Planning Analysis of the Badger Coulee Transmission Project

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1.0 Executive Summary

1.1 Introduction

The Badger Coulee Project is a proposed 345-kV transmission line connecting from La Crosse, Wisconsin to Madison, Wisconsin and Middleton, Wisconsin (hereafter "Badger Coulee"). The co-applicants for this project are American Transmission Company LLC by its corporate manager ATC Management Inc. (ATC) and Northern States Power Company, a Wisconsin corporation (NSPW), and wholly owned subsidiary of Xcel Energy Inc.

This Transmission Planning Analysis evaluates economic, reliability and public policy benefits of Badger Coulee and other transmission and non-transmission alternatives under various plausible future scenarios for the electric industry in the Upper Midwest.

Over the project evaluation process a number of project terminal endpoints were considered. A prescreening process was used to eliminate potential project alternatives. The two transmission project alternatives that were ultimately selected to be evaluated in detail are as follows:

- Badger Coulee: A 345-kV line from La Crosse, Wisconsin to the North Madison 345-kV Substation north of Madison, Wisconsin, continuing to the Cardinal 345-kV Substation in Middleton, Wisconsin.
- Low Voltage Alternative: A large number of transmission upgrades consisting of 69-kV, 115-kV, 138-kV and 161-kV facilities located in Wisconsin, Iowa, Illinois and Minnesota (hereafter "Low Voltage").

The benefits were identified as either local or regional in nature. Local benefits are those that would be provided to ATC's and NSPW's Wisconsin customers, while regional benefits are those that would be provided to all users of the Upper Midwestern transmission system.

1.2 Benefits and Costs for ATC Customers

Each of the transmission alternatives has a set of quantitative benefits and costs. The costs are the portion of the total construction cost and pre-certification estimates of the alternative as well as supporting projects included in ATC's annual revenue requirements. The total monetary benefits are the summation of the construction costs of the ATC avoided reliability projects, energy-cost savings derived by PROMOD modeling, Renewable Investment Benefit (RIB), Loss Savings, and Insurance Value.

ATC calculated the local economic benefits of each transmission alternative for ATC customers over a range of six plausible futures. The ATC Customer Benefit metric was used as the basis of measurement for these benefits.

In December 2010 and October 2011, the Federal Energy Regulatory Commission (FERC) approved the Midwest Independent System Operator's (MISO's) proposed Multi Value Project (MVP) Tariff that defines MVP standards and provides for cost-sharing of projects that meet these standards after a comprehensive planning analysis.[1] MISO staff subsequently analyzed and recommended a set of MVP projects, including Badger Coulee, for inclusion in Appendix A of the MISO Transmission Expansion Plan (MTEP) 2011 analysis.[2] These MVP projects were approved by the MISO Board of Directors (BOD) on December 8, 2011 with the BOD directing "transmission owners to use due diligence to construct the facilities approved in the plan."[3] ATC used the MISO Tariff (including the MVP tariff and the network-service tariff) to calculate the costs of Badger Coulee that will be included in the revenue requirements of customers in the ATC zone.

Figure 1: Net Project Cost / Benefit provides a graphical representation of all of the project costs and benefits described above for ATC customers.[4] Badger Coulee, with MISO MVP cost sharing, showed positive net benefits in all six of the futures analyzed. Low Voltage, which is not eligible for MVP cost sharing, showed positive net energy benefits in four of the six futures analyzed. Overall, Badger Coulee showed greater positive net benefits for ATC customers than Low Voltage in all of the six futures analyzed.

Table 1 summarizes the monetized benefits of the transmission alternatives.

[1] *Midwest Independent System Operator, Inc.,* Order Conditionally Accepting Tariff Revisions (12/16/10), FERC Docket No. ER10-1791-000 *Midwest Independent Transmission System Operator, Inc.* (10/11/11) Order Denying in Part and Granting in Part Rehearing, Conditionally Accepting Compliance Filing, and Directing Further Compliance Filings, FERC Docket No. ER10-1791.
[2] *MISO Transmission Expansion Plan 2011*; *MISO Multi Value Project Portfolio – Results and Analysis*, (01/10/12).
[3] *MISO Board Approves 215 New Transmission Projects*, News Release, (12/08/12).
[4] The values in this figure are the Net Present Value of the benefits or costs to ATC customers discounted to 2012 using a 6.7% discount rate. A positive value reflects net benefits; a negative value reflects net costs.

Figure 1: Net Project Cost / Benefit for ATC Customers

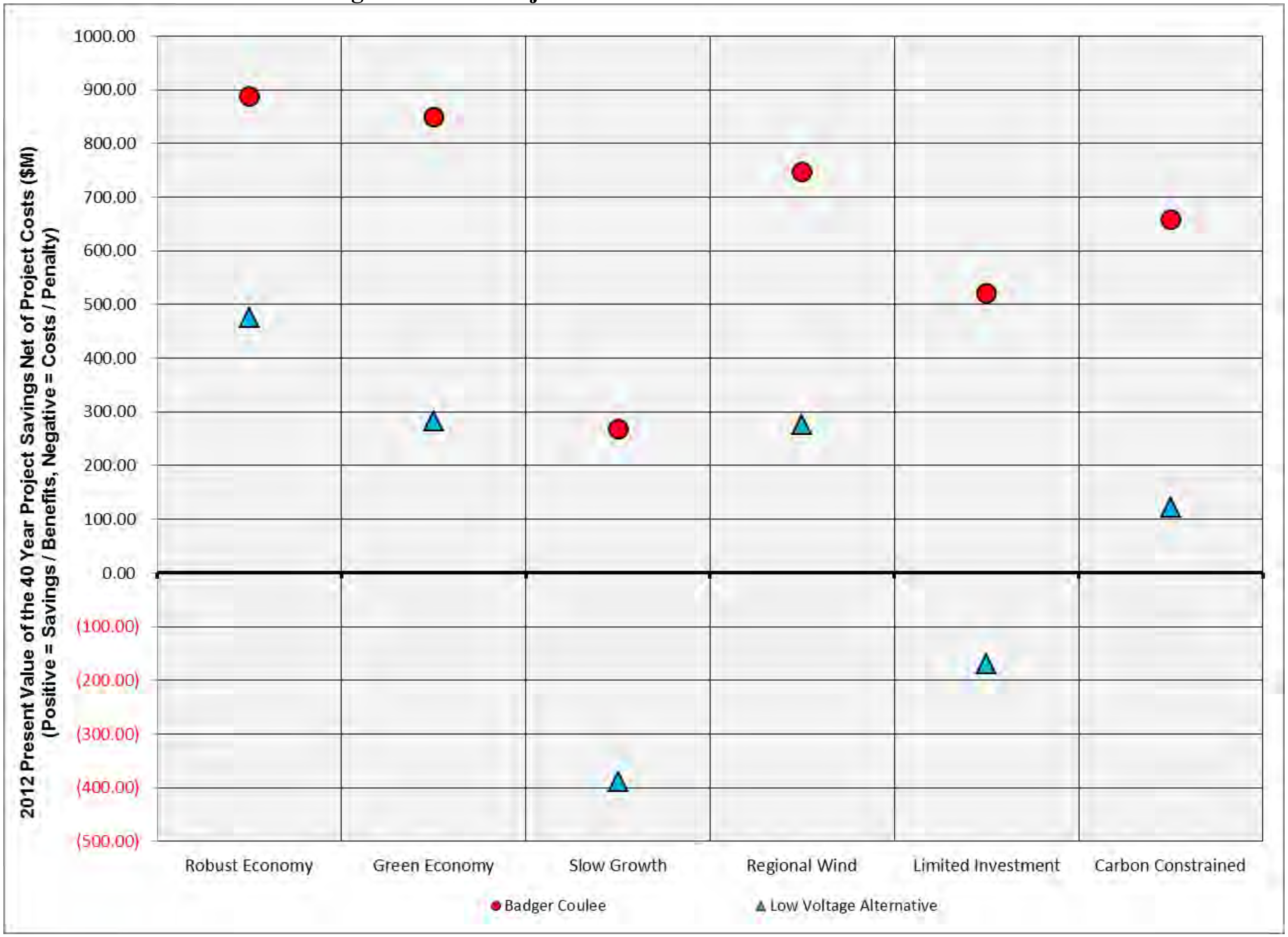


Table 1: Monetized Benefits of Transmission Alternatives for ATC Customers

	Badger Coulee	Low Voltage
PROJECT COSTS		
Total Project Cost ($M – Nominal)	($550.21)	($428.73)
2012 Present Value of the Revenue Requirement (PVRR 2012) - $M	($4.25)	($466.91)
PROJECT BENEFITS		
All Futures		
Avoided Cost of Potential Projects - <345-kV (PVRR 2012)	$141.87	$0.00
Insurance Value	$23.57	$0.00
Robust Economy		
Energy Benefits (PROMOD)	$356.26	$500.83
Loss Savings	$61.21	$33.75
RIB	$309.93	$408.60
NPV 2012 ($M)	**$888.60**	**$476.27**
Green Economy		
Energy Benefits (PROMOD)	$285.45	$267.11
Loss Savings	$67.63	$32.67
RIB	$335.33	$450.08
NPV 2012 ($M)	**$849.60**	**$282.95**
Slow Growth		
Energy Benefits (PROMOD)	$37.09	$34.58
Loss Savings	$17.01	($8.59)
RIB	$52.81	$52.39
NPV 2012 ($M)	**$268.16**	**($388.54)**
Regional Wind		
Energy Benefits (PROMOD)	$212.06	$277.34
Loss Savings	$33.12	$8.00
RIB	$340.04	$458.52
NPV 2012 ($M)	**$746.41**	**$276.96**
Limited Investment		
Energy Benefits (PROMOD)	$146.85	$140.50
Loss Savings	$56.49	$3.49
RIB	$155.59	$152.69
NPV 2012 ($M)	**$520.12**	**($170.23)**
Carbon Constrained		
Energy Benefits (PROMOD)	$112.10	$135.29
Loss Savings	$36.98	$1.96
RIB	$347.87	$452.40
NPV 2012 ($M)	**$658.15**	**$122.74**

Badger Coulee and Low Voltage, along with three other projects, were also evaluated to determine local reliability benefits in the Western Wisconsin Transmission Reliability Study (WWTRS). Each of the alternatives provided local reliability benefits by reducing the number of overloads in western Wisconsin. Each alternative also provided some voltage support and transient stability improvement to the transmission system in western Wisconsin. It was observed that Badger Coulee provided the greatest amount of reliability benefit to the transmission system in western Wisconsin.

The contribution of each alternative to providing local public policy benefits in the form of lower Renewable Portfolio Standards (RPS) compliance costs for ATC customers was determined mainly by the calculation of the RIB. The RIB is a measurement of the transmission system's ability to transfer generation generated from higher capacity factor renewable sources located to the west of Wisconsin to load being served in Wisconsin. Each of the alternatives did provide some level of RIB. Badger Coulee provided significant RIB to ATC customers in each of the futures.

ATC also determined that it would be appropriate to perform an additional sensitivity analysis in order to test the above results. ATC selected for this analysis the Business as Usual (BAU) with Mid-Low Demand and Energy Growth Rates future from the 2011 Midwest ISO Transmission Expansion Plan (MTEP 11)(also known as the MTEP 11 BAU-Low future). ATC performed a PROMOD analysis of Badger Coulee using the database from this future. The analysis measured net energy-cost savings as a result of Badger Coulee for ATC customers. The results set forth in Table 2 below, show positive net energy-cost savings of Badger Coulee, in both study years and on a present-value basis. Further information on this sensitivity analysis is provided in Addendum F.

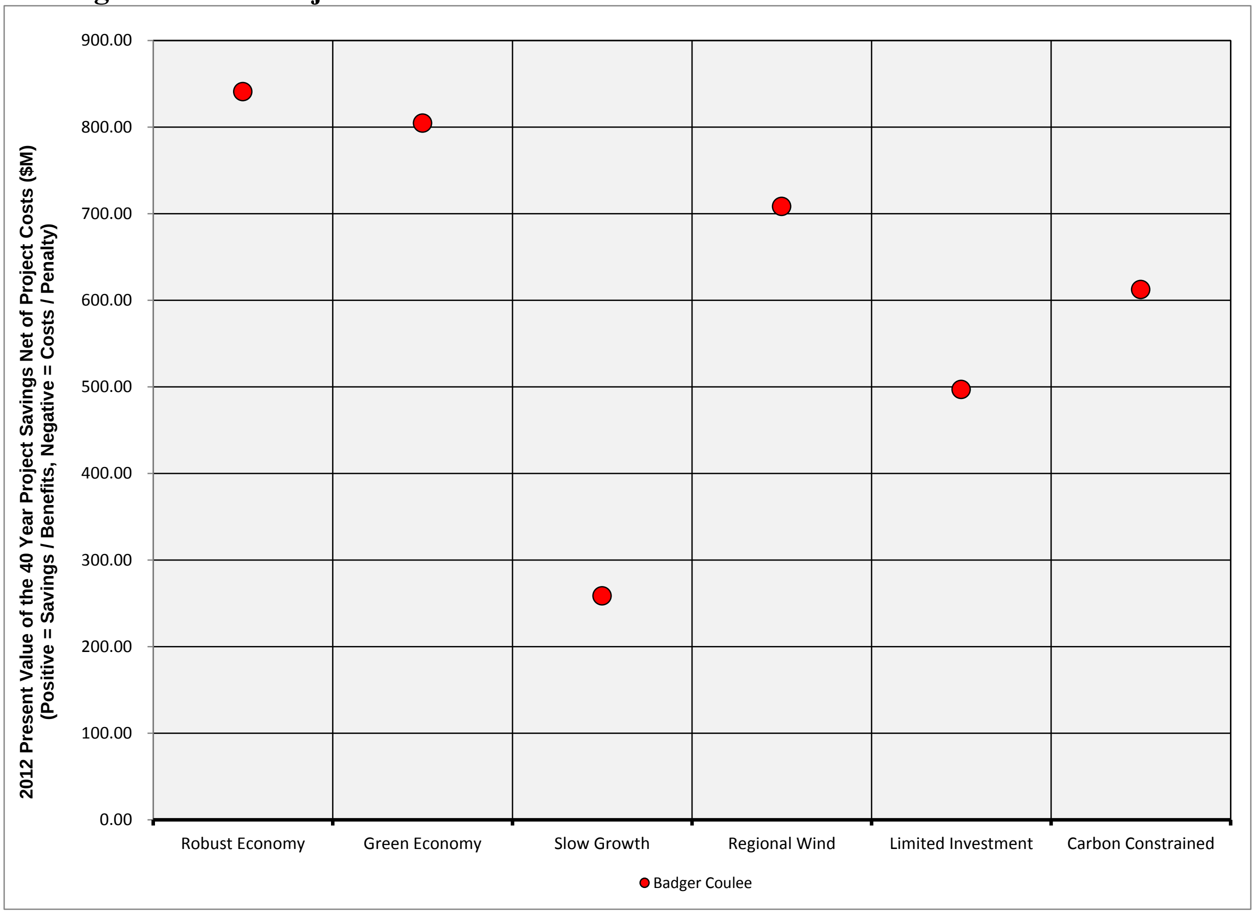
Table 2: Badger Coulee Customer Benefit Savings – MISO MTEP11 BAU - Low

	MTEP 11 BAU-LOW
2021 Savings ($M - 2021)	3.58
2026 Savings ($M - 2026)	4.55
40-Year PV Savings ($M - 2012)	50.35

1.3 Benefits and Costs for ATC's and NSPW's Wisconsin Customers

When NSPW became a co-applicant in this proceeding, ATC performed additional analysis for the purpose of calculating the net benefits or costs of Badger Coulee to ATC's and NSPW's Wisconsin customers. ATC calculated the proportionate share of the ATC-wide benefits and costs described above for its Wisconsin footprint, and calculated the project costs that would be included in the revenue requirements of its Wisconsin customers pursuant to the MISO MVP Tariff. For the NSPW territory ATC performed a similar analysis, first conducting a PROMOD analysis of adjusted production cost and energy loss savings in the entire NSP region and the costs allocated to that region under the MISO MVP tariff, and then reflecting the proportionate share of these benefits and costs to NSPW's Wisconsin customers. The results of this analysis, shown below in Figure 2, showed that ATC's and NSPW's Wisconsin customers would experience substantial net benefits as a result of Badger Coulee in each of the six futures.

Figure 2: Net Project Cost / Benefit for ATC's and NSPW's Wisconsin Customers



Further information on this sensitivity analysis is shown in Addendum G.

1.4 Regional Benefits and Costs

The Minnesota Renewable Energy Standard (RES) Upgrade Study evaluated Badger Coulee for regional economic benefits and determined that Badger Coulee was the most beneficial single project evaluated.[5] The Minnesota RES also evaluated Badger Coulee for regional reliability benefits. It determined that Badger Coulee would provide significant support to the regional transmission system by improving the generation stability response of generation units in Minnesota with the expected increase of renewable generation in the future.

Several other regional studies have identified the need for additional transmission facilities to aid in the development of renewable generation to satisfy RPS mandates for states located in the Upper Midwest region. The Upper Midwest Transmission Development Initiative (UMTDI) identified a corridor that correlates with Badger Coulee to efficiently move renewable generation from wind energy zones to customers. The Strategic Midwest Area Renewable Transmission (SMARTransmission) study has identified a need for transmission facilities connecting eastern

[5] *Final Report, Minnesota RES Upgrade Study* (3/31/09)

Minnesota to Wisconsin to deliver wind generation to load. The Minnesota RES and Capacity Validation Study (CVS) identified Badger Coulee as a necessary transmission facility to accommodate the 4,000 to 6,000 MW of generation capacity that is expected to be needed to satisfy Minnesota's RPS mandate by the year 2025.[6]

MISO also identified several Candidate MVPs in the Regional Generator Outlet Study (RGOS) that would be compatible with potential transmission overlays developed.[7] Badger Coulee and an additional 345-kV tie between Wisconsin and Iowa are MISO MVPs that will provide a continuation of west to east transmission paths to provide better access to wind generation to the west. As noted previously, the MVP Tariff has been approved by FERC and these projects have been approved for development and cost allocation by the MISO BOD.

1.5 Non-Transmission Alternatives to the Project

In addition to studying Low Voltage, ATC also incorporated numerous non-transmission alternatives into the Futures upon which its modeling is based. These non-transmission alternatives included varying levels of increased energy efficiency, load reduction, conventional generation, and renewable generation. These resources were added at the distribution level, within the ATC transmission system, and MISO-wide. The results showed that Badger Coulee produced value for Wisconsin customers even in the futures in which additional non-transmission alternatives were most vigorously implemented. Badger Coulee will thus be a valuable enhancement to non-transmission alternatives such as energy efficiency and renewable resources.

For this Planning Analysis, ATC developed and applied a planning technique that models "Distributed Resources" (DR) within the ATC system. DR incorporates additional demand response by customers and distributed generation within the ATC system. Deployment of these resources did not materially reduce or eliminate the need for and multiple benefits of Badger Coulee.

ATC has also provided a description of the energy-efficiency and load-response services that the statewide Focus on Energy (FoE) program provides to Wisconsin customers and the historical and potential future impacts of this program on load growth.

ATC has also considered the extent to which additional energy efficiency and load reduction could supplant the need for and multiple benefits of Badger Coulee. As noted above, Badger Coulee is an MVP that provides various reliability, economic, and policy benefits. ATC's analysis indicates that there is no basis for concluding that additional resources of this type could feasibly provide, on a firm, cost-effective basis, the same package of benefits as Badger Coulee.

1.6 Conclusion

Based on its analysis, ATC concludes that Badger Coulee provides substantial net economic, reliability, and policy benefits to its customers and to Wisconsin. Also, numerous studies

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[6] *Final Report, Minnesota Capacity Validation Study* (3/31/09)
[7] *Midwest ISO Regional Generator Outlet Study* (11/19/10), Study Overview

demonstrate that Badger Coulee provides additional benefits to regional customers. This project will reduce the delivered price of energy to customers without creating unreasonable risks for ratepayers. ATC therefore seeks approval for the necessary regulatory authorizations required to construct Badger Coulee and place its facilities in service.

2.0 Study Need

The needs described in this study are regional, statewide, and local. Regional needs derive principally from the MISO footprint but also include the PJM region and the Eastern Interconnection. Statewide needs refer to the State of Wisconsin, including the ATC footprint as well as the Western Wisconsin areas served by Dairyland Power Cooperative (DPC) and Northern States Power of Wisconsin (NSPW). Local needs arise within the ATC zone in eastern and southern Wisconsin and the Upper Peninsula of Michigan.

The factors driving this analysis arise at each of these geographical levels. They are conveniently classified in three major categories, although there is considerable overlap among the categories:

- Economic drivers;
- Reliability drivers; and
- Public Policy drivers.

The economic analysis takes as a given security-constrained economic dispatch within the MISO market. Within this context projects various combinations of market, business, and regulatory factors affecting the delivered cost of energy to customers, including different energy and demand forecasts and different generation and transmission alternatives. The economic analysis then evaluates how various project options contribute to reducing energy costs and minimizing risks within these scenarios.

The reliability analysis takes as an imperative whatever is necessary to preserve electric reliability in accordance with the North American Electric Reliability Corporation (NERC) reliability standards. This analysis is used to identify specific reliability problems likely to develop in each geographical area as a result of future changes in demand and energy consumption, generation retirement and expansion, and transmission topography. The analysis is then used to develop options for resolving these reliability problems.

Finally, public-policy analysis develops a range of environmental and regulatory requirements that may occur during the 40-year life of a project (including maintaining the status quo). These policy areas cover matters like emissions controls, energy efficiency and demand reduction, renewable-energy standards, and carbon pricing.

A large network project like Badger Coulee produces economic, reliability, and public policy impacts across the region, the state, and the ATC footprint. To the extent that a planning analysis shows that these effects are positive in relation to costs, this option becomes a multiple-benefits project for ATC, Wisconsin, and regional transmission users.

2.1 Regional Evaluation by MISO

MISO has regional planning responsibility for the area within which this project lies. It exercises this responsibility in accordance with its FERC Tariff and the MISO Transmission Owners

Agreement. Annually, it produces the MTEP, identifying various network upgrades within its region.

In 2010, MISO identified Badger Coulee as one of the projects in its Candidate MVP Portfolio. MVPs are large network upgrades that provide regional benefits to transmission users, including the reliability, economic, and policy benefits described above. In December 2010 and October 2011, FERC approved MISO's proposed MVP Tariff that defines MVP standards and provides for cost-sharing of projects that meet these standards after a comprehensive planning analysis.[8] MISO subsequently analyzed and recommended a set of MVP projects, including Badger Coulee, for inclusion in Appendix A of the MTEP 2011 analysis.[9] The MISO MVP projects were approved by the MISO BOD on December 8, 2011 with the BOD directing "transmission owners to use due diligence to construct the facilities approved in the plan."[10]

ATC evaluated the reliability, economic, and policy effects of this project under the ATC planning provisions of the MISO Tariff (Attachment FF-ATCLLC). The focus of the analysis was the local and statewide impacts of Badger Coulee and other transmission alternatives. ATC Planning cooperated and coordinated closely with MISO in its regional evaluation of this project.

2.2 Other Regional Studies

Badger Coulee appears as a base assumption or solution in several MISO System Planning and Analysis and Definitive Planning Phase studies.[11] It is also included among the projects in Appendix A of MTEP 2011 and MTEP 2012.[12]

In 2010, MISO completed the RGOS. The drivers of this study were the need of states within the MISO region to comply with existing RPS and MISO's own need to address the extensive queue of wind projects in its western region. Badger Coulee (along with the Dubuque to Spring Green to Cardinal Project) was among the specific projects recommended in this study.[13]

The UMTDI was a 2010 joint effort of the governors of five Upper Midwestern states (North Dakota, South Dakota, Iowa, Minnesota, and Wisconsin). This analysis identified several renewable energy corridors where transmission is needed. Both Badger Coulee and the Dubuque-Spring Green-Cardinal Project are within the corridors identified in the UMTDI Final Report.[14]

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[8] *Midwest Independent System Operator, Inc.,* Order Conditionally Accepting Tariff Revisions (12/16/10), FERC Docket No. ER10-1791-000; *Midwest Independent Transmission System Operator, Inc.* (10/11/11) Order Denying in Part and Granting in Part Rehearing, Conditionally Accepting Compliance Filing, and Directing Further Compliance Filings, FERC Docket No. ER10-1791.

[9] *MISO Transmission Expansion Plan 2011*; *MISO Multi Value Project Portfolio – Results and Analysis*, (01/10/12).

[10] *MISO Board Approves 215 New Transmission Projects*, News Release, (12/08/12).

[11] *MN DPP Cycle 1 System Impact Re-Study April 16, 2012; Generator Interconnection SPA System Impact Study SEMNIA November 2011 Study Group Final Report February 13, 2012; MN Group 5 System Impact Re-Study June 15, 2011; MISO MN Area SPA System Impact Study including Big Stone, Buffalo Ridge, and Southwest MN-IA Study Groups Tiers 1-3 October 30, 2009*

[12] *MISO Transmission Expansion Plan 2011*; *MISO Transmission Expansion Plan 2012; MISO Multi Value Project Portfolio – Results and Analysis*, (01/10/12).

[13] *Midwest ISO Regional Generator Outlet Study* (11/19/10), Study Overview, p. 14.

[14] *Upper Midwest Transmission Development Initiative, Executive Committee Final Report* (9/29/10), p. 10.

In 2009, the Minnesota Transmission Owners completed two transmission planning studies. The RES Upgrade Study found that a 345-kV line from La Crosse to Madison fulfilled a need to strengthen ties in order to increase regional reliability under both steady-state and dynamic stability conditions.[15] The CVS is another Minnesota study that identified a La Crosse to Madison 345-kV line as one of three priority projects that should be the focus of current transmission expansion efforts.[16]

2.3 Analysis of Local and Wisconsin Needs by ATC

ATC has focused its planning analysis to date mainly on the drivers for this project within its own service territory and the state of Wisconsin. This is also the main focus of this Planning Analysis. The emphasis is the extent to which Badger Coulee meets specific reliability, economic, and policy needs identified within the planning horizon. Since the ATC service territory represents a significant portion of the state of Wisconsin, the construction of ATC-specific transmission facilities, such as Badger Coulee, benefit both the customers of ATC in particular of the state of Wisconsin in general. Put another way, the main question for study is whether or not Badger Coulee produces benefits for ATC and Wisconsin customers that are greater than the costs to ATC and Wisconsin customers. The Wisconsin Certificate of Public Convenience and Necessity (CPCN) statute (Wis. Stat. § 196.491(3)) provides the template for analyzing these various needs, benefits, and costs.

2.4 Local Economic Drivers

ATC applied its Strategic Flexibility methodology to evaluate Badger Coulee and available transmission alternatives. In this approach key variables affecting the future delivered price of electricity are identified. These include factors like the load and energy forecasts, fuel prices, different levels and types of generation retirements and expansions, and the regional transmission topology. A plausible range of values is assigned to each of these drivers. Selected values for each of these drivers are then aggregated into different futures.

For this Planning Analysis there are six futures:

- Robust Economy;
- Green Economy;
- Slow Growth;
- Regional Wind;
- Limited Investment; and
- Carbon Constrained.

The premise is that a project that performs well in these futures is a robust project that will produce benefits and minimize risks for ATC customers.

[15] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 12.
[16] *Capacity Validation Study* (3/31/09), p. 8.

ATC Planning has developed modeling and other methods of measuring in quantitative terms the impacts of Extra High Voltage (EHV) projects on its customers. This Planning Analysis presents the results of its evaluation of the following impacts:

2.4.1 Energy Costs

ATC estimates the energy cost savings as a result of an EHV project with PROMOD, a market simulation model that uses production costs and locational marginal prices (LMP). In its Customer Benefit metric ATC has calibrated the measurement of these benefits to reflect likely actual savings to its customers; the result is a value for ATC customer energy-cost savings in each future that falls in between production-cost and LMP savings.

2.4.2 Losses

By strengthening the ATC transmission system, Badger Coulee will also reduce electrical losses for ATC customers that would otherwise have to be replaced by incremental generation. The PROMOD tool was also used to measure the economic impact associated with reduced losses for each future.

2.4.3 System-Failure Insurance Value

A project that strengthens the grid also reduces the economic impact of severe generation or transmission outages. ATC uses the standard insurance valuation elements of probability and impact of occurrence to measure the extent to which Badger Coulee mitigates energy cost increases in the wake of such outages.

2.4.4 Renewable Investment Benefit

This benefit analyzes the contribution of new transmission to capital-cost savings for load-serving entities within ATC's footprint that build wind generation facilities in higher capacity wind production areas outside of Wisconsin. Using conservative assumptions and metrics, it first measures capital cost savings due to building fewer wind generators to produce the same amount of needed renewable energy, then scales this savings to the increase in transfer capacity as a result of the proposed project, and also reduces the overall savings by the projected LMP differentials between the energy source and the load.

2.4.5 Competitive Effects

One of the state CPCN standards relates to the impact of the proposed project on competition in the relevant wholesale electric market. New transmission can improve competitiveness if it enables external suppliers to offer additional generation into the relevant market. Structural measures of competitiveness such as the Herfindahl-Hirschman Index (HHI) are commonly used to evaluate the extent of competition in power markets. In this Planning Analysis ATC has provided the change in the HHI score for the ATC footprint as a result of Badger Coulee.

2.5 Local and Statewide Reliability Drivers

One of ATC's main organizational purposes is to plan and build transmission facilities to provide for an adequate and reliable transmission system that meets the needs of all transmission users.

In western Wisconsin, the transmission system is not robust and its reliable operation is affected by system flows of power from the west to the east. Even moderate additional wind capacity to the west of Wisconsin would further stress this already constrained system. Hence in 2010, ATC and other transmission owners (including DPC and Xcel Energy) completed the WWTRS. This study analyzed specific reliability concerns in western Wisconsin, eastern Iowa, and eastern Minnesota and identified Badger Coulee as a viable solution for these problems.[17]

2.6 Local Public-Policy Drivers

Among the key drivers affecting the delivered price of energy for Wisconsin customers is the applicable regulatory and policy framework. For example, Wisconsin's RPS currently requires energy utilities to derive 10 percent of their energy from renewable sources. In the 40-year useful life of Badger Coulee, this requirement could remain the same (though the level of electrical energy required to meet it would increase to the extent that electrical consumption increased). The requirement could also be reduced or increased. Factors other than an RPS, such as greenhouse gas (GHG) or other environmental regulations affecting coal plants and increased demand by retail customers for renewable energy, could affect the state's level of renewable-energy usage over the planning horizon. Considering these various factors, ATC decided to assume no change in the state's level of renewable-energy usage in two of its futures, an increase to 20 percent in two other futures, and an increase to 25 percent in the remaining two futures. In this Planning Analysis, ATC evaluates whether Badger Coulee would allow load-serving entities to deliver renewable energy more economically to their customers in these various futures.

Other examples of policy-driven variables include various levels of energy efficiency, load reduction, and distributed generation within the ATC footprint. ATC has included reasonable ranges for each of these eventualities in its key drivers that make up the futures. This Planning Analysis thus considers the effects of Badger Coulee in a wide range of state regulatory environments.

3.0 Transmission Project Descriptions

Several different transmission project alternatives have been evaluated for effectiveness in achieving economic, reliability and public policy benefits. This section will provide a description of the transmission projects that have been evaluated in the greatest detail. The transmission line project one-line diagrams provided in this section are for illustrative purposes only and are not intended to depict future transmission line routes.

[17] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 3

3.1 Badger Coulee Transmission Project

Badger Coulee is a set of 345-kV lines that will originate in the La Crosse, Wisconsin area, extend to the Madison, Wisconsin area and continue to the Middleton, Wisconsin area.

Badger Coulee will extend a 345-kV transmission line from a substation located near La Crosse, Wisconsin to the North Madison Substation located near Madison, Wisconsin. The estimated line distance from the La Crosse area to the North Madison Substation is approximately 135 miles to 165 miles depending on the route chosen.

Badger Coulee will also extend a 345-kV line from the North Madison Substation to the Cardinal Substation located near Middleton, Wisconsin. The estimated line distance from the North Madison Substation to the Cardinal Substation is approximately 20 miles.

The 345-kV substation located in the La Crosse, Wisconsin area does not currently exist. A substation is being planned for construction in conjunction with a 345-kV project from Rochester, Minnesota to the La Crosse area as part of the CAPX2020 group of projects. The La Crosse area substation for Badger Coulee is being planned as an ultimate six position breaker and a half design.

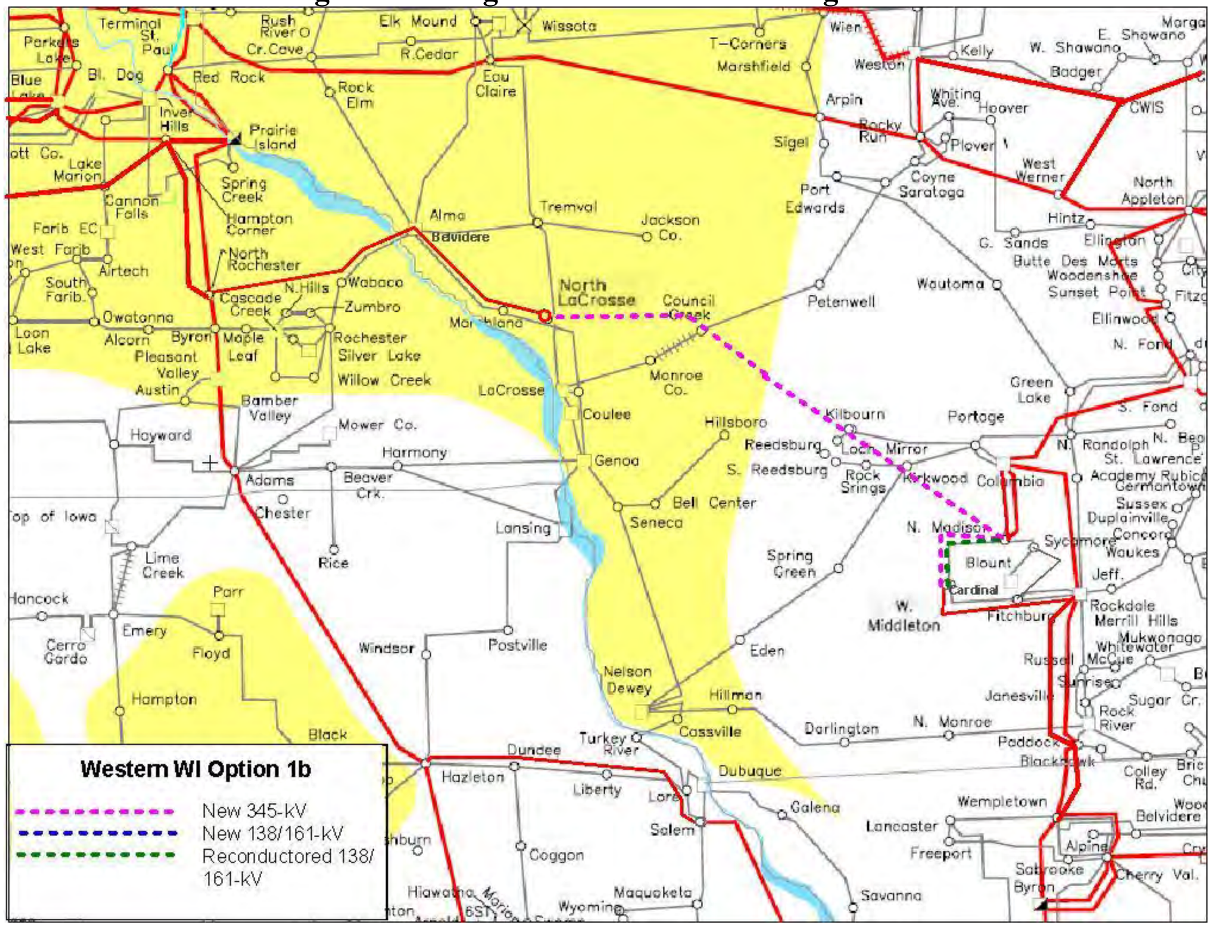
The Cardinal Substation was constructed in conjunction with a 345-kV project to extend a 345-kV line from the Rockdale Substation to the Cardinal Substation. The Cardinal Substation is being planned as an ultimate six position ring bus design but will be operated as a four position ring bus upon installation of Badger Coulee.

The North Madison Substation currently exists and is being planned as an ultimate six position ring bus design upon installation of Badger Coulee.

Badger Coulee has a total capital cost of $550 million in year-of-occurrence dollars and the present value (discounted to 2012) of the change in the net transmission charges to the ATC network customers over the 40-year life of the project is an increase of $4.25 million.

Badger Coulee was referenced as project 1b in the WWTRS report. The one-line diagram of this project is shown in Figure 3 below.

Figure 3: Badger Coulee One-Line Diagram [18]



3.2 Low Voltage Group of Transmission Projects

The Low Voltage Group of Transmission Projects is a large combination of new, rebuild and uprate construction of 161-kV, 138-kV, 115-kV and 69-kV transmission facilities to eliminate violations of NERC Category B reliability requirements and reactive compensation to eliminate NERC Category C reliability requirements.

The only new transmission line proposed with Low Voltage is the construction of a 161-kV line from the Liberty Substation near Dubuque, Iowa to the Nelson Dewey Substation near Cassville, Wisconsin at an estimated length of 18 miles. All other transmission line projects are either rebuilds or uprates of existing transmission lines, and all transformers identified are replacements of existing transformers. [redacted] Low Voltage has a total capital cost of $429 million in year-of-occurrence dollars and the present value (discounted to 2012) of the change in the net transmission charges to the ATC network customers over the 40-year life of the projects is an increase of $467million.

[18] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 7

The upgrades included in this project are shown in Table 3, Table 4, Table 5, Table 6, Table 7, and Table 8 below.

Table 3: Low Voltage – New Transmission Lines

Liberty – Nelson Dewey 161-kV	

Table 4: Low Voltage – Transformer Replacements

Galesburg 161/138-kV #2 (IL)	Hampton 161/69-kV (IA)
Sheffield 161/69-kV (IA)	Hillman 138/69-kV (WI)
Petenwell 138/69-kV (WI)	Whitcomb 115/69-kV (WI)
Harrison 138/69-kV (WI)	Nelson Dewey 161/138-kV (WI)

Table 5: Low Voltage – 161-kV Transmission Line Upgrades

Briggs Road – Mayfair (WI)	Elk Mound – Alma (WI)
Genoa – La Crosse Tap (WI)	Oak Grove – Galesburg (IL)
Adams – Beaver Creek (IA)	Salem – Julian (IA)
Lime Creek – Emery (IA)	8th St – Kerper (IA)
Southern GVW – 8th St (IA)	Southern GVW – Salem (IA)
East Calmus – Grand Mound (IA)	

Table 6: Low Voltage – 138-kV Transmission Line Upgrades

Rock Springs Tap – Artesian (WI)	Rock Springs Tap – Kirkwood (WI)
Darlington – North Monroe (WI)	Paddock – Town Line Road (WI)

Table 7: Low Voltage – 69-kV Transmission Line Upgrades

West Salem – La Crosse (WI)	Sand Ridge – Menominee (WI)
Harrison – Kaiser (WI)	Harrison – Lancaster (WI)
Menominee – Kieler Tap (WI)	Kaiser – Kieler Tap (WI)
Hurricane – Mount Hope Tap (WI)	Bell Center – Soldiers Grove Tap (WI)
Boaz – Dayton (WI)	Soldiers Grove Tap – Boaz (WI)
Lancaster – Hurricane (WI)	Lublin – Lakehead (WI)
Lublin Tap – Lakehead (WI)	Eden – Mineral Point (WI)
South Monroe – Browntown (WI)	Browntown – Jennings (WI)
Wiota – Gratiot Tap (WI)	Wiota – Jennings (WI)
Wauzeka – Boscobel (WI)	Wauzeka – Gran Grae (WI)
Pine River – Brewer (WI)	Sand Lake Tap – Sand Lake (WI)
West Middleton – Blackhawk (WI)	ACEC Brooks – McKenna (WI)
Hilltop – West Mauston Tap (WI)	West Middleton – West Towne (WI)
Lincoln Pumping Station – ACEC Brooks (WI)	

Table 8: Low Voltage – Reactive Compensation Requirements

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	

3.3 Other Alternatives Considered

Numerous alternative projects were considered as a part of this proceeding. Initial screening and analysis led to the inclusion of Badger Coulee and Low Voltage within this Planning Analysis. Other alternatives which were analyzed but not pursued further as a part of this proceeding include:

- 345-kV La Crosse – Spring Green – Madison Transmission Project
- 345-kV Extension to Iowa Transmission Project
- Combination 345-kV Transmission Project
- 765-kV Transmission Project

Further details of each of these alternatives are included below.

3.3.1 345-kV La Crosse – Spring Green – Madison Transmission Project

The 345-kV La Crosse – Spring Green – Madison Transmission Project is a set of 345-kV lines that will originate in the La Crosse, Wisconsin area, extend to the Spring Green, Wisconsin area and continue to the Middleton, Wisconsin area.

The 345-kV La Crosse – Spring Green – Madison Transmission Project would extend a 345-kV transmission line from a substation located to the north of La Crosse, Wisconsin to the Spring Green Substation located near Spring Green, Wisconsin. The estimated line distance from the La Crosse area substation to the Spring Green Substation is approximately 100 miles.

The 345-kV La Crosse – Spring Green – Madison Transmission Project would extend a 345-kV transmission line from the Spring Green Substation to the Cardinal Substation located near Middleton, Wisconsin. The estimated line distance from the Spring Green Substation to the Cardinal Substation is approximately 30 miles.

The La Crosse area substation does not currently exist. A substation is being planned for construction in conjunction with a 345-kV project from Rochester, Minnesota to the La Crosse area as part of the CAPX2020 group of projects. The La Crosse area substation for the Spring Green 345-kV project is being planned as an ultimate six position breaker and a half design.

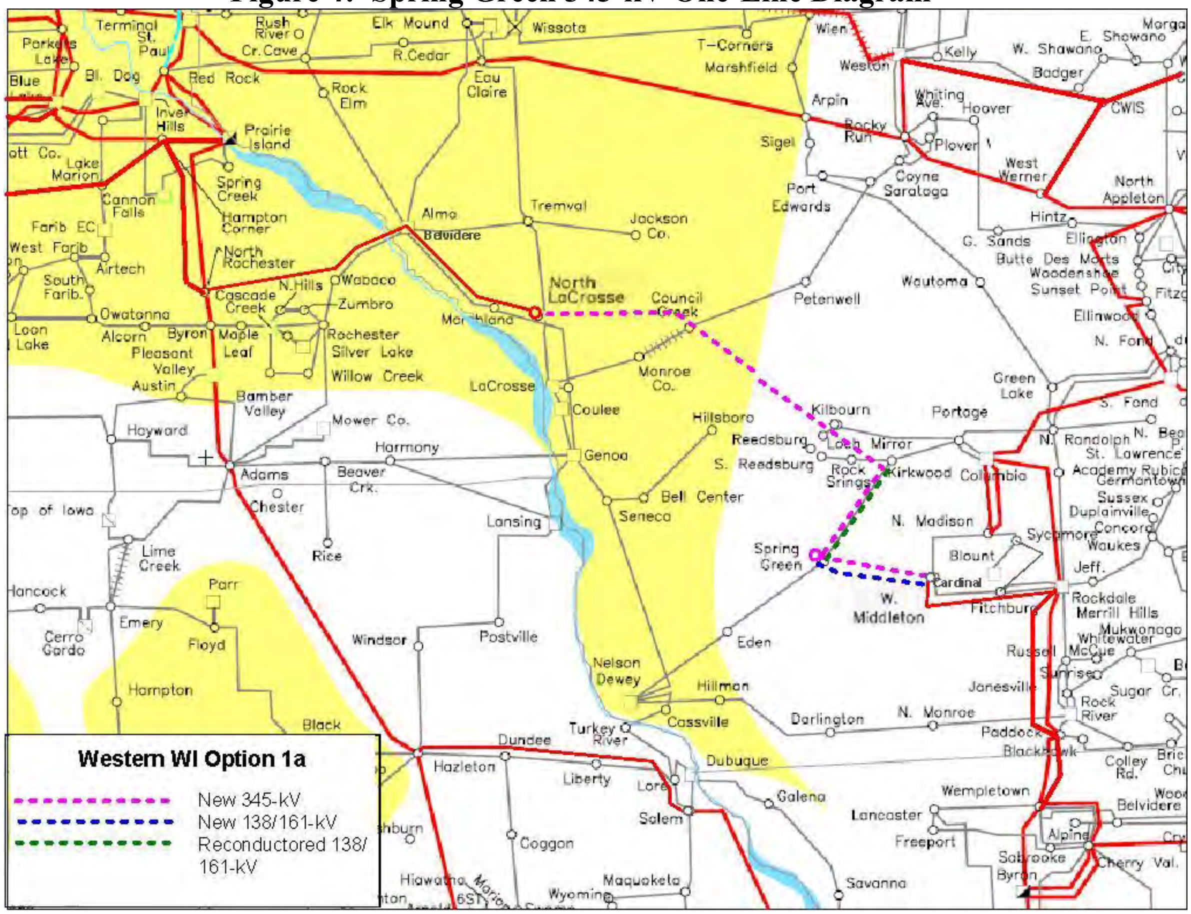
The Spring Green Substation currently exists but does not have any transmission facilities above the 138-kV voltage level. An expansion of the Spring Green Substation would be required with construction of this 345-kV project. The Spring Green 345-kV bus is being planned as an ultimate six position breaker and a half design while the 138-kV bus is being planned as an ultimate 8 position breaker and a half design.

The Cardinal Substation was constructed in conjunction with a 345-kV project to extend a 345-kV line from the Rockdale Substation to the Cardinal Substation. The Cardinal Substation is being planned as an ultimate six position ring bus design.

The La Crosse – Spring Green – Madison Transmission Project has a project cost estimate of $459 million in nominal dollars.[19]

The La Crosse – Spring Green – Madison Transmission Project was referenced as project 1a in the WWTRS report. From this point on, the La Crosse – Spring Green – Madison Transmission Project will be referenced as Spring Green 345-kV. The one-line diagram of this project is shown in Figure 4 below.

Figure 4: Spring Green 345-kV One-Line Diagram [20]



3.3.2 345-kV Extension to Iowa Transmission Project

The 345-kV Extension to Iowa Transmission Project is a set of 345-kV transmission lines that will originate in the Middleton, Wisconsin area, extend west to the Spring Green, Wisconsin area and continue to the Dubuque, Iowa area.

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[19] The La Crosse – Spring Green – Madison Transmission Project is based on the estimate provided in the WWTRS report. That estimate was provided in 2010 dollars and inflated by 3% annually to develop the nominal dollar estimate.
[20] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. B2

The 345-kV Extension to Iowa Transmission Project would extend a 345-kV transmission line from the Cardinal Substation located near Middleton, Wisconsin to the Spring Green Substation near Spring Green, Wisconsin. The estimated line distance from the Cardinal Substation to the Spring Green Substation is approximately 30 miles.

The 345-kV Extension to Iowa transmission line would also extend a 345-kV line from the Spring Green Substation to a new substation located near Dubuque, Iowa. The estimated line distance from the Spring Green Substation to the Dubuque area substation is approximately 80 miles.

The Cardinal Substation was constructed in conjunction with a 345-kV project to extend a 345-kV line from the Rockdale Substation to the Cardinal Substation. The Cardinal Substation is being planned as an ultimate six position ring bus design.

The Spring Green Substation currently exists but does not have any transmission facilities above the 138-kV voltage level. An expansion of the Spring Green Substation would be required for construction of this 345-kV project. The Spring Green 345-kV bus is being planned as an ultimate six position breaker and a half design while the 138-kV bus is being planned as an ultimate 8 position breaker and a half design.

