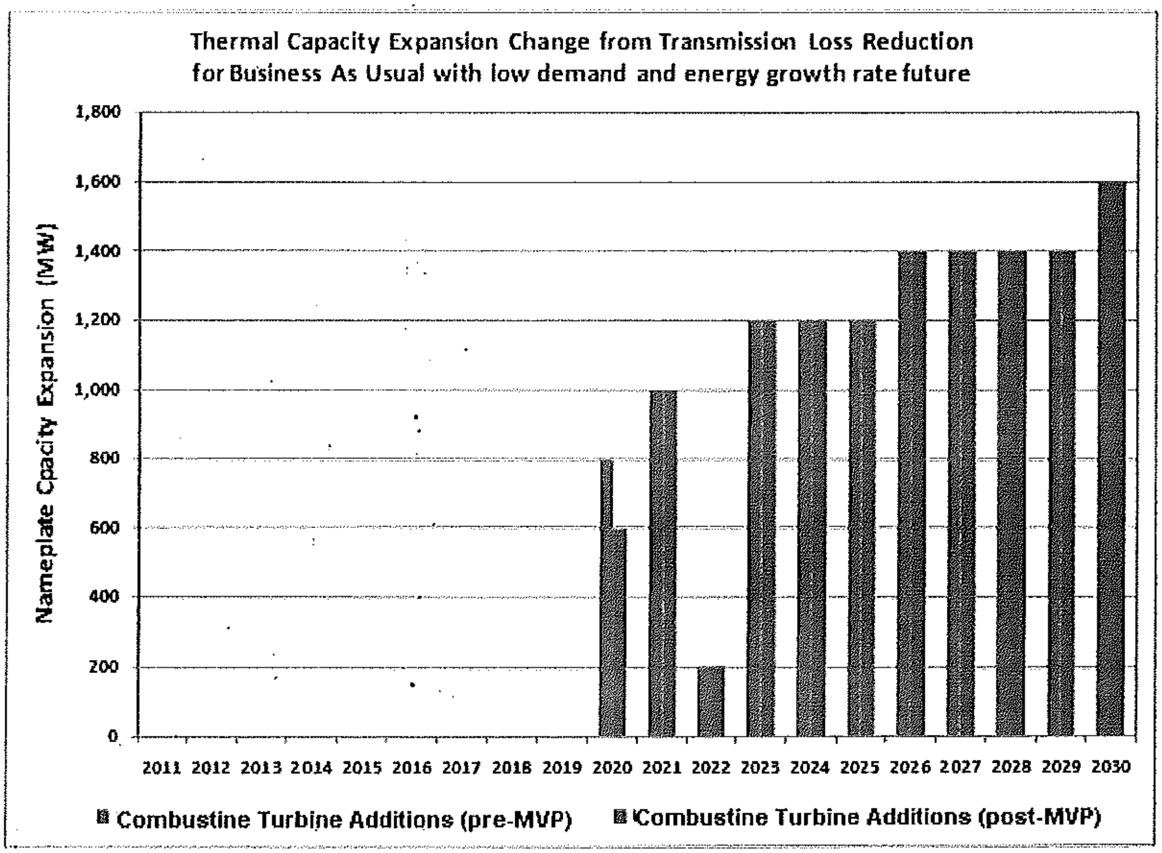


Figure 8.10: Business as Usual with Low Demand and Energy Capacity Additions, pre and post MVP

8.5 Wind turbine investment

As discussed previously, MISO determined 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. However, this strategy depends on a strong regional transmission system to deliver the wind energy. Without this regional transmission backbone, the wind generation would have to be sited close to load, requiring the construction of significantly larger amounts of wind capacity to produce the renewable energy mandated by public policy.

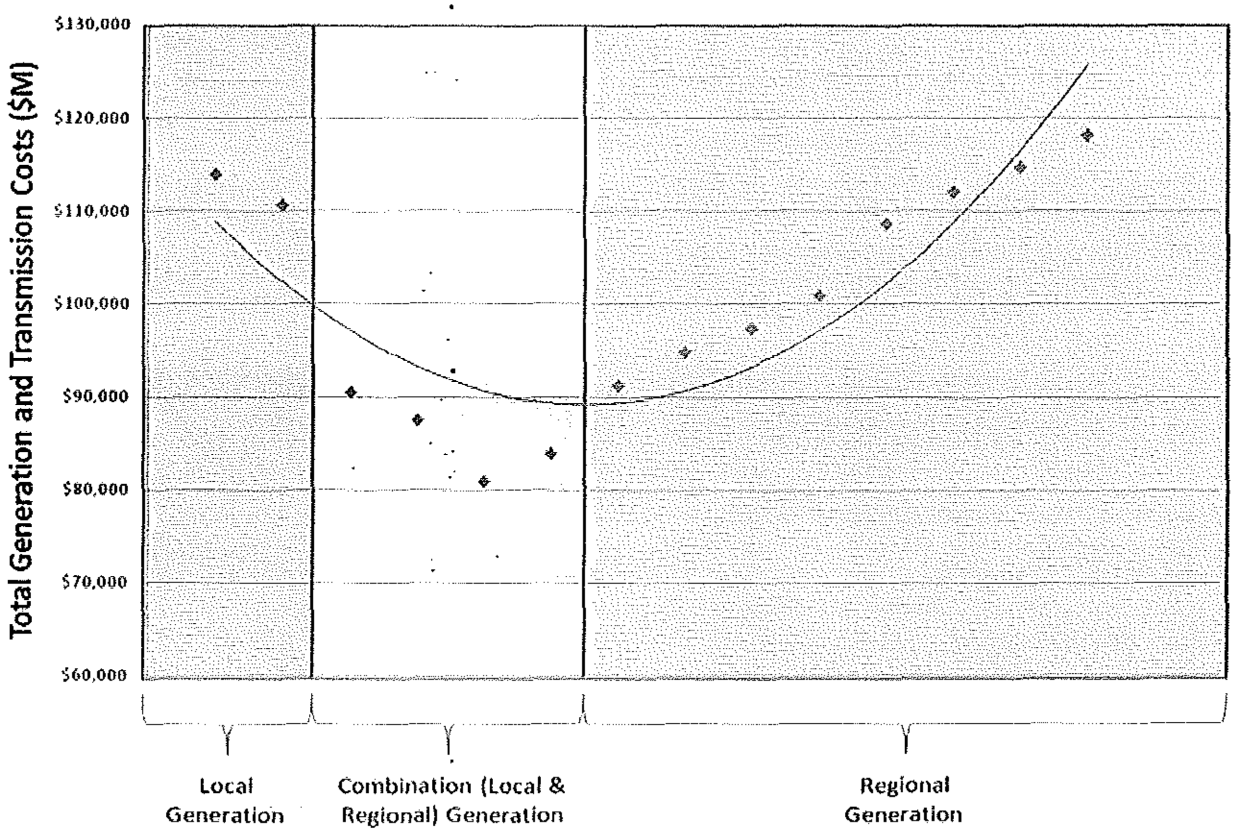


Figure 8.11: Local versus combination wind siting

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 recommended MVP portfolio. This resulted in a total of 2.9 GW of avoided wind generation, as shown in Table 8.8

Year	Recommended MVP Portfolio Enabled Wind (MW)	Equivalent Local Wind Generation (MW)	Incremental Wind Benefit (MW)
Pre-2016	12,408	13,802	1,394
2016	17,276	19,217	547
2021	21,173	23,552	438
2026	23,445	26,079	255
Full Wind Enabled	25,675	28,559	251

Table 8.8: Renewable Energy Requirements, Combination versus Local Approach

The incremental wind benefits were monetized by applying a value of $2.0 to $2.9 million/MW, based on the US Energy Information Administration's estimates of the capital costs to build onshore wind, as updated in November 2010. The total wind enabled benefits were then spread between 2015 and 2030, with half of the pre-2021 values lumped into 2021 for the purpose of this analysis. Also, to avoid 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.

The low cost wind siting methodology enabled by the recommended MVP portfolio creates benefits ranging from a present value of $1.4 to $2.5 billion in 2011 dollars, depending on which business case assumptions are applied.

8.6 Transmission investment

In addition to relieving constraints under shoulder peak conditions, the recommended MVP portfolio will eliminate some future baseline reliability upgrades. A model simulating 2031 summer peak load conditions was created by growing the load in the 2021 summer peak model by approximately 8 GW, and this model was run both with and without the recommended MVP portfolio. The investment avoided through the addition of the recommended MVP portfolio into the transmission system, as determined through this analysis, is shown below in Table 8.9.

Avoided Investment	Upgrade Required	Miles
Galesburg to East Galesburg 138 kV	Bus Tie	N/A
Portage to Columbia 1 138 kV	Transmission line, < 345 kV	6
Portage to Columbia 2 138 kV	Transmission line, < 345 kV	6
Arrowhead to Bear Creek 230 kV	Transmission line, < 345 kV	1
Forbes to 44 Line Tap 115 kV	Transmission line, < 345 kV	1
Stone Lake Transformer 345/161 kV	Transformer	N/A
Port Washington to Saukville Bus 6 138 kV	Transmission line, < 345 kV	5
Port Washington to Saukville Bus 5 138 kV	Transmission line, < 345 kV	5
Ipava South to Macomb West 138 kV	Transmission line, < 345 kV	21
Lafayette Cincinnati St. to Purdue 138 kV	Transmission line, < 345 kV	1
Grace VT7 to Ortonville 115 kV	Transmission line, < 345 kV	25
East Kewanee to Kewanee South Street 138 kV	Transmission line, < 345 kV	0
Cloverdale to Stilesville 138 kV	Transmission line, < 345 kV	13
Wilmarth to Field South 345 kV	Transmission line, 345 kV	29
Dundee Transformer 161/115 KV	Transformer	N/A
Stileville to WVC Valley 138 kV	Transmission line, < 345 kV	6
Lafayette South to Lafayette Shadeland 138 kV	Transmission line, < 345 kV	3
Purdue Nw Junction Tap 1 to Westwood 2 138kV	Transmission line, < 345 kV	3
Plainfield South to WVC Valley 138 kV	Transmission line, < 345 kV	5
Antigo to Aurora Street 115 kV	Transmission line, < 345 kV	2
Latham to Kickapoo 138 kV	Transmission line, < 345 kV	5
Bunker Hill to Black Brook 115 kV	Transmission line, < 345 kV	8
Grace VT7 to Morris 115 kV	Transmission line, < 345 kV	14

Table 8.9: Avoided transmission investment

The cost of this avoided investment was estimated using generic transmission costs, as estimated from projects in the MTEP database. The costs of this transmission investment was estimated to be spread between 2027 and 2031. Also, to represent potential production cost benefits that may be missed through avoiding this investment, the value of avoiding the 345 kV transmission line 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 8.10: Generic transmission costs

The recommended MVP portfolio eliminates the need for baseline reliability upgrades on 23 lines between 2026 and 2031. This creates benefits which have 20 and 40 year present values of $268 and $1,058 million, respectively.

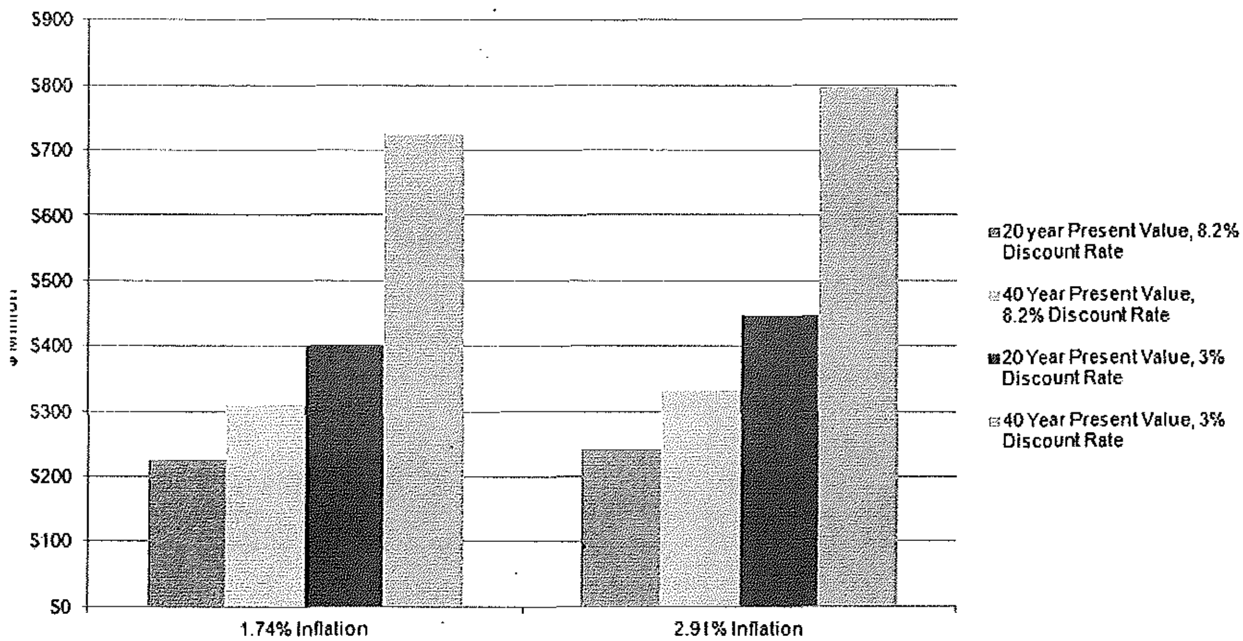


Figure 8.12: Avoided transmission investment

8.7 Business case variables and impacts

The recommended MVP portfolio provides significant benefits under every scenario studied. The base business case was built upon a fixed set of energy policies, with variances in discount rates and time horizons driving the range of benefits. However, additional variables also have the potential to impact the benefits provided by the recommended MVP portfolio.

The most critical variables considered were:

- Future energy policies
  - Includes a range of policy, demand and energy growth assumptions
  - Sensitivities were conducted to determine the impact of a legislated cost of carbon or national renewable energy mandate
- Length of Present Value Calculations: 20 or 40 years from the portfolio's in service date
- Discount Rate: 3 percent or 8.2 percent
- Natural gas prices: $5-$8 (Business as Usual Scenarios)
  $8-$10 (Combination Policy and Carbon Constrained Futures)
- Wind turbine capital cost: 2.0 or 2.9 $M/MW

To calculate the impact of any particular variable on the benefits provided by the recommended MVP portfolio, a series of analyses were performed. These analyses required changing a single variable, then comparing the resulting benefits and costs to a nominal case, which was defined as a 20 year present-value under an 8.2% discount rate. The maximum benefit-cost ratio was determined to be under a 40 year present value, using a 3% discount rate, high natural gas prices, and under the Combination Energy Policy future. The minimum benefit-cost ratio was calculated under a 20-year present value, using an 8.2% discount rate and assuming current economic policies continue under a continued economic recession.

Sensitivity Results ($M)										
	Nominal Benefits	Low Wind Turbine Capital	High Wind Turbine Capital	3% Discount Rate	40 Year Present Values	Future Policy Scenario (Low Demand and Energy Growth)	Future Policy Scenario (Combination Policy)	Natural Gas Price (High)	Maximum Benefit / Cost	Minimum Benefit / Cost
Congestion and Fuel Savings	$16,747	$16,747	$16,747	$25,846	$22,421	$14,740	$37,710	$21,534	$118,011	$14,740
Operating Reserves	$40	$40	$40	$59	$50	$40	$40	$40	$116	$33
Transmission Line Losses	$1,461	$1,461	$1,461	$3,406	$1,680	$272	$699	$1,461	$1,111	$272
System Planning Reserve Margin	$340	$340	$340	$262	$388	$1,216	$1,293	$340	$2,961	$1,216
Wind Turbine Investment	$2,635	$1,936	$3,334	$2,194	$2,635	$2,635	$2,635	$2,635	$2,778	$1,936
Future Transmission Investment	$295	$ 295	$295	$537	$406	$295	$ 295	$ 295	$ 1,058	$268
Total Benefits	$21,518	$ 20,819	$22,217	$32,304	$27,581	$19,198	$42,672	$26,305	$126,035	$18,465
Total Costs	$11,076	$ 11,076	$11,076	$15,699	$12,419	$10,444	$11,709	$11,076	$21,858	$10,444
B/C	1.9	1.9	2.0	2.1	2.2	1.8	3.6	2.4	5.8	1.8

Table 8.11: Recommended MVP portfolio benefits sensitivities

Depending on which variables are assumed, the present value of the benefits created by the entire portfolio can vary between $18.5 and $126.0 billion in 20 to 40 year present value terms. This savings yield benefits ranging from 1.8 to 5.8 times the portfolio cost.

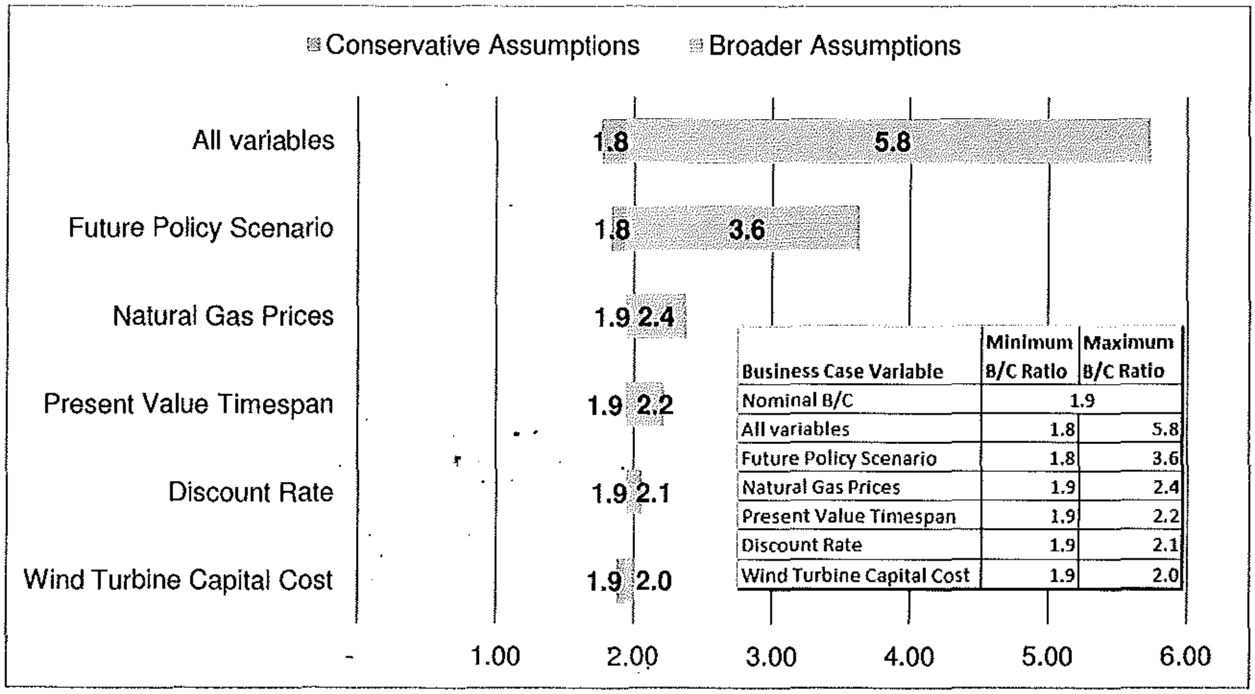


Figure 8.13: Benefit – cost variations due to business case assumptions

It should be noted that the benefits of the portfolio do not depend upon the implementation of any particular future energy policy to exceed the portfolio costs. Under existing energy policies, a conservative discount rate of 8.2 percent and 20 year present value terms, the portfolio produces benefits that are 1.8 times its cost. However, if other energy policies or enacted, or a lower discount rate is used, this benefit has the potential to greatly increase.

9 Qualitative and social benefits

The previous sections demonstrated that the recommended MVP portfolio provides widespread economic benefits across the MISO system. However, these metrics do not fully quantify the benefits of the portfolio. Other benefits, based on qualitative or social values, are discussed in the next section. These sections suggest that the quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the portfolio.

9.1 Enhanced generation policy flexibility

Although the recommended MVP portfolio was primarily evaluated on its ability to reliably deliver energy required by the renewable energy mandates, the portfolio will provide 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 as shown in Figure 9.1.

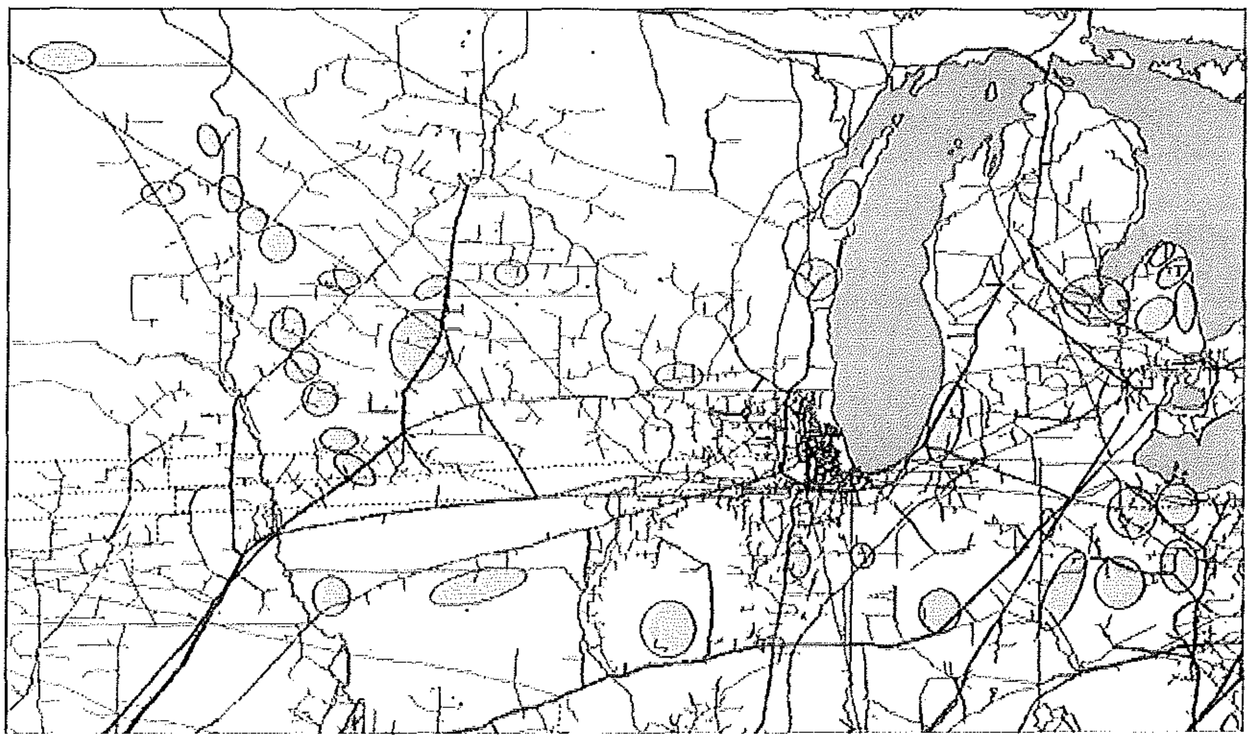


Figure 9.1: Energy zone correlation with natural gas pipelines

9.2 Increased system robustness

A transmission system blackout, or similar event, can have wide spread repercussions, resulting in billions of dollars of damage. The blackout of the Eastern and Midwestern U.S. during August 2003 affected more than 50 million people and had an estimated economic impact of between $4 and $10 billion.[27]

The recommended MVP portfolio creates a more robust regional transmission system which 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.

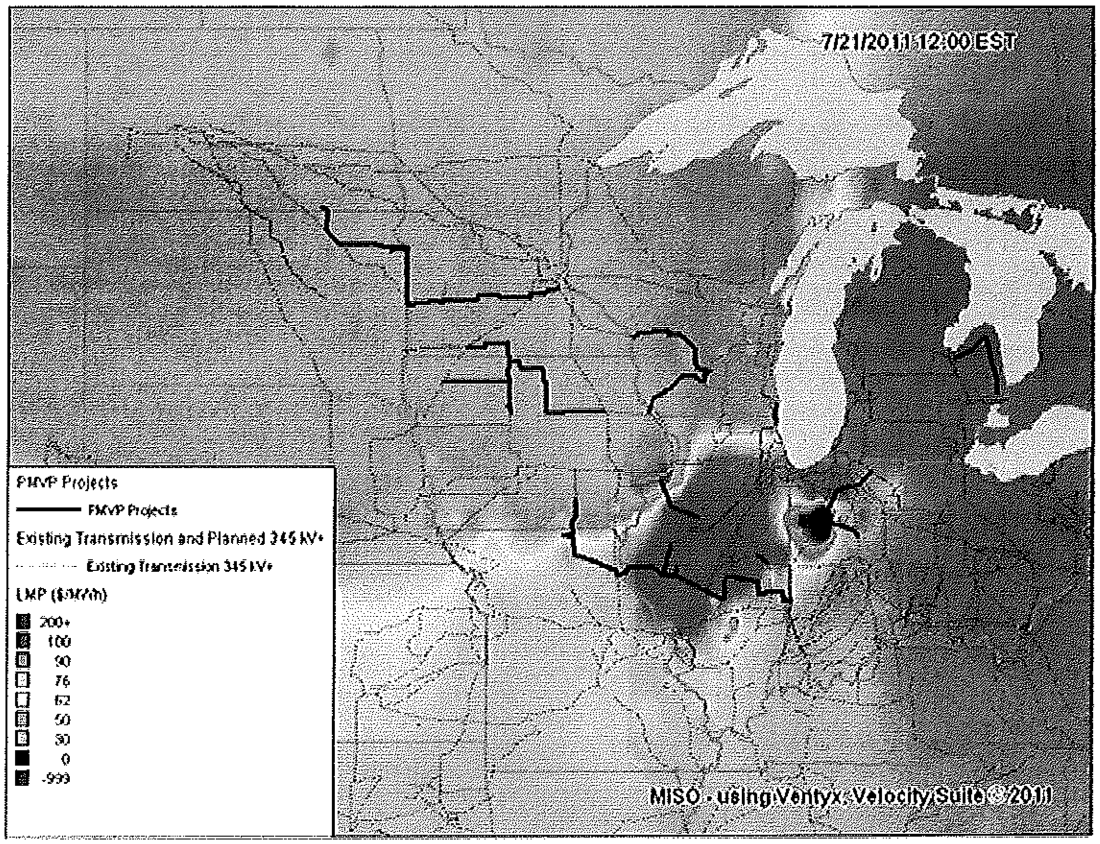


Figure 9.2: June 2011 LMP map with recommended MVP portfolio overlay

For example, the recommended MVP portfolio will allow the system to respond more efficiently during high load periods. During the week of July 17, 2011, high load conditions existed in the eastern portion of the MISO footprint, while the western portion of the footprint experienced lower temperatures and loads. Thermal limitations on west to east transfers across the system limited the ability of low cost generation from the west to serve the high load needs in the east, as shown in Figure 9.2. The recommended MVP portfolio will increase the transfer capability across the system, allowing access to additional generation resources to offset the impact and cost of severe or emergency conditions.

[27] Data sourced from: *The Economic Impacts of the August 2003 Blackout*, The Electricity Consumers Resource Council (ELCON)

9.3 Decreased natural gas risk

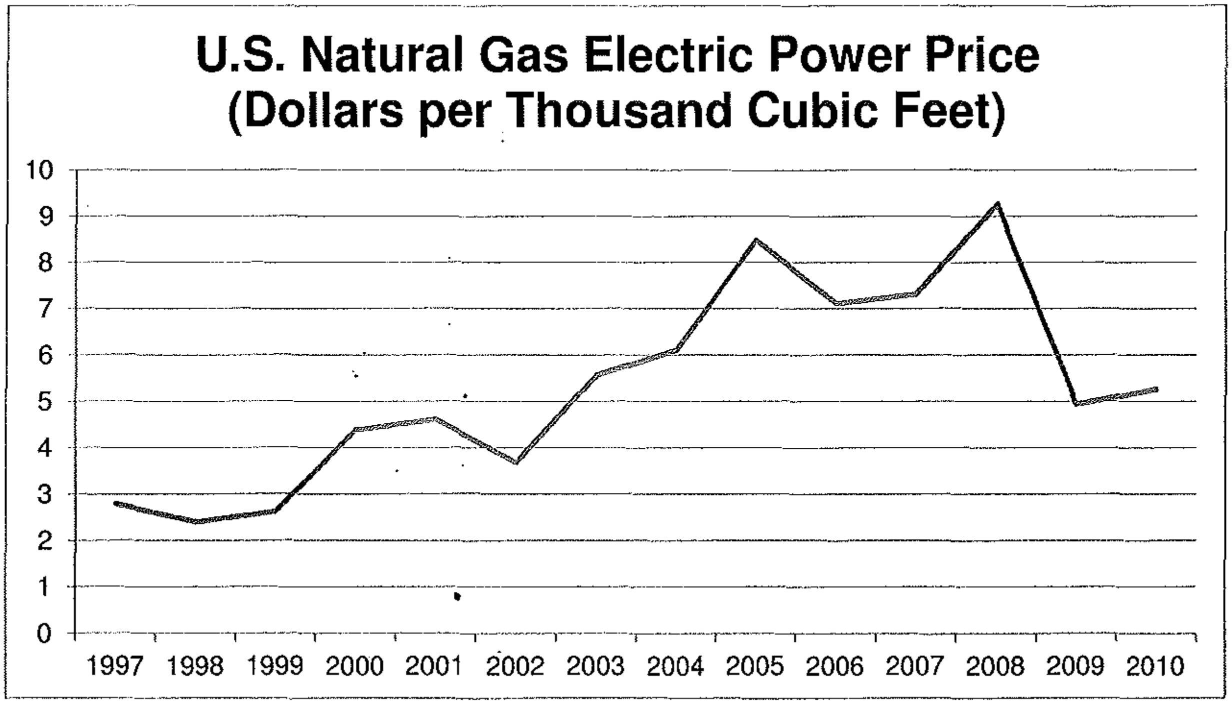


Figure 9.3: Historic U.S. natural gas electric power prices

Natural gas prices vary widely, causing corresponding fluctuations in the cost of energy from natural gas. Also, recent Environmental Protection Agency (EPA) regulations and proposed 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 as demand increases. The recommended MVP portfolio can partially offset the natural gas price risk by providing additional access to generation that uses fuels other than natural gas (e.g. nuclear, wind, solar and coal) during periods with high natural gas prices. Assuming a natural gas price increase of 25 percent to 60 percent, the recommended MVP portfolio provides approximately a 5 to 40 percent higher adjusted production cost benefits.

9.3.1 Sensitivity Assumptions

A set of sensitivity analyses were performed in PROMOD to quantify the impact of changes in natural gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the base business case analyses, except for the gas prices. The gas prices were increased from $5 to $8/MMBtu under the Business as Usual policy scenarios, and they were increased from $8 to $10/MMBtu under the Carbon Constrained and Combined Energy Policy scenarios. For each future scenario, the gas prices were increased starting in year 2011 and escalated by inflation thereafter.

9.3.2 Production cost benefit impact

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 recommended MVP portfolio. These increased benefits were driven by the efficient usage of renewable and low cost generation resources, as shown in

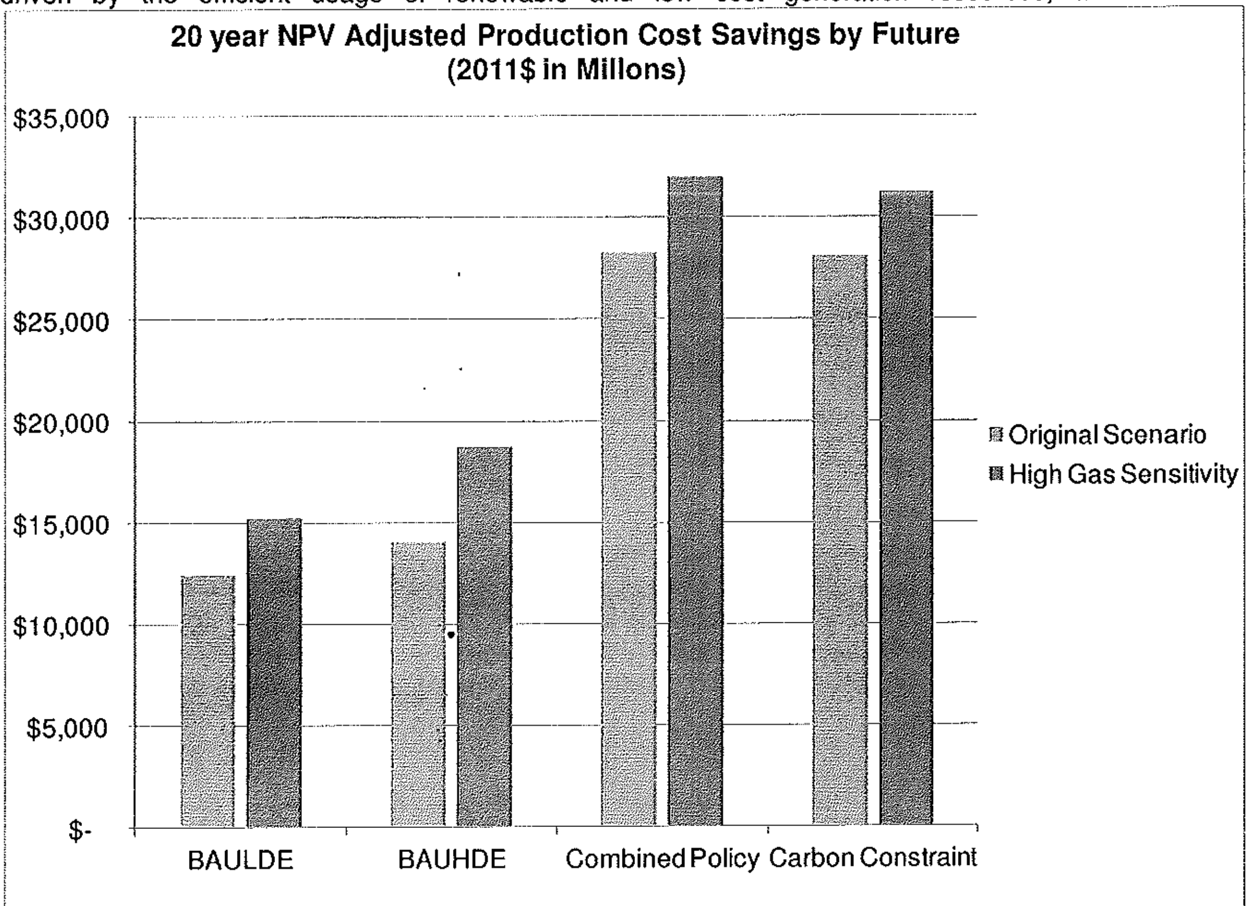


Figure 9.4.

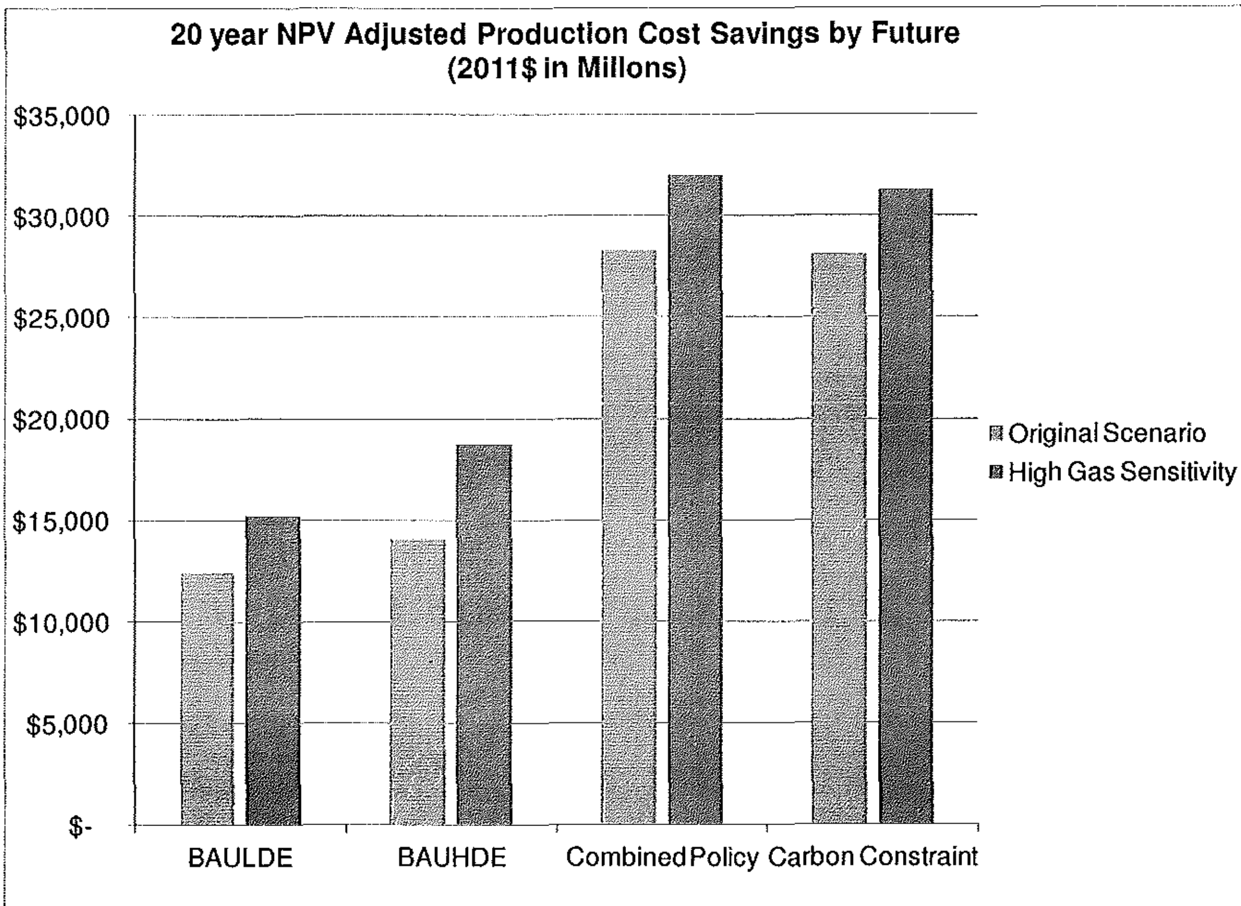


Figure 9.4: Recommended MVP Portfolio Adjusted Production Cost savings by future

9.3.3 Market price impact

The increase in market prices, or Locational Marginal Pricing (LMPs), was also calculated through the PROMOD sensitivities. The LMP is driven by the characteristics of the generation fleet and congestion on the system. With a $2-$3 increase in natural gas prices, the generation weighted average LMP increased by an average value of $7/MWh under a range of policy scenarios.

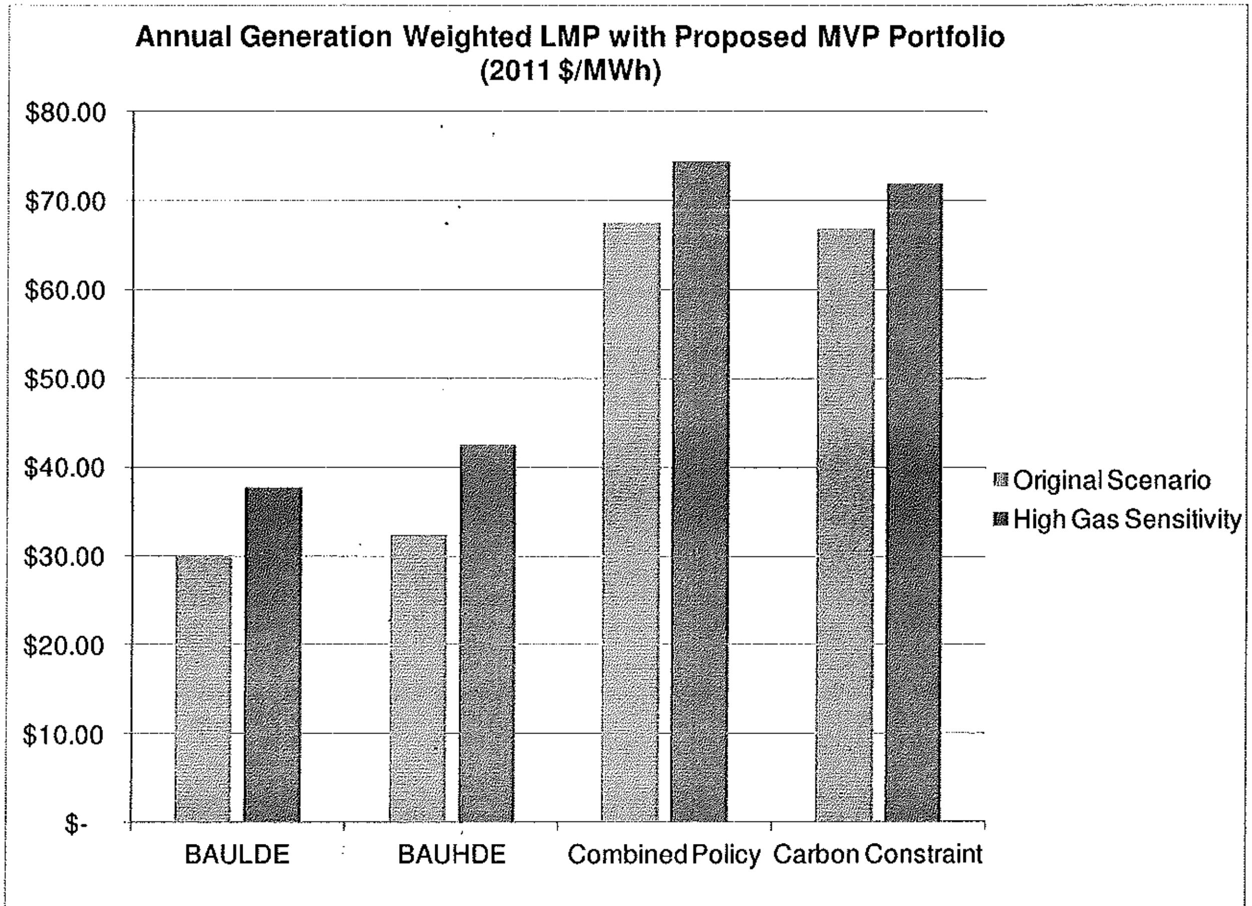


Figure 9.5: Annual generation weighted LMP with recommended MVP portfolio

9.4 Decreased wind generation volatility

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This 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 recommended MVP portfolio will increase the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time.

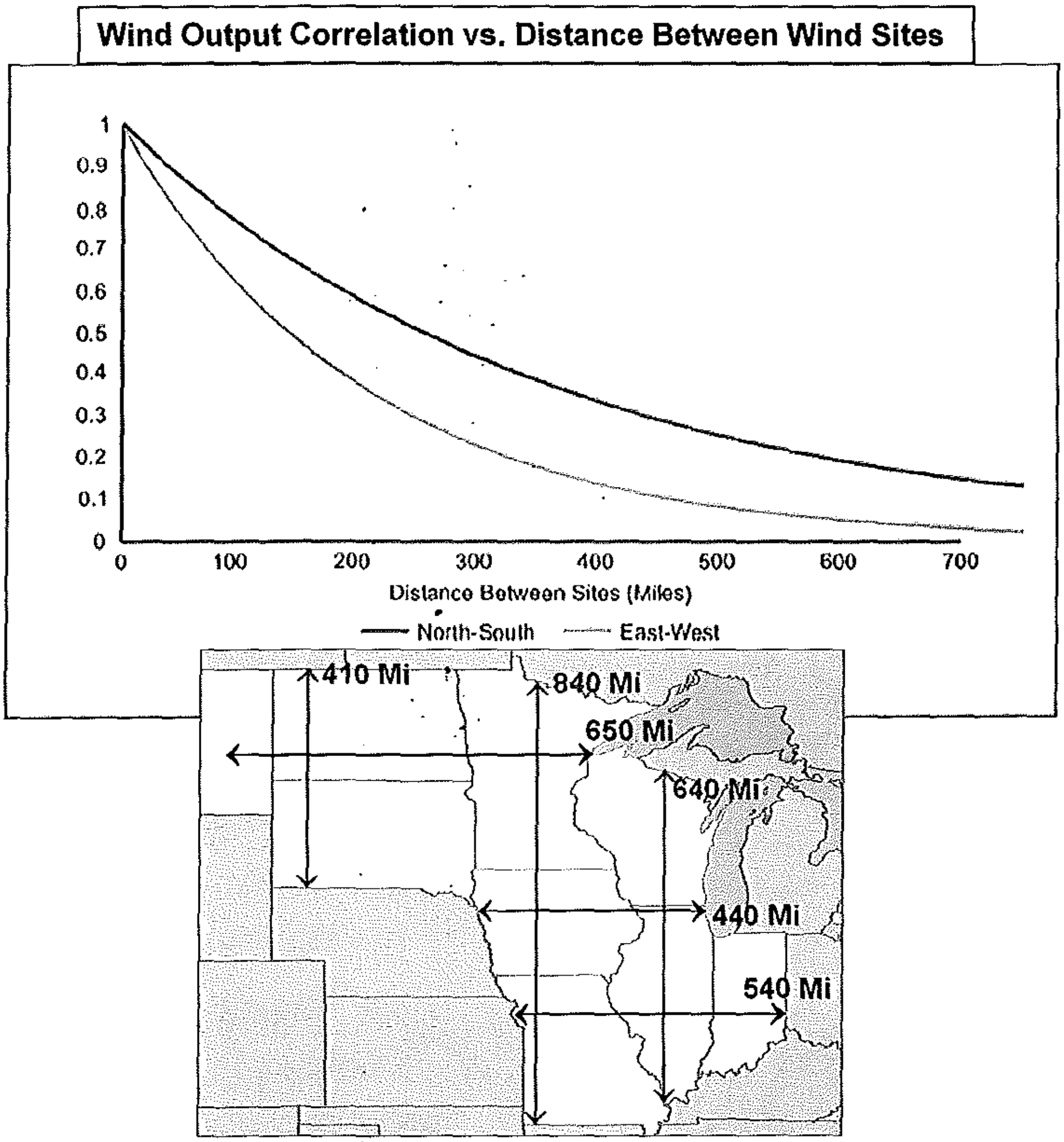


Figure 9.6: Wind Output correlation to distance between wind sites

9.5 Local investment and job creation

In addition to the direct benefits of the recommended MVP portfolio, studies have shown the indirect economic benefits of transmission investment. They estimated that, for each million dollars of transmission investment:

- Between $0.2 and $2.9 million of local investment is created.
- Between 2 and 18 employment years are created.[28]

The wide variations in these numbers are primarily due to the extent to which materials, equipment and workers can be sourced from a 'local' region. For example, each million dollars of local investment supports 11 to 14 employment years of local employment, as compared to 2 to 18 employment years which are created for non-location specific transmission investment.

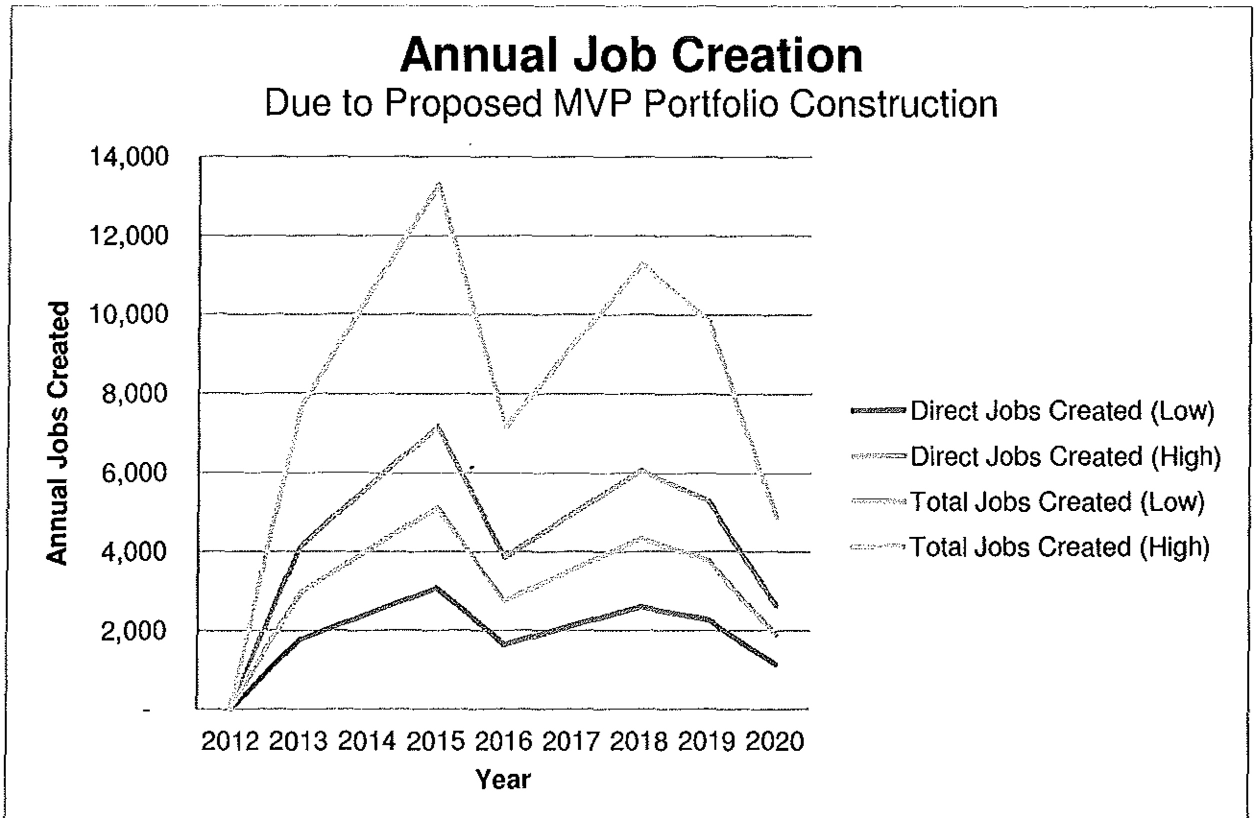


Figure 9.7: Annual Job Creation by Recommended MVP Portfolio

The recommended MVP portfolio supports the creation of between 17,000 and 39,800 local jobs, as well as $1.1 to $9.2 billion in local investment. This calculation is based upon a creation of $0.3 to $1.9 million local investment and 3 to 7 employment years per million of transmission investment. It also assumes that the capital investment for each MVP occurred equally over the 3 years prior to the project's in-service date.