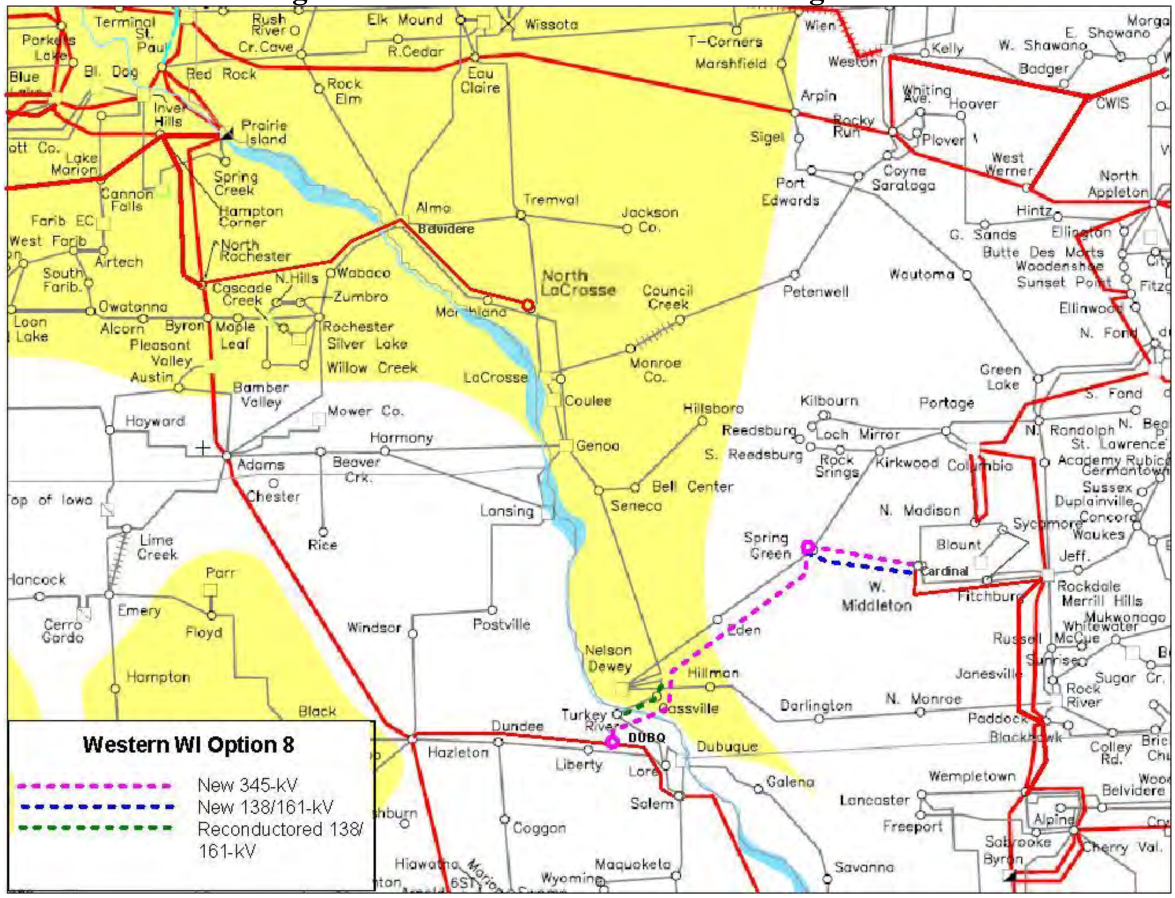
The Dubuque area substation to accommodate 345-kV transmission facilities does not currently exist. This substation would be required for construction in conjunction with this 345-kV project. The Dubuque area substation will tap into the proposed Hazleton – Salem 345-kV transmission project in Iowa. The Dubuque area substation would be designed as an ultimate six position breaker and a half design.

The 345-kV Extension to Iowa has a project cost estimate of $370 million in nominal dollars.[21]

The 345-kV Extension to Iowa Transmission Project was referenced as project 8 in the WWTRS report. From this point on, the 345-kV Extension to Iowa Transmission Project will be referenced as 345-kV to Iowa. The one-line diagram of this project is shown in Figure 5 below.

[21] The 345-kV Extension to Iowa Transmission Project is based on the estimate provided in the WWTRS report. That estimate was provided in 2010 dollars and inflated by 3% annually to develop the nominal dollar estimate.

Figure 5: 345-kV to Iowa One-Line Diagram [22]



3.3.3 Combination 345-kV Transmission Project – Combine both the Badger Coulee and 345-kV Extension to Iowa Transmission Projects

The Combination 345-kV Transmission Project would incorporate all facets of Badger Coulee and the 345-kV Extension to Iowa transmission project described previously. The project would extend 345-kV facilities from the La Crosse, Wisconsin area to the Madison, Wisconsin area. Additional 345-kV facilities would extend from the Madison, Wisconsin area to the Middleton, Wisconsin area and then to the Spring Green, Wisconsin area. The final portion of the project would be new 345-kV facilities from the Spring Green, Wisconsin area to the Dubuque, Iowa area.

The Combination 345-kV Transmission Project has a project cost estimate of $920 million in nominal dollars.[23]

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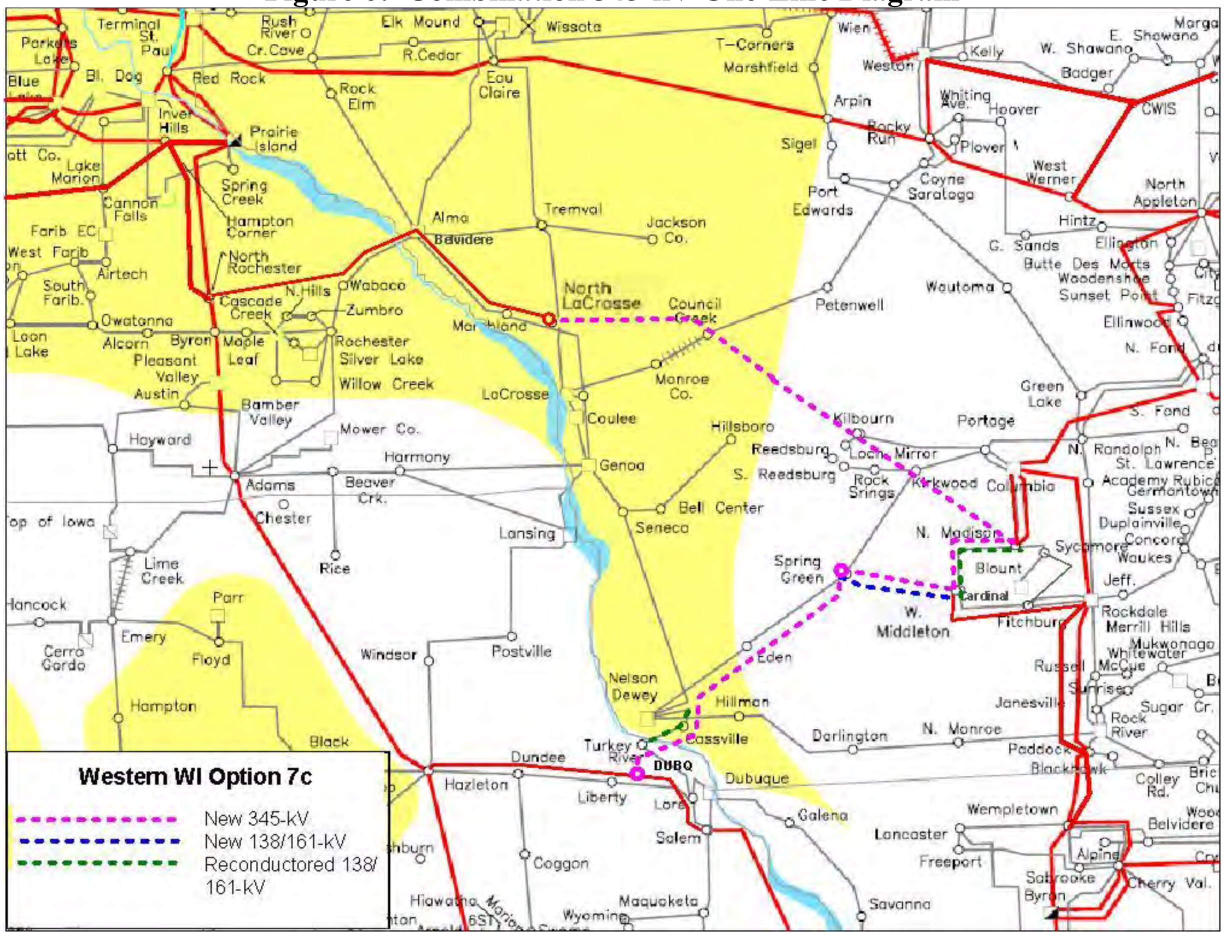
[22] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. B14

[23] The Combination 345-kV Transmission Project is based on combining the cost estimates of Badger Coulee and the 345-kV Extension to Iowa projects.

The Combination 345-kV Transmission Project was referenced as project 7c in the WWTRS report. From this point on, the Combination 345-kV Transmission Project will be referenced as Combination 345-kV. The one-line diagram of this project is shown in Figure 6 below.

Figure 6: Combination 345-kV One-Line Diagram [24]



3.3.4 765-kV Transmission Project

The 765-kV Transmission Project is a combination of 345-kV and 765-kV transmission lines that will connect multiple points in Western Wisconsin and Minnesota to points further east in South Central Wisconsin. Two new 345-kV lines that originate from the La Crosse, Wisconsin area and the Adams, Minnesota area would extend to the Genoa, Wisconsin area. A new 765-kV line would originate in the Genoa, Wisconsin area and extend to the Monroe, Wisconsin area. Two new 345-kV lines would originate in the Monroe, Wisconsin area and extend to the Beloit, Wisconsin area.

The 765-kV Transmission Project will extend a 345-kV transmission line from the Adams Substation located near Adams, Minnesota to the Genoa Substation located near Genoa,

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[24] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 8

Wisconsin. The estimated line distance from the Adams Substation to the Genoa Substation is approximately 80 miles.

The 765-kV Transmission Project would extend a 345-kV line from a substation located near La Crosse, WI to the Genoa Substation. The estimated line distance from the La Crosse area substation to the Genoa Substation is approximately 30 miles.

The 765-kV Transmission Project would extend a 765-kV line from the Genoa Substation to the North Monroe Substation located near Monroe, Wisconsin. The estimated line distance from the Genoa Substation to the North Monroe Substation is approximately 130 miles.

The 765-kV Transmission Project would extend a double circuit 345-kV line from the North Monroe Substation to the Paddock Substation located near Beloit, Wisconsin. The estimated line distance from the North Monroe Substation to the Paddock Substation is approximately 35 miles.

The Adams Substation currently exists, but would require expansion of 345-kV facilities to accommodate the new 345-kV line. The 345-kV bus would be expanded to a four position ring bus configuration.

The La Crosse area substation does not currently exist. A substation is being planned for construction in conjunction with a 345-kV project from Rochester, Minnesota to the La Crosse area as part of the CAPX2020 group of projects. The 345-kV bus for the 765-kV transmission project would be designed as an ultimate six position breaker and a half design.

The Genoa Substation currently exists, but does not have any transmission facilities above the 161-kV voltage level. The Genoa Substation would require a significant expansion to support the necessary 345-kV and 765-kV facilities required by this project. The 765-kV bus would accommodate 2 positions for connections to the transformer and the line. The 345-kV bus would be designed to an ultimate six position breaker and a half bus configuration. The 161-kV bus would be expanded to accommodate the new 345/161-kV transformer connection.

The North Monroe Substation currently exists, but does not have any transmission facilities above the 138-kV voltage level. The North Monroe Substation would require a significant expansion to support the necessary 345-kV and 765-kV facilities required by this project. The 765-kV bus would accommodate 2 positions for connections to the transformer and the line. The 345-kV bus would be designed for an ultimate six position breaker and a half design. The 138-kV bus would be expanded to accommodate the 345/138-kV transformer connection.

The Paddock Substation currently exists and does support 345-kV facilities. However, significant expansion of those 345-kV facilities would be required to support the necessary 345-kV facilities required by this project. The 345-kV bus would be designed to an ultimate six position breaker and a half design.

The 765-kV project has a project cost estimate of $1,071 million in nominal dollars.[25]

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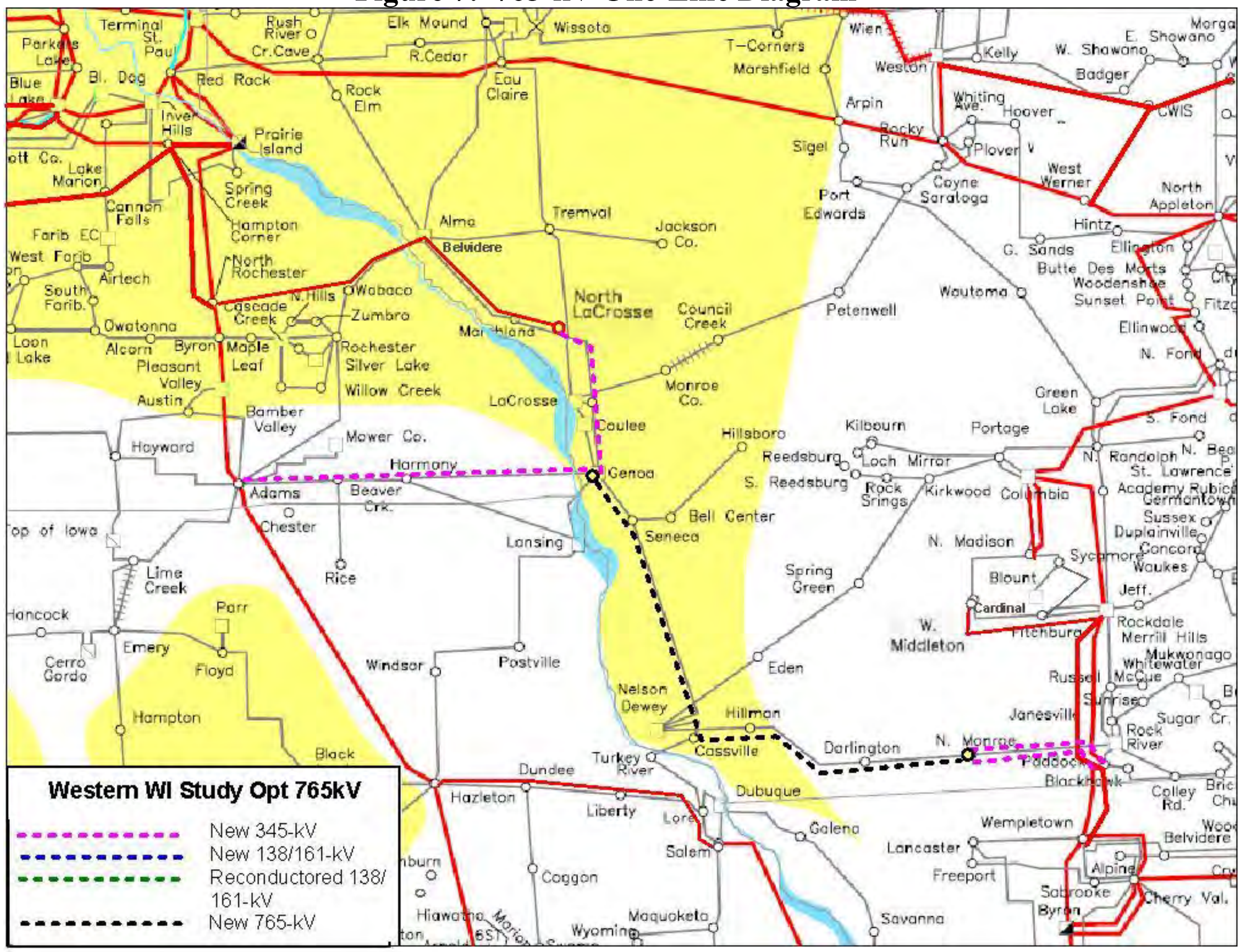
[25] The 765-kV Transmission Project is based on the estimate provided in the WWTRS report. That estimate was provided in 2010 dollars and inflated by 3% annually to develop the nominal dollar estimate.

The 765-kV Transmission Project was referenced as option 765-kV in the WWTRS report. From this point on, the 765-kV Transmission Project will be referenced as 765-kV. The one-line diagram of this project is shown in Figure 7 below.

Figure 7: 765-kV One-Line Diagram [26]



4.0 Introduction and Background to ATC's Planning Process

4.1 ATC's FERC Order 890 Open Stakeholder Process

In March 2008, FERC Order 890-A took effect. As part of this order, FERC requires a coordinated, open, and transparent transmission planning process on both a local and regional level. To comply with these requirements, ATC submitted a compliance filing on Order 890-A that provides a timeline of actions to ensure that the economic planning process is both coordinated and open.

Annually, ATC uses a process with consistent timelines that combines stakeholder input, historical data, future line flow forecasts, and updated information on the electric system to identify transmission upgrades for economic evaluation.

ATC conducts analyses of the projects identified for study over several months' time and posts the key results, including the extent to which these savings offset project costs. When the expected benefits of a studied project are high enough to justify its costs, the process of developing it as a formal proposal is begun.

ATC has analyzed Badger Coulee as a part of its Order 890 process starting in 2008. ATC has held numerous open stakeholder meetings to discuss the study process and results since that time. All meeting materials and information associated with ATC's Order 890 process can be found via the following web link: ATC Economic Project Planning
http://atc10yearplan.com/A8.shtml

4.2 ATC's Analysis of the Local Impacts of the Regional Market

The MISO Transmission and Energy Markets Tariff includes a system of security-constrained economic dispatch for generators in the MISO region, with pricing based upon LMPs. LMPs are comprised of bid-based energy costs, marginal congestion costs, and marginal losses.

ATC utilizes PROMOD software, licensed by Ventyx, to analyze the LMP markets in the MISO and PJM regions. It is through this analysis that ATC has determined many of the economic and market impacts associated with Badger Coulee. The details of this analysis and assumptions used to develop the PROMOD models are found throughout this report.

4.3 ATC's Coordination with Regional Planning Activities

ATC has been working closely with MISO planners in evaluating Badger Coulee. ATC has actively participated in the MISO process for cost-sharing of "economic" projects known as MVPs and in the FERC tariff proceeding on this subject. In addition, ATC has been an active participant in the RGOS and the UMTDI studies. Inputs from these studies as well as the MISO MTEP process have been integrated into the ATC economic planning models and analysis.

ATC coordinates regularly with adjoining transmission owners including Commonwealth Edison (ComEd), ITC Midwest (ITCM), (DPC), and Xcel Energy (Xcel) and has consulted with each of these transmission owners regarding Badger Coulee. ATC also monitors the proceedings of the CapX2020 Initiative, the purpose of which is to expand the EHV transmission system in Minnesota and adjoining states. ATC has incorporated this information into its evaluation of Badger Coulee.

4.4 Wisconsin Stakeholder Activities

In conducting this evaluation, ATC sought input from many other interested parties through its FERC Order 890 open stakeholder process and incorporated many of their suggestions into its analysis. It met several times with its major utility customers (Alliant Energy, Madison Gas & Electric Company, We Energies, Wisconsin Public Service Corporation, and Wisconsin Public Power, Inc.). It also consulted with retail customer groups (the Citizens Utility Board and the Wisconsin Industrial Energy Group), labor unions (the International Brotherhood of Electrical Workers), environmental groups (RENEW Wisconsin and Clean Wisconsin) and the Public Service Commission of Wisconsin (PSCW).

5.0 Local Economic Benefits

The economic analysis takes as a given security-constrained economic dispatch within the MISO market. Within this context it projects various combinations of market, business, and regulatory factors affecting the delivered cost of energy to ATC customers. It then evaluates how various project options contribute to reducing these costs and minimizing risks for ATC customers within these scenarios.

5.1 Summary of Methods for Analyzing Local Energy-Related Benefits and Results of Such Analyses

The analytical approach chosen by ATC tested Badger Coulee against six plausible futures for the electric industry in 2020 and 2026. These futures are Robust Economy, Green Economy, Slow Growth, Regional Wind, Limited Investment, and Carbon-Constrained. The six futures are based upon key drivers such as load and energy levels, generation retirement and expansion, fossil-fuel costs, use of renewable energy, and increased environmental regulation. ATC assigned a range of plausible outcomes for each of these factors based upon available data and estimates and then built up a plausible future composed of these selected values. The purpose of these futures is to “bound” the range of plausible futures. During the 40-year life of the project, we would expect that actual events would fall somewhere between the defined futures most of the time and only occasionally be completely in a particular future. The premise of this approach, known as Strategic Flexibility, is that if Badger Coulee performs well in most or all of these futures, it is a robust project that will produce benefits for ratepayers.

ATC then analyzed the major economic impacts of Badger Coulee and measured those impacts on an annual benefit basis for 2020 and 2026 and on a Present Value (PV) basis. ATC measured the benefits using the ATC Customer Benefit metric as the basis of its measurement. The ATC Customer Benefit metric measures the impact of a transmission project on the total energy and congestion-related cost of service of Wisconsin utilities, taking into account the existing market structure and regulatory environment in Wisconsin.

Table 9 shows the PV of the Badger Coulee project using this metric in each of the plausible futures. The PV is calculated over the 40-year life of the project using a 3 percent inflation factor and a 6.7 percent discount rate.

Table 9: Present Value of Aggregate PROMOD Energy Benefits for Badger Coulee [$M- Discounted to 2012]

	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Total PV Benefits: ATC Customer Benefit	356.26	285.45	37.09	212.06	146.85	112.10

The specific annual benefits that ATC estimated for Badger Coulee are shown in Table 10 and Table **11** for each of the two years ATC modeled: 2020 and 2026. This summation is made up of a number of individual benefits ATC identified as resulting from additional transmission projects, including:

- energy-cost savings for customers;
- reduced congestion costs and losses;
- system-failure insurance; and
- energy savings due to reduced losses.

Energy cost savings for customers were initially estimated using the PROMOD model; these estimates were adjusted to reflect the correct impacts on congestion costs and losses. Other standard methods were used to quantify other economic benefits of Badger Coulee such as system insurance value, and benefits from reduced energy losses.

Badger Coulee also produces other economic benefits such as Improved Competitiveness and RIB (by improving access to lower cost sources of renewable energy outside of ATC) and improved potential for increased regional transfers of renewable energy from sources to loads. These benefits are presented below.

Table 10 and
Table **11** are high-level summaries of the results of ATC's evaluation of specific Badger Coulee energy-related annual benefits in each of the futures for 2020 and 2026.

Table 10: 2020 Aggregate Annual PROMOD Energy Benefits of Badger Coulee [$M - 2020]

Benefit	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Customer Benefit Including FTR's, Congestion and Losses	18.87	9.34	2.61	6.98	7.65	5.75
Insurance Benefit During System Failure Events	0.97	0.97	0.97	0.97	0.97	0.97
Energy Savings from Reduced Losses	3.11	2.87	1.21	1.35	3.54	2.41
Total Annual Benefits to ATC Customers	22.95	13.18	4.79	9.30	12.16	9.13

Table 11: 2026 Aggregate Annual PROMOD Energy Benefits of Badger Coulee [$M - 2026]

Benefit	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Customer Benefit Including FTR's, Congestion and Losses	33.68	28.56	3.33	21.20	13.92	10.65
Insurance Benefit During System Failure Events	2.30	2.30	2.30	2.30	2.30	2.30
Energy Savings from Reduced Losses	5.82	6.59	1.53	3.24	5.19	3.37
Total Annual Benefit to ATC Customers	41.80	37.45	7.16	26.74	21.41	16.32

5.2 Analytical Framework of the Economic Analysis

5.2.1 Strategic Flexibility Methodology

Strategic Flexibility is an analytical approach developed by Deloitte Consulting to assist organizations in making major investment decisions in an uncertain environment. The premise of Strategic Flexibility is that, because we cannot know the future, high-cost projects should be tested against a range of plausible futures. These plausible futures are to "bound" the range of plausible outcomes, and not to identify the most likely future. The project is tested against each of the futures and should be chosen only if it is successful in most of the futures. The objective is to identify projects that are robust across a range of plausible futures.

ATC developed six scenarios that were designed to "bound" the range of plausible futures and coordinate with the MISO futures development that was occurring at the same time. ATC began the model development process by utilizing the futures developed by MISO during their MTEP process in conjunction with previous futures development initiatives undertaken at ATC. Through this process, six futures were identified and developed so that they are sufficiently different from each other and would capture a wide range of plausible outcomes. ATC built up the futures by identifying the variables or drivers that would most impact the results of the Badger Coulee analysis and determining how those drivers would behave in each scenario. Futures were specified for 2020 and 2026. The "plausible futures" were designed to describe the possible market conditions that could exist in 2020 and 2026.

5.2.2 Key Variables or Drivers

The drivers identified by ATC are:

- Load and energy levels inside and outside the ATC footprint;
- Total small coal retirements or conversions to natural gas within the ATC footprint;
- Expected generation additions within the ATC footprint;
- Amount and source of renewable energy consumed in Wisconsin;
- Natural gas, coal and fuel oil prices;

- Environmental regulations;
- Applicable RPS in Wisconsin and regionally;
- Nearby EHV transmission projects and regional transmission overlays; and
- Expected generation additions outside the ATC footprint.

Once the drivers were identified, the analysis team developed the range of plausible outcomes for each driver for 2020 and 2026. For some variables, including load levels and fuel prices, historical data was used to develop a range of future values while forecast data was used to develop the mid-level future value. For other variables, including environmental regulations, a more qualitative approach was used, based on publicly available information. The proposed ranges of plausible outcomes for each driver were reviewed with many stakeholders. Much of the feedback received was incorporated into the ranges.

5.2.3 Specific Futures

The approach to constructing futures was three-fold: 1) review the MISO MTEP process and analytical models for use as a starting point for the development of ATC's futures; 2) anchor each future at an upper or lower bound of a particular driver; and 3) determine the behavior of the other drivers in that scenario consistent with the anchor and the expanded ATC description. The objective was to have an internally consistent future with logical connections among all the drivers in the scenario.

Each future was specified for 2020 and 2026. The combination of futures was then reviewed graphically to evaluate whether the futures reasonably bounded the range of plausible futures. Again, the futures were reviewed with a variety of stakeholders including ATC customers, PSCW staff, and representatives of intervener groups, and their feedback was incorporated where appropriate. ATC believes the futures are sufficiently different and cover the range of plausible outcomes across the drivers.

ATC then analyzed the performance of Badger Coulee in each future. The analytical results were reviewed to determine how well the project performed across the range of plausible futures. A project that performs well across most of the futures is a project that can be undertaken with a high degree of confidence that the project will produce positive effects. It is a robust option. Badger Coulee performed well in the vast majority of the cases that were evaluated.

5.2.4 Descriptions of the Futures

Robust Economy Future

High energy and peak-demand rates of growth characterize this future because the economy recovers and expands vigorously due to increased capital investment, employment and consumer spending.

Higher energy consumption means that no additional small coal plants in Wisconsin are retired or converted to natural gas. Generator additions are needed within ATC based on MISO's Reference Plan, and they include coal, natural gas, and wind facilities.

A vigorous Wisconsin economy allows the state to increase its renewable-energy usage to 20 percent through a combination of internal and external resources. Higher demand for energy also results in higher costs for both natural gas and coal in addition to the need for additional generation within Wisconsin. The level of environmental regulation does not increase, and there is no carbon regulation or additional regulation of other emissions.

Regionally, Minnesota, Iowa, and Illinois meet their 2020/2026 renewable portfolio standards using wind power from these states and the Dakotas. The transmission overlay is the UMTDI Local 765-kV Overlay developed in the MISO RGOS for 15 GW of incremental wind (22 GW Overall), which was one of the levels specified by the UMTDI. The regional generation expansion plan is the MISO Reference Plan.

Green Economy Future

In this future, the economy experiences increased investment and growth due to policy initiatives like enhanced renewable-energy usage; a shift away from fossil fuels due to carbon regulation; Smart Grid with improved real-time demand response by customers; additional off-peak demand due to factors like off-peak charging of electric and plug-in hybrid vehicles; and increased energy-efficiency measures like improved building standards.

Energy and peak-demand grow within ATC and MISO because of increased economic activity in the new green manufacturing and construction sectors, aided by federal and state incentive programs. However, demand growth increases less than energy growth, due to the peak-shifting effects of demand-response programs, and increased off-peak usage due to lower electric rates during these hours and new factors like off-peak charging of electric and plug-in hybrid vehicles.

Stricter regulation of carbon and other emissions increases the cost of operating and retro-fitting smaller, older coal plants. These developments cause more of these units within ATC to be retired for economic reasons. The increased need for energy in the green economy is met by considerable additional wind power inside and outside ATC, allowing Wisconsin to reach 25 percent renewable energy usage by 2020/2026.

Carbon regulation increases production costs for coal-fired generation, due to an assumed carbon tax, and encourages greater use of natural gas as well as wind power. The additional wind power also results in more frequent dispatch of fast-start combustion turbines to compensate for the intermittency of the wind resource. These factors raise natural-gas prices higher than projected levels. Coal prices, on the other hand, are as projected because existing base load plants continue to be needed to meet increased energy growth.

The level of environmental regulation is higher because of the policy shift away from generating facilities producing high emissions.

Regionally, all MISO states with a 2020/2026 RPS are meeting these requirements using wind power from the highest-capacity factor wind zones. Increased reliance on gas-fired and wind-powered resources means that it is appropriate to use the Intra-Regional Transfer 345-kV

Transmission Overlay (for 25 GW of incremental wind and 32 GW Overall) and the MISO Gas-Only generation expansion plan.

Slow Growth Future

Energy and peak demand grow at a slower rate in this future due to a sluggish economy inside and outside ATC.

Lower demand and the high cost of retrofitting to meet environmental regulations cause some smaller, older coal-fired units within ATC to be retired for economic reasons. Beyond the currently planned wind generation facilities, there are virtually no new generator additions within ATC.

An enhanced RPS does not become law in Wisconsin, and the percentage of energy from renewable sources remains at the level required by current law, 10 percent.

The combination of lower energy demand and no carbon regulation results in lower costs for natural gas. For the same reasons, coal plants serve proportionately more of the need, resulting in continuing demand for coal, and the cost of coal increases as projected.

Regional wind development is at a lower level as RPS in other states also remains at present levels. The required transmission overlay is the most limited scenario ("Overlay Light"), and the MISO Reference case is the regional generation expansion plan.

Regional Wind Future

In this future, the potential of the Upper Midwest to produce and transfer its full potential of wind energy is realized.

ATC and regional energy and peak-demand growth are at higher levels.

Because of the additional wind resources and some level of carbon regulation, substantial retirements of older, and smaller Wisconsin coal plants occur. Mid-levels of additional wind are needed in Wisconsin, though regional wind development outpaces Wisconsin wind development. Renewable-energy usage in Wisconsin increases to 20 percent.

Additional generation capacity is needed in Wisconsin to meet the higher peak-demand growth rate. Steady demand for natural gas results in projected cost levels. Less coal-fired generation is needed because of the additional wind power, reducing the demand and cost for coal.

Additional environmental regulations are promulgated in the form of some carbon regulation and additional limits on other emissions.

Regionally, the highest capacity-factor wind zones are developed. The Intra-Regional Transfer 765-kV Overlay for 25 GW of incremental wind (32 GW Overall) is thus needed. The MISO Reference case provides the non-wind generation expansion plan.

Limited Investment Future

The main driver of this future is reduced capital investment in new energy infrastructure, especially new base load generation. There is less need for such investment because energy and peak-demand growth is modest within ATC and MISO due to an economy that is not growing at a robust rate.

In this future, credit markets do not provide easy access to investment capital, thus increasing the cost and transaction time for major projects. Regulatory proceedings for new, large generating facilities and major transmission facilities are also lengthy and uncertain due to public opposition, concern for rate impacts, and new environmental requirements.

Hence, there are limited generator additions within ATC, including new wind farms. The Wisconsin RPS remains as is, and there is no federal RPS. Natural gas prices are higher because of increased reliance on lower capital cost gas-fired units for new generation. Coal prices are also higher than projected because new supplies of coal are limited due to the investment climate. Finally, new environmental regulations do not increase production costs for or cause high retirement levels of existing coal units.

Regional wind development is at a relatively low level because the Minnesota and Iowa RPS also remain as is and are met from wind development in those states and the Dakotas. The transmission expansion case is the most limited scenario ("Overlay Light"), and the regional generation expansion plan is the MISO Gas-Only generation expansion plan.

Carbon-Constrained Future

The basic premise of this future is that carbon emissions must be reduced due to federal regulation, either a cap-and-trade system specifying increasingly stringent emissions levels or a direct tax on carbon emissions.

In this future, energy and peak-demand growth inside and outside ATC are restricted to low levels because demand reduction and energy efficiency are effective means of reducing carbon emissions. Expanded funding for programs like Focus on Energy and increased incentives for green building and energy-efficient appliances reduce peak demand and energy consumption below projected levels.

The pace of retirement of smaller, older coal plants within ATC increases to its highest feasible level. Generator additions within ATC are mainly additional wind facilities. The percentage of energy generated within the ATC footprint from renewable resources is at its highest plausible level, since renewable-energy usage increases in Wisconsin and new renewable generation within ATC is another means of reducing carbon emissions.

Natural gas prices are as projected because increasing demand for natural gas is offset by the fact that natural-gas fired generation also produces carbon emissions. Coal prices are lower than forecast because the demand for coal decreases as a result of carbon regulation.

The level of carbon regulation in 2020 is as projected because direct regulation of carbon emissions is still needed but is not the exclusive means of constraining carbon output. These levels increase to the highest plausible levels by 2026.

Regional RPS continue in effect as a contributor to carbon reduction, but are not at the highest plausible levels. Mid-levels of additional wind power are developed in Minnesota, Iowa, Illinois, and the Dakotas.

In this future, due to the relative prevalence of gas and wind generation, the transmission overlay is the UMTDI Local 345-kV Overlay for 15 GW of incremental wind (22 GW Overall), and the regional generation-expansion plan is the MISO Gas-Only generation expansion plan.

5.2.5 Futures Matrices

Table 12 and Table 13 list the various 2020 and 2026 drivers and the associated futures that were examined for Badger Coulee. Detailed information about the drivers and futures can be found in Badger Coulee Planning Analysis – Addendum C.

Table 12: ATC Futures for the 2020 Study Year

Drivers	Load Growth within ATC	Energy Growth within ATC	Load Growth outside ATC[2]	Energy Growth outside ATC[2]	Total Small Capacity Coal Retirements (or conversions to natural gas) Within ATC[3]	Generator Additions Within ATC[4]	Total Percent Energy from Renewables for ATC & Inside/Outside Percent[7]	Natural Gas Price Forecast	Coal Price Forecast for New Units[9]	Environmental Regulations[11]	Renewable Portfolio Standards (RPSs) and Wind Power Zones	Transmission Overlay Outside ATC[16]	Generation Portfolio Outside ATC[17]
Bounds	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020
Lower	0.2%	0.1%	0.3%	0.3%	907 MW	Planned Wind[5] Plus Wind Specified Below	10/7.4/2.6%	-40%	-10%	\$0/ton for CO_2, 0% higher mercury costs	Current State RPSs for MN, IA & WI (for 2020) and Allocation to Wind Zones located only in the UMTDI States in Proportion to Associated Cap. Factors[12]	Overlay Light-CAPX, Corridor & RIGO Projects	See Below
Mid[1]	1.40%	1.10%	0.75%	1.00%	453 MW	Planned Wind[5] Plus Wind Specified Below	20/10.5/9.5%[8]	NYMEX for as many years as available followed by EIA esc. rate.	MISO Central & West \$2.07 & \$1.74 per MMBTU, respectively, for 2020.[10]	\$25/ton for CO_2, 25% higher mercury costs	WI 20%[13] RPS & MN, IA & IL RPSs (for 2020) and Allocation to RGOS I Wind Zones in Proportion to Associated Capacity Factors[14]	15 GW RGOS I Overlay	See Below
Upper	2.5%	2.2%	1.6%	2.19%	Announced (289 MW)	Fossil[6] & Planned Wind[5] Plus Wind Specified Below	25/13/12%[8]	50%	20%	\$44/ton for CO_2, 25% higher mercury costs	WI 25%[13] & All MISO States with an RPS (for 2020) and Allocation to RGOS I Wind Zones in Proportion to Associated Capacity Factors[15]	25 GW RGOS I Overlay	See Below
2020 Futures Descriptions													
Robust Economy	2.50%	2.2%	1.6%	2.19%	Upper	+1,176 MW ATC Wind[6]	20/9.8/10.2%[8]	Mid-Upper +25%	Upper	Low	Mid (Existing + ~9.2 GW)[22]	15 GW-765KV Overlay	Reference
Green Economy	1.4%[18]	2.2%[18]	0.75%	2.19%	Lower	+1,823 MW ATC Wind & DRG[20]	25/12.5/12.5%[8]	Upper	Mid	Upper	Upper (Existing + ~20.7 GW)[22]	25 GW-345kV Overlay	Gas-only
Slow Growth	0.2%	0.1%	0.3%	0.3%	Mid	+31 MW ATC Wind	10/7.4/2.6%	Lower	Mid	Low	Low (Existing + ~3.2 GW)[22]	Overlay Light	Reference
Regional Wind	1.70%	1.4%	1.6%	1.32%	Lower	+918 MW ATC Wind[6]	20/9.7/10.3%[8]	Mid	Lower	Mid	Upper-20% WI (Existing + ~17.5 GW)[22]	25 GW-765kV Overlay	Reference
Limited Investment	1.0%	0.7%	0.75%	1.0%	Mid	+113 MW ATC Wind	10/7.2/2.8%	Mid-Upper +25%	Upper	Mid	Low (Existing + ~3.8 GW)[22]	Overlay Light	Gas-only
Carbon Constrained	0.2%[19]	0.1%[19]	0.3%	0.3%	Lower	+1,047 MW ATC Wind & DRG[20]	25/12.4/12.6%[8]	Mid	Lower	Mid[21]	Mid-25% WI[23] (Existing + ~7.3 GW)[22]	15 GW-345kV Overlay	Gas-only

Notes:

1) For ATC, the Mid load and energy growth rates are based on 2009 customer-supplied forecasts.
2) Outside ATC is defined as all of MISO, the Non-MISO Midwest Reliability Organization (MRO) Areas and Commonwealth Edison excluding the ATC utilities (e.g. Alliant, MG&E, We Energies, WPPI, and WPS). Load and energy growth rates are those from the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP) planning study. For reference, MISO's 15 GW Reference PROMOD model has MISO on peak load and energy growth rates of 1.21% and 1.07%, respectively, and Outside ATC rates of 1.31% and 1.15%, respectively.
3) Some small coal-fired retirements have been publicly announced and/or have recently occurred and are included as basecase assumptions. Conversion of Blount 6 & 7 from coal to natural gas at the end of 2011 is included in the "Announced" coal-fired retirements total. Other announced retirements include Blount units 3, 4 & 5 (totaling ~90 MW) by the end of 2013. Presque Isle Units 3 & 4 (116 MWs) and Pulliam units 3 & 4 (~55 MW) were already retired.
4) The uprate of Point Beach is a basecase assumption.
5) 439 MW of wind are expected to be in-service by the end of 2009 within ATC. An additional 539 MW of "planned" wind have signed Interconnection Agreements (IAs) that are not in suspension as of June 30, 2009. These total 978 MW.
6) Generator Additions Within ATC from MISO's Expansion Plans:

PowerBase In-Service Date	Regional Wind	Location	Robust Economy	Location
1/1/2013	600 MW CT	699785_ROCKY RN (WPS) (S. of Weston)	600 MW CT	699119_ROE 345 (WPL) (Rockdale)
1/1/2016	------------	--------------------------------	600 MW Coal	699157_COL 345 (WPL) (Columbia)
1/1/2020	------------	--------------------------------	600 MW CT	699785_ROCKY RN (WPS) (South of Weston)

7) 2,080 MW of new Manitoba Hydro generation is a basecase assumption in MISO's PROMOD models, however, it does not qualify under the current Renewable Portfolio Standard (RPS) for WI, but would under the WI Governor's Global Warming Task Force (GWTF) recommended RPS.
8) The new Manitoba Hydro (MH) generation for WPS and WPPI, which totals 600 MW, is estimated to provide approximately 3,504 GWh of energy to meet the WI GWTF RPS recommended renewable percentages.
9) Most existing coal-fired generators have unit specific coal price forecasts from Ventyx (formerly NewEnergy Associates).
10) Use "MISO Central" coal costs for MISO expansion plan generators added within ATC.
11) The generation expansion plan comes from MISO so the CO_2 tax only affects generation dispatch in ATC's PROMOD model. CAIR's and CAMR's status is uncertain, but other air pollution regulations have a similar impact to these regulations.
12) The RPS requirements for Illinois, Michigan, Ohio-Pennsylvania & Missouri are assumed to be met internally. UMTDI is the Upper Midwest Transmission Development Initiative and includes wind zones in SD, ND, MN, IA & WI to primarily serve the RPS requirements for MN, IA & WI.
13) Based on the Wisconsin Governor's Task Force on Global Warming (GWTF) recommendation of 20% by 2020 and 25% by 2025.
14) RGOS is MISO's Regional Generator Outlet Study. The RGOS I wind zones include the UMTDI wind zones plus zones in Illinois. The RPS requirements for the RGOS II states (including MI, OH-PA & MO) are assumed to be met internally.
15) Sufficient wind power is added so that all of the Load Serving Entities (LSEs) within MISO that have state RPS requirements can meet them from wind power coming from the RGOS I wind zones. However, the wind power to meet Michigan's RPS must be met by in-state resources and therefore does not come from the RGOS I wind zones. States without RPS requirements as of 9/15/09 with MISO LSEs include Indiana and Kentucky. North and South Dakota have renewable goals, rather than mandates, and are therefore not included in the requirements.
16) CAPX Group 1 and the Minnesota "Corridor" and "RIGO" projects are assumed in place by 2020. The transmission overlays are designed to move wind generation to load centers. However, transmission was not added to deliver the expansion plan generation (mainly fossil) added by MISO to maintain adequate reserve margins in 2020.
17) Reference and Gas-Only refer to separate MISO generation expansion plans and futures.
18) A lower peak load growth rate relative to energy growth rate was selected for the Green Economy future due to increased Demand Side Management and Smart Grid, not because of low economic growth.
19) The low peak demand and energy growth rates are assumed to result from increased demand-side management (DSM) and energy efficiency.
20) Distributed Renewable Generation (DRG) provides 0.5% of the energy subject to the WI RPS in 2020 and includes Solar PV, Biogass, and Wind. Depending on the assumed energy growth rate, this percentage results in up to 67 MW of DRG. PSC Staff assumed 80 MW of DRG in its ratepayer impact scenario in its 5/20/09 Advanced Renewable Tariff (ART) Memo.
21) The Mid carbon-tax value is used to serve as a proxy for having to purchase a moderate level of allowances. It is unlikely that 100% of allowances will be allocated, some will have to be purchased. The significant amounts of renewables and DSM available and in use in this future would probably help moderate allowance costs and therefore it makes sense to use the "Mid" value.
22) The "existing" renewables are from MISO's PowerBase database. For MN, IA and WI the existing renewables total 4.4 GW, of which 0.9 GW is hydro and biomass. For MN, IA, WI and IL the existing renewables total 4.8 GW, of which 0.9 GW is hydro and biomass. The incremental GWs of wind needed to meet the specified "Lower", "Mid" and "Upper" RPS requirements are provided for information purposes and are approximate. The wind power to meet Michigan's RPS must be met by in-state resources and therefore does not come from the RGOS I wind zones and is not included in the total.
23) Consistent with a lower amount of additional transmission.

Table 13: ATC Futures for the 2026 Study Year

Drivers	Load Growth within ATC	Energy Growth within ATC	Load Growth outside ATC[2]	Energy Growth outside ATC[2]	Total Coal Retirements (or conversions to natural gas) Within ATC[3]	Generator Additions Within ATC[4]	Total Percent Energy from Renewables for ATC & Inside/Outside Percent[7]	Natural Gas Price Forecast	Coal Price Forecast for New Units[9]	Environmental Regulations[11]	Renewable Portfolio Standards (RPSs) and Wind Power Zones (GW: Existing Model / Expansion / Total)[24]	Transmission Overlay Outside ATC[16]	Generation Portfolio Outside ATC[17]
Bounds	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026
Lower	0.2%	0.1%	0.3%	0.3%	2,039 MW	Planned Wind[5] Plus Wind Specified Below	10/7.4/2.6%	-40%	-10%	\$0/ton for CO_2, 0% higher mercury costs	Current State RPSs for MN, IA, IL & WI (for 2026) and Allocation to Wind Zones located only in the UMTDI States in Proportion to Associated Cap. Factors[12]	Overlay Light-CAPX, Corridor & RIGO Projects	See Below
Mid[1]	1.40%	1.10%	0.75%	1.00%	907 MW	Planned Wind[5] Plus Wind Specified Below	20/10.5/9.5%[8]	NYMEX for as many years as available followed by EIA esc. rate (2026 Avg: \$9.09/MMBtu)	MISO Central & West \$2.34 & \$1.96 per MMBTU, respectively, for 2026[10]	\$25/ton for CO_2, 25% higher mercury costs	WI 20%[13] RPS & MN, IA & IL RPSs (for 2026) and Allocation to RGOS I Wind Zones in Proportion to Associated Capacity Factors[14]	RGOS Phase I UMTDI Local / Intra-Regional Transfer Overlay	See Below
Upper	2.5%	2.2%	1.6%	2.19%	Announced (289 MW)	Fossil[6] & Planned Wind[5] Plus Wind Specified Below	25/13/12%[8]	50%	20%	\$50/ton for CO_2, 25% higher mercury costs	WI 25%[13] & All MISO States with an RPS (for 2026) and Allocation to RGOS I Wind Zones in Proportion to Associated Capacity Factors[15]	RGOS Phase I plus latest RGOS additions	See Below
2026 Futures Descriptions													
Robust Economy	2.50%	2.2%	1.6%	2.19%	Upper	+1,593 MW ATC Wind[6]	20/9.8/10.2%[8]	Mid-Upper +25%	Upper	Low	Mid (~4.7 GW / ~14.9 GW / ~19.6 GW)[21]	UMTDI Local-765KV Overlay	Reference
Green Economy	1.4%[18]	2.2%[18]	0.75%	2.19%	Mid (907 MW)	+2,333 MW ATC Wind & DRG[6,20]	25/12.5/12.5%[8]	Upper	Mid	Upper	Upper (~4.7 GW / ~26.9 GW / ~31.6 GW)[21]	Intra-Regional Transfer-345kV Overlay + latest RGOS	Gas-only
Slow Growth	0.2%	0.1%	0.3%	0.3%	Mid-Upper (453 MW)	+44 MW ATC Wind	10/7.4/2.6%	Lower	Mid	Low	Low (~4.7 GW / ~7.2 GW / ~11.9 GW)[21]	Overlay Light	Reference
Regional Wind	1.70%	1.4%	1.6%	1.32%	Mid (907 MW)	+1,159 MW ATC Wind[6]	20/9.7/10.3%[8]	Mid	Lower	Mid	Upper-20% WI (~4.7 GW / ~22.6 GW / ~27.3 GW)[21]	Intra-Regional Transfer-765kV Overlay + latest RGOS	Reference
Limited Investment	1.0%	0.7%	0.75%	1.0%	Mid-Upper (453 MW)	+172 MW ATC Wind	10/7.2/2.8%	Mid-Upper +25%	Upper	Mid	Low (~4.7 GW / ~8.6 GW / ~13.3 GW)[21]	Overlay Light	Gas-only
Carbon Constrained[23]	0.2%[19]	0.1%[19]	0.3%	0.3%	Lower	+1,077 MW ATC Wind & DRG[20]	25/12.4/12.6%[8]	Mid	Lower	Upper	Mid-25% WI[22] (~4.7 GW / ~9.4 GW / ~14.1 GW)[21]	UMTDI Local-345kV Overlay	OMS CARP

Notes:

1) For ATC, the Mid load and energy growth rates are based on 2009 customer-supplied forecasts.
2) Outside ATC is defined as all of MISO, the Non-MISO Midwest Reliability Organization (MRO) Areas and Commonwealth Edison excluding the ATC utilities (e.g. Alliant, MG&E, We Energies, WPPI, and WPS). Load and energy growth rates are those from the Organization of MISO States (OMS) Cost Allocation and Regional Planning (CARP) planning study.
3) Some small coal-fired retirements have been publicly announced and/or have recently occurred and are included as basecase assumptions. Conversion of Blount 6 & 7 from coal to natural gas at the end of 2011 is included in the "Announced" coal-fired retirements total. Other announced retirements include Blount units 3, 4 & 5 (totaling ~90 MW) by the end of 2013. Presque Isle Units 3 & 4 (116 MWs) and Pulliam units 3 & 4 (~55 MW) were already retired. The "Upper" level of retirements as used in the Carbon Constrained Future includes some intermediately sized units and is consistent with MISO's Cap and Trade Scenario from the OMS CARP analysis.
4) The uprate of Point Beach is a basecase assumption.
5) 439 MW of wind are expected to be in-service by the end of 2009 within ATC. An additional 856.5 MW of "planned" wind have signed Interconnection Agreements (IAs) that are not in suspension as of March 31, 2010. These total 1295.5 MW.
6) Generator Additions Within ATC from MISO's Expansion Plans:

Unit Type	Unit Size	Location	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Photovoltaic	30 MW	Rockdale	---	---	---	---	---	X
Photovoltaic	10 MW	Rockdale	---	---	---	---	---	X
Photovoltaic	110 MW	Rockdale	---	---	---	---	---	X
Biomass	200 MW	North Madison	---	---	---	---	---	X
CT Gas	600 MW	Rocky Run	X	X	---	X	---	---
CT Gas	600 MW	Rockdale	X	X	---	X	---	---
CT Gas	600 MW	Rockdale	X	---	---	---	---	---
Combined Cycle	600 MW	North Appleton	X	---	---	X	---	---
Combined Cycle	600 MW	Werner West	X	---	---	---	---	---
Combined Cycle	600 MW	Racine	X	---	---	---	---	---
Combined Cycle	600 MW	Cedarsauk	X	---	---	---	---	---
ST Coal	600 MW	Columbia	X	---	---	X	---	---
ST Coal	600 MW	Gardner Park	X	---	---	---	---	---

7) 2,080 MW of new Manitoba Hydro generation is a basecase assumption in MISO's PROMOD models, however, it does not qualify under the current Renewable Portfolio Standard (RPS) for WI, but would under the WI Governor's Global Warming Task Force (GWTF) recommended RPS.
8) The new Manitoba Hydro (MH) generation for WPS and WPPI, which totals 600 MW, is estimated to provide approximately 3,504 GWh of energy to meet the WI GWTF RPS recommended renewable percentages.
9) Most existing coal-fired generators have unit specific coal price forecasts from Ventyx (formerly NewEnergy Associates).
10) Use "MISO Central" coal costs for MISO expansion plan generators added within ATC.
11) The upper CO_2 tax of \$50/ton is consistent with values used by MISO in the OMS CARP analysis. The generation expansion plan comes from MISO so the CO_2 tax only affects generation dispatch in ATC's PROMOD model. CAIR's and CAMR's status is uncertain, but other air pollution regulations have a similar impact to these regulations.
12) The RPS requirements for Illinois, Michigan, Ohio-Pennsylvania & Missouri are currently assumed to be met internally. This assumption was made to be consistent with the Upper Midwest Transmission Development Initiative (RGOS, Phase 1) which includes wind zones in SD, ND, MN, IA, and WI to primarily serve the RPS requirements for MN, IA & WI. ATC is reviewing the assumption and may refine this to be more consistent with other regional studies.
13) Based on the Wisconsin Governor's Task Force on Global Warming (GWTF) recommendation of 20% by 2020 and 25% by 2025.
14) RGOS is MISO's Regional Generator Outlet Study. The RGOS I wind zones include the UMTDI wind zones plus zones in Illinois. The RPS requirements for the RGOS II states (including MI, OH-PA & MO) are assumed to be met internally.
15) Sufficient wind power is added so that all of the Load Serving Entities (LSEs) within MISO that have state RPS requirements can meet them from wind power coming from the RGOS I wind zones. However, the wind power to meet Michigan's RPS must be met by in-state resources and therefore does not come from the RGOS I wind zones. States without RPS requirements as of 9/15/09 with MISO LSEs include Indiana and Kentucky. North and South Dakota have renewable goals, rather than mandates, and are therefore not included in the requirements.
16) CAPX Group 1 and the Minnesota "Corridor" and "RIGO" projects are assumed in place by 2026. The transmission overlays are designed to move wind generation to load centers. However, transmission was not added to deliver the expansion plan generation (mainly fossil) added by MISO to maintain adequate reserve margins in 2026. "UMTDI Local" is equivalent to the previously named "15 GW" case. "Intra-Regional Transfer" is equivalent to the previously named "25 GW" case. The inclusion of the latest RGOS additions to the overlay will primarily be focused on new additions to the east of the RGOS Phase I (UMTDI) footprint, including Indiana, Michigan, and Ohio.
17) Reference and Gas-Only refer to separate MISO generation expansion plans and futures. ATC utilizes the identified generator additions within these expansion plans in order to develop its futures based on changes in peak demand forecasts. For cases where peak demand growth is low, generating units are typically removed from the expansion plan and may not be used at all for significantly low growth rates. For cases where peak demand growth is high, generating units are added to accomodate this growth. Reference refers to expansion consisting of CT Gas, Combined Cycle, and ST Coal generators. Gas-Only refers to expansion consisting of CT Gas and Combined Cycle generators. OMS CARP expansion was used for the Carbon Constrained Future in alignment with the MISO OMS CARP Cap and Trade Scenario.
18) A lower peak load growth rate relative to energy growth rate was selected for the Green Economy future due to increased Demand Side Management and Smart Grid, not because of low economic growth.
19) The low peak demand and energy growth rates are assumed to result from increased demand-side management (DSM) and energy efficiency.
20) Distributed Renewable Generation (DRG) provides 0.5% of the energy subject to the WI RPS in 2020 and includes Solar PV, Biogass, and Wind. Depending on the assumed energy growth rate, this percentage results in up to 67 MW of DRG. PSC Staff assumed 80 MW of DRG in its ratepayer impact scenario in its 5/20/09 Advanced Renewable Tariff (ART) Memo.
21) The "existing" renewables are from MISO's PowerBase database. The MISO-wide total for existing and planned wind within this model is 4.7 GW. MISO total installed wind capacity as of 12-1-2009 was approximately 7.72 GW. For MN, IA and WI the existing renewables total 4.4 GW, of which 0.9 GW is hydro and biomass. For MN, IA, WI and IL the existing renewables total 4.8 GW, of which 0.9 GW is hydro and biomass. The incremental GWs of wind needed to meet the specified "Lower", "Mid" and "Upper" RPS requirements are provided for information purposes and are approximate. The wind power to meet Michigan's RPS must be met by in-state resources and therefore does not come from the RGOS I wind zones and is not included in the total.
22) Consistent with a lower amount of additional transmission.
23) Assumptions of the Carbon Constrained Future as they pertain to small capacity coal retirements within ATC have been modified to match those assumptions used by MISO in the OMS CARP Cap and Trade Scenario.
24) Assumptions of the Renewable Portfolio Standards external to ATC are under review and may be revised to ensure appropriate levels are utilized within the analysis.

In reviewing the details of these Futures Matrices, it is important to note that they include specific assumptions about the key factors or drivers of the electric industry *in the 2020 and 2026 study years.* Thus, the fact that some current data may be different from these factors is to be expected. The test is whether the drivers for a particular future, taken together, constitute a reasonable assessment of one plausible scenario for 2020 and 2026, and whether all six of the future scenarios, taken together, present a reasonably complete picture of the likely future conditions in the industry.

During the 40-year life of this project, actual events are more likely to move through and even between the various futures, rather than remain statically within a single future. Planning models based on these Futures Matrices will continue to have predictive value as long as prevailing industry conditions generally remain within the low, medium, and high values for most of the drivers.

Inevitably, a complex Planning Analysis like the one conducted for Badger Coulee must conclude well in advance of the filing of a CPCN application for the project, since ATC must first determine that the project is needed and meets all relevant regulatory criteria before it prepares its application. In this case, in order to test the validity of the results in its Planning Analysis, ATC performed a sensitivity analysis using data from the Business as Usual (BAU) with Mid-Low Demand and Energy Growth Rates Future in the 2011 Midwest ISO Transmission Expansion Plan (MTEP 11)(also known as the MTEP 11 BAU-Low Future). This future is the most conservative of the MTEP 11 futures, and assumes a slow recovery from the current economic downturn. Details regarding this future and the results of ATC's sensitivity analysis are presented in Badger Coulee Planning Analysis – Addendum F. The results fall within the bounds of the results in this Planning Analysis and show net positive energy benefits for ATC customers.

5.3 Summary Value Measures Used in this Section

ATC used different summary measures to calculate the benefits of Badger Coulee. It measured benefits on a Net Present Value (NPV) basis and also evaluated the impacts of the project for two years, 2020 and 2026. Each study year has a different generation and transmission topology depending on the future analyzed.

When calculating the NPV, the following assumptions were made:

- A nominal discount rate of 6.7 percent was used to be consistent with a long term estimate of the FERC rate.
- ATC's present tariff was used throughout the life of the projects.
- The book and tax treatment of the assets was modeled to be consistent with the current methods.
- Inflation was assumed to be 3.0 percent per year.
- The economic benefits calculated for test years 2020 and 2026 were used in this analysis. The benefits assumed in years 2021 – 2025 were interpolated using a straight line method and for years beyond 2026 the benefits escalated with inflation. The benefits for 2018 and 2019 were reduced from the 2020 result to account for inflation.

The analysis assumes a December 31, 2018 in-service date for Badger Coulee. Therefore, the benefit calculations and initial accrual of annual benefits begins in 2019, immediately following the in-service date for the project.

5.4 Specific Local Economic Benefits of Badger Coulee

5.4.1 Benefit Definition

Badger Coulee produces energy-cost savings in the form of reductions in the cost of delivered energy for load-serving entities within ATC's service area. It will reduce congestion charges associated with moving energy from generation sources to load, increase the quantity of Financial Transmission Rights (FTRs) available to Load Serving Entities (LSEs) within ATC, and reduce electrical losses. The level of energy-cost savings depends upon several variables, including the extent to which Wisconsin LSEs are subject to cost-based versus market-based rates, and the degree to which this project increases transfer capacity and FTR coverage for Wisconsin LSEs. In this section ATC presents a detailed analysis and calculation of the full range of energy-cost savings as a result of Badger Coulee.

5.4.2 Summary of Measurement Methods

Initial estimates of energy-cost savings were developed using PROMOD, a LMP electric market simulation model. The savings were calculated using the ATC Customer Benefit metric. This metric was developed by ATC in an effort to attain a more precise energy cost calculation that explicitly takes into account: (1) the degree of cost-based versus market based generation in Wisconsin; (2) the level of FTR coverage for ATC-internal generation; (3) the level of FTR coverage for imports into the ATC service area; (4) the extent to which Badger Coulee makes additional FTRs available to LSEs in the ATC service area; and (5) the difference between marginal losses, loss refunds, and the PROMOD modeling of energy losses. This ATC Customer Benefit metric is discussed further in section 5.4.7 below.

5.4.3 Energy-Cost Savings Results from PROMOD

Table 14 and Table 15 show the energy cost differences for the ATC footprint with and without Badger Coulee for the 2020 and 2026 futures using the ATC Customer Benefit metric. Note that the values are in year-of-simulation dollars and that positive values denote benefits.

Table 14: Annual PROMOD Energy Savings Attributable to Badger Coulee for ATC Footprint for Various 2020 Futures [$M– 2020]

Metric	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Customer Benefit	18.87	9.34	2.61	6.98	7.65	5.75

Table 15: Annual PROMOD Energy Savings Attributable to Badger Coulee for ATC Footprint for Various 2026 Futures [$M– 2026]

Metric	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Customer Benefit	33.68	28.56	3.33	21.20	13.92	10.65

5.4.4 Refinements to PROMOD Results for Benefits from Congestion, FTR Allocations, and Marginal Losses

The ATC benefit measures largely utilize Adjusted Production Cost (APC) metrics as a base point for calculating the Customer Benefit metric. APC is calculated by adding the production cost paid for generation within a market region, adding the payment for imports to that region (priced at the Load-weighted LMP of the region) and subtracting revenue from exports from the region (priced at the Generator-weighted LMP of the region). However, APC on its own does not specifically account for: 1) the extent to which LSEs are hedged against charges for transmission congestion through FTR allocations; and 2) the extent to which LSEs pay marginal loss charges and receive MISO loss refunds.

Because transmission expansion reduces congestion and losses and may increase the number of FTRs available for allocation to load-serving entities, these factors can be important in evaluating the benefits of a transmission project. To the extent that the APC benefit measures do not accurately consider these factors, ATC has developed adjustments that account for them. The methodologies used to arrive at these adjustments for congestion/FTR and losses are documented in more detail in sections 5.4.5 and 5.4.6 below.

5.4.5 Congestion Charges and FTR Revenues

Benefit Definition. In MISO, utilities and other market participants pay congestion charges when transmitting energy from low-priced nodes to higher-priced nodes (unless the difference in nodal prices is only due to losses). Congestion charges can be hedged through offsetting revenues from FTRs that are allocated to or bought by load-serving entities, including the Wisconsin utilities. However, such FTR revenues do not exactly offset all congestion charges because allocated FTRs are often insufficient to cover peak flows but are often sufficient to cover non-peak flows.

If a new transmission project reduces congestion, congestion charges and FTR revenues both decrease, but often not in equal and offsetting amounts. Therefore, both changes in FTR revenues and changes in congestion charges are an important part of the benefit-cost analysis of new transmission projects.

To more accurately consider the extent to which a transmission project affects the congestion charges and FTR values, the following adjustments can be made to the APC metric:

- The impact of the transmission project on the estimated volume and value of allocated FTRs available for *imports* needs to be added to the APC measure.
- The impact of the transmission project on estimated congestion costs associated with *ATC-internal* transactions that are un-hedged through allocated FTRs needs to be added to the APC measure.

Methodology. The congestion charges on internal transactions that are missing from the APC can be quantified by multiplying the hourly load served by internal generation by the difference between the marginal congestion component (MCC) of load and the MCC of internal generation.

For each hour, PROMOD provides the load-weighted average MCC for all load buses and the generation-weighted average MCC for all generators in the ATC footprint.

Based on discussions with our customers, ATC assumes that FTRs provide an 85 percent hedge against internal congestion costs, with annual FTR revenues equal to 85 percent of the calculated annual congestion cost. ATC also conservatively assumes that Badger Coulee does not increase the quantity of ATC-internal FTRs available to the Wisconsin utilities.

FTR revenues on imports are given by the quantity of FTRs multiplied by the MCC differential between ATC Load and external hubs from which ATC imports will likely originate. The MCCs are taken from the PROMOD runs, but the quantity of FTRs must be estimated separately. Based on an analysis of existing FTR allocations, we found that there were at the time of this analysis approximately 280 MW of FTRs from Illinois to the Wisconsin-Upper Michigan System (WUMS) and approximately 800 MW from Minnesota and Iowa to WUMS. We assume this distribution persists through 2020 and 2026 and that the total amount incremental level of FTRs from these outside markets is given by the projected increase in First Contingency Incremental Transfer Capability (FCITC) for imports into the ATC service area with and without Badger Coulee. MISO's methodology for allocating FTRs is related to transfer capability but not determined directly by FCITC. On that basis, Badger Coulee would make available an additional 346 MW of FTRs for imports from these markets in 2020 and 2026. However, we consider FTR allocations from Illinois, Minnesota, and Iowa only if the anticipated congestion revenues are positive. In some futures, the MCC is higher externally than in Wisconsin, in which case it is presumed that utilities would not nominate FTRs of negative value from an external area.

5.4.6 Marginal Losses and Loss Refunds

Benefit Definition. As energy is transmitted, some energy is lost in the form of heat. Losses must be replaced, increasing the total amount of generation required to serve load. Under MISO market operation, the marginal cost of incremental generation needed to replace losses is reflected in the marginal loss component (MLC) of the LMP at each node. The difference in MLCs between two nodes determines the marginal loss charges imposed on transactions between those two points. However, because marginal losses are twice average losses, MISO's collection of marginal loss provides MISO with twice the funds it needs to compensate generators for the incremental generation replacing losses. MISO returns the surplus to LSEs as a refund that is equal, on average, to half of the marginal loss charges collected. Hence, it is important to estimate changes in marginal loss charges and loss refunds as part of the analysis of project benefits and costs.

Methodology. The PROMOD simulations include losses only by applying a static loss factor, which does not vary across cases, to increase forecasted loads. As a result, estimated production costs incorporate only a static estimate of the average cost of losses. Thus, the loss-adjusted load forecast does not fully capture how a transmission project changes marginal loss payments made and loss refunds received by the Wisconsin utilities.

Changes in marginal loss charges and loss refunds can be estimated using the MLCs from PROMOD as follows: marginal loss charges for transmitting internal generation to load are given by the MLC differential between load and generation; and the loss refund returns half of that amount. Similarly, marginal loss charges on imports into ATC are given by the MLC differential between ATC load and external sources. The change in total marginal loss charges and loss refunds due to Badger Coulee can thus be calculated from the MLCs in the PROMOD simulations with Badger Coulee versus without Badger Coulee.

The APC measure does not consider changes in *ATC-internal* marginal loss charges nor the associated refunds. These values consequently need to be incorporated for a more complete description of transmission project benefits. Marginal loss charges on imports are already included implicitly in the APC measure because imports are valued at the ATC-internal Load LMP. However, the associated loss refund, given by half of the MLC differential, is not reflected in the APC cost, and it must be applied as a credit in order to produce a more comprehensive measure of changes in customer costs.

5.4.7 ATC Customer Benefit

Benefit Definition. The previous section quantified congestion, FTR, and loss-related costs and benefits to LSEs in Wisconsin that are not fully reflected in the APC measure. However, even with these adjustments, the APC measure does not capture how a transmission project affects the total energy and congestion-related cost of service of Wisconsin utilities. This is because the APC measure does not fully reflect the existing structure of the market and regulatory environment in Wisconsin. Rather, this metric quantifies a transmission project's benefits to LSEs only under various simplified assumptions about market structure and the extent to which LSEs are subjected to cost-based versus market-based rates.

Methodology. Badger Coulee's estimated impact on the energy and congestion-related costs of Wisconsin utilities explicitly takes into account the estimated degree of cost-based versus market-based generation in Wisconsin; the estimated level of FTR coverage for ATC-internal generation; the estimated level of FTR coverage of imports into the ATC service area; the extent to which Badger Coulee is estimated to make additional FTRs available to LSEs in the ATC service area; and the difference between marginal losses, loss refunds, and the PROMOD modeling of energy losses.

Table 16 documents the methodology used to measure the transmission project's impact on the energy and congestion-related cost of service of Wisconsin utilities by calculating these benefits for the 2020 "Robust Economy" case. This "energy formula," based on a variety of PROMOD simulation results and additional data, assembles a bottom-up estimate of the total energy and congestion-related cost of serving Wisconsin load as the sum of (1) total cost of generation supply; (2) congestion charges *net of* FTR revenues; and (3) marginal loss charges *net of* loss refunds.

As shown in Table 16, the total <u>*cost of generation supply*</u> is determined as the sum of total utility production costs, market-based purchases from merchant generators, and the cost of imports (priced at the LMP of the source of the imported energy, outside of ATC) less any revenues from exports. The costs and benefits associated with congestion, FTRs and losses are determined as discussed in sections 5.4.5 and 5.4.6 above. Total *congestion charges* imposed on Wisconsin utilities are determined based on the quantity of imports and internally-supplied generation times the MCC differences between source locations (external hubs and ATC-internal generation) and ATC-internal load. These congestion charges are partially offset by *FTR revenues*, which are estimated based on the quantity of allocated FTRs available to hedge both imports and internal transactions. Marginal *loss charges* are determined based on the quantity of imports and internally-supplied load multiplied by the MLC differences between sources and load. Credits associated with *loss refunds* are estimated as half of the marginal loss charges. Finally, to avoid double counting, the production costs associated with the static losses that are embedded in the PROMOD load forecast must, again, be removed.

Results. Table 16 shows that Badger Coulee decreases the total cost of generation supply of the Wisconsin utilities by $8.04 million per year for the 2020 "Robust Economy" future. The Wisconsin utilities total annual congestion charges are estimated to drop by approximately $17.17 million, but that reduction is offset by a $7.15 million reduction in FTR revenues (note, however, that the $7.15 million decrease in FTR revenues results from the combination of a $10.24 million decrease of FTR revenues associated with ATC-internal transactions in addition to a $3.09 million increase in import-related FTR revenues). Table 17 also shows that $2.40 million in reduced marginal loss charges are offset by $1.20 million in reduced loss refunds. Finally, $0.37 million of changes in costs associated with static losses reflected in the PROMOD estimate of production costs need to be added back to avoid double counting of loss-related benefits. The sum total of all of these cost impacts is a $19.64 million annual benefit in 2020 for a "Robust Economy" under today's market structure.

The Customer Benefit impact to the Wisconsin utilities' cost of service for each of the evaluated futures is presented in Table 17 for the year 2020 and in Table 18 for the year 2026.

Table 16: Badger Coulee Calculation of Customer Benefit Impact on Wisconsin LSEs ("Robust Economy", 2020) [$M - 2020]

			Without Badger Coulee	With Badger Coulee	Change
Customer Benefit Formula					
Cost of Generation Supply			**$ - Millions**	**$ - Millions**	**$ - Millions**
	Total ATC Production Costs	Production Costs	$2,143.03	$2,112.17	$30.86
+	Production Cost of ATC Utility Generation	(Production Cost - IPP Production Cost)	$2,046.32	$2,019.08	$27.23
+	Cost to Utilities of Purchasing IPP Gen	(IPP Unit Revenue)	$160.12	$155.27	$4.85
+	Cost of Imports (Market price at external hubs)	Imports * (2 * LMPil + LMPmn)/3	$291.74	$312.12	-$20.39
+	Revenue from Exports	Exports * LMPgen	-$80.81	-$77.15	-$3.65
	Subtotal	*sum*	$2,417.37	$2,409.32	**$8.04**
Congestion Charges					
+	Utility Congestion Charges on Internal Transactions	(Load-Imports) * (MCCload - MCCgen)	$66.48	$54.43	$12.05
+	Utility Congestion Charges on Imports: External Hubs to Load	Imports * (MCCload - [2 * MCCil + MCCmn]/3)	$15.18	$10.05	$5.12
	Subtotal	*sum*	$81.65	$64.48	**$17.17**
FTR Revenues					
	Into ATC				
	Existing Valuable FTRs into ATC, without Project		1,082	1,082	0
	Existing Valuable FTRs into ATC, with Project		1,082	1,082	0
	Incremental Valuable FTRs into ATC due to Project		---	152	152
+	Value of Existing FTRs	Existing FTRs * (MCCload - MCCoutsidegen)	-$57.68	-$51.39	-$6.29
+	Value of Incremental FTRs	Incremental FTRs * (MCCload - MCCoutsidegen)	$0.00	-$9.38	$9.38
	Subtotal	*sum*	-$57.68	-$60.77	**$3.09**
	Within ATC				
	Fraction of Internal Congestion Hedged	assumption based on customer responses	85%	85%	
+	Revenues on Internal FTRs	Hedged % * Internal Congestion Costs	-$56.50	-$46.26	-$10.24
	Subtotal	*sum*	-$56.50	-$46.26	**-$10.24**
Loss Charges					
+	Utility Loss Charges on Internal Transactions	(Load-Imports) * (MLCload - MLCgen)	$170.73	$167.48	$3.25
+	Utility Loss Charges on Imports: External Hubs to Load	Imports * (MLCload - [2 * MCCil + MCCmn]/3)	$23.67	$24.52	-$0.85
	Subtotal	*sum*	$194.40	$192.01	**$2.40**
Loss Refund and "Credit" for Losses Already Captured in Production Cost (and then again through MLCs)					
+	Loss Refund Internal: Utility & IPP Gen to Load	1/2 of Utility Loss Charges on Internal Transactions	-$85.37	-$83.74	-$1.63
+	Loss Refund on Imports: External Sources to Load	1/2 of Utility Loss Charges on Imports	-$11.84	-$12.26	$0.43
+	Loss Refund on Internal and Imports	*sum*	-$97.20	-$96.00	**-$1.20**
	Adjusted Production Cost	From PROMOD	$2,392.81	$2,381.72	$11.09
	Static Loss % Included in Load Forecast	From case w/o Project: Avg. Loss from MLC / Prod. Cost	$0.00	$0.00	0.00%
+	Cost of Losses Already Captured	Adj. Prod. Cost * Static Loss %	-$85.37	-$84.97	**-$0.40**
= Customer Benefit		*sum of subtotals*	$2,396.67	$2,377.80	**$18.87**

Table 17: Badger Coulee Calculation of Customer Benefit Impact on Wisconsin LSEs (All Futures, 2020) [$M - 2020]

		Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Customer Benefit Formula							
Cost of Generation Supply		**$ - Millions**	**$ - Millions**	**$ - Millions**	**$ - Millions**	**$ - Millions**	**$ - Millions**
	Total ATC Production Costs	$30.86	$26.74	$15.49	$5.98	$28.41	$25.11
+	Production Cost of ATC Utility Generation	$27.23	$24.31	$13.64	$5.31	$24.80	$21.40
+	Cost to Utilities of Purchasing IPP Gen	$4.85	$3.40	$2.39	$0.89	$4.39	$4.93
+	Cost of Imports (Market price at external hubs)	-$20.39	-$21.89	-$4.76	-$7.44	-$15.14	-$11.01
+	Revenue from Exports	-$3.65	-$0.86	-$9.36	$3.32	-$10.52	-$9.96
	Subtotal	**$8.04**	**$4.95**	**$1.91**	**$2.08**	**$3.53**	**$5.37**
Congestion Charges							
+	Utility Congestion Charges on Internal Transactions	$12.05	$7.16	$4.48	$3.67	$11.41	$3.06
+	Utility Congestion Charges on Imports: External Hubs to Load	$5.12	$4.10	$0.34	$1.59	$1.38	-$0.53
	Subtotal	**$17.17**	**$11.26**	**$4.82**	**$5.27**	**$12.79**	**$2.52**
FTR Revenues							
	Into ATC						
	Existing Valuable FTRs into ATC, without Project	0	622	358	978	338	98
	Existing Valuable FTRs into ATC, with Project	0	622	358	978	338	98
	Incremental Valuable FTRs into ATC due to Project	152	118	15	132	11	18
+	Value of Existing FTRs	-$6.29	-$1.97	-$0.57	-$0.89	$0.43	-$0.44
+	Value of Incremental FTRs	$9.38	$0.34	$0.05	$2.94	$0.09	$0.17
	Subtotal	**$3.09**	**-$1.62**	**-$0.52**	**$2.05**	**$0.53**	**-$0.27**
	Within ATC						
	Fraction of Internal Congestion Hedged		85%	85%	85%	85%	85%
+	Revenues on Internal FTRs	-$10.24	-$6.09	-$3.81	-$3.12	-$9.70	-$2.60
	Subtotal	**-$10.24**	**-$6.09**	**-$3.81**	**-$3.12**	**-$9.70**	**-$2.60**
Loss Charges							
+	Utility Loss Charges on Internal Transactions	$3.25	$3.53	$0.67	$1.67	$1.89	$2.01
+	Utility Loss Charges on Imports: External Hubs to Load	-$0.85	-$1.39	-$0.17	-$0.08	-$0.68	-$0.39
	Subtotal	**$2.40**	**$2.14**	**$0.50**	**$1.60**	**$1.21**	**$1.62**
Loss Refund and "Credit" for Losses Already Captured in Production Cost (and then again through MLCs)							
+	Loss Refund Internal: Utility & IPP Gen to Load	-$1.63	-$1.77	-$0.34	-$0.84	-$0.95	-$1.01
+	Loss Refund on Imports: External Sources to Load	$0.43	$0.70	$0.09	$0.04	$0.34	$0.19
+	Loss Refund on Internal and Imports	**-$1.20**	**-$1.07**	**-$0.25**	**-$0.80**	**-$0.60**	**-$0.81**
	Adjusted Production Cost	$11.09	$6.70	$1.53	$3.37	$3.44	$3.21
	Static Loss % Included in Load Forecast	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
+	Cost of Losses Already Captured	**-$0.40**	**-$0.23**	**-$0.03**	**-$0.09**	**-$0.10**	**-$0.08**
= Customer Benefit		**$18.87**	**$9.34**	**$2.61**	**$6.98**	**$7.65**	**$5.75**

Table 18: Badger Coulee Calculation of Customer Benefit Impact on Wisconsin LSEs (All Futures, 2026) [$M - 2026]

		Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Customer Benefit Formula							
Cost of Generation Supply		**$ - Millions**	**$ - Millions**	**$ - Millions**	**$ - Millions**	**$ - Millions**	**$ - Millions**
	Total ATC Production Costs	$59.17	$77.29	$14.46	$33.08	$33.52	$37.81
+	Production Cost of ATC Utility Generation	$55.23	$74.75	$13.69	$30.46	$32.11	$38.77
+	Cost to Utilities of Purchasing IPP Gen	$3.78	$6.08	$0.93	$3.18	$3.20	$2.22
+	Cost of Imports (Market price at external hubs)	-$33.16	-$57.92	-$5.99	-$21.60	-$20.22	-$20.22
+	Revenue from Exports	-$13.58	-$3.19	-$6.38	-$1.38	-$9.42	-$9.34
	Subtotal	**$12.27**	**$19.72**	**$2.25**	**$10.66**	**$5.67**	**$11.42**
Congestion Charges							
+	Utility Congestion Charges on Internal Transactions	$24.71	$22.18	$2.86	-$1.49	$10.30	$3.73
+	Utility Congestion Charges on Imports: External Hubs to Load	$4.98	$9.25	$0.29	$2.20	$3.66	$0.44
	Subtotal	**$29.70**	**$31.43**	**$3.15**	**$0.70**	**$13.96**	**$4.17**
FTR Revenues							
	Into ATC						
	Existing Valuable FTRs into ATC, without Project	1,082	1,082	1,062	1,082	742	802
	Existing Valuable FTRs into ATC, with Project	1,082	1,082	1,062	1,082	742	802
	Incremental Valuable FTRs into ATC due to Project	152	152	148	152	140	152
+	Value of Existing FTRs	-$8.92	-$11.65	-$1.68	-$3.49	-$4.24	-$6.42
+	Value of Incremental FTRs	$19.15	$6.43	$1.62	$10.49	$6.09	$3.43
	Subtotal	**$10.23**	**-$5.23**	**-$0.06**	**$7.00**	**$1.85**	**-$2.99**
	Within ATC						
	Fraction of Internal Congestion Hedged	85%	85%	85%	85%	85%	85%
+	Revenues on Internal FTRs	-$21.01	-$18.85	-$2.43	$1.27	-$8.75	-$3.17
	Subtotal	**-$21.01**	**-$18.85**	**-$2.43**	**$1.27**	**-$8.75**	**-$3.17**
Loss Charges							
+	Utility Loss Charges on Internal Transactions	$8.46	$11.50	$1.21	$4.91	$4.18	$3.59
+	Utility Loss Charges on Imports: External Hubs to Load	-$2.11	-$6.97	-$0.28	-$1.09	-$1.36	-$0.76
	Subtotal	**$6.36**	**$4.52**	**$0.93**	**$3.82**	**$2.83**	**$2.83**
Loss Refund and "Credit" for Losses Already Captured in Production Cost (and then again through MLCs)							
+	Loss Refund Internal: Utility & IPP Gen to Load	-$4.23	-$5.75	-$0.60	-$2.45	-$2.09	-$1.80
+	Loss Refund on Imports: External Sources to Load	$1.05	$3.49	$0.14	$0.55	$0.68	$0.38
+	Loss Refund on Internal and Imports	**-$3.18**	**-$2.26**	**-$0.47**	**-$1.91**	**-$1.41**	**-$1.42**
	Adjusted Production Cost	$15.30	$18.46	$2.11	$11.20	$6.19	$7.93
	Static Loss % Included in Load Forecast	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
+	Cost of Losses Already Captured	**-$0.69**	**-$0.78**	**-$0.05**	**-$0.34**	**-$0.22**	**-$0.20**
= Customer Benefit		**$33.68**	**$28.56**	**$3.33**	**$21.20**	**$13.92**	**$10.65**

5.4.8 Insurance Benefits

Benefit Definition. The most important job of the transmission system is to maintain system reliability so that load can be served. Transmission enhancements reduce the likelihood and extent of loss of load by improving the stability of the system and/or increasing access to additional resources. Such enhancements improve the ability of the transmission system to respond to emergencies. Projects whose primary objective is "economic" also tend to improve system reliability by reducing the likelihood or magnitude of load-shedding events under certain contingencies or system conditions. Indeed, due to system growth, such economically-justified projects could ultimately be necessary to satisfy reliability criteria. The economic value of such reliability benefits can be quantified based on the avoidance of load-shedding events and the economic harm caused by such events.

The insurance benefit of a project is the positive result it produces in mitigating the energy-cost impacts of more severe generation or transmission outages. The PROMOD runs used to evaluate energy-cost savings are consistent with NERC standards which require the continued stable operation of the system and continuity of service to all load and generation in the event of a forced outage of *single* system elements and generation units. Given past actual system events, it is also reasonable to consider the performance of the system with and without the project when confronted with more severe *multiple* outages to generation units and transmission elements. Such outages may occur from time to time over the 40-year evaluation period of the project. Several scenarios of multiple outages are listed in the NERC Transmission Planning Standards and are referred to as "Category C" for loss of two or more Bulk Electric System (BES) elements and "Category D" for extreme BES events.

NERC standards state that "depending on system design and expected system impacts, the controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary[27]" to maintain ongoing operation of the transmission system. Therefore the value of this benefit is defined as:

1) The difference in the value of energy and congestion with and without the proposed project; and
2) The difference in the value of unserved energy with and without the proposed project when evaluating the performance of the BES under these multiple or extreme system failure events.

New transmission can improve the performance of the BES and provide an insurance benefit against the loss of load, generation or transmission service under these multiple element or extreme events.

Methodology. To determine the insurance benefit of a project in the event of more severe outages, the appropriate methodology to use is the standard insurance valuation tools of probability of occurrence and impact of occurrence for several generation scenarios and several transmission scenarios. Impact is defined as: (1) the energy and congestion cost impacts on the

[27] NERC Reliability Standard TPL-003-0 – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) – Footnote C.

load served as evaluated when each of the major contingencies was run through the PROMOD model, plus (2) the value of load not served. However, the PROMOD simulations generally do not estimate the magnitude of unserved energy. For this reason ATC adopted a conservative approach and did not calculate the additional $/MWh value of lost load with and without the project for these more severe scenarios.

Probabilities were derived from historical experience events in Wisconsin and their impact on the performance of the BES in Wisconsin and a review of the relevant similar regions nationally. The prominent drivers found were weather [redacted], regulatory mandate [redacted] and sabotage [redacted]. The duration of these outages was also derived from historical events, with the most severe durations based on the time to order long lead-time equipment replacements.

Transmission scenarios were based on locations where multiple circuits share the same Rights of Way (ROW), structure or substation. Three risk levels were evaluated based on two circuits (one high voltage and one EHV[28]), two circuits (both EHV) and a complete substation outage.

Generation scenarios were based on generation risks derived from a common campus with shared facilities or common design basis which might result in a common regulatory mandate (requiring the shutdown of multiple plants until the regulatory deficiencies are resolved). Two risk levels were evaluated based on a common system failure at a coal generation campus and a regulatory mandate across three common design basis nuclear units. A third level of generation risk is already embedded in the PROMOD software protocol which removes single units on the basis of their forced outage characteristics.

Results. Table 19 shows the insurance benefit of Badger Coulee in the event of extreme multiple-element system-outage events.

[28] For the purposes of this report, "high voltage" is defined as facilities of voltage class less than 200-kV and "EHV" is defined as facilities of voltage class 200-kV and greater.

Table 19: Insurance Benefit Results

Generation Events (Event Description)	Frequency of Occurrence (Probability)	Duration	Customer Benefit Savings [$M - 2020]	Customer Benefit Savings [$M - 2026]	40-Year PV of Customer Benefit Savings [$M - – 2012]
2 – Large Coal-Fired Units (Coal Campus)	20 Years (5%)	3 weeks (3/52)	0.07	0.14	1.46
3 – Nuclear Units	40 Years (2.5%)	1 year (52/52)	0.61	1.51	15.38
Transmission Events (Event Description)					
1 – 345-kV Line	10 Years (10%)	2 weeks (2/52)	0.04	0.09	0.93
2 – 345-kV Lines	20 Years (5%)	4 weeks (4/52)	0.02	0.07	0.69
1 – 345-kV Substation	40 Years (2.5%)	6 months (26/52)	0.23	0.50	5.16
Totals			0.97	2.30	23.63

The annual benefit of $0.97 M in 2020 is deescalated at an assumed 3.0 percent inflation rate to achieve an in-service date of December 31, 2018. The annual values between 2020 and 2026 are calculated by linear interpolation between the individual 2020 and 2026 data points. The 2026 value is then escalated at an assumed 3.0 percent inflation rate and discounted at an assumed 6.7 percent nominal discount rate resulting in 40-Year Present Value benefits of $23.63 M discounted to 2012. ATC included the PV of these energy cost reductions in the calculation of project benefits.

5.4.9 Energy Savings from Reduced Losses

Benefit Definition. Energy losses on the transmission system can result in increased costs to utilities and ratepayers due to the need to generate enough energy to adequately serve loads while accounting for the losses accrued during the transmission of this energy. To the extent that new transmission changes dispatch and flow patterns, transmission losses will also change. If transmission losses decrease, utilities will not have to install as much generation in order to meet their energy needs.

Methodology. ATC has developed a tool which utilizes outputs from PROMOD simulations to determine the total energy losses per year that are accrued on the ATC transmission system. These losses are subsequently priced at ATC Zonal LMPs also taken from PROMOD. These two metrics were then used to determine the impact that Badger Coulee has on ATC system-wide energy losses and subsequent financial impact of the change in energy losses attributed to the addition of the project. The difference in energy losses between the with- and without-Badger Coulee cases was applied to all futures and both 2020 and 2026 study years.

Results. Using PROMOD and ATC's loss evaluation tool, energy loss savings associated with Badger Coulee were calculated for all futures and study years.
Table 20 and Table 21 detail the annual energy savings determined for the project. Table 22 and Table 23 provide the annual financial savings associated with the Badger Coulee energy savings.

Table 20: Annual PROMOD Energy Loss Savings Attributable to Badger Coulee for ATC Footprint for Various 2020 Futures [MWh/yr]

Metric	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Energy Loss Savings	36,927	20,757	28,102	17,206	35,217	27,963

Table 21: Annual PROMOD Energy Loss Savings Attributable to Badger Coulee for ATC Footprint for Various 2026 Futures [MWh/yr]

Metric	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Energy Loss Savings	48,788	24,741	34,628	32,191	40,297	21,783

Table 22: Annual PROMOD Energy Loss Savings Attributable to Badger Coulee for ATC Footprint for Various 2020 Futures [$M – 2020]

Metric	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Energy Loss Savings	3.11	2.87	1.21	1.35	3.54	2.41

Table 23: Annual PROMOD Energy Loss Savings Attributable to Badger Coulee for ATC Footprint for Various 2026 Futures [$M - 2026]

Metric	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Energy Loss Savings	5.82	6.59	1.53	3.24	5.19	3.37

5.4.10 Reserve Requirements

Transmission projects that increase import capability, like Badger Coulee, could have a positive impact on our ability to reduce reserve-margin requirements while still meeting reliability requirements.

Reserve requirements are calculated annually by MISO through the use of Loss of Load Expectation (LOLE) analysis. The following excerpt from the Executive Summary of the MISO 2011 – 2012 LOLE Study Report provides further details regarding the latest results of MISO's annual LOLE study:[29]

> A Planning Reserve Margin unforced capacity (PRMUCAP) of 3.81% applied to Load Serving Entity (LSE) non-coincident peaks has been established for the planning year starting June 2011 and ending May 2012. This value was determined through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. PROMOD IV® was used to perform a security constrained economic dispatch which provided the congestion-driven zonal definitions used within MARS. The analysis resulted with one uniform Planning Reserve Margin, applicable to the Midwest ISO Market footprint as a single Planning Reserve Zone.

[29] MISO 2011 – 2012 LOLE Study Report, January 12, 2011.

The goal of a Loss of Load Expectation (LOLE) study is to determine a minimum planning reserve margin that would result in the Midwest ISO system experiencing less than one loss of load event every ten years. This ten year metric, if realized uniformly over a 10 year period, would be approximately like a 10% probability for one insufficient capacity event each year. As modeled within the GE MARS software, the system would achieve this reliability level when the amount of installed capacity available is 1.174 times that of the Midwest ISO system coincident peak. The annual run for a given year at the break even 1 day in 10 criteria, achieves a 0.1 day/year solution point. The Midwest ISO Tariff states in 68.3:

The Loss of Load Expectation

The Transmission Provider will annually calculate and post the PRM such that the LOLE is equal to the one (1) day in ten (10) years, or 0.1 day per year resource adequacy criteria. The minimum PRM requirement will be determined using the LOLE analysis by stressing the Transmission System, by either adding Demand or removing Capacity, until the LOLE reaches 0.1 day per year.

Within Module E, individual LSEs maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a 4.55% diversity factor. This resulted in an individual LSE reserve level of 12.06%, reduced from what would otherwise be a 17.4% reserve without accounting for diversity. Taking into account average unit availability within the Midwest ISO system a forced outage rate of 7.357% was used to arrive at an unforced capacity margin of 3.81%.

The MISO LOLE study process included sensitivities to determine the impact of reducing congestion on the system-wide Planning Reserve Margin (PRM). This sensitivity revealed that congestion did not seem to contribute significantly to the PRM in the 1-year and 5-year planning horizons but did begin to impact and raise the required PRM by the 10-year planning horizon. ATC has not performed any specific studies or sensitivities to determine the potential impacts of Badger Coulee on the MISO system-wide PRM.

5.5 Transmission Alternatives

The system alternatives considered in this analysis are listed below. More information about the process that identified these alternatives and the reliability-related planning results for these alternatives can be found in the WWTRS created in September 2010.

The system alternatives evaluated were:

- Badger Coulee;

- Spring Green 345-kV;
- 345-kV to Iowa;
- Combination 345-kV;
- 765-kV; and
- Low Voltage.

5.5.1 Comparing the Performance of Alternatives

Methodology. PROMOD analysis was performed on each of the alternatives across the aforementioned futures in an effort to develop economic performance comparisons. The ATC Customer Benefit, as described in section 5.4.7, was utilized for calculation of project savings. In addition, Insurance Benefits, as described in section 5.4.8, and Energy Loss Savings, as described in section 5.4.9, were utilized for additional project benefits. However, Insurance Benefits were not included for the WWTRS Low Voltage alternative.

Initial screening of two of the alternatives showed limited performance potential when compared to the other alternatives analyzed. This included both the Spring Green 345-kV project as well as the 765-kV project. As such, only PROMOD analysis for the 2020 study year was performed and a 3 percent inflation value was utilized to determine the savings through the remainder of the 40-year economic evaluation of these projects. The 2020 results and estimated 2026 results for these two alternatives were utilized to determine the 40-year PV values detailed below.

Results. Table 24 shows the full 40-Year PV of energy-related savings accrued for each of the alternatives studied. These values are inclusive of PROMOD results for 2020 and 2026 based on the ATC Customer Benefit metric, Insurance Benefits, and Energy Loss Savings.

Table 24: PV of Aggregate PROMOD Energy Benefits – ATC Customer Benefit [$M - 2012]

	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Badger Coulee	356.26	285.45	37.09	212.06	146.85	112.10
Spring Green 345-kV[1]	322.88	128.33	80.06	147.46	113.65	119.23
345-kV to Iowa	747.77	461.94	77.30	392.22	242.63	155.00
Combination 345-kV	967.23	603.45	90.80	521.46	312.49	213.63
765-kV[1]	241.29	79.80	28.56	113.23	61.48	84.26
Low Voltage	500.83	267.11	34.58	277.34	140.50	135.29

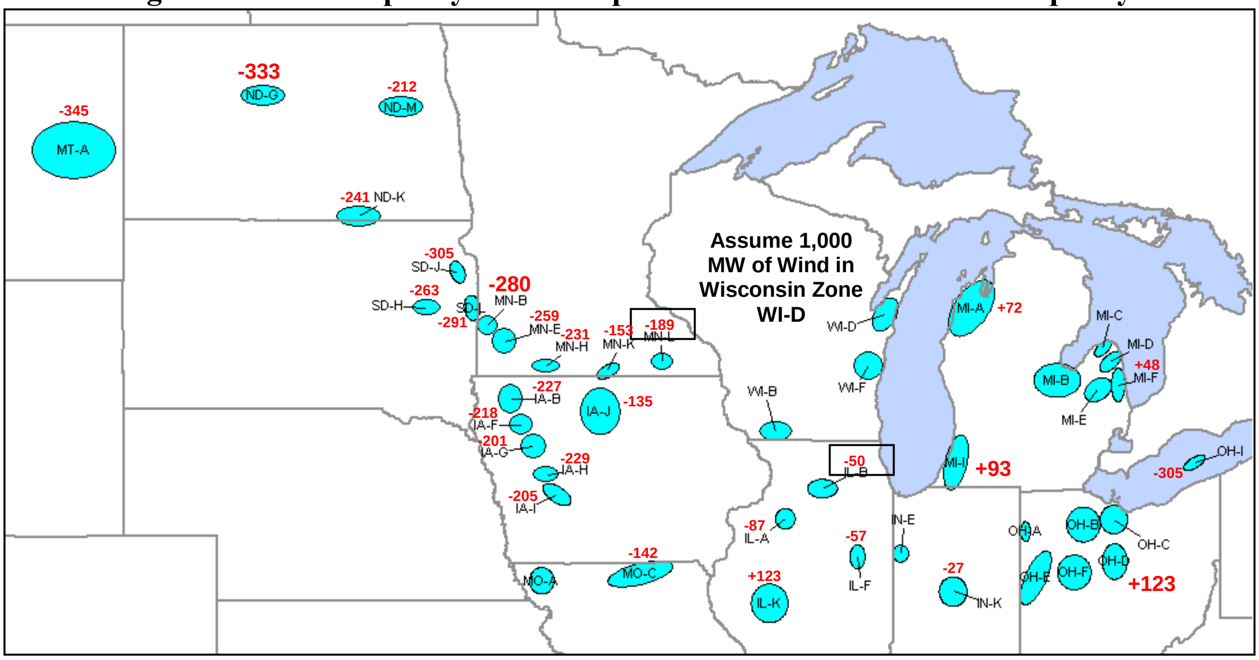
[1] PV Calculations for 765-kV and Spring Green 345-kV include simulations results for 2020 and an estimate for 2026 results.

5.6 Renewable Investment Benefit

RPSs are typically expressed in terms of the percentage of renewable energy that must be produced by renewable resources. A capacity factor measures the actual energy output of a power plant relative to its maximum capability if it operated all of the time. It is a ratio (often expressed as a percentage) and is typically calculated using a year's worth of hourly generation data. For wind power, capacity factors vary widely across the Midwest. Because wind speed and consistency varies widely across the United States, capacity factors for large-scale wind plants can range between 20 and 40 percent. For example, a 100 MW wind plant with a 30 percent annual capacity factor generates on average 30 MW. However, sometimes it may be generating little or no power and other times its full 100 MW output.

Wind capacity factors in states west of Wisconsin (including Iowa, Minnesota, North and South Dakota, etc.) can be up to 15 percent higher than in Wisconsin. This translates into a significant decrease in the number of wind turbines and overall capacity of wind generation plants needed to produce the same amount of wind energy in these states relative to Wisconsin. The map in Figure 8 illustrates this situation.

Figure 8: Wind Capacity Factor Impact on Installed Generation Capacity



Assuming 1,000 MW of wind capacity was built in Wisconsin in wind zone "WI-D", 720 MW (280 MW less) of wind capacity could be built in wind zone "MN-B" (in south western Minnesota) and produce the same amount of wind energy. Similarly, in wind zone "ND-G" (in central North Dakota), 667 MW (333 MW less) would need to be built to match the energy produced by the 1,000 MW in Wisconsin. These wind zones were identified in the MISO RGOS as having the highest wind potential in each state.

The RIB is designed to capture the value of this reduction in the capacity of wind generation plants needed to satisfy the demand for renewable energy, which can in turn result in significant capital/construction cost savings.

The RIB is defined as the value created by constructing wind generation in higher capacity wind production areas when there is sufficient transfer capability to deliver wind energy to load centers.

The actual economic metric is:

- Dollar value of the capital cost savings (technically the revenue requirements savings) due to building fewer wind generators to produce the same amount of energy;
- Adjusted for the increase in transfer capability as a result of a new transmission project; and
- Reduced by the difference in the estimated LMP payments ("generator market revenue") that wind generation inside Wisconsin would receive from the MISO market relative to wind outside Wisconsin.

5.6.1 RIB and Increase in Transfer Capability

A transmission project's ability to import more wind power into the ATC footprint was estimated based on the increase in the FCITC with the project relative to without the transmission project. The FCITC calculation was based on the summer off-peak power flow model from the WWTRS. [30] The summer off-peak case was utilized for RIB calculations due to the assumed connection between higher wind speeds on a seasonal basis and the likelihood that benefits associated with higher wind speeds would be more reasonably realized in the off-peak time periods. The increase in transfer capacity for each transmission alternative was the average of the Iowa to Wisconsin and Minnesota to Wisconsin FCITC, which is shown in Table 25 and Table 25.

For the Slow Growth and Limited Investment Futures (where the energy growth rates for load are relatively low) the amount of wind capacity needed to satisfy the RPS requirement is less than the increase in transfer capacity. In these cases the lower value (the RPS wind need) is used in the RIB calculation (78 and 304 MW, respectively) rather than the FCITC.

FCITC is the amount of real power that can be moved or transferred over the transmission system from a source location to a sink location for a given set of assumptions made in a power flow model. The FCITC is the point where real power is no longer able to be delivered from the source to the sink due to a transmission facility loaded to 100 percent of its applicable rating (continuous rating with an intact system or emergency rating with a contingency). Limits to transfer capability are only considered valid if at least 3 percent of the transfer is flowing on the limiting transmission facility. Phase shifting transformers were modeled as constant flow in the base case and fixed angle in contingencies, consistent with the MISO Coordinated Seasonal Assessments. Existing or proposed operating guides and Special Protection Systems were modeled. FCITC was calculated for both the summer peak load and off-peak load models.