[28] Source: *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, The Brattle Group

9.6 Carbon reduction

With the recommended MVP portfolio delivering significant amounts of wind energy across MISO and the neighboring regions, carbon emissions were reduced because of the more efficient usage of the generation fleet with conventional generation resources displaced by wind. Figure 9.8 summarizes the carbon emission reductions in million tons for each scenario with a range of 8.3 to 17.8 million tons annually.

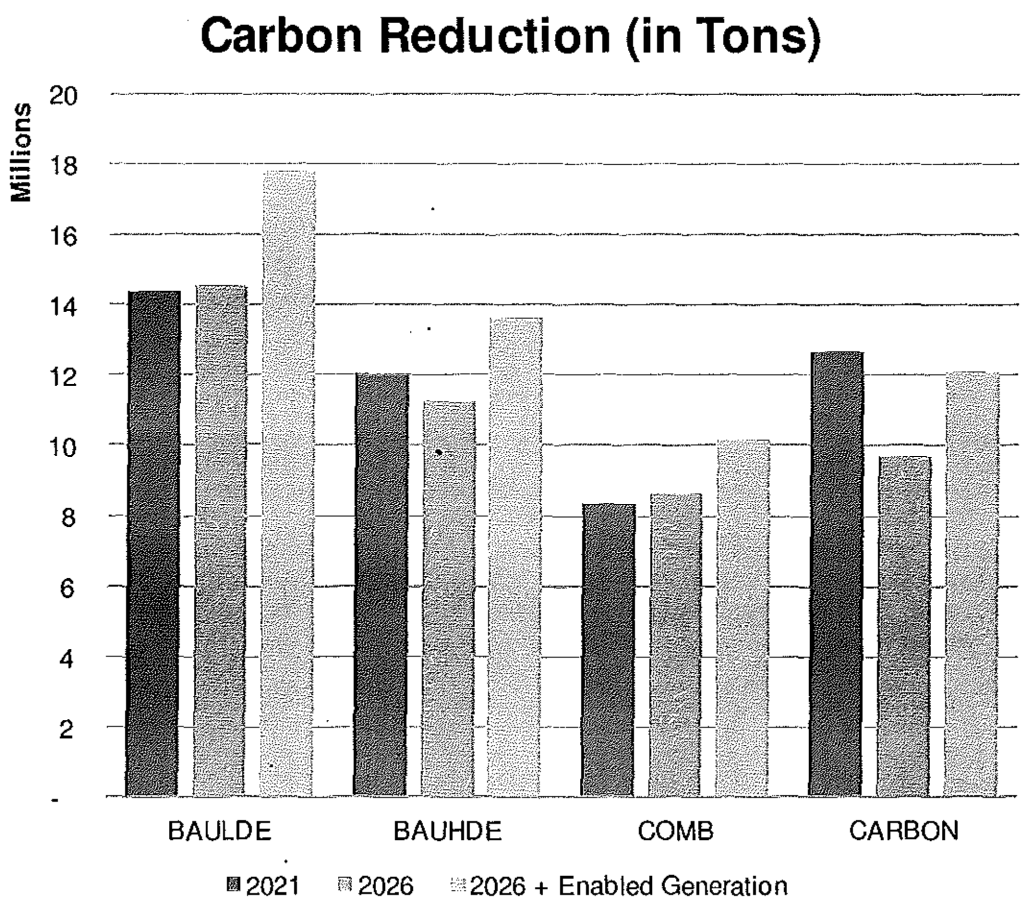


Figure 9.8: Carbon reduction by scenario

For the Combined Energy Policy and Carbon Constrained future scenarios, a $50/ton carbon cost was included to meet aggressive carbon reduction targets, as required by the proposed Waxman-Markey legislation. If policies were enacted that mandate a financial cost of carbon, the benefits provided by the recommended MVP portfolio would increase by between $3.8 and $15.4 billion in 20 and 40 year present value terms respectively, as depicted in Figure 9.9.

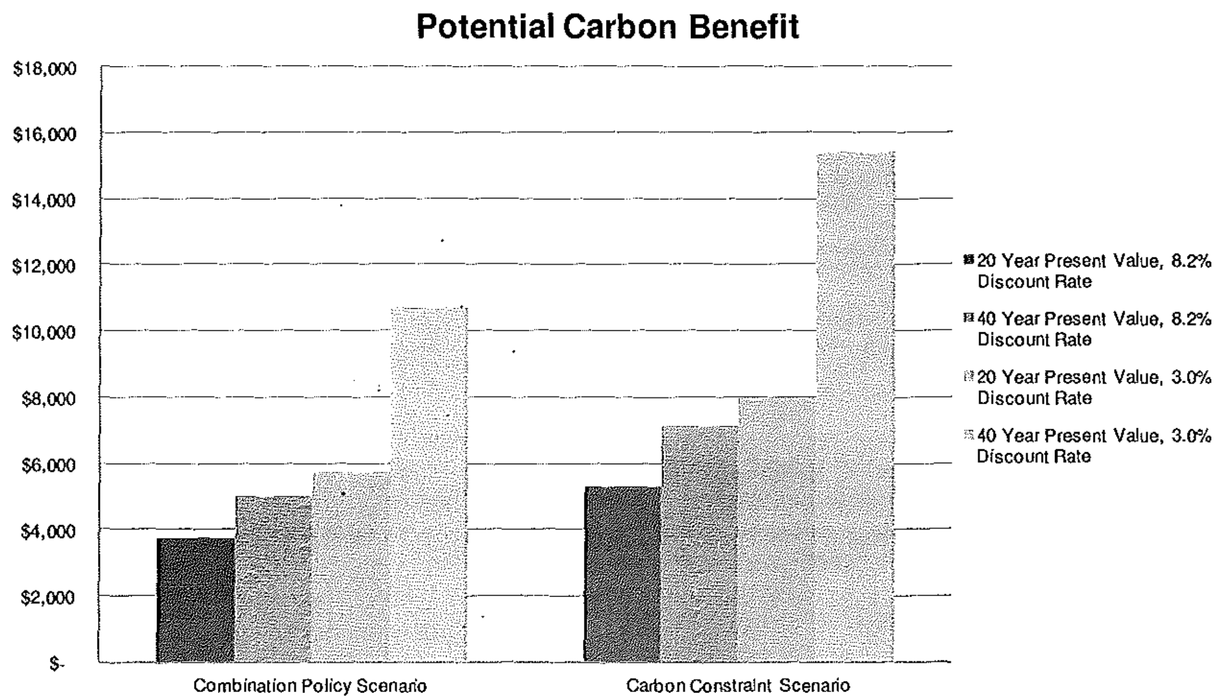


Figure 9.9: Potential carbon benefits

10 Proposed Multi Value Project Portfolio Overview

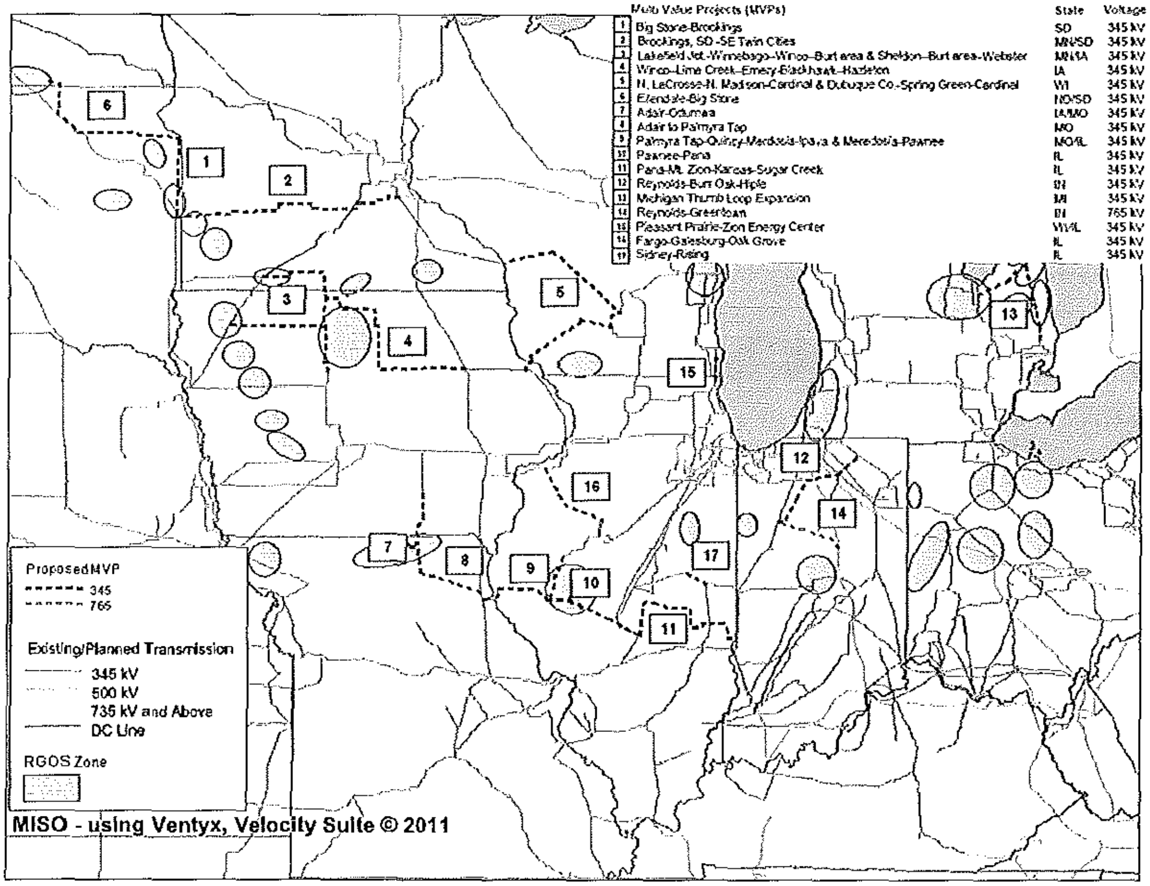


Figure 10.1: 2011 recommended MVP portfolio

The recommended MVP portfolio consists of 17 projects spread across the MISO footprint. These projects work together with the existing transmission network to enhance the reliability of the system, support public policy goals and enable a more efficient dispatch of market resources. Table 10.1 describes the projects that make up the recommended MVP portfolio.

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[29]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co.–Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$149
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo–Galesburg-Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$76
	Total				$5,180

Table 10.1: Recommended MVP portfolio

[29] Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.

10.1 Underbuild requirements

To ensure that the recommended MVP portfolio works well with the existing system to maintain reliability, MISO conducted analyses to determine any constraints that are present with the recommended MVP portfolio and not present without the portfolio. Any new constraints were identified for mitigations, and the appropriate mitigation was determined in coordination with the impacted Transmission Owners.

Below is a full list of the underbuild upgrades. These upgrades were identified through the steady state reliability analyses, using both off peak and peak models. No additional upgrades were identified through the stability analyses. Overall, approximately $70 million of transmission investment is associated with the underbuild upgrades.

Underbuild requirements
Burr Oak to East Winamac 138 kV line uprate[30]
Lake Marian 115/69 kV transformer replacement
Arlington to Green Isle 69 kV line uprate
Columbus 69 kV transformer replacement
Casey to Kansas 345 kV line uprate
Lake Marian to NW Market Tap 69 kV line uprate
Franklin 115/69 kV transformer replacements
Castle Rock to ACEC Quincy 69 kV line uprate
Kokomo Delco to Maple 138 kV line uprate
Wabash to Wabash Container 69 kV line uprate
Spring Green 138/69 kV transformer replacement
Davenport to Sub 85 161 kV line uprate
West Middleton West Towne 69 kV line uprate
Ottumwa Montezuma 345 kV line uprate

Table 10.2: Recommended MVP portfolio underbuild requirements

[30] Burr Oak to East Winamac upgrade also identified as part of the Meadow Lake wind farm upgrades.

10.2 Portfolio benefits and cost spread

A key principle of the MISO planning process is that the benefits from a given transmission project must be spread commensurate with its costs. The MVP cost allocation methodology distributes the costs of the portfolio on a load ratio share across the MISO footprint, so the recommended MVP portfolio must be shown to deliver a similar spread of benefits.

Each economic business case metric calculated for the full recommended MVP portfolio was analyzed to determine how it would accrue to stakeholders across the footprint. These results were then rolled up to a zonal level, based on the proposed Local Resource Zones for Resource Adequacy. This level of detail was chosen to provide stakeholders with an understanding of the benefits spread, without getting into a detail level which may be falsely precise due to the impact of individual stakeholder actions on actual benefit spreads.

The allocation of each of the economic metrics is discussed in more detail below.

10.2.1 Congestion and Fuel Savings

The Production Cost model simulations return results at a granular, generator-specific level. These results were then rolled up from this detailed level to a zonal level.

10.2.2 Operating Reserve Benefits

The costs of Operating Reserves were allocated across the footprint on a load-ratio share basis. This distribution matches the allocation of these costs through the MISO Energy and Ancillary Service markets. As such, although certain areas in the footprint may see reductions in the Operating Reserves they must hold within their area, the benefits of the more economic dispatch of these resources will be shared by the full MISO footprint.

10.2.3 System Planning Reserve Margin Benefits

The benefits accruing from the reduction in the system Planning Reserve Margin (PRM) were distributed across the footprint on a load-ratio share basis. This allocation was selected due to the widespread nature of the system PRM; the reduced planning margin will apply to all load in the MISO system, reducing the capacity needs for the full system.

10.2.4 Transmission Line Loss Benefits

The benefits accruing from the reduction in transmission line losses were allocated across the footprint on a load-ratio share basis. This approach reflects the integrated nature of the transmission system, as the market allows generation to be transported large distances to remote load. This integrated nature is enhanced by the inclusion of the recommended MVP portfolio into the transmission system, as congestion is reduced, and transfer capacity is increased, across the system.

10.2.5 Wind Turbine Investment

The benefits of reducing the required investment in wind turbines are not applicable for areas that do not have either renewable energy mandates or goals that can be sourced from outside the area. This benefit is also enhanced for areas with lower wind capacity factors, as the differential in wind turbine investment is substantially higher for these areas than for those with, on average, higher wind speeds. As a result, this benefit was allocated to the zones through a weighted average of the renewable energy mandates or needs that can be sourced outside of the zone, along with the relative wind capacity factors, when compared to the system's highest wind speed area.

Zone	Average Capacity Factor	Capacity Factor Differential From System Maximum	Average Out-of-State Renewable Mandates or Goals (%)	Out-of-State Renewable Generation Mandates or Goals (MW)	2026 Projected Load (GWh)	Out-of-State Renewable Generation Mandates or Goals (GWh)	Renewable Generation Weighted by Capacity Factor Differential	Zonal Allocation
1	38%	5%	28%		108,371	29,927	1,446	19%
2	28%	16%	10%		80,267	8,027	1,260	16%
3	36%	8%	N/A	3,000	55,648	9,338	716	9%
4	28%	16%	18%		60,063	11,087	1,730	22%
5	33%	10%	14%		55,485	7,788	809	10%
6	29%	14%	9%		143,528	13,013	1,833	24%
7	28%	15%	0%		119,017	-	-	0%

Table 10.3: Wind Turbine Investment Allocation[31]

[31] All values shown in the table exclude in-state renewable energy goals or mandates.

10.2.6 Future Transmission Investment

Higher voltage Baseline Reliability Projects (BRPs), under Attachment FF of the MISO Tariff, are allocated as a mixture of system wide costs and local costs. More specifically, 20% of the costs of the transmission upgrades are allocated across the system, and 80% of the project costs are allocated to affected pricing zones.

The benefits accruing from the ability of the recommended MVP portfolio to avoid future Baseline Reliability Project investment was allocated using this methodology.

10.2.7 Costs Distribution

The costs of the portfolio were allocated across the footprint on a load-ratio share basis, as required by the Multi Value Project cost allocation methodology. Additional information on the distribution of the costs of the Multi Value Project portfolio may be found in the following section, section 10.3.

10.2.8 Zonal Benefit-Cost Ratio

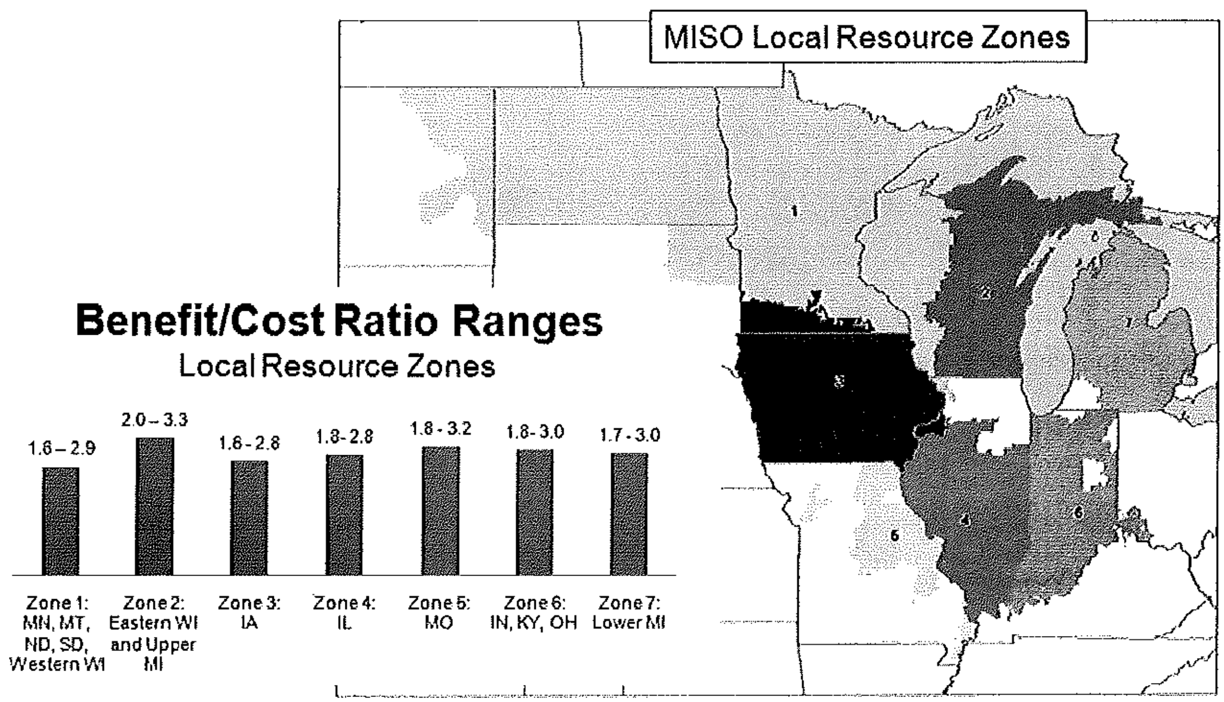


Figure 10.2: Recommended MVP portfolio production cost benefits spread

The recommended MVP portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to its costs allocation. For each of the local resource zones, as shown in Figure 10.2, the portfolio's benefits are at least 1.6 to 2.9 times the cost allocated to the zone.

10.3 Cost allocation

Multi Value Projects represent a new project type eligible for cost sharing effective since July 16, 2010, and conditionally accepted by the Federal Energy Regulatory Commission on December 16, 2010. Multi Value Projects provide numerous benefits, including, improved reliability, reduced congestion costs, and meeting public policy objectives.

> The costs of Multi Value Projects will have a 100 percent regional allocation and will be recovered from customers through a monthly energy usage charge calculated using the applicable MVP Usage Rate.

The proposed Multi Value Project portfolio described in this report includes the Michigan Thumb Loop project, approved in August 2010; the Brookings to Minneapolis-St. Paul project, conditionally approved in June 2011; and 15 additional projects being proposed to the MISO Board of Directors for approval in December 2011. The cost of the recommended MVP portfolio in 2011 dollars is $5.2 billion, including the $1.2 billion in projects that have previously been approved or conditionally approved by the MISO Board of Directors. See Table 10.1 for individual project costs.

The costs of Multi Value Projects will have a uniform 100 percent regional allocation based on withdrawals and will be recovered from customers through a monthly energy usage charge. This charge will apply to all MISO load, excluding load under Grandfathered Agreements, and also to export and wheel-through transactions not sinking in PJM.

Figure 10.3 shows a 40-year projection of indicative annual MVP Usage Rates based on the recommended MVP portfolio using current year cost estimates and estimated in-service dates. Additional detail on the indicative MVP Usage Rate, including indicative annual MVP charges by Local Balancing Authority, is included in Appendix A-3 of the MTEP11 report.

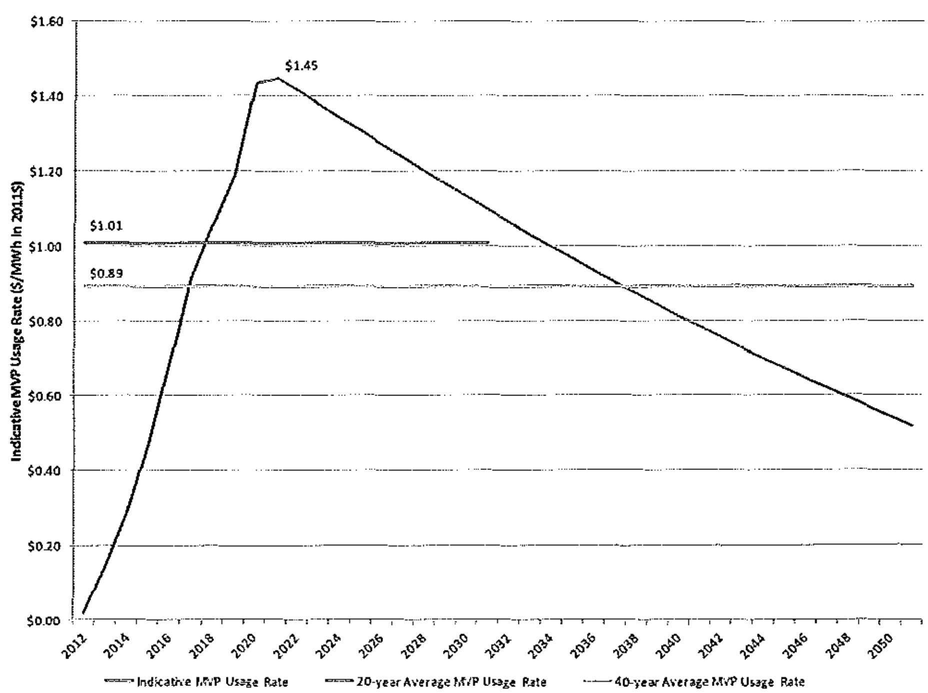
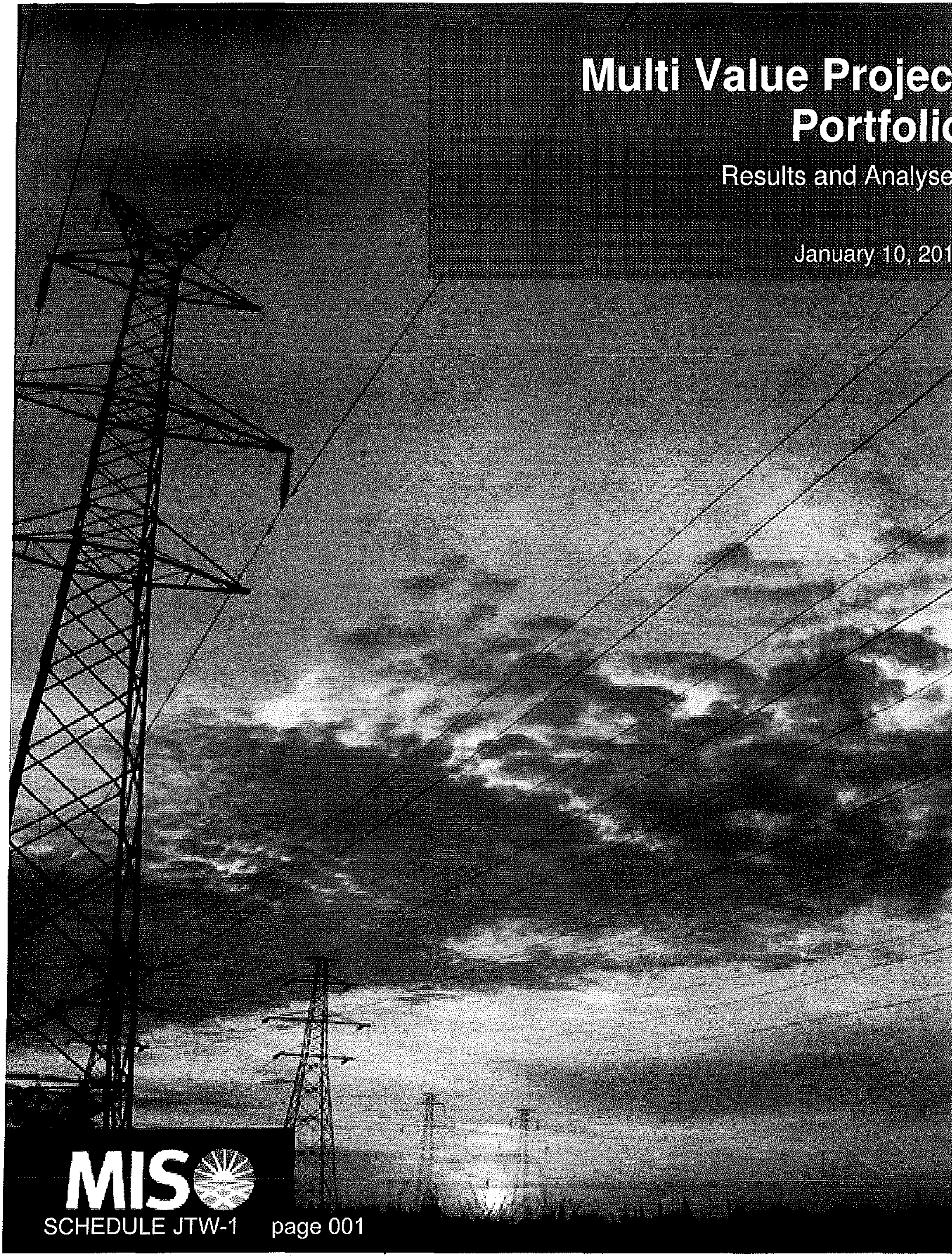


Figure 10.3: Indicative MVP usage rate for recommended MVP portfolio from 2012 to 2051

11 Conclusions and recommendations

MISO staff recommends the recommended MVP portfolio to the MISO Board of Directors for their review and approval. This recommendation is premised on the ability of the portfolio to meet MVP criterion 1, as each project in the portfolio 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.

The recommendation is also supported by the strong economic benefits of the portfolio, which delivers a large amount of value in excess of costs under all conditions and policy scenarios studied. Furthermore, these benefits are spread across the MISO footprint, in a manner commensurate with the allocation of the portfolio's costs.



Multi Value Project Portfolio

Results and Analyses

January 10, 2012

1 Executive Summary

MISO staff recommends that the Multi Value Project (MVP) portfolio described in this report be approved by the MISO Board of Directors for inclusion into Appendix A of MTEP11. This recommendation is based on the strong reliability, public policy and economic benefits of the portfolio that are distributed across the MISO footprint in a manner that is commensurate with the portfolio's costs. In short, the proposed portfolio will:

- 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.

This report summarizes the key reliability, public policy and economic benefits of the recommended MVP portfolio, as well as the scope of the analyses used to determine these benefits.

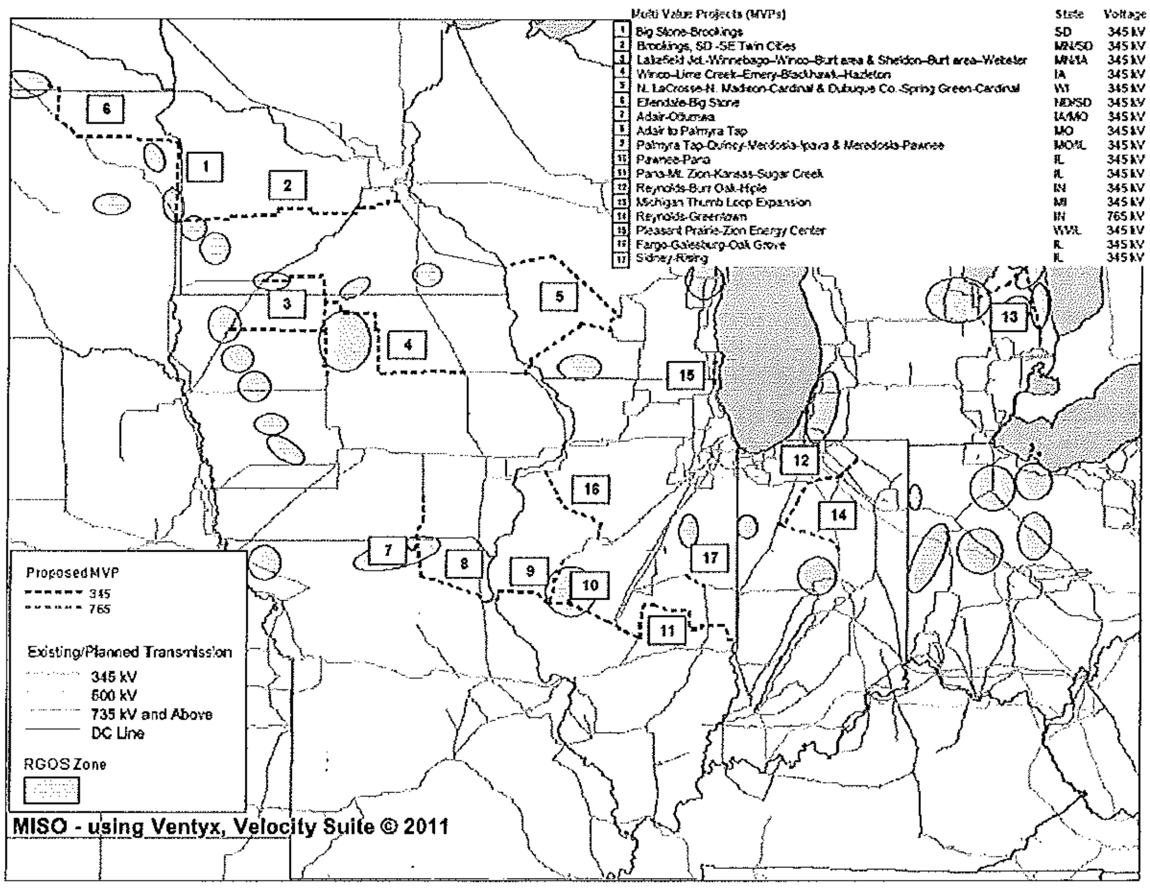


Figure 1.1: MVP portfolio[1]

[1] MVP line routing shown throughout the report is for illustrative purposes only and do not represent the final line routes.

The recommended MVP portfolio includes the Brookings Project, conditionally approved in June 2011, and the Michigan Thumb Loop project, approved in August 2010. It also includes 15 additional projects which, when integrated into the transmission system, provide multiple kinds of benefits under all future scenarios studied[2].

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[3]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. –Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co. –Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$152
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop Expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo-Galesburg–Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$90
	Total				$5,197

Table 1.1: MVP portfolio[4]

[2] More information on these scenarios may be found in the business case description.
[3] Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.
[4] In-service dates represent the best information available at the time of publication. These dates may shift as the projects progress through the state regulatory processes.

Public policy decisions over the last decade have driven changes in how the transmission system is planned. The recent adoption of Renewable Portfolio Standards (RPS) and clean energy goals across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

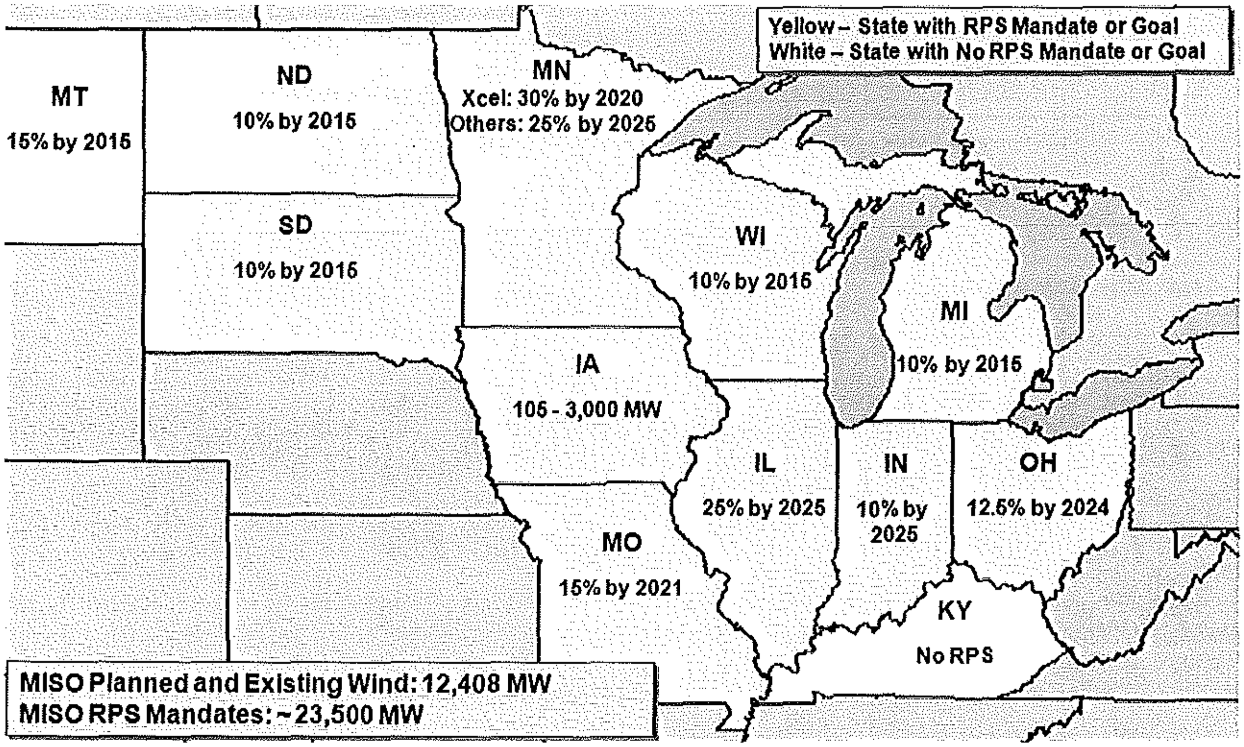


Figure 1.2: Renewable energy mandates and clean energy goals within the MISO footprint[5],[6]

Beginning with the MTEP03 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.

The recent adoption of Renewable Portfolio Standards (RPS) across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers.

The goal of the RGOS analysis was to design transmission portfolios that would enable RPS mandates to be met at the lowest delivered wholesale energy cost. The cost calculation combined the expenses of the new transmission portfolios with the capital costs of the new renewable generation, balancing

[5] Existing and planned wind as included in the MVP Portfolio analyses. State RPS mandates and goals include all policies signed into law by June 1, 2011.

[6] The higher number for Iowa's state RPS mandates and goals reflects the wind online rather than a statutory requirement.

the trade offs of a lower transmission investment to deliver wind from low wind availability areas, typically closer to large load centers; against a larger transmission investment to deliver wind from higher wind availability areas, typically located further from load centers.

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 zones.

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. Figure 1.3 depicts the correlation between the natural gas pipelines in the MISO footprint and the energy zones.

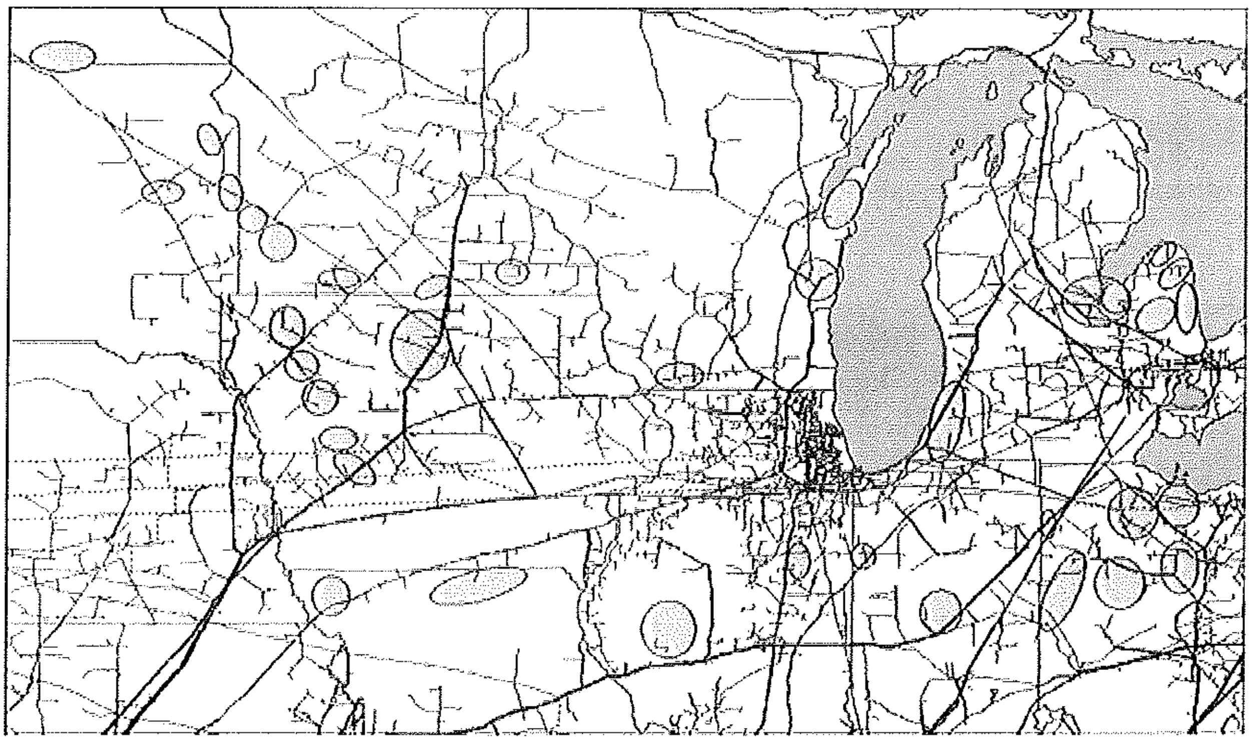


Figure 1.3: RGOS and MVP Analyses Incremental Energy Zones and natural gas pipelines

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 which were believed to provide multiple kinds of reliability and economic benefits under all alternate futures studied.

The output from the study, a recommended MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

The 2011 MVP portfolio analysis hypothesized that this set of candidate projects will create a high value transmission portfolio, enabling MISO states to meet their near term RPS mandates. The study evaluated the candidate MVP portfolio against the MVP cost allocation criteria to prove or disprove this hypothesis, as well as to confirm that the benefits of the portfolio would be widely distributed across the footprint. The output from the study, a recommended MVP portfolio, will reduce the wholesale cost of energy delivery for the consumer by enabling the delivery of low cost generation to load, reducing congestion costs and increasing system reliability, regardless of the future generation mix.

Over the course of the MVP portfolio analysis, the candidate MVP portfolio was refined into the portfolio that is now recommended to the MISO Board of Directors for approval. The portfolio was refined to ensure that the portfolio as a group and each project contained within it was justified under the MVP criteria, discussed below, and to ensure that the portfolio benefit to cost ratio was optimized.

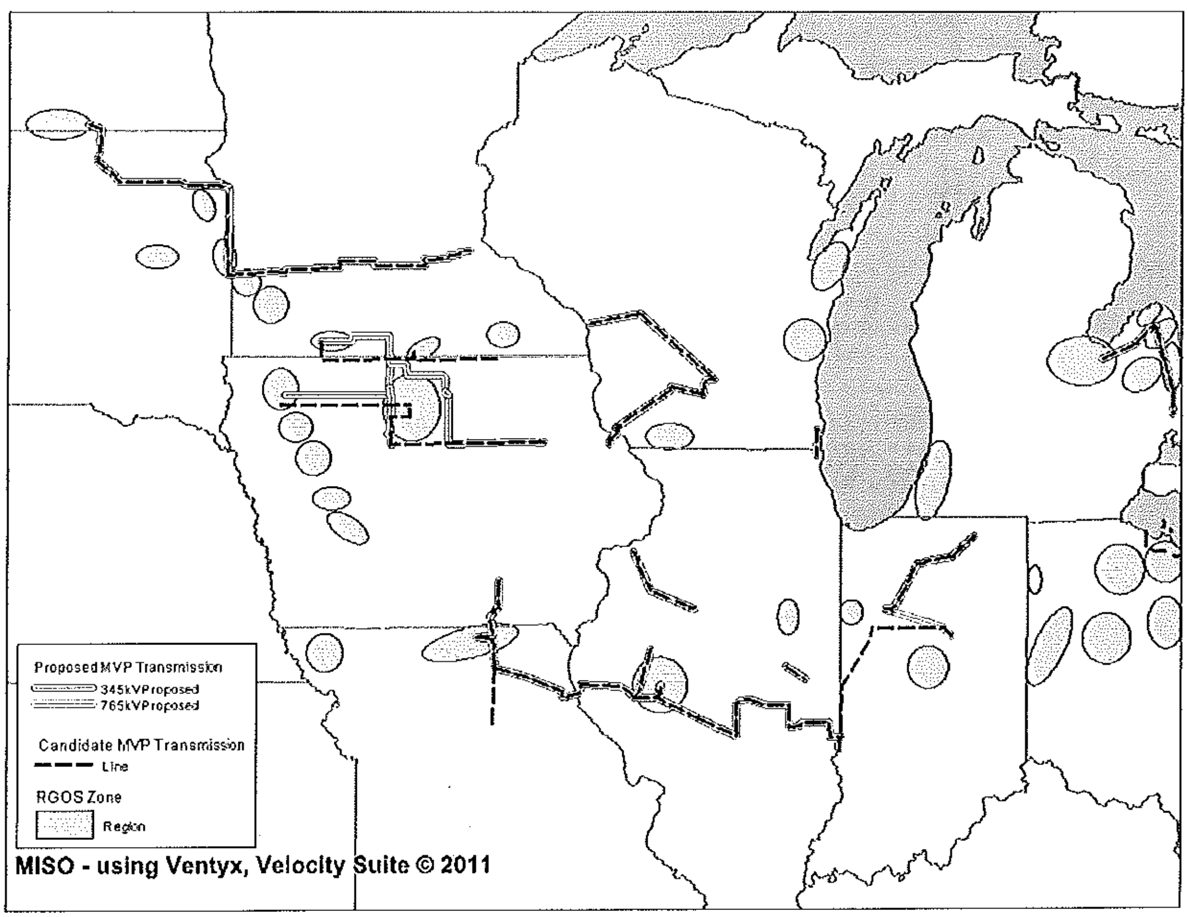


Figure 1.4: Candidate versus Recommended MVP Portfolios

The recommended MVP portfolio will enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be 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.

> The benefits created by the recommended MVP portfolio are spread across the system, in a manner commensurate with its costs.

Under all future policy scenarios studied, the recommended MVP portfolio delivers widespread regional benefits to the transmission system. For example, based on scenarios that did not consider new energy policies, the benefits of the proposed portfolio were shown to range from 1.8 to 3.0 times its total cost. These benefits are spread across the system, in a manner commensurate with their costs, as demonstrated in Figure 1.5.

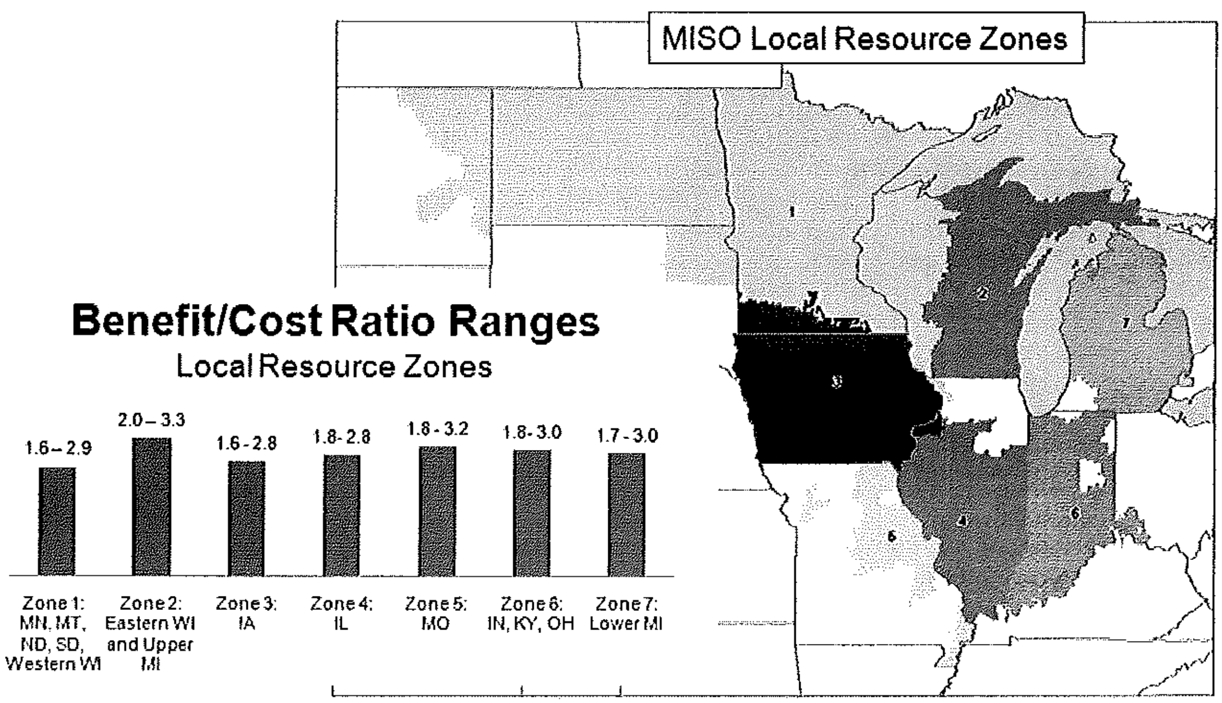


Figure 1.5: Recommended MVP portfolio benefits spread

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 criterion 1 through its reliability and public policy benefits, MISO staff recommended the 2011 MVP portfolio to the MISO Board of Directors for their review and approval.

2 MISO Planning Approach

The goal of the MISO planning process is to develop a comprehensive expansion plan that reflects a fully integrated view of project value inclusive of reliability, market efficiency, public policy and other value drivers across all planning horizons. This process is guided by a set of principles established by the MISO Board of Directors, adopted on August 18, 2005. The principles were created in an effort to improve and guide transmission investment in the region and to furnish an element of strategic direction to the MISO transmission planning process. These principles, modified and approved by the MISO Board of Directors System Planning Committee on May 16, 2011, are:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by providing access to the lowest electric energy costs.
- **Guiding Principle 2:** Provide a transmission infrastructure that safeguards local and regional reliability and supports interconnection-wide reliability.
- **Guiding Principle 3:** Support state and federal energy policy objectives by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost mechanism that ensures the realization of benefits over time is commensurate with the allocation of costs.
- **Guiding Principle 5:** Develop transmission system scenario models and make them available to state and federal energy policy makers to provide context and inform the choices they face.

A number of conditions must be met to build longer term transmission able to support future generation growth and accommodate new energy policies. These conditions are intertwined with the planning principles put forth by the MISO Board of Directors and supported by an integrated, inclusive transmission planning approach. The conditions that must be met to build transmission include:

- A robust business case that demonstrates value sufficient to support the construction of the transmission project.
- Increased consensus on current and future energy policies.
- A regional tariff that matches who benefits with who pays over time.
- Cost recovery mechanisms that reduce financial risk.

3 Multi Value Project portfolio drivers

The 2011 MVP portfolio analysis was based on the need to economically and reliably help states meet their public policy needs. The study identified a regional transmission portfolio that will enable the MISO Load Serving Entities (LSEs) to meet their Renewable Portfolio Standards (RPS). The analyses and their results describe a robust business case for the portfolio. This business case demonstrates that not only will the recommended MVP portfolio reliably enable Renewable Portfolio Standards to be met, but it will do so in a manner where its economic benefits exceed its costs.

While the study focused upon the RPS requirements, the transmission portfolio will ultimately have widespread benefits beyond the delivery of wind and other renewable energy. It will enhance system reliability and efficiency under a variety of different generation build outs. It will also open markets to competition, reducing congestion and spreading the benefits of low cost generation across the MISO footprint. The MVP portfolio analysis focused on identifying and increasing the benefits of the transmission portfolio, including the reliability, economic and public policy drivers.

3.1 Tariff requirements

The MVP portfolio analysis and the recommendation were premised on the MVP criteria described in Attachment FF of the MISO Tariff and shown below.

> Criterion 1
>
> A Multi Value Project must be developed through the transmission expansion planning process to enable the transmission system to deliver energy reliably and economically in support of documented energy policy mandates or laws enacted or adopted through state or federal legislation or regulatory requirement. These laws must directly or indirectly govern the minimum or maximum amount of energy that can be generated. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.
>
> Criterion 2
>
> A Multi Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP benefit to cost ratio of 1.0 or higher, where the total MVP benefit to cost ratio is described in Section II.C.7 of Attachment FF to the MISO Tariff. The reduction of production costs and the associated reduction of LMPs from a transmission congestion relief project are not additive and are considered a single type of economic value.
>
> Criterion 3
>
> A Multi Value Project must address at least one transmission issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic based transmission issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.

The MVP cost allocation criteria requires evaluation of the portfolio on a reliability, economic and energy delivery basis. The scope of the analysis was designed to demonstrate this value, both on a project and portfolio basis. The projects in the MVP portfolio were evaluated against MVP criteria 1 and their ability to reliably enable the renewable energy mandates of the MISO states was quantified.

In addition, the Tariff identifies specific types of economic value which can be provided by Multi Value Projects. These values are:

- Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.
- Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.
- Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.
- Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.
- Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.

The full proposed portfolio was evaluated against the benefits defined in the Tariff for MVPs. In addition to the benefits described above, the operating reserve and wind siting benefits for the portfolio were quantified, as allowed under the last Tariff defined economic value. These benefits are described more fully in the economic benefit section later in the report.