Transfers were evaluated from two different source points. One source was defined as the generation located in Iowa, which includes the ITCM, MidAmerican Energy Company (MEC), and Muscatine Power and Water (MPW) areas. The other source was defined as the generation located in Minnesota, which includes the Minnesota Power (MP), Southern Minnesota Municipal Power Agency (SMMPA), Otter Tail Power (OTP), and Great River Energy (GRE) areas and the Xcel-Minnesota (XEL-MN) zone. Both sources excluded MISO RGOS wind zones from the transfer. In addition, the Minnesota source excluded units at Center, Coyote, and Coal Creek

[30] ATC utilized a more conservative assumption related to local constraints than those utilized in the WWTRS as a part of this Planning Analysis.

because they deliver power via HVDC lines which maintain existing real power control settings during source to sink transfers.

The transfer was evaluated with a single sink point defined as the generation in WUMS, the generation located in the service territories of Alliant East, We Energies, Wisconsin Public Service, Madison Gas and Electric and Upper Peninsula Power Company.

The following region was monitored for overloads:

- All ATC branches and ties ≥ 69-kV;
- All branches and ties ≥ 69-kV in SMMPA, XEL-MN, XEL-WI, and DPC;
- All branches and ties ≥ 100-kV in GRE, ITCM, and MEC; and
- All other MISO transmission ≥ 345-kV.

All single contingencies were modeled in the following areas:

- All ATC branches and ties ≥ 69-kV;
- All branches and ties ≥ 100-kV in SMMPA, XEL-MN, XEL-WI, DPC, GRE, ITCM, and MEC; and
- All branches and ties ≥ 345-kV in ComEd.

As shown in the Table 25 and Table 26 below, all options increase average transfer capability in the summer peak and off-peak cases.

Table 25: FCITC Summary – Summer Peak

Case	Imports From IA (MW)	Imports From MN (MW)	Average (MW)	Average Increase From Base (MW)
Base	639	768	703	0
Badger Coulee	811	1,142	977	273
Spring Green	1,271	1,954	1,613	909
345-kV to Iowa	1,669	1,461	1,565	861
Combination 345-kV	1,543	2,955	2,249	1,545
765-kV	991	964	978	274
Low Voltage	1,633	2,338	1,986	1,282

Table 26: FCITC Summary – Summer Off-Peak

Case	Imports From IA (MW)	Imports From MN (MW)	Average (MW)	Average Increase From Base (MW)
Base	0	0	0	0
Badger Coulee	0	1,212	606	606
Spring Green	0	1,329	664	664
345-kV to Iowa	1,045	1,050	1,048	1,048
Combination 345-kV	1,037	1,630	1,334	1,334
765-kV	130	134	132	132
Low Voltage	862	771	816	816

5.6.2 RIB and Difference in LMP Payments to Wind Generation Outside WI Relative to Inside WI

LMP payments from the MISO market to outside wind plants (“generator market revenue”) are predicted to be somewhat lower than those to wind plants inside Wisconsin due to prevailing and predicted congestion and electric losses on the transmission grid. As indicated above, the capital cost savings (due to the ability to build fewer wind turbines outside Wisconsin relative to inside Wisconsin while producing the same amount of energy) needs to be adjusted for this reduction in generator market revenue for outside wind generators.

The outside wind LMP (and the basis for calculating the corresponding annual market revenue for outside wind generators) is the average annual LMP for the four MISO Wind Zones shown in Figure 8: IA-J; MN-H; MN-K; and MN-L. ATC’s annual load-weighted LMP is the proxy for the inside wind LMP (and is the basis for calculating the corresponding annual market revenue for inside wind generators). Using ATC’s load-weighted LMP as a proxy to calculate the inside wind generator revenue is conservative because it provides an upper bound for this revenue. Load-weighted LMPs are almost always higher than generator LMPs (in the same general area) because losses and congestion between generation and load tend to drive up the LMP for load buses relative to generator buses. The difference in loss charges between the outside and inside wind is captured in the difference between the MCCs of the outside and inside wind. The MCC is one of the three components that make up the LMP. The other two are the MLC and the energy component.

The average hourly differences in LMPs for inside versus outside wind plants come from the 2020 and 2026 PROMOD runs, vary by future, and are shown in Table 27 and Table 28.

Table 27: 2020 Average Hourly LMP Differential between WI[1] and MN/IA[2] [$/MWh]

Future	Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
Robust Economy	9.06	8.84	8.97	8.43	9.40	9.79
Green Economy	6.11	6.01	5.62	5.50	5.99	6.34
Slow Growth	2.73	2.76	1.79	2.54	2.90	2.92
Regional Wind	7.44	7.42	7.27	7.20	7.40	7.46
Limited Investment	6.20	5.91	5.84	5.83	6.52	6.48
Carbon Constrained	4.69	4.69	4.76	4.35	4.76	4.80

[1] For WI wind, ATC's Load Weighted LMP is used as a proxy for the LMP payment.
[2] For MN/IA wind, the LMP is the average for the following four RGOS Wind Zones: IA-J, MN-H, MN-K, and MN-L.

Table 28: 2026 Average Hourly LMP Differential between WI[1] and MN/IA[2] [$/MWh]

Future	Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
Robust Economy	13.48	13.15	12.94	11.80	13.99	13.65
Green Economy	12.88	12.68	12.48	11.70	12.62	12.88
Slow Growth	3.01	3.05	2.08	2.80	3.21	3.14
Regional Wind	9.61	9.58	9.21	8.89	9.56	9.57
Limited Investment	7.62	7.27	7.08	6.85	8.02	7.87
Carbon Constrained	9.92	9.91	9.77	9.02	10.05	10.55

[1] For WI wind, ATC's Load Weighted LMP is used as a proxy for the LMP payment.
[2] For MN/IA wind, the LMP is the average for the following four RGOS Wind Zones: IA-J, MN-H, MN-K, and MN-L.

5.6.3 RIB and Capital Costs of Wind Generation Facilities

In addition to geographical differences in capacity factors, the capital cost of wind generation facilities is another key variable in calculating RIB. In order to determine a reasonable range of values for these costs, ATC Planning researched available regional and national data regarding capital costs for land-based wind generation facilities. These sources included the federal Energy Information Administration (EIA) Updated Estimates of Power Plant Capital Costs (November 2010) and MISO Planning's generation capital costs for its Futures Matrix (December 2010).

ATC paid particular attention to the estimated capital costs for three recent wind generation facilities owned by Wisconsin load-serving entities and approved by the PSCW. These projects are:

- Crane Creek Wind Farm, a 99 MW facility in Iowa owned by Wisconsin Public Service Corporation (PSCW Docket No. 6690-CE-194)(2008);
- Bent Tree Wind Farm, a 200 MW facility in Minnesota owned by Alliant Energy d/b/a Wisconsin Power & Light Company (PSCW Docket No. 6680-CE-173)(2009); and
- Glacier Hills Wind Park, an up to 207 MW facility in Wisconsin owned by Wisconsin Electric Power Company (PSCW Docket No. 6630-CE-302) (2010).

ATC also reviewed the publicly available analyses of capital costs for 100 MW generic wind facilities provided by the applicant and by PSCW Staff in the PSCW proceeding regarding the proposed Biomass Cogeneration Facility in Rothschild, Wisconsin (PSCW Docket No. 6630 CE 305).

ATC's review indicated that the actual capital costs for wind facilities in the Upper Midwest tend to be slightly higher than national averages. Wind farms in this region have to deal with harsher weather conditions and consequently may have somewhat higher capital costs. Siting and regulatory costs also tend to be somewhat higher than national averages.

Based upon this research, ATC selected a low, mid, and high value for overnight wind capital costs in the Upper Midwest. These values are expressed in 2008 dollars, because most of the capital cost estimates were referenced to 2008.

As it did for other drivers in its Future Matrix, ATC also assigned one of these values to each of its futures, based upon which value was most likely to prevail for that future.

Table 29: Wind Capital Costs by Future[1]

	Low	Mid	High
Wind Capital Cost [2008$/kW]	$2,000	$2,300	$2,500
Futures	Slow Growth, Limited Investment	Regional Wind, Carbon Constrained	Robust Economy, Green Economy

[1] Range based on the capital costs for the Glacier Hills, Bent Tree and Crane Creek wind farms.

5.6.4 RIB and Present Value Calculation Assumptions

For the RIB PV calculations, wind plants are assumed to have a 25 year life and are replaced "like-for-like" in the 26th year. ATC Finance converted the capital cost savings due to building fewer wind generators into the associated PV of the revenue requirements savings.

Forty years is used for the PV calculations because this is the assumed ("book"/financial) life of transmission facilities. The PV calculations also assume an inflation rate of 3.0 percent and a nominal discount rate of 6.7 percent. This discount rate is consistent with the values used by FERC[31]. In the PV calculations the transmission projects are assumed to be in-service on December 31, 2018.

5.6.5 RIB and Capacity Factors for Wind Generation

MISO calculated three year average wind capacity factors using National Renewable Energy Lab (NREL) wind data. The values are 30.0, 36.3, and 37.8 percent for Wisconsin, Minnesota and Iowa, respectively. For the "outside" wind, an average of the Minnesota and Iowa capacity factors was used in the RIB calculation, i.e. 37.0 percent.

[31] "Table 9.1-14: Other Cost Assumptions" from MISO's Final MTEP 10 Report (p. 274).

5.6.6 Detailed Sample RIB Calculation

Table 30 shows the details of the RIB calculation. The Robust Economy Future is used for illustration purposes only and the calculation methodology is the same for each of the Futures.

Table 30: Detailed Sample RIB Calculation for Badger Coulee for Robust Economy

1	FCITC Increase Relative to Base Case or Expected Wind Capacity Needed to Meet WI RPS [MW][1]	606.0
2	"Outside" Wind Capacity Factor	37.0%
3	Wisconsin Wind Capacity Factor	30.0%
4	% Higher "Outside" Wind Plant Energy Relative to WI	23.3%
5	Wind to Build Inside WI [MW][2]	747.4
6	Wind to Build Outside WI [MW]	606.0
7	Wind Capacity that Would Not Need to be Built in WI [MW]	141.4
8	Capital Cost Saved [2018$M][3]	$475.07
9	Present Value of the Capital Cost Revenue Requirement Savings [2012$M][4]	$597.48
10	Amount of Wind Energy Generated Outside of WI [MWh][5]	1,964,167
11	Difference in Average Outside & Inside Wind LMPs for 2020 [2020 $/MWh]	($9.06)
12	LMP payment difference between Outside and Inside Wind for 2020[6] [2020 $M]	($17.80)
13	Difference in Average Outside & Inside Wind LMPs for 2026 [2026 $/MWh]	($13.48)
14	LMP payment difference between Outside and Inside Wind for 2026[7] [2026 $M]	($26.49)
15	Present Value of the LMP payment difference between Outside and Inside Wind [2012$M][8]	($287.54)
16	Present Value of the RIB [2012$M][9]	$309.93
17	Overnight capital cost for wind capacity [2008 $/kW]	$2,500.00
18	Overnight capital cost for wind capacity [2018 $/kW]	$3,359.79

[1] Average additional MW that can be imported into WI from MN and IA due to Badger-Coulee. For the Slow Growth and Limited Investment Futures the amount of wind (MW) needed to satisfy the WI RPS requirement is less than the increase in transfer capacity. These lower values are used in the RIB calculation (78 and 304 MW, respectively) rather than the FCITC.
[2] Row 6 (and 1) increased by 23.3% = 658.4 MW x 1.233 = 812.0 MW
(i.e. 23.3% more MW of wind needed in WI to produce the same amount of energy)
[3] Row 7 x (Conversion Factor from kW to MW) x Row 18
= 153.6 MW x (1,000 kW/1 MW) x $3,359.79/kW = $516,153,484
[4] 40 year present value (PV) revenue requirements calculation based on Row 8 and using a 6.7 % nominal discount rate.
[5] Max. Generating Capacity x Capacity Factor (as a fraction) x Hours per year (for the "outside" wind)
= 658.4 MW x (0.37) x 8,760 hrs/year = 2,134,006 MWh
[6] Row 10 x Row 11 (Generator revenue difference between Outside and Inside Wind for 2020)
[7] Row 10 x Row 13 (Generator revenue difference between Outside and Inside Wind for 2026)
[8] Result of the 40 year PV calculation using the following assumptions and a 6.7% nominal discount rate. The LMP payment (generator revenue) difference between outside and inside wind was assumed to increase linearly between 2020 and 2026, i.e. between the two PROMOD run years. Prior to 2020, values are de-escalated by the inflation [to the 2018 in-service year] and after 2026, values are escalated by the inflation rate (i.e. 3%/year). This convention is consistent with the rest of the economic analysis.
[9] The PV of RIB is Row 9 plus Row 15 (i.e. the "PV of the generator revenue difference between Outside and Inside Wind", which is a negative value and hence a reduction).

Table 31: RIB Calculation for Robust Economy Future

		Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
1	FCITC Increase Relative to Base Case or Expected Wind Capacity Needed to Meet WI RPS [MW][1]	606	664	1,048	1,334	132	816
2	"Outside" Wind Capacity Factor	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
3	Wisconsin Wind Capacity Factor	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
4	% Higher "Outside" Wind Plant Energy Relative to WI	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
5	Wind to Build Inside WI [MW]	747	819	1,293	1,645	163	1,006
6	Wind to Build Outside WI [MW]	606	664	1,048	1,334	132	816
7	Wind Capacity that Would Not Need to be Built in WI [MW]	141	155	245	311	31	190
8	Capital Cost Saved [2018$M]	$475.07	$520.54	$821.58	$1,045.79	$103.48	$639.70
9	Present Value of the Capital Cost Revenue Requirement Savings [2012$M]	$597.48	$654.66	$1,033.26	$1,315.23	130.14	804.52
10	Amount of Wind Energy Generated Outside of WI [MWh]	1,964,167	2,152,157	3,396,778	4,323,761	427,838	2,644,819
11	Difference in Average Outside & Inside Wind LMPs for 2020 [2020 $/MWh]	($9.06)	($8.84)	($8.97)	($8.43)	($9.40)	($9.79)
12	LMP payment difference between Outside and Inside Wind for 2020 [2020 $M]	($17.80)	($19.02)	($30.46)	($36.46)	($4.02)	($25.89)
13	Difference in Average Outside & Inside Wind LMPs for 2026 [2026 $/MWh]	($13.48)	($13.15)	($12.94)	($11.80)	($13.99)	($13.65)
14	LMP payment difference between Outside and Inside Wind for 2026 [2026 $M]	($26.49)	($28.30)	($43.96)	($51.04)	($5.99)	($36.09)
15	Present Value of the LMP payment difference between Outside and Inside Wind [2012$M]	($287.54)	($307.28)	($479.58)	($559.49)	($65.00)	($395.92)
16	Present Value of the RIB [2012$M]	$309.93	$347.38	$553.68	$755.74	$65.15	$408.60
17	Overnight capital cost for wind capacity [2008 $/kW]			$2,500			
18	Overnight capital cost for wind capacity [2018 $/kW]			$3,360			

[1] Average additional MW that could be delivered to Wisconsin from Minnesota and Iowa.

Table 32: RIB Calculation for Green Economy Future

		Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
1	FCITC Increase Relative to Base Case or Expected Wind Capacity Needed to Meet WI RPS [MW][1]	606	664	1,048	1,334	132	816
2	"Outside" Wind Capacity Factor	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
3	Wisconsin Wind Capacity Factor	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
4	% Higher "Outside" Wind Plant Energy Relative to WI	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
5	Wind to Build Inside WI [MW]	747	819	1,293	1,645	163	1,006
6	Wind to Build Outside WI [MW]	606	664	1,048	1,334	132	816
7	Wind Capacity that Would Not Need to be Built in WI [MW]	141	155	245	311	31	190
8	Capital Cost Saved [2018$M]	$475.07	$520.54	$821.58	$1,045.79	$103.48	$639.70
9	Present Value of the Capital Cost Revenue Requirement Savings [2012$M]	$597.48	$654.66	$1,033.26	$1,315.23	$130.14	$804.52
10	Amount of Wind Energy Generated Outside of WI [MWh]	1,964,167	2,152,157	3,396,778	4,323,761	427,838	2,644,819
11	Difference in Average Outside & Inside Wind LMPs for 2020 [2020 $/MWh]	($6.11)	($6.01)	($5.62)	($5.50)	($5.99)	($6.34)
12	LMP payment difference between Outside and Inside Wind for 2020 [2020 $M]	($12.00)	($12.94)	($19.08)	($23.78)	($2.56)	($16.77)
13	Difference in Average Outside & Inside Wind LMPs for 2026 [2026 $/MWh]	($12.88)	($12.68)	($12.48)	($11.70)	($12.62)	($12.88)
14	LMP payment difference between Outside and Inside Wind for 2026 [2026 $M]	($25.30)	($27.29)	($42.39)	($50.58)	($5.40)	($34.05)
15	Present Value of the LMP payment difference between Outside and Inside Wind [2012$M]	($262.15)	($282.77)	($436.70)	($523.63)	($55.97)	($354.44)
16	Present Value of the RIB [2012$M]	$335.33	$371.89	$596.56	$791.61	$74.17	$450.08
17	Overnight capital cost for wind capacity [2008 $/kW]			$2,500			
18	Overnight capital cost for wind capacity [2018 $/kW]			$3,360			

[1] Average additional MW that could be delivered to Wisconsin from Minnesota and Iowa.

Table 33: RIB Calculation for Slow Growth Future

		Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
1	Expected Wind Capacity Needed to Meet WI RPS [MW]	78	78	78	78	78	78
2	"Outside" Wind Capacity Factor	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
3	Wisconsin Wind Capacity Factor	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
4	% Higher "Outside" Wind Plant Energy Relative to WI	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
5	Wind to Build Inside WI [MW]	96	96	96	96	96	96
6	Wind to Build Outside WI [MW]	78	78	78	78	78	78
7	Wind Capacity that Would Not Need to be Built in WI [MW]	18	18	18	18	18	18
8	Capital Cost Saved [2018$M]	$48.92	$48.92	$48.92	$48.92	$48.92	$48.92
9	Present Value of the Capital Cost Revenue Requirement Savings [2012$M]	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52
10	Amount of Wind Energy Generated Outside of WI [MWh]	252,814	252,814	252,814	252,814	252,814	252,814
11	Difference in Average Outside & Inside Wind LMPs for 2020 [2020 $/MWh]	($2.73)	($2.76)	($1.79)	($2.54)	($2.90)	($2.92)
12	LMP payment difference between Outside and Inside Wind for 2020 [2020 $M]	($0.69)	($0.70)	($0.45)	($0.64)	($0.73)	($0.74)
13	Difference in Average Outside & Inside Wind LMPs for 2026 [2026 $/MWh]	($3.01)	($3.05)	($2.08)	($2.80)	($3.21)	($3.14)
14	LMP payment difference between Outside and Inside Wind for 2026 [2026 $M]	($0.76)	($0.77)	($0.53)	($0.71)	($0.81)	($0.79)
15	Present Value of the LMP payment difference between Outside and Inside Wind [2012$M]	($8.71)	($8.81)	($5.96)	($8.11)	($9.28)	($9.13)
16	Present Value of the RIB [2012$M]	$52.81	$52.71	$55.56	$53.41	$52.25	$52.39
17	Overnight capital cost for wind capacity [2008 $/kW]			$2,000			
18	Overnight capital cost for wind capacity [2018 $/kW]			$2,688			

Table 34: RIB Calculation for Regional Wind Future

		Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
1	FCITC Increase Relative to Base Case or Expected Wind Capacity Needed to Meet WI RPS [MW][1]	606	664	1,048	1,334	132	816
2	"Outside" Wind Capacity Factor	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
3	Wisconsin Wind Capacity Factor	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
4	% Higher "Outside" Wind Plant Energy Relative to WI	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
5	Wind to Build Inside WI [MW]	747	819	1,293	1,645	163	1,006
6	Wind to Build Outside WI [MW]	606	664	1,048	1,334	132	816
7	Wind Capacity that Would Not Need to be Built in WI [MW]	141	155	245	311	31	190
8	Capital Cost Saved [2018$M]	$437.07	$478.90	$755.85	$962.13	$95.20	$588.53
9	Present Value of the Capital Cost Revenue Requirement Savings [2012$M]	$549.68	$602.29	$950.60	$1,210.02	$119.73	$740.16
10	Amount of Wind Energy Generated Outside of WI [MWh]	1,964,167	2,152,157	3,396,778	4,323,761	427,838	2,644,819
11	Difference in Average Outside & Inside Wind LMPs for 2020 [2020 $/MWh]	($7.44)	($7.42)	($7.27)	($7.20)	($7.40)	($7.46)
12	LMP payment difference between Outside and Inside Wind for 2020 [2020 $M]	($14.61)	($15.96)	($24.69)	($31.12)	($3.17)	($19.72)
13	Difference in Average Outside & Inside Wind LMPs for 2026 [2026 $/MWh]	($9.61)	($9.58)	($9.21)	($8.89)	($9.56)	($9.57)
14	LMP payment difference between Outside and Inside Wind for 2026 [2026 $M]	($18.87)	($20.62)	($31.28)	($38.43)	($4.09)	($25.32)
15	Present Value of the LMP payment difference between Outside and Inside Wind [2012$M]	($209.64)	($229.10)	($348.76)	($430.47)	($45.46)	($281.64)
16	Present Value of the RIB [2012$M]	$340.04	$373.19	$601.84	$779.55	$74.27	$458.52
17	Overnight capital cost for wind capacity [2008 $/kW]			$2,300			
18	Overnight capital cost for wind capacity [2018 $/kW]			$3,091			

[1] Average additional MW that could be delivered to Wisconsin from Minnesota and Iowa.

Table 35: RIB Calculation for Limited Investment Future

		Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
1	Expected Wind Capacity Needed to Meet WI RPS [MW]	304	304	304	304	304	304
2	"Outside" Wind Capacity Factor	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
3	Wisconsin Wind Capacity Factor	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
4	% Higher "Outside" Wind Plant Energy Relative to WI	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
5	Wind to Build Inside WI [MW]	375	375	375	375	375	375
6	Wind to Build Outside WI [MW]	304	304	304	304	304	304
7	Wind Capacity that Would Not Need to be Built in WI [MW]	71	71	71	71	71	71
8	Capital Cost Saved [2018$M]	$190.66	$190.66	$190.66	$190.66	$190.66	$190.66
9	Present Value of the Capital Cost Revenue Requirement Savings [2012$M]	$239.78	$239.78	$239.78	$239.78	$239.78	$239.78
10	Amount of Wind Energy Generated Outside of WI [MWh]	985,325	985,325	985,325	985,325	985,325	985,325
11	Difference in Average Outside & Inside Wind LMPs for 2020 [2020 $/MWh]	($6.20)	($5.91)	($5.84)	($5.83)	($6.52)	($6.48)
12	LMP payment difference between Outside and Inside Wind for 2020 [2020 $M]	($6.11)	($5.82)	($5.76)	($5.74)	($6.42)	($6.38)
13	Difference in Average Outside & Inside Wind LMPs for 2026 [2026 $/MWh]	($7.62)	($7.27)	($7.08)	($6.85)	($8.02)	($7.87)
14	LMP payment difference between Outside and Inside Wind for 2026 [2026 $M]	($7.51)	($7.17)	($6.97)	($6.75)	($7.90)	($7.75)
15	Present Value of the LMP payment difference between Outside and Inside Wind [2012$M]	($84.19)	($80.30)	($78.36)	($76.29)	($88.52)	($87.09)
16	Present Value of the RIB [2012$M]	$155.59	$159.47	$161.42	$163.48	$151.26	$152.69
17	Overnight capital cost for wind capacity [2008 $/kW]			$2,000			
18	Overnight capital cost for wind capacity [2018 $/kW]			$2,688			

Table 36: RIB Calculation for Carbon Constrained Future

		Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
1	FCITC Increase Relative to Base Case or Expected Wind Capacity Needed to Meet WI RPS [MW][1]	606	664	1,048	1,334	132	816
2	"Outside" Wind Capacity Factor	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%
3	Wisconsin Wind Capacity Factor	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
4	% Higher "Outside" Wind Plant Energy Relative to WI	23.3%	23.3%	23.3%	23.3%	23.3%	23.3%
5	Wind to Build Inside WI [MW]	747	819	1,293	1,645	163	1,006
6	Wind to Build Outside WI [MW]	606	664	1,048	1,334	132	816
7	Wind Capacity that Would Not Need to be Built in WI [MW]	141	155	245	311	31	190
8	Capital Cost Saved [2018$M]	$437.07	$478.90	$755.85	$962.13	$95.20	$588.53
9	Present Value of the Capital Cost Revenue Requirement Savings [2012$M]	$549.68	$602.29	$950.60	$1,210.02	$119.73	$740.16
10	Amount of Wind Energy Generated Outside of WI [MWh]	1,964,167	2,152,157	3,396,778	4,323,761	427,838	2,644,819
11	Difference in Average Outside & Inside Wind LMPs for 2020 [2020 $/MWh]	($4.69)	($4.69)	($4.76)	($4.35)	($4.76)	($4.80)
12	LMP payment difference between Outside and Inside Wind for 2020 [2020 $M]	($9.22)	($10.09)	($16.18)	($18.79)	($2.04)	($12.69)
13	Difference in Average Outside & Inside Wind LMPs for 2026 [2026 $/MWh]	($9.92)	($9.91)	($9.77)	($9.02)	($10.05)	($10.55)
14	LMP payment difference between Outside and Inside Wind for 2026 [2026 $M]	($19.48)	($21.33)	($33.18)	($39.00)	($4.30)	($27.90)
15	Present Value of the LMP payment difference between Outside and Inside Wind [2012$M]	($201.81)	($220.94)	($344.95)	($404.91)	($44.57)	($287.76)
16	Present Value of the RIB [2012$M]	$347.87	$381.35	$605.65	$805.10	$75.17	$452.40
17	Overnight capital cost for wind capacity [2008 $/kW]			$2,300			
18	Overnight capital cost for wind capacity [2018 $/kW]			$3,091			

[1] Average additional MW that could be delivered to Wisconsin from Minnesota and Iowa.

5.6.7 Present Value of the RIB

Table 37 gives the present values of the RIB for each of the project alternatives and each of the Futures.

Table 37: Present Value of the Renewable Investment Benefit [$M – 2012]

Future	Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
Robust Economy	309.93	347.38	553.68	755.74	65.15	408.60
Green Economy	335.33	371.89	596.56	791.61	74.17	450.08
Slow Growth	52.81	52.71	55.56	53.41	52.25	52.39
Regional Wind	340.04	373.19	601.84	779.55	74.27	458.52
Limited Investment	155.59	159.47	161.42	163.48	151.26	152.69
Carbon Constrained	347.87	381.35	605.65	805.10	75.17	452.40

The transmission projects that provide the greatest RIB value are those projects that provide the greatest increase in transfer capability from locations to the west of Wisconsin that have a better wind generation capacity factor than locations within Wisconsin. All of the 345-kV projects and Low Voltage provide a significant increase in transfer capability from locations to the west of Wisconsin, thus resulting in the largest amount of RIB benefit. In comparison, the 765-kV project does not greatly improve transfer capability from locations west of Wisconsin; thus it does not provide a significant RIB value.

The RIB has not been previously monetized, but it can clearly provide significant benefits to ratepayers and customers.

5.7 Economic Benefit Summary of Alternatives

Table 38 provides a summary of the PV of aggregate economic benefits of all the evaluated transmission alternatives, for all of the futures over a 40-year life of the project. These economic benefits are comprised of the following:

- ATC Customer Benefit including FTRs, congestion and losses;
- Insurance Benefit During System Failure Events;
- Energy Savings from Reduced Losses; and
- RIB.

When all four benefits are totaled, the results indicate that all of the transmission alternatives evaluated provide positive energy benefits to ATC ratepayers. As seen in Table 38, the Insurance Value for all of the high voltage alternatives has been assumed to be the same as that for Badger Coulee due to the anticipated similar performance of these alternatives in the various Insurance Value scenarios. Low Voltage was not assumed to provide any Insurance Value due to the limited amount of new infrastructure added in this alternative which could provide system support during the various Insurance Value scenarios. In addition, Loss analysis for the Spring Green 345-kV and 765-kV projects was performed on a single case and applied for all of the futures.

Table 38: PV of Aggregate Economic Benefits [$M – 2012]

	Future	Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
ATC Customer Benefit Including FTRs, Congestion and Losses	Robust Economy	356.26	322.88	747.77	967.23	241.29	500.83
	Green Economy	285.45	128.33	461.94	603.45	79.80	267.11
	Slow Growth	37.09	80.06	77.30	90.80	28.56	34.58
	Regional Wind	212.06	147.46	392.22	521.46	113.23	277.34
	Limited Investment	146.85	113.65	242.63	312.49	61.48	140.50
	Carbon Constrained	112.10	119.23	155.00	213.63	84.26	135.29
Insurance Benefit During System Failure Events	Robust Economy	23.57	23.57	23.57	23.57	23.57	0.00
	Green Economy	23.57	23.57	23.57	23.57	23.57	0.00
	Slow Growth	23.57	23.57	23.57	23.57	23.57	0.00
	Regional Wind	23.57	23.57	23.57	23.57	23.57	0.00
	Limited Investment	23.57	23.57	23.57	23.57	23.57	0.00
	Carbon Constrained	23.57	23.57	23.57	23.57	23.57	0.00
Energy Savings from Reduced Losses	Robust Economy	61.21	25.92	97.32	136.99	19.03	33.75
	Green Economy	67.63	25.92	123.49	155.19	19.03	32.67
	Slow Growth	17.07	25.92	19.29	28.29	19.03	(8.59)
	Regional Wind	33.12	25.92	53.48	73.99	19.03	8.00
	Limited Investment	56.49	25.92	71.07	98.70	19.03	3.49
	Carbon Constrained	36.98	25.92	36.71	53.29	19.03	1.96
RIB	Robust Economy	309.93	347.38	553.68	755.74	65.15	408.60
	Green Economy	335.33	371.89	596.56	791.61	74.17	450.08
	Slow Growth	52.81	52.71	55.56	53.41	52.25	52.39
	Regional Wind	340.04	373.19	601.84	779.55	74.27	458.52
	Limited Investment	155.59	159.47	161.42	163.48	151.26	152.69
	Carbon Constrained	347.87	381.35	605.65	805.10	75.17	452.40
Totals	Robust Economy	750.98	719.75	1,422.33	1,883.53	349.04	943.18
	Green Economy	711.98	549.72	1,205.57	1,573.81	196.57	749.85
	Slow Growth	130.54	182.26	175.72	196.07	123.40	78.37
	Regional Wind	608.79	570.15	1,071.10	1,398.56	230.10	743.86
	Limited Investment	382.50	322.61	498.68	598.24	255.34	296.68
	Carbon Constrained	520.53	550.07	820.92	1,095.59	202.02	589.65

5.8 Improved Competitiveness

5.8.1 Introduction

A new transmission facility can improve the market structure and competitiveness if the facility enables external suppliers to offer additional generation into specifically-defined market. The increased generation alternatives will increase competition causing a reduction in market prices. To the extent that suppliers who participate in the market are exposed to such market prices through short-term purchases and the turnover of longer-term contracts, these reductions in market prices will also reduce end-user costs.

5.8.2 Defining the Market

Given the significant correlation among the MISO Hub LMPs (defined as the Minnesota (MISO), the Illinois (MISO) and the Northern Illinois (PJM) hubs) and the ATC LMP, the market appears to be defined as the MISO market; however, the ATC service area has two limiting characteristics:

- Lake Michigan to the east
- Lake Superior to the north

These two geographical barriers limit the ability to import and/or export power from the west and from the south. The ATC transmission system is also a limiting factor. Since the inception of the centralized MISO energy market in April 2005, WUMS, Northern WUMS, and the area defined as Northern Iowa, southwestern Wisconsin, and southeast Minnesota regions have been designated as Narrow Constrained Areas (NCAs) within MISO.

The Independent Market Monitor (IMM) for MISO has deemed WUMS as one of the least competitive market areas within MISO. In the Informational Filing filed on February 3, 2012, the IMM concludes:

> "Congestion into WUMS has also declined in recent years, due in part key transmission enhancements as well as new generation additions. The congestion is now often from north to south from WUMS to Com Ed. However, congestion remained above 500 hours. Although there have been a number of transmission projects in WUMS, we still expect that the constraints that define the WUMS NCA to surpass the 500-hour criteria during the next 12 months." [32]

From the Resource Adequacy perspective, "MISO developed Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within MISO Region to reliably meet Demand and LOLE requirements."[33] MISO determined that the ATC service area is its own LRZ based on, among other considerations, the

[32] Informational Filing of Midwest Independent Transmission System Operator, Inc.'s Independent Market Monitor, February 3, 2012, page 4.
[33] Resource Adequacy Business Practice Manual, October 1, 2012, page 5-1.

electrical boundaries of Local Balancing Authorities (LBAs) and the relative strength of transmission interconnections among LBAs.

Given the established geographical and transmission system limitations, it is reasonable to assume the ATC service area as a uniquely-defined subset of the overall MISO market that provides market participants the opportunity to buy and sell power in the summer on- and off-peak markets.

5.8.3 Measuring Market Power

The Herfindahl-Hirschman Index (HHI)[34] is used to evaluate the extent of competition in power markets. Markets in which the HHI is between 1000 and 1800 points are considered to be moderately concentrated and those in which the HHI is in excess of 1800 points are considered to be highly concentrated.[35]

The HHI can be calculated for expected market conditions with and without new transmission facilities, such as Badger Coulee. The competitiveness of a region varies with the assumed fraction of generation capacity available to the market by the suppliers that make up the market, as well as by amount of summer on- and off-peak incremental transfer capability that results from the construction of the proposed transmission facility.

The competitiveness of the market is analyzed from two perspectives: Gross HHI and Net HHI. The Gross HHI does not consider the suppliers' load obligations and exposes the entire generation capability to the market. The Net HHI subtracts the suppliers' load obligations from their supply portfolios. The residual generation capability represents the supplier-specific capacity that is available to the market. Since Wisconsin is not a retail choice state, the supplier (i.e., the state-based electric utility) has an obligation to serve its native load; as a result, the Net HHI is more relevant to the analysis than the Gross HHI.

5.8.4 Results

The results of the summer on-peak competitiveness analysis for the year 2018 are provided in Table 39 and Table 40 below. The summer on-peak Gross and Net HHIs are calculated for the base case, Badger Coulee, and each of the five alternatives.

In the base case scenario, the Gross HHI of 2321 indicates that the market is concentrated, but competitiveness is improved with the addition of the proposed facility. The improved

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[34] The HHI is a commonly accepted measure of market concentration. It is calculated by squaring the market share of each supplier competing in the market and then summing the resulting numbers.

The HHI takes into account the relative size and distribution of the suppliers in a market and approaches zero when a market consists of a large number of suppliers of relatively equal size. The HHI increases both as the number of suppliers in the market decreases and as the disparity in size among those suppliers increases.

[35] In Docket No. RM11-14-000 (February 16, 2012), page 18, FERC declined to adopt the HHI thresholds in the Horizontal Merger Guidelines issued by the Department of Justice (DOJ) and Federal Trade Commission (FTC) on August 19, 2010.

competitiveness is driven by the increased import capability (as measured by the incremental FCITC for each alternative) from non-local suppliers (all else equal).

Table 39: 2018 Summer Peak Gross HHI

		Gross HHI		
Alternative	Incremental FCITC [MW]	Base Case	With Alternative	Change in Gross HHI
Base Case	0	2,321	2,321	0
Badger Coulee	273	2,321	2,268	52
Spring Green 345-kV	909	2,321	2,155	165
345-kV to Iowa	861	2,321	2,163	157
Combination 345-kV	1,545	2,321	2,054	267
765-kV	274	2,321	2,268	53
Low Voltage	1,282	2,321	2,094	226

Once the suppliers' load obligations are subtracted from their supply portfolios, the Net HHI is 1034, which suggests the market is moderately concentrated. In addition, the competitiveness of the market is improved by the addition of the proposed facility.

Table 40: 2018 Summer Peak Net HHI

		Net HHI		
Alternative	Incremental FCITC [MW]	Base Case	With Alternative	Change in Net HHI
Base Case	0	1,034	1,034	0
Badger Coulee	273	1,034	1,014	20
Spring Green 345-kV	909	1,034	988	46
345-kV to Iowa	861	1,034	989	45
Combination 345-kV	1,545	1,034	980	54
765-kV	274	1,034	1,014	20
Low Voltage	1,282	1,034	981	53

The results of the summer off-peak competitiveness analysis for the year 2018 are provided in Table 41 and Table 42 below. The summer off-peak Gross HHI sand Net HHIs are calculated for the base case, Badger Coulee, and each of the five alternatives.

For each of the seven scenarios, the generation capacity is assumed to remain the same, which results in the summer on- and off-peak Gross HHIs under the base case scenario to be the same for all the scenarios (i.e., 2321). This is, however, not the case for the Net HHI. Since the on-peak demand is greater than the off-peak demand, suppliers have more off-peak capacity to sell into the market. In the base case scenario, the Net HHI for the summer off peak is 1299 (suggesting a moderately concentrated market) as compared to the on-peak HHI of 1034.

In the base case scenario, the summer on- and off-peak Gross HHI indicates that the market remains concentrated, but competitiveness is improved with the addition of the proposed facility.

Table 41: 2018 Summer Off-Peak Gross HHI

		Gross HHI		
Alternative	Incremental FCITC [MW]	Base Case	With Alternative	Change in Gross HHI
Base Case	0	2,321	2,321	0
Badger Coulee	606	2,321	2,208	113
Spring Green 345-kV	664	2,321	2,197	123
345-kV to Iowa	1,048	2,321	2,132	188
Combination 345-kV	1,334	2,321	2,086	234
765-kV	132	2,321	2,295	26
Low Voltage	816	2,321	2,171	150

From the Net HHI perspective, the summer off-peak market is moderately concentrated, but the proposed facility improves the competitiveness.

Table 42: 2018 Summer Off-Peak Net HHI

		Net HHI		
Alternative	Incremental FCITC [MW]	Base Case	With Alternative	Change in Net HHI
Base Case	0	1,299	1,299	0
Badger Coulee	606	1,299	1,209	90
Spring Green 345-kV	664	1,299	1,201	98
345-kV to Iowa	1,048	1,299	1,157	142
Combination 345-kV	1,334	1,299	1,129	170
765-kV	132	1,299	1,277	22
Low Voltage	816	1,299	1,183	116

5.8.5 Key Data used in the Analysis

Table 43: Market Participant Data

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5.8.6 Key Assumptions used in the Analysis

- The market is defined as the ATC service area
- The market suppliers consists of:
    - Wisconsin Electric Power Co.
    - Wisconsin Power & Light Co. (Alliant East)
    - Wisconsin Public Service Corporation
    - Madison Gas & Electric Co.
    - Wisconsin Public Power, Inc. (WPPI)
    - Aggregated Upper Peninsula Area Utilities
        - Upper Peninsula Power Company
        - Edison Sault Electric
        - Cloverland Coop
        - City of Escanaba
    - Aggregated suppliers without Purchase Power Agreements or load obligations
    - Aggregated non-WPPI municipalities
        - Manitowoc (including Custer Energy Center)
        - Janesville
        - Kaukauna
        - Marshfield
- The analysis year is 2018
- Generator-specific maximum capacity (*i.e.,* nameplate rating) for generators, which does not reflect maintenance, forced, and scheduled outages
    - RGOS Wind Zone generation in Wisconsin is excluded
    - The capacity credit for wind generators is 8 percent
    - The wind farms (Crane Creek and Bent Tree) are included in the analysis
    - Nelson Dewey Power Plant (Unit 1 108 MW and Unit 2 112 MW) and Edgewater Unit 3 (71 MW) are assumed to be retired.

- Peak demand forecasts for Alliant East, Madison Gas & Electric, Wisconsin Electric, Upper Peninsula Power Company, and Wisconsin Public Service
    - The WPPI peak demand forecast is assumed to be equal to sum of WPPI-specific capacity
    - All available generation capability is exposed to the market for suppliers with no peak demand forecasts (*i.e.*, Calpine)
- Behind-the-meter (BTM), Interruptible, and Direct Load Control (DLC) programs act as resources, similar to generation resources
- Average import capability is the maximum 2011 imports of 2751 MW
- Incremental transfer capability of the transmission line (which is the increase in FCITC) varies by alternative and on- and off-peak period
    - The available generator-specific capacity did not vary by alternative
- Average import capability is symmetrically allocated to six non-incumbent generation suppliers

5.9 Avoided Cost of Reliability Projects

All of the transmission alternatives have additional lower voltage facilities that have been identified as additional upgrades that are needed to satisfy NERC reliability requirements. The identified lower voltage upgrades are needed to resolve system conditions due to Category B (single contingencies) or Category C (multiple contingencies) that could occur on the system.

Table 44 shows the total cost of both ATC and non-ATC supporting facilities. In total, Low Voltage would cost $272.12M for upgrades to the ATC transmission system and $101.21M for upgrades outside of ATC. The supporting facilities for the other alternatives are a subset of the Low Voltage project portfolio. The difference between the cost of Low Voltage (adjusted by approximately $21.75M for Study Based Ratings Methodology related upgrades) and the Category B and C upgrades associated with each alternative is the avoided cost of potential projects for that alternative. Table 45 shows the total avoided costs in ATC for each alternative.

Table 44: Costs of the Supporting Facilities [36]

Alternative	[$M - 2012]			
	All Cat B Facilities	All Cat C Facilities	Cat B & C in ATC	Cat B & C non-ATC
Badger Coulee	200.19	0.00	126.25	73.94
Spring Green 345-kV	194.78	0.00	139.61	55.17
345-kV to Iowa	217.91	0.00	107.58	110.33
Combination 345-kV	152.77	0.00	91.56	61.11
765-kV	190.96	0.00	145.24	45.83
Low Voltage	285.59	87.84	272.12	101.21

Table 45: ATC Avoided Costs for Each Alternative

Alternative	[$M - 2012]		
	Adjusted Cost of	Cost of	Avoided Costs

[36] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 30

	Low Voltage Facilities in ATC[1]	Cat B & C in ATC[2]	in ATC[3]
Badger Coulee	250.48	126.25	124.23
Spring Green 345-kV	250.48	139.61	110.86
345-kV to Iowa	250.48	107.58	142.90
Combination 345-kV	250.48	91.56	158.82
765-kV	250.48	145.24	105.24

1. The adjusted cost of Low Voltage facilities in ATC ($250.48M) = ATC Cat B upgrades ($184.38M) plus ATC Cat C upgrades ($87.84M) minus Low Voltage facilities required to be uprated as part of the Study Based Ratings Methodology facilities improvements (i.e. Wauzeka – Boscobel 69-kV and Wauzeka – Gran Grae 69-kV $21.75M).
2. Supporting project costs defined as the cost of individual Low Voltage upgrades in ATC required with the listed Alternative.
3. Avoided Costs defined as the ATC only avoided capital costs = Adjusted cost of Low Voltage facilities in ATC minus supporting project costs.

6.0 Local Reliability

The transmission system in western Wisconsin is not robust and its reliable operation is affected by transmission system flows of power from the west to the east. Even moderate additional wind capacity to the west of Wisconsin would further stress this already constrained system. The transmission system in this geographic area is comprised mainly of 69-kV facilities with some 138-kV and 161-kV facilities intended for local load serving purposes.

The WWTRS, completed in 2010, analyzed specific reliability concerns in western Wisconsin, eastern Iowa, and eastern Minnesota. The WWTRS identified the thermal, voltage, and system stability needs of this geographic area. It identified Badger Coulee as a viable solution to the reliability concerns in the western Wisconsin area.

6.1 Western Wisconsin Transmission Reliability Study

The WWTRS utilized three separate modeling scenarios to identify the reliability needs of this geographic area. The models represented the expected transmission topology and load forecast in the year 2018. Summer peak and off-peak (70 percent of summer peak load) were the two different load levels were evaluated. The off-peak load level was evaluated with two different wind generation output levels. One wind generation output level ranged from 35 percent to 45 percent of maximum capacity while the other assumed output of 90 percent maximum capacity. The reliability analysis associated with the varying levels of wind generation output is a step further than the traditional reliability analysis of ATC's Ten Year Assessment (TYA) utilizing ATC's planning criteria.

Several transmission alternatives were then evaluated for their ability to address the reliability needs of this geographic area. Badger Coulee was identified as a viable solution to address the reliability needs of this geographic area.

6.1.1 Western Wisconsin Transmission Reliability Study Thermal Results

Table 46, Table 47, and Table 48 contain the single contingency thermal loading information from the WWTRS comparing the Base Model with each of the transmission alternatives under consideration. A cutoff value of 90 percent was used for the table. Empty cells are branch loadings less than 90 percent.

Table 46: Thermal Branch Loading (WWTRS Summer Peak)

Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
[redacted]	[redacted]	[redacted]	[redacted]						
[redacted]	[redacted]	[redacted]						[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]
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Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
[redacted]									

Table 47: Thermal Branch Loading (WWTRS Off-Peak with 35-45% Wind Output)

Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
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[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]						
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Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
[redacted]	[redacted]	[redacted]	[redacted]			[redacted]			
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Table 48: Thermal Branch Loading (WWTRS Off-Peak with 90% Wind Output)

Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
[redacted]	[redacted]	[redacted]	[redacted]						[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]		
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Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
[redacted]	[redacted]	[redacted]							[redacted]
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Limiting Element	Contingency	Rating (MVA)	Percent Loading (%)						
			Base	P1	P2	P3	P4	P5	P6
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Table 49 summarizes the total number of thermal overloads that each transmission alternative eliminates, creates, or has no impact upon. The results in Table 49 indicate that Low Voltage performs the best from the viewpoint of reducing the number of thermal loading concerns. This is because Low Voltage was optimized to address local thermal loading concerns, whereas the 345-kV and 765-kV alternatives are optimized to address the delivery of regional generation sources to load.

The 345-kV and 765-kV alternatives appear to have similar impact on reducing thermal loading concerns on ATC facilities. Therefore the ability of these transmission alternatives to reduce thermal loading is not a significant driver in the selection of a preferred transmission alternative.

Table 49: Summary of Thermal Limit Counts from the WWTRS

Study Scenario	Category	**P1**		**P2**		**P3**		**P4**		**P5**		**P6**	
Summer Peak Load	Overloads Not Eliminated Total	38		29		24		22		32		16	
	ATC / Non-ATC	14	24	9	20	9	15	8	14	14	18	5	11
	Eliminated Overloads Total	3		12		17		19		9		25	
	ATC / Non-ATC	1	2	6	6	6	11	7	12	1	8	10	15
	New Overloads Total	3		3		4		4		4		5	
	ATC / Non-ATC	1	2	0	3	1	3	1	3	2	2	0	5
	Remaining Overloads Total	41		32		28		26		36		21	
	ATC / Non-ATC	15	26	9	23	10	18	9	17	16	20	5	16
Summer Off Peak 35% to 45% Wind Output	Overloads Not Eliminated Total	18		17		12		11		13		10	
	ATC / Non-ATC	8	10	8	9	9	3	9	2	6	7	9	1
	Eliminated Overloads Total	14		15		20		21		19		22	
	ATC / Non-ATC	9	5	9	6	8	12	8	13	11	8	8	14
	New Overloads Total	2		1		4		1		5		5	
	ATC / Non-ATC	1	1	1	0	1	3	1	0	5	0	0	5
	Remaining Overloads Total	20		18		16		12		18		13	
	ATC / Non-ATC	9	11	9	9	10	6	10	2	11	7	9	6
Summer Off Peak 90% Wind Output	Overloads Not Eliminated Total	35		32		31		27		20		25	
	ATC / Non-ATC	11	24	11	21	10	21	8	19	4	16	8	17
	Eliminated Overloads Total	20		23		24		28		35		30	
	ATC / Non-ATC	9	11	9	14	10	14	12	16	16	19	12	18
	New Overloads Total	2		3		7		3		9		9	
	ATC / Non-ATC	1	1	2	1	4	3	2	1	7	2	1	8
	Remaining Overloads Total	37		35		38		30		29		34	
	ATC / Non-ATC	12	25	13	22	14	24	10	20	11	18	9	25

P1: Badger Coulee
P2: Spring Green 345-kV
P3: 345-kV to Iowa
P4: Combination 345-kV
P5: 765-kV
P6: Low Voltage

6.1.2 Western Wisconsin Transmission Reliability Study Voltage Performance

The WWTRS utilized the ATC Severity Index tool to aid in evaluating AC contingency results of the different alternatives.

The ATC Severity Index tool is used to numerically summarize and visually present the results of thermal or voltage limitations from the AC contingency analysis for a group of contingencies, such as Category B or specified Category C contingencies. The Severity Indices calculated for the base case and cases with different transmission options can then be compared and ranked. The Severity Index calculation sums up the weights of all identified limitations to obtain an overall Severity Index number for each case.[37]

Table 50: WWTRS Option Rankings - Voltage Performance for Category B and Category C contingencies[38]

Alternative	Category B Ranking	Category C Ranking
Badger Coulee	4	3
Spring Green 345-kV	4	4
345-kV to Iowa	4	4
Combination 345-kV	5	5
765-kV	3	2
Low Voltage	1	1

A score of “1” in Table 50 indicates the worst performance while a score of “5’ indicates the best performance from a voltage perspective. Table 50 shows Combination 345-kV is the alternative that provides the most robust voltage support in the western Wisconsin area, while the other 345-kV alternatives provide nearly as beneficial voltage support for the same area. The voltage results from the WWTRS indicate that any of the 345-kV alternatives would significantly benefit this geographic area.