3.2 Transmission strategy

A transmission strategy addressing both local needs and regional drivers allows the MISO system to realize significant economic and reliability benefits. Regional transmission, such as the transmission in the recommended MVP portfolio, increases reliability in the MISO footprint and opens the market to increased competition by providing access to low cost generation, regardless of fuel type. Development of a strong regional transmission backbone is analogous to the development of the U.S. Interstate Highway System. While developed for specific national security justifications, the system has realized significant additional benefits in subsequent years. Similarly, the recommended MVP portfolio will create reliability, economic and public policy benefits reaching beyond the immediate needs exhibited in this analysis.

The overall goal for the MVP portfolio analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system. The portfolio was designed using reliability and economic analyses, applying several futures scenarios to determine the robustness of the designed portfolio under a number of future potential energy policies.

3.3 Public policy needs

Twelve of thirteen states in the MISO footprint have enacted either RPS requirements or renewable energy goals which require or recommend varying amounts of load be served with energy from renewable energy resources. The MVP portfolio analysis focused on the transmission necessary to economically and reliably meet the state RPS mandates. Figure 3.1 provides additional details on these renewable energy requirements and goals.

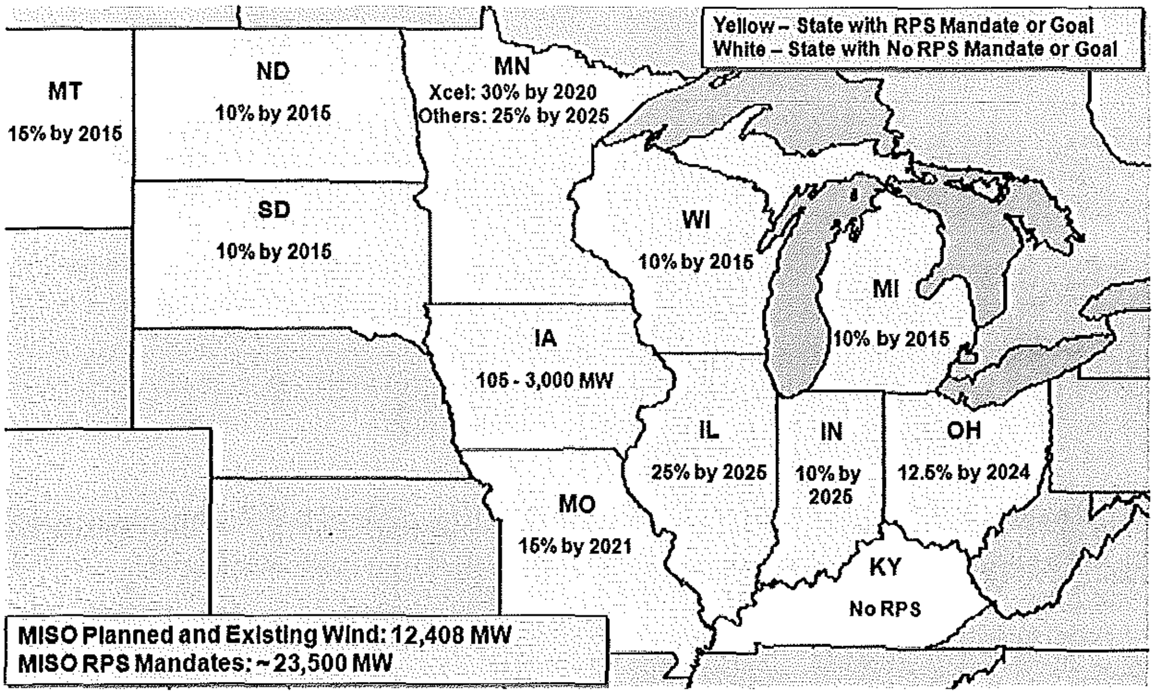


Figure 3.1: RPS mandates and goals within the MISO footprint[7]

RPS mandates vary from state to state in their specific requirement details and implementation timing, but they generally start in about 2010 and are indexed to increase with load growth. While state laws support a number of different types of renewable resources, and multiple types of renewable resources will play a role in meeting state RPS mandates, the majority of renewable energy resources installed in the foreseeable future will likely focus on harnessing the abundant wind resources throughout the MISO footprint.

> The goal of the MVP portfolio analysis was to design a transmission portfolio which takes advantage of the linkages between local and regional reliability and economic benefits to bring value to the entire MISO system.

3.4 Enhanced reliability and economic drivers

The ultimate goal of the MISO planning process is enable the reliable delivery of energy to load at the lowest possible cost. This requires a strategy premised upon a low cost approach to transmission and generation investment. This premise supports the overall constructability of the transmission portfolio, while reducing financial risk associated with overbuilding the system.

[7] The higher number for Iowa's state RPS mandates and goals reflects the wind online rather than a statutory requirement.

4 MVP Portfolio Development and Scope

The MVP portfolio was developed by considering regional system enhancements, from previous MISO analyses, that could potentially provide multiple types of value, including enhanced reliability, reduced congestion, increased market efficiency, reduced real power losses and the deferral of otherwise needed capital investments in transmission.

This portfolio was also based upon a set of energy zones, developed to provide a low-cost approach to wind siting when both generation and transmission capital costs are considered. Incremental wind necessary to meet the 2021 or 2026 renewable mandates for MISO stakeholders was added to these zones, as described in the following sections.

Finally, the MVP portfolio was intensively evaluated to ensure its composite projects, and the portfolio in total, are justified under the MVP cost allocation criterion. This analysis included an evaluation of each individual project justification against MVP criterion 1. It also included an evaluation of the full portfolio, both on a reliability and economic basis.

4.1 Development of the MVP Portfolio

MISO began to investigate the transmission required to integrate wind and provide the best value to consumers in 2002. The analyses continued through subsequent MTEP cycles, with exploratory and energy market analyses. As the demand for renewable energy grew, driven largely by an increasing level of renewable energy mandates or goals, additional regional studies were conducted to determine the transmission necessary to support these policy objectives. These studies included the Joint and Coordinated System Plan (JCSP), the Regional Generation Outlet Studies (RGOS), and analyses by the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP) group.

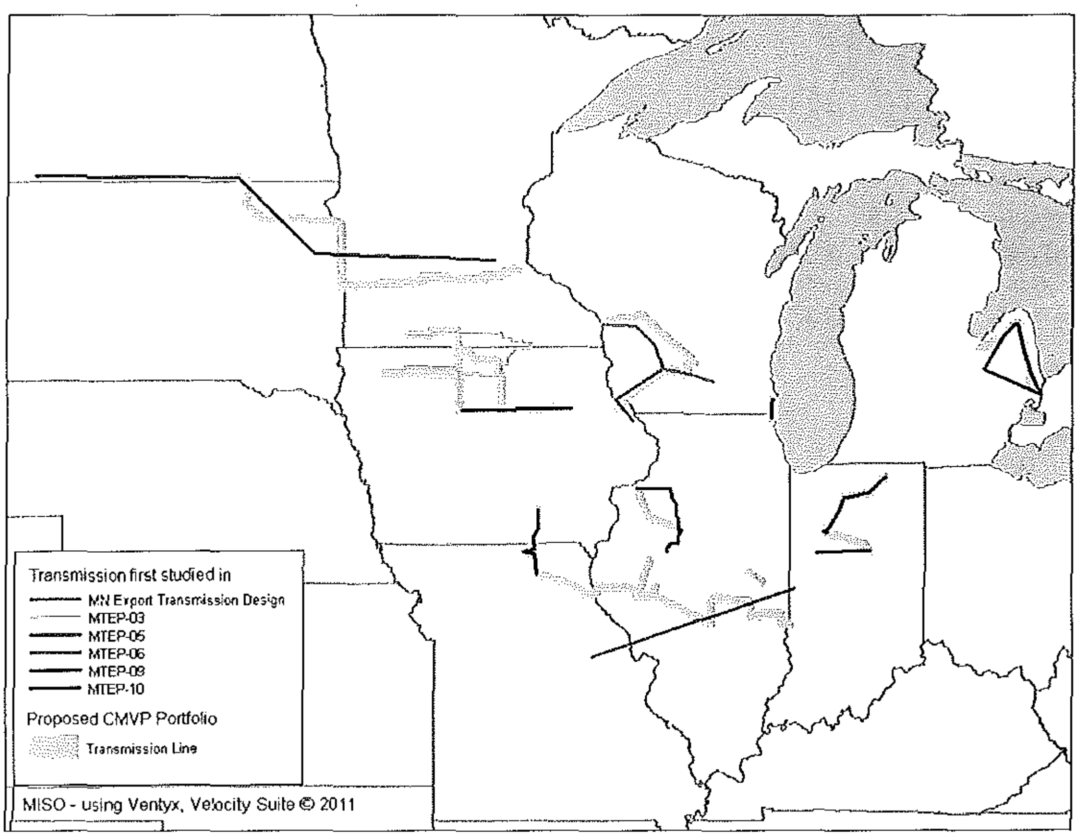


Figure 4.1: Summary of prior study input into recommended MVP portfolio

As analyses continued, the policy and economic drivers behind a regional transmission plan continued to grow. This growth was partly fueled by the development of the MISO energy and operating reserve market, which allows for regional transmission to provide regional benefits through increasing market efficiency, enabling low cost generation to be delivered to load. Simultaneously, an increase in state energy policy mandates drove the need for a robust regional transmission network, capable of responding to legislated changes in generation requirements.

It is worth noting that, although individual projects were identified beginning in MTEP03, these projects were not studied only in the year they were first identified. Subsequent MTEP analyses built on the analyses of previous years and culminated in the final recommendation of the recommended MVP portfolio.

4.1.1 MTEP03 high wind generation development scenario

In the first MISO Transmission Expansion Plan, MTEP03, the MISO evaluated at a high level the potential economic benefits of large regional transmission projects under various postulated generation development scenarios. MTEP 03 evaluated a dozen such plans based on analysis of the base planned transmission system, and its ability to accommodate substantial new additions of coal, wind and gas generation based on the interconnection queues at the time. The transmission and generation scenario analysis showed generally that there was significant potential for the right regional transmission to result in substantial reductions in marginal energy costs, particularly if that transmission was coupled with introduction of low cost coal and wind energy resources.

More specifically, MTEP03 included a high wind development scenario, which included approximately 8,600 to 10,000 MW of new wind development. This scenario was used to evaluate several transmission scenarios on a conceptual level, including a set of high voltage lines in Iowa, running from Lakefield to Adams in southern Minnesota, then looping back to tap the line from Raun to Lakefield line in Iowa.

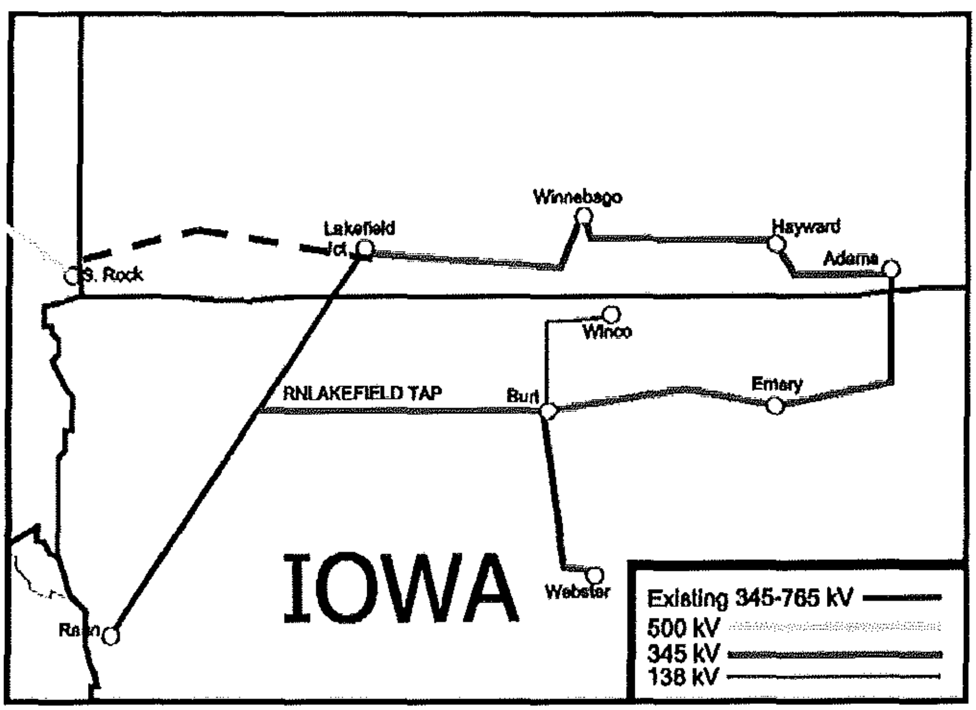


Figure 4.2: Iowa transmission identified in MTEP03

This line was studied in subsequent MTEP cycles, and it eventually led to the identification and incorporation of several Iowa lines into the MVP portfolio. MTEP03 also identified a potential upgrade of the Sidney-Rising line, as a conceptual transmission project.

4.1.2 MTEP05

MTEP05 continued the exploratory transmission analysis began in MTEP03, with two studies which focused in the area around the Dakotas and Northern Minnesota, along with the area around Iowa and Southern Minnesota. It was expected that high voltage transmission projects in these areas would provide additional access to existing base load generation, as well as future wind investment.

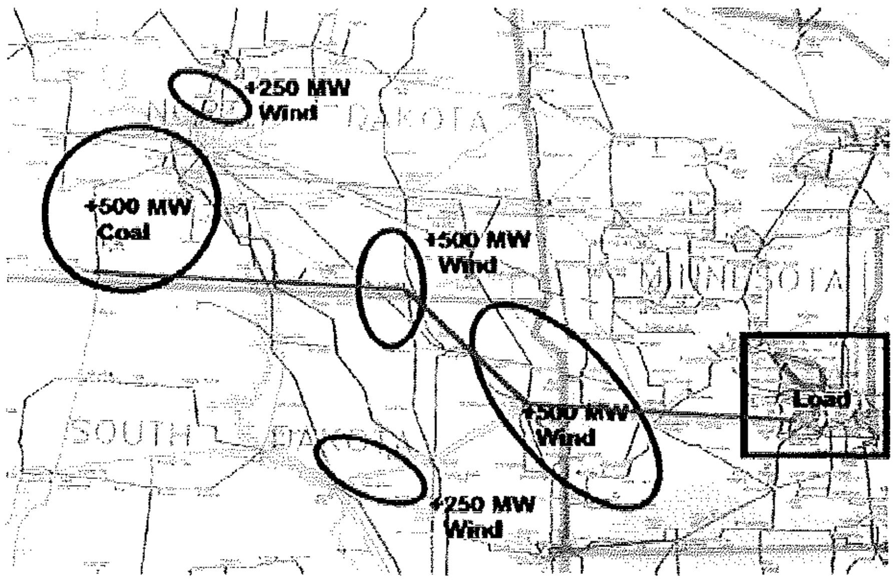


Figure 4.3: Northwest Transmission Option 2

The Northwest study identified the need for at least one, and potentially several, new transmission corridors between the Dakotas and to the Twin Cities of Minnesota. These lines were further studied through the MISO stakeholder CapX 2020 study effort, and they formed the basis of several lines included in the recommended MVP portfolio.

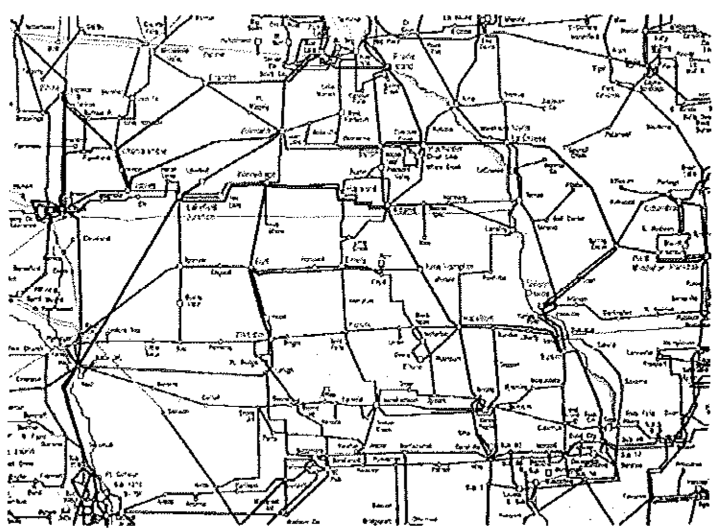


Figure 4.4: Iowa-Minnesota Transmission Scenario 2

The Iowa-Minnesota study further reinforced the need for transmission through southern Minnesota and Iowa. It also identified the need for transmission extending from Minnesota to the Spring Green area in Wisconsin, then from the Spring Green area southwest to the Dubuque area.

4.1.3 MTEP06

In MTEP06, the Vision Exploratory Study modeled scenario which included 20% wind energy for Minnesota and 10% wind energy for the other MISO states, for a total of 16 GW. This hypothetical generation scenario was used to evaluate additional high voltage transmission needs. Although this study focused on a 765 kV solution, it determined that transmission would be needed along many of the corridors identified in prior studies. Additionally, it identified that a transmission path would be required across south-central Illinois to efficiently deliver wind energy to load.

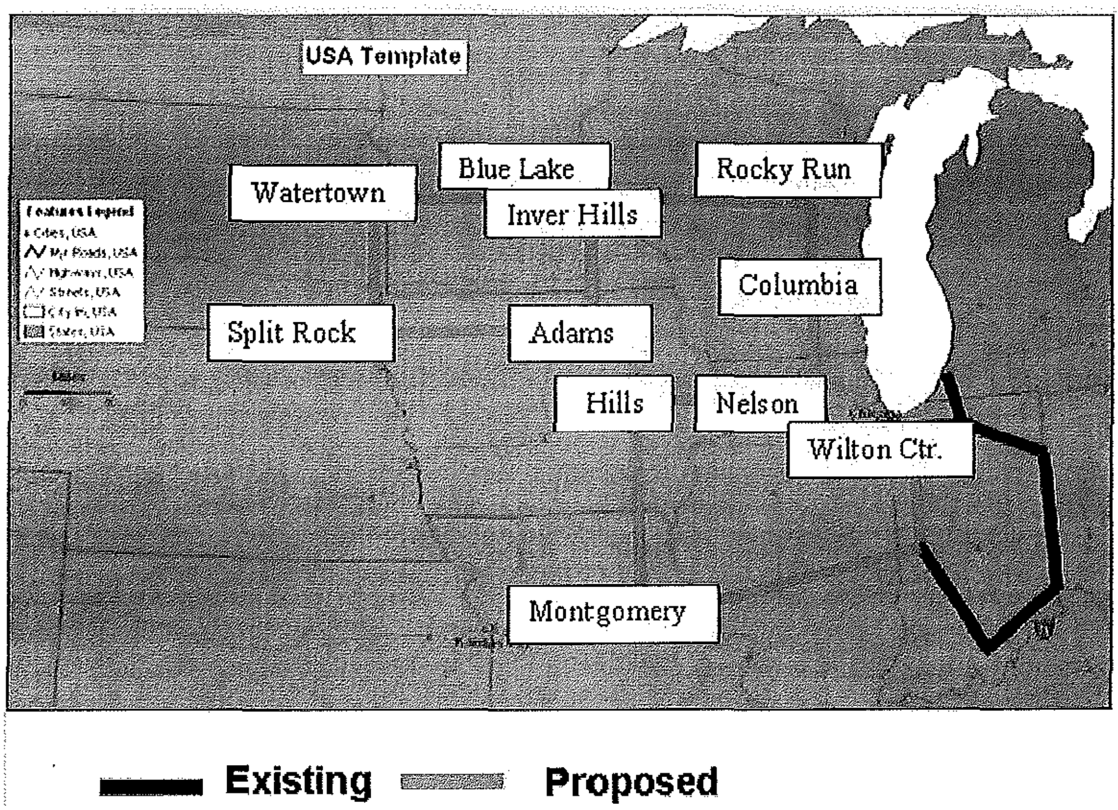


Figure 4.5: Proposed Vision Lines

4.1.4 Regional Generation Outlet Study (RGOS)

Beginning in MTEP09, MISO began the Regional Generation Outlet Study (RGOS). This study was intended, at a high level, to identify the transmission required to support the renewable mandates and goals of the MISO states, while minimizing the cost of energy delivered to the consumers. The study was conducted in two phases: Phase I focused on the western portion of the footprint, while Phase II focused on the full footprint.

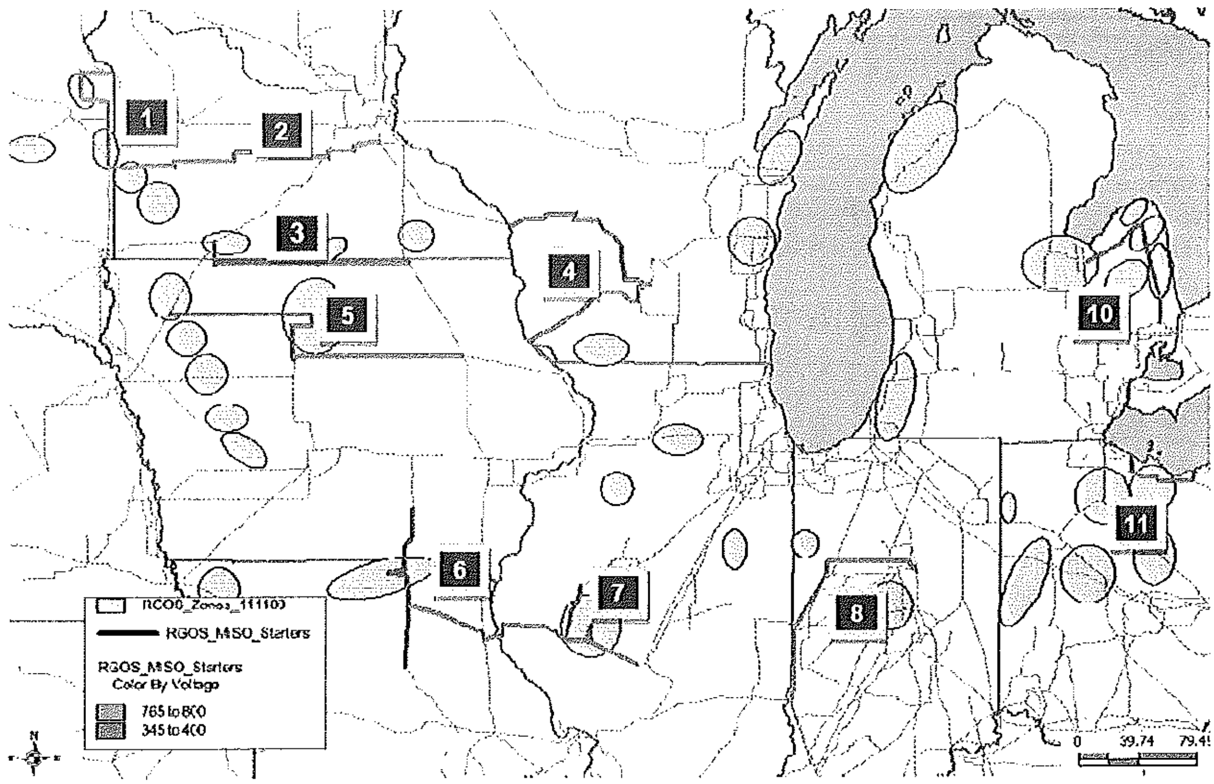


Figure 4.6: Regional Generator Outlet Study Input into MVP Portfolio

At the conclusion of the RGOS analyses, a set of three alternative expansion portfolios were identified. These portfolios, designed to meet the renewable energy mandates and goals of the full load for all the states in the MISO footprint, ranged in cost from $16 to $22 billion. They included transmission identified through the previous MTEP analyses, as highlighted earlier. Common transmission projects or corridors were identified between the three scenarios, and these projects formed transmission recommendations for the initial candidate MVP portfolio.

4.1.5 Candidate MVP Portfolio

The candidate MVP portfolio was created based on stakeholder feedback, as well as input from the analyses described in section 4.1. The portfolio was designed to meet the renewable energy mandates of all MISO load, and the projects in the portfolio were hypothesized to provide widespread benefits across the footprint. The projects selected as candidates for possible inclusion in the broader portfolio were then intensively evaluated in the MVP portfolio analysis to ensure they were justified and contributed to the portfolio business case.

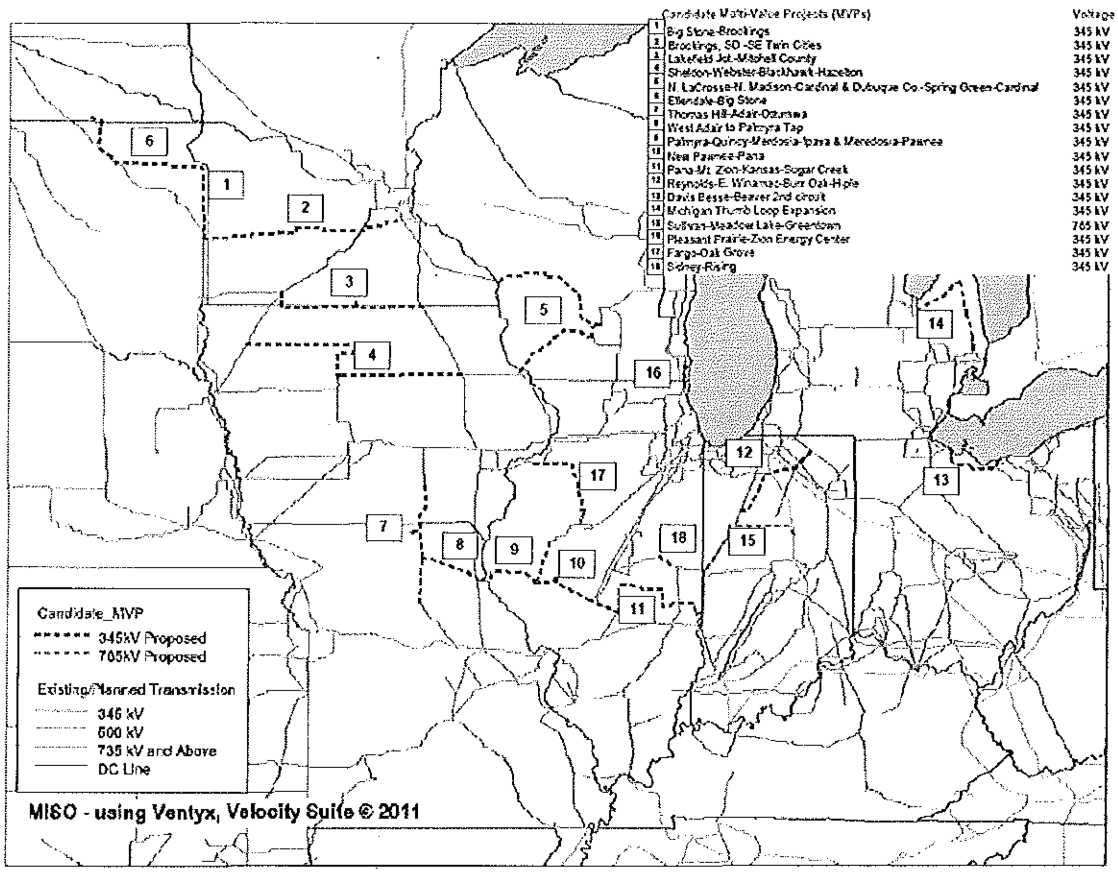


Figure 4.7: Initial Candidate MVP portfolio

4.2 Wind siting strategy

Key assumptions of the MVP portfolio study revolved around the amount and location of wind energy zones modeled within the study footprint. This energy zone development was based on stakeholder surveys focusing on expected renewable energy needs over the next 20 years and how much of that need is expected to be met with wind generation.

During the RGOS energy zone development, MISO staff evaluated multiple energy zone configurations to meet renewable energy requirements. In this process, study participants identified capital costs associated with generation capacity as well as capital costs associated with indicative transmission that would help deliver the energy to the system. It was determined that the most expensive energy delivery options were those options relying: 1) solely on the best regional wind source areas (with higher amounts of transmission needed) or 2) those options relying solely on the best local wind source areas (with higher amounts of generation capital required).

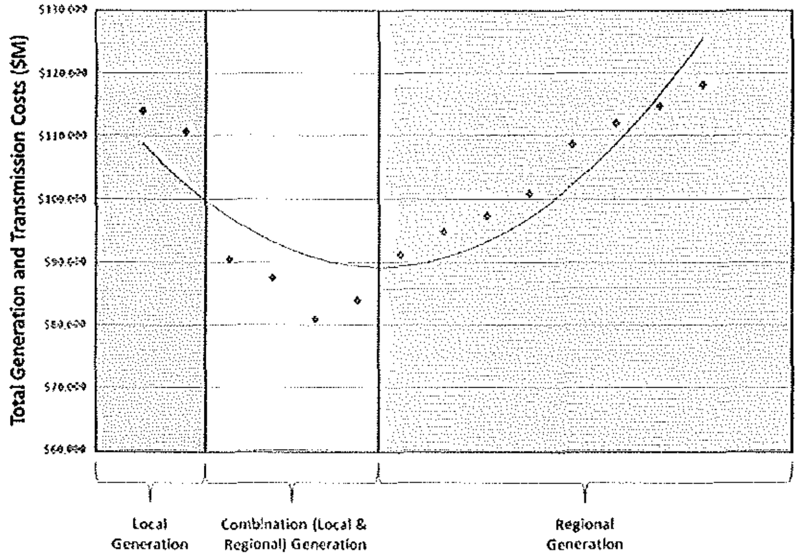


Figure 4.8: Generation and Transmission Capacity, by Energy Zone Location

As a result of RGOS energy zone development efforts as well as interaction with regulatory bodies such as the Upper Midwest Transmission Development Initiative (UMTDI) and various state agencies within the MISO, a set of energy zones was selected. These zones represent the intention of state governments to source some renewable energy locally while also using the higher wind potential areas within the MISO market footprint. Zone selection was based on a number of potential locations developed by MISO utilizing mesoscale wind data supplied by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. The analysis found wind zones distributed across the region resulted in the best method to meet renewable energy requirements at the least overall system cost.

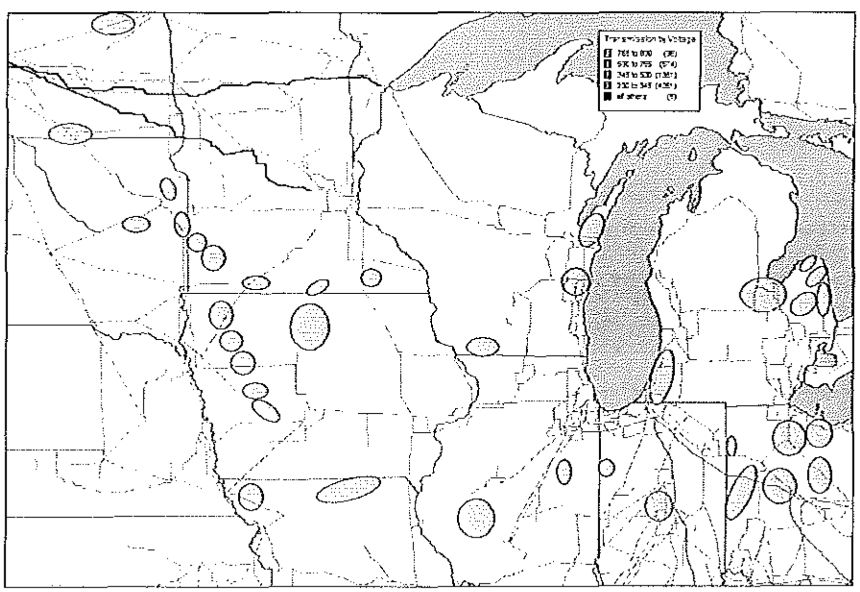


Figure 4.9::Energy Zone Locations

4.3 Incremental Generation Requirements

Once the location of the incremental wind generation was determined, through the low cost wind siting approach described above, additional analyses were required to determine how much incremental generation will be required to meet the renewable energy mandates of the MISO stakeholders. These analyses are based upon the 2009 retail sales for each area, as provided by the U.S. Energy Information Administration, a growth rate of 1.125% annually, and the specifics of each state's public policy requirements. Details on each state's public policy requirements may be found in Appendix A, while the calculations used to determine the total energy requirements may be found in Appendix B.

	2021 RPS Requirements (MWh)	2026 RPS Requirements (MWh)
IL - Ameren Illinois	3,072,047	4,274,713
IL - Alternative Retail Energy Suppliers in Ameren Illinois	2,016,516	3,046,465
MI - Total State of Michigan less AEP[8]	8,383,843	8,383,843
MN - Xcel Energy	10,535,661	11,141,777
MN - Total State of Minnesota less Xcel Energy	8,050,396	10,641,919
MO - Ameren Missouri	5,825,834	6,160,994
MO - Columbia Water and Light	122,809	194,812
MT - Montana-Dakota Utilities	113,581	120,115
OH - Duke Ohio[9]	2,099,315	2,921,169
WI - Total State of Wisconsin	7,682,829	8,124,821
TOTAL	**47,902,831**	**55,010,629**

Table 4.1: State Renewable Energy Mandates

Incremental wind generation was added to the model to satisfy these mandated needs. The amount of incremental generation for each zone was based on the capacity factor, the planned and proposed generation, and existing wind with power purchase agreements to serve non-MISO load ascribed to each zone. It was also based on a total wind buildout following the distributed, low-cost wind siting approach described in section 4.2.

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
IA-B	300	474
IA-F	292	462
IA-G	271	427
IA-H	215	339
IA-I	127	201
IA-J	18	28
IL-F	400	415
IL-K	449	449
IN-E	145	229

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
MN-L	0	0
MO-A	356	356
MO-C	500	500
MT-A	136	214
ND-G	199	313
ND-K	164	259
ND-M	59	94
OH-A	30	42
OH-B	30	42

[8] RPS requirement must be sourced entirely within Michigan
[9] Half of RPS requirement must be sourced from within Ohio.

Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)	Wind Zone	2021 Incremental Wind (MW)	2026 Incremental Wind (MW)
IN-K	194	306	OH-C	30	42
MI-A	0	0	OH-D	30	42
MI-B	601	601	OH-E	30	42
MI-C	549	549	OH-F	30	42
MI-D	442	442	OH-I	30	42
MI-E	601	601	SD-H	300	474
MI-F	601	601	SD-J	292	461
MI-I	303	303	SD-L	300	474
MN-B	75	119	WI-B	234	370
MN-E	0	0	WI-D	257	405
MN-H	0	0	WI-F	0	0
MN-K	175	277			

Table 4.2: Incremental Generation Added to the MVP Portfolio Analysis Model

4.4 Analyses Performed

The MVP portfolio analysis combined the MISO Board of Director planning principles and the conditions precedent to transmission construction to develop a transmission portfolio that meets public policy, economic and reliability requirements. The analysis built a robust business case for the recommended transmission, using the newly created MVP cost allocation methodology approved by FERC. The candidate transmission was tested against a variety of potential policy futures. This maximized the value of the transmission portfolio and reduced potential negative risks associated with its construction due to changes in future demand and energy growth. The output of the study was a justified portfolio of recommended MVPs for inclusion in MTEP11 Appendix A and, if approved by the MISO Board of Directors, subsequent construction.

The MVP cost allocation criteria requires the evaluation of the portfolio on a reliability, economic and energy delivery basis. The analyses were designed to demonstrate this value, both on a project and portfolio basis. To this end, the MVP portfolio analysis included the studies and output shown in Table 4.3.

These analyses focused on three main areas. The project valuation analyses focused on justifying each individual MVP against the MVP criteria. The portfolio valuation analyses determined the benefits of the portfolio in aggregate, quantifying additional reliability and economic benefits. Finally, a series of system performance analyses were performed to ensure that the system reliability will be maintained with the recommended MVP portfolio in service.

Analysis Type	Analysis Output	Purpose
Steady state	List of thermal overloads mitigated by each project in the MVP portfolio	Project valuation
Alternatives	Relative value of each MVP against a stakeholder or MISO identified alternative Can include steady state and production cost analyses	Project valuation
Underbuild requirements	Incremental transmission required to mitigate constraints created by the addition of the recommended MVP portfolio	System performance
Short circuit	Incremental upgrades required to mitigate any short circuit / breaker duty violations	System performance
Stability	List of violations mitigated by the recommended MVP portfolio Includes both transient and voltage stability analysis	System performance Portfolio valuation
Generation enabled	Wind enabled by the MVP portfolio	Portfolio valuation
Production cost	Adjusted Production Cost (APC) benefits of the entire MVP portfolio	Portfolio valuation
Robustness testing	Quantification of MVP portfolio benefits under various policy futures or transmission conditions	Portfolio valuation
Operating reserves Impact	Impact of the MVP portfolio on existing operating reserve zones and quantification of this benefit	Portfolio valuation
Planning Reserve Margin (PRM) benefits	Capacity savings due to reductions in the system-wide Planning Reserve Margin caused by the addition of the MVP portfolio to the transmission system	Portfolio valuation
Transmission loss reductions	Capacity losses savings caused by the addition of the MVP portfolio to the transmission system, where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour	Portfolio valuation
Wind generation capital investment	Quantification of the incremental wind generator capital cost savings enabled by the wind siting methodology supported by the MVP portfolio	Portfolio valuation
Avoided capital investment (transmission)	Future baseline transmission investment that may be avoided due to the installation of the MVP portfolio	Portfolio valuation

Table 4.3: MVP Portfolio Analyses and Output

4.5 Stakeholder involvement

Stakeholders reviewed and contributed to the development of the recommended MVP portfolio throughout the study process. A Technical Study Task Force (TSTF), composed of regulators, transmission owners, renewable energy developers, and market participants, met at least monthly with MISO engineers to provide input, feedback, and guidance throughout the MVP study processes. Also, regular updates were given to the MISO Planning Advisory Committee (PAC) and Planning Subcommittee (PSC). Finally, all study results were available for stakeholder review Feedback or analyses requested throughout the study process were incorporated into the MVP portfolio scope.

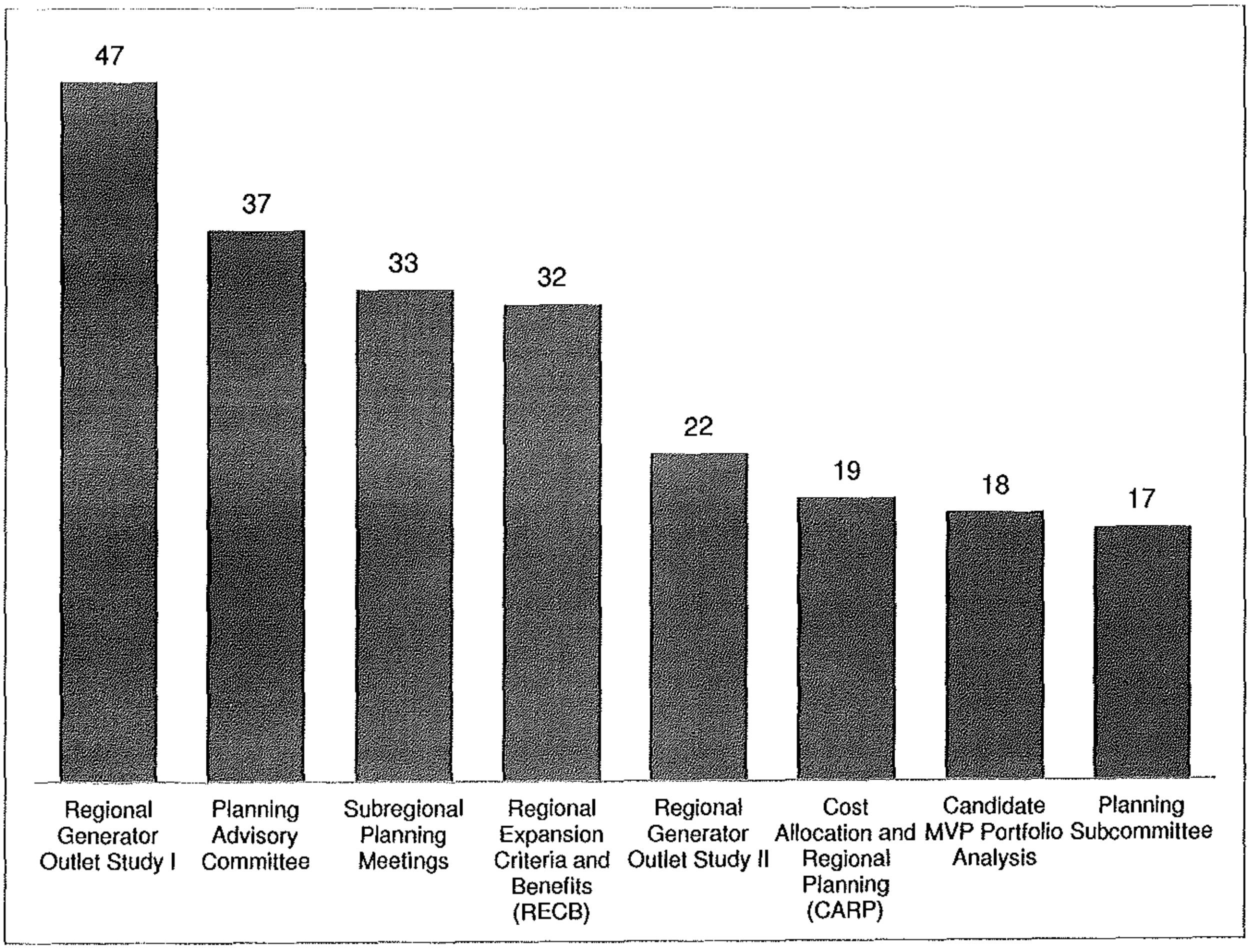


Figure 4.10: Regional Planning Stakeholder Meetings, 2008 - 2011

5 Project justification and alternatives assessment

Each project in the MVP portfolio was analyzed to ensure that the project is justified against MVP cost allocation criterion 1, and to determine if any relevant alternatives exist to the proposed projects. The projects listed below constitute the final projects, which are recommended to the MISO Board of Directors.

5.1 Big Stone to Brookings County 345 kV Line

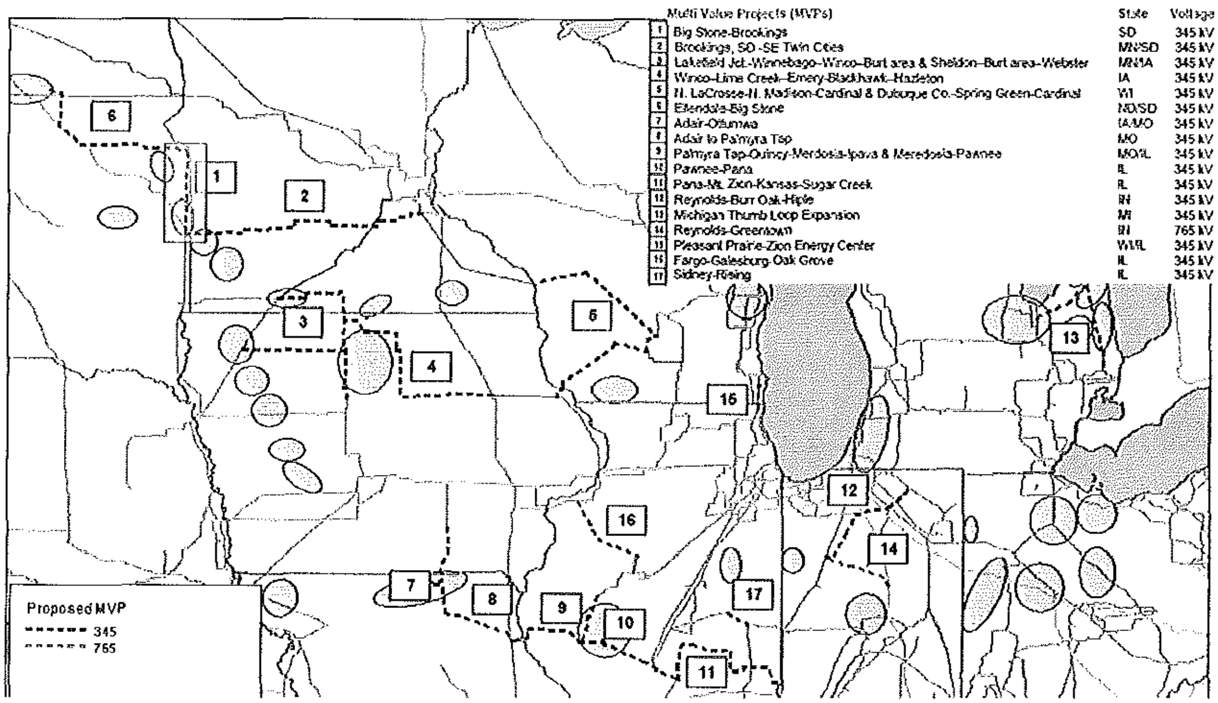


Figure 5.1: Big Stone to Brookings County

Project(s): 2221

Transmission Owner(s): OTP, XEL

Project Description: This project creates a new 345 kV path on the border of South Dakota and Minnesota by connecting XEL's Brookings County and OTP's Big Stone. Approximately 69 miles of new 345 kV transmission will be installed between these two substations along with a new 345 kV terminal at Big Stone and two 345/230 kV, 672 MVA transformers. The total estimated cost of this project is $191 million[10]. The expected in service date for this project is December 2017.

Project Justification: The new 345 kV outlet from Big Stone removes overloads on the 230 kV paths from Big Stone to Blair and Hankinson to Wahpeton along with 115 kV paths from Johnson to Morris , Big Stone to Highway 12 to Ortonville, Pipestone to Buffalo Ridge and Canby to Granite Falls. The overloaded Watertown 345/230 kV is also alleviated. Along with project 2220, this project reliably moves mandated renewable energy from the Dakotas to major 345 kV transmission hubs and load centers.

Alternatives Considered: An alternative to build a new 345 kV from Big Stone to Canby to Granite Falls to Minnesota Valley and rebuild the 230 kV or build a new 345 kV to Morris could provide an

[10] In 2011 dollars.

alternative outlet for Big Stone wind. The cost of this alternative is higher than the 345 kV path to Brookings County.

5.2 Brookings County to Southeast Twin Cities 345 kV Line

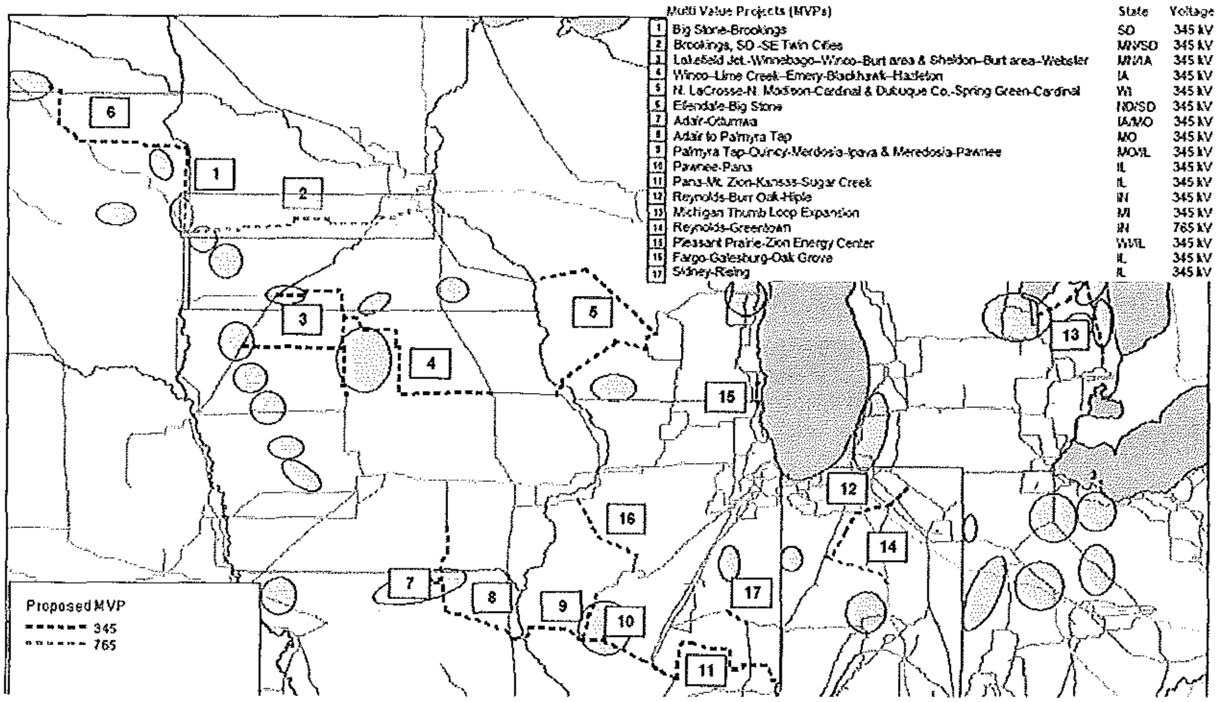


Figure 5.2: Brookings County to Southeast Twin Cities

Project(s): 1203

Transmission Owner(s): XEL, GRE

Project Description:
This project creates a new 345 kV path through southern Minnesota, by connecting XEL's Brookings County substation to the Twin Cities. Single circuit 345 kV transmission will be constructed from Brookings County to Lyon County, from Helena to Lake Marion to Hampton Corner, and from Lyon County to Hazel Creek to Minnesota Valley. The Hazel Creek to Minnesota Valley section will be operated at 230 kV initially. Double circuit 345 kV transmission will be constructed from Lyon Count to Cedar Mountain to Helena. A 115 kV line will be built between the new Cedar Mountain and the existing Franklin substations. The project includes one 345/230 kV, 336 MVA transformer at Hazel Creek, three 345/115 kV, 448 MVA transformers at Lyon County, Lake Marion and Cedar Mountain, one upgraded 115/69 kV, 140 MVA transformer at Lake Marion and two upgraded 115/69 kV, 70 MVA transformers at Franklin. A new breaker and deadend structure is planned at Lake Marion and the Arlington to Green Isle 69 kV line will be upgraded to 477 ACSR. The project adds a total of 351 miles of new 345 kV, 5 miles of new 115 kV and 5.8 miles of rebuilt 69 kV lines. The total estimated cost of this project is $695 million[11]. The expected in service dates for these projects are:

- June 2013 (Cedar Mountain 345/115 kV transformer)
- August 2013 (Cedar Mountain to Helena 345 kV double circuit line and Arlington to Green Isle 69 kV rebuild)

[11] In 2011 dollars

- October 2013 (Lyon County 345/115 kV transformer)
- November 2013 (Lyon County to Cedar Mountain 345 kV double circuit line)
- January 2014 (Franklin 115/69 kV transformers)
- February 2014 (Cedar Mountain to Franklin 115 kV line)
- March 2014 (Lake Marion 345/115 kV and 115/69 kV transformers and station work)
- April 2014 (Helena to Lake Marion 345 kV line)
- June 2014 (Lake Marion to Hampton Corner 345 kV line)
- January 2015 (Brookings to Lyon County 345 kV line and Hazel Creek 345/230 kV transformer)
- February 2015 (Lyon County to Hazel Creek to Minnesota Valley 345 kV line)

Project Justification:
Without the Brookings County to Twin Cities 345 kV line, the loss of Split Rock to White 345 kV leaves only the 230kV system to feed load to the East. This overloads the Watertown 345/230 kV transformer without the parallel 345 kV path from Brookings County. Not having the project also impacts the 115 kV network in southern Minnesota which is connected on both sides by 230 kV. The loss of either 230kV source causes multiple overloads in the surrounding 115 kV network without this project. The loss of any segment of the Wilmarth-Helena-Blue Lake 345 kV line in southeast Minnesota leads to overloads on the underlying 115 kV network. Without this project, the power flowing west to east is forced through the 115 kV system, overloading the underlying 115 kV lines. The Wilmarth to Eastwood and Wilmarth to Swan Lake 115 kV lines are overloaded without the additional 345kV support to the north that is included with project 1203. At the Minnesota/Wisconsin interface, the loss of 345 kV lines at Blue Lake, Prairie Island, Red Rock, Coon Creek and Chisago substations overload the Prairie Island 345/161 kV transformer, particularly for any NERC Category C5 outages involving lines between the aforementioned substations. The Brookings County to Twin Cities project would bring an additional 345 kV source into this area to reduce loading along the path into Wisconsin. There are also 115 kV overloads in this area which are mitigated by this project.

Alternatives Considered:
With the existing 345 kV outlets out of Brookings County thermally constrained and with most of the 230 and 115 kV paths between Brookings County and the Twin Cities overloaded, mitigating all these constraints through underlying line rebuilds would be infeasible and costlier compared to this project.

5.3 Lakefield Junction to Winnebago to Winnco to Burt area; Sheldon to Burt area to Webster 345 kV Lines

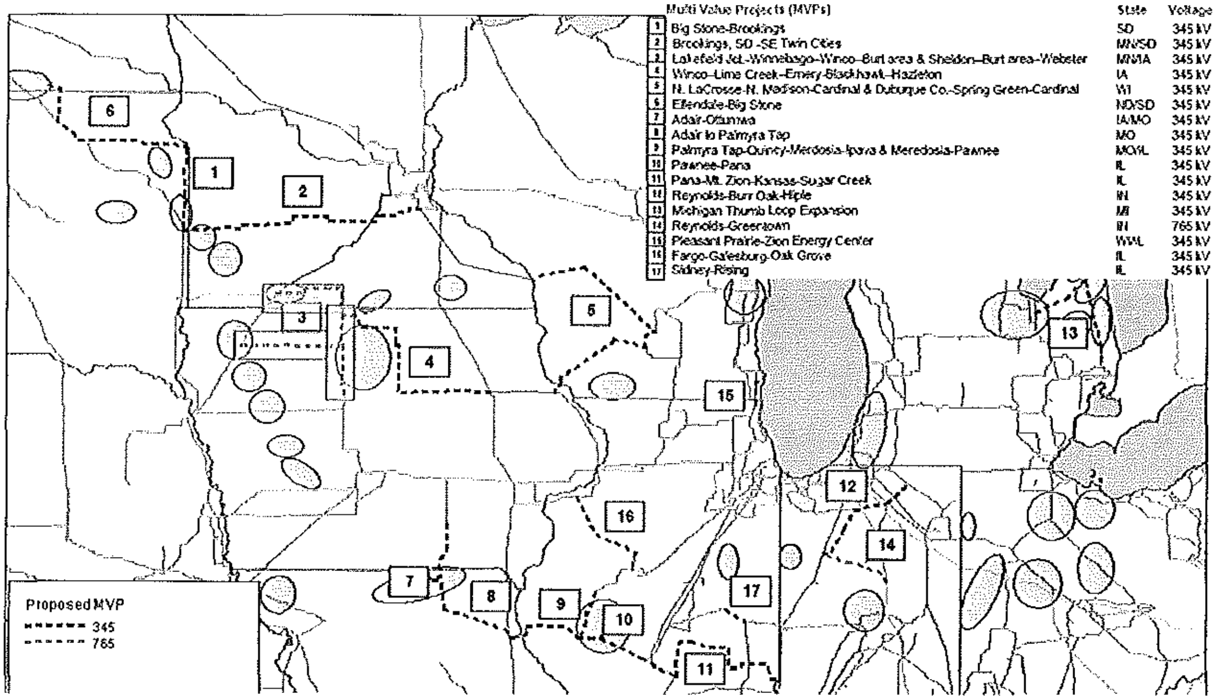


Figure 5.3: Lakefield Jct to Winnebago to Winnco to Burt area; Sheldon to Burt area to Webster

Project(s): 3205

Transmission Owner(s): MEC, ITCM

Project Description:
Designed to connect with project 3213, this project creates a double circuit 345/161 kV path through the border of Minnesota and Iowa. New 345 kV transmission will be built from Lakefield Junction to Winnebago to Winnco to Burt and from Sheldon to Burt to Webster. Rebuilt 161 kV transmission will be on the same towers and go from Lakefield to Fox Lake to Rutland to Winnebago to Winnco and Wisdom to Osgood to Burt to Hope to Webster. Winnebago, Winnco, Sheldon and Burt are all new 345 kV stations. Sheldon will be a tap on the existing Raun to Lakefield 345 kV line. A 345/161 kV, 450 MVA transformer will be installed at Winnebago. This project adds 218 miles of new 345 kV and 92 miles of rebuilt 161 kV transmission. The total estimated cost of this project is $506 million[12]. The expected in service dates for these projects are:

- December 2015 (All Lakefield Junction to Burt work)
- December 2016 (All Sheldon to Webster work)

Project Justification:
The new 345 kV path through southern Minnesota and northern Iowa effectively mitigates the Fox Lake – Rutland – Winnebago 161 kV constraint. Existing wind in the Winnebago and Wisdom areas are benefitted by 345 kV transmission moving generation out of these constrained areas. Working in tandem with project 3213, this project reliably moves mandated renewable energy from western and

[12] In 2011 dollars

northern Iowa along with existing wind at the Winnebago, Wisdom and Lime Creek/Emery areas to major 345 kV transmission hubs.

Alternatives Considered:
An Iowa alternative of Lakefield Junction to Mitchell County and Sheldon to Burt to Webster to Black Hawk to Hazleton 345 kV was analyzed but was not effective in collecting Lime Creek/Emery area wind or lowering congestion on the Mitchell County to Hazleton 345 kV line. It had similar cost to the combined Iowa projects 3205 and 3213.

5.4 Winco to Lime Creek to Emery to Black Hawk to Hazleton 345 kV Line

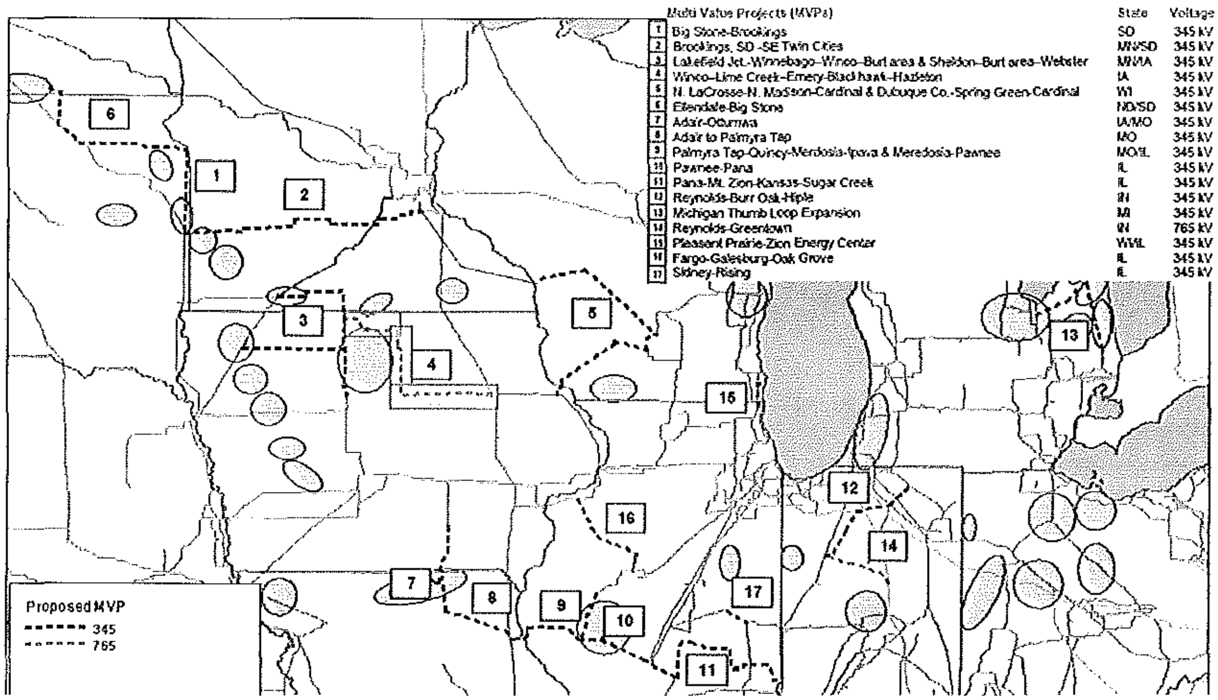


Figure 5.4: Winnco to Lime Creek to Emery to Black Hawk to Hazleton 345 kV line

Project(s): 3213

Transmission Owner(s): MEC, ITCM

Project Description:
Designed to connect with project 3205, this project creates a double circuit 345/161 kV path through northern Iowa. New 345 kV transmission will be built from the new Winnco substation to Lime Creek to Emery to Black Hawk to Hazleton. Rebuilt 161 kV transmission will be on the same towers as the 345 kV and will go from Lime Creek to Emery to Hampton to Franklin to Union Tap to Black Hawk to Hazleton. A 345/161 kV, 450 MVA transformer will be installed at Lime Creek, Emery and Black Hawk. This project adds 206 miles of new 345 kV, 23 miles of new 161 and 149 miles of rebuilt 161 kV transmission. The total estimated cost of this project is $480 million[13]. The expected in service date of the project is December 2015.

Project Justification:

[13] In 2011 dollars

The new 345 kV path through Iowa mitigates constraints seen on the Lime Creek – Emery – Floyd – Bremer – Black Hawk 161 kV line. The 345/161 kV transformers at Lime Creek and Emery are effectively acting as step-up transformers for wind and lowering congestion on the lower voltages. The additional 345 kV path into Hazleton significantly increases the transfer capability of the Mitchell County – Hazleton 345 kV line. Working in tandem with project 3205, this project reliably moves mandated renewable energy from western and northern Iowa along with existing wind at the Winnebago, Wisdom and Lime Creek/Emery areas to major 345 kV transmission hubs.

Alternatives Considered:
An Iowa alternative of Lakefield Junction to Mitchell County and Sheldon to Burt to Webster to Black Hawk to Hazleton 345 kV was analyzed but was not effective in collecting Lime Creek/Emery area wind or lowering congestion on the Mitchell County to Hazleton 345 kV line. It had similar cost to the combined Iowa projects 3205 and 3213.

5.5 North LaCrosse to North Madison to Cardinal 345 kV Line

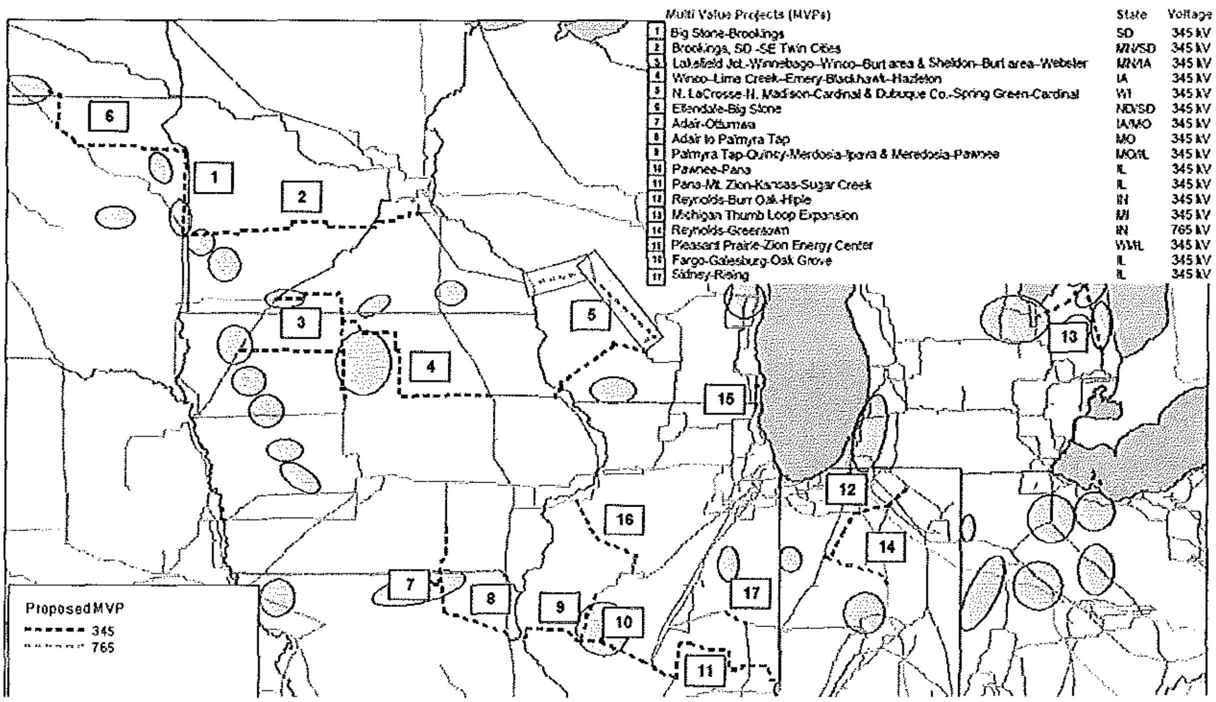


Figure 5.5: North LaCrosse to North Madison to Cardinal

Project(s): 3127

Transmission Owner(s): ATC, XEL

Description: This creates a 345 kV line from the North LaCrosse (Briggs Road) substation, to the North Madison substation, to the Cardinal substation, through southwestern Wisconsin. A 448 MVA, 345/161 kV transformer will be installed at Briggs Road, and approximately 20 miles of 138 kV line between the North Madison and Cardinal substations will be reconductored. The new 345 kV line will be approximately 157 miles long. The estimated cost is $390 million[14]. The expected in service date is December 2018.

[14] In 2011 dollars

Justification: The 345 kV line from North LaCrosse to North Madison creates a tie between the 345kV network in western Wisconsin to the 345 kV network in southeastern Wisconsin. This creates an additional wind outlet path across the state; pushing power into southern Wisconsin, where it can go east into Milwaukee, or south to Illinois, providing access to less expensive wind power in two major load centers. With the Brookings project, the wind coming into North LaCrosse needs an outlet, and the line to North Madison is the best option studied. From a reliability perspective, the addition of the North LaCrosse to North Madison to Cardinal 345 kV path helps relieve constraints on the 345 kV system parallel to the project to the north and south of the new line. The 138 and 161 kV system in southwest Wisconsin and nearby in Iowa are also overloaded during certain contingent events, and the new line relieves those constraints. This project will mitigate twelve bulk electric system (BES) NERC Category B thermal constraints and eight NERC Category C constraints. It will also relieve 30 non-BES NERC Category B and 36 NERC Category C constraints.

Alternatives Considered:
Rebuilding the overloaded 138 and 161 kV lines, along with adding transformers or upgrading the existing units to handle the increased loading, was the only other alternative considered. This was not a viable alternative, because the cost is greater than the proposed project. The proposed project also provides the most benefit to the transmission grid in the future.

5.6 Dubuque to Spring Green to Cardinal 345 kV Line

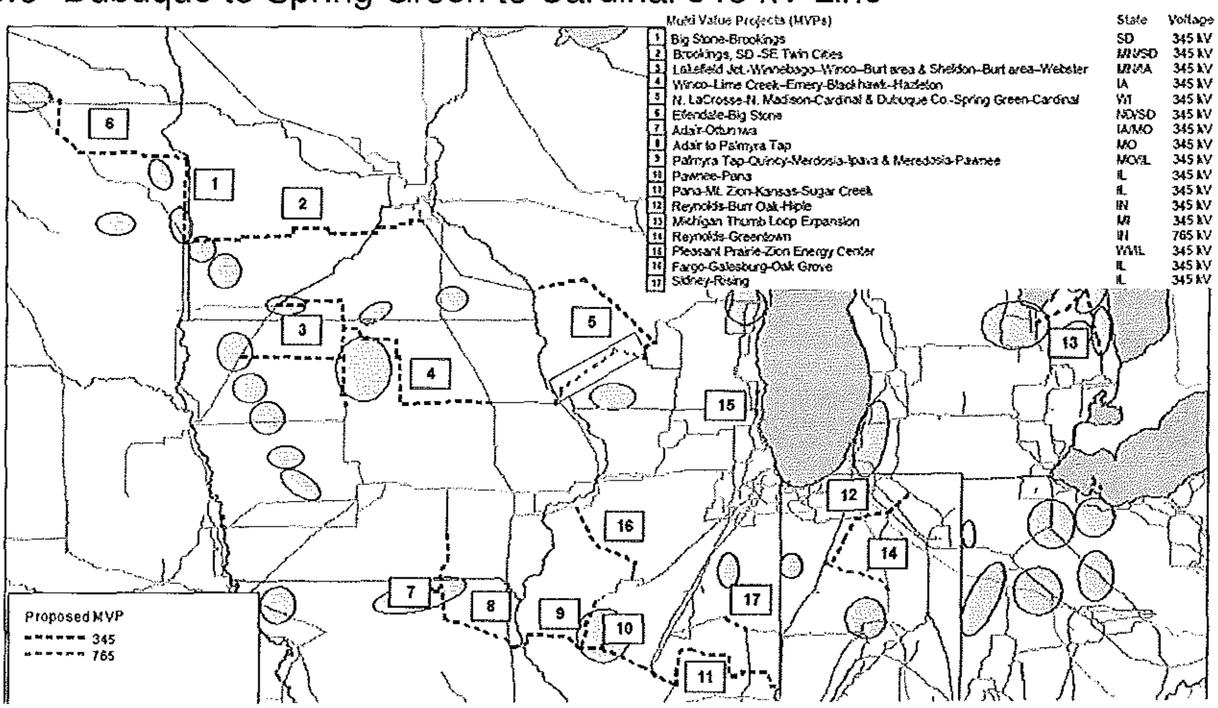


Figure 5.6: Dubuque to Spring Green to Cardinal

Project(s): 3127

Transmission Owner(s): ATC, ITCM

Description: A 345 kV line is created from the Dubuque substation in Iowa, to the Spring Green substation to the Cardinal substation through southwestern Wisconsin. A new Dubuque County 345 kV switching station will be created, and the Spring Green substation will be upgraded to accommodate the new connections. A new 500 MVA, 345/138 kV transformer will be added. To accommodate the new 345 kV connections from Spring Green and North Madison, the Cardinal substation will be upgraded. There are also upgrades to the 69 kV system, which is being converted to operate at 138 kV, in the Mazomanie – Black Earth – Stagecoach area. The new 345 kV line is approximately 136 miles long. The estimated cost is $324 million[15]. The expected in service date is December 2020.

Justification: The 345 kV line from Dubuque to Spring Green to Cardinal creates a tie between the 345kV network in Iowa to the 345 kV network in southcentral Wisconsin. This expansion creates an additional wind outlet path across the state; bringing power from Iowa into southern Wisconsin, where it can then go east into Milwaukee or south toward Chicago providing access to less expensive wind power in two major load centers. In combination with another Multi Value Project, the Oak Grove – Galesburg – Fargo 345 kV line, this project enables 1,100 MW of wind power transfer capability. This new path will help offload the lines that feed the Quad City (Iowa) area by bringing power flow to the north. From a reliability perspective, the addition of the Dubuque – Spring Green – Cardinal 345 kV path helps relieve constraints on the 345 kV system parallel to the project to the north and south of the new line, as well as 138 kV system constraints in the aforementioned areas and to the west of the new line. The 138 kV system in southwest Wisconsin and nearby in Iowa is also overloaded during certain contingent events, and the new line relieves those constraints. Those overloaded facilities that are not relieved by the 345 kV project are relieved by upgrades to the lower voltage transmission system, including converting part of the 69 kV system to operate at 138 kV. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and ten NERC Category C constraints. It will also relieve two non-BES NERC Category B and two NERC Category C constraints.

Alternatives Considered: An alternative to the proposed project would be to rebuild the 138 kV lines that were overloaded. The cost of this alternative would be more than the proposed project, without providing benefits of the proposed project.

[15] In 2011 dollars

5.7 Ellendale to Big Stone 345 kV Line

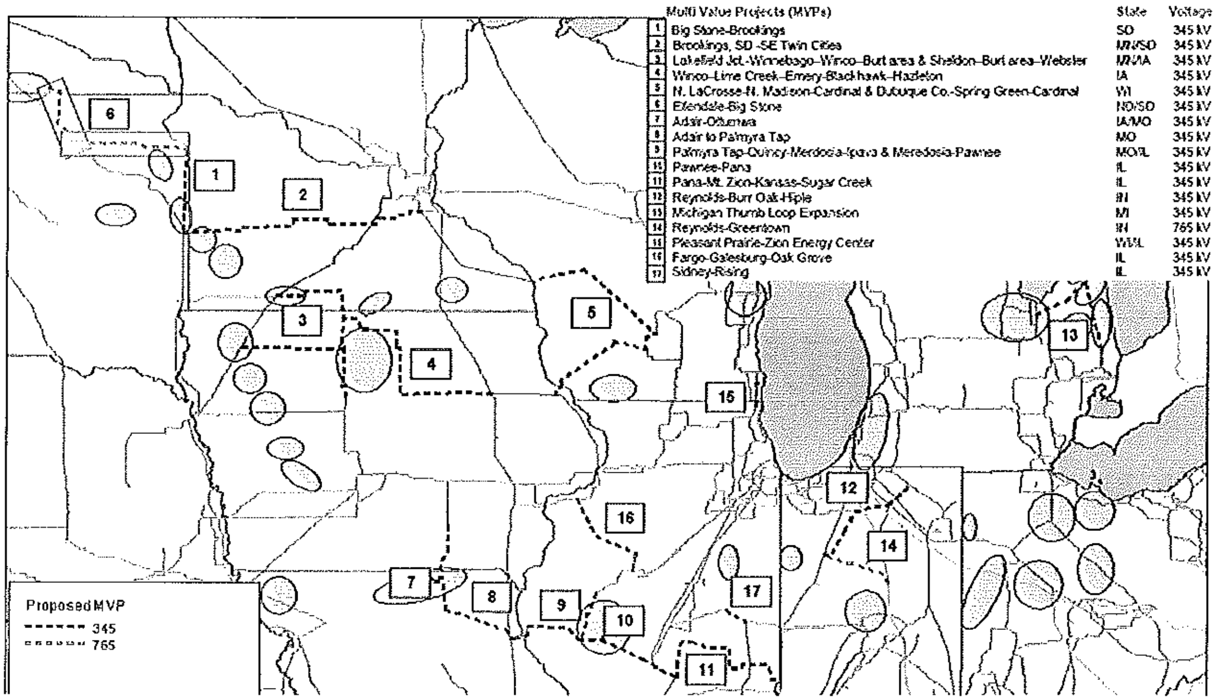


Figure 5.7: Ellendale to Big Stone

Project(s): 2220

Transmission Owner(s): OTP, MDU

Project Description:
This project creates a new 345 kV path through the border of the Dakotas by connecting OTP's Big Stone and MDU's Ellendale substations. Approximately 145 miles of new 345 kV transmission will be installed between these substations along with a new 345kV terminal at Ellendale and a 345/230 kV, 500 MVA transformer. The total estimated cost of this project is $261 million[16]. The expected in service date for this project is December 2019.

Project Justification:
The new 345 kV outlet from Ellendale removes overloads on the 230 kV path from Ellendale to Oakes to Forman and the 115 kV path from Ellendale to Aberdeen. Overloads on the 230/115 kV transformers at Ellendale, Forman and Heskett are also alleviated. Along with project 2221, this project reliably moves mandated renewable energy from the Dakotas to major 345 kV transmission hubs and load centers.

Alternatives Considered:
An alternative to convert the 115 kV path from Ellendale to Huron could alleviate the southern path constraints out of Ellendale but downstream transmission may also need to be rebuilt to accommodate wind injection delivered through a lower impedance line. The eastern 230 kV path out of Ellendale would need to be rebuilt to 345 kV up to Fergus Falls. The cost of this alternative is higher than a 345 kV path to Big Stone.

[16] In 2011 dollars

5.8 Ottumwa to Adair to Palmyra Tap 345 kV Line

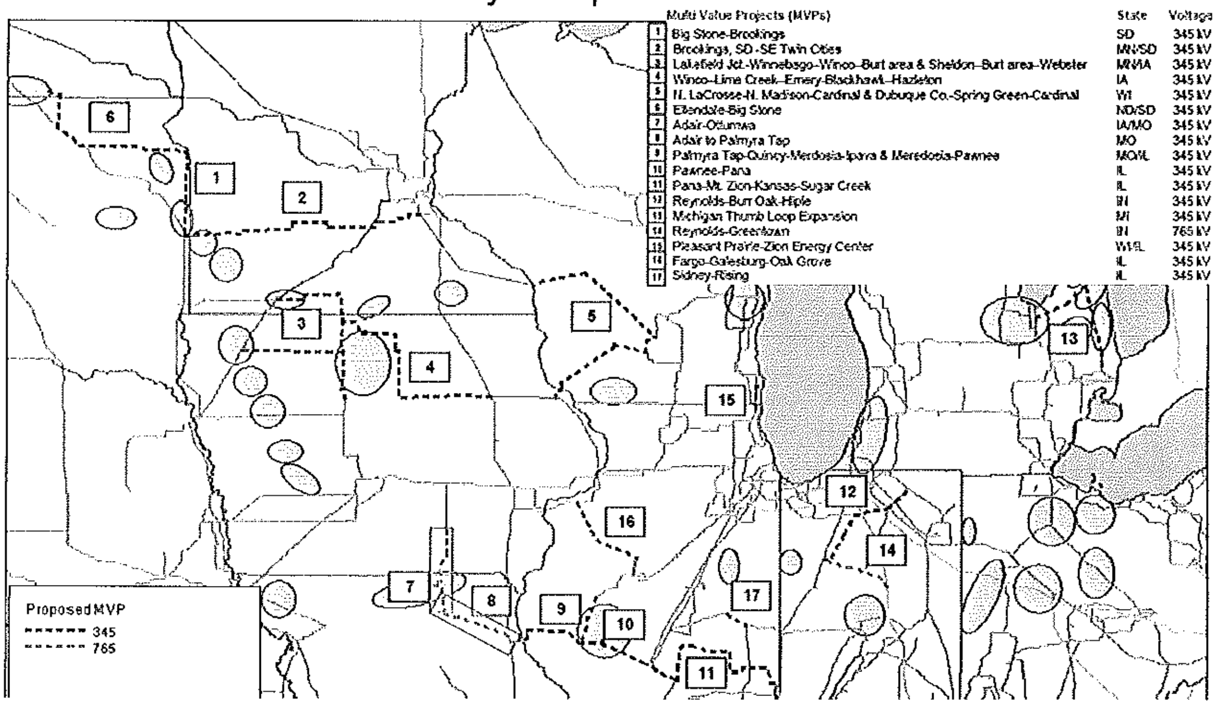


Figure 5.8: Ottumwa to Adair to Palmyra Tap

Project(s): 2248, 3170

Transmission Owner(s): Ameren Missouri, MEC, ITCM

Project Description:
This creates a 345 kV path through central/eastern Missouri by connecting Iowa's Ottumwa substation to Ameren Missouri's West Adair substation (P2248). It then extends 345 kV from West Adair to Ameren Missouri's Palmyra substation Tap (P3370), near the Missouri/Illinois border. Approximately 88 miles of new and rebuilt 345 kV line will be installed between Ottumwa and Adair, along with a 345kV terminal at Adair and a 345/161 kV, 560 MVA step down transformer. Sixty-three miles of new 345 kV line will be built between West Adair and the Palmyra Tap, where a new 345 kV switching station will be established. The estimated cost is $250 million[17]. The New Palmyra Tap substation will be ready by November 2016. The Ottumwa to West Adair 345 kV line and West Adair substation work will be ready by June 2017. The West Adair to Palmyra 345 kV line and West Adair 345/161 kV transformer will be ready by November 2018.

Project Justification:
The new 345 kV lines from Ottumwa to West Adair to Palmyra will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. In addition to providing a wind outlet, the new lines will provide reliability benefits by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformer at West Adair is especially effective in resolving 161 kV line overloads on the lines out of West Adair and preventing the loss of the generation at West Adair during certain NERC Category C events. This project will mitigate two bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints. It will also relieve three non-BES NERC Category B and two NERC Category C constraints.

[17] In 2011 dollars

Alternatives Considered:
An alternative was to incorporate an additional 345 kV line from West Adair to Thomas Hill. While improving reliability in the area, the addition would not improve the distribution of benefits within MISO. Thus the alternative was removed, and the proposed project was recommended.

5.9 Palmyra Tap to Quincy to Meredosia to Pawnee; Meredosia to Ipava 345kV Line

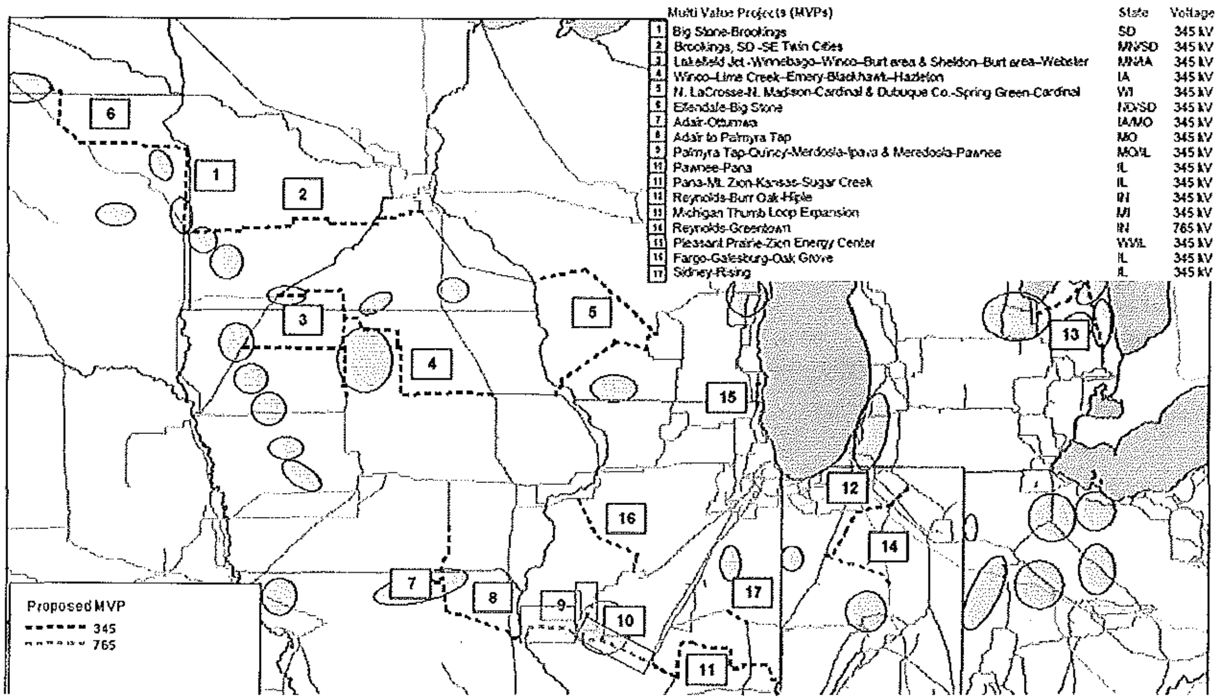


Figure 5.9: Palmyra Tap to Quincy to Meredosia to Pawnee; Meredosia to Ipava

Project(s): 3017

Transmission Owner(s): Ameren

Description: This creates a 345 kV path through western/central Illinois by construction of 345 kV lines between the new Palmyra Tap switching station to Quincy, Meredosia and Pawnee. Another 345 kV line would go from Meredosia north to the Ipava substation. A total of 116 miles of new 345 kV line will be built between the Palmyra switching station and Pawnee, with new 345/138 kV, 560 MVA transformers at Quincy and Pawnee. The new 345 kV line from Meredosia to Ipava would be 41 miles long. The estimated cost is $392 million[18]. The New Palmyra Tap switching station will be ready by June 2016. The Palmyra Tap switching station to Quincy to Meredosia 345 kV line and the Quincy and Pawnee 345/138kV transformers will be ready by November 2016. The Ipava substation upgrades for new 345 kV connection from Meredosia will be ready by June 2017. The Meredosia to Ipava and Meredosia to Pawnee 345 kV lines will be ready by November 2017.

Justification: The 345 kV lines from the Palmyra switching station to Pawnee and from Meredosia to Ipava will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. In addition to providing a wind outlet, the new lines will

[18] In 2011 dollars

provide reliability benefits by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformers in this project will keep the power flow on the 345 kV system. Otherwise, it would be, injected into the lower voltage transmission networks if the 345 kV additions are not made, which causes a number of lower voltage network constraints to be alleviated. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and three NERC Category C constraints.

Alternatives Considered: A 345 kV connection between Palmyra and Sioux would alleviate some constraints, but would not affect constraints in the Tazewell area, which would also need a 345 kV connection to Palmyra. The alternative would not provide regional distribution of benefits with the multi value project, as it would constrain the 345 kV path from St. Louis across southern Illinois and into Indiana. Therefore the proposed project is recommended for the greatest benefit.

5.10 Pawnee to Pana to Mt. Zion to Kansas to Sugar Creek 345kV Line

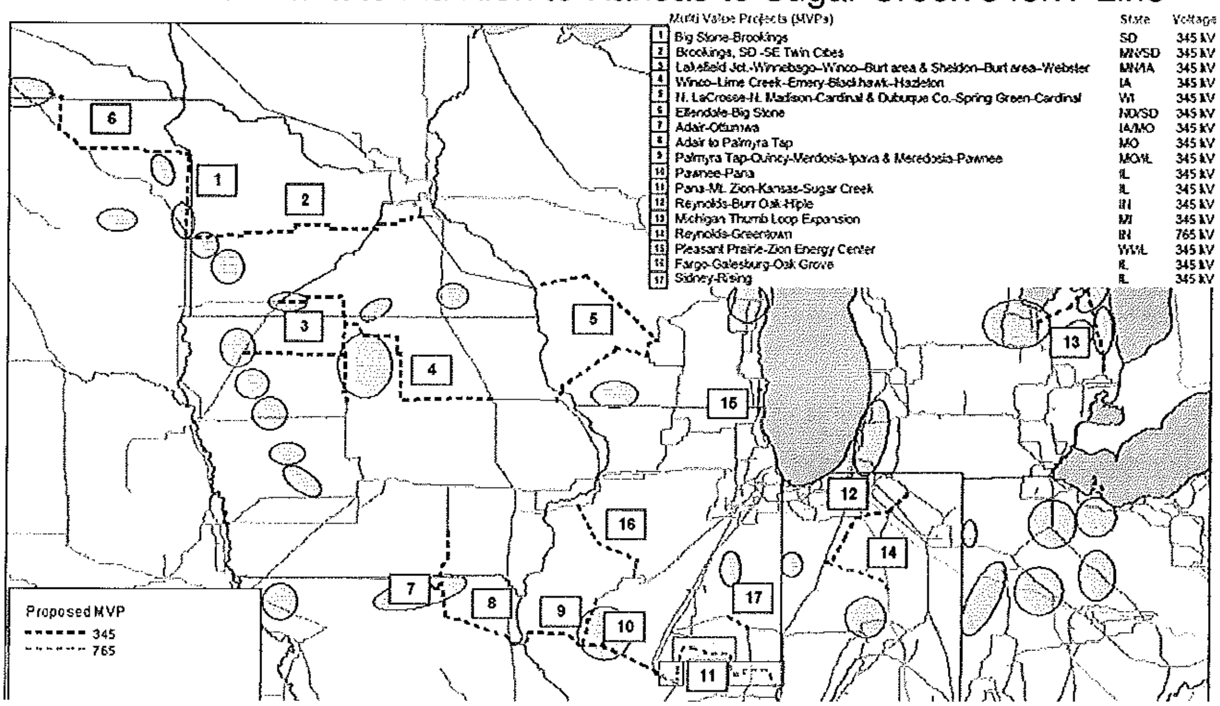


Figure 5.10: Pawnee to Pana to Mt. Zion to Kansas to Sugar Creek

Project(s): 2237, 3169

Transmission Owner(s): Ameren

Description: This creates a 345 kV path through eastern/central Illinois by building 345 kV lines between the Pawnee substation to Pana, Mt. Zion, Kansas and Sugar Creek (Indiana). A total of 146 miles of new 345 kV line will be constructed between the Pawnee substation and Sugar Creek substation on the eastern Illinois/Indiana border, with new 345/138 kV, transformers at Mt. Zion, Pana (both transformers are 560 MVA) and Kansas (448 MVA transformer). The estimated cost is $372 million[19] All components will be in service by November 2018, except the new Kansas to Sugar Creek 345 kV Line, which will be ready by November 2019.

[19] In 2011 dollars

Justification: The 345 kV lines from the Pawnee to Sugar Creek in western Indiana will provide an outlet for wind generation in the western region to move toward the more densely populated load centers to the east. This 345 kV extension creates another 345 kV path across central Illinois to connect to the existing 345 kV network in Indiana at Sugar Creek. This provides access wind generation to all of Indiana, and supplies major load centers such as Indianapolis and the Chicago suburbs in northern Indiana. The new lines will provide a wind outlet and reliability benefits, by mitigating a number of contingent outage events during peak and shoulder periods, where the wind generation component is much higher. The addition of the 345 kV lines and step down transformers in this project will keep the power flow on the 345 kV system. Otherwise, it would be injected into the lower voltage transmission networks in Illinois if the 345kV additions are not made, which causes a number of lower voltage network constraints to be alleviated. This project will mitigate eight bulk electric system (BES) NERC Category B thermal constraints and 12 NERC Category C constraints.

Alternatives Considered: An alternative to the proposed project was a parallel 345 kV path to the north, which would have built a 345 kV line through Bloomington into Brokaw, through Gilman and to the Reynolds Substation in northwest Indiana. Although the benefits of taking this northern path were similar to the southern route, there were fewer benefits gained by going with the northern path. It also cost more than the recommended project.

5.11 Reynolds to Burr Oak to Hiple 345 kV line

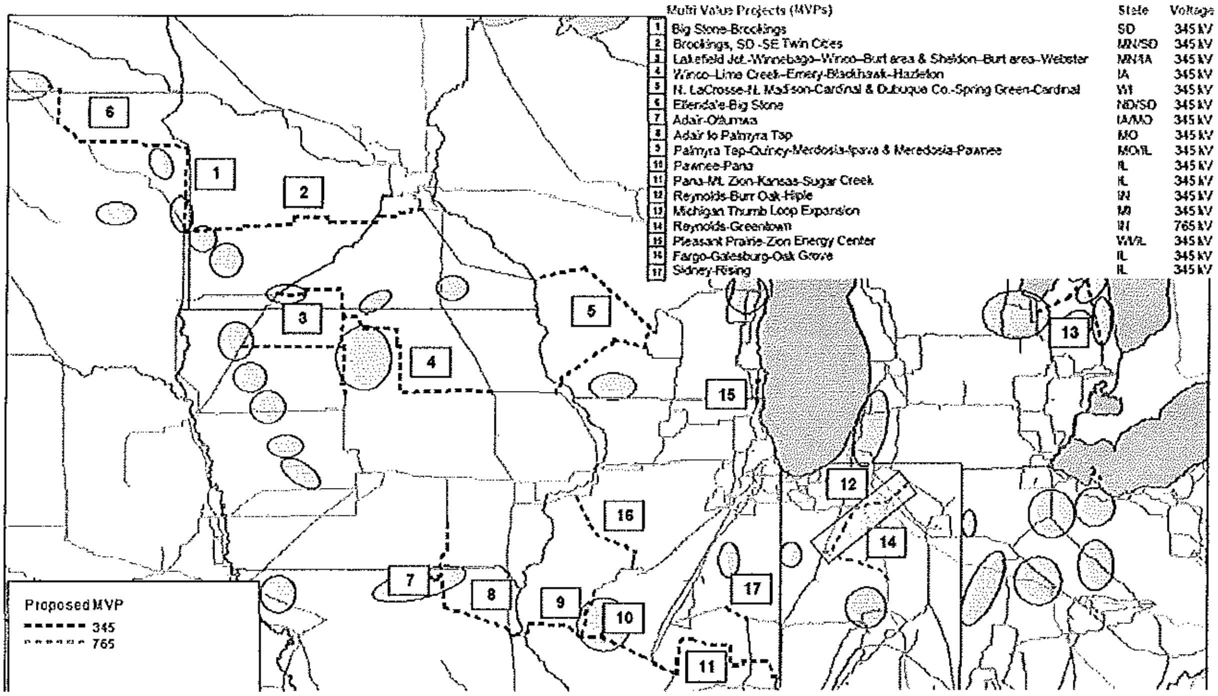


Figure 5.11: Reynolds to Burr Oak to Hiple

Project(s): 3203

Transmission Owner(s): NIPSCo

Description: This creates a 345 kV line from Reynolds substation to Burr Oak to Hiple through northern Indiana. At the Reynolds and Hiple stations, it creates a tie to 345kV lines routed near those two stations but do not connect electrically at those points. The 345 kV line is approximately 100 miles long, along with the substation upgrades at Reynolds and Hiple necessary to accommodate the new 345 kV line connections. The estimated cost of this project is $284 million[20]. The expected in service date is December 2019.

Justification: The project from Reynolds to Burr Oak to Hiple through northern Indiana will create a 345 kV path across the northern portion of Indiana toward Michigan, with the new tie at Hiple connecting an existing 345 kV line to the Argenta Station in southern Michigan. This path will provide an additional 345 kV path to move wind energy across Indiana, and closer to the east coast, bringing less expensive wind generation into areas where the expense to generate power can be considerably greater. The line will relieve overloads on the 138 kV system along a parallel path as well as the 138 kV network in the Lafayette, IN, area. The additional ties at Reynolds and Hiple also reduce loading on the existing 345 kV lines and creates a second path for power flow in this area, enhancing system reliability. This project will mitigate five bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints.

Alternatives Considered: There is no viable alternative to the proposed plan. The proposed project runs parallel to the constraints identified and is the most effective at relieving them.

5.12 MI Thumb Loop Expansion

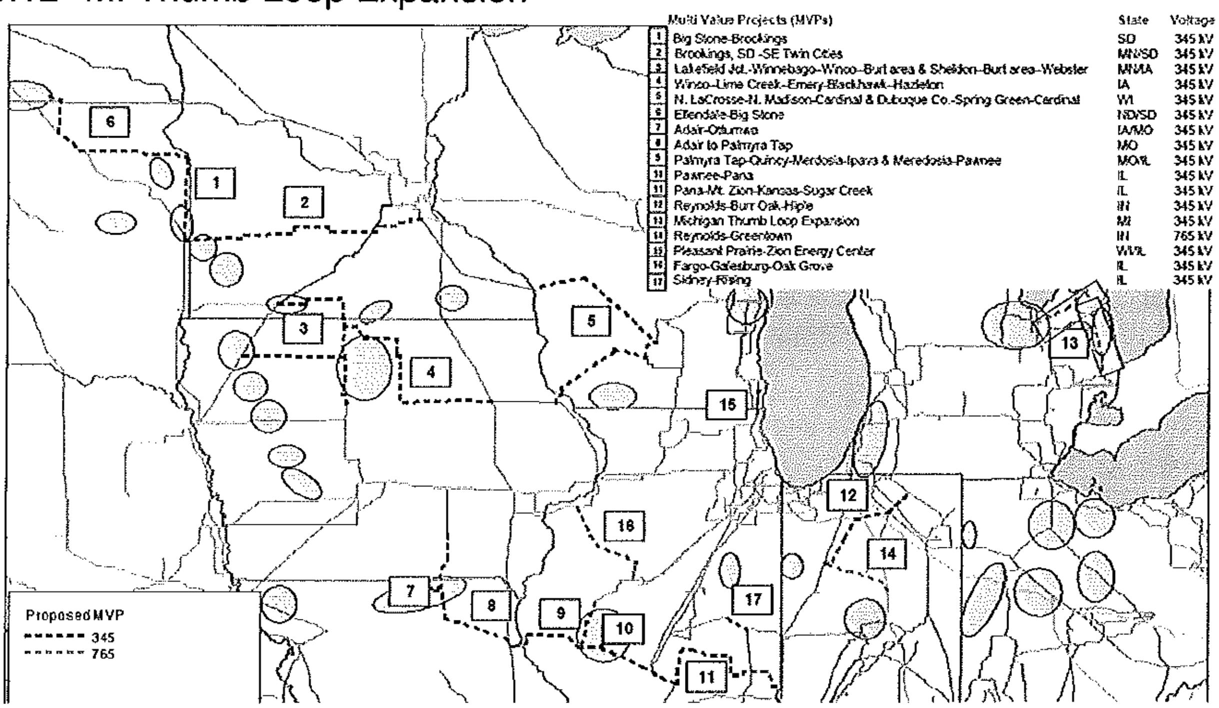


Figure 5.12: Michigan Thumb Loop Expansion

Project(s): 3168

Transmission Owner(s): ITC

Description: The proposed transmission line will connect into a new station to the south and west of the Thumb area that will tap three existing 345 kV circuits; one between the Manning and Thetford 345 kV stations, one between the Hampton and Pontiac 345 kV stations and one between the Hampton and Thetford 345 kV stations. Two new 345 kV circuits will extend from this new station, to be called Baker (formerly Reese), up to a new station, to be called Rapson (formerly Wyatt or Wyatt East) that will be

[20] In 2011 dollars

located to the north and east of the existing 120 kV Wyatt station. In order to support the existing 120 kV system in the northern tip of the Thumb, the two existing 120 kV circuits between the Wyatt and Harbor Beach stations, one that connects directly between Wyatt and Harbor Beach and that connects Wyatt to Harbor Beach through the Seaside station, will be cut into the new Rapson station. From the Rapson station, two 345 kV circuits will extend down the east side of the Thumb to the existing Greenwood 345 kV station and then continue south to the point where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. To facilitate connection to the existing transmission system a new 345 kV station, to be called Fitz (formerly Saratoga), is included in the plan at a site due south of the existing Greenwood station and just north of where the existing three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The Fitz station will then tap the existing Pontiac to Belle River to Greenwood 345 kV circuit and the existing Belle River to Blackfoot 345 kV circuit. Transformation from the 345 kV facilities to the 120 kV facilities will be necessary to maintain continuity to the existing system in and around the Sandusky area. The existing 120 kV facilities between the sites that will facilitate the new 345 kV to 120 kV transformation can be utilized to facilitate a connection between the new 345 kV to 120 kV transformation and the existing 120 kV facilities in the Sandusky area. The cost of this project is $510 million[21].

Justification: This project was needed pursuant to the directives of the Michigan Public Service Commission' and the Final Report of the Michigan Wind Energy Resource Zone Board ("Board"). This project is necessary to deliver wind mandate in Region 4, the primary wind zone region in Michigan (the Thumb). Reliability analysis tested 13 different system conditions involving Ludington pumped storage scenarios and Ontario interface transfers. Without mitigations, overloads were up to 155% and instability may happen for some multiple contingencies. With the existing system and alternative designs tested, NERC reliability standards cannot be met when renewable sufficient to deliver the wind mandates are connected.

Alternative 1 Considered: Replace the existing single circuit 120 kV loop from Tuscola up to Wyatt and down to Lee with two new 230 kV circuits on a 230 kV double circuit tower line that will extend from a new 230 kV station at or near the existing 120 kV Wyatt station southwest to a new 345/230 kV station southwest of the existing Atlanta 138/120 kV station and two more 230 kV circuits on a 230 kV double circuit tower line that will extend from the new 230 kV station at or near the Wyatt station down around to the existing Greenwood 345 kV station utilizing high temperature 1431 ACSR conductor (or an equivalently rated conductor) and 230 kV double circuit tower (or steel pole) construction, existing ROW as available and new ROW where necessary. Also, add two new 230 kV circuits (on new ROW) on a 230 kV double circuit tower line that will extend from the new station at or near the Wyatt station down around the west side of the Thumb to the new station south west of the Atlanta 138/120 kV station and two new 230 kV circuits on a 230 kV double circuit tower line that will extend from the Wyatt station down to the Greenwood station along the east side of the Thumb utilizing a similar conductor/tower configuration as the "inner loop". Continue south from the Greenwood 345 kV station with a new 345 kV double circuit tower line containing two new 345 kV circuits toward a new 345 kV station at a site due south of the existing Greenwood station and just north of the point where the three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The two new 345 kV circuits from Greenwood to this new station south of Greenwood would parallel the existing 345 kV circuit along that same path. These routes would utilize existing ROW to the extent possible.

Total Project Cost Estimate: $740, 000,000

Alternative 2 Considered: Replace the existing single circuit 120 kV loop from Tuscola up to Wyatt and down to Lee with two new 230 kV circuits on a 230 kV double circuit tower line that will extend from a new 230 kV station at or near the existing 120 kV Wyatt station southwest to a new 345/230 kV station southwest of the existing Atlanta 138/120 kV station and two more 230 kV circuits on a 230 kV double circuit tower line that will extend from the new 230 kV station at or near the Wyatt station down around to the existing Greenwood 345 kV station utilizing high temperature 1431 ACSR conductor (or an equivalently rated conductor) and 230 kV double circuit tower (or steel pole) construction, existing ROW

[21] In 2011 dollars

as available and new ROW where necessary. Also, add two new 230 kV circuits (on new ROW) on a 230 kV double circuit tower line that will extend from the new station at or near the Wyatt station down around the west side of the Thumb to the new station south west of the Atlanta 138/120 kV station utilizing a similar conductor/tower configuration as the "inner loop". Then continue south from the Greenwood 345 kV station with a new 345 kV double circuit tower line containing two new 345 kV circuits toward a new 345 kV station at a site due south of the existing Greenwood station and just north of the point where the three ended Pontiac to Greenwood to Belle River 345 kV circuit combines. The two new 345 kV circuits from Greenwood to this new station south of Greenwood would parallel the existing 345 kV circuit along that same path. These routes would utilize existing ROW to the extent possible.