[37] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 20
[38] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 32

6.1.3 Western Wisconsin Transmission Reliability Study Stability Performance

The WWTRS evaluated the impact the alternatives have on both the voltage stability performance and the transient stability performance in this geographic area.

Table 51: WWTRS rankings for voltage stability[39]

Alternatives	Ranking
Badger Coulee	2
Spring Green 345-kV	2
345-kV to Iowa	3
Combination 345-kV	5
765-kV	4
Low Voltage	1

A score of "1" in Table 51 indicates the worst performance while a score of "5' indicates the best performance from a voltage stability perspective. Table 51 shows Combination 345-kV is the alternative that provides the most robust voltage stability support in the Western Wisconsin area, followed by 765-kV.

Table 52: WWTRS Rankings for Supporting System Transient Stability[40]

Alternatives	Ranking
Badger Coulee	4
Spring Green 345-kV	1
345-kV to Iowa	1
Combination 345-kV	5
765-kV	1
Low Voltage	1

A score of "1" in Table 52 indicates the worst performance while a score of "5' indicates the best performance from a system transient stability perspective, which is the ability of system generation units to remain stable for various system disturbances. Table 52 indicates Combination 345-kV is the alternative that provides the most robust system transient stability in the Western Wisconsin area, while Badger Coulee provides nearly as beneficial system transient stability for the same area.

6.2 La Crosse Area 345-kV Network

Additional local reliability benefits would exist in the La Crosse, Wisconsin area. A proposal to construct a 345-kV project from Rochester, Minnesota to the La Crosse, Wisconsin area has been approved. This project would meet the local load serving needs in La Crosse, Wisconsin. The project would increase load serving capability in the La Crosse/Winona areas to 791 MW, 300

[39] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 57
[40] *Western Wisconsin Transmission Reliability Study Final Report* (9/20/10), p. 62

MW above the projected 2012 level.[41] Badger Coulee would provide back-up benefits to the La Crosse area in the event the 345-kV line to Rochester would be out of service.

7.0 Local Public Policy Benefits

Among the key drivers affecting the delivered price of energy for Wisconsin customers is the applicable regulatory and policy framework. ATC develops a range of environmental and regulatory developments that may occur during the 40-year life of a project (including maintaining the status quo). These policy areas cover matters like emissions controls, energy efficiency and demand reduction, renewable-energy usage, and carbon pricing.

For example, Wisconsin's RPS currently requires energy utilities to derive 10 percent of their energy from renewable sources. In the 40-year useful life of Badger Coulee, this requirement could remain the same (though the level of electrical energy required to meet it would increase to the extent that electrical consumption increased), or this requirement could be reduced or increased. Factors other than an RPS, such as greenhouse gas (GHG) or other environmental regulations affecting coal plants and increased demand by retail customers for renewable energy, could affect the state's level of renewable-energy usage over the planning horizon. In this Planning Analysis, ATC evaluates whether in the various futures Badger Coulee would allow load-serving entities to deliver renewable energy more economically to their customers.

8.0 Regional Economic, Reliability and Public Policy Benefits

Many states in the upper Midwest region have enacted legislation to implement RPS or RES requiring electric utilities to obtain certain amounts of energy from renewable generation sources. The upper Midwest region has significant renewable energy potential to be sourced from wind. The states of North Dakota, South Dakota, Nebraska, Minnesota and Iowa are all ranked in the top ten states for potential wind energy production according to the American Wind Energy Association (AWEA). According to AWEA (as of September 30, 2010) these states have a combined total of more than 7,200 MW of installed wind capacity with an additional 1,300 MW of wind capacity under construction.[42] Given the significant potential to generate electricity from wind in the upper Midwest region, most of the energy generated to satisfy the demand for renewable energy has been sourced from wind generation.

Regardless of any long-term uncertainty regarding renewable energy standards, states within MISO will need new transmission to meet current and near-term renewable energy requirements, ensure reliable operation of the transmission grid, relieve current and projected areas of congestion, and facilitate the generation interconnection queue process.[43]

Badger Coulee would provide an important transmission connection to the west, which would aid in the delivery of wind energy to serve load.

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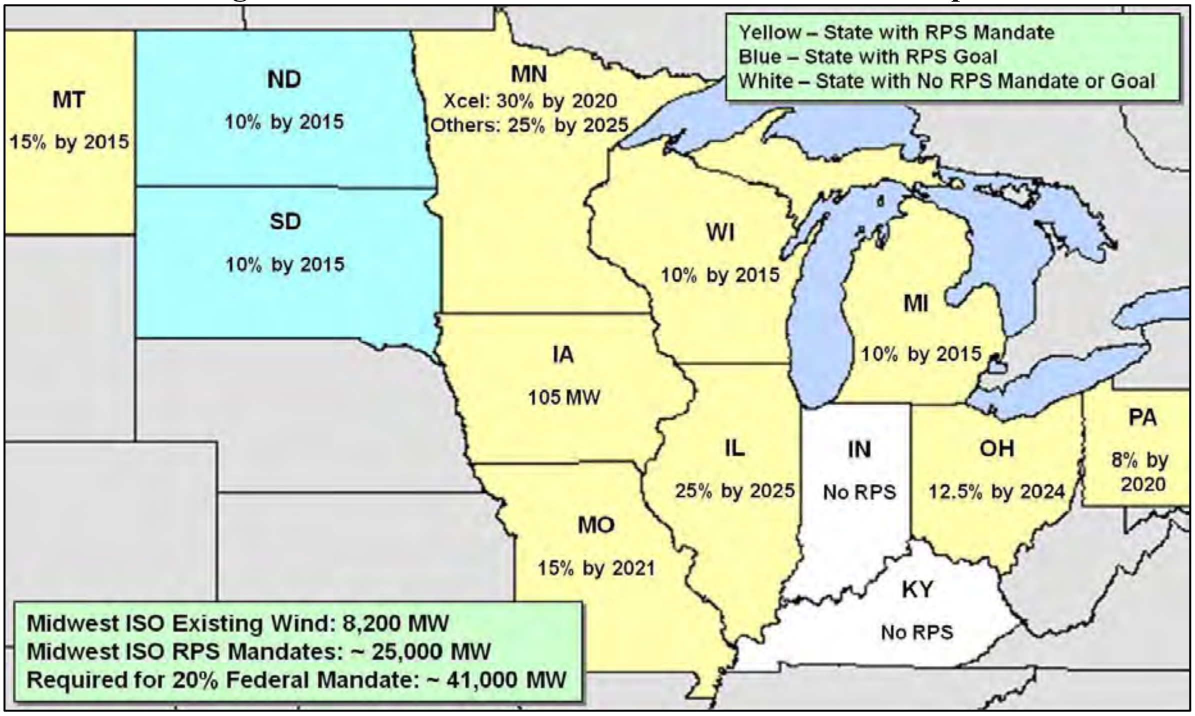
[41] *Hampton – Rochester – La Crosse 345-kV Transmission Project Wisconsin PSC Docket #5-CE-136*, p. 1-8
[42] AWEA Wind Projects, Updated March 31, 2007
[43] *Midwest ISO Regional Generator Outlet Study* (11/19/10), Study Overview, p. 97

Figure 9: Individual State RPS Mandate and Goal Map[44]



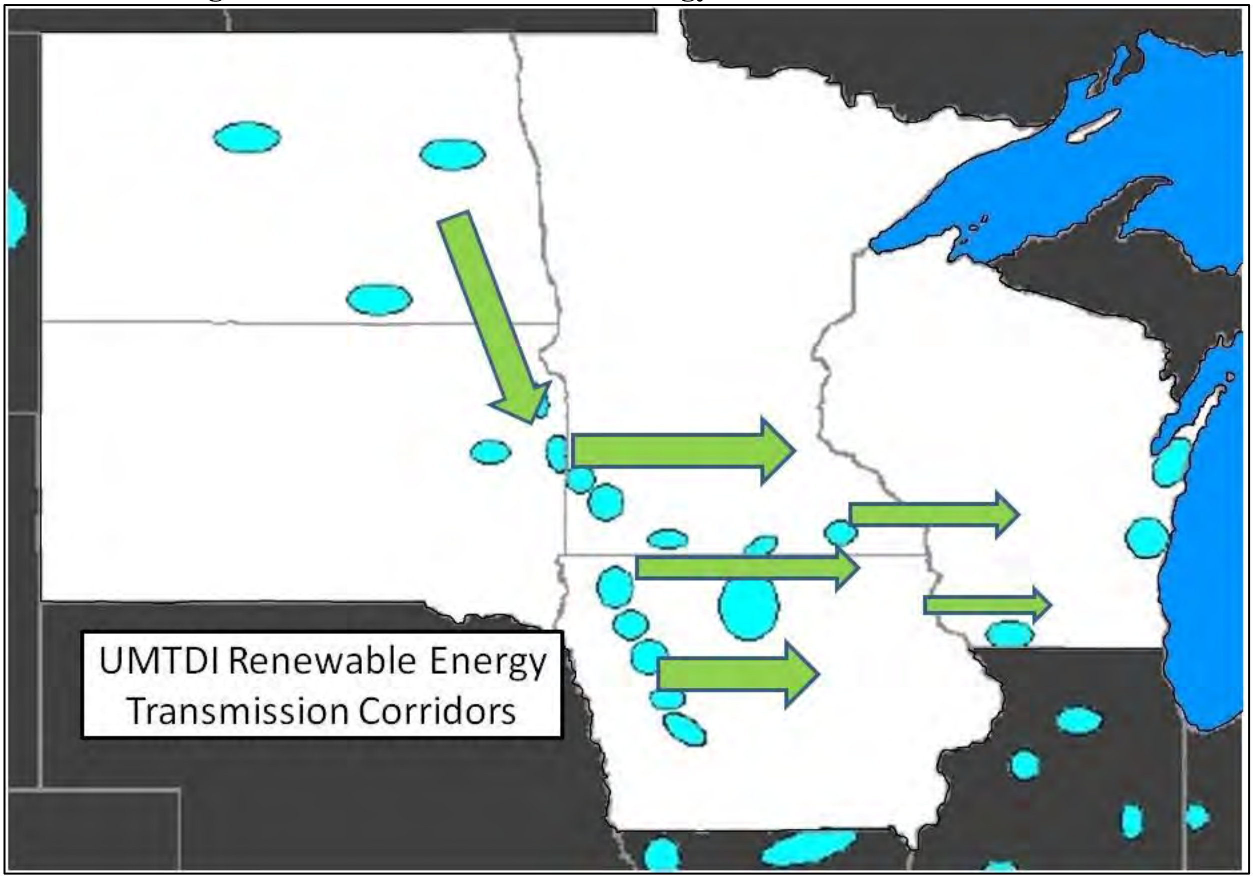
The northeast United States blackout of 2003 is a reminder how disastrous the results can be if regional transmission system reliability is not maintained. Badger Coulee is a key component in maintaining the reliability of the upper Midwest transmission system with the anticipated expansion of renewable generation sources to the west of Wisconsin.

8.1 Upper Midwest Transmission Development Initiative

The governors of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin formed the UMTDI that identified six transmission corridors that would efficiently move energy from wind energy zones to customers, and serve as a backbone for a variety of future development needs in the region. One of the UMTDI identified transmission corridors correlates well with the proposed connection points of Badger Coulee.

[44] *Midwest ISO Regional Generator Outlet Study* (11/19/10), Study Overview, p. 22

Figure 10: UMTDI Renewable Energy Transmission Corridors[45]

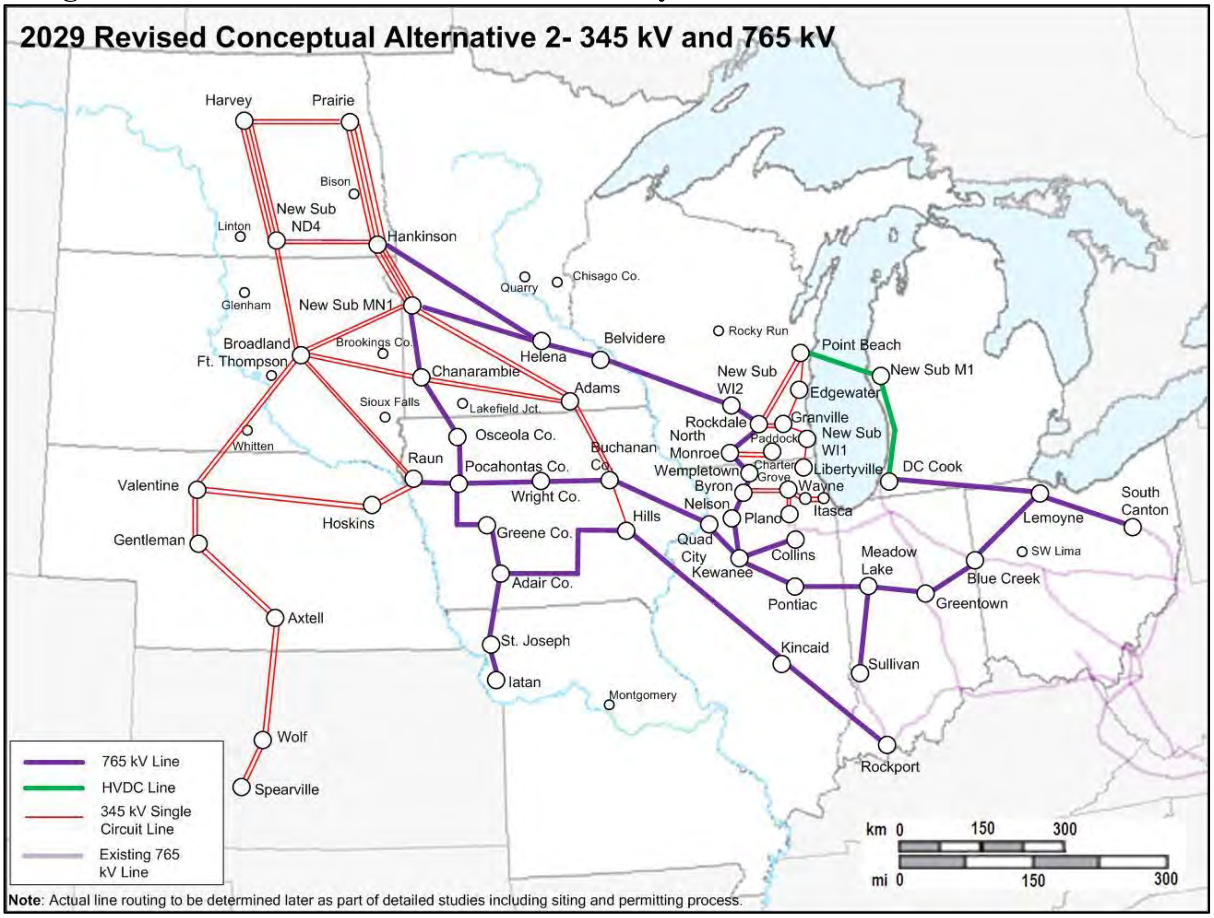


8.2 Strategic Midwest Area Renewable Transmission (SMARTransmission) Study

The SMARTransmission Study investigated transmission overlay possibilities that will facilitate the development of Midwest wind energy generation and enable its delivery to consumers in the Midwest. A focus of the SMARTransmission Study was to identify potential transmission facilities to support state and national energy policies, which included utilizing the Midwest's wind potential to generate approximately 56.8 GW of wind capacity. This level of wind capacity was estimated to satisfy a federal RPS of 20 percent as well as individual state mandates that might be a larger percentage.[46] Badger Coulee was modeled as an assumed base facility in the SMARTransmission Study, and with the levels of modeled wind, the revised alternatives developed in the SMARTransmission Study identified needed transmission additions connecting eastern Minnesota to Wisconsin. This can be seen in Figure 11, Figure 12, and Figure 13 with the transmission line connecting from Belvidere in Eastern Minnesota to New Sub WI2. The results from the SMARTransmission Study indicate that as the amount of wind generation in the Upper Midwest increases, transmission connections from Minnesota into Wisconsin become vitally important for delivery of wind generation to load.

[45] *Upper Midwest Transmission Development Initiative, Executive Committee Final Report* (9/29/10), p. 10
[46] *Phase 1 Strategic Midwest Area Renewable Transmission (SMARTransmission)* (7/1/2010), p. 7

Figure 11: SMARTransmission Revised Study Alternative 2 – 345-kV and 765-kV[47]



[47] *Phase 1 Strategic Midwest Area Renewable Transmission (SMARTransmission)* (7/1/2010), p. 8

Figure 12: SMARTransmission Revised Study Alternative 5 – 765-kV[48]

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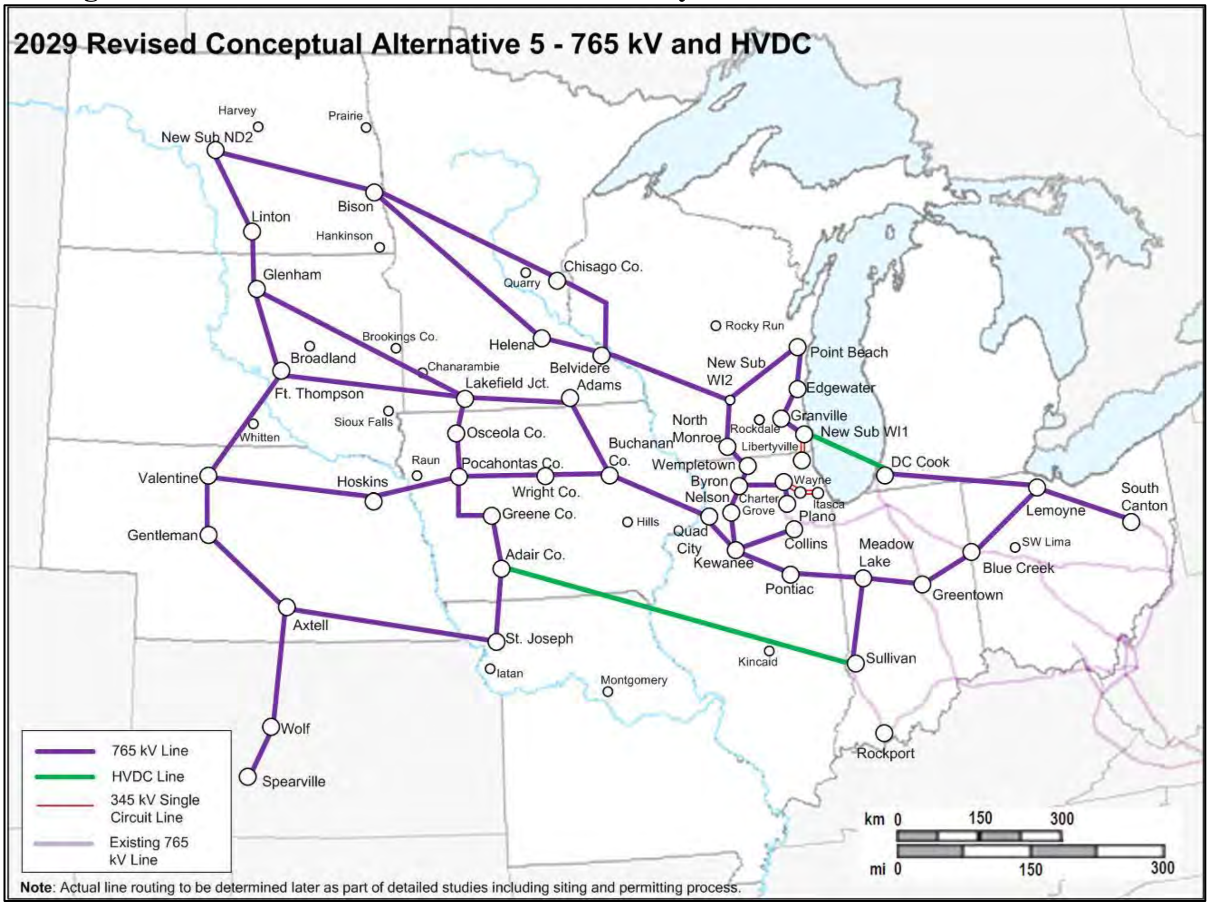
48 *Phase 1 Strategic Midwest Area Renewable Transmission (SMARTransmission)* (7/1/2010), p. 9

Figure 13: SMARTransmission Revised Study Alternative 5 – 765-kV and HVDC[49]



8.3 Minnesota Capacity Validation Study and Renewable Energy Standard Study

Transmission owners in the state of Minnesota have performed studies to determine transmission system upgrades that are needed to allow the development of 4,000 to 6,000 MW of additional wind generation capacity expected to be needed to meet Minnesota's 2025 RES requirements. Badger Coulee was one of three transmission projects identified in the Minnesota CVS that utilities should focus expansion efforts on to meet the RES requirements in Minnesota.[50]

The Minnesota RES Study performed an economic comparison of different transmission alternatives that would aid Minnesota in accommodating their RES mandates. One aspect of the economic analysis performed was the monetary value due to loss reduction of the transmission system. Badger Coulee was shown to provide the largest reduction in losses, based upon the entire Eastern Interconnect, of any single transmission facility evaluated in the RES Study. Badger Coulee was calculated to reduce system losses at summer peak load conditions by 43.4 MW.[51] The significant amount of loss reduction was attributed to providing a new 345-kV transmission connection to the MISO market outside of Minnesota. The RES Study went on to

[49] *Phase 1 Strategic Midwest Area Renewable Transmission (SMARTransmission)* (7/1/2010), p. 10
[50] *Final Report, Minnesota Capacity Validation Study* (3/31/09), p. 8
[51] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 46

calculate what the monetary value of the loss reduction would be over 40 years. The 40 year loss saving was calculated to be valued at $134,000,000.[52]

The second aspect of the economic analysis in the RES study was the PROMOD simulation results. The PROMOD results utilized 70 percent of the production cost savings and 30 percent of the load cost savings when evaluating the economic worth of a project.[53] Badger Coulee was shown to have a 40-year Production and Load Cost Savings of $803,000,000 to the entire MISO market.[54] The savings value was the largest savings value for any single facility addition evaluated in the RES Study, and Badger Coulee achieved greater savings than many of the upgrades with multiple facility additions.

With the estimated introduction of 4,000 to 6,000 MW of wind generation in Minnesota to achieve the 2025 RES requirements, generation units in Minnesota could experience situations where system instability could occur. The RES Study states that the possibility the system reaches instability during various disturbances becomes more and more likely to happen if no transmission is built to strengthen the regional grid[55] The instability would occur because without Badger Coulee the installed wind generation have be offset by reducing generation primarily based in the Twin Cities. With Badger Coulee the installed wind generation could be delivered to locations further east thus allowing the reduction of generation units across a much larger geographic area to eliminate the instability concern.

As the RES stability study demonstrates, a lack of sufficient transmission resources will expose the upper Midwest region to degraded reliability and the potential for relatively innocuous transmission contingencies to cascade into large-scale regional concerns.[56]

The Minnesota RES Study found Badger Coulee provided the greatest overall system benefits of the projects evaluated.[57] Not only does Badger Coulee improve generation delivery in Minnesota, it was also found to improve the delivery of generation located in North Dakota. The Minnesota RES Study determined that the benefits of installing generation in Minnesota to meet RES mandates would extend into Wisconsin with implementation of Badger Coulee as depicted in Figure 14.

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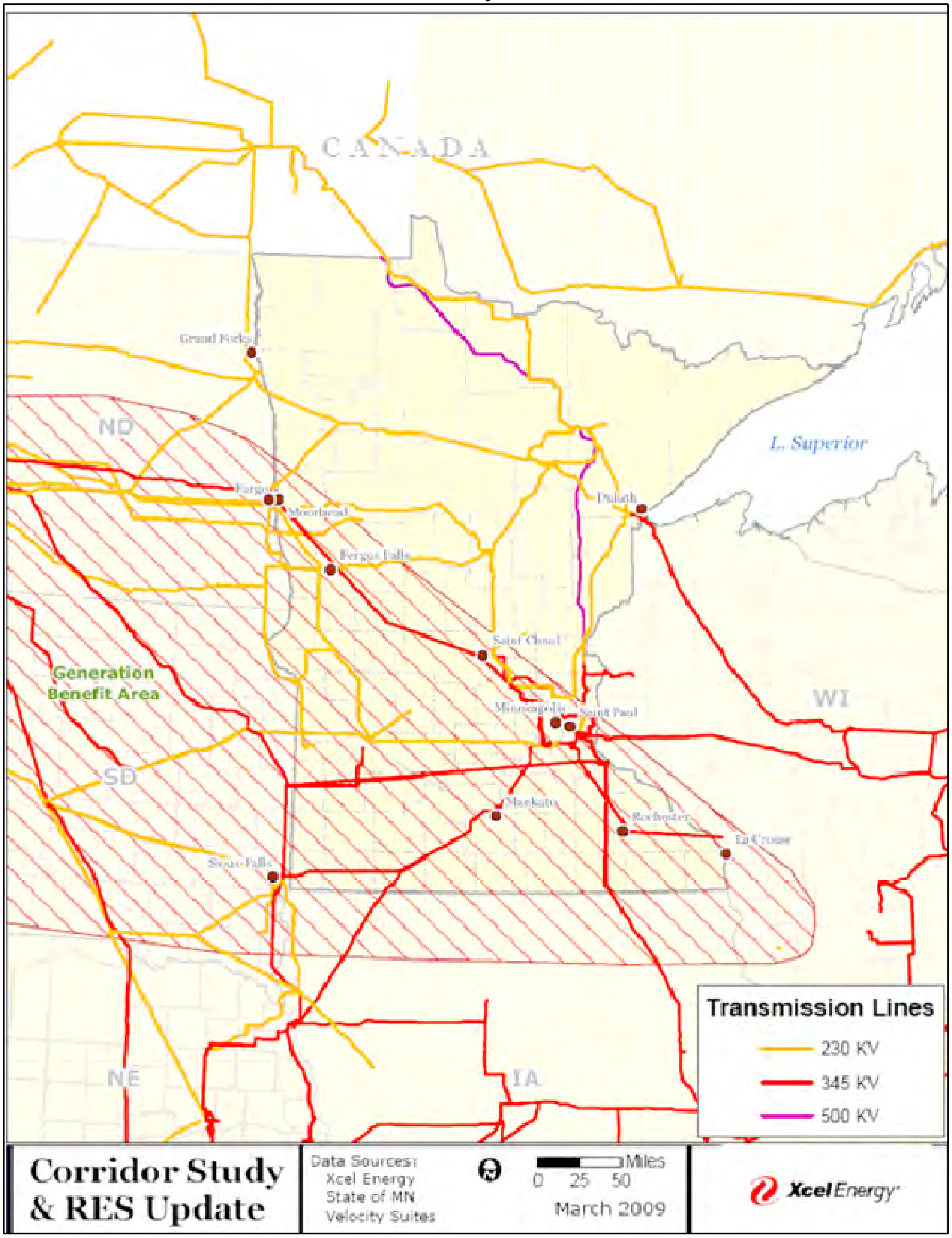
[52] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 49
[53] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 51
[54] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 55
[55] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 41
[56] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 45
[57] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 3

Figure 14: RES Generation Benefit area with RES Identified Facilities (Minnesota RES Study)[58]



[58] *Final Report, Minnesota RES Upgrade Study* (3/31/09), p. 4

8.4 MISO – Regional Public Policy Benefits

In the RGOS, MISO observed two significant drivers for transmission expansion in its region: (1) state RPS mandates; and (2) associated generation in the MISO Generation Interconnection Queue (GIQ).[59] MISO worked to develop transmission portfolios that allow for fulfillment of state RPS mandates in the RGOS. The RGOS determined the best fit solution to this challenge to be a transmission overlay encompassing all MISO states.

As a part of the transmission overlay, a set of robust Candidate MVPs designed to address current renewable energy mandates and the regional reliability needs of MISO members were selected. Badger Coulee was selected as a Candidate MVP in the initial group of projects identified as a practical first step towards achieving renewable energy requirements. The selected Candidate MVPs were determined to be compatible with RGOS developed overlays and provide potential value for other needs identified within the transmission system.[60]

In December 2010 and December 2011, FERC approved MISO's proposed MVP Tariff that defines MVP standards and provides for cost-sharing of projects that meet these standards after a comprehensive planning analysis[61]. MISO staff subsequently analyzed and recommended a set of MVP projects, including Badger Coulee, for inclusion in Appendix A of the MTEP 2011 analysis[62]. The MISO MVP projects were approved by the MISO BOD on December 8, 2011 with the BOD directing "transmission owners to use due diligence to construct the facilities approved in the plan[63]."

As a part of the MVP analysis and development, MISO Staff determined the regional benefits associated with the MVP portfolio. MISO determined that the benefits of the MVP projects outweighed the costs in each of the seven LRZs utilized in their evaluation. Figure 15 provides detail of the benefit / cost ratios calculated for the MVP portfolio and shows that the ATC area (which is largely encompassed in LRZ 2) has a benefit /cost ratio range from 2.0 to 3.3.

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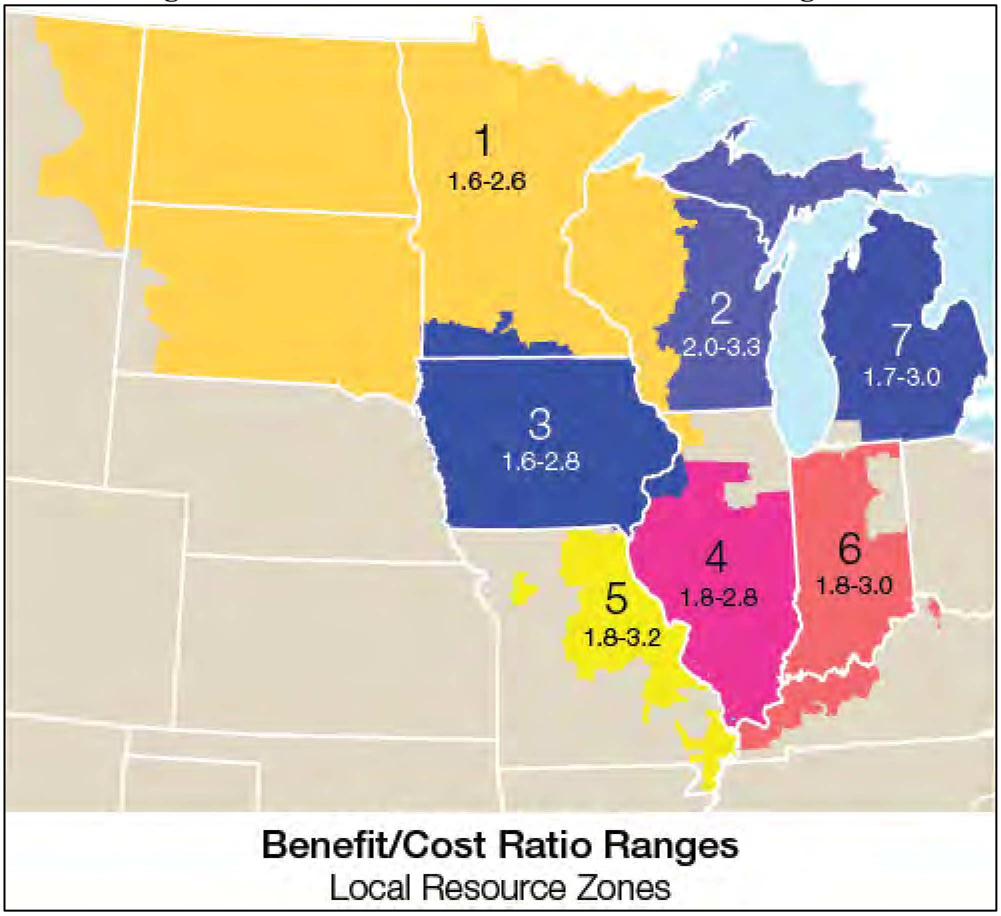
[59] *Midwest ISO Regional Generator Outlet Study* (11/19/10), Study Overview, p. 2
[60] *Midwest ISO Regional Generator Outlet Study* (11/19/10), Study Overview, p. 13
[61] *Midwest Independent System Operator, Inc.,* Order Conditionally Accepting Tariff Revisions (12/16/10), FERC Docket No. ER10-1791-000 *Midwest Independent Transmission System Operator, Inc.* (10/11/11) Order Denying in Part and Granting in Part Rehearing, Conditionally Accepting Compliance Filing, and Directing Further Compliance Filings, FERC Docket No. ER10-1791.
[62] *MISO Transmission Expansion Plan 2011*; *MISO Multi Value Project Portfolio – Results and Analysis*, (01/10/12).
[63] *MISO Board Approves 215 New Transmission Projects*, News Release, (12/08/12).

Figure 15: MISO MVP Benefit / Cost Ratio Ranges[64]



As a part of its analysis, MISO provided detail pertaining to the justification of Badger Coulee. Specifically, "the 345 kV line from North La Crosse to North Madison creates a tie between the 345 kV 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 La Crosse needs an outlet, and the line to North Madison is the best option studied. From a reliability perspective, the addition of the North La Crosse 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[65]."

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[64] MISO 2011 Multi-Value Project Portfolio – MISO MVP One Pager Document.
[65] *MISO Multi Value Project Portfolio – Results and Analysis*, (01/10/12), Section 5.5 North La Crosse to North Madison to Cardinal 345 kV Line, p. 29.

9.0 Badger Coulee Integration with Future Transmission Facilities

The evaluation of a significant transmission addition such as Badger Coulee requires analysis of how the project will interact with potential future transmission additions. Several regional studies have evaluated the Badger Coulee and 345-kV to Iowa projects in combination for determination of benefits.

The UMTDI identified six transmission corridors that would efficiently move energy from wind energy zones to customers, and serve as a backbone for a variety of future development needs in the region. Two of the UMTDI identified transmission corridors are located in Wisconsin. One of the corridors correlates well with the proposed connection points of Badger Coulee, while the other correlates well with the proposed connection points of 345-kV to Iowa. The combination of both of these UMTDI corridors correlates with the Combination 345-kV alternative.

One of the MVPs approved by the MISO BOD is the combination of Badger Coulee and the 345-kV to Iowa. Development of these corridors will provide for the continuation and extension of the west to east transmission path to provide more areas with greater access to the high wind areas within the Buffalo Ridge and beyond. These projects can be well integrated regardless of the long range transmission expansion strategy adopted by MISO.[66]

Throughout the entire analysis process, ATC Planning has evaluated how Badger Coulee would interact with 345-kV to Iowa, resulting in the Combination 345-kV analysis results. In many of these analysis results, Badger Coulee is not the highest performing alternative from an ATC perspective. As seen in the Economic and Reliability analyses, in certain cases the Combination 345-kV is the highest performing alternative followed by 345-kV to Iowa and then Badger Coulee.

The WWTRS determined that Badger Coulee provides benefits for even moderate regional wind development to the west of Wisconsin. The Minnesota RES and CVS studies indicated that future wind generation development to the west of Wisconsin would be hampered without Badger Coulee. Minnesota has an aggressive RES mandate, and Badger Coulee provides a direct transmission connection to the expected wind generation development in Minnesota.

Regional wind development is also a source of some of the economic savings calculated in the ATC analysis. More installed wind generation means more sources of low cost renewable energy which leads to economic savings when that energy can be delivered to serve load. It is reasonable to expect that wind development to the west of Wisconsin would be less with 345-kV to Iowa than with Badger Coulee due to limitations of the transmission system's ability to deliver the expected wind generation developed in Minnesota.

As determined in the WWTRS, the Combination 345-kV also provides the most local reliability benefits to the western Wisconsin transmission system by providing the best voltage support, system stability and significant thermal loading relief. After Badger Coulee is completed, the second leg of the Combination 345-kV, the 345-kV to Iowa portion, could be developed at a later time when the regional transmission system needs additional facilities to support renewable

[66] *MISO Multi Value Project Portfolio – Results and Analysis*, (01/10/12).

generation or when it is determined that benefits to ATC customers are sufficient to support project development.

10.0 Non-Transmission Alternatives

Non-transmission alternatives include energy efficiency and load reduction as well as conventional generation and renewable generation (including distributed generation). In conducting its Planning Analysis, ATC from the outset considered a wide variety of such non-transmission alternatives at the distribution level, within its own transmission system, and MISO-wide.

10.1 Energy Efficiency and Demand Reduction in ATC's Strategic Flexibility Analysis

Energy consumption and peak load are key drivers of ATC's Futures Matrix. These drivers provide the building blocks for the six different futures within which ATC measured the economic impact of Badger Coulee.

ATC did not merely use a single forecast for its economic analysis. It independently identified low, middle, and high levels of energy usage and demand within its service territory. It separately incorporated the MISO's low, middle, and high energy and load forecasts within its analysis.

ATC's low levels of energy usage and load growth are 0.1 and 0.2 percent, respectively. ATC selected this low level of usage and demand in the Green Economy and Carbon Constrained Futures to account for increased energy efficiency and demand reduction in these futures and not due to any economic downturn or recession. These levels are used in the Carbon Constrained Future due to increased energy efficiency and demand-side management as a result of utility, customer, and policy conservation measures. Similarly, in the Green Economy Future load growth is less than energy growth because of an increased focus on Smart Grid demand measures.

ATC also included interruptible loads and direct load control within its analyses. As further described below in section 10.3, it modeled targeted load management by dispatching "Distributed Resources" at various substations at price points that studies have shown customers are willing to consider load reductions.

10.2 Generation in ATC's Strategic Flexibility Analysis

The key drivers for the Futures Matrix also include various generation scenarios, including both conventional and renewable resources. There are low, middle, and high levels for coal retirements within ATC and for overall generation additions within ATC. Generation additions within ATC include, depending on the scope of the expansion, gas, coal and renewable generation. ATC's 2026 Carbon Constrained Future, for example, adds substantial photovoltaic and biomass capacity in Wisconsin. ATC's 2020 and 2026 Green Economy and Carbon Constrained Futures also include a reasonable estimate for distributed renewable generation within ATC, and this generation is placed at appropriate substations within ATC.

Similarly, the generation portfolios outside ATC include three different MISO generation-expansion scenarios: a scenario consisting primarily of coal and gas units, a gas-only scenario, and a scenario that would comply with carbon constraints.

Renewable alternatives are also systematically evaluated in ATC's analysis. Within ATC a low, middle, and high percentage of total energy from renewable energy is studied based on current and potential future renewable-energy usage.

A similar set of renewable energy alternatives is also established for the MISO region. The low, middle, and high levels of this driver vary both the location of the wind power within the region and the states to which this wind power is allocated for RPS-compliance purposes.

Complete details about how these generation and energy efficiency alternatives were included in the variables that make up ATC's six futures are set forth in the Futures Matrices in Tables 12 and 13. Detailed descriptions of how these factors were developed for the PROMOD study analysis can be found in Addenda C through E.

10.3 Use of Distributed Resources (DR) in this Planning Analysis

For this Planning Analysis, ATC developed and applied a planning technique that models "Distributed Resources" (DR) within the ATC system. This technique mimics demand response and distributed-generation technologies that may serve to offset load in the future. In addition, these DR units serve to prevent unrealistic PROMOD results such as "buying through" constraints at unrealistically high prices or dispatching "emergency" generation.

The DR modeling used in this analysis includes components to address both energy efficiency as well as behind the meter renewable generation that may exist across the scenarios analyzed. Price points were established to develop a dispatch curve for the DR units which would mimic energy efficiency programs and consumer response to electric market conditions. The units were distributed across the ATC footprint to model impacts with various load types and system configurations. The units were included in both the base models as well as the project models and the impacts of the units are subsequently accounted for within the project savings metrics presented previously. Additional details and descriptions of this planning technique can be found in Addendum C.

10.4 Description of Energy Efficiency and Load Response Programs

Focus on Energy is the statewide energy efficiency and load response program in Wisconsin.[67] In Addendum H, ATC provides a description of the programs and services that FoE provides to Wisconsin customers and the historical and potential future impacts of this program on load growth.

In the most recent year for which data is available (2012), FoE reported net savings of 66.8 MW and 461 GWh. This represents approximately 0.5 percent of Wisconsin's total electric load.

[67] See, generally, Sec. 196.374, Wis. Stats. and www.focusonenergy.com.

Thus, the net impacts of the FoE programs are decreasing the electricity growth rate in Wisconsin by approximately 0.5 percent compared to what would be expected in the absence of the program. This level of savings is embedded into the historic load data and growth trends at the statewide level. Program spending in 2012 was $81.7 million.

10.5 Assessment of Additional Energy Efficiency and Load Reduction Needed to Replace the Project

Badger Coulee is an MVP fulfilling three separate and distinct types of need. First, it avoids the need for several lower-voltage reliability projects in Wisconsin and improves the regional reliability of the transmission system. Second, it improves access to regional generation resources of all types, reducing energy costs and losses for Wisconsin customers. Third, it reduces the overall cost of delivered renewable energy to the Wisconsin load.

It would be very difficult to calculate a total amount of energy efficiency and load reduction that would fulfill all of these needs and hence eliminate the need for Badger Coulee. For example, to provide the same local reliability benefits as Badger Coulee, energy efficiency and load reduction would have to be targeted to each of the substations where reliability violations were shown to occur in the Western Wisconsin Transmission Reliability Study.

With respect to the economic savings of Badger Coulee (including reduced cost of delivered renewable energy), additional energy efficiency and load reduction would not serve as an adequate substitute for these benefits, since these benefits reduce the price of electricity for Wisconsin customers, irrespective of energy efficiency and load reduction.

One of the economic benefits of Badger Coulee is the Renewable Investment Benefit as described above in Section 5.6. One measure that ATC used to evaluate this benefit is the increase in transfer capacity from generation in Iowa and Minnesota into the ATC zone. As shown in Tables 25 and 26 above, this analysis showed that Badger Coulee will increase FCITC by 273 MW at summer peak and by 606 MW at summer off-peak. In order to serve as a viable substitute for just this one benefit of Badger Coulee (increased west-to-east transfer capacity), energy efficiency and load reduction would have to achieve similar reductions in load on peak and off peak.

10.6 Feasibility of Achieving Necessary Additional Levels of Energy Efficiency and Load Reduction

There are practical difficulties to achieving substantial additional reductions in energy consumption and demand. Fundamental changes in legislative policy, programs, and budgets would be required. Also, ATC does not offer load management programs to retail electric customers nor does it have the ability to curtail retail load (except through actions of load-serving entities under emergency conditions). Moreover, under current law, as long as Wisconsin utilities are making their required contributions to the FoE program, they cannot be required to offer additional energy efficiency and load reductions programs.

Persistence is an additional requirement when evaluating these resources as substitutes for transmission. Not only would such measures have to be installed on a timely basis and at the right locations, they would also have to function as continuous, firm resources reliably into the future. Most energy efficiency and load reduction programs (including the FoE program) are voluntary, and thus lack the firmness of a hard asset like Badger Coulee.

Finally, such resources would have to be shown to be technically feasible and cost-effective. Based on its review of publicly available data, ATC is unable to conclude that any combination of energy efficiency and load reduction could feasibly and cost-effectively provide the same package of diverse benefits as Badger Coulee.

11.0 Total Comparison of Transmission Alternatives

A full evaluation of each alternative requires a complete comparison of all the identified benefits and costs of that alternative, including both quantitative and qualitative benefits. Each of the alternatives has a set of quantitative benefits and costs. The costs are the construction cost estimates of the alternative as well as supporting projects, including the annual revenue requirements in order to recover these capital costs. The total monetary benefits are the summation of the construction costs of the avoided projects, energy-cost savings derived by PROMOD, RIB, Loss Savings and Insurance Value. The qualitative benefits are whether or not the project provides a Regional Wind Outlet, a 345-kV loop in La Crosse, whether or not it is supported by the Minnesota RES/CVS, and its performance in the Competitive HHI Analysis, the Reliability Indices and the Transient Stability Benefit.

Assuming that all of the 345-kV and 765-kV alternatives would be eligible for MISO MVP cost sharing, all of the alternatives evaluated (including Badger Coulee) have net positive values for ATC customers in all futures.

While Low Voltage also has net positive values in four out of the six futures, there are several compelling reasons why it is not the preferred alternative. First of all, this alternative is not expected to receive MISO MVP cost sharing because its voltage level is below the eligibility threshold.

Secondly, unlike all of the other studied alternatives, Low Voltage does not provide a regional wind outlet to the Upper Midwest. Nor does Low Voltage provide a looped feed for the 345-kV system in La Crosse. Such a feed would provide additional reliability benefits to the La Crosse area. Thirdly, the Minnesota RES and CVS analyses came to a conclusion that did not support the implementation of Low Voltage. The conclusion from these studies supports an alternative with a 345-kV extension from La Crosse. Finally, Low Voltage scores much lower than any of the 345-kV alternatives in providing system support, as shown by the Reliability Indices and Transient Stability Benefits from the WWTRS.

The preferred alternative should provide significant quantitative benefits while achieving as many of the qualitative benefits as possible. Badger Coulee demonstrates excellent quantitative results. It also scores well in all of the important qualitative measures. In addition, when Badger Coulee and the 345-kV to Iowa alternatives are combined to create the Combination 345-kV alternative, the quantitative results have the highest level of benefits of all the alternatives. Therefore, when factoring in all of the pertinent quantitative and qualitative results, Badger Coulee is the preferred transmission alternative.

Table 53 and Figure 16 provide a complete comparison of the monetized benefits and costs of the alternatives assuming that all of the 345-kV and 765-kV alternatives would be eligible for MISO MVP cost sharing. Detailed revenue requirement analysis was not performed for the Spring Green 345-kV, 345-kV to Iowa, Combination 345-kV, and 765-kV alternatives. It was assumed that these alternatives would all be eligible for MVP cost sharing and an estimate of their revenue requirement was calculated by applying a ratio based on the Badger Coulee revenue requirement analysis. The avoided costs for these alternatives are based on costs calculated as a part of the WWTRS which were subsequently escalated by inflation to convert these values from 2010 dollars to nominal dollars.

Table 54 provides a comparison of non-monetized benefits of all of the alternatives. Further details of these benefits can be found in the WWTRS.