Total Project Cost Estimate: $560,000,000

5.13 Reynolds to Greentown 765 kV line

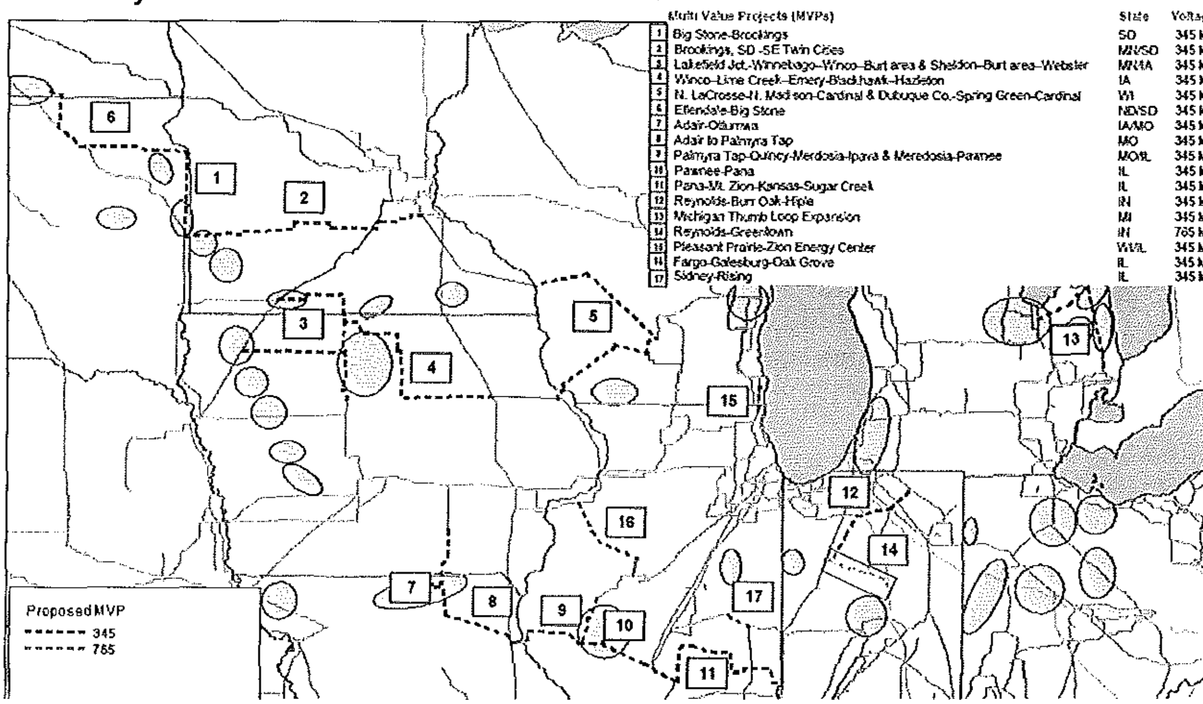


Figure 5.13: Reynolds to Greentown

Project(s): 2202

Transmission Owner(s): NIPSCO, Duke

Description: This project creates a 765 kV line from the Reynolds substation to the Greentown substation through Indiana, north of the Lafayette area. A 765/345 kV transformer/substation will also be installed at the Reynolds substation. The length of 765 kV line is approximately 66 miles, along with the 765 kV substation terminal upgrades at Greentown necessary to accommodate the 765 kV line connection. The estimated cost of this project is $245 million[22]. The 765 kV line project will be ready by June 2018. The 765/345 kV substation upgrade/construction will be ready by August 2018.

Justification: The 765 kV line from Reynolds to Greentown path across central Indiana will create an additional wind outlet path across the state, pushing power closer to the east coast, bringing less expensive wind generation into areas where the generation of power can be considerably more expensive. There are constraints on reliability on the 345 kV system to the north going toward

[22] In 2011 dollars

Chicago and Michigan, and to the south, crossing the Illinois/Indiana border and down into southwestern Indiana. These are mitigated with the new 765 kV line. The system flows attempt to bring power back to the Greentown substation, which cause numerous overloads for contingent scenarios that can be mitigated with the proposed 765 kV line. The line will also relieve constraints on the 138 kV system along a parallel path in the Lafayette, Indiana, area as well as the 138 kV line to the south between Dresser and Bedford. This 765 kV line will provide reliability benefits throughout Indiana. This project will mitigate seven bulk electric system (BES) NERC Category B thermal constraints and 21 NERC Category C constraints. It also relieves four non-BES NERC Category C constraints.

Alternatives Considered: Alternatives to the proposed project would be building lines to bypass the Lafayette area, which would relieve the constraints identified in this analysis, but load up the 230 and 138kV systems beyond the Lafayette area. The 345 kV in the Cayuga area is also heavily loaded, and upgrading would not be recommended. The proposed project is effective in alleviating all these constraints, without creating new ones, and provides a reduction of loadings on the existing lines.

5.14 Pleasant Prairie to Zion Energy Center 345 kV line

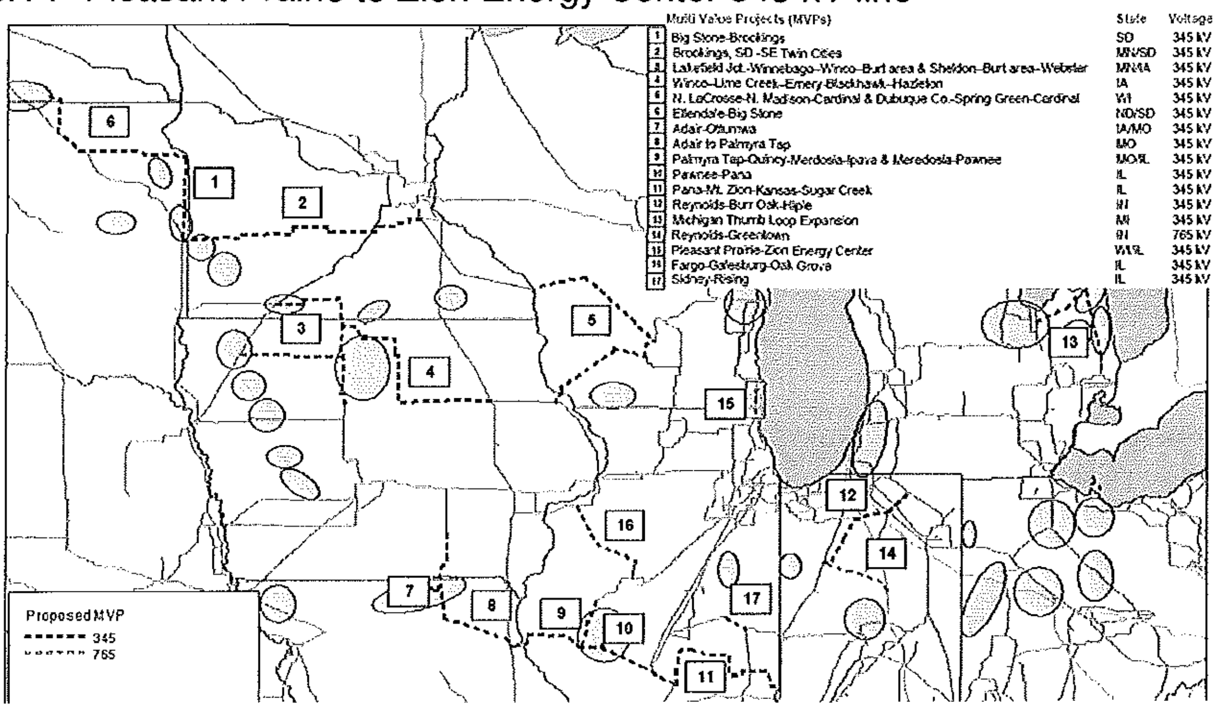


Figure 5.14: Pleasant Prairie to Zion Energy Center

Project(s): 2844

Transmission Owner(s): ATC

Description: A 345 kV line will be created from the Pleasant Prairie substation in Wisconsin to the Zion Energy Center substation in Illinois. The line will be approximately 5.3 miles long. The estimated cost is $26 million[23]. The expected in service date is March 2014.

Justification: The 345 kV line from Pleasant Prairie to Zion Energy Center creates an additional 345kV tie between these two stations, allowing more power to flow from the north down into Illinois.

[23] In 2011 dollars

That will bring wind energy from the north and west into this area. From a reliability perspective, the addition of the path relieves constraints on the 138 kV system adjacent to the project as well as 138 kV system constraints to the west of the new line. This project will mitigate seven bulk electric system (BES) NERC Category B thermal constraints and four NERC Category C constraints.

Alternatives Considered: No viable alternatives to this project were identified. The proposed project, which creates a parallel path to the existing constrained line, is the most effective solution.

5.15 Oak Grove to Galesburg to Fargo 345 kV line

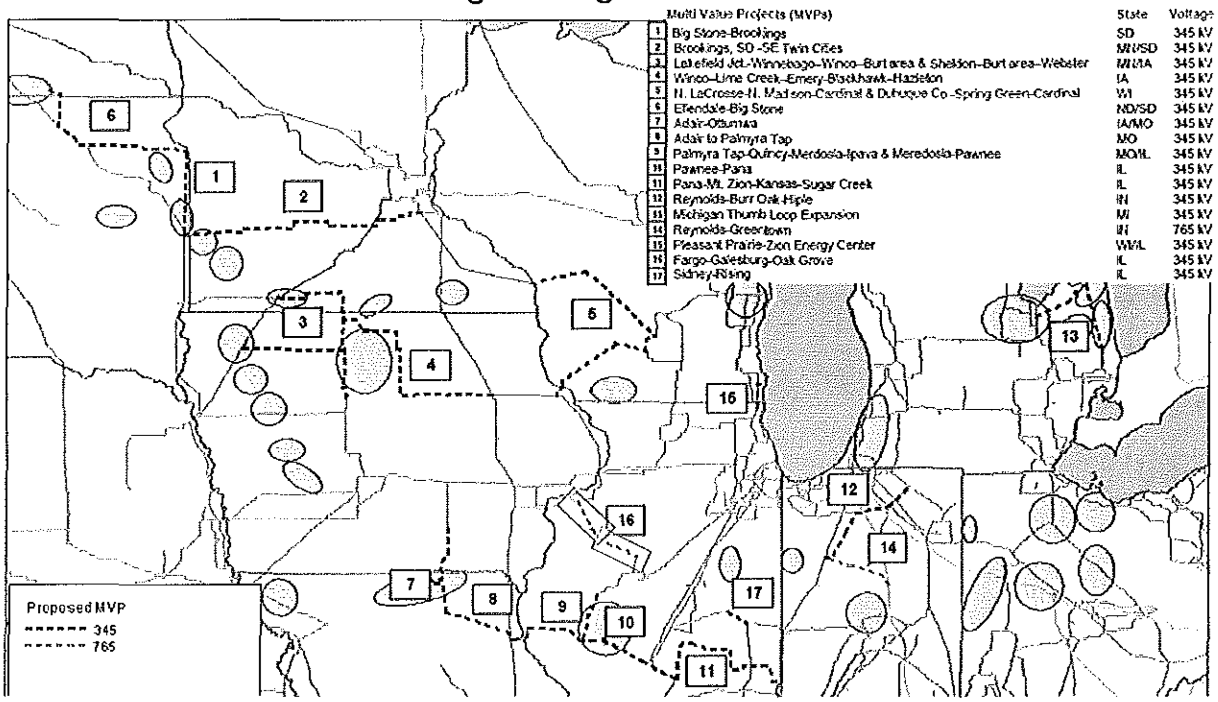


Figure 5.15: Oak Grove to Galesburg to Fargo 345 kV line

Project(s): 3022

Transmission Owner(s): Ameren, MEC

Description: This creates a 345 kV line from the MEC's Oak Grove substation to Ameren's Galesburg substation and to the Fargo substation through central Illinois. A new 560 MVA, 345/138 kV transformer will be installed at the Galesburg substation in addition to terminal additions/upgrades at all three substations. The 345 kV line is approximately 70 miles long, along with 40 miles of reconductor/rebuild at 345 kV and 138 kV to complete the project. The estimated cost is $193 million[24]. The Oak Grove – Galesburg 345 kV line and the Oak Grove 345 kV substation upgrades are expected to be ready by December 2016. The Fargo – Oak Grove 345 kV Line and Galesburg transformer addition are expected to be ready by November 2018. The Fargo substation upgrades are expected to be in service in 2018.

Justification: The new 345 kV line from Oak Grove to Galesburg to Fargo creates a path from western Illinois near the Iowa/Illinois border to central Illinois. This expansion creates an additional wind outlet path across the state, pushing power into central Illinois. In combination with another MVP, Dubuque – Spring Green – Cardinal 345 kV line, this enables 1,100 MW of wind power transfer

[24] In 2011 dollars

capability. From a reliability perspective, the addition of the Oak Grove to Fargo 345 kV path helps relieve constraints on the 345 kV system to the north. The 138kV system in the same area is also overloaded during certain contingent events. With the MVPs proposed in Wisconsin, Oak Grove to Fargo is needed to provide an outlet for the power coming from the west. It will keep that power on the 345 kV transmission system, rather than forcing it through the 138 kV system, requiring significant upgrades to carry the increased power flow.

Analysis also shows that the north ties from ATC to ComEd will remain constrained despite a new MVP from Pleasant Prairie to Zion, if the Oak-Grove Fargo 345 kV line is not built. This is because both outlets, Dubuque-Cardinal and Oak Grove-Fargo, are needed to effectively mitigate constraints on the transmission network supplying the Chicago area. This project will mitigate six bulk electric system (BES) NERC Category B thermal constraints and five NERC Category C constraints.

Alternatives Considered: Alternatives to the proposed project would be upgrading the 345 and 138 kV lines that are overloaded going toward Chicago. Upgrading the overloaded lines would likely lead to more overloads to the east, by injecting the additional power into an already constrained 345 kV path through Com Ed's Silver Lake area. The proposed project provides the greatest benefit to the transmission system.

5.16 Sidney to Rising 345kV Line

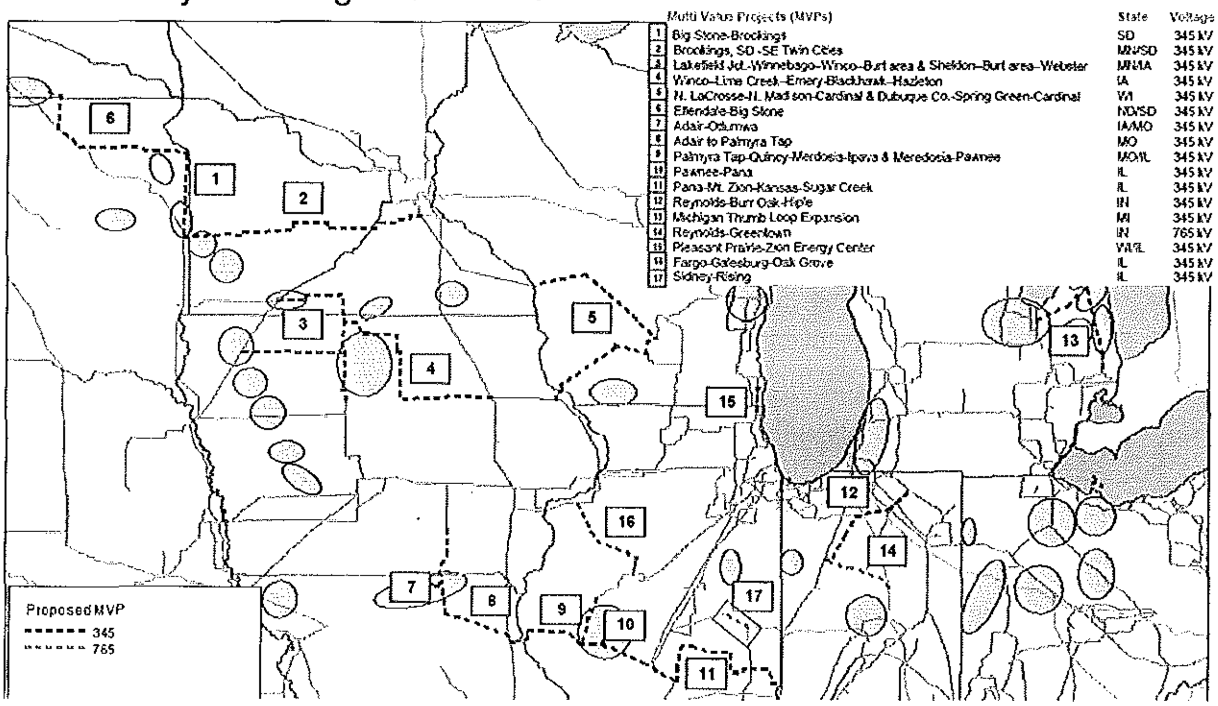


Figure 5.16: Sidney to Rising 345 kV line

Project(s): 2239

Transmission Owner(s): Ameren

Description: This builds a 345 kV line between the Sidney and Rising substation through eastern/central Illinois. That would create approximately 27 miles of 345 kV line, along with the substation upgrades at Sidney and Rising needed to accommodate the new line. The estimated cost of this project is $90 million[25]. The Sidney and Rising substation upgrades are expected to be ready by June 2016, and the 345 kV line should be ready by November 2016.

Justification: The 345 kV line from Rising to Sidney in Illinois will connect a gap in the 345 kV network in the area, promoting wind generation moving from the west to the east into Indiana. It will mitigate constraints by keeping the power on the 345 kV system, rather than pushing it into the 138 kV network at Rising. That causes overloads on the Rising transformer and on nearby 138 kV lines fed from Rising. This project will mitigate one bulk electric system (BES) NERC Category A thermal constraint, one NERC Category B constraint and three NERC Category C constraints.

Alternatives Considered: Upgrading the transformer at Rising and the 138 kV lines are a possible alternative, but that transformer was upgraded recently. Analysis shows that the power flow is being forced into the 138 kV system between Sidney and Rising to step back up to the 345 kV system. Completing the short connection between Sidney and Rising is the most effective recommendation for a long term solution.

[25] In 2011 dollars

6 Portfolio reliability analyses

In addition to the individual project justification, the MVP portfolio analysis also included an evaluation of the complete recommended MVP portfolio to ensure that system reliability is maintained. The recommended MVP portfolio maintains system reliability by resolving violations on approximately 650 transmission elements for more than 6,700 system conditions. It also mitigates 31 system instability conditions. More information on the constraints for each individual project may be found in Section 6 of this report.

6.1 Steady state

6.1.1 Reliability Planning Methodology Overview

The reliability assessment performed for the MVP portfolio analysis tested the transmission system using appropriate North American Electric Reliability Corporation (NERC) Table 1 events to determine if the system, as planned, meets Transmission Planning (TPL) standards. Any violation of these standards was identified, and the components of the portfolio were tested to determine their effectiveness in addressing the identified issues. In addition secondary transmission upgrades were developed to mitigate any unresolved issues. The performance of the mitigation plan was tested to ensure it alleviates the identified issues and does not create additional issues.

6.1.2 Planning Criteria and Monitored Elements

In accordance with the MISO Transmission Owners Agreement, the MISO Transmission System is to be planned to meet local, regional and NERC planning standards. The MVP portfolio analysis, performed by MISO staff, tested the performance of the system against the NERC Standards when applicable Renewable Portfolio Standards (RPS) were applied. Compliance with local requirements, where the local requirements exceed NERC standards, was not evaluated. This analysis will be performed by the responsible Transmission Owners. All system elements that were loaded at 95% or higher were flagged as transmission issues for Category A, B and C events. Elements under Category C3 contingencies were flagged as transmission issues at loadings of 125% and higher.

All system elements, 100 kV and above, within the MISO Planning regions, as well as tie lines to neighboring systems, were monitored. Elements 69 kV and above were monitored in select MISO Planning regions per Transmission Owner planning standards. Some non-MISO member systems were monitored if they were within the MISO Reliability Coordination Area.

6.1.3 Baseline Modeling Methodology

The MVP portfolio analysis powerflow models were developed to represent various system conditions in the planning horizon. 2021 Summer Peak and 2021 Shoulder Peak powerflow models were developed. MISO coordinated with external seam regions, including TVA, SPP, MAPP and PJM, to reflect the latest topology of the corresponding regions. For all other areas, modeling data from the 2020 Eastern Interconnection Planning Collaborative (EIPC) model was applied.

6.1.4 Contingencies Examined

Regional contingency files were developed by MISO staff collaboratively with Transmission Owners and regional study group input. NERC Category A, B and C contingency events on the transmission system under MISO functional control were analyzed. In general, contingencies on the MISO members' transmission system at 100 kV and above were analyzed, although some 69 kV transmission was also analyzed. The MTEP10 MRO contingency files were used with updates from MISO Transmission Owners. Automated single contingencies and bus double contingencies were also performed on the new MVP and surrounding transmission.

6.1.5 Results

A total of 384 thermal overloads were mitigated by the recommended MVP portfolio under shoulder peak conditions, for approximately 4,600 system conditions. In addition, approximately 100 additional thermal overloads and 150 voltage violations were mitigated by the recommended MVP portfolio in the summer peak analysis.

6.2 Transient stability

The purpose of performing transient stability analysis is to identify loss of synchronism, sometimes referred to as 'out of step' conditions for existing and proposed generation under severe fault conditions required by NERC and regional reliability standards. For the MVP portfolio transient stability analysis, two scenarios were studied.

Tasks of the two studies were evaluation of the impact of major fault conditions on the ability of the generators to remain synchronized to the electric system without any voltage or damping criteria violations.

6.2.1 Methodology and base case creation

Transient stability analysis was performed on two cases representing the shoulder peak conditions, in 2021, after the addition of RGOS wind zones and the 17 MVP portfolio lines. The following two cases were created for comparative analysis. These models were based upon the MTEP11 powerflow models utilized for the steady state analysis, as described in the previous section.

1. A base case, or the "No MVP portfolio case," was developed by adding all the incremental wind zones, without the portfolio, to the MTEP11 case.

2. A study case, or the "With MVP portfolio case," was developed by adding all the incremental wind zones, with the portfolio, to the MTEP11 case.

The corresponding dynamic files, for the power flow cases mentioned above, were created by adding the GE 1.5 MW turbines (GEWTG1- Type 3 model) to represent each wind zone. It was assumed that all new wind turbines would have a +/-0.95 power factor range. The machine data for all existing units was unchanged because it had been reviewed by the Transmission Owners during the MTEP10 review process. For all external models where the data was not available, machines were modeled with a classical machine model (GENCLS).

6.2.2 Monitored facilities

For evaluating the transient stability performance under fault conditions, the rotor angle, active power output, terminal voltage and the reactive power output for each machine was monitored. For evaluating the transient voltage violations under fault conditions, 345kV bus voltages in each MISO control area were monitored. The list of monitored bus voltages can be seen in Appendix C of this report.

6.2.3 Fault analysis and assumptions

All faults that were analyzed during the MTEP10 stability analysis review were used as the starting point for the stability analysis. In addition, several three phase faults and single line to ground faults (SLG) were developed to simulate fault conditions on the MVP portfolio lines. All these faults were reviewed by the Technical Study Task Force in the first quarter of 2011.

A two cycle margin was added to the fault clearing times to determine if system reliability would be maintained under more stressed conditions. Generally, when the fault clearing times are increased, the probability of having an unstable condition is also increased. Therefore, it was important to determine whether the existing MTEP10 faults would cause system instability; with a two cycle embedded margin to account for modeling errors that can mask underlying reliability issues if the clearing times are close to the critical clearing times. This analysis was not required to comply with any NERC reliability criteria, but was performed to check the strength of the power system with increased wind generation and transmission under the 2021 conditions.

At the time this fault analysis was conducted, short circuit data was not available to model SLG fault conditions for the CMVP faults. NERC Category C6, C7, C8 and C9 reliability criteria requires the system to be stable under SLG faults cleared under delayed clearing such as a stuck breaker condition. NERC Category D1, D2, D3 and D4 reliability criteria, which is a lot more stringent, requires the system to be stable under three phase fault conditions with delayed clearing. Typically, a three phase fault is a lot more severe than a SLG fault and is a lot easier to simulate due to the absence of zero sequence fault currents. Therefore, SLG faults with delayed clearing on the MVP portfolio lines were simulated as three phase faults with delayed clearing.

The rationale for choosing this approach was simple. If the Three Phase faults were stable under delayed clearing conditions, then it could be reasonably assumed that the same faults would also be stable under SLG with delayed clearing. However, if the analysis revealed that a few faults caused instability, then only those faults would then be re-analyzed with correct fault impedance.

6.2.4 Results

The transient stability analysis revealed that the addition of the MVP portfolio to the transmission system made the system more stable under several fault conditions and 2021 shoulder peak conditions. There were a few fault conditions, which required the addition of minor reactive support devices at a couple of 345kv buses in the western region of the MISO transmission system. The evaluation of optimized reactive support locations under these fault conditions will be studied during the regular MTEP12 reliability analysis, which requires additional stakeholder input and more detailed analysis. The results of the transient stability analysis are under Appendix C of this report.

6.3 Voltage stability

Voltage stability analysis was performed to identify voltage collapse conditions under high energy transfer conditions from major generation resources to major load sinks. For this analysis, high transfer conditions were analyzed, from the wind rich west region of the MISO footprint to major load centers such as Minneapolis-St. Paul, Madison, St Louis and Des Moines. The idea was to evaluate the incremental transfer capability, between the generation resources and the load sinks, that is created by the addition of the MVP portfolio under 2021 summer peak conditions.

6.3.1 Methodology and base case creation

The evaluation of the MVP portfolio's incremental transfer capability benefits can only be quantified when the results are compared to identical system conditions without the MVP lines. Therefore, two different power flow cases were created for 2021 summer peak conditions, shown below.

1. A base case or the "No MVP portfolio case" was developed by adding all the incremental wind zones without the portfolio.
2. A study case or the "With MVP portfolio case" was developed by adding all the incremental wind zones with the portfolio.

For each of the two cases mentioned above, four different transfers were modeled by increasing the generation in the source areas and reducing the generation in the load areas. The idea is to transmit maximum megawatts over the transmission system before a voltage collapse condition occurs due to the contingency loss of a major transmission line. For each simulated transfer, an interface consisting of major import transmission lines into the load centers was created and monitored for each contingency.

The voltage stability transfer analysis was simulated under several contingency conditions to identify the worst contingency and the corresponding maximum megawatt transfer levels over the defined interface. This method was repeated for each transfer and for both the 2021 summer peak load cases as described above.

6.3.2 Results

The comparative analysis summary below shows that the addition of the MVP lines boosted transfer capabilities from wind rich regions to major load centers within the MISO footprint. The details of the voltage stability analysis showing the PV plots and reactive reserve margins for each transfer, under both scenarios, can be viewed in Appendix C of this report.

Voltage Stability Transfer Analyzed	Without Multi Value Project Portfolio (MW)	With Multi Value Project Portfolio (MW)	Incremental Transfer enabled by the MVPs (MW)	Incremental Transfer enabled by the MVPs (percent)
MISO West - Twin Cities	3399	5240	1841	54 percent
MISO West - Madison	1720	3160	1440	84 percent
MISO West - Des Moines	2000	3100	1100	55 percent
MISO West - St Louis	3700	4660	960	26 percent

Table 6.1: Transfer capabilities under high transfer conditions

6.4 Short circuit

The reliability analysis component of the MVP portfolio study included a short-circuit analysis. The goal was to determine whether the installation of the MVP transmission facilities would cause certain existing circuit breakers to exceed their short-circuit fault interrupting capability.

Per the Tariff, should the installation of one or more MVPs cause an electrical issue on a facility, the resolution can be included in the scope of the MVP. The costs can then be shared using the same regional cost allocation mechanism applicable to the base MVPs, as long as the electrical issue is associated with a facility that is owned by a MISO Transmission Owner and classified as a transmission plant. While many electrical issues resulting from MVPs are loading or voltage related, it is also possible for the MVPs to raise the available short-circuit fault current at specific buses.

When the available short-circuit fault current increases beyond the capability of one or more circuit breakers to interrupt the fault current, the situation must be remedied. Typical remedies include replacing the affected circuit breaker with those with higher short circuit fault interrupting capabilities. In some situations, it may be necessary to reconfigure the topology of the system (e.g., splitting buses, etc.) if the available short-circuit fault currents exceed the capabilities of available circuit breakers.

To perform the short-circuit analysis, MISO developed default criteria to govern the short-circuit study. MISO then requested each Transmission Owner to conduct a short-circuit analysis on their own circuit breakers, using either their own internal criteria or MISO's default criteria, to determine if there are fault duty issues with any circuit breakers caused by the installation of one or more MVPs. Most Transmission Owners elected to use the default MISO criteria. The Transmission Owners then submitted results to MISO, including any recommendations to be added to the scope of existing MVPs. The default MISO criteria for the short-circuit analysis follows.

6.4.1 Default criteria for worst case fault current interruption exposure

This default criteria will establish the worst case fault current interruption exposure for each circuit breaker when there is no established criteria for worst case fault current interruption exposure for a specific Transmission Owner:

- Three-phase, phase-to-ground and double phase-to-ground faults will be evaluated. Phase-to-phase faults will not be evaluated.

- Faults will be simulated with zero fault impedance.
- Fault currents will be calculated in accordance with IEEE/ANSI Standard C37.010-1999 using the X/R multiplying factors.
- Faults will be simulated with all generation on-line with the sub transient reactance or equivalent modeled for all generators.
- Faults will be simulated with all network buses and branches in their normal configuration.
- For branch faults, fault locations will be simulated at the branch-side terminals of the circuit breaker in question.
- For branch and bus faults, faults current circuit breaker flows will be determined assuming all other circuit breakers protecting the branch or bus are open. While this results in a lower total fault current, this typically represents the highest fault current exposure for a specific circuit breaker.
- For each circuit breaker, simulations will be made to determine the worst case fault current interruption exposure for primary and backup zones of protection, where backup zones of protection are covered by a specific circuit breaker under the failure of a different circuit breaker.

6.4.2 Default criteria for circuit breaker fault duty calculations

The following default criteria will be used to establish the fault duty for each circuit breaker when there is no established criteria for circuit breaker fault duty calculations for a specific Transmission Owner:

- For each circuit breaker, the interrupting capability of the circuit breaker must be greater than the worst case fault current interrupting exposure of the circuit breaker, plus a safety margin of 2.5 percent
- When specific circuit breakers must be derated for reclosing duty, the Transmission Owner will inform MISO about the specific derates and the associated zones of protection where they apply for each circuit breaker. These derates will be applied in determining the fault duty for the circuit breaker.

6.4.3 Results

The results of the short-circuit analysis indicated the need for only nine circuit breaker replacements, representing an estimated capital cost of about $2.2 million, or less than 0.1 percent of the recommended MVP portfolio. The circuit breaker replacements represented lower voltage circuit breakers exposed to higher fault current levels due the installation of nearby MVP facilities. The recommended circuit breaker replacements are shown in the table below:

Substation	Voltage	Number of Breaker Replacements	Driving MVP
Blount	69 kV	3	N. Lacrosse – Cardinal - Dubuque
Lakefield	161 kV	1	Lakefield - Hazleton
Winnebago	161 kV	3	Lakefield – Hazleton
Lime Creek	161 kV	1	Lakefield – Hazleton
Hazleton	161 kV	1	Lakefield – Hazleton

Table 6.2: Circuit breaker replacements

7 Portfolio Public Policy Assessment

The projects in the proposed Multi Value Project portfolio were evaluated against criterion 1, which require the projects to reliably or economically enable energy policy mandates. To demonstrate the ability of the portfolio to enable the renewable energy mandates of the footprint, a set of analyses were conducted to quantify the renewable energy enabled by the footprint.

This analysis took part in two parts. The first part demonstrated the wind needed to meet the 2026 renewable energy mandates that would be curtailed but for the recommended MVP portfolio. The second part demonstrated the additional renewable energy, above the 2026 mandate, that will be enabled by the portfolio. This energy could be used to serve mandated renewable energy needs beyond 2026, as most of the mandates are indexed to grow with load.

7.1 Wind Curtailment

A wind curtailment analysis was performed to find the percentage of mandated renewable energy which could not be enabled but for the recommended 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 as mitigated by the recommended MVP portfolio. The 429 monitored element/contingent element pairs (flowgates) consisted of 205 Category B and 224 Category C contingency events. These constraints were taken from a blend of 2021 and 2026 wind levels with the final calculations based on the 2026 wind levels.

Since the majority of the western region MVP justification was based on 2021 wind levels, it was assumed that any incremental increase to reach the 2026 renewable energy mandated levels would be curtailed. A transfer of the 193 wind units, sourced from both committed wind units and the RGOS energy zones, to the system sink, Browns Ferry in TVA, 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 Multi Value Project justifications, a target loading of less than or equal to 95% was used. 24 of the 429 flowgates could not achieve the target loading reduction, and their targets were relaxed in order to find a solution.

The algorithm found that 10,885 MW of dispatched wind would be curtailed. As a connected capacity, this equates to 12,095 MW as the wind is modeled at 90% of its nameplate. A MISO-wide per-unit capacity factor was averaged from the 2026 incremental wind zone capacities to 32.8%.

The curtailed energy was calculated to be 34,711,578 MWHr from the connected capacity times the capacity factor times 8,760 hours of the year. Comparatively, the full 2026 RPS energy is 55,010,629 MWHr. As a percentage of the 2026 full RPS energy, 63% would be curtailed in lieu of the MVP portfolio.

7.2 Wind Enabled

Additional analyses were performed to determine any incremental wind energy, in excess of the 2026 requirements, enabled by the recommended MVP portfolio. This energy could be used to meet renewable energy mandates beyond 2026, as most of the state mandates are indexed to grow with load. A set of two First Contingency Incremental Transfer Capability (FCITC) analyses were run on the 2026 model to determine how much the wind in each zone could be ramped up prior to additional reliability constraints occurring.

First, a transfer was sourced from all the wind zones in proportion to their 2026 maximum output. All the Bulk Electric System (BES) elements in the MISO system were monitored, with constraints being flagged at 100% 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, in the proportions below. 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 7.1: Transfer Sink Distribution

As a result of this analysis, it was determined that an additional 981 MW could be reliably sourced from the energy zones. Because of regional transfer limits, no additional western wind could be increased beyond this level. The output levels of the wind zones were updated in the model and a second transfer analysis was performed to determine any incremental wind that could be sourced from the Central and East wind zones. This analysis was performed with the same methodology and sink as the first analysis, but all the western wind zones were excluded from the transfer source. This analysis determined that 1,249 MW of additional generation could be sourced from the Central and Eastern wind zones.

Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled	Wind Zone	Incremental Wind Enabled
IA-BF	22.5	IN-E	144.9	MT-A	15.4
IA-GH1	27.4	IN-K	483.0	ND-M	2.4
IA-H2	76.0	MN-B	109.5	SD-HJ	130.1
IA-J	5.1	MN-H	254.7	SD-L	15.4
IL-F	678.6	MN-K	34.8	WI-B	230.4

Table 7.2: Incremental Wind Enabled Above 2026 Mandated Level, by Zone

In total, it was determined that 2,230 MW of additional generation could be sourced from the incremental energy zones to serve future renewable energy mandates. When the results from the curtailment analyses and the wind enabled analyses are combined, the recommended MVP portfolio enables a total of 41 million MWhs of renewable energy to meet the renewable energy mandates.

8 Portfolio economic benefits analyses

Multi Value Projects represent the next step in the evolution of the MISO transmission system: a regional network that, when combined with the existing system, provides value in excess of its costs under a variety of future policy and economic conditions. These benefits are discussed below, as well as the analyses used to determine them.

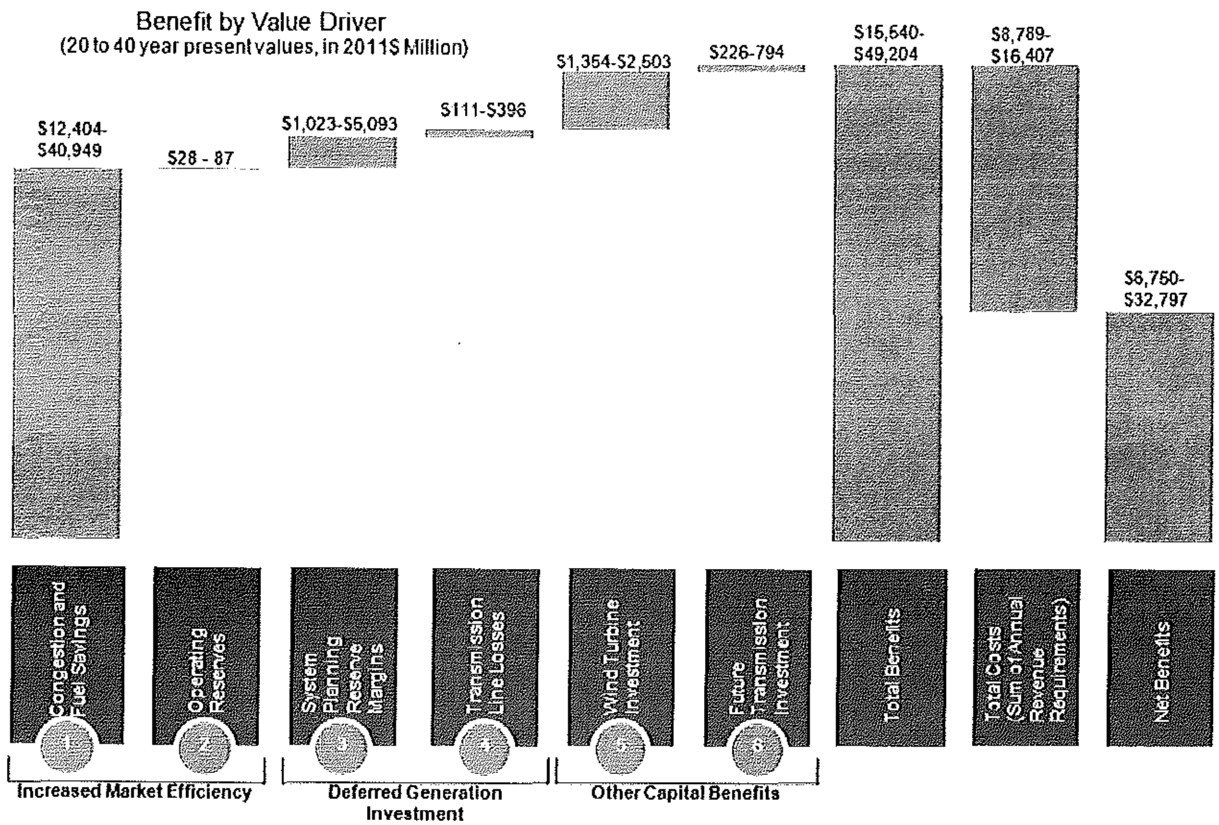


Figure 8.1: Recommended MVP portfolio economic benefits

8.1 Congestion and fuel savings

The recommended 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 captured the economic benefits of the recommended 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.

The future scenarios without any new energy policy requirements provide a baseline of the recommended MVP portfolio's benefits under current policy conditions. Additionally, the evaluation of the Carbon Constrained and Combined Policy future scenarios provide "bookends," helping to show the full range of benefits that may be provided by the portfolio. Looking at the "Business as Usual" future scenarios with no new energy policies, the recommended MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year present value adjusted production cost benefits, depending on the timeframe, discounts and growth rates of energy and demand. This benefit increases to a maximum present value of $91.7 billion under the Combined Policy future scenario.

8.1.1 Production cost model development

PROMOD IV® is an integrated electric generation and transmission market simulation system, and was the primary tool used to support economic assessment of the recommended MVP portfolio. It incorporates details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions and market system operations. It performs an 8,760-hour centralized security constrained unit commitment and economic dispatch, recognizing generation and transmission impacts at the nodal level. It uses an hourly chronological dispatch algorithm that minimizes cost, while recognizing a variety of operating constraints.

These include generating unit characteristics, transmission limits, fuel and environmental considerations, reserve requirements and customer demand. It provides a wide spectrum of forecasts on hourly energy prices, unit generation, fuel consumption, energy market prices at bus level, regional energy interchanges, transmission flows and congestion prices.

To be able to perform a credible economic assessment on the recommended MVP portfolio, production cost models require detailed model input assumptions on generation, fuel, demand and energy, transmission topology and system configuration, described below.

8.1.2 Models

The primary economic analysis was performed with 2021 and 2026 production cost models, with incremental wind mandates considered for 2021, 2026 and 2031, respectively. Three various levels of wind mandates and loads were modeled: 2021 RPS mandates and load levels, 2026 RPS mandates and load levels and 2026 load levels, plus all generation enabled by the recommended MVP portfolio used to estimate benefits in year 2031.

The transmission topology was taken from the 2021 summer peak power flow model developed through the MTEP11 planning process. The 2026 production cost models used the same transmission topology as 2021. The PROMOD study footprint included the majority of the Eastern Interconnection with ISO-New England, Eastern Canada and Florida excluded. Although these regions have very limited impact on the study results, fixed transactions were modeled to capture the influence of these regions on the rest of the study footprint.

8.1.3 Event file

Production cost models use an "event file" to capture a set of transmission constraints. The constraints ensure system reliability by performing hourly security constrained unit commitment and economic dispatch. The event file was developed based on the latest Book of Flowgates from MISO and NERC, updated to incorporate rating and configuration changes from concurrent studies in the MTEP11 planning cycle. In addition, MUST AC analyses and PROMOD Analysis Tool (PAT) contingency screening analyses were performed to identify a number of additional monitored/contingencies to ensure the most severe limiters of the transmission system are captured in the event file. As an integral part of the study, stakeholders and interested parties were extensively involved in the review of the event file.

8.1.4 Benefit measure

Comprised of 17 projects spread across the MISO footprint, the recommended MVP portfolio enables the renewable energy delivery required by public policy mandates that could not otherwise be realized. To determine the economic benefits of the recommended MVP portfolio, two production cost model simulations were performed with and without the combination of the recommended MVP portfolio and the wind it enables. The difference between these two cases provides measurable benefits associated with the recommended MVP portfolio, focusing on Adjusted Production Cost savings according to the tariff provisions. Adjusted Production Cost is the annual generation fleet production costs, including fuel, variable operations and maintenance, start up cost and emissions, adjusted with off-system purchases and sales. Adjusted Production Cost savings are achieved through reduction of transmission congestion costs and more efficient use of generation resources across the system.

8.1.5 Policy driven future scenarios

To account for out-year public policy and economic uncertainties, MISO collaborated with its stakeholders to refresh available future policy scenarios to better align them with potential policy outcomes taking place. The future scenarios were designed to bookend the potential range of future policy outcomes, ensuring that all of the most likely future policy scenarios and their impacts were within the range bounded by the results. Four futures were refreshed and analyzed:

- Business As Usual with Continued Low Demand and Energy Growth (BAULDE) assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.
- Business As Usual with Historic Demand and Energy Growth (BAUHDE) assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates.
- Carbon Constrained assumes that current energy policies will be continued, with the addition of a carbon cap modeled on the Waxman-Markey Bill.
- Combined Energy Policy assumes multiple energy policies are enacted, including a 20 percent federal RPS, a carbon cap modeled on the Waxman-Markey Bill, implementation of a smart grid and widespread adoption of electric vehicles.

The various input assumptions and uncertain variables defined for each policy driven future dictate a unique set of generation expansion plans on a least cost basis to meet regional Resource Adequacy Requirements, detailed in Table 8.1.

Future Scenarios	Wind Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price	Carbon Cost / Reduction Target
BAULDE	State RPS	0.78 percent	0.79 percent	$5	None
BAUHDE	State RPS	1.28 percent	1.42 percent	$5	None
Combined Energy Policy	20 percent Federal RPS by 2025	0.52 percent	0.68 percent	$8	$50/ton (42 percent by 2033)
Carbon Constrained	State RPS	0.03 percent	0.05 percent	$8	$50/ton (42 percent by 2033)

Table 8.1: MTEP11 Future Scenario Assumptions

8.1.6 Economic analysis results

A holistic economic assessment for the recommended MVP portfolio was performed against a wide range of future policy driven scenarios. This was done to minimize the risk imposed by the uncertainties around potential policy decisions. The future scenarios without any new energy policy mandates provide a baseline of the recommended MVP portfolio's benefits under current policy conditions. The evaluation of the Carbon Constrained and Combined Energy Policy future scenarios also provide "bookends" which help show the full range of benefits that may be provided by the portfolio.

8.1.7 Adjusted Production Cost savings and benefit spread

With the recommended MVP portfolio providing access to the lowest electric energy costs and relieving transmission congestion across the MISO footprint, the portfolio brought a wide range of adjusted production cost savings, from an estimated $12.4 to $28.3 billion in 20 year present value terms under the four selected future scenarios, as shown in Figure 8.2.

The recommended MVP portfolio also collects renewable energy from a distributed set of wind energy zones, enables the wind delivery and provides widespread regional benefits across the MISO footprint, regardless of future policy outcomes.

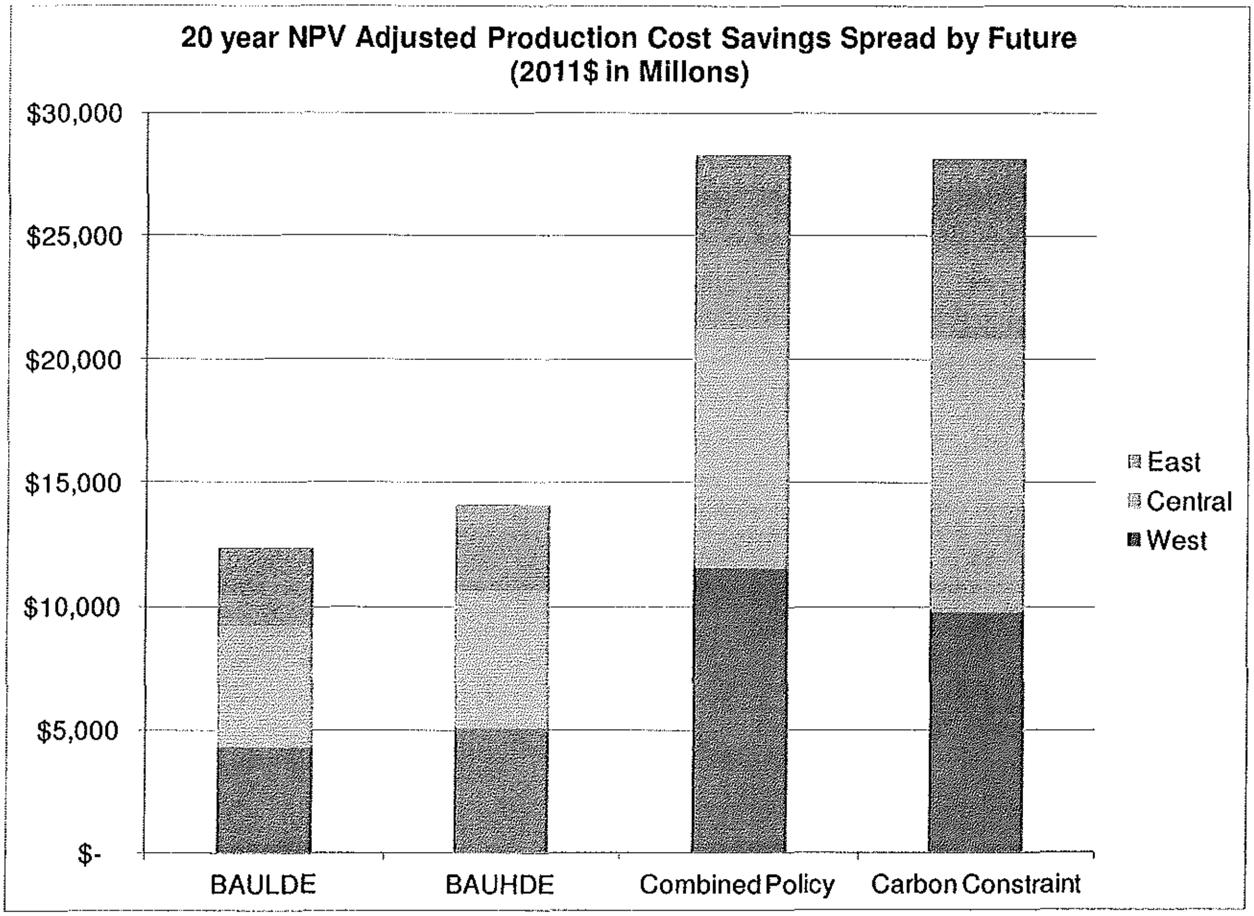


Figure 8.2: Adjusted Production Cost Savings spread by future

8.1.8 Generation displacement

Figure 8.3 summarizes the 2021 annual energy production changes between the base case and the change case. The recommended MVP portfolio enables the delivery of renewable energy to meet the near term RPS mandates of MISO states in a more reliable and economic manner, causing higher cost units to be displaced by the wind resources enabled by the proposed portfolio across the MISO footprint. Moreover, the recommended MVP portfolio allows low cost energy in the western regions to reach a wider footprint. It leads to a more efficient usage of generation resource across the entire study footprint, with some level of generation displacement occurring in external regions, particularly in PJM and SERC.