Table 53: Net Monetized Project (Costs) / Benefits

	Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
PROJECT COSTS						
Total Project Cost ($M – Nominal)	($550.21)	($458.96)	($369.87)	($920.09)	($1,070.75)	($428.73)
2012 Present Value of the Revenue Requirement (PVRR 2012) - $M	($4.25)	$32.69	$24.47	$20.21	$70.83	($466.91)
PROJECT BENEFITS						
All Futures						
Avoided Cost of Potential Projects - <345-kV (PVRR 2012)	$141.87	$129.29	$166.65	$185.22	$122.73	$0.00
Insurance Value	$23.57	$23.57	$23.57	$23.57	$23.57	$0.00
Robust Economy						
Energy Benefits (PROMOD)	$356.26	$322.88	$747.77	$967.23	$241.29	$500.83
Loss Savings	$61.21	$25.92	$97.32	$136.99	$19.03	$33.75
RIB	$309.93	$347.38	$553.68	$755.74	$65.15	$408.60
Net Present Value Revenue Requirement ($M – 2012)	**$888.60**	**$881.73**	**$1,613.45**	**$2,088.96**	**$542.60**	**$476.27**
Green Economy						
Energy Benefits (PROMOD)	$285.45	$128.33	$461.94	$603.45	$79.80	$267.11
Loss Savings	$67.63	$25.92	$123.49	$155.19	$19.03	$32.67
RIB	$335.33	$371.89	$596.56	$791.61	$74.17	$450.08
Net Present Value Revenue Requirement ($M – 2012)	**$849.60**	**$711.70**	**$1,396.69**	**$1,779.25**	**$390.13**	**$282.95**
Slow Growth						
Energy Benefits (PROMOD)	$37.09	$80.06	$77.30	$90.80	$28.56	$34.58
Loss Savings	$17.07	$25.92	$19.29	$28.29	$19.03	($8.59)
RIB	$52.81	$52.71	$55.56	$53.41	$52.25	$52.39
Net Present Value Revenue Requirement ($M – 2012)	**$268.16**	**$344.23**	**$366.84**	**$401.51**	**$316.96**	**($388.54)**
Regional Wind						
Energy Benefits (PROMOD)	$212.06	$147.46	$392.22	$521.46	$113.23	$277.34
Loss Savings	$33.12	$25.92	$53.48	$73.99	$19.03	$8.00
RIB	$340.04	$373.19	$601.84	$779.55	$74.27	$458.52
Net Present Value Revenue Requirement ($M – 2012)	**$746.41**	**$732.12**	**$1,262.22**	**$1,604.00**	**$423.66**	**$276.96**
Limited Investment						
Energy Benefits (PROMOD)	$146.85	$113.65	$242.63	$312.49	$61.48	$140.50
Loss Savings	$56.49	$25.92	$71.07	$98.70	$19.03	$3.49
RIB	$155.59	$159.47	$161.42	$163.48	$151.26	$152.69
Net Present Value Revenue Requirement ($M – 2012)	**$520.12**	**$484.59**	**$689.80**	**$803.67**	**$448.90**	**($170.23)**
Carbon Constrained						
Energy Benefits (PROMOD)	$112.10	$119.23	$155.00	$213.63	$84.26	$135.29
Loss Savings	$36.98	$25.92	$36.71	$53.29	$19.03	$1.96
RIB	$347.87	$381.35	$605.65	$805.10	$75.17	$452.40
Net Present Value Revenue Requirement ($M – 2012)	**$658.15**	**$712.05**	**$1,012.04**	**$1,301.02**	**$395.58**	**$122.74**

Figure 16: Net Monetized Project (Costs) / Benefits

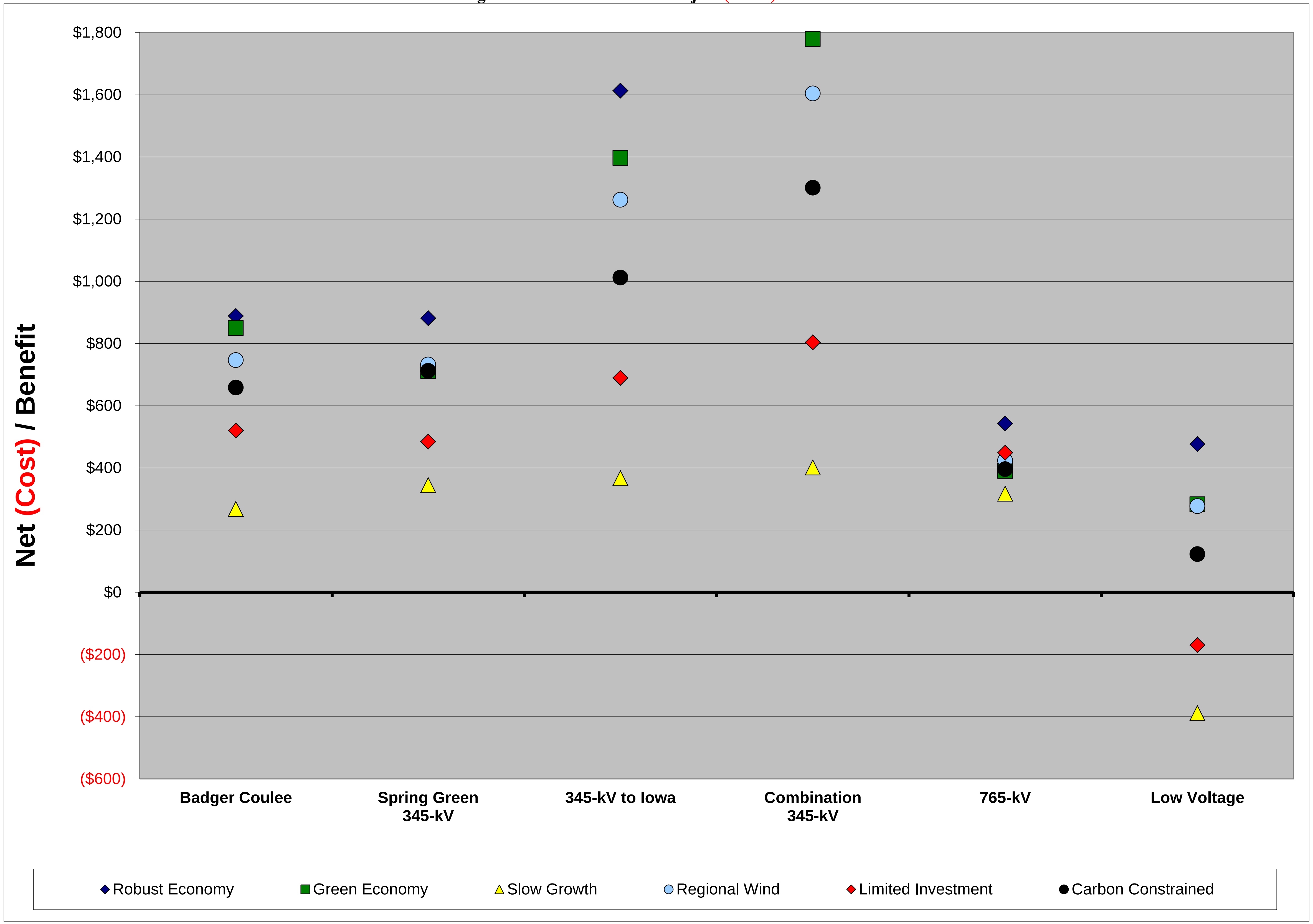

Table 54: Non-Monetized Project Benefits

		Badger Coulee	Spring Green 345-kV	345-kV to Iowa	Combination 345-kV	765-kV	Low Voltage
NON-MONETIZED BENEFITS							
Regional wind outlet	qualitative	Yes	Yes	Yes	Yes	Yes	
Looping La Crosse 345 kV	qualitative	Yes	Yes		Yes		
MN RES/CVS supported	qualitative	Yes	Yes		Yes		
Competitive / HHI	HHI % improvement	4.71%	6.17%	8.02%	9.60%	1.80%	7.24%
Reliability Indices	RI (larger is better)	2.7	2.6	3.0	3.8	3.6	1.1
Transient Stability Benefit	Ranking (lower is better)	1	2	2	1	3	3

12.0 Conclusions

Based on its analysis, ATC concludes that Badger Coulee provides substantial net economic, reliability, and policy benefits to its customers and to Wisconsin. Also, numerous studies demonstrate that Badger Coulee provides additional benefits to regional customers. This project will reduce the delivered price of energy to customers without creating unreasonable risks for ratepayers. ATC therefore seeks approval for the necessary regulatory authorizations required to construct Badger Coulee and place its facilities in service.

Badger Coulee Planning Analysis – Addendum

A. Western Wisconsin Transmission Reliability Study

AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY

Western Wisconsin Transmission Reliability Study

Final Report

September 20, 2010

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Director of Strategic Projects

Transmission – Transmission Planning Analysis
Attachment FF- ATCLLC of the
Midwest ISO Tariff

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EXECUTIVE SUMMARY

This Transmission Study assesses the reliability needs of the western Wisconsin area, shown in Figure I, which has unique reliability-related characteristics. It includes several load centers such as Rochester, Minneapolis and St. Paul in Minnesota, La Crosse, Eau Claire, Madison, Stevens Point, Wisconsin Rapids and Wisconsin Dells in Wisconsin, and Dubuque in Iowa. This Transmission Study is part of a larger "combination of benefits" analysis that takes into account the reliability needs of the study area through this study, the economic savings created by the projects under study and the public policy benefits that would be created by these options.

The transmission facilities located in western Wisconsin are important to reliably serve load and to facilitate reliable power transfers between and through these upper Midwest states. The reliable operation of the existing transmission facilities can be impacted by heavy power through-flows in various directions especially the flow of power from west to east, often referred to as the "west to east bias." This flow bias causes additional stress to the area's transmission network. The west to east transfer capability of the existing transmission facilities through the Minnesota-Wisconsin Export (MWEX) interface is presently limited due to voltage stability and transient voltage recovery limitations. Wind-powered generation has been and will continue to be added in the upper Midwest to meet state Renewable Portfolio Standard (RPS) requirements in the geographical region and beyond. These generation additions will most likely increase the levels of the west to east flows, particularly during off-peak load periods.

The purpose of the Western Wisconsin Transmission Reliability Study is to identify and document the reliability needs in the western Wisconsin area in the eight- to ten-year-out time frame and also to evaluate the extent to which different transmission options would meet these needs using various reliability measures.

The steady-state power flow analyses used three 2018 Summer Peak and Off-peak (70% peak load) models. The existing, planned and future wind generation included in the Midwest ISO (MISO) region in the study models is 13,277 MW. Total wind generation included in North Dakota (ND) and South Dakota (SD) within the MISO region is 583 MW. Total wind generation included in Minnesota (MN), Iowa (IA) and Wisconsin (WI) within the MISO region is 10,006 MW, which is approximately the amount of wind needed to meet the RPS requirements of the Minnesota, Wisconsin and Iowa in 2020[1]. The steady-state power flow analyses include power flow AC contingency analysis, First Contingency Incremental Transfer Capability (FCITC) analysis and Power-Voltage (PV) stability analysis. The study also includes a transient stability analysis using a 2014 light load model.

This study includes two phases: the initial screening and the detailed analysis. The initial screening evaluated the base case and 15 different transmission options using AC contingency

[1] Based on Midwest ISO Regional Generation Outlet Study (RGOS) Phase I & II survey data (with modifications to correct the data anomalies identified by American Transmission Company, LLC) .

analysis. Options that did not have significant and positive impact on the reliability of the western Wisconsin study area were excluded from further detailed analysis. Of the 15 different transmission options that were initially evaluated, seven provided sufficient impact on the reliable operation of the transmission system in the study cases to warrant further detailed evaluation. These are the seven transmission options evaluated in detail:

- Option 1: North La Crosse – Hilltop – Spring Green – Cardinal 345 kV project
- Option 1a: North La Crosse – Spring Green – Cardinal 345 kV project
- Option 1b: North La Crosse – North Madison – Cardinal 345 kV project
- Option 8: Dubuque – Spring Green – Cardinal 345 kV project
- Option 7c: North La Crosse – North Madison – Cardinal and
  Dubuque – Spring Green – Cardinal 345 kV projects
- Low Voltage Option: a collection of 69 kV, 138 kV and 161 kV facilities
- 765 kV Option: Genoa – North Monroe 765 kV project and supporting 345kV[2]

Full descriptions of the seven transmission options studied in the detailed analysis can be found in Appendix A. Three of the options (Options 1, 1a, and 1b) connect to the CapX2020 [3] "Group 1" Hampton Corners – North La Crosse 345 kV line, which has a targeted in-service date between 2013 and 2015, to the Cardinal substation (formerly named West Middleton) in Middleton, Wisconsin, forming network interconnections with the 345 kV facilities in the Madison area. Hilltop is an existing substation in the ATC area with multiple 69 kV lines.

The results as summarized in Table ES-1 show that the Low Voltage Option has the lowest rankings for all aspects of the reliability performance evaluated using non-monetized measures. These aspects include system voltage performance under Category B and C contingencies, severe local low voltages under a Category C2 contingency, voltage stability and robustness and system transient stability. These rankings are further described within the report at their respective sections.

[2] As stated in Appendix A , supporting 345kV facilities for the 765kV option include a N. LaCrosse-Genoa 345kV, Adams-Genoa 345 kV, double circuit N. Monroe-Paddock 345 kV lines and transformers at Genoa and N. Monroe
[3] CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service. www.capx2020.com

Table ES.1 – Summary of non- monetized reliability performance measures

Rankings of benefits not captured by cost analysis (1=Lowest, 5=Highest)	Low Voltage	NLAX-HLT-SPG-CDL (1)	NLAX-SPG-CDL (1a)	NLAX-NMA-CDL (1b)	DBQ-SPG-CDL (8)	NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	Genoa-NOM 765 kV
Voltage performance under Cat-B contingencies	1	4	4	4	4	5	3
Voltage performance under converged Cat-C contingencies	1	5	4	3	4	5	2
Alleviate Cat-C2 severe local low voltages	1	5	5	1	5	5	1
Support voltage stability and robustness	1	3	2	2	3	5	4
Support system transient stability	1	3	1	4	1	5	1

For these aspects, the Low Voltage Option consistently performs at inferior levels compared to the EHV options. As shown in Table ES.2 below, for the reliability aspects evaluated using the monetized measure, the Low Voltage Option is less costly than the EHV options. However, because of their advantages in supporting system voltages, voltage stability and transient stability, the EHV options are preferred over the Low Voltage Option.

The 765 kV Option would represent the first 765 kV element in the western Wisconsin area. The results show that the overall reliability rankings are lower for the 765 kV Option than the 345 kV options for those aspects evaluated using non-monetized measures. For the reliability aspects evaluated using the monetized measure, the 765 kV Option is shown to have the highest cost.

Three of the seven options are in the corridor between North LaCrosse to Madison. These options (Options 1, 1a, and 1b) are comparable from an overall reliability performance perspective and Option 1b (North LaCrosse-North Madison-Cardinal) has the lowest overall cost of the three options. A 345kV line in this corridor provides the voltage stability and interconnection to Minnesota which is one of the desired benefits of this study.

Option 8 (Dubuque-Spring Green-Cardinal) also performs well from a reliability perspective. It has a slightly lower cost than Option 1b (North LaCrosse-North Madison-Cardinal) but does not provide the transient stability that is desired. Option 7c – the combination North La Crosse-North Madison-Cardinal and Dubuque-Spring Green-Cardinal 345 kV project – performed the best across all aspects of the reliability analyses. Option 7c also provides additional benefits over and above the single 345 kV options such as providing the highest level of transfer capability for wind generation in Minnesota and Iowa.

The conclusion of this study is that Option 7c provides the most reliability benefit to the western Wisconsin area. and thatOption 1b provides a portion of the benefit realized in Option 7c and includes the additional interconnection to Minnesota. Option 8 provides significant reliability benefits to western Wisconsin as well but not the needed reinforcements for Minnesota

The transmission maps of the western Wisconsin study area, and Options 1b and 7c are shown in Figures I, II and III. Transmission maps for all studied options can be found in Appendix B.

The summary presented below in Table ES-2 is also found in Section 6, Conclusions.

Finally, it is critical to note that this study evaluates only the reliability benefits of the projects under study. It does not take into account any other benefits of these options, including energy and loss savings, and other economic and policy benefits such as the ability to integrate and deliver renewable energy. ATC believes that the total combination of benefits versus costs, as well as information from the Midwest ISO's Regional Generator Outlet Study, should be taken into account in making a choice to pursue any of the options listed above. ATC has been analyzing the combined reliability, economic, and policy benefits of these options for approximately two years and has determined that a 345 kV project from the La Crosse area to the greater Madison area (the Badger Coulee Project) would provide multiple benefits. ATC has recently announced its intention to finalize its evaluation of these combined benefits and to begin public outreach on the Badger Coulee Project.[4]

[4] Further information about this announcement is located at: http://www.atc-projects.com/BadgerCoulee.shtml

Table ES.2 – Summary of the comparisons of the reliability performance using monetized measures

Summary of project costs in 2010 dollars			Low Voltage	NLAX-HLT-SPG-CDL (1)	NLAX-SPG-CDL (1a)	NLAX-NMA-CDL (1b)	DBQ-SPG-CDL (8)	NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	Genoa-NOM 765 kV
EHV projects			**Opt LV**	**Opt1**	**Opt1a**	**Opt1b**	**Opt8**[1]	**Opt7c**	**Opt 765**
			$0	$454,492,920	$377,454,200	$357,590,989	$304,187,200	$672,785,400	$880,598,000
Category B Supporting Facilities	**Loading**	**ATC Facilities**	$173,768,164	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
	Loading	**Non-ATC Facilities**	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	**$269,165,514**	**$156,943,463**	**$183,640,721**	**$188,698,156**	**$205,393,188**	**$143,951,649**	**$180,046,843**
Category C Supporting Facilities	**Loading**	**ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
	Voltage	**ATC Facilities**	$82,758,813	$0	$0	$0	$0	$0	$0
	Loading	**Non-ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
	Voltage	**Non-ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
		Total	**$82,758,813**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Category B & C Supporting Facilities		**ATC Facilities**	$256,526,977	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
		Non-ATC Facilities	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	**$351,924,327**	**$156,943,463**	**$183,640,721**	**$188,698,156**	**$205,393,188**	**$143,951,649**	**$180,046,843**
Total cost estimates for project packages (main + support)			**$351,924,327**	**$611,436,383**	**$561,094,921**	**$546,289,145**	**$509,580,388**	**$816,737,049**	**$1,060,644,843**

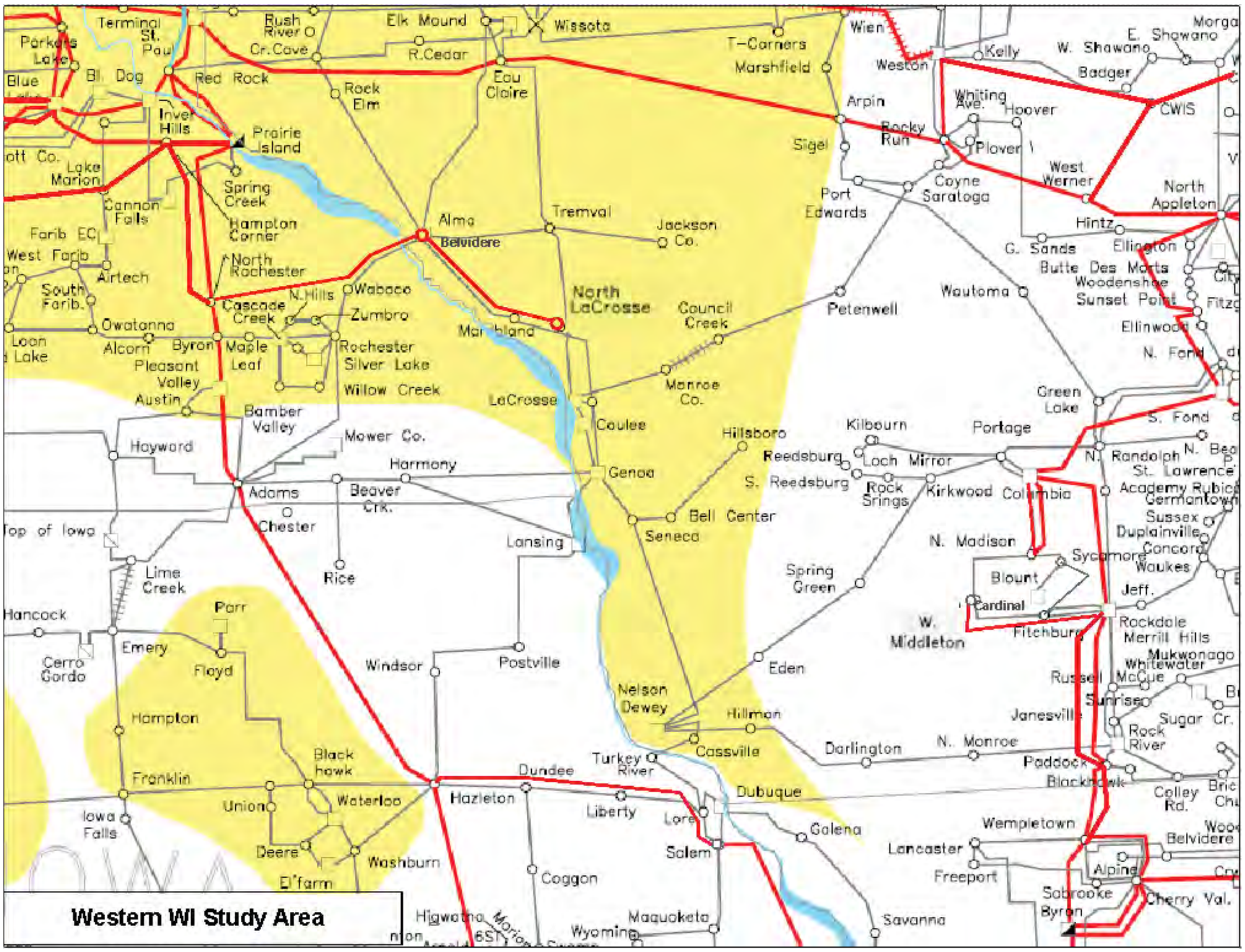

Figure I – Western Wisconsin study area[5]

[5] Yellow shaded area on Option maps represents the Mid-Continent Area Power Pool (MAPP) region.

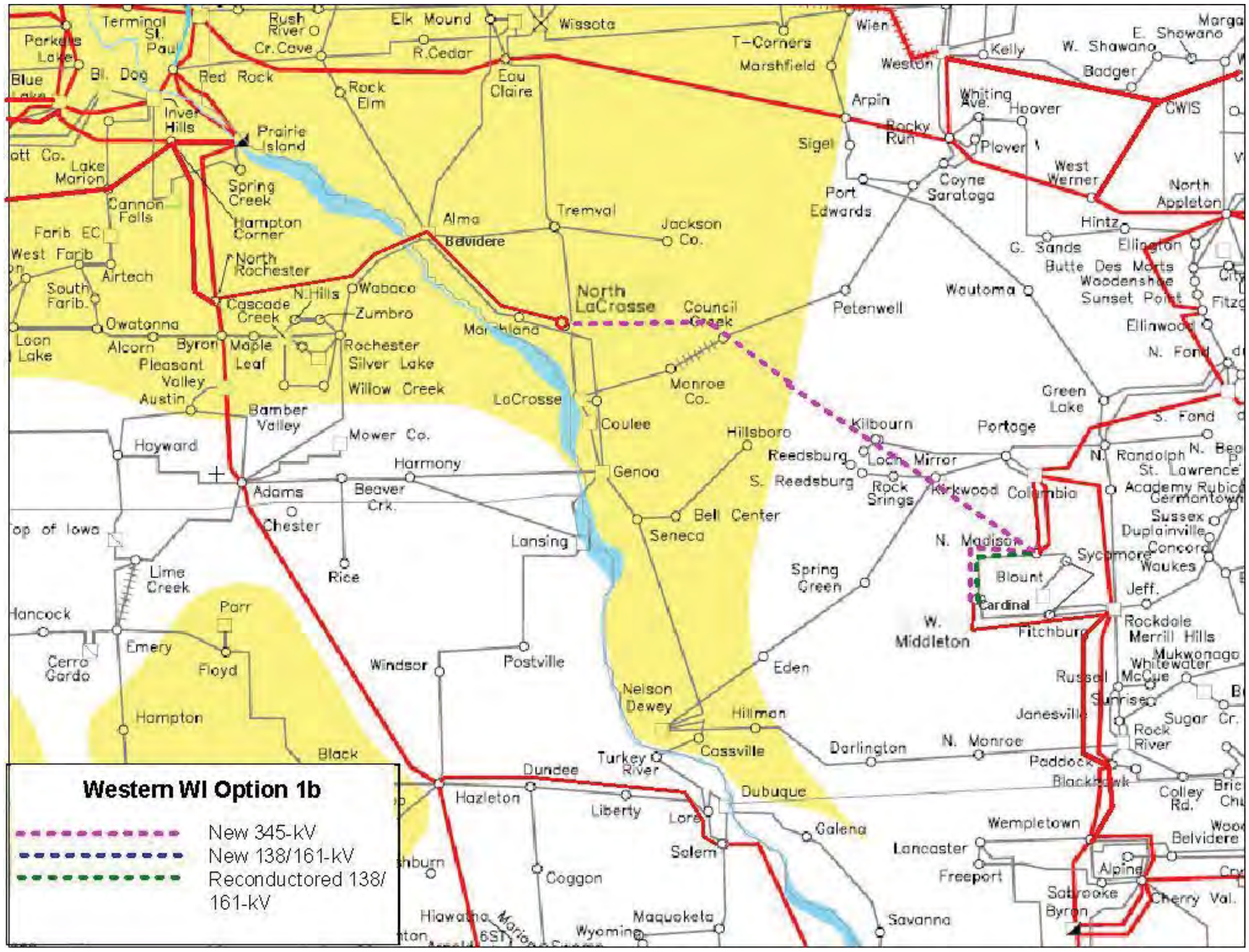

Figure II – North La Crosse - North Madison – Cardinal 345 kV project (Option 1b)[6]

[6] Yellow shaded area on Option maps represents the Mid-Continent Area Power Pool (MAPP) region.

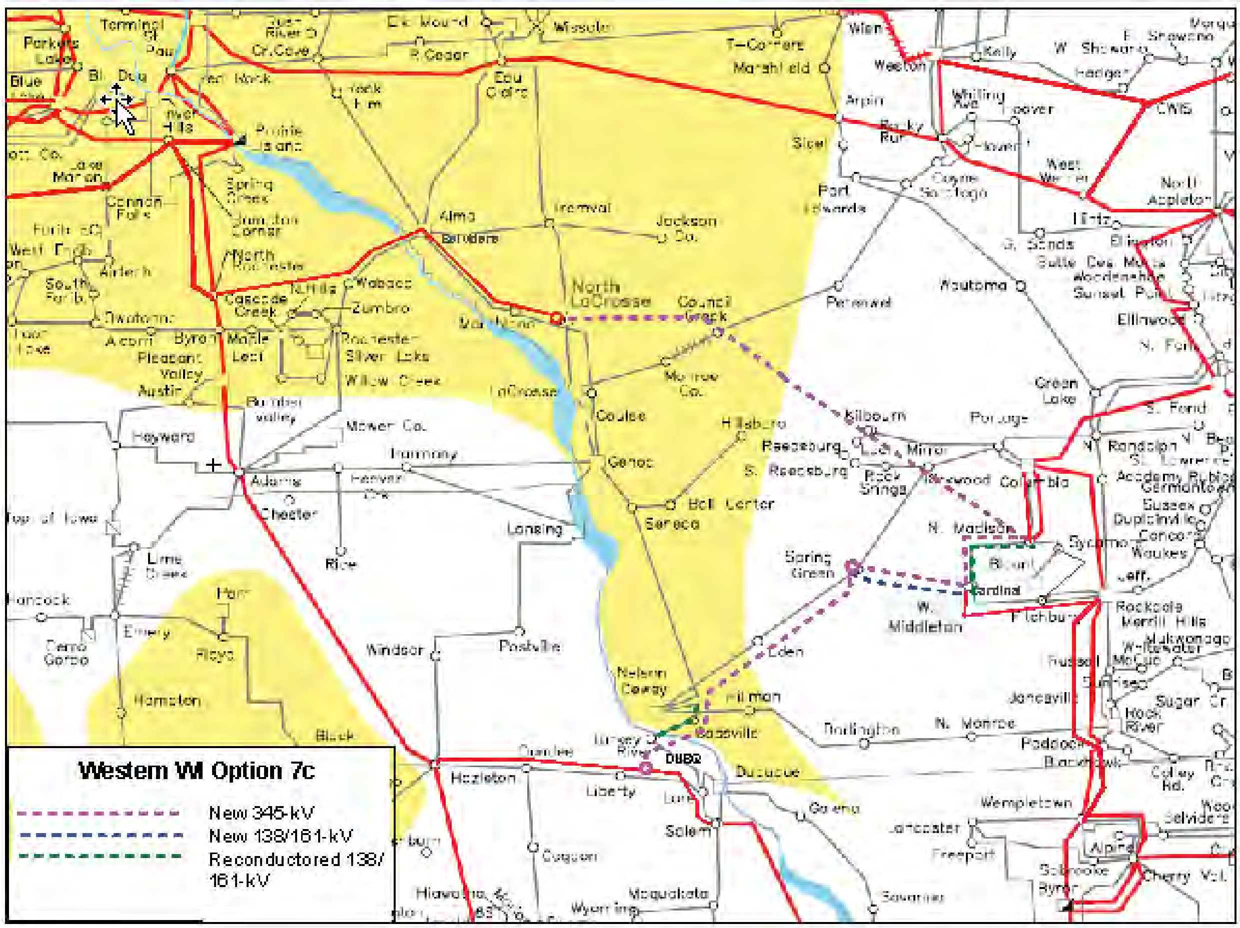

Figure III – North La Crosse-North Madison-Cardinal and Dubuque-Spring Green-Cardinal 345 kV project (Option 7c)[7]

[7] Yellow shaded area on Option maps represents the Mid-Continent Area Power Pool (MAPP) region.

1. Introduction

1.1 Background

The CapX2020 Group I project Hampton Corners – North Rochester – North La Crosse 345 kV line (targeted in-service date 2013 – 2015) addresses the load serving needs in the Rochester and La Crosse areas. It was anticipated that extending this 345 kV line to interconnect with the existing Wisconsin 345 kV network will be beneficial to regional reliability as well as the western Wisconsin area.

The western Wisconsin area, shown in Figure I, has unique characteristics. It includes several load centers such as Rochester, Minneapolis and St. Paul in Minnesota; La Crosse, Eau Claire Madison, Stevens Point, Wisconsin Rapids and Wisconsin Dells in Wisconsin; and Dubuque in Iowa. The western Wisconsin area interconnects the transmission network between Minnesota, Iowa and Wisconsin. A robust transmission network in the area is important to reliably serve the load and also to facilitate reliable power transfers between and through these upper Midwest states.

The western Wisconsin area can be impacted by heavy power flows in various directions; particularly well noted is the west to east flow bias. These flow biases cause additional stress to the area's transmission network. The west to east transfer through the Minnesota-Wisconsin Export (MWEX) interface is currently limited due to voltage stability and transient voltage recovery limitations. Wind-powered generation has been and will continue to be added in the upper Midwest to meet the state Renewable Portfolio Standard (RPS) requirements in the geographical region and beyond. These additions will most likely increase the levels of the west to east flows, particularly during off-peak load periods.

The purpose of the Western Wisconsin Transmission Reliability Study is to identify and document the reliability needs in the eight- to 10-year time frame and also to identify potential transmission solutions to meet the reliability needs.

Several Transmission Owners (TOs) whose existing transmission facilities could be potentially impacted by transmission additions in the western Wisconsin area initiated a joint transmission reliability study. The study is led by American Transmission Company, LLC (ATC). The following Transmission Owners and the Midwest ISO participated in the study:

Xcel Energy (Xcel)
Dairyland Power Cooperative (DPC)
International Transmission Company, Midwest (ITCM)
Great River Energy (GRE)
CapX2020 (CapX)
Southern Minnesota Municipal Power Agency (SMMPA)

The TO group coordinated the model building efforts with the Midwest ISO. The Midwest ISO assisted in creating the Security Constrained Economic Dispatches (SCED) for the study models. Also, it should be noted that the study participants collaborated on this regional transmission planning study in accordance with the regional planning coordination requirement of FERC Order No. 890[8] and in accordance with ATC's planning requirements under Attachment FF-ATCLLC of the Midwest ISO Tariff.[9]

1.2 Scope

This reliability study includes AC power flow contingency analysis of NERC Category A, Category B and Category C contingencies; First Contingency Incremental Transfer Capability (FCITC) analysis to identify thermal constraints under increasing levels of west to east transfers; P-V voltage stability analysis to evaluate voltage stability and robustness under increasing levels of west to east transfers; transient stability analysis; and an analysis of the estimated comparative costs of the transmission options. The three study models used for steady state power flow analysis are 2018 Summer Peak, 2018 Summer Off-peak (70% Load) with 35-45% wind output, and 2018 Summer Off-peak (70% Load) with 90% wind output. The transient stability analysis used a 2014 light load model.

1.3 Studied Options

This study includes two phases: the initial screening and the detailed analysis. The initial screening evaluated the base case and 15 different transmission options using AC contingency analysis. These options are listed in Table 1.1. Further details of all studied transmission options can be found in Appendix A. The transmission maps for all studied options are included in Appendix B.

The initial screening showed that some of the options did not have notable impact on the western Wisconsin study area and these options were excluded from further detailed analysis. Options that were evaluated in further detail are highlighted in yellow in Table 1.1.

[8] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 (2007) at PP 523 and 528. FERC put in place the "Regional Participation" principle that states that "each transmission provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources..." The coordinated regional planning must "address both reliability and economic considerations."

[9] Midwest ISO FERC Electric Tariff, Fourth Revised Volume No. 1, Original Sheet No. 3387

Table 1.1 – List of studied options

Option #	Option Name
Opt 1	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV project
Opt 1a	North La Crosse–Spring Green–Cardinal 345 kV project
Opt 1b	North La Crosse–North Madison–Cardinal 345 kV project
Opt 8	Dubuque–Spring Green–Cardinal 345 kV project
Opt 7c	North La Crosse-North Madison-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 765	Genoa–North Monroe 765 kV project
Opt LowV	Low Voltage option
Opt 2	North La Crosse-Dubuque 345 kV project
Opt 2a	North La Crosse-Genoa-Dubuque 345 kV project
Opt 3	Eau Claire-North La Crosse 345 kV project
Opt 4	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and Eau Claire-North La Crosse 345 kV project
Opt 5	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and North La Crosse-Dubuque 345 kV project
Opt 6	North La Crosse-North Cassville-Dubuque 345 kV and North Cassville-Spring Green-Cardinal 345 kV project
Opt 7	North La Crosse-Hilltop-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7a	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7b	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project

2. Study Assumptions, Methodology and Criteria

2.1 Steady State Power Flow Analyses

Study Models

The base models (starting points) for the steady state power flow analyses are the 2018 summer peak and off-peak models developed for the Midwest ISO Transmission Expansion Plan 2008 (MTEP08). The model is described in MTEP08 report in the following manner: “The regional resource forecasted units developed for the Reference Generation Portfolio future” (through the first two steps in the MTEP08 economic study process) “are sited in the models. The 2018 off peak model has 70% of summer peak load level in Midwest ISO footprint and has the same transmission topology as the 2018 summer peak model. Generation dispatch in Midwest ISO footprint was based on Security Constrained Economic Dispatch (SCED) to mitigate all possible N-1 constraints in Midwest ISO 200 kV and above systems. Wind generation in the Midwest ISO footprint is dispatched at 15% of its capacity in 2018 summer peak model and 100% of its capacity in 2018 off peak model.”[10]

System topologies and load in the original models were updated for the western Wisconsin study area. The non-wind types of future/conceptual generating units sited inside the study area were removed. The following three study models were created including the Security Constrained Economic Dispatches (SCED) that was created. The Minnesota-Wisconsin Export Interface (MWEX) flow, the ATC western interface flow, the MRO export and the ATC import in these three study models are as follows:

- 2018 Summer Peak (SUPK)
  - Wind generation at 20% of nameplate capacity
  - MWEX interface = 485 MW
  - ATC Western Interface = 540 MW Import
  - MRO Export = 1175 MW
  - ATC Import = 1218 MW
- 2018 Summer Off-peak (70% of peak load) (SUOP)
  - Wind generation at 35-45% of nameplate capacity (45% in ND, SD, MN and IA; 35% for the rest of the MISO region)
  - MWEX interface = 928 MW
  - ATC Western Interface = 1330 MW Import
  - MRO Export = 1150 MW
  - ATC Import = 1318 MW
- 2018 Summer Off-peak (70% of peak load) with 90% wind output (SUOP90)
  - Wind generation at 90% of nameplate capacity
  - MWEX interface = 1029 MW
  - ATC Western Interface = 1440 MW Import
  - MRO Export = 1585 MW
  - ATC Import = 1263 MW

[10] MTEP08 Report, Section 4.3.2 http://www.midwestiso.org/page/Expansion+Planning

It can be observed that the west to east flows through the MWEX interface and the ATC western interface are higher in the off-peak cases than in the summer peak case. Also, the west to east flows are higher in the 90% wind output case than in the 35-45% wind output case. Since many wind units are located in the western part of the Midwest ISO region, increasing wind unit output resulted in increased west to east flows. Note that the above documented west to east flows are for the base cases without addition of any studied transmission options. It was observed that with the addition of a 345 kV or 765 kV option, the west to east flow through the ATC western interface increases, although in general flows on the existing facilities of the interface are reduced to a certain extent.

The total amount of existing, planned and future wind generation included in the study models is 13,277 MW for the Midwest ISO region. Most of the wind units are sited in the western part of the Midwest ISO region. Table 2.1 summarizes total wind generation by locations within the Midwest ISO region included in the study models. Table 2.2 summarizes the locations and sizes of the future wind units in Minnesota, Iowa and Wisconsin within the Midwest ISO region included in the study models. The existing, planned and future wind units in the western part of the Midwest ISO region are also marked on a transmission map as shown in Figure 2.1.

Table 2.1 – 2018 wind generation included in the Midwest ISO region

Location	**Wind generation, MW**
SD	0
ND	583
IA	2,401
WI	2,823
MN	4,782
Sub-total for study area	**10,006**
Total in MISO region	**13,277**

Table 2.2 – Future wind units included in the Midwest ISO region

Substation	**Control Area**	**Wind generation MW**
Burlington 138 kV	WEC 295	100
Hillman 138 kV	ALTE 694	100
Rocky Run 345 kV	WPS 696	300
South Fond du Lac 345 kV	ALTE 694	800
Adams 345 kV	XEL 600	1000
Wilmarth 345 kV	XEL 600	500
Lakefield 345 kV	ITCM 627	400
Magnolia 161 kV	ITCM 627	350
Total		**3550**

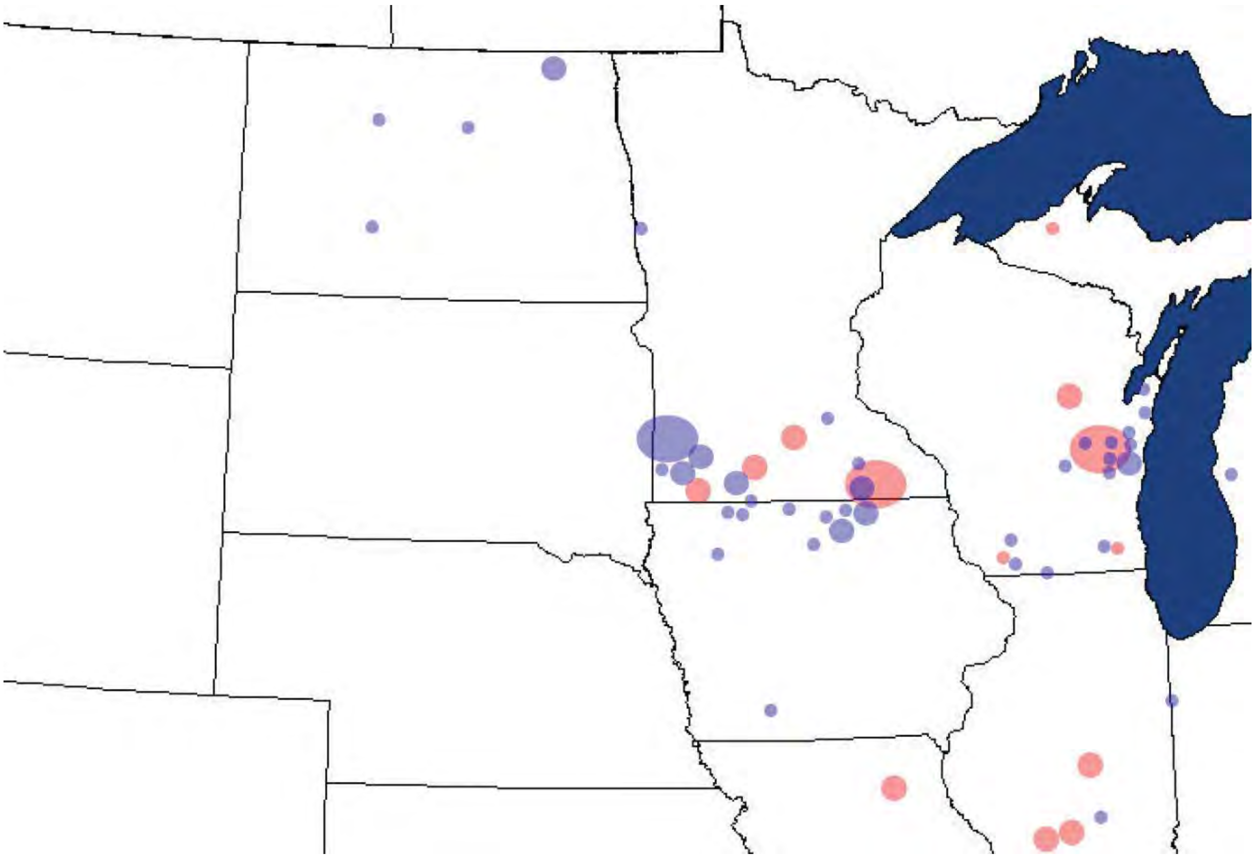

Figure 2.1 – Existing, planned and future wind generation included in the study models for the western part of the MISO region
Blue = existing/proposed, Red = Conceptual
Small/Medium/Large Ovals = 0-200, 201-750, 751-1000 MW

Study Area

The study area, as shown in Figure I, is defined according to the following:

- Xcel Energy facilities from the Twin Cities south and east in Minnesota
- Xcel Energy facilities from the Hayward area south (Stone Lake Substation) in Wisconsin
- ITC Midwest facilities in southeast Minnesota and northern Iowa
- MEC facilities in northern Iowa
- DPC facilities in Minnesota, Wisconsin, Iowa and Illinois
- GRE facilities in southeast Minnesota
- SMMPA facilities in southeast Minnesota
- ATC facilities from Wausau south and west of North Appleton
- RPU facilities in Minnesota

The Monitored Facilities Subsystem includes the following facilities:

- SMMPA Zone 631 69 kV – 345 kV facilities
- SMMPA Area 613 69 kV – 345 kV facilities
- XEL-MN Zone 601 69 kV – 345 kV facilities
- XEL-WI Zone 604 69 kV – 345 kV facilities
- DPC Area 680 69 kV – 345 kV facilities
- GRE Area 615 100 kV – 345 kV facilities
- ITCM Area 627 100 kV – 345 kV facilities
- MEC Area 635 100 kV – 345 kV facilities
- ATC Zone 1696 69 kV – 345 kV facilities[11]

The Contingent Facilities Subsystem includes the following facilities:

- SMMPA Zone 631 69 kV – 345 kV facilities
- SMMPA Area 613 100 kV – 345 kV facilities
- XEL-MN Zone 601 100 kV – 500 kV facilities
- XEL-WI Zone 604 100 kV – 345 kV facilities
- DPC Area 680 100 kV – 345 kV facilities
- GRE Area 615 100 kV – 345 kV facilities
- ITCM Area 627 100 kV – 345 kV facilities
- MEC Area 635 100 kV – 345 kV facilities
- ATC Zone 1696 69 kV – 345 kV facilities
- ATC Zone 1686 230 kV – 345 kV facilities[12]
- ComEd Area 222 345 kV – 765 kV facilities

Types of Contingencies Studied

Category B contingencies:

- All contingencies specified by study participants
- All single elements defined in the Contingent Facilities Subsystem
- All 100 kV -765 kV ties to the defined Contingent Facilities Subsystem

[11] ATC Zone 1696 was defined to represent the ATC region in the western Wisconsin study area.
[12] ATC Zone 1686 includes all 230 kV and above facilities in ATC region and ties to ATC region.

Specified Category C contingencies:

- 1,141 study participant specified Category C1, C2 and C5 contingencies. Most N-2 contingencies include the outage of at least one generator.

Enumerated N-2 contingencies:

- N-2 combinations of transmission lines and transformers in Minnesota, Iowa, northern ComEd and ATC regions:
  - 5,995 northern ComEd 345 kV and above transmission line and transformer pairs.
  - 861 Iowa transmission line and transformer pairs consisting of Area 680 and 627 345 kV facilities, transformers from 345 kV to 230/161/138/115 kV and the studied transmission option segments.
  - 6,105 Minnesota transmission line and transformer pairs consisting of Area 613, 615, 680 and Zone 601 and 604 345 kV facilities, transformers from 345 kV to 230/161/138/115 kV and the studied transmission option segments.
  - 7,626 ATC region transmission line and transformer pairs consisting of ATC 345 kV facilities, ATC transformers from 345 kV to 230/161/138/115 kV and the studied transmission option segments.

Major Planned or Proposed Projects Included in the Base Models

The following major transmission line projects within or in proximity to the study area are included in the study base models[13]:

- Gardner Park – Highway22 – Werner West 345 kV (ATC)
- Highway22 – Morgan 345 kV (ATC)
- Paddock – Rockdale – Cardinal 345 kV (ATC)
- Fargo – Twin Cities 345 kV project (CapX2020)
- Hampton Corner – North Rochester – North La Crosse 345 kV (CapX2020)
- Brookings County – Lyon County – Cedar Mountain (Franklin) – Helena – Lake Marion– Hampton Corner 345 kV (CapX2020)
  - Lyon County-Cedar Mountain-Helena are double circuited
- Hazel Creek-Panther-McLeod-Blue Lake 345 kV (Minnesota “Corridor” project)
  - Double circuited, second line Hazel Creek-Blue Lake 345 kV
  - McLeod 345/115 kV Transformer #1
  - Panther 345/69 kV Transformer #1
  - Remove Hazel Creek-Minn Valley Tap 230 kV
- Byron-Pleasant Valley 161 kV (Xcel)
- Pleasant Valley 345/161/13.8 kV transformer #2 (Xcel)
- Hazelton-Salem 345 kV (ITCM)
- Arpin-Rocky Run 345 kV line rebuild (ATC)
- Monroe Co-Council Creek 161 kV (ATC)

[13] The Big Stone II 670 MW generation and transmission facilities were included in the study cases. The study cases were created before the Big Stone II generation project cancellation announcement, on November 2, 2009. Since these facilities are far away from the western Wisconsin study area, the study participants did not think removing these facilities from the study cases would have notable impact on the study results.

Study Methodology and Criteria

Siemens PTI, PSS™ MUST version 8.3.2 was used for the AC power flow contingency analysis. This software was also used for the First Contingency Incremental Transfer (FCITC) analysis. A 3% Distribution Factor (DF) threshold was used for the FCITC analysis. The PowerTech Labs VSAT program was used for voltage stability analysis. See *Section* 4 and *Section* 5 for further details of the methodologies used in various reliability analyses performed in this study. The study results were evaluated in accordance with the NERC TPL Standards. ATC's Planning Criteria was used for this study, neighboring Transmission Owners may have a different criteria than what was evaluated in this study.

Thermal Loading Criteria: For intact system facility Normal Ratings (Rate A) were used. Under contingencies facility Emergency Ratings (Rate B) were used.

Steady State Voltage Criteria: The acceptable voltage range is 95 percent to 105 percent of nominal voltage in the intact system and 90 percent to 110 percent under contingencies.

2.2 Transient Stability Analysis

Study model

The base model (starting point) for the transient stability analysis is the MTEP09 2014 Light Load (40% of peak load) stability model and data set[14]. This model includes 6,000 MW of wind generation. The following modifications were made to the starting model to fit the purpose of this study:

- Major planned and proposed projects included in the power flow models for steady state analysis as discussed in *Section* 2.1 are also verified or included in the 2014 light load model for transient stability analysis.
- An additional 3,150 MW of future wind generation was added to the starting model. Total wind generation included in the stability model is 9,150 MW in the Midwest ISO region. The locations and sizes of the future wind generation included in the stability case are shown in Table 2.3. Part of the added wind generation was offset by re-dispatching non-wind generation in the same control areas in which the future wind generation was added. Part of the added wind generation was offset by export generation to the eastern part of the MISO region.

Table 2.3 – Future wind units added to the stability case

Substation	Control Area	Wind generation (MW)
Hillman 138 kV	ALTE 694	100
South Fond du Lac 345 kV	ALTE 694	800
Adams 345 kV	XEL 600	1000
Wilmarth 345 kV	XEL 600	500
Lakefield 345 kV	ITCM 627	400

[14] See MTEP09 Report, Section 6.1.3 for MTEP09 model building methodology. http://www.midwestiso.org/page/Expansion+Planning

Magnolia 161 kV	ITCM 627	350
Total		**3150**

Study Methodology and Criteria

The transient stability analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-30 (PSS/E, Version 30.5.1) program from Power Technologies, Inc (PTI).

Angular Stability Criteria

Critical Clearing Time (CCT) is a period relative to the start of a fault, within which all generators in the system remain stable (synchronized). CCT is obtained from simulation. Maximum Expected Clearing Time (MECT) determines a period of time that is needed to clear a fault using the existing system facilities. MECT is dictated by the existing system facilities. In any contingency, if the computed CCT is less than the MECT plus a margin determined by a Transmission Owner, it is considered an unstable situation and is unacceptable. Otherwise, it is considered acceptable transient stability performance. The ATC Planning Criteria requires 1.0 cycle margin for studies using estimated generator data and 0.5 cycle margin for studies using confirmed generator data. The 0.5 cycle margin is applicable to the generating units in the ATC region for this study. The 1.0 cycle margin is used as a proxy for generating units outside of the ATC region. Further refinement can be made to the 1.0 cycle margin based on additional information from the TO participants.

Transient Voltage Recovery

According to ATC Planning Criteria, voltages of all transmission system buses must recover to be at least 70% of the nominal system voltages immediately after fault removal and 80% of the nominal system voltages in 2.0 seconds after fault removal. Transient voltage recovery was checked for generation units in the ATC region using this criterion. This criterion was also used as a proxy for checking generation units outside the ATC region but located in the study area. Further refinement can be made based on additional information from the Transmission Owner participants.

3. Overall Approach for the Reliability Analysis

This study includes two phases: the initial screening and the detailed analysis. The initial screening evaluates the base case and 15 different transmission options using AC contingency analysis of Category B and specified Category C contingencies (see *Section* 2.1.2 for discussions of the studied contingencies). Options that did not show positive notable impacts on the western Wisconsin study area were excluded from further detailed analysis. The detailed analysis further compares seven selected transmission options using results of AC contingency analysis, FCITC analysis, voltage stability analysis, transient stability analysis and the costs of constructing the transmission options.

4. Initial Screening

The initial screening evaluated the base case and 15 different transmission options using AC contingency analysis of Category B and specified Category C contingencies. These 15 transmission options are listed in Table 4.1 below. Further details on and the transmission maps of these options can be found in Appendix A and B respectively. The three study cases, as discussed in *Section* 2.1.1, are used in this evaluation.

Table 4.1 – Transmission options evaluated in initial screening

Option #	Abbreviated Name	Full Name
Opt 1	NLAX-HLT-SPG-CDL	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV project
Opt 1a	NLAX-SPG-CDL	North La Crosse–Spring Green–Cardinal 345 kV project
Opt 1b	NLAX-NMA-CDL	North La Crosse–North Madison–Cardinal 345 kV project
Opt 8	DBQ-SPG-CDL	Dubuque–Spring Green–Cardinal 345 kV project
Opt 2	NLAX-DBQ	North La Crosse-Dubuque 345 kV project
Opt 2a	NLAX-GENOA-DBQ	North La Crosse-Genoa-Dubuque 345 kV project
Opt 3	EAU-NLAX	Eau Claire-North La Crosse 345 kV project
Opt 4	NLAX-HLT-SPG-CDL & EAU-NLAX	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and Eau Claire-North La Crosse 345 kV project
Opt 5	NLAX-HLT-SPG-CDL & NLAX-DBQ	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and North La Crosse-Dubuque 345 kV project
Opt 6	NLAX-NCAS-DBQ & NCAS-SPG-CDL	North La Crosse-North Cassville-Dubuque 345 kV and North Cassville-Spring Green-Cardinal 345 kV project
Opt 7	NLAX-HLT-SPG-CDL & DBQ-SPG	North La Crosse-Hilltop-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7a	NLAX-SPG-CDL & DBQ-SPG	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7b	NLAX-SPG-CDL & DBQ-SPG-CDL	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 7c	NLAX-NMA-CDL & DBQ-SPG-CDL	North La Crosse-North Madison-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 765	GENOA-NOM 765 kV	Genoa–North Monroe 765 kV project

4.1 Diverged Single Event Category C Contingencies

Three single event Category C contingencies (C5 or C2), were found to cause solution divergence or converged to severe low voltages for some of the studied cases. [redacted]

- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]

- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
- [redacted]
  - [redacted]
  - [redacted]
  - [redacted]

These results indicate potential voltage collapse conditions under the three single event Category C contingencies in the base case without a transmission option included. The results also indicate that Option 2 (NLAX-DBQ), Option 2a (NLAX-GENOA-DBQ), and Option 3 (EAU-NLAX) are not effective in controlling the identified voltage collapse conditions.

4.2 Severity Index

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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[redacted]

4.3 Initial Screening Results

Category B Thermal Loading Results

The Severity Index evaluation of the AC contingency analysis thermal loading results under Category B contingencies are shown in the charts below.

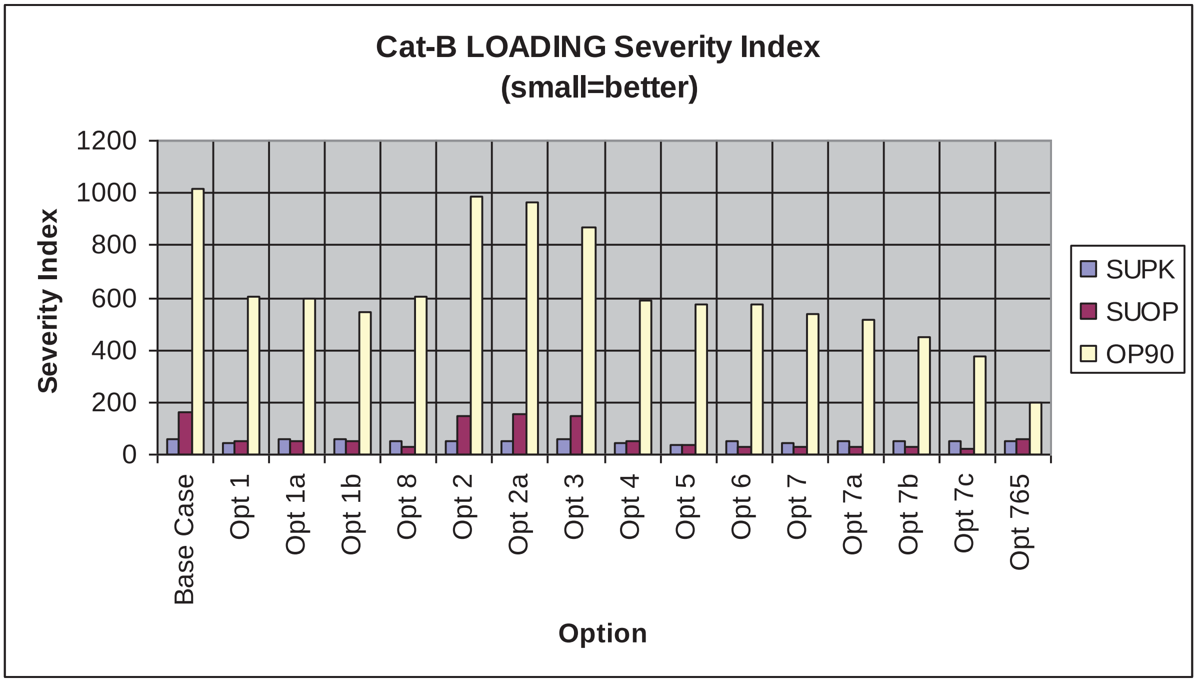


Figure 4.1 – Category B thermal loading results Severity Index review

Figure 4.1 shows the thermal loading Severity Indices for the base case and the cases with the studied transmission options under Category B contingencies for all three study models. It shows that compared to Summer Peak (SUPK) and Summer Off-Peak (SUOP) model overall thermal limitations are worst in the Off-Peak with 90% (OP90) wind output model, which has the most west to east flow bias through the western Wisconsin study area (see *Section* 2.1.1 for discussions of the three study models).

Figure 4.2 shows all positive thermal loading Severity Index changes comparing the option cases to the base case for all three study models. This indicates that overall the transmission options reduce the thermal loading limitations under the studied Category B contingencies. The varying values of the Severity Index change indicate varying degrees of the effectiveness of the transmission options.

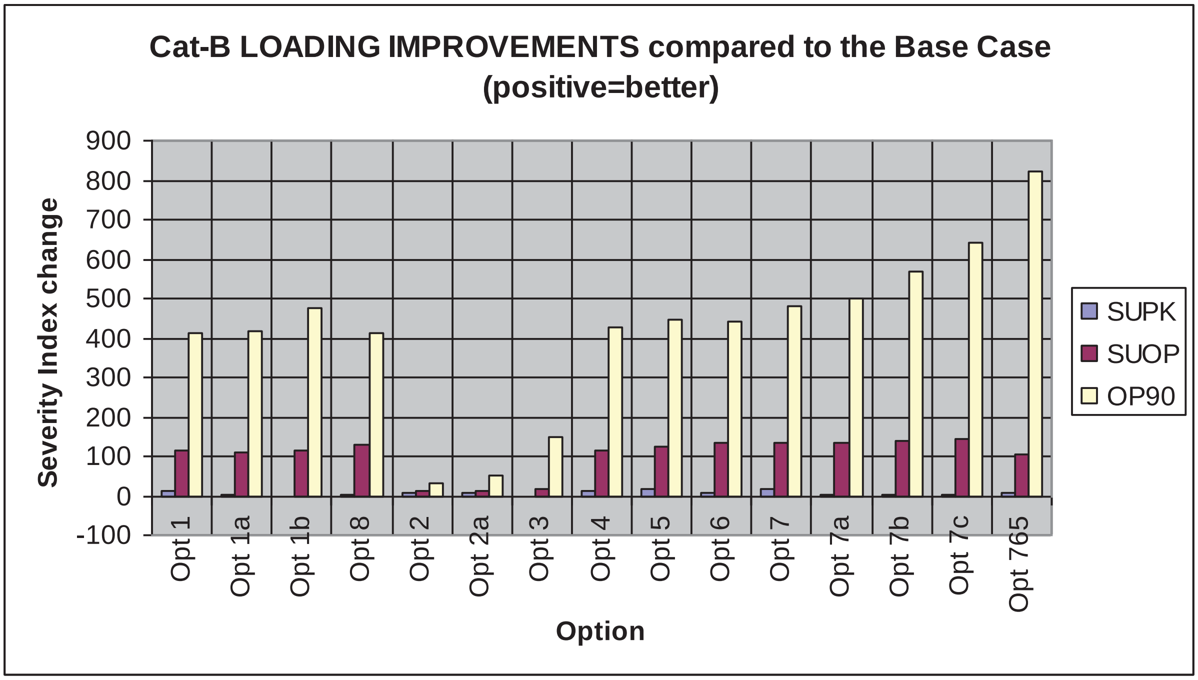


Figure 4.2 – Category B thermal loading results Severity Index review

The Category B thermal results were also reviewed using a measure that compares the loading difference between the base case and an option case for unique monitored elements. This analysis applies to facility loadings of 90% and above. A 10% loading difference threshold was applied in the results shown in Figure 4.3. This means that the loading difference between the base case and an option case needs to be at least 10% (in either direction) in order to be captured in the analysis result. Figure 4.3 shows a number of unique monitored elements, the loading of which are increased or decreased by at least 10% comparing an option case and the base case. A positive number is associated with a reduction in loadings in an option case compared to the base case. A negative number is associated with an increase in loadings in an option case compared to the base case. The 10% threshold used in this result captures relatively large changes in loadings between the base case and an option case. It shows that overall the studied transmission options have a positive impact in reducing the loadings, some options more effectively than others. The studied transmission options are also shown to have some negative impact to facility loadings, but to a much lesser extent when compared to the positive impact.

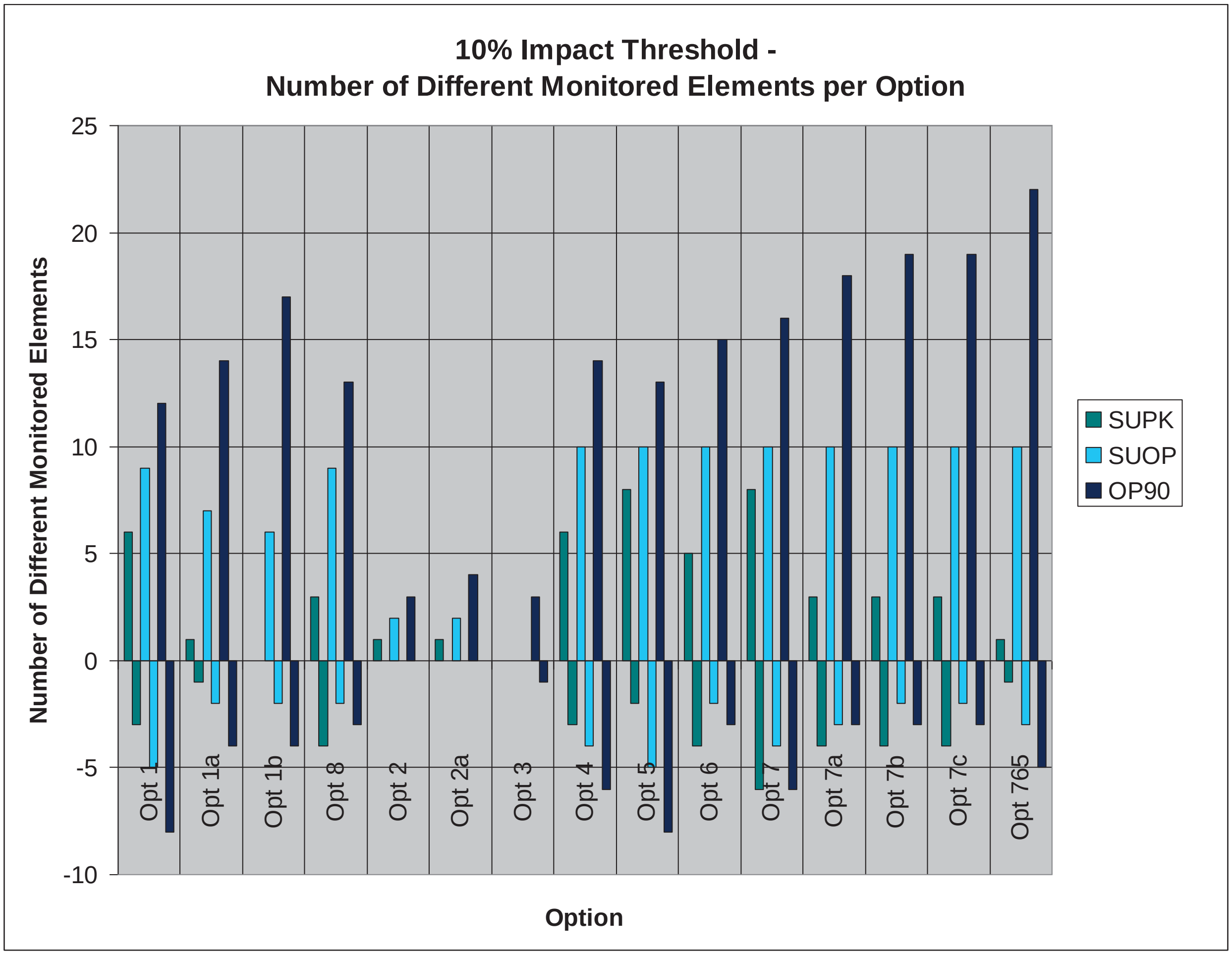


Figure 4.3 – Loading difference between the base case and option cases using 10% threshold for unique monitored elements

Category B voltage performance results

Only minor low voltage violations were identified under Category B contingencies in the Summer Peak and Off-peak models. No valid low voltage violations were identified in the Off-peak with 90% wind output model. No valid high voltage violations under Category B [redacted]

Table 4.5 – Category B worst low voltage violations in the base case and Summer Peak model

			Base case low voltages					
[redacted]	From Area	To Area	Bus Num	Bus Name	KV	Area	Voltage	Worst of
	697	697	698136	PLV 138	138	694	0.8949	4

Table 4.6 – Category B worst low voltage violations in the base case and Off-peak model

			Base case low voltages					
[redacted]	From Area	To Area	Bus Num	Bus Name	KV	Area	Voltage	Worst of
	694	694	699048	BLK 138	138	694	0.8963	4

Figure 4.4 shows mostly positive voltage Severity Index changes comparing the option cases to the base case for all three study models.

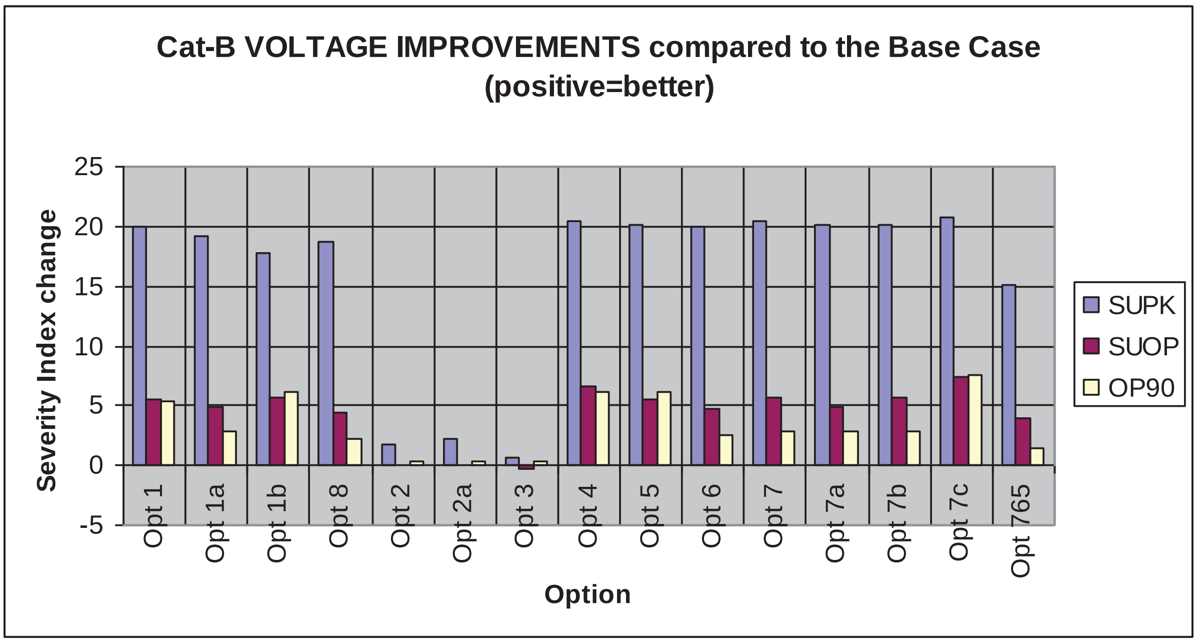


Figure 4.4 – Category B voltage performance results Severity Index review

Category C Thermal Loading Results

For the specified Category C contingencies, the thermal limitations were observed to be worse in the Off-peak models than in the Summer Peak model and worst in the Off-peak with 90% wind output model. This is similar to what was observed from the Category B thermal results. Note that non-converged contingencies were excluded equally from the Severity Index review of each option. Figure 4.5 shows mostly positive thermal loading Severity Index changes comparing the option cases to the base case. This indicates that overall the transmission options reduce the thermal loading limitations under the specified Category C contingencies. The varying values of the Severity Index change indicate varying degrees of the effectiveness of the transmission options.

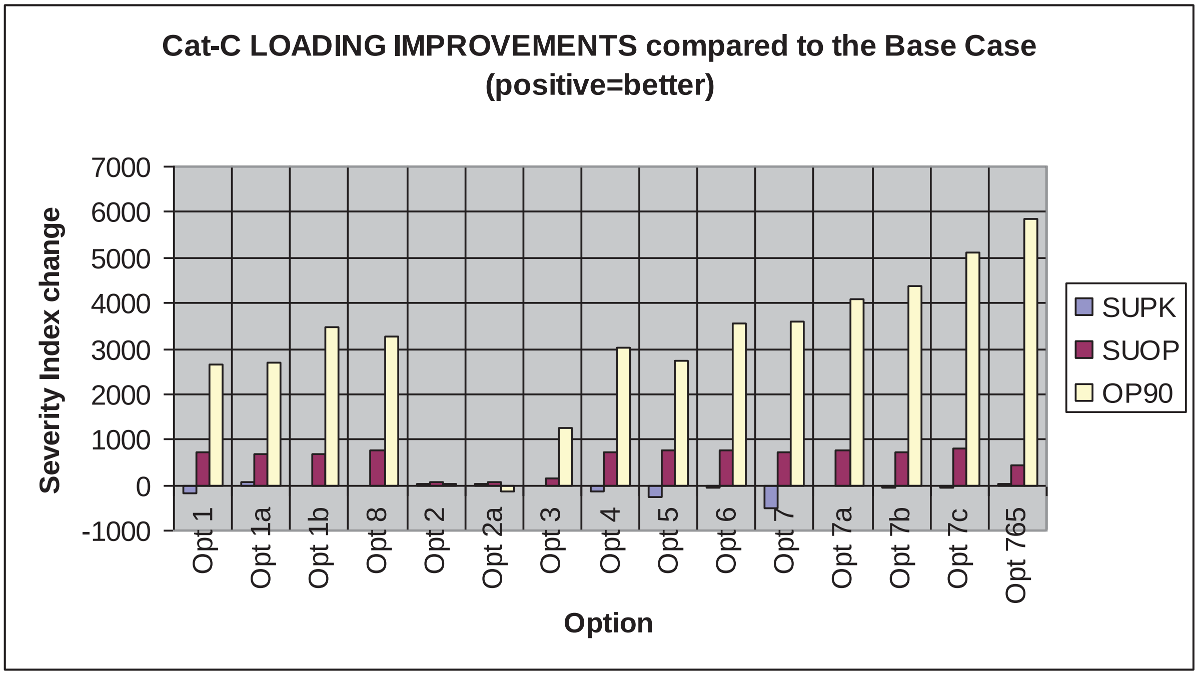


Figure 4.5 – Category C thermal loading results Severity Index review

Category C voltage performance results

Figure 4.6 shows mostly positive voltage Severity Index changes comparing the option cases to the base case for all three study models.

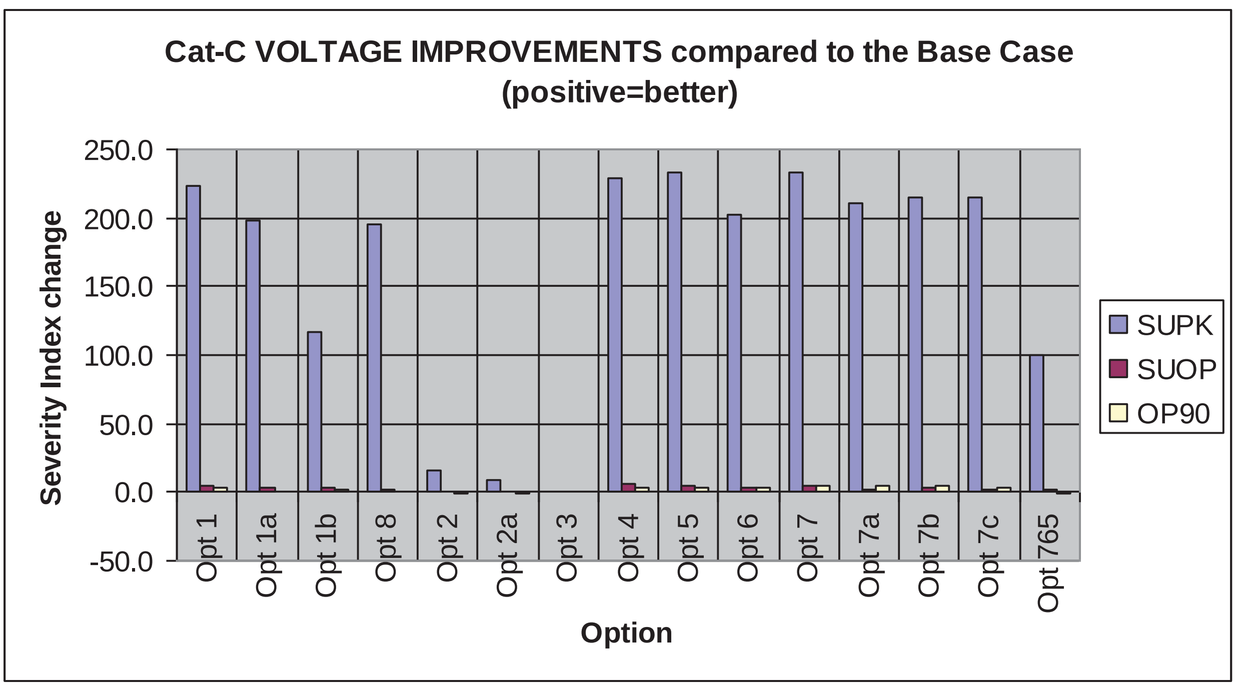


Figure 4.6 – Category C voltage performance results Severity Index review

Initial Screening Summary

The initial screening identified thermal loading and voltage performance limitations (including potential voltage collapse) in the base case without any transmission options for the system conditions simulated in the three study models. The base case and the cases with 15 transmission options were evaluated for Category B and specified Category C contingencies. One of the purposes of the initial screening was to select a few options for further detailed analysis. It was identified that out of the single element options (1, 1a, 1b, 8, 2, 2a and 3), Option 2, 2a, 3 (NLAX-DBQ, NLAX-GENOA-DBQ, and EAU-NLAX, respectively) did not seem to be effective in improving the reliability performance in the western Wisconsin study area. Option 7c (NLAX-NMA-CDL & DBQ-SPG-CDL) was shown to be the most effective 345 kV combination option in terms of improving reliability performance. The 765 kV Option was shown to perform positively for most of the reliability analysis categories. Based on the initial screening results, Options 1 (NLAX-HLT-SPG-CDL), 1a (NLAX-SPG-CDL), 1b (NLAX-NMA-CDL, 8 (DBQ-SPG-CDL), 7c (NLAX-NMA-CDL & DBQ-SPG-CDL) and the 765 kV Option (GENOA-NOM 765 kV) were selected for further detailed analysis and comparison.

Low Voltage Option

Based on the results of Category B thermal limitations, a Low Voltage option was also created. The Low Voltage option eliminates the identified thermal limitations under the Category B contingencies on a piece-by-piece basis. The Low Voltage option is a collection of lower than 345 kV facilities that include a new 161 kV line and upgrades of 48 individual facilities. Details of the Low Voltage option can be found in Appendix A. This option is also evaluated in the detailed analysis.

List of Options to be Evaluated in Detailed Analysis

All selected options evaluated in the detailed analysis are shown in Table 4.7 below.

Table 4.7 – Transmission options selected for further detailed analysis

Option #	**Abbreviated Name**	**Full Name**
Opt 1	NLAX-HLT-SPG-CDL	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV project
Opt 1a	NLAX-SPG-CDL	North La Crosse–Spring Green–Cardinal 345 kV project
Opt 1b	NLAX-NMA-CDL	North La Crosse–North Madison–Cardinal 345 kV project
Opt 8	DBQ-SPG-CDL	Dubuque–Spring Green–Cardinal 345 kV project
Opt 7c	NLAX-NMA-CDL & DBQ-SPG-CDL	North La Crosse-North Madison-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 765	GENOA-NOM 765 kV	Genoa–North Monroe 765 kV project
Opt LV	Low Voltage	A collection of lower than 345 kV facilities that include a new 161 kV line and upgrades of 48 individual facilities.

5. Detailed Analysis

The detailed analysis compares the seven selected transmission options based on costs and reliability performance in the AC contingency analysis, FCITC analysis, voltage stability analysis and transient stability analysis.

5.1 Monetized and Non-Monetized Measures

Monetized and non-monetized measures are applied to different aspects of the reliability study results for comparison between the seven options. The monetized measure is based on construction cost estimates and comparison. This type of measure was applied to the Category B thermal loading results, solution divergence under the three single event Category C contingencies and the FCITC results. The basic approach is to identify the supporting facilities that would be needed to address these reliability issues for each option; such that the reliability performance will be comparable between the options including these facilities. Costs are then compared between the options including the main EHV components and the supporting facilities. All costs referenced in this study are in 2010 dollars. Monetized measures were not applied to some aspects of the reliability analysis, such as voltage performance under Category B and converged specified Category C contingencies, voltage stability analysis and transient stability analysis. For each of these aspects of the reliability analyses, quantitative rankings were assigned to the studied options. To be consistent, rankings are all in the range of 1 to 5, with "1" representing the best performance and "5" representing the worst performance. The rankings may not be from 1 to 5 continuously. For example, if the results show a clear divide of better and comparable performance for a sub-group of the seven options, and worse and comparable performance for the rest of the options, then "1" is assigned to the options in the first sub-group and "5" is assigned to the rest of the options. The span of 5 is always used.

In the following sections, comparisons between the options using monetized or non-monetized measures for each studied aspect of the reliability analysis are discussed. At the end of *Section* 5, a summary table is provided that includes comparison of all studied aspects of the reliability analysis using monetized and non-monetized measures.

5.2 Construction Cost Estimates for the EHV Options

Cost estimates for the EHV components of the studied options are shown in Table 5.1.

Table 5.1 – Cost estimates for the EHV components

Options	$ in 2010
Low Voltage	$0
NLAX-HLT-SPG-CDL (1)	$454,492,920
NLAX-SPG-CDL (1a)	$377,454,200
NLAX-NMA-CDL (1b)	$357,590,989
DBQ-SPG-CDL (8)	$304,187,200
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	$672,785,400
Genoa-NOM 765 kV	$880,598,000

5.3 Supporting Facilities to Overcome Category B Thermal Loading Limitations

It should be noted that the EHV components alone in any option do not address all identified Category B thermal limitations. To compare the option costs on a level ground, supporting facilities were identified for each option such that all identified thermal limitations are eliminated in any of the option cases. Thermal loadings above 95% of applicable Ratings were captured in this evaluation; 95% was used instead 100% to capture near misses. For the Low Voltage Option, the facilities that eliminate the Category B thermal limitations were already identified, as shown in Appendix A. Cost estimates for these facilities are also included in Appendix A. The supporting facilities needed to eliminate all identified thermal limitations under Category B contingencies for the EHV options can be found in Appendix D. Cost estimates for these facilities are also included in Appendix D.

Table 5.2 summarizes the costs of the supporting facilities needed for each of the seven options to eliminate the identified Category B thermal limitations. The total cost of the Low Voltage Option also is included. Each EHV option needs supporting facilities, thus, they do not resolve all identified Category B thermal limitations by themselves. However, fewer supporting facilities were needed with the EHV options than those identified in the Low Voltage Option on a piece-by-piece basis. Also, it should be noted that if the only reliability concern is Category B thermal limitations, the Low Voltage Option would seem to be less expensive than the EHV options and the corresponding supporting facilities for each option. However, critical reliability concerns are not limited to just Category B thermal and voltage limitations for the western Wisconsin study area. Evaluations of several of these other key aspects are discussed in the following sections.

Table 5.2 – Costs of the supporting facilities for Category B thermal loading limitations

Options	$ in 2010
Low Voltage	$269,165,514
NLAX-HLT-SPG-CDL (1)	$156,943,463
NLAX-SPG-CDL (1a)	$183,640,721
NLAX-NMA-CDL (1b)	$188,698,156
DBQ-SPG-CDL (8)	$205,393,188
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	$143,951,649
Genoa-NOM 765 kV	$180,046,843

5.4 Voltage Performance under Category B and Specified Converged Category C Contingencies

Figures 5.1 and 5.2 show the voltage performance comparison between the seven options under Category B and specified converged Category C contingencies. It is shown that the 345 kV options are more effective in improving system voltage performance than the 765 kV Option or the Low Voltage Option. The Low Voltage Option showed the worst performance in this evaluation.

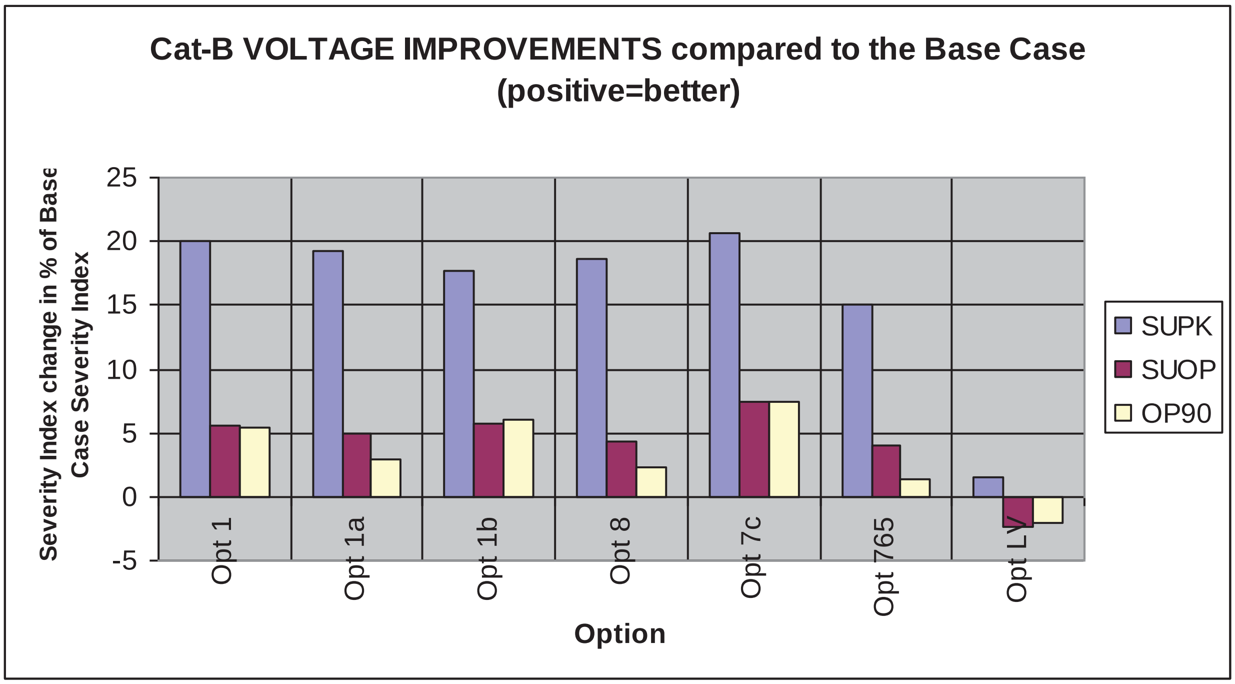


Figure 5.1 – Category B voltage performance results Severity Index review

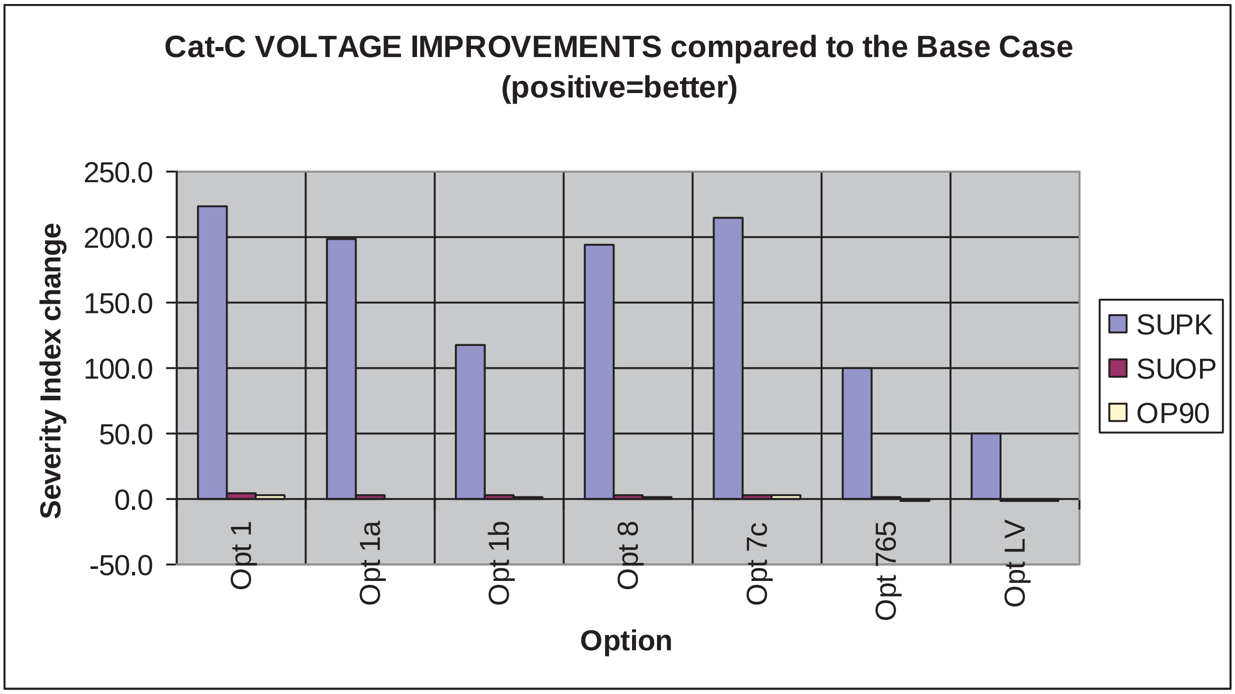


Figure 5.2 – Category C voltage performance results Severity Index review

Based on the results of this evaluation, rankings are given to the seven options, as shown in Table 5.3. A ranking of “1” represents the worst performance and “5” represents the best performance. These rankings were determined using engineering judgment and the charts above, comparing across all options.

Table 5.3 – Option rankings for the voltage performance under Cat-B, Cat-C contingencies

Options	Cat-B Ranking	Cat-C Ranking
Low Voltage	1	1
NLAX-HLT-SPG-CDL (1)	4	5
NLAX-SPG-CDL (1a)	4	4
NLAX-NMA-CDL (1b)	4	3
DBQ-SPG-CDL (8)	4	4
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5	5
Genoa-NOM 765 kV	3	2

5.5 Review of Diverged Category C5 and C2 Contingencies

Three single event Category C contingencies (C5 or C2) were found causing solution divergence or solved with severe low voltages for some of the studied cases. A preliminary discussion was provided in *Section* 4.1. These conditions are indications of voltage collapse. Further evaluation was performed to determine reactive supports needed to control these conditions. [redacted]

- [redacted]
- [redacted]
- [redacted]

These contingencies were evaluated for the base case and seven transmission options using all three study models.

Load shedding and opening of facilities were taken into account in this evaluation of potential cascading outages as a result of a multiple contingency. Each multiple contingency was applied and thermal loadings and voltage levels were monitored. The assumed tripping levels due to low voltage or thermal loading are described as follows. If the post contingent voltage of a bus was below 0.87 p.u., it was assumed the load connected to that bus would be automatically shed by relay action. Also, if post contingent thermal loading of a facility was greater than 125% of its emergency rating, that facility would be assumed to trip and be removed from service by either relay action or operator interaction. If both unacceptable low voltage and thermal loading were experienced, then load would be shed first to determine if it improved the voltage and/or the thermal loading. If the voltage was improved but the thermal loading remained, a facility would be opened to remove or reduce the flow. If low voltages remain, additional load connected to buses with voltages below 0.87 p.u. would be shed.

Option 1a (NLAX-SPG-CDL)

[redacted] created conditions where the switching criteria as discussed above were met. During the off-peak load conditions, a few facilities experienced thermal loadings greater than 125%. However, the loading concerns were eliminated by opening the facilities of concern. Upon opening of these facilities, all thermal loadings greater than 125% were removed and all voltages were above 0.87 p.u. No low voltage wide area cascading outage conditions were identified under this contingency.

Option 1b (NLAX-NMA-CDL)

For Option 1b, the contingency of [redacted]

[redacted] These can be mitigated by shedding load in the immediate vicinity of the outage. [redacted] Alternatively, [redacted] reactive support would be needed to correct the severe local low voltages [redacted]

[redacted]

Option 8 (DBQ-SPG-CDL)

For Option 8, the contingency [redacted] created conditions where the switching criteria as discussed above were met. During the off-peak load conditions a few facilities experienced thermal loadings greater than 125%. However, the loading concerns were eliminated by opening the facilities of concern. Upon opening of these facilities, all thermal loadings greater than 125% were removed and all voltages were at least 0.87 p.u. No low voltage wide area cascading outage conditions were identified under this contingency.

The contingency [redacted] caused minor low voltages in the local area, which can be corrected using [redacted] reactive support:

[redacted]

765 kV Option (Genoa-NOM 765 kV)

For the 765 kV Option, the contingency [redacted] caused some severe low voltages. These can be mitigated by shedding load in the immediate vicinity of the outage. [redacted] Alternatively, the following reactive support would be needed to correct the severe low voltage condition without load shedding:

[redacted]

The contingency [redacted] caused minor low voltages in the local area, which can be corrected using the following reactive support:

[redacted]

Low Voltage Option

For the Low Voltage Option, the contingency [redacted] of load shed to control voltage collapse. The following reactive supports are needed to control the voltage collapse conditions, without load shedding, caused by the contingency:

[redacted]

[redacted] These can be mitigated by shedding load in the immediate vicinity of the outage. [redacted] Alternatively, the following reactive support would [redacted] without load shedding:

[redacted]

The voltage issues associated with the contingency [redacted] are addressed using the reactive [redacted]

Option 1 (NLAX-HLT-SPG-CDL) and Option7c (NLAX-NMA-CDL + DBQ-SPG-CDL)

Detailed analysis was not performed for these two options. It was assumed that the reactive support needed for these two options are comparable to Option 1a. Option 1 is comparable to Option 1a since the only difference between the two options is Option 1 has an additional 345/138 kV transformer modeled at the Hilltop substation. Option 7c is comparable to Option 1a since both options have 345/138 kv transformers modeled at the Spring Green substation and an interconnection at the Cardinal substation.

Reactive Support Summary

Table 5.4 summarizes the costs of the reactive support needed to control low voltage wide area cascading outages under the identified single event Category C contingencies. [redacted]

Table 5.4 – Costs of reactive supports or amount of load shed needed to control voltage collapse under Category C contingencies

Options	**Reactive support $ in 2010**	[redacted]
Low Voltage	$82,758,813	[redacted]
NLAX-HLT-SPG-CDL (1)	$0	[redacted]
NLAX-SPG-CDL (1a)	$0	[redacted]
NLAX-NMA-CDL (1b)	$0	[redacted]
DBQ-SPG-CDL (8)	$0	[redacted]
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	$0	[redacted]
Genoa-NOM 765 kV	$0	[redacted]

Table 5.5 summarizes the amount of load shed needed to alleviate severe local low voltages under a single event Category C contingency. Costs of the alternative remedy of reactive supports needed to alleviate the condition are also shown in the table.

Table 5.5 – Amount of [redacted] of reactive support needed to control severe local low voltages under a Category C contingency

Options	[redacted]	Reactive support $ in 2010
Low Voltage	[redacted]	$54,569,472
NLAX-HLT-SPG-CDL (1)	[redacted]	$0
NLAX-SPG-CDL (1a)	[redacted]	$0
NLAX-NMA-CDL (1b)	[redacted]	$53,821,824
DBQ-SPG-CDL (8)	[redacted]	$0
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	[redacted]	$0
Genoa-NOM 765 kV	[redacted]	$54,569,472

It could be argued from a cost perspective that local load shedding is preferred over installing SVC's to control severe local low voltages under Category C events. Both remedies are acceptable according to current NERC TPL Standards. To capture the merits of alleviating severe local low voltages using a non-monetized measure, the project options are ranked as shown in Table 5.6. A ranking of "1" represents the worst performance and "5" represents the best performance. Those with needed SVC's or Cap Banks received a ranking of 1 and those without a need received a ranking of 5.

Table 5.6 – Option rankings for alleviating severe local low voltages under a single event Category C contingency

Options	Rankings
Low Voltage	1
NLAX-HLT-SPG-CDL (1)	5
NLAX-SPG-CDL (1a)	5
NLAX-NMA-CDL (1b)	1
DBQ-SPG-CDL (8)	5
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5
Genoa-NOM 765 kV	1

This evaluation shows that the 345 kV options are more effective in controlling the voltage collapse and for alleviating severe local low voltages than the 765 kV or the Low Voltage Option. The Low Voltage Option showed the worst performance in this evaluation.

5.6 Non-Converged N-2 Contingencies

The non-converged N-2 contingencies identified in any of the studied cases are listed in Appendix E. No conclusive comparisons have been obtained based on this result. Further analysis is needed in this aspect of the reliability analysis.

5.7 First Contingency Incremental Transfer (FCITC) Analysis

The western Wisconsin study area often experiences west to east flow biases that cause additional stress to the transmission system in the area. The FCITC analysis demonstrates the robustness of the system with each transmission option and compares the options with respect to thermal loading characteristics under increasing west to east transfers.

The following three transfer directions were evaluated in detail using the Off-peak with 35-45% wind output model:

- Minnesota to Wisconsin
- Iowa to Wisconsin
- Minnesota and Iowa to the Midwest ISO central and east planning sub-regions

Note that the supporting facilities to eliminate all identified Category B thermal limitations were taken into account in the FCITC analysis. The charts in Figures 5.3 through 5.5 show the FCITC results for the seven options. The results show that the 345 kV options are more effective than the Low Voltage Option in improving the west to east transfer capability. Option 7c is most effective. The 765 kV Option is not as effective as Option 7c, particularly for sub-regional transfers of MN to WI and IA to WI.

Higher FCITC capabilities indicate stronger robustness of the system to cope with thermal loading issues under flow biases. During initial screening, the three east to west transfers (opposite to the west to east transfers listed above) were also simulated. The level of congestion identified was much less compared with the west to east transfers. Therefore the detailed study focused on the west to east transfers.

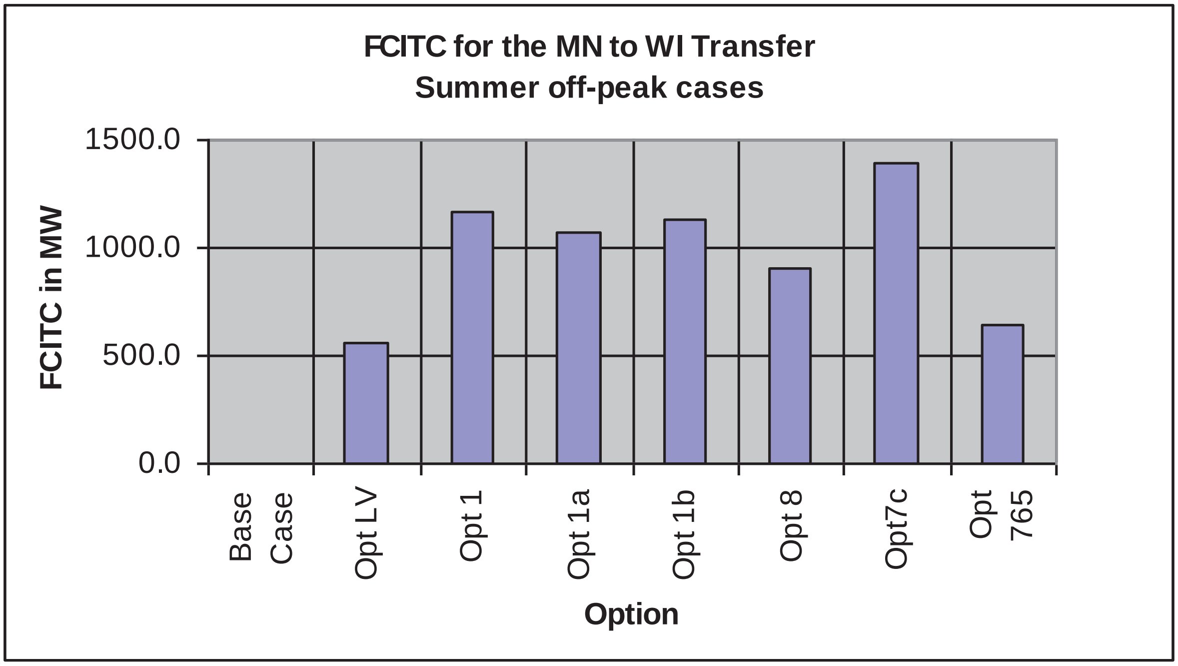


Figure 5.3 – FCITC for the MN to WI transfer

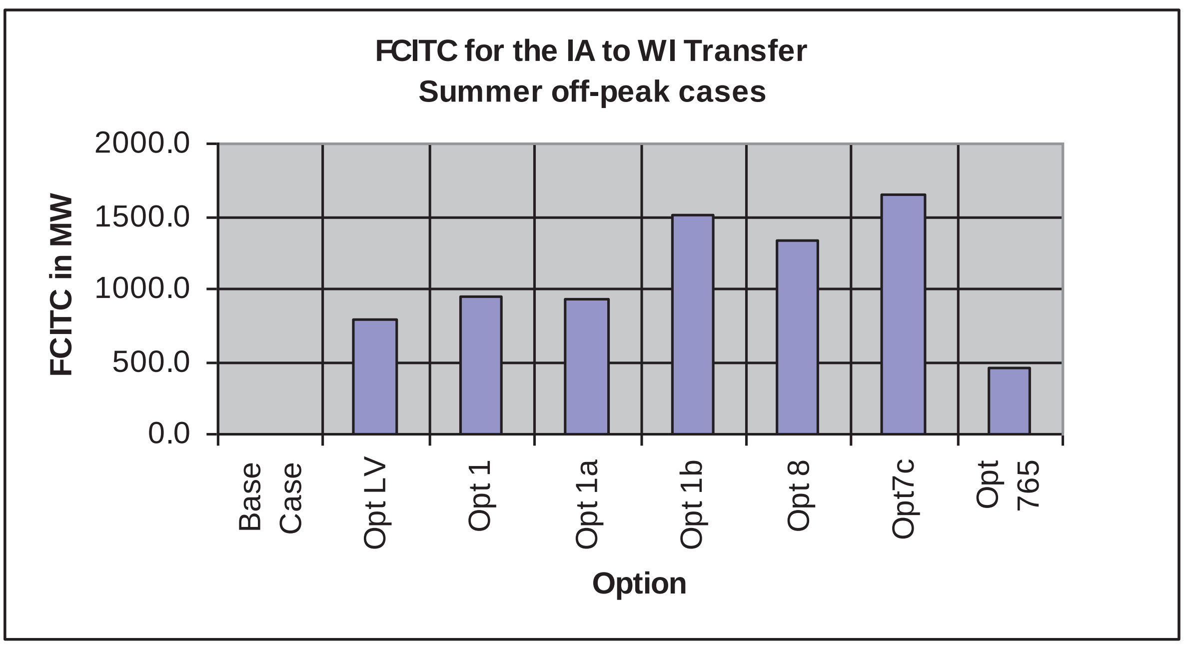


Figure 5.4 – FCITC for the IA to WI transfer

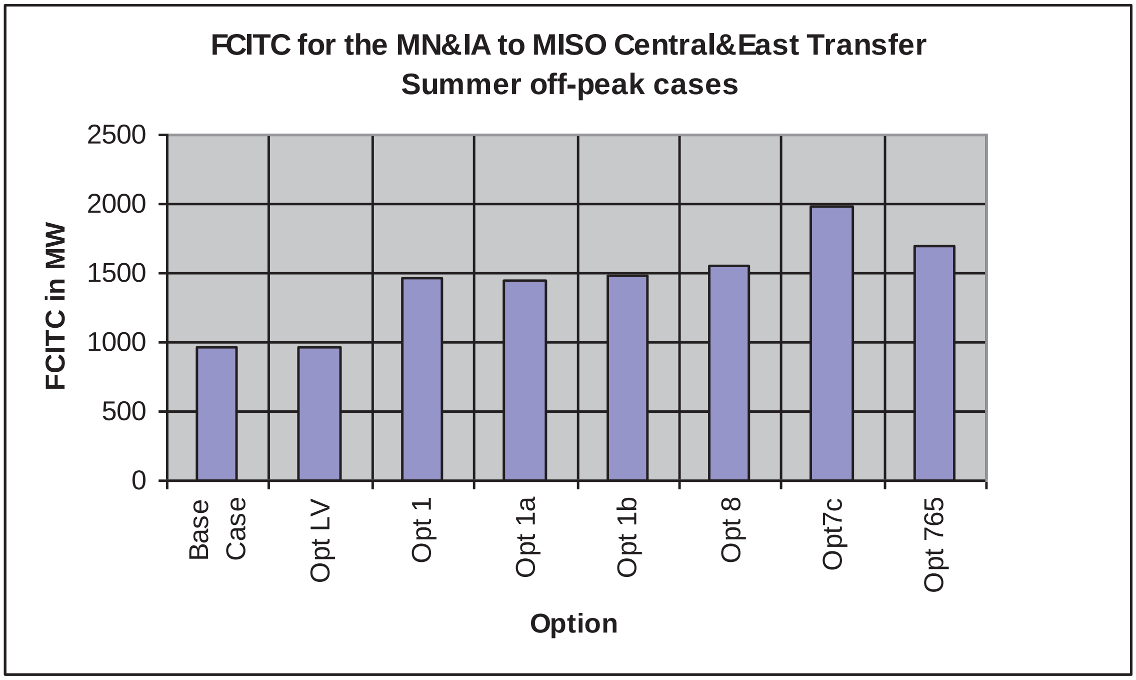


Figure 5.5 – FCITC for the MN&IA to MISO Central and East transfer

5.8 P-V Voltage Stability Analysis

Voltage stability is an important issue for the western Wisconsin study area. Currently, the Minnesota – Wisconsin Export interface (MWEX) is limited by voltage stability and transient low voltage recovery. The voltage stability analysis demonstrates the robustness of the system with each transmission option and compares between the options in respect to voltage stability characteristics under increasing west to east transfers.