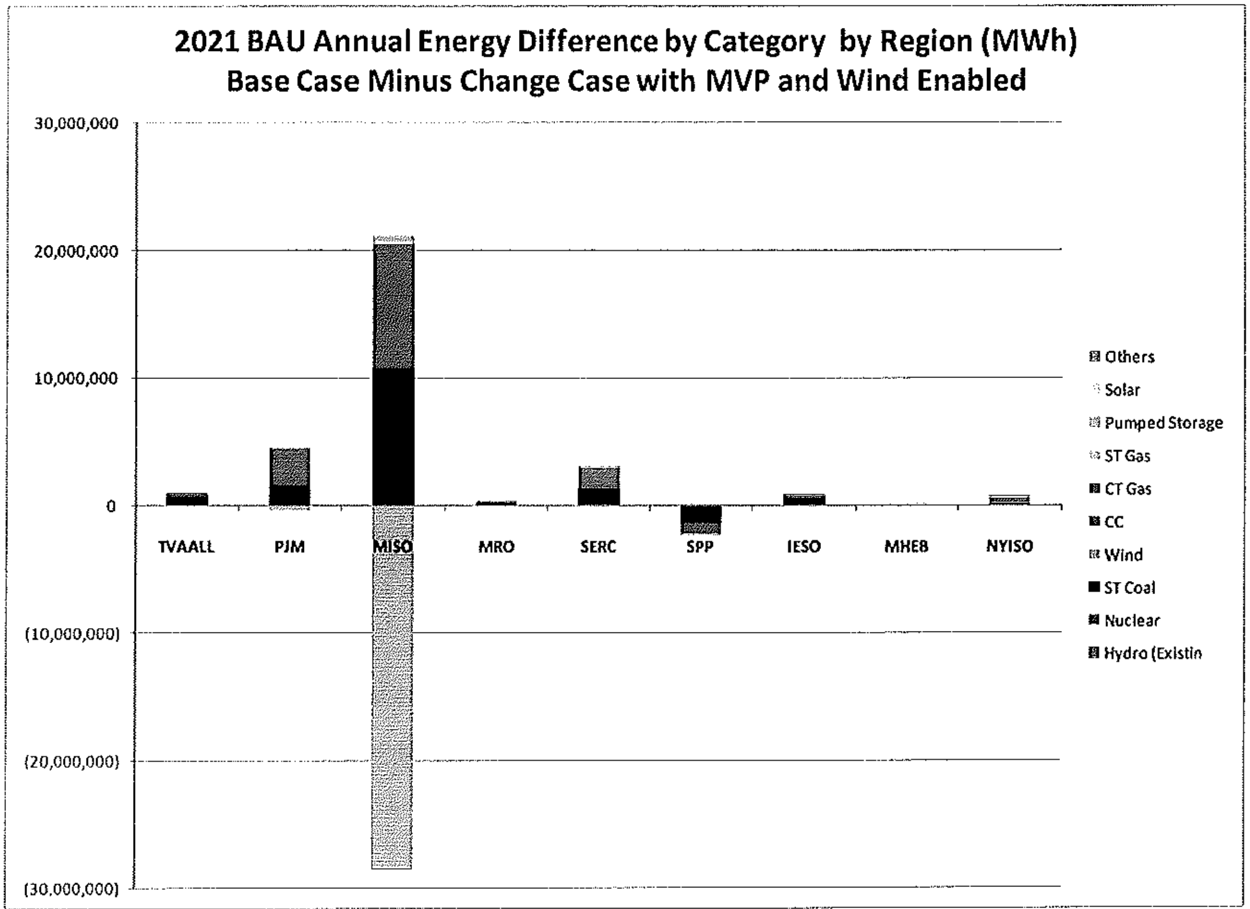


Figure 8.3: Generation displacement by region

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8.1.9 Economic Variable Impact

The projected benefits of the recommended MVP portfolio depend on projections of future policy and economic variables. Figure 8.4 shows the impacts of economic variable assumptions on the projected economic benefits achieved by the recommended MVP portfolio, with the primary focus on the time of present value calculations and discount rate.

Considering solely the 'Business as Usual' future scenarios with no new energy policies, the recommended MVP portfolio will produce an estimated $12.4 to $40.9 billion in 20 to 40 year present value adjusted production cost savings, depending on the time, discount rates and rate of energy and demand growth. This benefit would increase to a maximum present value of $91.7 billion under the Combined Energy Policy future scenario.

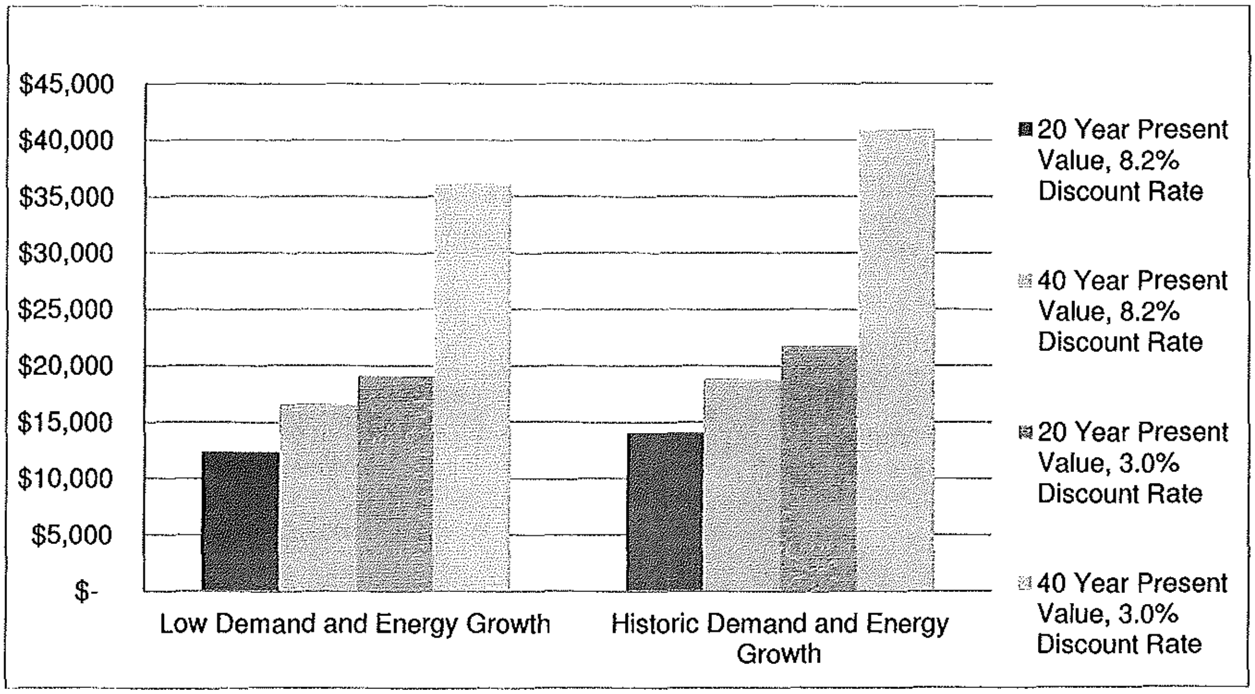


Figure 8.4: Adjusted Production Cost Benefits from recommended MVP portfolio

8.2 Operating reserves

In addition to the energy benefits quantified in the production cost analyses, the recommended MVP portfolio will also reduce operating reserve costs. The recommended MVP portfolio decreases congestion on the system, increasing the transfer capability into several key areas that would otherwise have to hold additional operating reserves under certain system conditions.

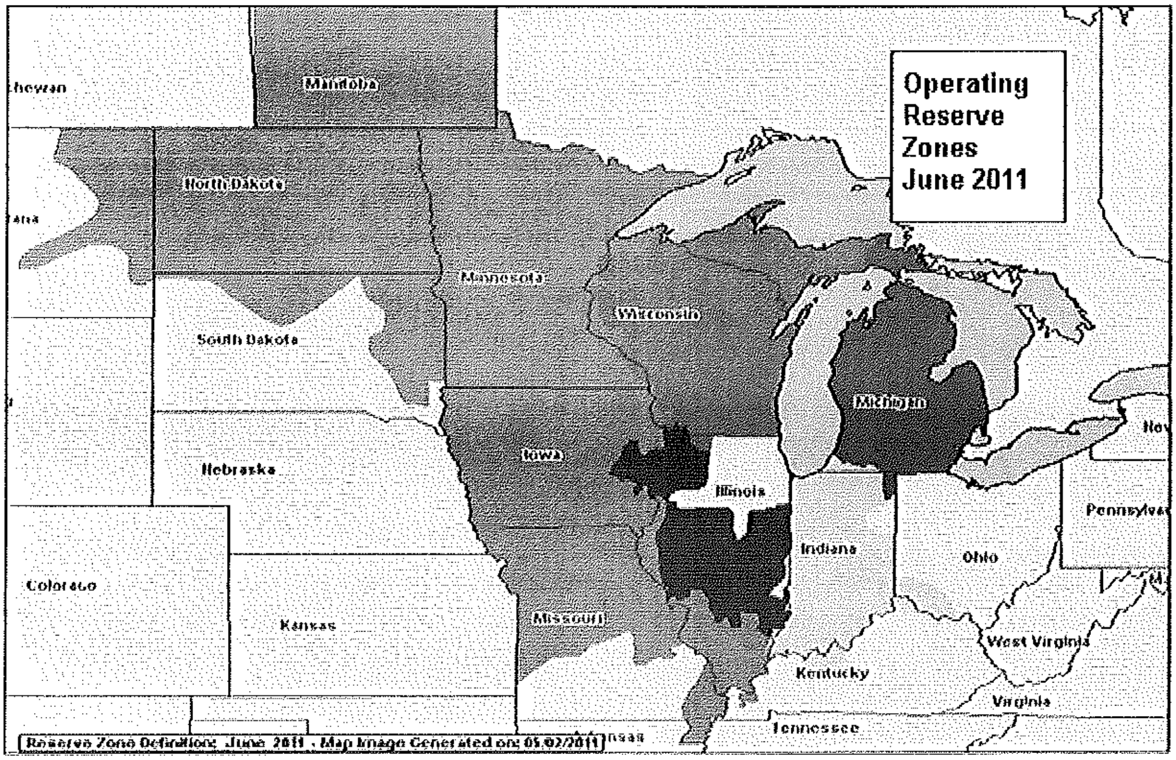


Figure 8.5: Operating reserve zones

MISO determined that the addition of the recommended MVP portfolio will eliminate the need for the Indiana operating reserve zone, as shown in Figure 8.5, and the need for additional system reserves to be held in other zones across the footprint would be reduced by half. This creates 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, creating benefits of $28 to $87 million in 20 to 40 year present value terms.

8.2.1 Analyses

Operating reserve zones are determined, on an ongoing basis, by monitoring the energy flowing through certain flowgates across the system. The zonal operating reserve requirements, based on the actual conditions from June 2010 through May 2011, are shown below in Table 8.2.

Zone	Total Requirement (MW)	Days with Requirement (#)	Average daily requirement (MW)
Missouri	95	1	95.1
Indiana	14966	53	282.4
N-Ohio	9147	15	609.8
Michigan	4915	17	289.1
Wisconsin	227	2	113.4
Minnesota	376	1	376.3

Table 8.2: Historic operating requirements

Transfer analyses were performed to determine the changes in flows due to the addition of the recommended MVP portfolio to the system. These analyses were performed on both the most recent model used to create the operating reserve limitations, as well as on the 2021 MTEP11 power flow model.

Zone	Limiter	Contingency	Operating Model Change in Flows	MTEP11 Model Change in Flows
Missouri	Coffeen - Roxford 345	Newton-Xenia 345	-0.8%	-18.5%
Indiana	Bunsonville-Eugene 345	Casey-Breed 345	-17.5%	-87.2%
Indiana	Crete-St. Johns Tap 345	Dumont-Wilton Center 765	-4.5%	-9.4%
Michigan	Benton Harbor - Palisades 345	Cook - Palisades 345	-10.8%	-4.6%
Wisconsin	MWEX	N/A	-20.2%	-2.3%
Minnesota	Arnold-Hazleton 345	N/A	-60.9%	15.9%

Table 8.3: Change in transfers, pre-MVP minus post-MVP

As a result of these transfer analyses, it was determined that the need for the Indiana operating zone would be eliminated by the addition of the recommended MVP portfolio to the transmission system. Also, it was determined that the need for operating reserve requirements in other zones throughout the MISO footprint would be reduced by half.

The ability to locate reserves at the least-cost location, rather than in a specific zone, will drive a benefit equal to between \$5/MWh and \$7/MWh. These benefits were assumed to grow with load growth, at roughly 1% per year. As a result, the recommended MVP portfolio will create $33 to $116 million in present value benefits.

IN Operating Reserve, no-MVP (MWh)	IN Operating Reserves, with MVP (MWh)	Other Zonal Operating Reserve, no-MVP (MWh)	Other Zonal Operating Reserves, with MVP (MWh)	Total Zonal Operating Reserves, no-MVP	Total Zonal Operating Reserves, with MVP	Nominal Benefits - Low ($M)	Nominal Benefits - High ($M)
359,195	0	354,252	177,126	713,446	177,126	$2.68	$3.75

Table 8.4: 2011 operating reserve reductions and quantification

8.3 System Planning Reserve Margin

The system planning reserve is calculated by determining the amount of generation required to maintain a one day in 10 years Loss of Load Expectation (LOLE). The reserve margin requirement is calculated through summing two components: the unconstrained system Planning Reserve Margin (PRM) and a congestion contribution. The recommended MVP portfolio reduces transmission congestion across MISO, thereby reducing the system PRM and decreasing the amount of generation required to meet the PRM. By reducing the PRM, the recommended MVP portfolio defers new generation, creating present value benefits equal to $1.0 to $5.1 billion in 2011 dollars under business as usual conditions. Results for each set of future scenarios and business case assumptions are shown in Table 8.5.

	20 year NPV		40 year NPV	
	3%	8.20%	3%	8.20%
Business As Usual with Continued Low Demand and Energy Growth	$1,460	$1,023	$1,869	$1,151
Business As Usual with Historic Demand and Energy Growth	$3,811	$1,281	$5,093	$1,496
Combined Energy Policy	$1,610	$971	$2,222	$1,167
Carbon Constraint	$2,145	$1,159	$2,747	$1,309

Table 8.5: Planning Reserve Margin Capacity Reduction

8.3.1 Congestion Impact

Additional transmission investment may ease congestion in the system, reducing the congestion component used to calculate the system PRM and reducing the future capacity required to meet system load. The reduction in system congestion, as calculated through the production cost models as the reduction in congestion costs, was determined to be 21%.

In the 2011 Planning Year LOLE Study Report, it was determined that the system Planning Reserve Margin would begin to increase due to congestion in 2016. Congestion was found to increase by 0.3 percent annually, rising to 1.5 percent by 2020[26] and 4.5 percent by 2030.

The recommended MVP portfolio will decrease this congestion by 21 percent, when the entire portfolio is in-service. The reduction was phased-in to account for the different in-service dates of the various projects in the portfolio, with the congestion reduction starting at 3.5 percent in 2016 and growing linearly to 21 percent by 2021. This congestion reduction was multiplied by the pre-MVP congestion to find the total impact of the recommended MVP portfolio. This resulted in the congestion components shown in Table 8.6.

Year	Pre-MVP Congestion Component [1]	MVP Congestion Reduction Percentage [2]	MVP Congestion Reduction Impact [3]=[1]*[2]	Post-MVP Congestion Component [4]=[1]-[3]
2011	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2012	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2013	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2014	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2015	0.0 percent	0.0 percent	0.0 percent	0.0 percent
2016	0.3 percent	3.5 percent	0.0 percent	0.3 percent
2017	0.6 percent	7.0 percent	0.0 percent	0.6 percent
2018	0.9 percent	10.5 percent	0.1 percent	0.8 percent
2019	1.2 percent	14.0 percent	0.2 percent	1.0 percent
2020	1.5 percent	17.5 percent	0.3 percent	1.2 percent
2021	1.8 percent	21.0 percent	0.4 percent	1.4 percent
2022	2.1 percent	21.0 percent	0.4 percent	1.7 percent
2023	2.4 percent	21.0 percent	0.5 percent	1.9 percent
2024	2.7 percent	21.0 percent	0.6 percent	2.1 percent
2025	3.0 percent	21.0 percent	0.6 percent	2.4 percent
2026	3.3 percent	21.0 percent	0.7 percent	2.6 percent
2027	3.6 percent	21.0 percent	0.8 percent	3.0 percent
2028	3.9 percent	21.0 percent	0.8 percent	3.1 percent
2029	4.2 percent	21.0 percent	0.9 percent	3.3 percent
2030	4.5 percent	21.0 percent	0.9 percent	3.6 percent

Table 8.6: Planning Reserve Margins Congestion Component

[26]For more information, refer to table 5.1 in the Planning Year 2011 LOLE Study Report, at the link below: https://www.misoenergy.org/Library/Repository/Study/LOLE/2011%20LOLE%20Study%20Report.pdf

8.3.2 Planning Reserve Margin Reduction

The uncongested Planning Reserve Margin was set to 17.4 percent for the full study period. This margin was summed with the congestion component, as calculated above, to find the full Planning Reserve Margin Requirement, both with and without the recommended MVP portfolio. Figure 8.6 shows the expected system PRM for 2011 through 2030 accounting for congestion and system PRM relief from the recommended MVP portfolio.

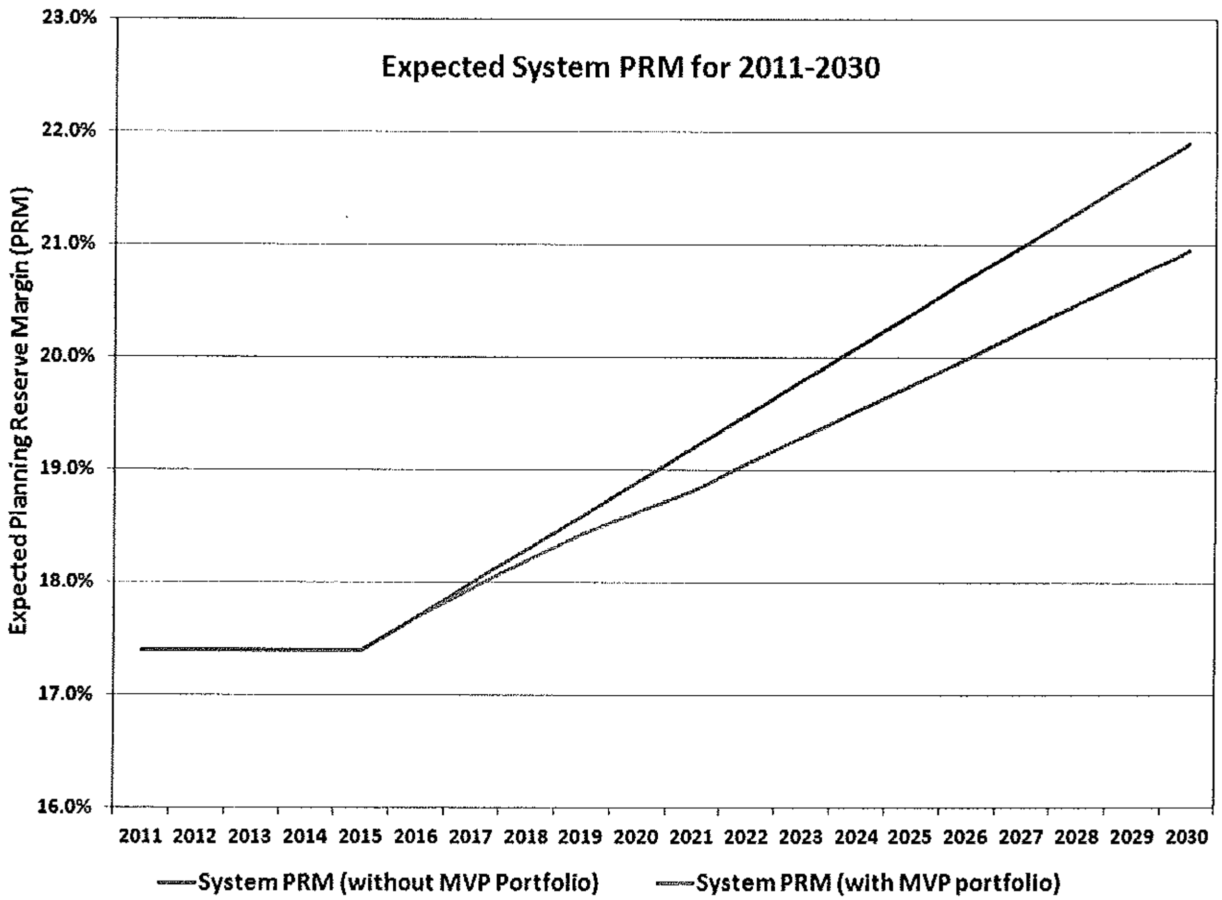


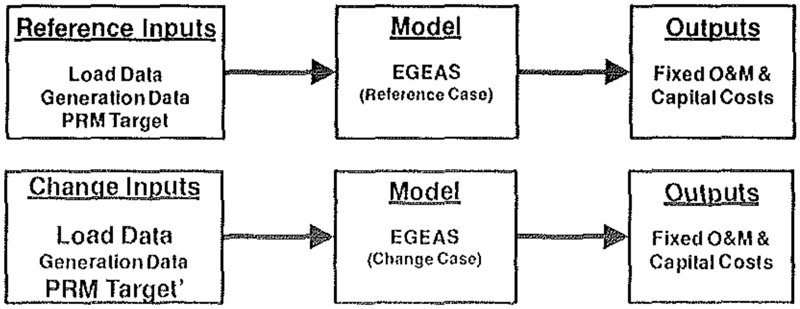
Figure 8.6: Expected System PRM, with and without the recommended MVP portfolio

8.3.3 Deferred Capacity Calculation

Sufficient generation must be built to ensure that, as the system Planning Reserve Margin increases, enough capacity is available to meet the system load and Planning Reserve Margin requirements. A lower PRM will require less future generation investment, resulting in a reduction in required capital outlays.

Electric Power Research Institute (EPRI's) Electric Generation Expansion Analysis System (EGEAS) was used to calculate the capacity benefits from PRM reduction due to transmission investment. The EGEAS model requires load forecast data, existing generation data, planned generation capacity and Planning Reserve Margin target as inputs.

Two series of analyses were run. The first set of analyses, representing the pre-MVP case, contained higher Planning Reserve Margins. The second set of analyses held all the variables constant except for the Planning Reserve Margin, modeling the lower Planning Reserve Margin created by the proposed Multi Value Project portfolio. The difference in the required capacity expansion between the two models is a benefit of the recommended MVP portfolio.



Capacity Cost Savings = Cost $_{\text{Reference Case}}$ - Cost $_{\text{Change Case}}$

Figure 8.7: Capacity cost savings will be calculated by running two EGEAS cases.

EGEAS accurately captures the type and timing of resource additions that would occur with and without the Planning Reserve Margin (PRM) congestion relief. EGEAS outputs unit-by-unit capital fixed charge reports for each of these new capacity additions by year from 2011 through 2030. The capital cost of these capacity projections were then calculated as the 20-year or 40-year present values figures. These benefits include the reduction in annual fixed operations and maintenance charges from deferred capacity, as well as the capital charges from the reduced capacity requirements.

As can be seen in Figure 8.8 below, 400 MW of CT would be deferred by the additional of the recommended MVP portfolio in 2020, and 200 MW would be deferred in 2024. These results were documented for the Business as Usual with continued low demand growth rate future. Similar results were documented for the other futures.

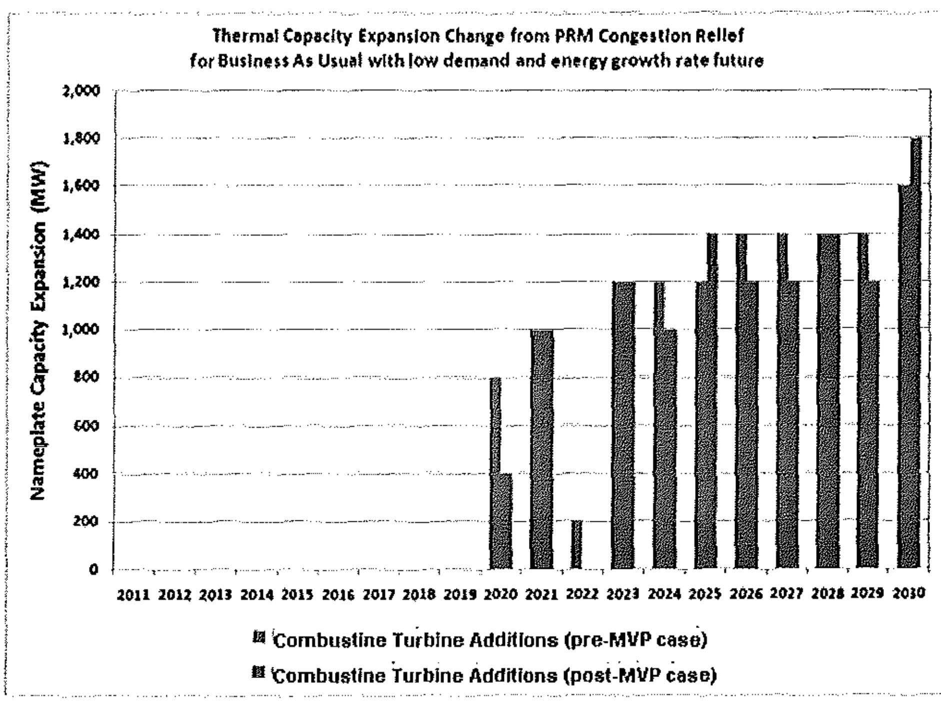


Figure 8.8: Business as Usual capacity expansion results, PRM benefit

8.4 Transmission line losses

The addition of the recommended 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. Specifically, when installed generation capacity is just sufficient to meet peak system load plus the planning reserve margin, a reduction in transmission losses reduces the amount of generation that must be built. This saves $111 million to $396 million in 2011 dollars, excluding the impacts of any potential future policies. Table 8.7 shows the capacity deferral results, depending on the timeline of the present value calculations, the discount rate and future scenarios analyzed.

	20 year NPV		40 year NPV	
	3%	8.20%	3%	8.20%
Business As Usual with Continued Low Demand and Energy Growth	$317	$229	$396	$251
Business As Usual with Historic Demand and Energy Growth	$111	$305	$196	$358
Combined Energy Policy	$655	$525	$834	$532
Carbon Constraint	$737	$229	$749	$248

Table 8.7: Transmission Line Losses Capacity Deferral

8.4.1 Transmission Losses Reduction

The transmission loss reduction was calculated through the PSS/E model. More specifically, the transmission line losses in the MTEP11 2021 summer peak models were compared, both with and without the recommended MVP transmission. This value was then used to extrapolate the transmission line losses for 2016 through 2021, assuming escalation at the normal demand growth rate.

The difference in capital fixed charges and fixed operation and maintenance costs in the reference, or pre-MVP case, and the post-MVP case is equal to the capacity benefit from transmission loss reduction, due to the addition of the recommended MVP portfolio to the transmission system. This capacity benefit was studied for the four MTEP11 future scenarios and observed during the study period (2011-2030). The capital impact of the change in capacity was then captured between 2021-2040 for a 20-year benefit value, and 2021-2060 for a 40-year capacity benefit value. As can be seen in Figure 8.10, 200 MW of CT is deferred in 2020 in the Business As Usual with a Low Demand and Energy Future at 8.2 percent discount rate.

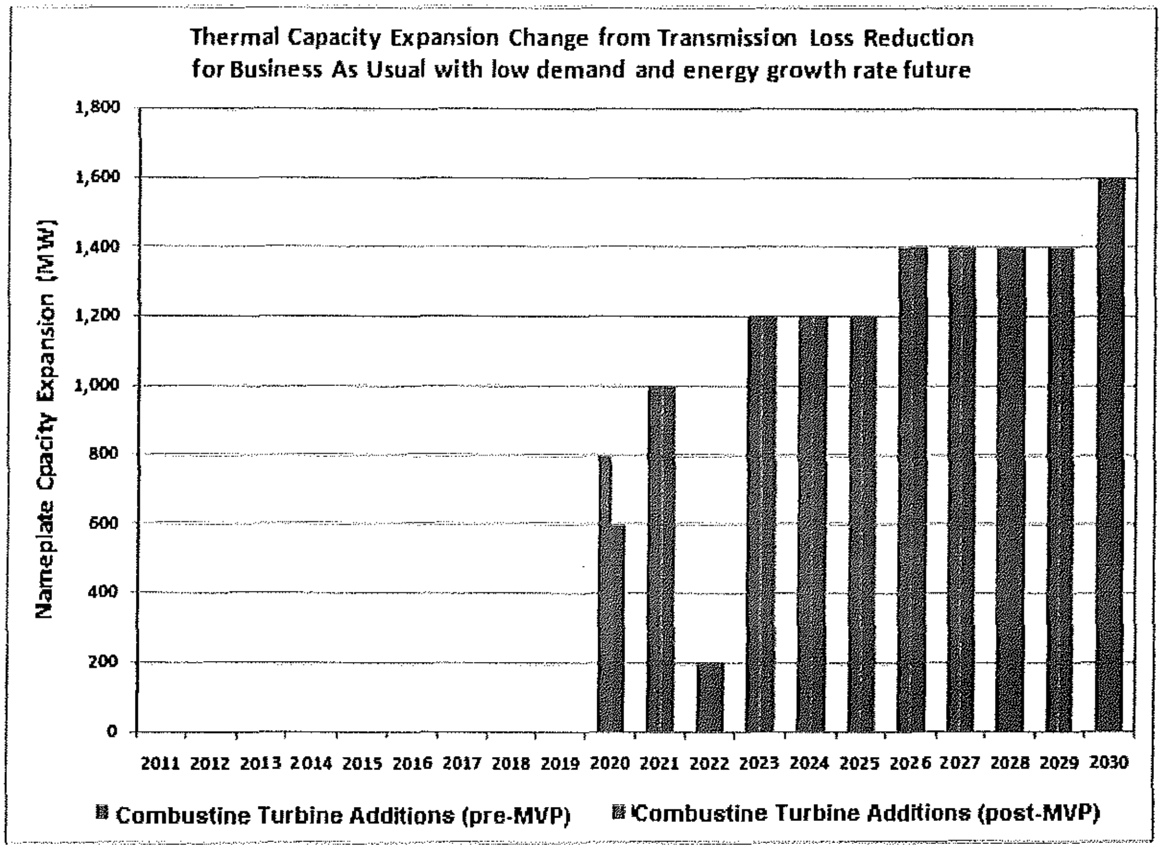


Figure 8.10: Business as Usual with Low Demand and Energy Capacity Additions, pre and post MVP

8.5 Wind turbine investment

As discussed previously, MISO determined 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. However, this strategy depends on a strong regional transmission system to deliver the wind energy. Without this regional transmission backbone, the wind generation would have to be sited close to load, requiring the construction of significantly larger amounts of wind capacity to produce the renewable energy mandated by public policy.

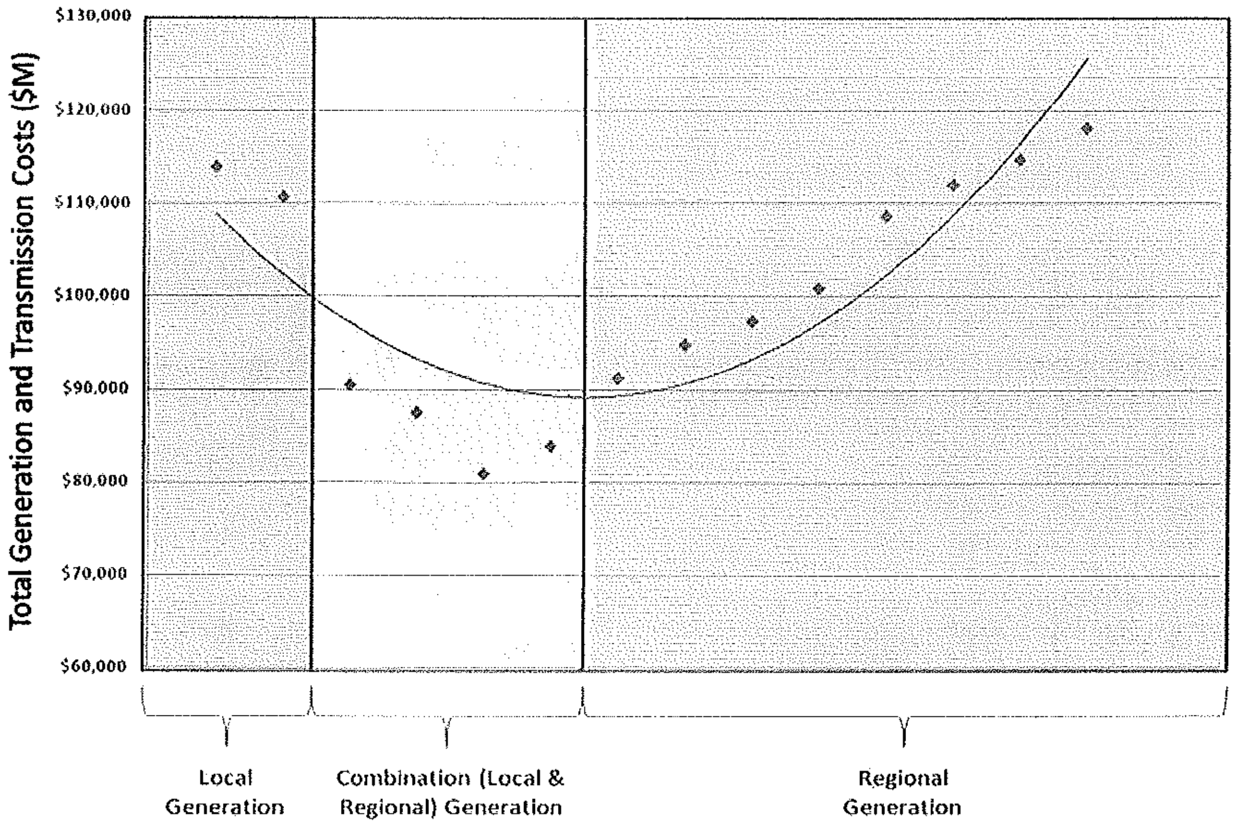


Figure 8.11: Local versus combination wind siting

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 recommended MVP portfolio. This resulted in a total of 2.9 GW of avoided wind generation, as shown in Table 8.8

Year	Recommended MVP Portfolio Enabled Wind (MW)	Equivalent Local Wind Generation (MW)	Incremental Wind Benefit (MW)
Pre-2016	12,408	13,802	1,394
2016	17,276	19,217	547
2021	21,173	23,552	438
2026	23,445	26,079	255
Full Wind Enabled	25,675	28,559	251

Table 8.8: Renewable Energy Requirements, Combination versus Local Approach

The incremental wind benefits were monetized by applying a value of $2.0 to $2.9 million/MW, based on the US Energy Information Administration's estimates of the capital costs to build onshore wind, as updated in November 2010. The total wind enabled benefits were then spread between 2015 and 2030, with half of the pre-2021 values lumped into 2021 for the purpose of this analysis. Also, to avoid 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.

The low cost wind siting methodology enabled by the recommended MVP portfolio creates benefits ranging from a present value of $1.4 to $2.5 billion in 2011 dollars, depending on which business case assumptions are applied.

8.6 Transmission investment

In addition to relieving constraints under shoulder peak conditions, the recommended MVP portfolio will eliminate some future baseline reliability upgrades. A model simulating 2031 summer peak load conditions was created by growing the load in the 2021 summer peak model by approximately 8 GW, and this model was run both with and without the recommended MVP portfolio. The investment avoided through the addition of the recommended MVP portfolio into the transmission system, as determined through this analysis, is shown below in Table 8.9.

Avoided Investment	Upgrade Required	Miles
Galesburg to East Galesburg 138 kV	Bus Tie	N/A
Portage to Columbia 1 138 kV	Transmission line, < 345 kV	6
Portage to Columbia 2 138 kV	Transmission line, < 345 kV	6
Arrowhead to Bear Creek 230 kV	Transmission line, < 345 kV	1
Forbes to 44 Line Tap 115 kV	Transmission line, < 345 kV	1
Stone Lake Transformer 345/161 kV	Transformer	N/A
Port Washington to Saukville Bus 6 138 kV	Transmission line, < 345 kV	5
Port Washington to Saukville Bus 5 138 kV	Transmission line, < 345 kV	5
Ipava South to Macomb West 138 kV	Transmission line, < 345 kV	21
Lafayette Cincinnati St. to Purdue 138 kV	Transmission line, < 345 kV	1
Grace VT7 to Ortonville 115 kV	Transmission line, < 345 kV	25
East Kewanee to Kewanee South Street 138 kV	Transmission line, < 345 kV	0
Cloverdale to Stilesville 138 kV	Transmission line, < 345 kV	13
Wilmarth to Field South 345 kV	Transmission line, 345 kV	29
Dundee Transformer 161/115 KV	Transformer	N/A
Stileville to WVC Valley 138 kV	Transmission line, < 345 kV	6
Lafayette South to Lafayette Shadeland 138 kV	Transmission line, < 345 kV	3
Purdue Nw Junction Tap 1 to Westwood 2 138kV	Transmission line, < 345 kV	3
Plainfield South to WVC Valley 138 kV	Transmission line, < 345 kV	5
Antigo to Aurora Street 115 kV	Transmission line, < 345 kV	2
Latham to Kickapoo 138 kV	Transmission line, < 345 kV	5
Bunker Hill to Black Brook 115 kV	Transmission line, < 345 kV	8
Grace VT7 to Morris 115 kV	Transmission line, < 345 kV	14

Table 8.9: Avoided transmission investment

The cost of this avoided investment was estimated using generic transmission costs, as estimated from projects in the MTEP database. The costs of this transmission investment was estimated to be spread between 2027 and 2031. Also, to represent potential production cost benefits that may be missed through avoiding this investment, the value of avoiding the 345 kV transmission line 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 8.10: Generic transmission costs

The recommended MVP portfolio eliminates the need for baseline reliability upgrades on 23 lines between 2026 and 2031. This creates benefits which have 20 and 40 year present values of $268 and $1,058 million, respectively.

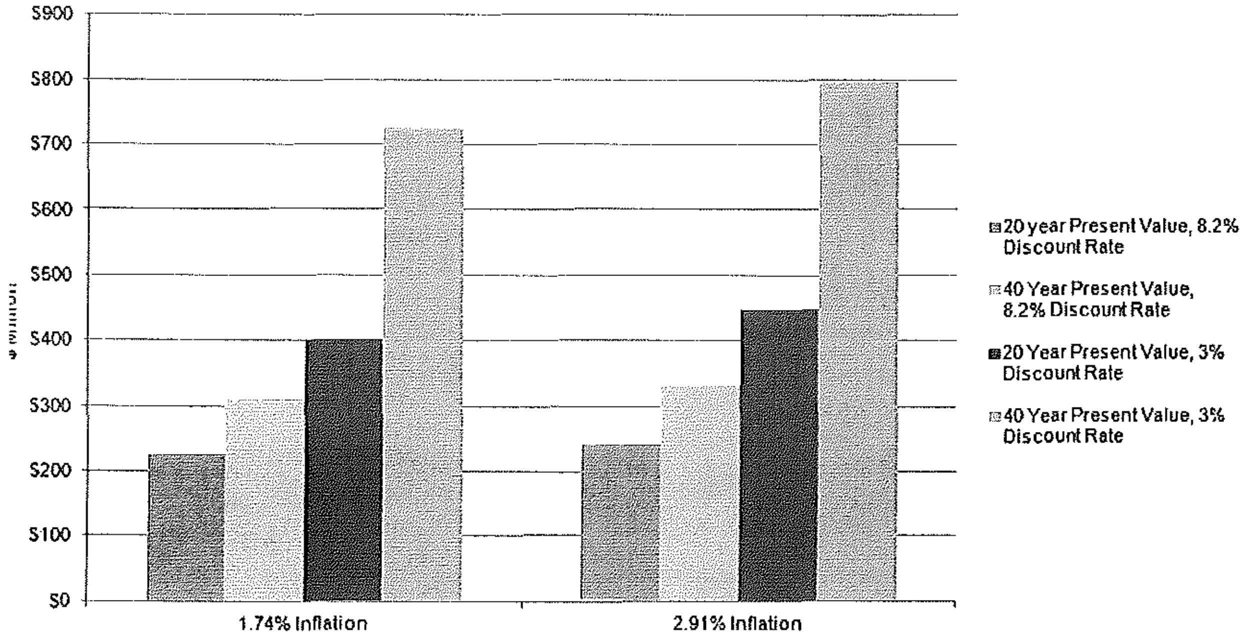


Figure 8.12: Avoided transmission investment

8.7 Business case variables and impacts

The recommended MVP portfolio provides significant benefits under every scenario studied. The base business case was built upon a fixed set of energy policies, with variances in discount rates and time horizons driving the range of benefits. However, additional variables also have the potential to impact the benefits provided by the recommended MVP portfolio.

The most critical variables considered were:

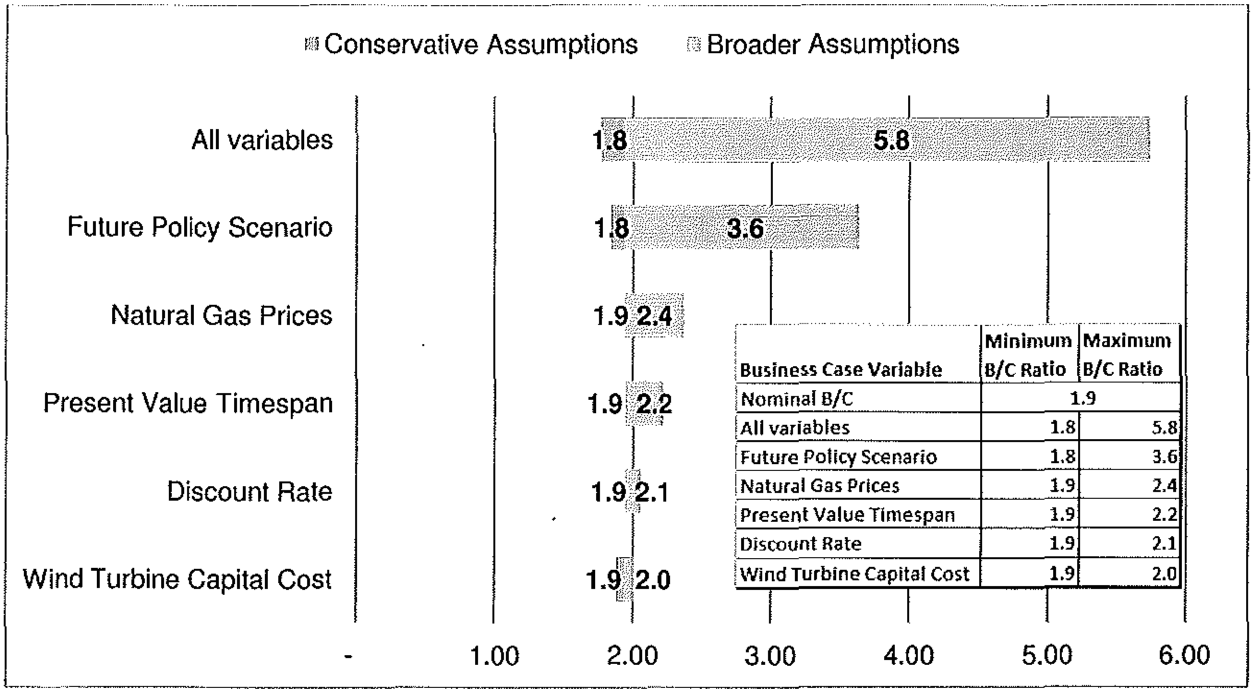
- Future energy policies
  - Includes a range of policy, demand and energy growth assumptions
  - Sensitivities were conducted to determine the impact of a legislated cost of carbon or national renewable energy mandate
- Length of Present Value Calculations: 20 or 40 years from the portfolio's in service date
- Discount Rate: 3 percent or 8.2 percent
- Natural gas prices: $5-$8 (Business as Usual Scenarios)
  $8-$10 (Combination Policy and Carbon Constrained Futures)
- Wind turbine capital cost: 2.0 or 2.9 $M/MW

To calculate the impact of any particular variable on the benefits provided by the recommended MVP portfolio, a series of analyses were performed. These analyses required changing a single variable, then comparing the resulting benefits and costs to a nominal case, which was defined as a 20 year present-value under an 8.2% discount rate. The maximum benefit-cost ratio was determined to be under a 40 year present value, using a 3% discount rate, high natural gas prices, and under the Combination Energy Policy future. The minimum benefit-cost ratio was calculated under a 20-year present value, using an 8.2% discount rate and assuming current economic policies continue under a continued economic recession.

Sensitivity Results ($M)										
	Nominal Benefits	Low Wind Turbine Capital	High Wind Turbine Capital	3% Discount Rate	40 Year Present Values	Future Policy Scenario (Low Demand and Energy Growth)	Future Policy Scenario (Combination Policy)	Natural Gas Price (High)	Maximum Benefit / Cost	Minimum Benefit / Cost
Congestion and Fuel Savings	$16,747	$16,747	$16,747	$25,846	$22,421	$14,740	$37,710	$21,534	$118,011	$14,740
Operating Reserves	$40	$40	$40	$59	$50	$40	$40	$40	$116	$33
Transmission Line Losses	$1,461	$1,461	$1,461	$3,406	$1,680	$272	$699	$1,461	$1,111	$272
System Planning Reserve Margin	$340	$340	$340	$262	$388	$1,216	$1,293	$340	$2,961	$1,216
Wind Turbine Investment	$2,635	$1,936	$3,334	$2,194	$2,635	$2,635	$2,635	$2,635	$2,778	$1,936
Future Transmission Investment	$295	$ 295	$295	$537	$406	$295	$ 295	$ 295	$ 1,058	$268
Total Benefits	$21,518	$ 20,819	$22,217	$32,304	$27,581	$19,198	$42,672	$26,305	$126,035	$18,465
Total Costs	$11,076	$ 11,076	$11,076	$15,699	$12,419	$10,444	$11,709	$11,076	$21,858	$10,444
B/C	1.9	1.9	2.0	2.1	2.2	1.8	3.6	2.4	5.8	1.8

Table 8.11: Recommended MVP portfolio benefits sensitivities

Depending on which variables are assumed, the present value of the benefits created by the entire portfolio can vary between $18.5 and $126.0 billion in 20 to 40 year present value terms. This savings yield benefits ranging from 1.8 to 5.8 times the portfolio cost.



Business Case Variable	Minimum B/C Ratio	Maximum B/C Ratio
Nominal B/C	1.9	
All variables	1.8	5.8
Future Policy Scenario	1.8	3.6
Natural Gas Prices	1.9	2.4
Present Value Timespan	1.9	2.2
Discount Rate	1.9	2.1
Wind Turbine Capital Cost	1.9	2.0

Figure 8.13: Benefit – cost variations due to business case assumptions

It should be noted that the benefits of the portfolio do not depend upon the implementation of any particular future energy policy to exceed the portfolio costs. Under existing energy policies, a conservative discount rate of 8.2 percent and 20 year present value terms, the portfolio produces benefits that are 1.8 times its cost. However, if other energy policies or enacted, or a lower discount rate is used, this benefit has the potential to greatly increase.

9 Qualitative and social benefits

The previous sections demonstrated that the recommended MVP portfolio provides widespread economic benefits across the MISO system. However, these metrics do not fully quantify the benefits of the portfolio. Other benefits, based on qualitative or social values, are discussed in the next section. These sections suggest that the quantified values from the economic analysis may be conservative because they do not account for the full potential benefits of the portfolio.

9.1 Enhanced generation policy flexibility

Although the recommended MVP portfolio was primarily evaluated on its ability to reliably deliver energy required by the renewable energy mandates, the portfolio will provide 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 as shown in Figure 9.1.

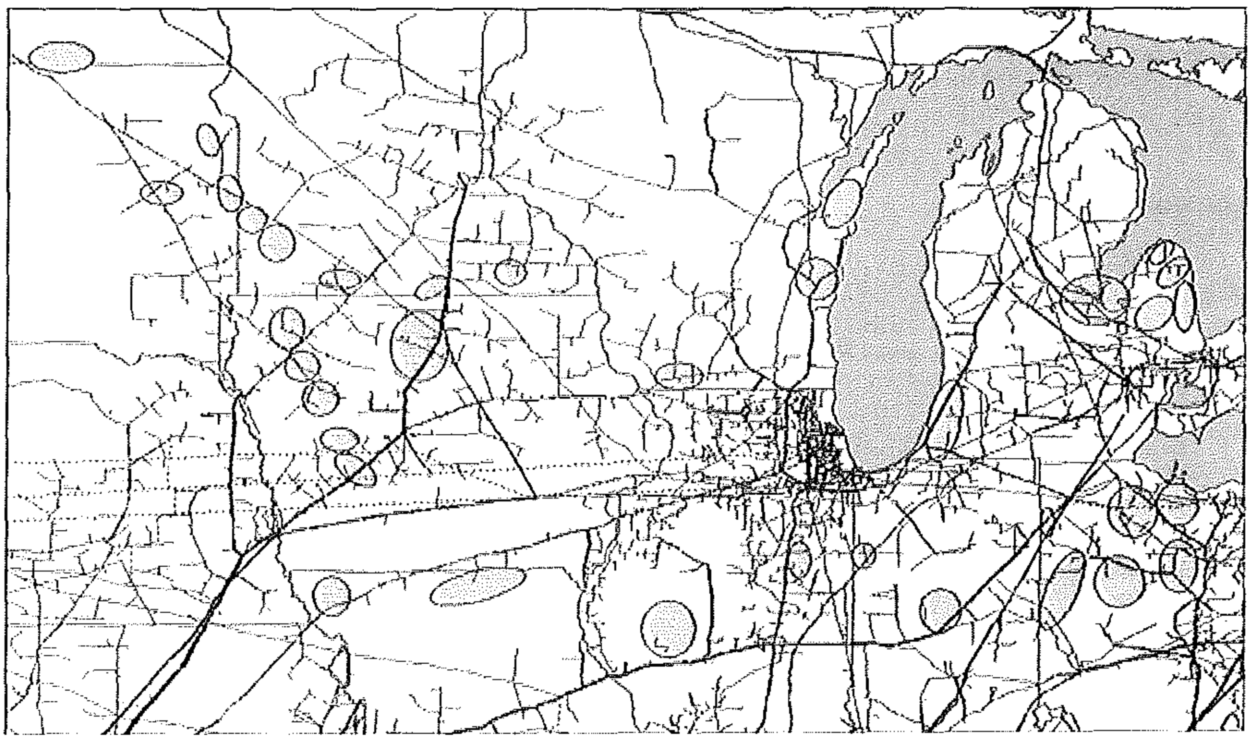


Figure 9.1: Energy zone correlation with natural gas pipelines

9.2 Increased system robustness

A transmission system blackout, or similar event, can have wide spread repercussions, resulting in billions of dollars of damage. The blackout of the Eastern and Midwestern U.S. during August 2003 affected more than 50 million people and had an estimated economic impact of between \$4 and \$10 billion.[27]

The recommended MVP portfolio creates a more robust regional transmission system which 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.

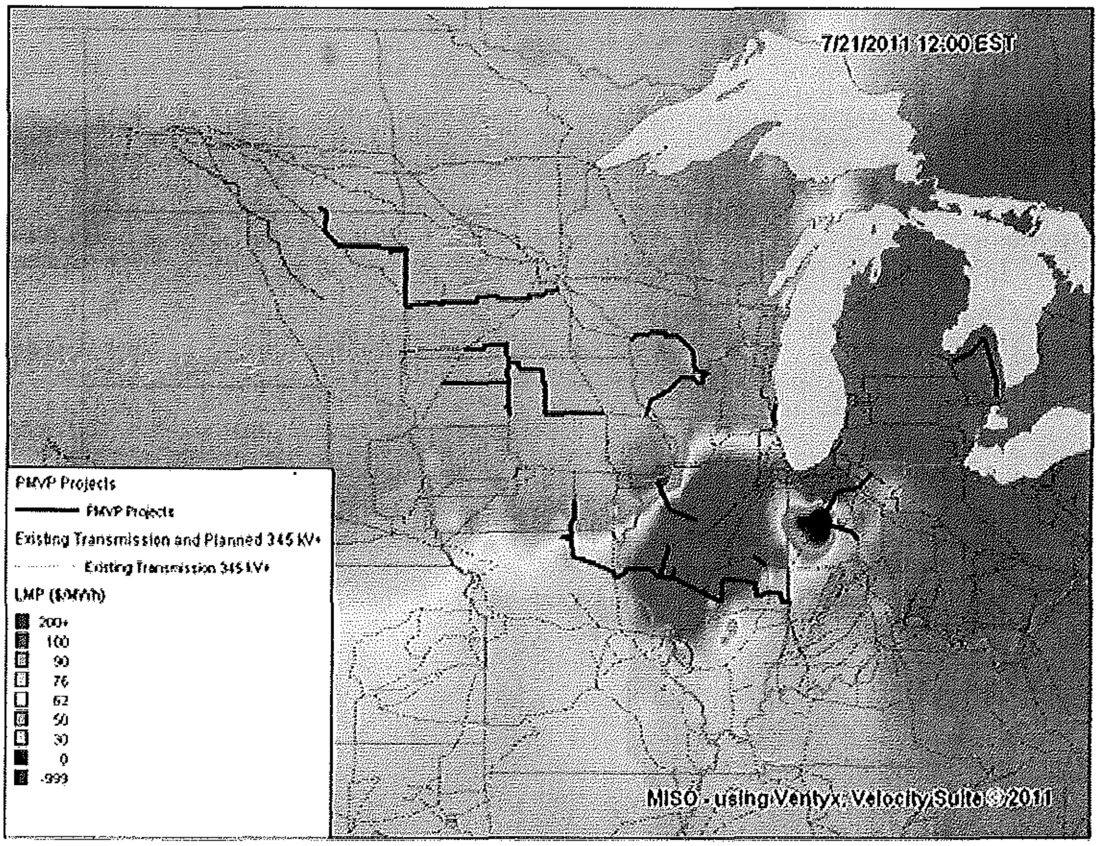


Figure 9.2: June 2011 LMP map with recommended MVP portfolio overlay

For example, the recommended MVP portfolio will allow the system to respond more efficiently during high load periods. During the week of July 17, 2011, high load conditions existed in the eastern portion of the MISO footprint, while the western portion of the footprint experienced lower temperatures and loads. Thermal limitations on west to east transfers across the system limited the ability of low cost generation from the west to serve the high load needs in the east, as shown in Figure 9.2. The recommended MVP portfolio will increase the transfer capability across the system, allowing access to additional generation resources to offset the impact and cost of severe or emergency conditions.

[27] Data sourced from: *The Economic Impacts of the August 2003 Blackout*, The Electricity Consumers Resource Council (ELCON)

9.3 Decreased natural gas risk

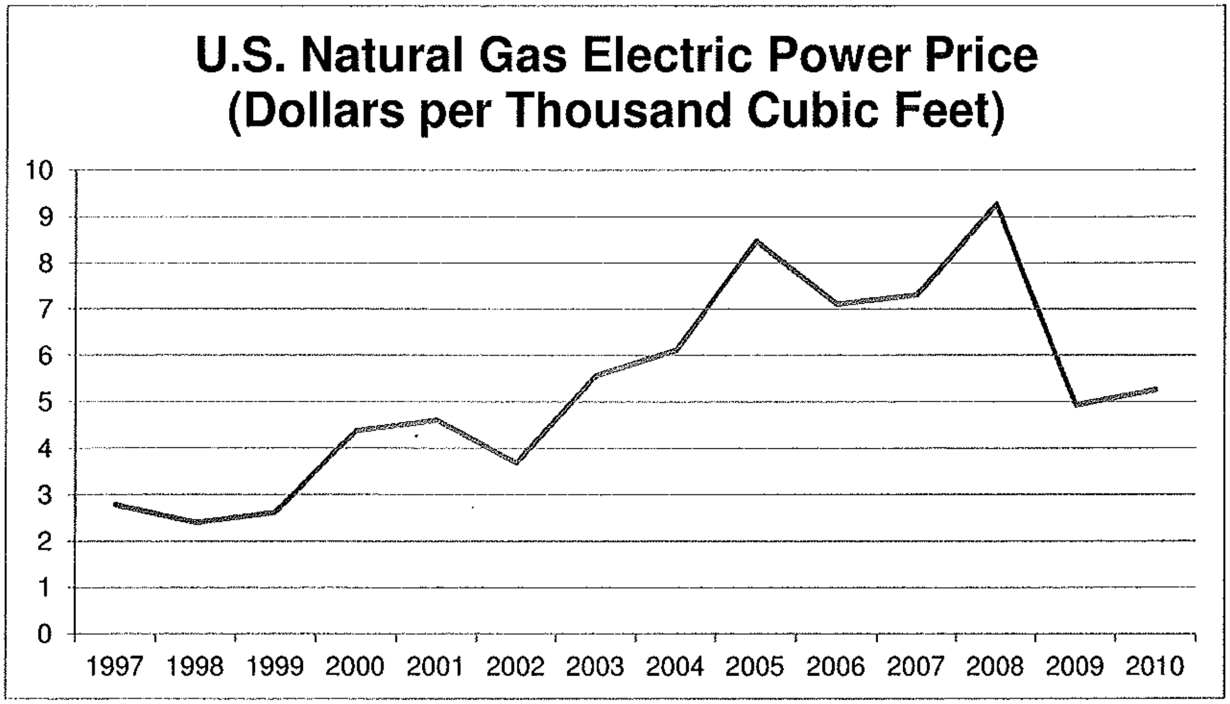


Figure 9.3: Historic U.S. natural gas electric power prices

Natural gas prices vary widely, causing corresponding fluctuations in the cost of energy from natural gas. Also, recent Environmental Protection Agency (EPA) regulations and proposed 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 as demand increases. The recommended MVP portfolio can partially offset the natural gas price risk by providing additional access to generation that uses fuels other than natural gas (e.g. nuclear, wind, solar and coal) during periods with high natural gas prices. Assuming a natural gas price increase of 25 percent to 60 percent, the recommended MVP portfolio provides approximately a 5 to 40 percent higher adjusted production cost benefits.

9.3.1 Sensitivity Assumptions

A set of sensitivity analyses were performed in PROMOD to quantify the impact of changes in natural gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the base business case analyses, except for the gas prices. The gas prices were increased from \$5 to \$8/MMBtu under the Business as Usual policy scenarios, and they were increased from \$8 to \$10/MMBtu under the Carbon Constrained and Combined Energy Policy scenarios. For each future scenario, the gas prices were increased starting in year 2011 and escalated by inflation thereafter.

9.3.2 Production cost benefit impact

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 recommended MVP portfolio. These increased benefits were driven by the efficient usage of renewable and low cost generation resources, as shown in

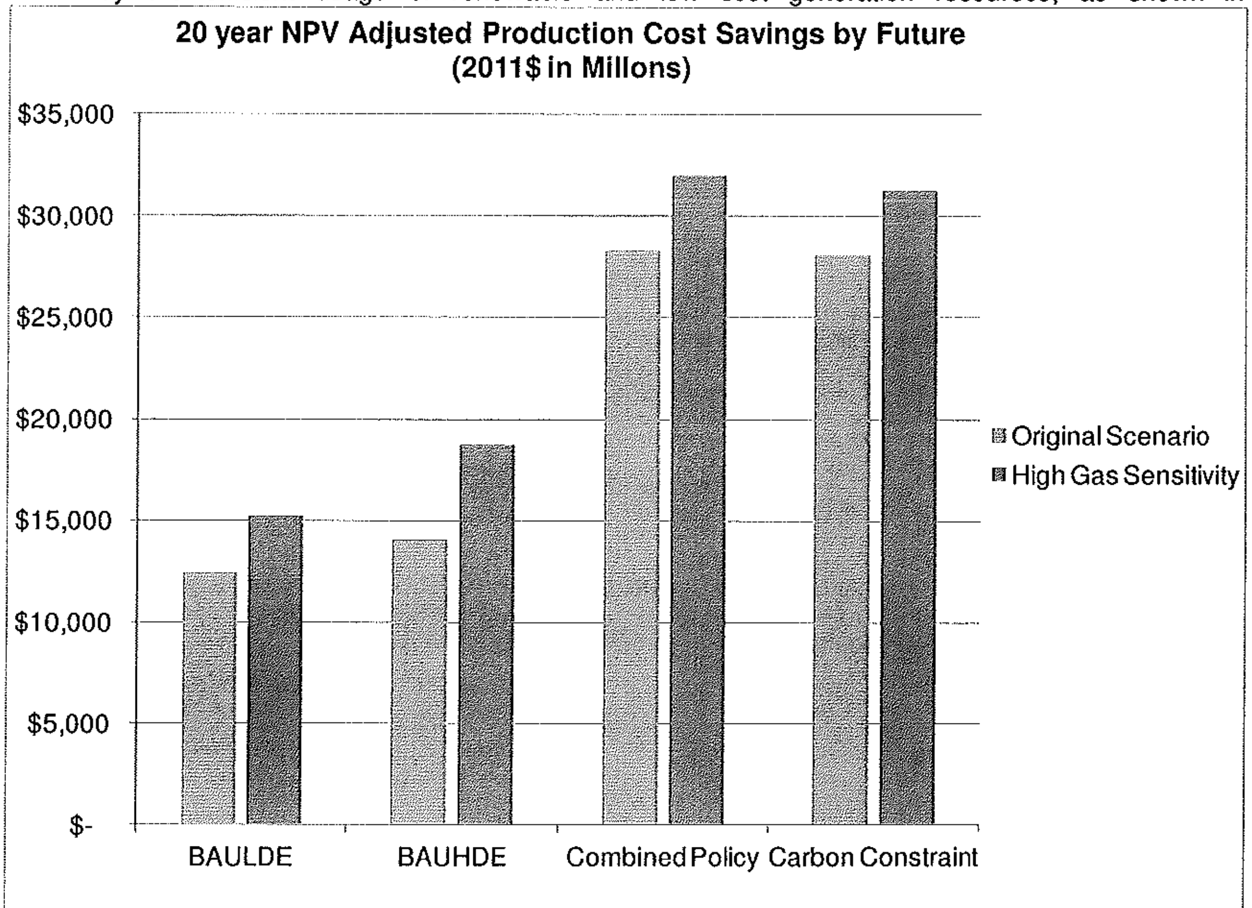


Figure 9.4.

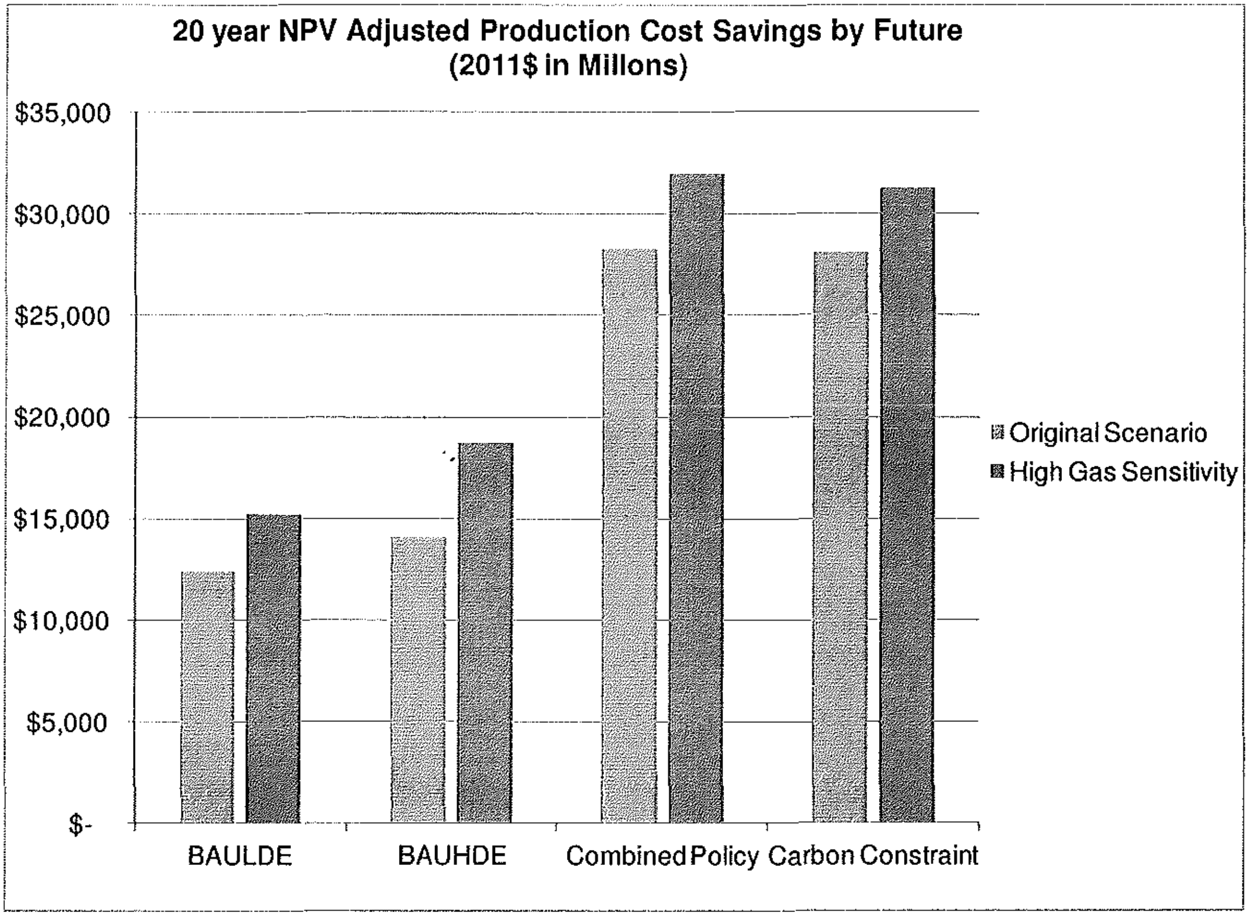


Figure 9.4: Recommended MVP Portfolio Adjusted Production Cost savings by future

9.3.3 Market price impact

The increase in market prices, or Locational Marginal Pricing (LMPs), was also calculated through the PROMOD sensitivities. The LMP is driven by the characteristics of the generation fleet and congestion on the system. With a $2-$3 increase in natural gas prices, the generation weighted average LMP increased by an average value of $7/MWh under a range of policy scenarios.

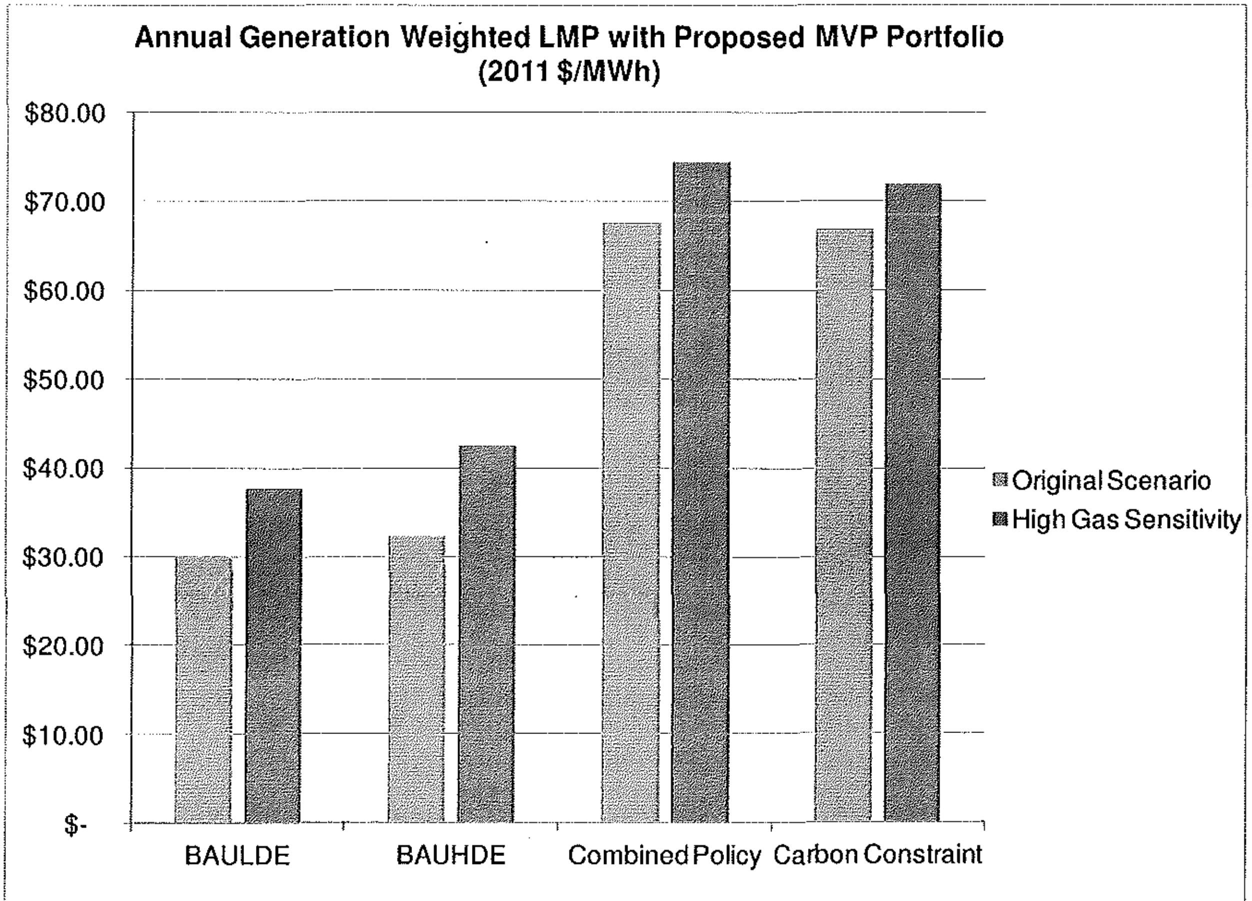


Figure 9.5: Annual generation weighted LMP with recommended MVP portfolio

9.4 Decreased wind generation volatility

As the geographical distance between wind generation increases, the correlation in the wind output decreases. This 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 recommended MVP portfolio will increase the geographic diversity of wind resources that can be delivered, increasing the average wind output available at any given time.

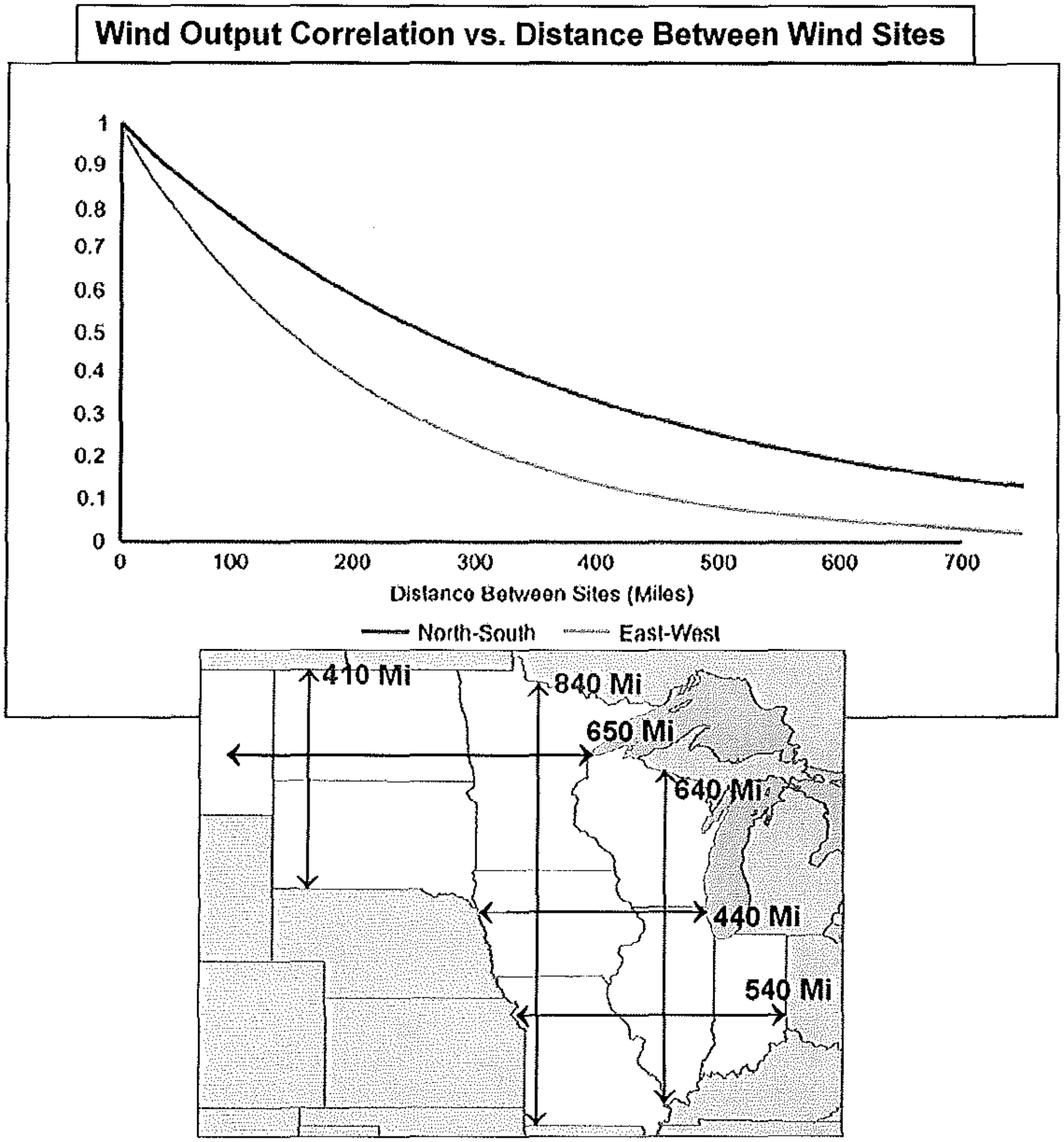


Figure 9.6: Wind Output correlation to distance between wind sites

9.5 Local investment and job creation

In addition to the direct benefits of the recommended MVP portfolio, studies have shown the indirect economic benefits of transmission investment. They estimated that, for each million dollars of transmission investment:

- Between $0.2 and $2.9 million of local investment is created.
- Between 2 and 18 employment years are created.[28]

The wide variations in these numbers are primarily due to the extent to which materials, equipment and workers can be sourced from a 'local' region. For example, each million dollars of local investment supports 11 to 14 employment years of local employment, as compared to 2 to 18 employment years which are created for non-location specific transmission investment.

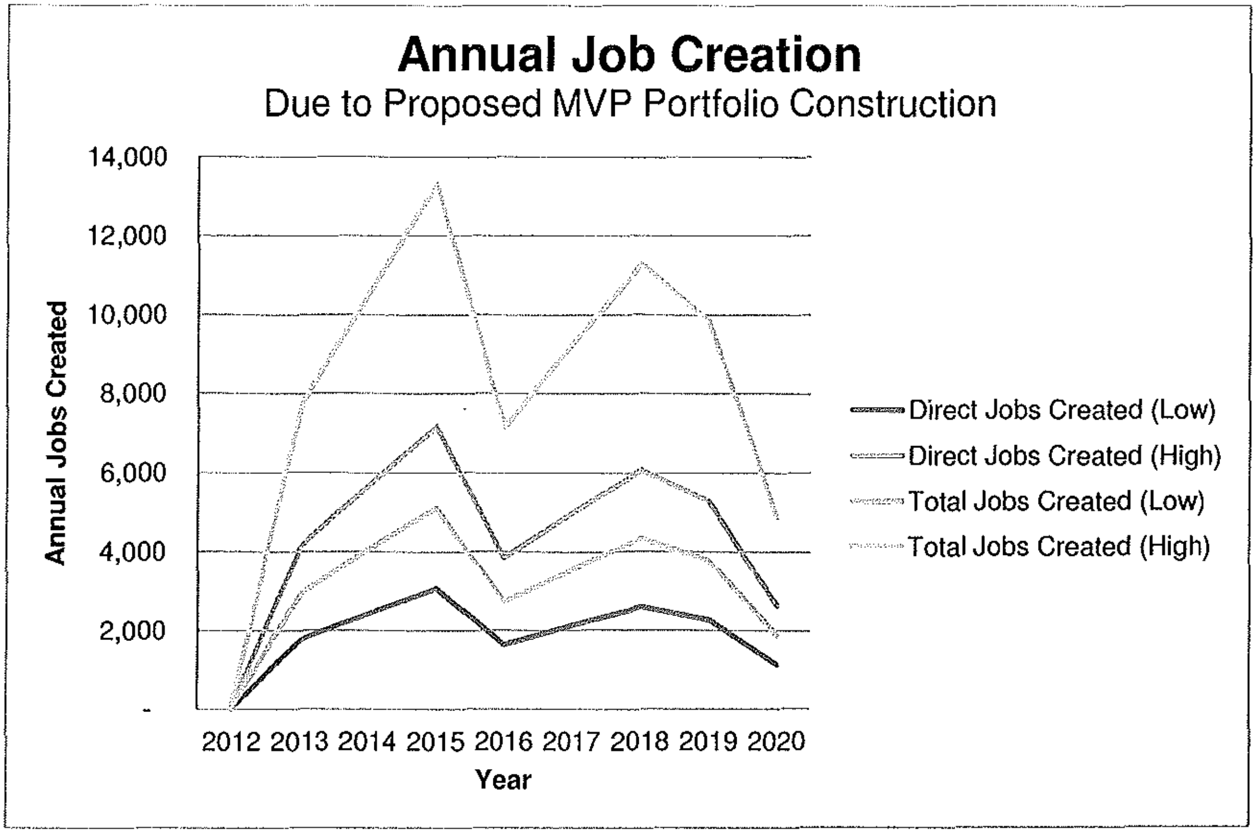


Figure 9.7: Annual Job Creation by Recommended MVP Portfolio

The recommended MVP portfolio supports the creation of between 17,000 and 39,800 local jobs, as well as $1.1 to $9.2 billion in local investment. This calculation is based upon a creation of $0.3 to $1.9 million local investment and 3 to 7 employment years per million of transmission investment. It also assumes that the capital investment for each MVP occurred equally over the 3 years prior to the project's in-service date.

[28] Source: *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, The Brattle Group

9.6 Carbon reduction

With the recommended MVP portfolio delivering significant amounts of wind energy across MISO and the neighboring regions, carbon emissions were reduced because of the more efficient usage of the generation fleet with conventional generation resources displaced by wind. Figure 9.8 summarizes the carbon emission reductions in million tons for each scenario with a range of 8.3 to 17.8 million tons annually.

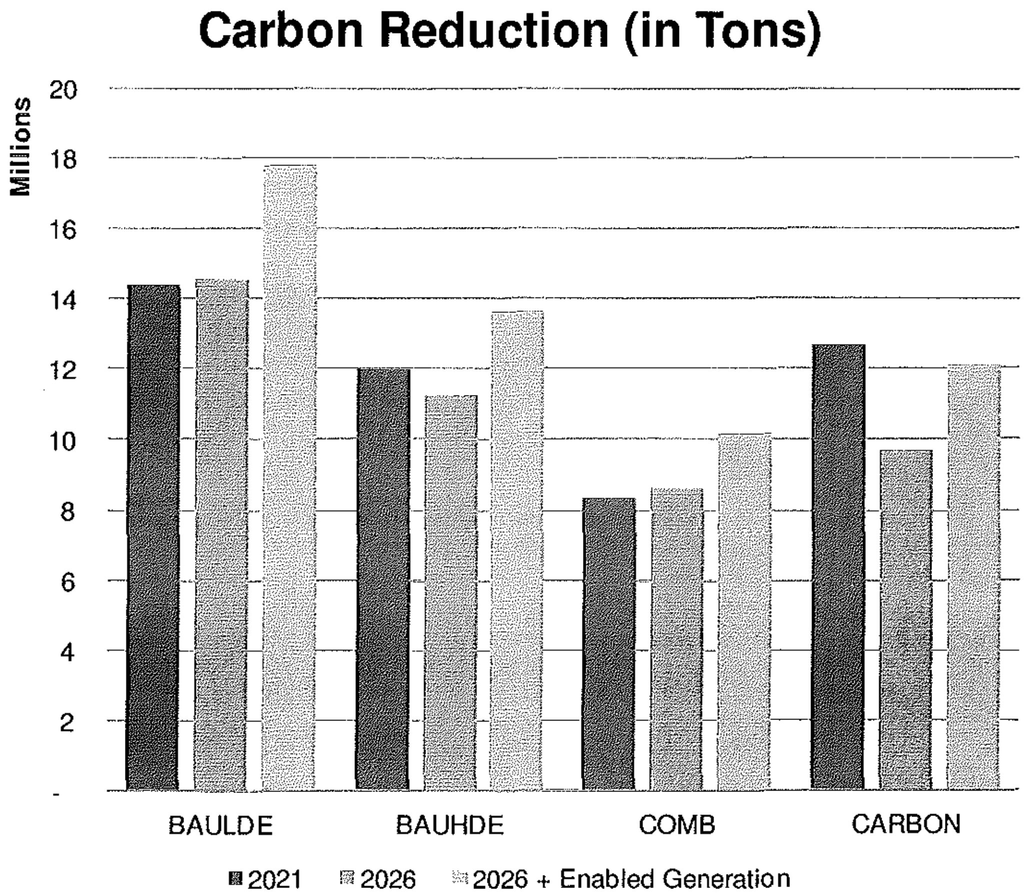


Figure 9.8: Carbon reduction by scenario

For the Combined Energy Policy and Carbon Constrained future scenarios, a $50/ton carbon cost was included to meet aggressive carbon reduction targets, as required by the proposed Waxman-Markey legislation. If policies were enacted that mandate a financial cost of carbon, the benefits provided by the recommended MVP portfolio would increase by between $3.8 and $15.4 billion in 20 and 40 year present value terms respectively, as depicted in Figure 9.9.

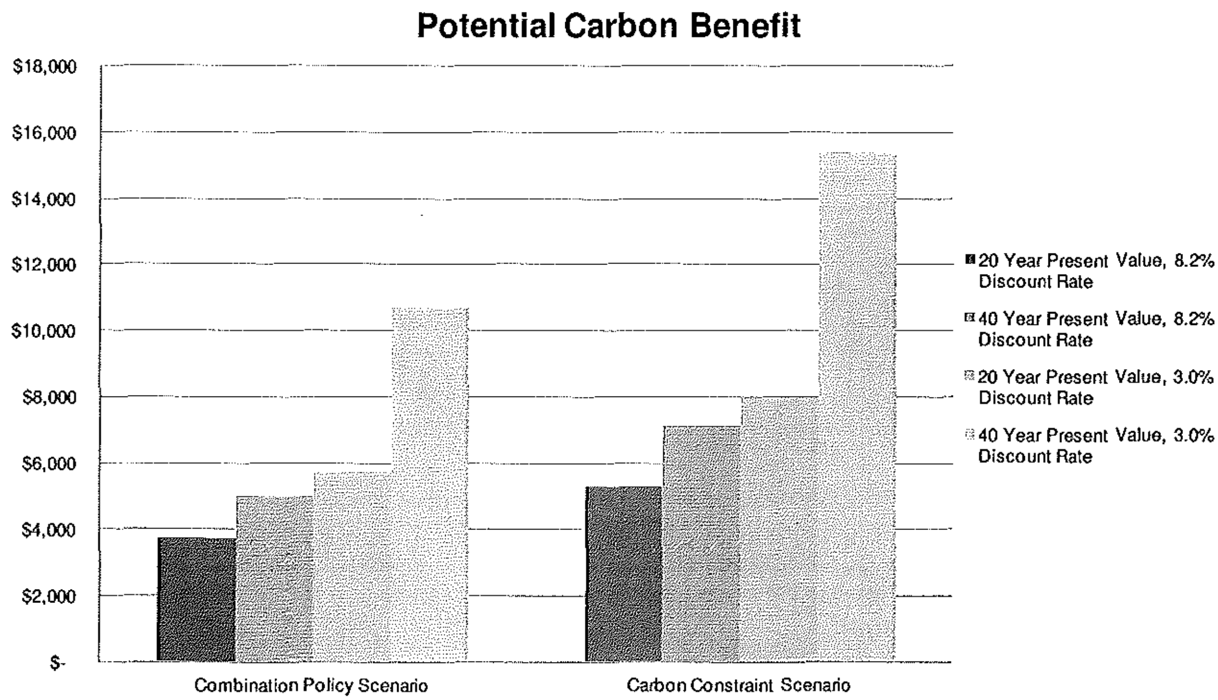


Figure 9.9: Potential carbon benefits

10 Proposed Multi Value Project Portfolio Overview

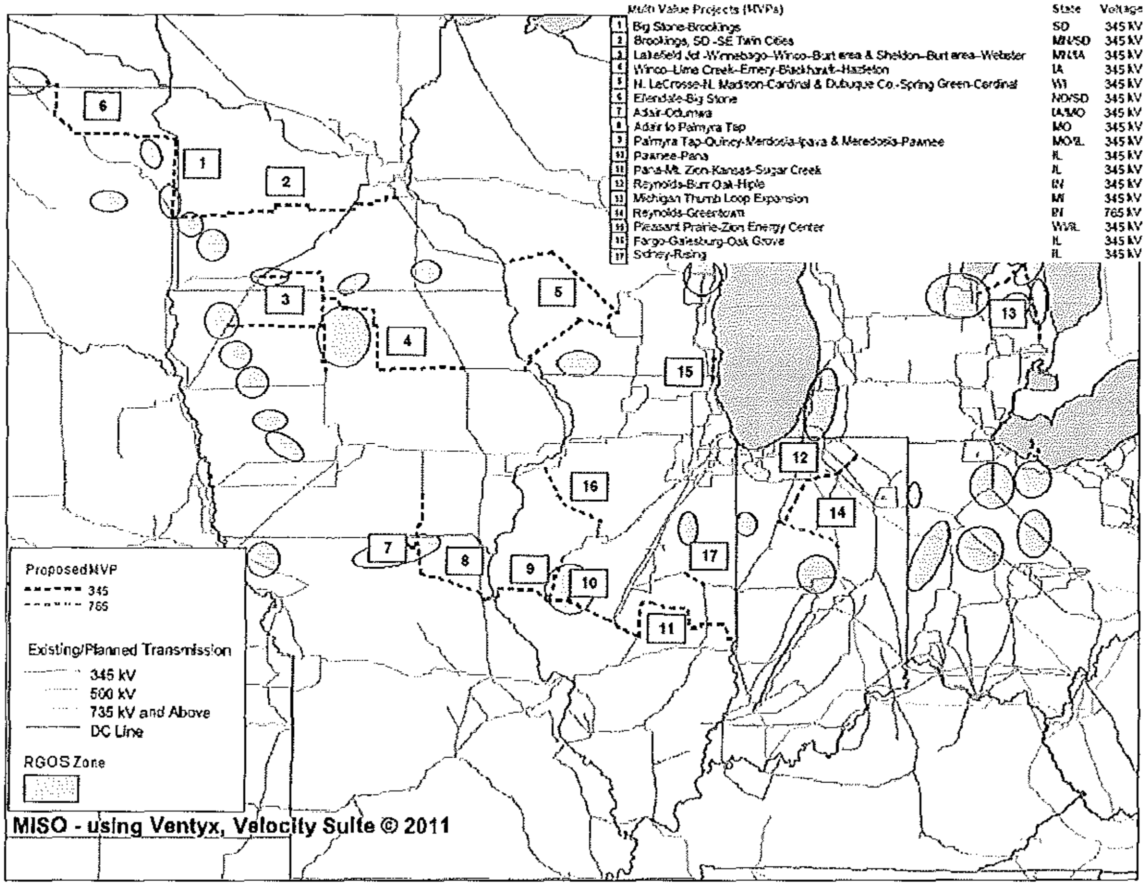


Figure 10.1: 2011 recommended MVP portfolio

The recommended MVP portfolio consists of 17 projects spread across the MISO footprint. These projects work together with the existing transmission network to enhance the reliability of the system, support public policy goals and enable a more efficient dispatch of market resources. Table 10.1 describes the projects that make up the recommended MVP portfolio.

	Project	State	Voltage (kV)	In Service Year	Cost (M, 2011$)[29]
1	Big Stone–Brookings	SD	345	2017	$191
2	Brookings, SD–SE Twin Cities	MN/SD	345	2015	$695
3	Lakefield Jct. Winnebago–Winco–Burt area & Sheldon–Burt area–Webster	MN/IA	345	2016	$506
4	Winco–Lime Creek–Emery–Black Hawk–Hazleton	IA	345	2015	$480
5	N. LaCrosse–N. Madison–Cardinal & Dubuque Co.–Spring Green–Cardinal	WI	345	2018/2020	$714
6	Ellendale–Big Stone	ND/SD	345	2019	$261
7	Adair–Ottumwa	IA/MO	345	2017	$149
8	Adair–Palmyra Tap	MO/IL	345	2018	$98
9	Palmyra Tap–Quincy–Merdosia–Ipava & Meredosia–Pawnee	IL	345	2016/2017	$392
10	Pawnee–Pana	IL	345	2018	$88
11	Pana–Mt. Zion–Kansas–Sugar Creek	IL/IN	345	2018/2019	$284
12	Reynolds–Burr Oak–Hiple	IN	345	2019	$271
13	Michigan Thumb Loop expansion	MI	345	2015	$510
14	Reynolds–Greentown	IN	765	2018	$245
15	Pleasant Prairie–Zion Energy Center	WI/IL	345	2014	$26
16	Fargo–Galesburg-Oak Grove	IL	345	2018	$193
17	Sidney–Rising	IL	345	2016	$76
	Total				$5,180

Table 10.1: Recommended MVP portfolio

[29] Costs shown are inclusive of transmission underbuild upgrades and upgrades driven by short circuit requirements.

10.1 Underbuild requirements

To ensure that the recommended MVP portfolio works well with the existing system to maintain reliability, MISO conducted analyses to determine any constraints that are present with the recommended MVP portfolio and not present without the portfolio. Any new constraints were identified for mitigations, and the appropriate mitigation was determined in coordination with the impacted Transmission Owners.

Below is a full list of the underbuild upgrades. These upgrades were identified through the steady state reliability analyses, using both off peak and peak models. No additional upgrades were identified through the stability analyses. Overall, approximately $70 million of transmission investment is associated with the underbuild upgrades.

Underbuild requirements
Burr Oak to East Winamac 138 kV line uprate[30]
Lake Marian 115/69 kV transformer replacement
Arlington to Green Isle 69 kV line uprate
Columbus 69 kV transformer replacement
Casey to Kansas 345 kV line uprate
Lake Marian to NW Market Tap 69 kV line uprate
Franklin 115/69 kV transformer replacements
Castle Rock to ACEC Quincy 69 kV line uprate
Kokomo Delco to Maple 138 kV line uprate
Wabash to Wabash Container 69 kV line uprate
Spring Green 138/69 kV transformer replacement
Davenport to Sub 85 161 kV line uprate
West Middleton West Towne 69 kV line uprate
Ottumwa Montezuma 345 kV line uprate

Table 10.2: Recommended MVP portfolio underbuild requirements

[30] Burr Oak to East Winamac upgrade also identified as part of the Meadow Lake wind farm upgrades.

10.2 Portfolio benefits and cost spread

A key principle of the MISO planning process is that the benefits from a given transmission project must be spread commensurate with its costs. The MVP cost allocation methodology distributes the costs of the portfolio on a load ratio share across the MISO footprint, so the recommended MVP portfolio must be shown to deliver a similar spread of benefits.

Each economic business case metric calculated for the full recommended MVP portfolio was analyzed to determine how it would accrue to stakeholders across the footprint. These results were then rolled up to a zonal level, based on the proposed Local Resource Zones for Resource Adequacy. This level of detail was chosen to provide stakeholders with an understanding of the benefits spread, without getting into a detail level which may be falsely precise due to the impact of individual stakeholder actions on actual benefit spreads.

The allocation of each of the economic metrics is discussed in more detail below.

10.2.1 Congestion and Fuel Savings

The Production Cost model simulations return results at a granular, generator-specific level. These results were then rolled up from this detailed level to a zonal level.

10.2.2 Operating Reserve Benefits

The costs of Operating Reserves were allocated across the footprint on a load-ratio share basis. This distribution matches the allocation of these costs through the MISO Energy and Ancillary Service markets. As such, although certain areas in the footprint may see reductions in the Operating Reserves they must hold within their area, the benefits of the more economic dispatch of these resources will be shared by the full MISO footprint.

10.2.3 System Planning Reserve Margin Benefits

The benefits accruing from the reduction in the system Planning Reserve Margin (PRM) were distributed across the footprint on a load-ratio share basis. This allocation was selected due to the widespread nature of the system PRM; the reduced planning margin will apply to all load in the MISO system, reducing the capacity needs for the full system.

10.2.4 Transmission Line Loss Benefits

The benefits accruing from the reduction in transmission line losses were allocated across the footprint on a load-ratio share basis. This approach reflects the integrated nature of the transmission system, as the market allows generation to be transported large distances to remote load. This integrated nature is enhanced by the inclusion of the recommended MVP portfolio into the transmission system, as congestion is reduced, and transfer capacity is increased, across the system.

10.2.5 Wind Turbine Investment

The benefits of reducing the required investment in wind turbines are not applicable for areas that do not have either renewable energy mandates or goals that can be sourced from outside the area. This benefit is also enhanced for areas with lower wind capacity factors, as the differential in wind turbine investment is substantially higher for these areas than for those with, on average, higher wind speeds. As a result, this benefit was allocated to the zones through a weighted average of the renewable energy mandates or needs that can be sourced outside of the zone, along with the relative wind capacity factors, when compared to the system's highest wind speed area.

Zone	Average Capacity Factor	Capacity Factor Differential From System Maximum	Average Out-of-State Renewable Mandates or Goals (%)	Out-of-State Renewable Generation Mandates or Goals (MW)	2026 Projected Load (GWh)	Out-of-State Renewable Generation Mandates or Goals (GWh)	Renewable Generation Weighted by Capacity Factor Differential	Zonal Allocation
1	38%	5%	28%		108,371	29,927	1,446	19%
2	28%	16%	10%		80,267	8,027	1,260	16%
3	36%	8%	N/A	3,000	55,648	9,338	716	9%
4	28%	16%	18%		60,063	11,087	1,730	22%
5	33%	10%	14%		55,485	7,788	809	10%
6	29%	14%	9%		143,528	13,013	1,833	24%
7	28%	15%	0%		119,017	-	-	0%

Table 10.3: Wind Turbine Investment Allocation[31]

[31] All values shown in the table exclude in-state renewable energy goals or mandates.

10.2.6 Future Transmission Investment

Higher voltage Baseline Reliability Projects (BRPs), under Attachment FF of the MISO Tariff, are allocated as a mixture of system wide costs and local costs. More specifically, 20% of the costs of the transmission upgrades are allocated across the system, and 80% of the project costs are allocated to affected pricing zones.

The benefits accruing from the ability of the recommended MVP portfolio to avoid future Baseline Reliability Project investment was allocated using this methodology.

10.2.7 Costs Distribution

The costs of the portfolio were allocated across the footprint on a load-ratio share basis, as required by the Multi Value Project cost allocation methodology. Additional information on the distribution of the costs of the Multi Value Project portfolio may be found in the following section, section 10.3.

10.2.8 Zonal Benefit-Cost Ratio

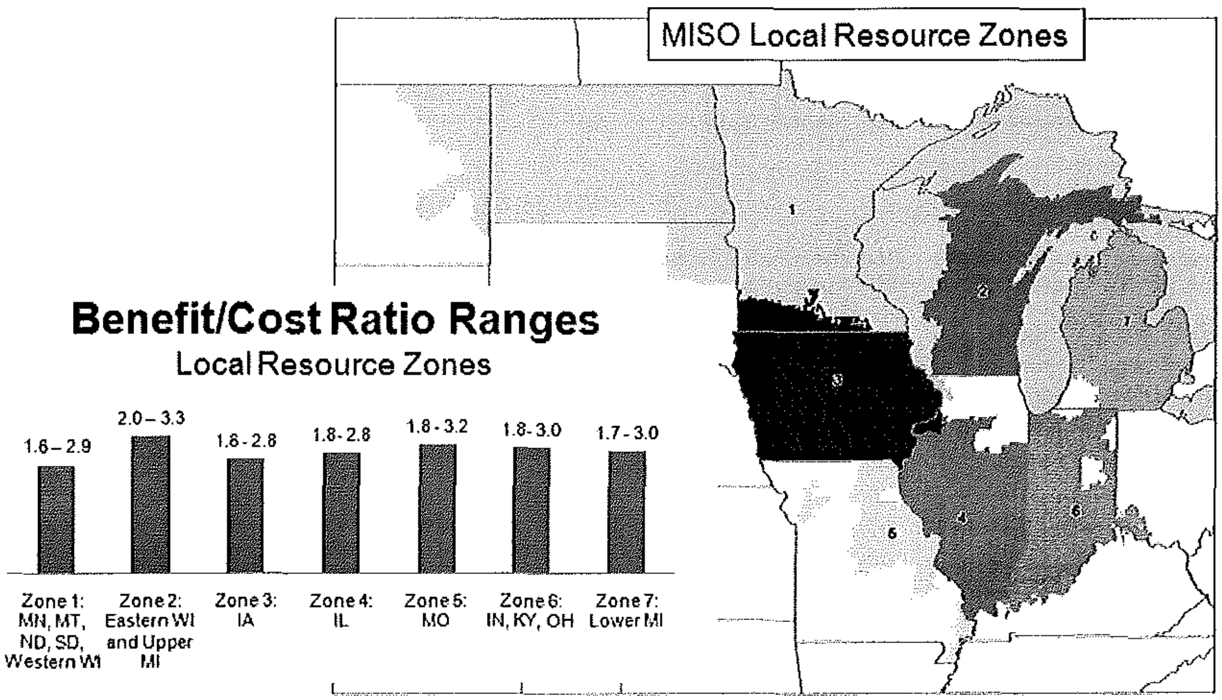


Figure 10.2: Recommended MVP portfolio production cost benefits spread

The recommended MVP portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to its costs allocation. For each of the local resource zones, as shown in Figure 10.2, the portfolio's benefits are at least 1.6 to 2.9 times the cost allocated to the zone.

10.3 Cost allocation

Multi Value Projects represent a new project type eligible for cost sharing effective since July 16, 2010, and conditionally accepted by the Federal Energy Regulatory Commission on December 16, 2010. Multi Value Projects provide numerous benefits, including, improved reliability, reduced congestion costs, and meeting public policy objectives.

> The costs of Multi Value Projects will have a 100 percent regional allocation and will be recovered from customers through a monthly energy usage charge calculated using the applicable MVP Usage Rate.

The proposed Multi Value Project portfolio described in this report includes the Michigan Thumb Loop project, approved in August 2010; the Brookings to Minneapolis-St. Paul project, conditionally approved in June 2011; and 15 additional projects being proposed to the MISO Board of Directors for approval in December 2011. The cost of the recommended MVP portfolio in 2011 dollars is $5.2 billion, including the $1.2 billion in projects that have previously been approved or conditionally approved by the MISO Board of Directors. See Table 10.1 for individual project costs.

The costs of Multi Value Projects will have a uniform 100 percent regional allocation based on withdrawals and will be recovered from customers through a monthly energy usage charge. This charge will apply to all MISO load, excluding load under Grandfathered Agreements, and also to export and wheel-through transactions not sinking in PJM.

Figure 10.3 shows a 40-year projection of indicative annual MVP Usage Rates based on the recommended MVP portfolio using current year cost estimates and estimated in-service dates. Additional detail on the indicative MVP Usage Rate, including indicative annual MVP charges by Local Balancing Authority, is included in Appendix A-3 of the MTEP11 report.

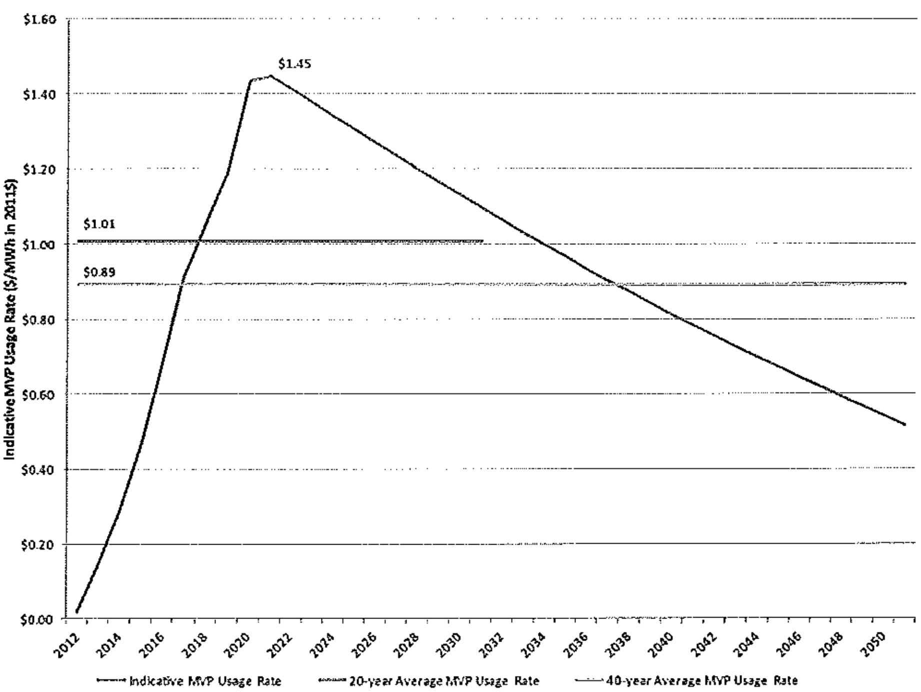


Figure 10.3: Indicative MVP usage rate for recommended MVP portfolio from 2012 to 2051

11 Conclusions and recommendations

MISO staff recommends the recommended MVP portfolio to the MISO Board of Directors for their review and approval. This recommendation is premised on the ability of the portfolio to meet MVP criterion 1, as each project in the portfolio 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.

The recommendation is also supported by the strong economic benefits of the portfolio, which delivers a large amount of value in excess of costs under all conditions and policy scenarios studied. Furthermore, these benefits are spread across the MISO footprint, in a manner commensurate with the allocation of the portfolio's costs.

MISO

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.

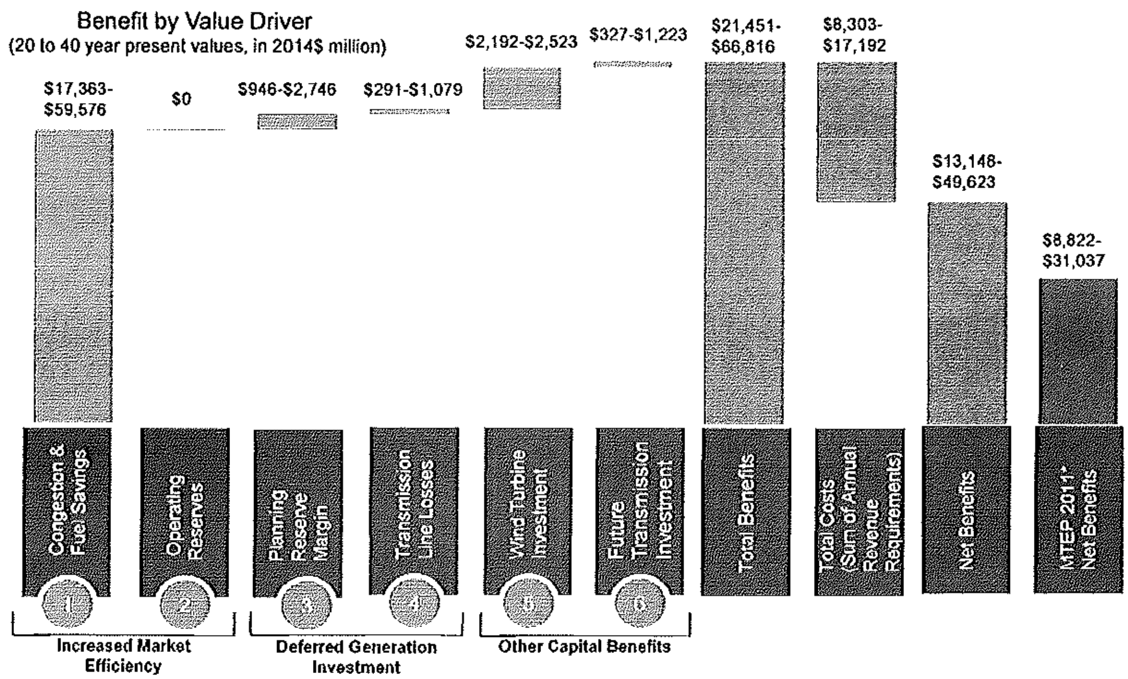


Figure E-1: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

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).

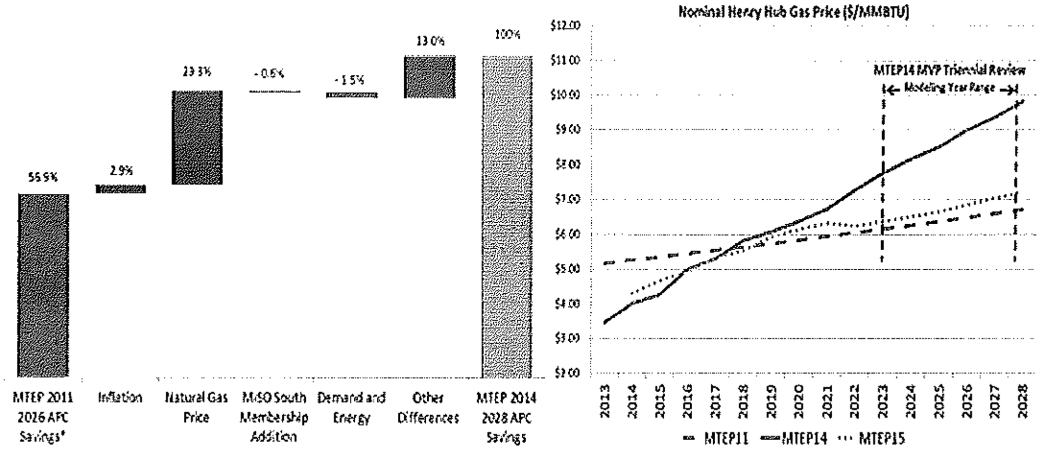


Figure E-2: Breakdown of Congestion and Fuel Savings Increase from MTEP11 to MTEP14

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

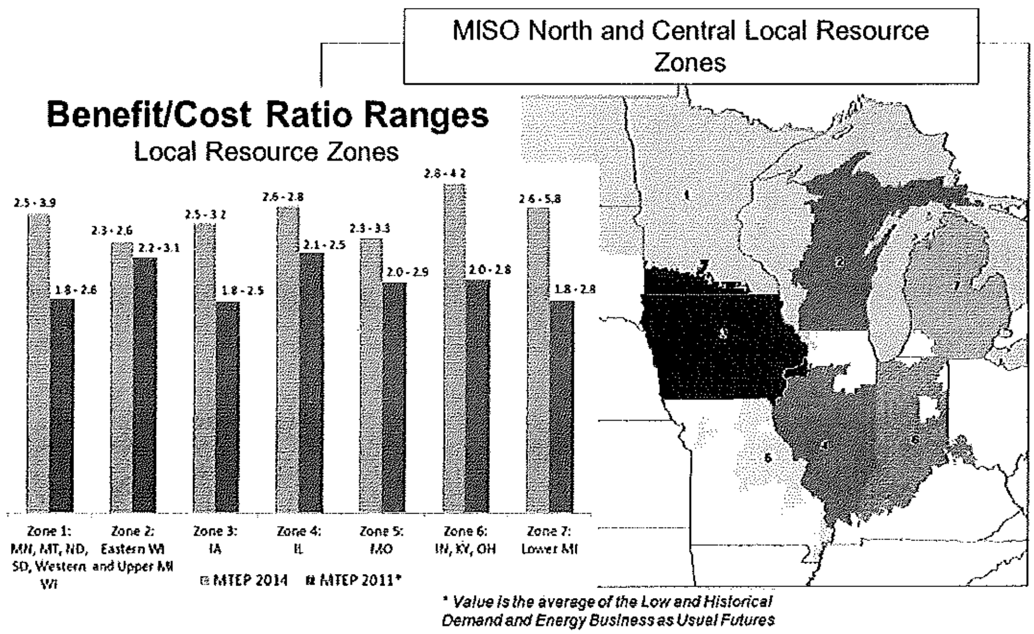


Figure E-3: MVP Portfolio Total Benefit Distribution

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.

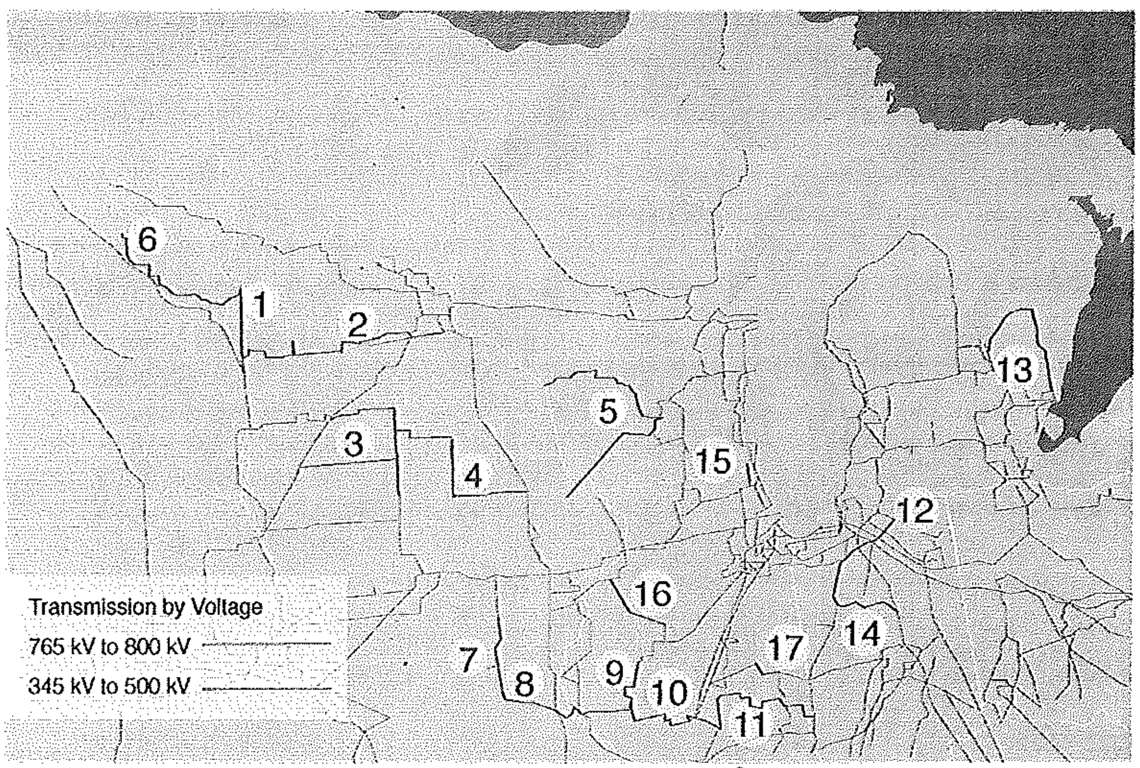


Figure 2-1: MVP Portfolio[3]

[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.

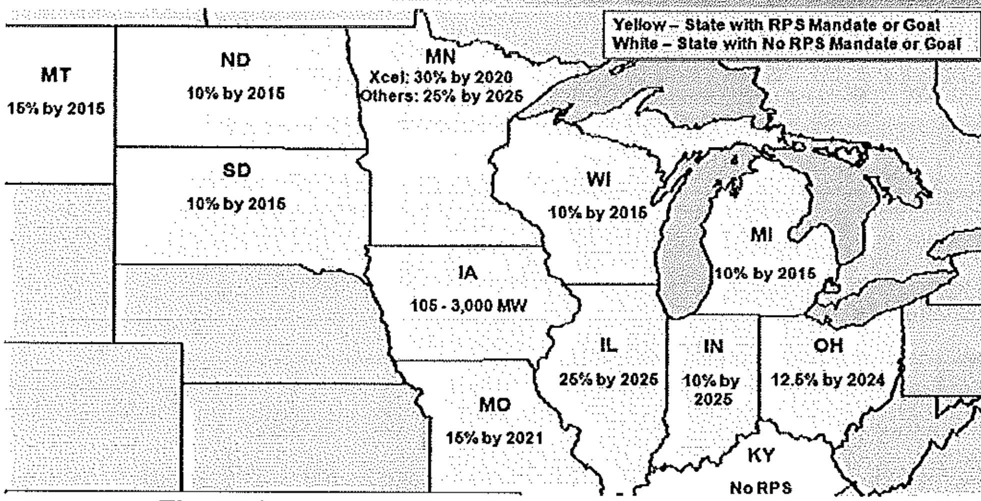


Figure 2-2: Renewable Portfolio Standards - 2011

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).

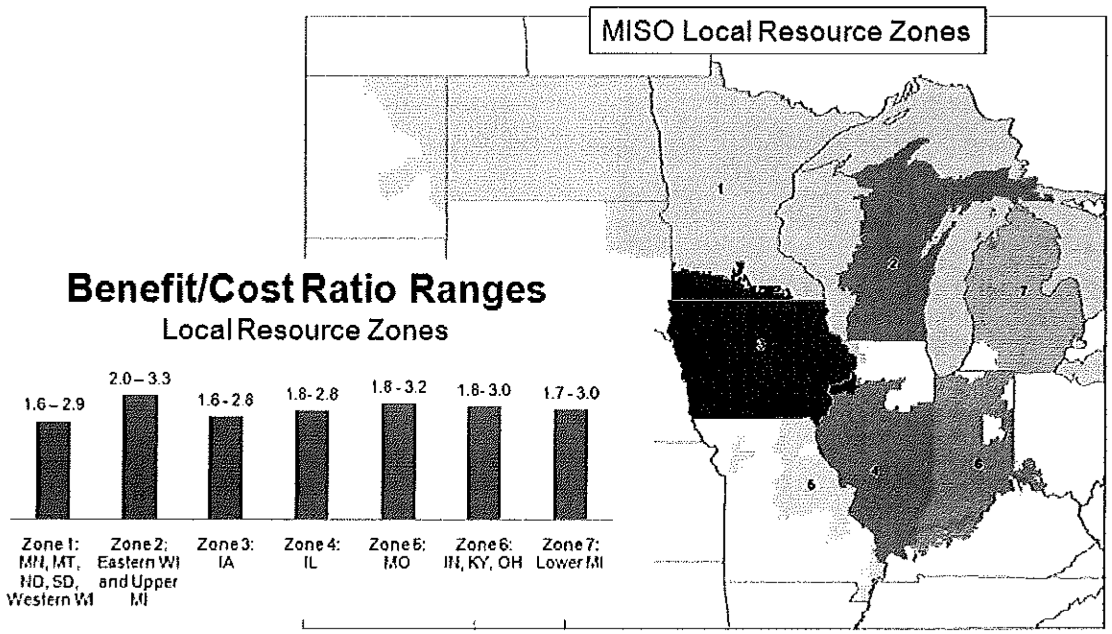


Figure 2-3: MTEP11 MVP Portfolio Benefit Spread

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.

[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.

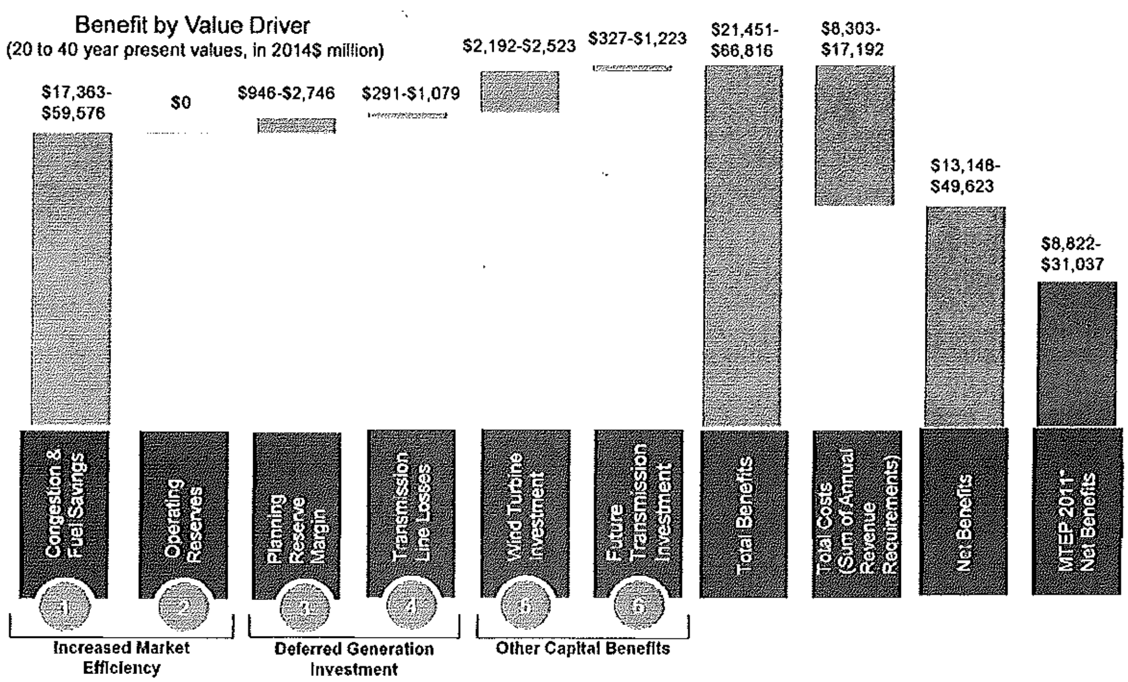


Figure 6-1: MVP Portfolio Economic Benefits from MTEP14 MVP Triennial Review

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.

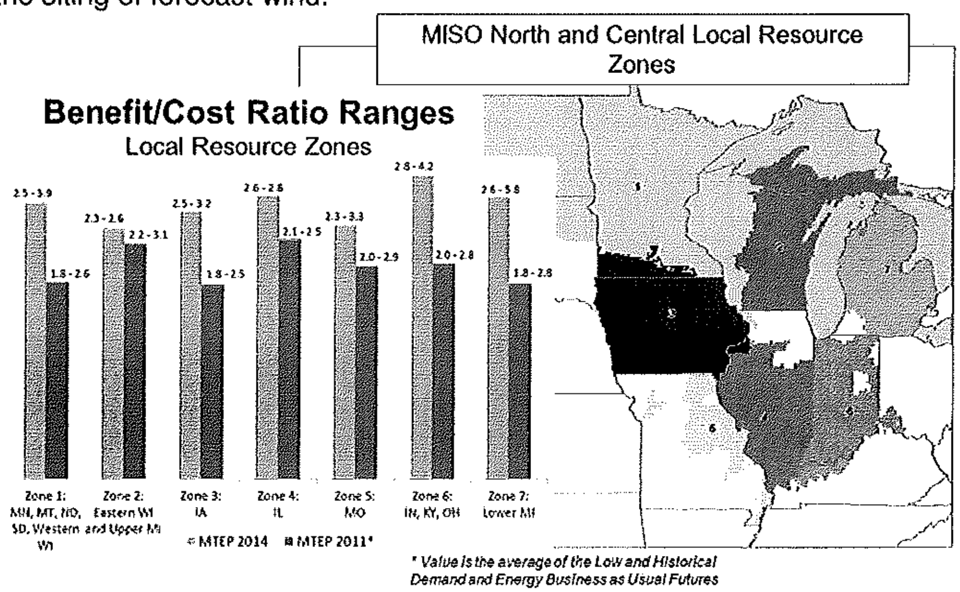


Figure 6-2: MVP Portfolio Production Cost Benefit Spread

[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.

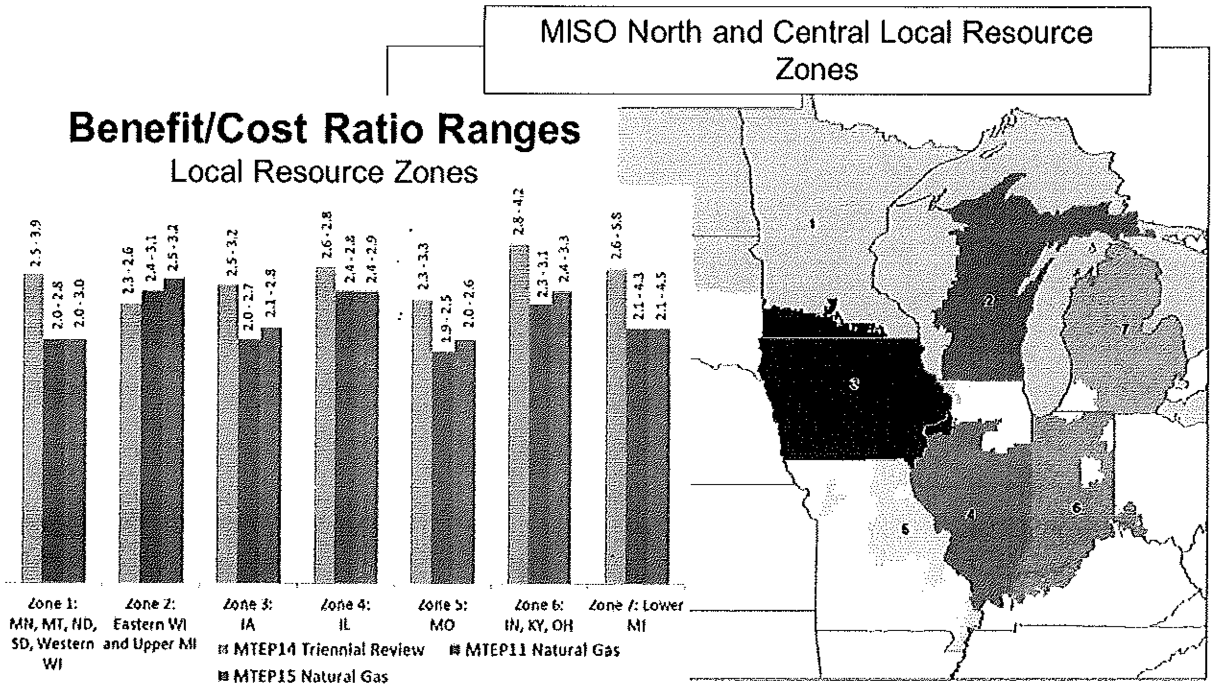


Figure 6-3: MVP Portfolio Production Cost Benefit Spread – Natural Gas Price Sensitivities[11]

[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.

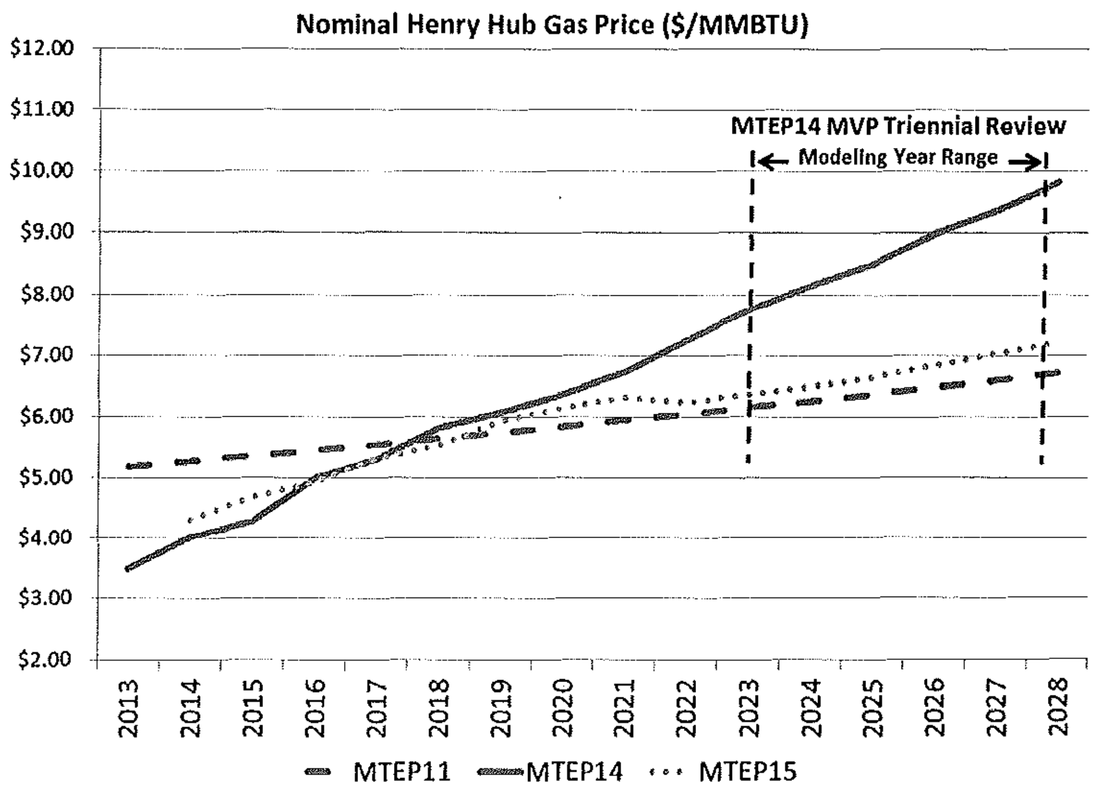


Figure 6-4: Natural Gas Price Forecast Comparison

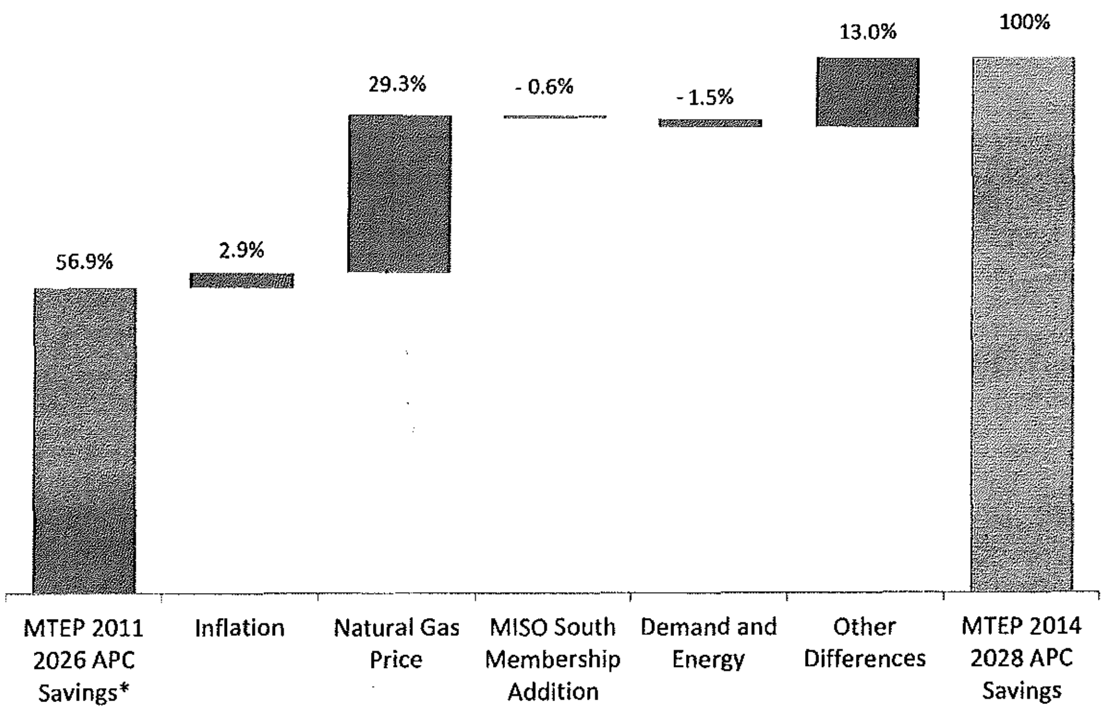
MISO membership changes have little net effect on benefit-to-cost ratios. For example if Duke Ohio/Kentucky and First Energy's benefits and costs are either both included or excluded the benefit-to-cost ratio calculation yields similar results. The exclusion of Duke Ohio/Kentucky and First Energy from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

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

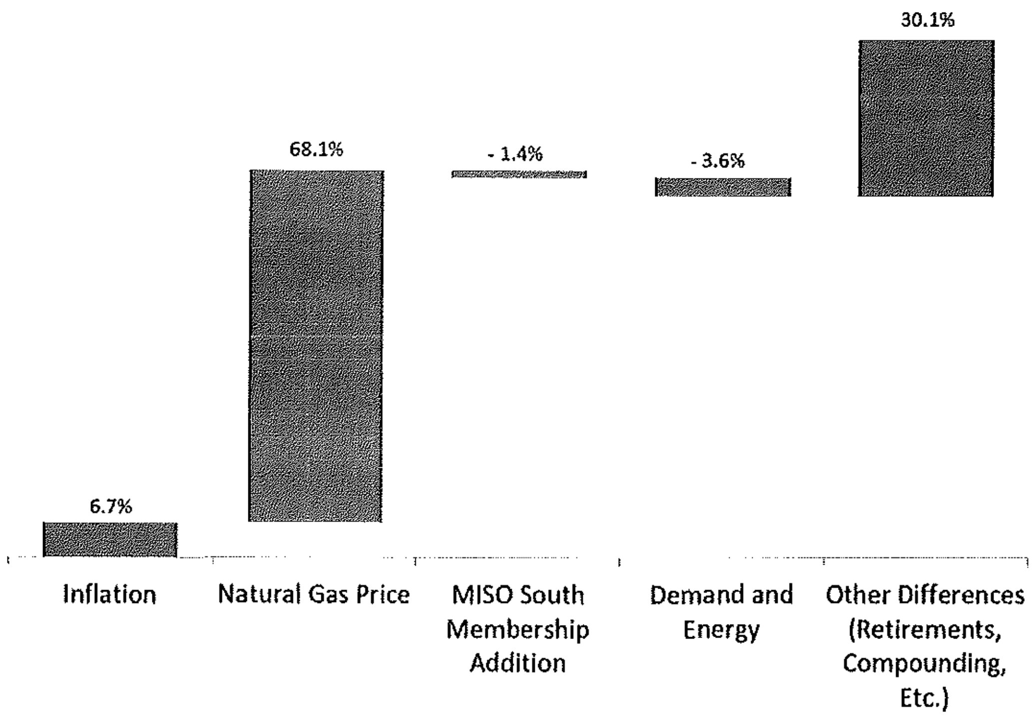


Figure 6-6: Breakdown of Annual Congestion and Fuel Savings Benefit Increase from MTEP11 to MTEP14 – Values a percentage of difference between MTEP14 year 2028 and MTEP11 year 2026 Adjusted Production Cost (APC) Savings

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

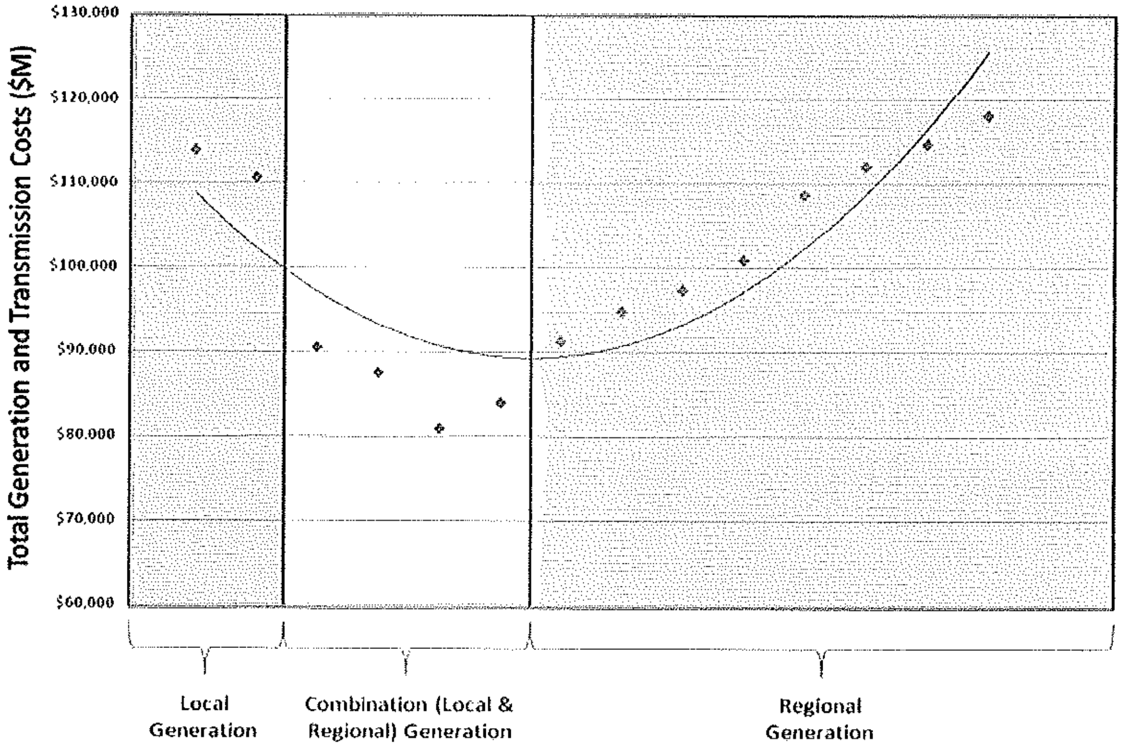


Figure 6-7: Local versus Combination Wind Siting

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).

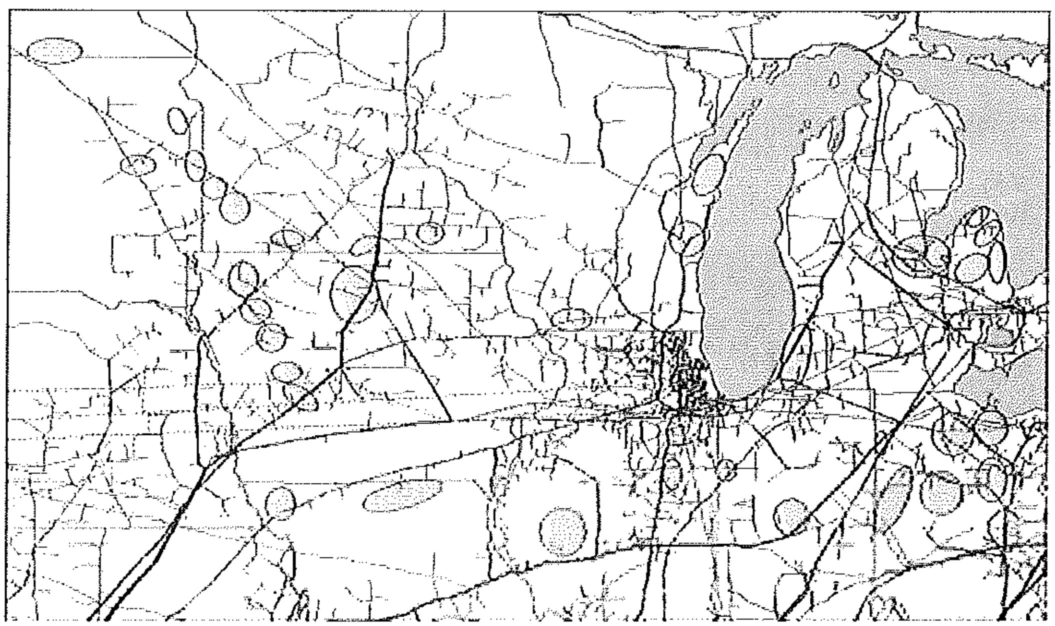


Figure 7-1: Energy Zone Correlation with Natural Gas Pipelines

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.

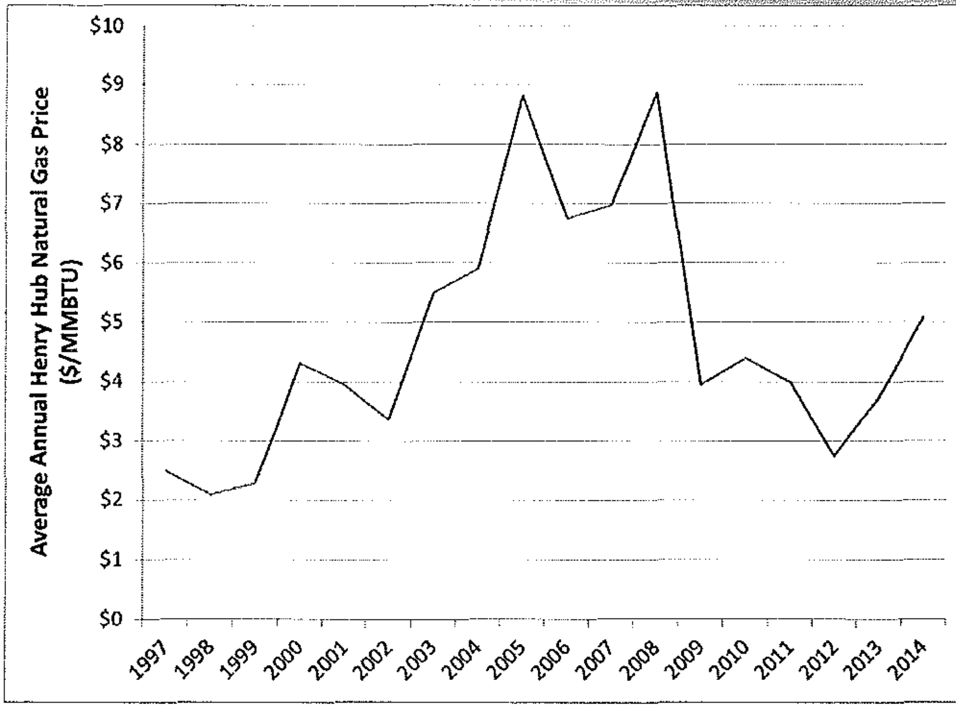


Figure 7-2: Historic Henry Hub Natural Gas Prices

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).

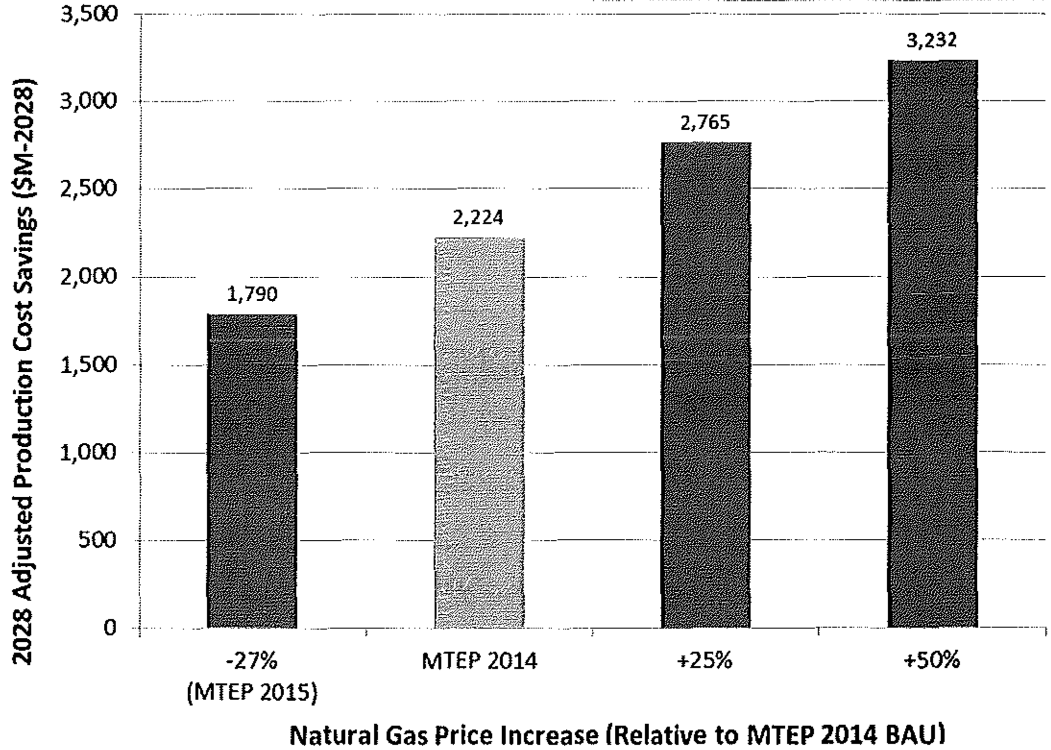


Figure 7-3: MVP Portfolio Adjusted Production Cost Savings by Natural Gas Price

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.

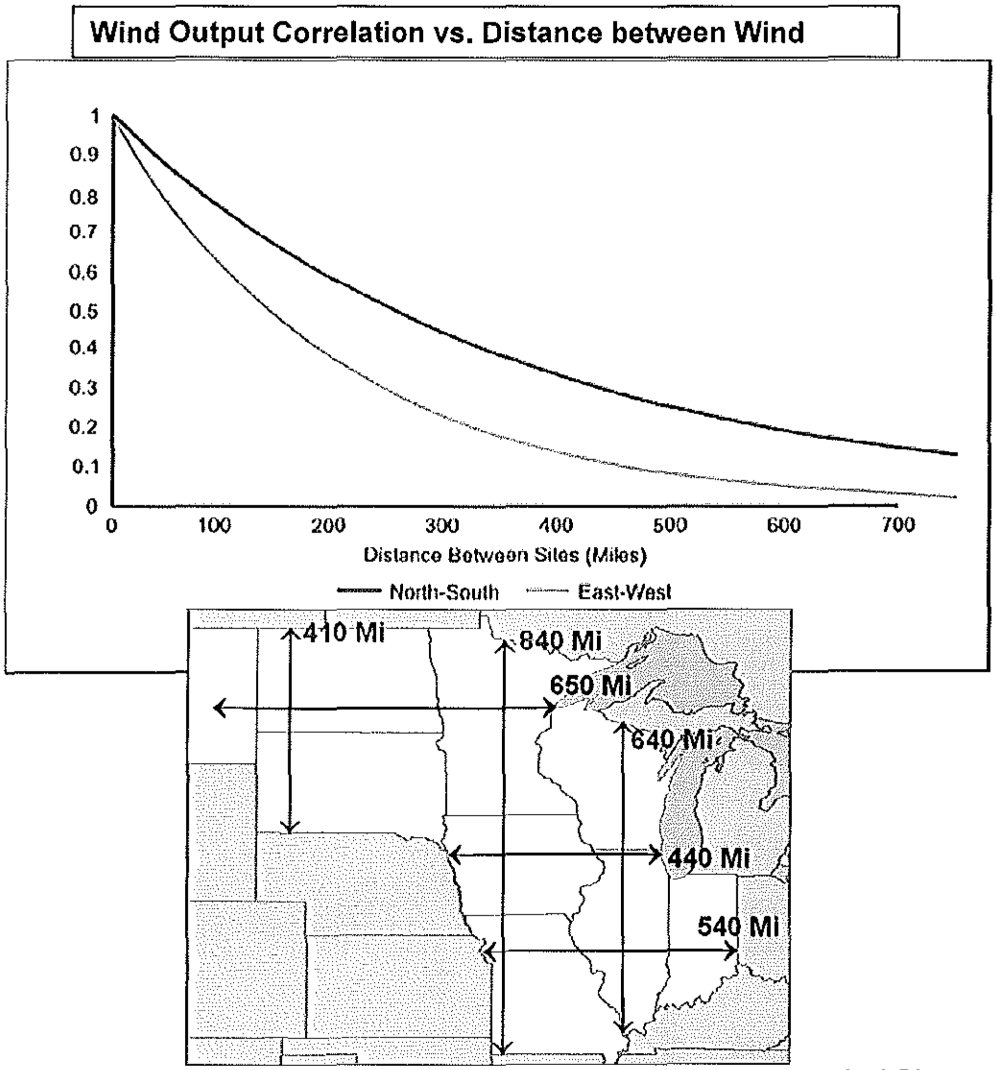


Figure 7-4: Wind Output Correlation to Distance between Wind Sites

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.

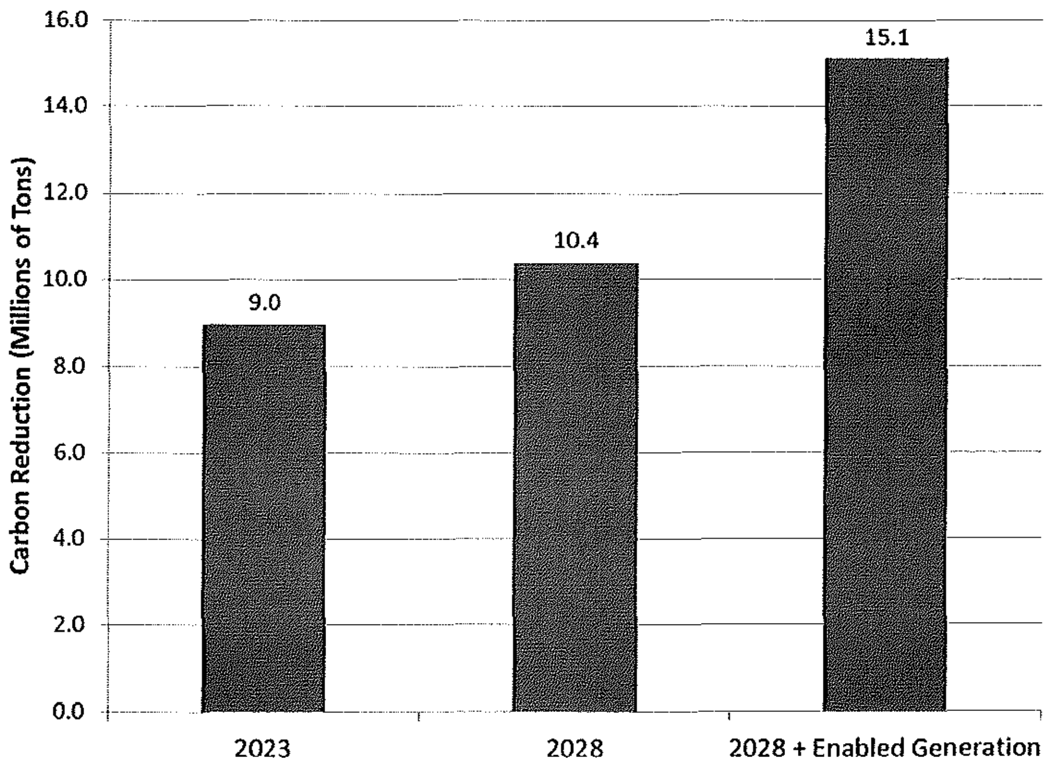


Figure 7-5: Forecasted Carbon Reduction from the MVP Portfolio by Year

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

Independent Statistics & Analysis
U.S. Energy Information Administration

Assumptions to the Annual Energy Outlook 2015

September 2015

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	Online Year[1]	Size (MW)	Lead time (years)	Base Overnight Cost in 2014 (2013 $/kW)	Contingency Factors: Project Contin-gency Factor[2]	Contingency Factors: Techno-logical Optimism Factor[3]	Total Overnight Cost in 2014[4] (2013 $/kW)	Variable O&M[5] (2013 $/ mWh)	Fixed O&M (2013 $/ kW/yr.)	Heatrate[6] in 2014 (Btu/ kWh)	nth-of-a-kind Heatrate (Btu/ kWh
Scrubbed Coal New	2018	1300	4	2,726	1.07	1.00	2,917	4.47	31.16	8,800	8,740
Integrated Coal- Gasifi-fication Comb Cycle (IGCC)	2018	1200	4	3,483	1.07	1.00	3,727	7.22	51.37	8,700	7,450
IGCC with Carbon sequestion	2018	520	4	5,891	1.07	1.03	6,492	8.44	72.80	10,700	8,307
Conv Gas/Oil Comb Cycle	2017	620	3	869	1.05	1.00	912	3.60	13.16	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2017	400	3	942	1.08	1.00	1,017	3.27	15.36	6,430	6,333
Adv CC with carbon sequestration	2017	340	3	1,845	1.08	1.04	2,072	6.78	31.77	7,525	7,493
Conv Comb Turbine[8]	2016	85	2	922	1.05	1.00	968	15.44	7.34	10,783	10,450
Adv Comb Turbine	2016	210	2	639	1.05	1.00	671	10.37	7.04	9,750	8,550
Fuel Cells	2017	10	3	6,042	1.05	1.10	6,978	42.97	0.00	9,500	6,960
Adv Nuclear	2022	2234	6	4,646	1.10	1.05	5,366	2.14	93.23	10,479	10,479
Distributed Generation - Base	2017	2	3	1,407	1.05	1.00	1,477	7.75	17.44	9,015	8,900
Distributed Generation - Peak	2016	1	2	1,689	1.05	1.00	1,774	7.75	17.44	10,015	9,880
Biomass	2018	50	4	3,399	1.07	1.01	3,659	5.26	105.58	13,500	13,500
Geothermal[7,9]	2018	50	4	2,331	1.05	1.00	2,448	0.00	112.85	9,516	9,516
Muncipal Solid Waste	2017	50	3	7,730	1.07	1.00	8,271	8.74	392.60	14,878	18,000
Conventional Hydropower[9]	2018	500	4	2,410	1.10	1.00	2,651	5.76	15.15	9,516	9,516

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Table 8.2. Cost and performance characteristics of new central station electricity generating technologies (cont.)

Technology	Online Year[1]	Size (MW)	Lead time (years)	Base Overnight Cost in 2014 (2013 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2014[4] (2013 $/kW)	Variable O&M[5] (2013 $/ mWh)	Fixed O&M (2013 $/ kW/yr.)	Heatrate[6] in 2014 (Btu/ kWh)	nth-of-a-kind Heatrate (Btu/ kWh
Wind	2017	100	3	1,850	1.07	1.00	1,980	0.00	39.53	9,516	9,516
Wind Offshore	2018	400	4	4,476	1.10	1.25	6,154	0.00	73.96	9,516	9,516
Solar Thermal[7]	2017	100	3	3,787	1.07	1.00	4,052	0.00	67.23	9,516	9,516
Photovoltaic[7,10]	2016	150	2	3,123	1.05	1.00	3,279	0.00	24.68	9,516	9,516

[1]Online year represents the first year that a new unit could be completed, given an order date of 2014.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."

[3]The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2014.

[5]O&M = Operations and maintenance.

[6]For hydropower, wind, solar and geothermal technologies, the heat rate shown represents the average heat rate for conventional thermal generation as of 2013. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7]Capital costs are shown before investment tax credits are applied.

[8]Combustion turbine units can be built by the model prior to 2016 if necessary to meet a given region's reserve margin.

[9]Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[10]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.

Sources: For the AEO2015 cycle, EIA continues to use the previously developed cost estimates for utility-scale electric generating plants, updated by external consultants for AEO2013. This report can be found at http://www.eia.gov/forecasts/capitalcost/. The costs were assumed to be consistent with plants that would be ordered in 2012, and learning from capacity built in 2012 and 2013 has been applied in the initial costs above. Wind capital costs were updated for AEO2015 using recent reports from trade press and reports from Lawrence Berkeley National Laboratory. Site-specific costs for geothermal were provided by the National Renewable Energy Laboratory, "Updated U.S. Geothermal Supply Curve," February 2010.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building four units) the technological optimism factor is gradually reduced to 1.0.

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