The voltage stability results should not be interpreted as identifying a set of valid operating ranges. The voltage stability simulations ignore transmission overloads and push power flow transfers to levels where voltages become depressed and collapse. The results do attempt to correlate the characteristic power flow across an interface as an indicator of voltage stability. Demonstrating this is accomplished by means of a set of Power transfer vs. Voltage (PV) charts.
For the purpose of this study the produced charts focus on power flow across two interfaces: through the ATC western tie lines, and an interface which includes all ATC tie lines and represents ATC imports. Simulating voltage stability in this manner is consistent with industry practices using such tools.

This study compares simulations with and without the transmission options. For comparison of voltage stability characteristics, the baseline interface flows, voltage, and losses reported in this study are not as significant as the improvements in those values produced by each option.

Power transfer across the study interfaces has the potential to increase real (MW) and reactive (MVAR) losses on the system. Similar to the PV charts, this report will use Power vs. Loss (PL) charts to demonstrate how the real and reactive losses are expected to change as power flow increases across the study interfaces.

The various reported results demonstrate the characteristics that each option contributes toward the voltage stability and robustness of the study region.

PV Analysis - Study Conditions

The voltage stability analysis used two study models - the 2018 Summer Off-peak with 35-45% wind output (SUOP) model and the 2018 Summer Peak (SUPK) model. The voltage stability analysis tested the following:

Base	Base reference starting case
Option 1	N. La Crosse-Hilltop-Spring Green-Cardinal 345 kV
Option 1a	N. La Crosse-Spring Green-Cardinal 345 kV
Option 1b	N. La Crosse-North Madison-Cardinal 345 kV
Option 8	Dubuque-Spring Green-Cardinal 345 kV
Option 7c	N. La Crosse-North Madison-Cardinal 345 kV + Dubuque-Spring Green-Cardinal 345 kV
Option HV (765)[15]	Genoa-North Monroe 765 kV and supporting 345 kV
Option LV	Low Voltage Option

Several variations of the transmission options above were also tested with addition of all the reactive supports (SVCs and Capacitors) identified in the Category C reliability analysis, as discussed in *Section* 5.5 previously. These are the additional simulations (note that the notation "+caps" refers to capacitor additions and other reactive resource additions such as SVCs):

Base	(+caps)
Option 1b	(+caps)
Option 8	(+caps)
Option HV (765)	(+caps)
Option LV	(+caps)

The PowerTech Labs VSAT program was used to test voltage stability. To improve the solution convergence and provide a more robust set of results, various small adjustments were made to the study case. For example, some changes could include minor bus tie impedance changes, resolving voltage regulation conflicts. Many of the changes were remote from the study area, but were needed to provide a more robust set of results.

PV Analysis - Monitored Facilities

Selected buses within the study region were monitored for additional output. Some of these locations are used in the power transfer vs. voltage (PV) charts. A list of the locations is provided in Appendix F.

A number of interfaces were defined to examine the power transfers in the simulations. Examples of interfaces used include monitoring the ATC western WI tie lines, and monitoring an

[15] Option HV in this section refers to the 765 kV Option as referenced throughout the report.

ATC import interface consisting of all ATC tie lines. When studying the various transmission options, these interfaces were augmented with any additional lines that are part of an option.

VSAT parameter settings were activated to report information regarding zonal MW and MVAR losses. The loss information is used to produce charts of power transfer vs. losses (PL).

The VSAT program provides additional output that is not discussed in this section, but can be made available as part of the supporting materials upon request.

PV Analysis - Contingencies Tested

Each VSAT run tested approximately 30-40 contingencies that were considered to be among the most severe for the study region. The tests did not include contingencies that were considered farther from the study area since they would have a poor correlation to the studied transmission options. The contingencies used included significant outages identified in the reliability results. An additional VSAT screening was also performed to include additional contingencies (above 161 kV) that may be significant. Within the study region selected unit outages and capacitor bank outages were also included. When studying the various transmission options, several additional contingencies were included to account for facilities of each option. A compete list of the tested contingencies can be found in Appendix F.

PV Analysis - Stability Settings

This section describes some of the VSAT program parameters used for each simulation. The simulations are set to ignore pre-contingency and post contingency overloads. The simulations do not attempt to assess or simulate cascading outage conditions. The simulations are not set to perform any operating steps or other overload mitigation methods other than the items mentioned in this report.

These are some of the more significant VSAT solution parameter file settings that are used in the simulations:

Limit Generator Reactive Var output within limits	(Always)
Transfer Analysis	(To First Limit)
Contingency Analysis	(To First Insecure)
Adjust ULTCs transformers for voltage control	(In pre-contingency)
Adjust phase-shifters for MW flow control	(In pre-contingency)
Adjust discrete switched shunts	(Always)
Adjust area interchange	(Never)

Because the model includes power flow features that model some load outside of its power flow control areas, the area interchange feature cannot readily be turned on in VSAT. Therefore, losses are handled by the system swing located within Tennessee Valley Authority in the east. Adjustments were made to the case to make it more robust so that the swing will not have EHV outlet issues when supplying losses to the system.

PV Analysis - Phase Shifter Operation

The Arrowhead phase shifter located near Duluth, Minnesota was set to be in operation in each of the power flow cases. [redacted] As mentioned, the simulation parameter was set to allow for pre-contingent adjustment of the phase shifters. Therefore the phase shifter can adjust to keep pre-contingent flow with the selected bandwidth. This is consistent with the description in the operating guide. However to prevent excessive utilization of the phase shifter and to hold back for post-contingent conditions, the phase shifter angle in the case was also limited to +/- 10 degrees.

PV Analysis - Transfer Assumptions

A full description of the transfer direction participation points can be made available as part of the supporting materials. This section provides a summary of the transfer directions.

The Summer Off-peak (SUOP) case was studied using two transfer directions:

SUOP Transfer 1 (West to East – primarily to ATC load)
Source: 70% from western wind (including wind in the ATC region)
30% from western generation units with reserve

Sink: 80% scaling up ATC region load (using constant power factor)
20% scaling up load in the eastern part of MISO region (using unity power factor)

SUOP Transfer 2 (West to East – primarily to ATC generation)
Source: 70% from western wind (including wind in the ATC region)
30% from western generation units with reserve

Sink: 50% follow a back-down order (with turn-off) of selected units within ATC (smaller and less economic)
20% scaling down of remaining units in ATC region (excluding wind)
30% scaling down of generation in the eastern part of MISO region

The Summer Peak (SUPK) case was studied using one transfer direction:

SUPK Transfer 3 (West to East – primarily to ATC gas generation)
Source: 70% from western wind (excluding wind in the ATC region)
30% from western generation units with reserve

Sink: 35% follow a back-down order (with turn-off) of select units within ATC (gas units excluding combined cycle)
20% follow a back-down order (with turn-off) of select units within ATC (gas combined cycle)
15% scaling down of remaining units in ATC region (excluding wind)
30% scaling down of generation in the eastern part of MISO region

PV Analysis - Results

Characteristic Strength during Transfer

The strength of each transmission option can be characterized in a number of ways. One way is by the amount of source to sink transfers achieved before voltage collapse. Another way is by the amount of transfers through an interface such as the ATC Western Ties interface or the ATC import interface achieved before voltage collapse. If a project alternative is effective, it will direct a larger percentage (or shift factor) of the power transfer through the interface as opposed to power flowing around the interface. The following bar charts depict the interface flows achieved before voltage collapse of each test transfer.

It is observed from the bar charts that the single element 345 kV options (1, 1a, 1b) increase the transfers through the ATC West Ties interface by approximately 372-609 MW. Option 8 performed slightly better as a single element 345 kV option (582-772 MW). Option 7c with 2-345 kV lines performed similar to the combined increases of its component projects Options 1b and 8. For example, in Transfer 2, Option 7c increases transfer through the West Ties interface by 1211 MW, compared to its individual components, Options 1b and 8, which had increases of 772 MW and 530 MW. The 765 kV Option performed better than the 345 kV single element options, but not as well as the double 345 kV option, Option 7c

Figure 5.6 - Transfer 1 ATC West Ties Interface Limit for Each Option

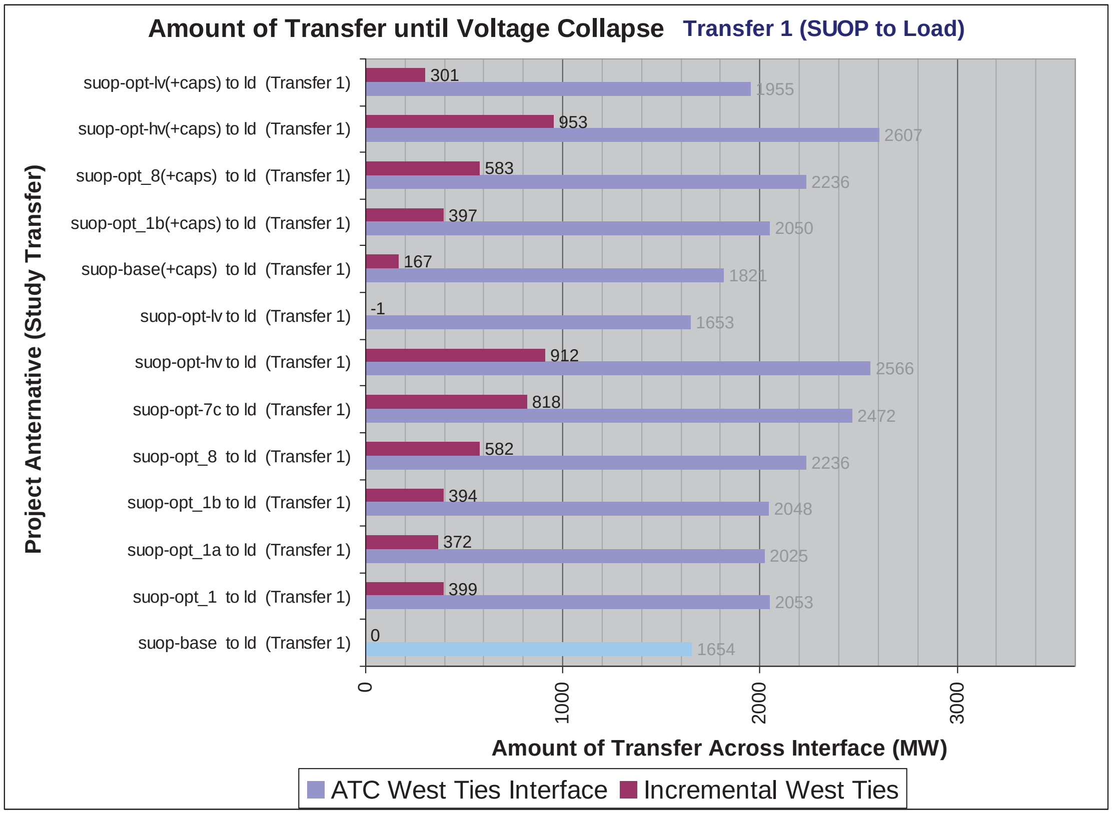


Figure 5.7 - Transfer 1 ATC Import Interface Limit for Each Option

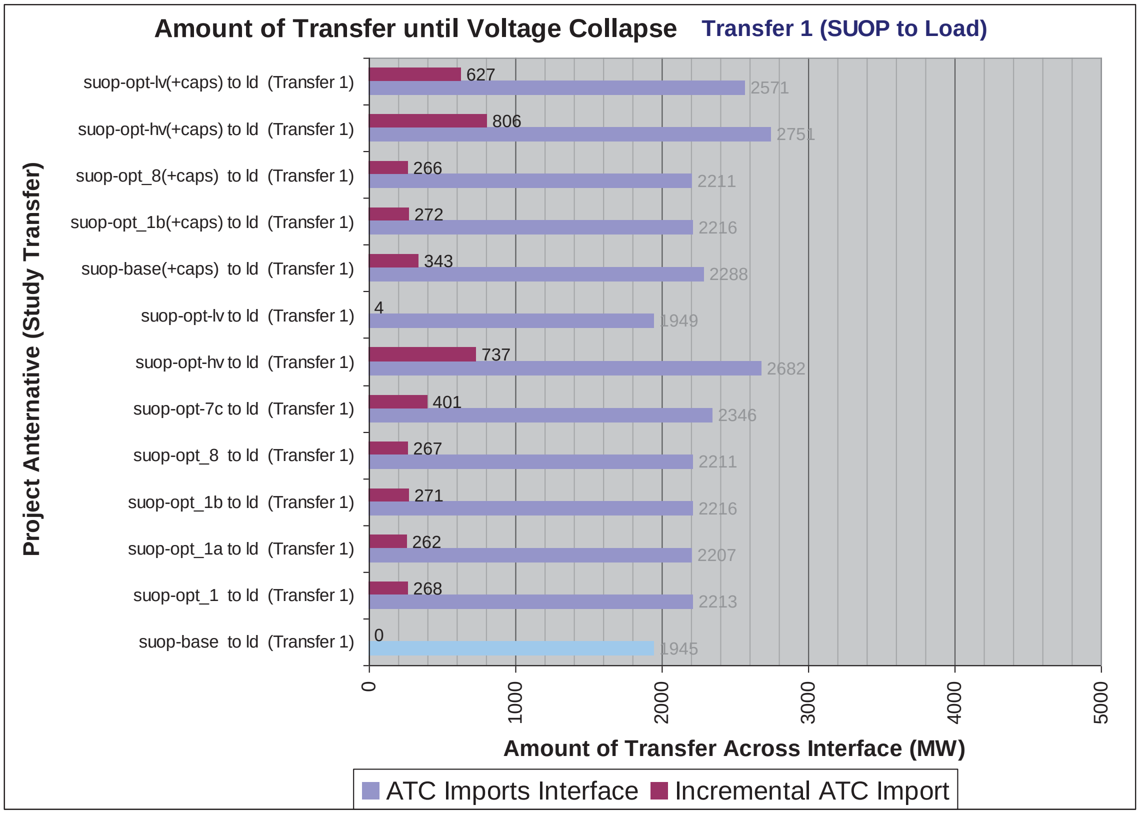


Figure 5.8 - Transfer 2 ATC West Ties Interface Limit for Each Option

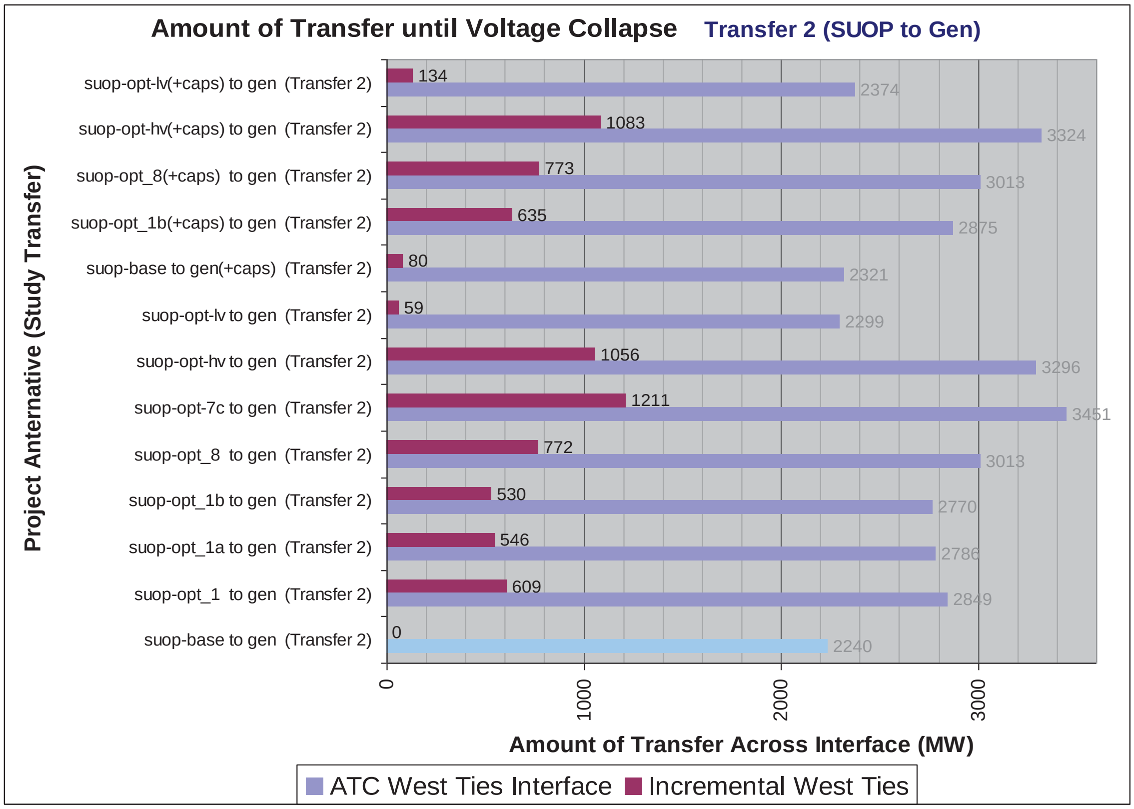


Figure 5.9 - Transfer 2 ATC Import Interface Limit for Each Option

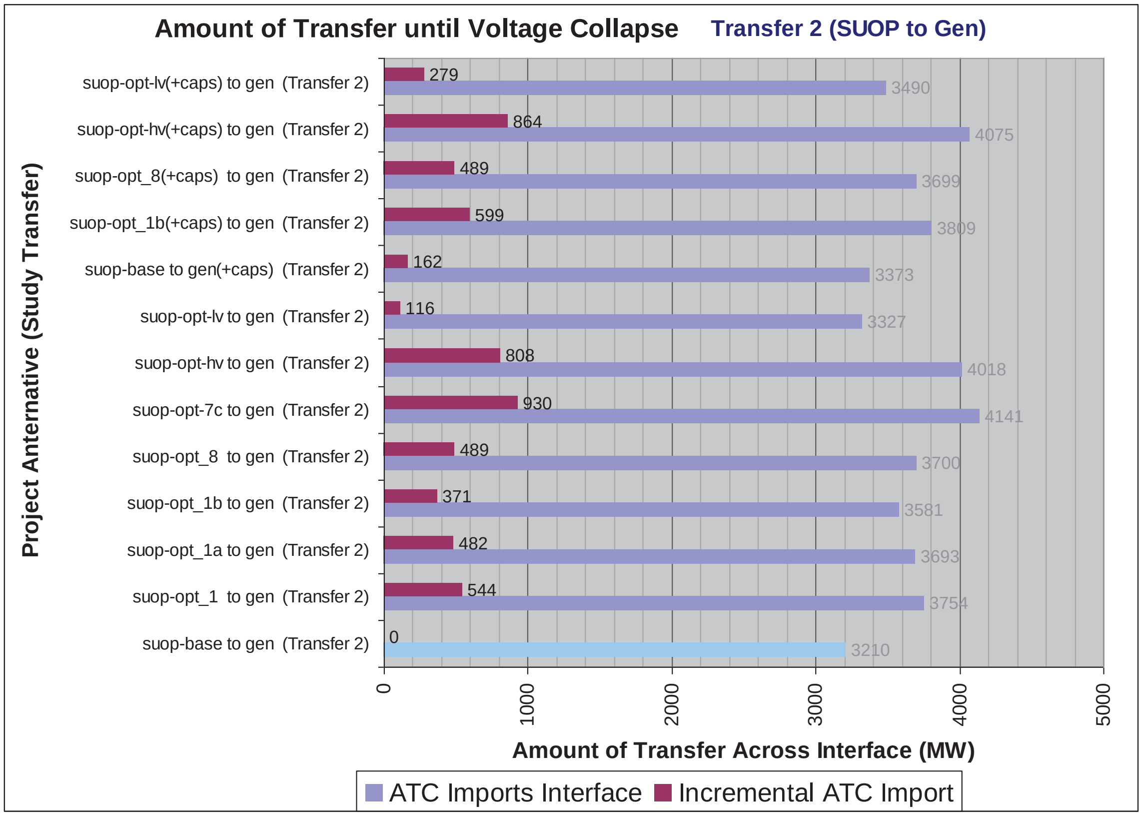


Figure 5.10 - Transfer 3 ATC West Ties Interface Limit for Each Option

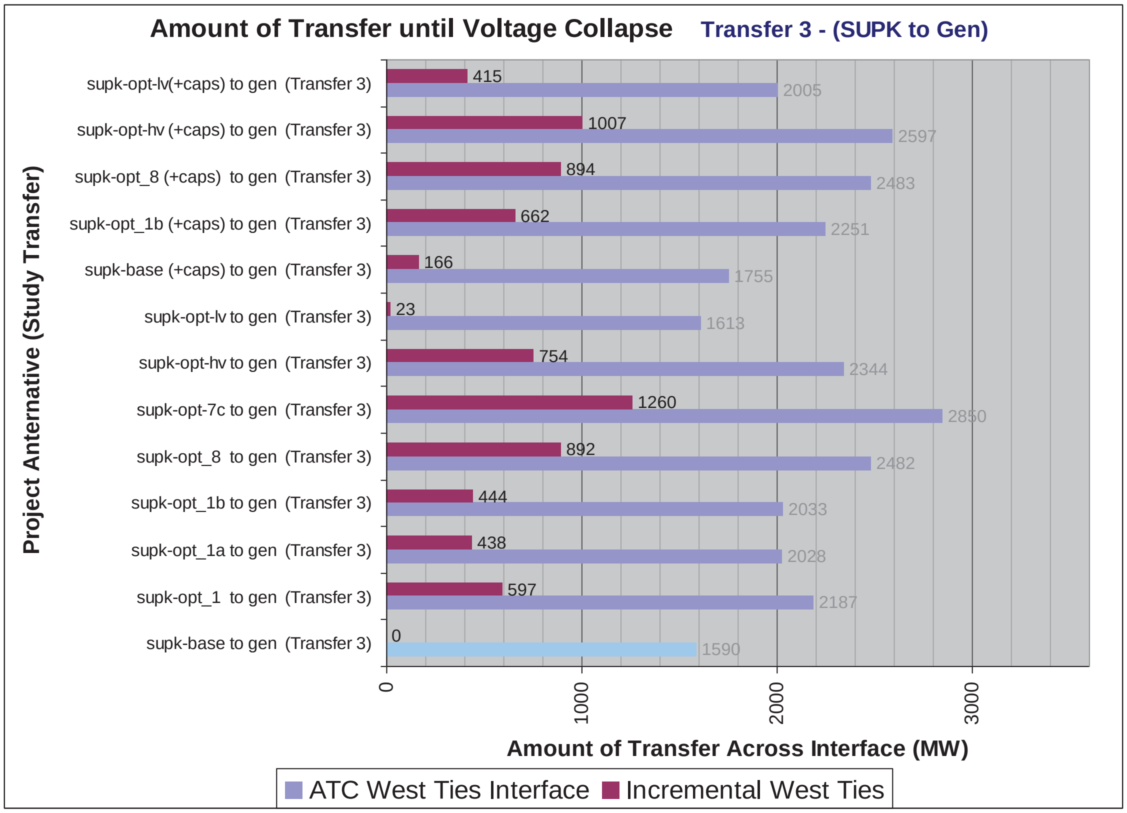
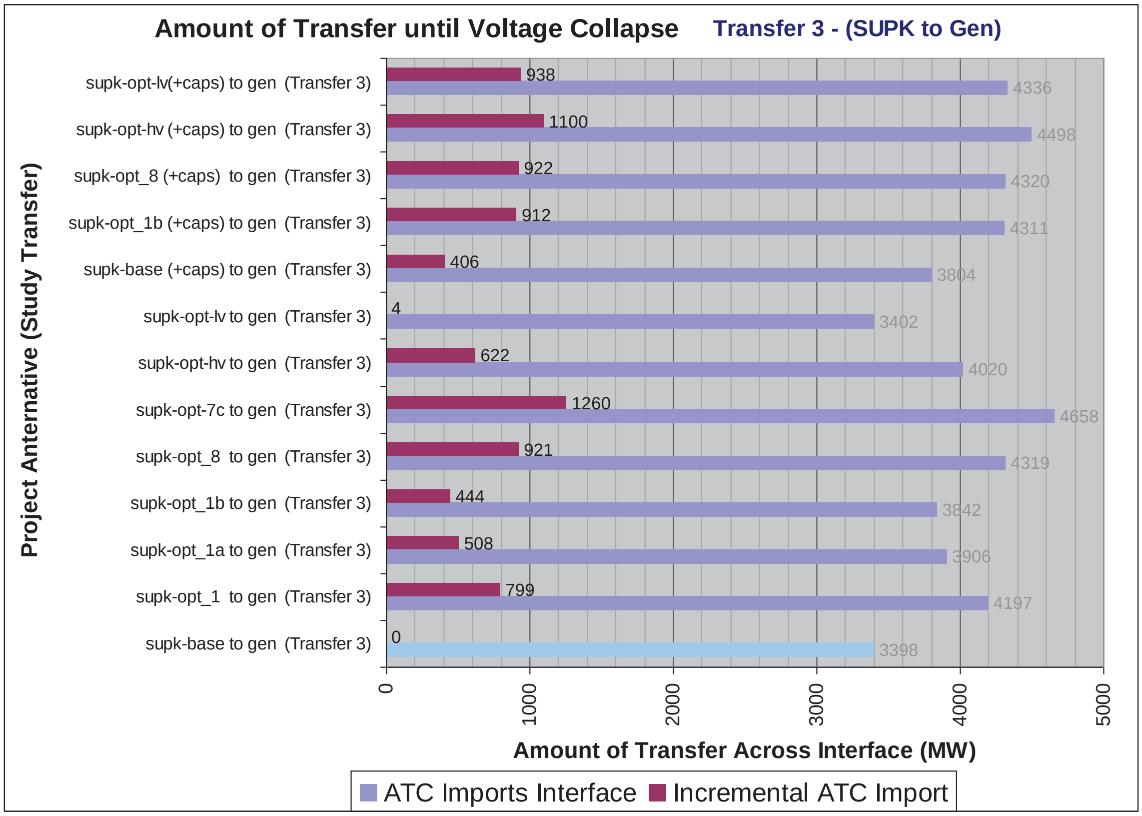


Figure 5.11 - Transfer 3 ATC Import Interface Limit for Each Option



The simulations increment the test transfer until one of the test contingencies or other criterion demonstrates voltage collapse. At that point the simulation is ceased for all contingencies. [redacted]

[redacted]

The Transfer 1 simulations terminated at a lower transfer level than experienced for Transfers 2 and 3. [redacted] In the SUOP case, a number of generation reactive resources are not participating due to their economic dispatch for the off-peak period.

PV Analysis – Plot Interpretation

For this study, the PV charts show the voltage changes versus flows across multi-line interfaces. This report focuses on the flows across the ATC western WI tie lines interface, and the ATC import interface. However, as a simpler example, an interface may consist of a single line. [redacted]

As the power transfer increases the reported voltage in the PV chart will eventually progress downward. The largest voltage drops may be seen at the points closest to the critical collapse, but the voltage reductions will also be seen to a lesser extent at other locations on the system. The limited number of charts provided in this report focus on the use of some locations (such as Spring Green) which are considered central to the impacted study region.

The interface flows in the PV chart may or may not start at the same amount. When plotted against ATC import levels, they all start at the same import amount, but when plotted against the ATC West Tie flows they do not. The definition of the West Tie flows is adjusted for each transmission option. The new facilities impact (increase) the starting flows across the interface when compared to the flows experienced in the base case.

For this study, charts are also provided that show changes in MW (or MVAR) losses versus flows across multi-line interfaces. As the power transfers increase, the reported losses will likely increase. Losses can decrease for situations where transfer may reduce flow, but the general trend will likely be upward at higher transfer levels.

The charts may have a less smooth progression that can be attributed to a number of possible conditions including but not limited to: transfers reducing some line flows; transfers reaching levels where some generators may be turned off; activation of switched shunts and capacitors; adjustments of transformer ratios; reaching the maximum range of reactive control devices and phase shifter adjustments. In general, the calculations have more variability to these influences as they approach the collapse transfer limit.

For the loss charts, the notation of “ATC” will denote the facilities within ATC. The notation of “non-ATC (WWI)” denotes the facilities external to ATC that are within the study region identified in the study scope.

PV Analysis - Losses and Voltage Drop

As power transfers through resistive line impedances, it experiences real MW losses. As power transfers through reactive line impedances, it experiences MVAR losses and is a large contributor toward voltage drop across the line.

Decoupling of power flow equations show that real power flow (MW) is strongly correlated to voltage angle, and reactive power flow (MVAR) is strongly correlated to voltage magnitude.

MW flow through resistive line impedances largely contributes to the real MW losses in proportion to the square of the current times the resistance (I^2R). Current is based on MVA flow consisting of MW and MVAR component flows. The MW flow will typically be the largest component of MVA flow. Therefore without decoupling, the actual MW losses are slightly higher when based on the current of MVA flow.

Similarly, MVAR flow through reactive line impedances are a large contributor toward voltage drop across the line. However, the movement of MVARs is encumbered by the MVAR losses on a line during high power flow. Assuming small MVAR flows, the current from MW flows passing through reactive line impedances largely contributes to the MVAR losses in proportion to the square of the current times the reactance (I^2X). Without decoupling, the actual MVAR losses are higher based on the current of MVA flow.

In contrast to MVAR losses, transmission lines also have a line charging characteristic that produces MVARs. The line charging is more significant at higher voltage levels. Depending on overhead construction type, at 345 kV it can be on the order of 0.8 MVAR - 1.0 MVAR per mile for overhead transmission. At 765 kV it can be on the order of 4 MVAR – 5 MVAR per mile for overhead. The line charging helps to support line voltage and offsets some of the reactive MVAR losses on the line. The theoretical point where line reactive losses are equal to the line charging is called the Surge Impedance Loading (SIL). Transfer of power above the SIL implies that the transmission line will need external compensation to help with the line flow. That compensation can come from other sources such as capacitors or generation MVAR support. At high power transfers above SIL, the square function of I^2X MVAR losses will grow at an increasing rate. Large reactive line losses are one of the characteristics that can lead to voltage collapse conditions. The SIL rating is based on line construction characteristics and is independent of line length. SIL ratings are an engineering line characteristic measure and they are not related to actual operating limits for the line which are usually higher. A typical 345 kV line may have a SIL of approximated 300 MW – 400 MW.

As an example of SIL properties, consider a 100-mile line with a SIL of 300 MW. Such a line may have line charging of about 90 MVAR. Using 100 MVA base, a 300 MVA (or MW) flow will have approximately a 3 per unit current. At 600 MVA (or MW) the per unit current will be about 6. Doubling the current will produce four times the reactive losses. The MVAR losses for the flow above 300 MW will need to be compensated. At 600 MW of flow (2 x SIL), 270 MVAR of external MVAR compensation may be required to serve the reactive line losses. At higher flows, the MVAR losses increase at ever higher rates.

PV Analysis - Charts

Output of the VSAT runs were compiled to produce various chart views that compare results across the various transmission options. Detailed charts are provided in Appendix F for each test transfer. Some charts show voltage performance for power transfer across interfaces. Other charts show how losses change as power flows across the interfaces. The charts provide some insight into the voltage stability simulations.

[redacted] For each test transfer, the following Power vs. Voltage (PV) charts can be found in Appendix F:

ATC West Tie Flow [redacted] [redacted]
ATC West Tie Flow [redacted] [redacted]
ATC West Tie Flow [redacted] [redacted]

ATC Imports [redacted] [redacted]
ATC Imports [redacted] [redacted]
ATC Imports [redacted] [redacted]

Real (MW) and reactive (MVAR) losses increase as power flow increases across the Western ties interface or the ATC Import interface. For each test transfer, the following Power vs. Loss (PL) charts can be found in Appendix F:

ATC West Tie Flow	[redacted]	vs. ATC(WWI)	MW losses
ATC West Tie Flow	[redacted]	vs. Non-ATC(WWI)	MW losses
ATC West Tie Flow	[redacted]	vs. ATC(WWI)	MW losses
ATC West Tie Flow	[redacted]	vs. ATC(WWI)	MW losses
ATC West Tie Flow	[redacted]	vs. ATC(WWI)	MVAR line losses
ATC West Tie Flow	[redacted]	vs. Non-ATC(WWI)	MVAR line losses
ATC West Tie Flow	[redacted]	vs. ATC(WWI)	MVAR line losses
ATC West Tie Flow	[redacted]	vs. ATC(WWI)	MVAR line losses
ATC Imports	[redacted]	vs. ATC(WWI)	MVAR line losses
ATC Imports	[redacted]	vs. Non-ATC	MVAR line losses

[redacted] (also located in Appendix F) are samples of the Power vs. [redacted].

[redacted]

[redacted]

[redacted]

PV Analysis - Integrated Evaluation of Characteristic Strengths

This report objectively evaluates each transmission option by numerically scoring a sampling of voltage stability characteristic strengths. The characteristic strengths are broken up into three categories: transfer achieved before collapse, voltage performance and loss performance.

Each category is composed of various scores ranging from poorest (score of 0) to best (score of 5). Scoring is based on an improvement in performance compared to the base case. No change in performance is treated as a score of 1. Any decrease in performance is scored as 0. The following scoring tables show various selected characteristic attributes of voltage robustness. Table 5.8 summarizes the results for the Summer Off-Peak Transfer 1. Table 5.9 summarizes the results for the Summer Off-Peak Transfer 2. Table 5.10 summarizes the results for the Summer Peak Transfer 3.

The selected characteristics for scoring provide a balanced mix of characteristics that measure the amount of transfers before collapse, voltage performance at common transfer levels and loss performance. Each summarized characteristic is given a score and it is color coded. Comparing between projects, the high or low deviation from the base case reported values are used to determine the graduated scores from 1 to 5. A score of zero indicates that it performed worse than the base starting case. Voltage was scored slightly different in that some minimum and maximum voltage ranges were applied where results did not exceed those values. Voltage was scored with a low score value based on the lower of 0.95 p.u. and the base case value. Voltage was scored with a high score value based on the higher of the 1.0 p.u. and the best voltage.

The scoring tables evaluate an overall score using the weighting shown for each characteristic. The three scoring categories were chosen to be rather evenly weighted, but with a slightly higher weighting on the transfer capability. Voltage stability limits typically assign facility ratings based on voltage stability under transfer. The overall score places a 40% weighting on the transfer before collapse, a 30% weighting on voltage performance at common transfer levels and a 30% weighting on loss performance.

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Table 5.8 - Summary of SUOP Transfer 1 Results

Description					Wt	Score (0=Worse, 1=No Change, 5=Best)											
	Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	[redacted]		Opt 1	Opt 1a	**Opt 1b**	**Opt 8**	Opt 7c	**Opt HV**	**Opt LV**	Base + claps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
	Transfer 1 -- SUOP to Load			[redacted]													
TRANSFER 40%	**Incremental Transfer**	**Source Transfer**	at collapse level	[redacted]	10	2.3	2.3	2.3	2.3	3.0	4.7	1.0	2.7	2.3	2.3	5.0	4.0
	Transfer Limit	**ATC West Ties**	at collapse level	[redacted]	10	2.7	2.6	2.7	3.4	4.4	4.8	0.0	1.7	2.7	3.4	5.0	2.3
	Transfer Limit	**ATC Import**	at collapse level	[redacted]	10	2.3	2.3	2.3	2.3	3.0	4.7	1.0	2.7	2.3	2.3	5.0	4.1
	Differences in Regional Flow Through ATC			[redacted]													
	Regional Flow	(W. Ties) - (Imports)	at Base collapse	[redacted]	3.333	2.9	2.7	3.1	3.9	5.0	4.4	0.0	1.0	3.1	3.9	4.4	0.0
	Regional Flow	(W. Ties) - (Imports)	at Base collapse	[redacted]	3.333	2.7	2.6	2.7	4.0	5.0	4.0	0.0	1.0	2.7	4.0	4.0	1.0
	Regional Flow	(W. Ties) - (Imports)	at Base collapse	[redacted]	3.333	2.8	2.6	2.8	4.0	5.0	3.9	0.0	1.2	2.8	4.0	3.9	1.2
VOLTAGE PROFILE 30.0%	**p.u. Voltage**	Spring Green 138kV	at Base collapse	[redacted]	1	2.9	2.1	5.0	2.3	3.5	4.8	3.4	4.1	5.0	2.4	4.8	3.8
	p.u. Voltage	N. Monroe 138kV	at Base collapse	[redacted]	1	3.7	3.4	3.8	3.6	4.0	5.0	2.2	4.1	3.8	3.6	5.0	4.0
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1	3.9	3.9	4.2	3.8	3.8	3.6	3.0	3.2	4.1	3.9	3.6	3.2
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1	3.9	3.9	3.9	4.3	4.2	3.3	3.1	2.6	3.8	4.3	3.3	3.5
	p.u. Voltage	Paddock 138kV	at Base collapse	[redacted]	1	3.2	3.0	3.3	3.3	3.7	4.3	2.0	2.6	3.3	3.4	4.3	2.7
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	4.0	3.4	5.0	4.1	4.6	4.6	2.9	3.9	5.0	4.2	4.6	3.6
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	2.8	2.9	3.6	2.6	3.1	2.9	0.0	1.4	3.6	2.7	2.8	1.3
	p.u. Voltage	Hillsboro 161kV	at Base collapse	[redacted]	1.25	3.3	4.7	5.0	4.7	3.3	3.0	3.4	3.6	5.0	4.7	3.0	3.6
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1.25	3.5	3.4	3.7	3.7	4.0	3.1	1.7	1.6	3.7	3.8	3.1	2.3
	p.u. Voltage	Richland Ctr 69kV	at Base collapse	[redacted]	1.25	3.5	3.8	4.6	4.1	4.0	3.4	2.4	2.7	4.6	4.1	3.4	2.9
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	1.9	1.1	4.1	1.3	2.8	4.1	0.0	2.9	4.2	1.4	4.1	2.5
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	3.0	3.3	3.4	3.1	3.4	2.9	0.0	2.0	3.4	3.1	2.9	2.0
	p.u. Voltage	Hillsboro 161kV	at Base collapse	[redacted]	1.25	3.4	4.9	5.0	5.0	3.4	3.1	3.6	4.0	5.0	5.0	3.1	4.1
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1.25	3.6	3.6	3.6	3.9	4.1	3.2	1.6	2.0	3.6	4.0	3.2	2.8
	p.u. Voltage	Richland Ctr 69kV	at Base collapse	[redacted]	1.25	3.5	3.9	4.2	4.3	4.0	3.2	2.0	2.9	4.3	4.3	3.3	3.1
	p.u. Voltage	Paddock 138kV	at Base collapse	[redacted]	1.25	1.7	1.6	1.9	1.7	2.1	2.3	0.0	2.9	1.9	1.7	2.2	2.9
	p.u. Voltage	N. Monroe 138kV	at Base collapse	[redacted]	1.25	2.1	2.0	2.4	2.1	2.8	4.8	0.0	3.2	2.4	2.1	4.8	3.1
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	1.4	0.0	3.6	0.0	2.8	4.4	0.0	3.1	3.7	1.0	4.4	2.8
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	2.4	1.7	5.0	2.0	3.3	4.7	2.9	3.8	5.0	2.0	4.7	3.4
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	3.4	3.4	3.9	3.3	3.5	3.2	2.2	2.3	3.9	3.3	3.2	2.4
	p.u. Voltage	W. Middleton 138kV	at Base collapse	[redacted]	1.25	2.3	1.8	2.9	1.9	2.9	2.2	0.0	1.8	3.0	2.0	2.3	2.0
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	3.9	3.8	3.9	3.7	3.4	3.2	2.4	2.9	3.8	3.7	3.2	2.7
	p.u. Voltage	Hillsboro 161kV	at Base collapse	[redacted]	1.25	3.7	4.9	5.0	4.9	3.2	2.9	3.9	3.8	5.0	5.0	2.9	4.0
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	2.9	2.2	5.0	2.3	3.5	4.8	3.4	4.0	5.0	2.4	4.8	3.8
MW & MVAR LOSS 30%	**MW loss**	**ATC**	w/o transfer	[redacted]	2.5	5.0	4.3	3.9	3.2	4.6	3.4	1.8	1.1	4.0	3.3	3.4	2.0
	MW loss	ATC	at Base collapse	[redacted]	2.5	5.0	3.7	3.5	3.1	4.2	3.9	1.4	1.2	3.5	3.1	3.9	1.8
	MW loss	**External_WWI**	w/o transfer	[redacted]	2.5	0.0	0.0	0.0	2.0	1.3	4.9	0.0	1.1	0.0	2.0	5.0	0.0
	MW loss	External_WWI	at Base collapse	[redacted]	2.5	1.6	2.5	2.2	2.0	3.3	4.9	0.0	1.1	2.3	2.0	5.0	0.0
	MVAR line loss	ATC	**w/o transfer**	[redacted]	2	5.0	3.7	3.5	1.4	2.6	1.1	3.2	1.1	3.5	1.4	1.2	3.5
	MVAR line loss	**ATC**	**at Base collapse**	[redacted]	2	5.0	2.5	2.2	1.6	2.2	1.7	2.4	1.3	2.2	1.7	1.7	3.0
	MVAR line loss	ATC	at Base collapse	[redacted]	2	5.0	2.4	3.1	1.8	2.3	1.5	2.3	1.7	3.2	1.9	1.5	3.1
	MVAR line loss	ATC	at Base collapse	[redacted]	2	5.0	3.0	2.9	2.6	3.4	2.3	1.8	2.0	2.9	2.6	2.4	3.1
	MVAR line loss	ATC	at Base collapse	[redacted]	2	5.0	3.3	3.3	2.8	3.8	4.2	1.9	3.4	3.4	2.9	4.2	4.6
	MVAR line loss	**External_WWI**	w/o transfer	[redacted]	2	0.0	0.0	0.0	1.7	0.0	4.8	0.0	1.2	0.0	1.7	5.0	0.0
	MVAR line loss	**External_WWI**	at Base collapse	[redacted]	2	0.0	1.9	1.6	1.9	2.8	4.8	0.0	1.2	1.8	1.9	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse	[redacted]	2	0.0	1.3	1.9	1.4	1.9	4.8	0.0	1.2	2.1	1.4	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse	[redacted]	2	0.0	1.9	1.6	2.0	2.8	4.8	0.0	1.4	1.8	2.0	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse	[redacted]	2	0.0	1.9	1.5	1.9	2.7	4.8	0.0	1.3	1.7	1.9	5.0	0.0
	Transfer 1 - Transfer Score		**Weighted Average**		40	2.5	2.5	2.5	3.0	3.9	4.6	0.5	2.0	2.6	3.0	4.8	2.8
	Transfer 1 - Voltage Score		**Weighted Average**		30	2.9	2.9	3.8	3.0	3.3	3.4	1.8	2.8	3.8	3.1	3.4	2.9
	Transfer 1 - Losses Score		**Weighted Average**		30	2.6	2.3	2.2	2.1	2.7	3.8	1.0	1.4	2.3	2.2	3.8	1.5
	Transfer 1 TOTAL		**Weighted Average**		100	2.7	2.6	2.8	2.8	3.4	4.0	1.1	2.1	2.9	2.8	4.1	2.4
						1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV

Table 5.9 - Summary of SUOP Transfer 2 Results

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	Description: Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	[redacted]	Wt	Opt 1	Opt 1a	Opt 1b	Opt 8	Opt 7c	Opt HV	Opt LV	Base + caps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
	Score (0=Worse, 1=No Change, 5=Best)																
	Transfer 2 -- SUOP to Gen																
TRANSFER 40%	**Incremental Transfer**	**Source Transfer**	at collapse level		10	3.4	3.1	2.6	3.1	5.0	4.5	1.5	1.7	3.6	3.1	4.8	2.2
	Transfer Limit	**ATC West Ties**	at collapse level		10	3.0	2.8	2.8	3.6	5.0	4.5	1.2	1.3	3.1	3.6	4.6	1.4
	Transfer Limit	**ATC Import**	at collapse level		10	3.3	3.1	2.6	3.1	5.0	4.5	1.5	1.7	3.6	3.1	4.7	2.2
	Differences in Regional Flow Through ATC																
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	3.0	2.8	3.1	3.7	5.0	4.5	1.1	0.0	3.1	3.7	4.5	1.2
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.8	2.6	2.8	3.8	5.0	4.3	0.0	1.0	2.8	3.8	4.3	1.0
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.9	2.7	2.9	3.8	5.0	4.6	1.1	0.0	2.9	3.8	4.6	1.2
VOLTAGE PROFILE 30%	**p.u. Voltage**	Spring Green 138kV	at Base collapse		1	1.6	0.0	4.4	1.1	2.8	4.2	0.0	2.1	4.4	1.1	4.2	2.1
	p.u. Voltage	N. Monroe 138kV	at Base collapse		1	3.7	3.0	4.2	3.7	4.5	4.5	0.0	3.8	4.2	3.7	4.5	3.2
	p.u. Voltage	Hilltop 69kV	at Base collapse		1	2.1	2.7	2.9	2.0	2.9	2.6	1.1	1.3	2.9	2.0	2.6	1.3
	p.u. Voltage	Boscobell 69kV	at Base collapse		1	3.2	3.0	2.8	3.3	3.7	2.5	1.5	0.0	2.9	3.3	2.6	1.8
	p.u. Voltage	Paddock 138kV	at Base collapse		1	2.4	2.0	2.7	2.5	3.0	2.3	0.0	2.6	2.7	2.5	2.3	2.6
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.5	0.0	4.0	1.2	3.2	3.6	0.0	1.3	4.0	1.2	3.6	2.8
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.5	3.0	3.4	2.4	3.7	3.1	0.0	0.0	3.4	2.4	3.2	1.6
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	4.5	3.8	4.2	3.6	3.6	4.0	1.2	0.0	4.2	3.6	4.0	2.2
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.4	3.0	3.1	3.1	4.0	3.1	1.2	0.0	3.1	3.1	3.1	2.2
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.7	3.0	3.6	3.1	3.8	3.3	0.0	0.0	3.6	3.1	3.3	2.0
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	2.1	1.5	3.7	1.9	3.1	4.0	0.0	2.3	3.8	1.9	3.8	3.2
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.5	3.0	3.1	2.6	3.4	3.0	0.0	1.9	3.1	2.6	2.7	2.1
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	2.6	4.2	4.4	4.1	3.1	2.3	2.1	2.6	4.4	4.1	2.0	3.2
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.2	3.1	2.9	3.4	3.9	2.9	1.4	1.4	2.9	3.3	2.8	2.7
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.2	3.2	3.4	3.5	3.7	2.8	1.2	2.1	3.4	3.5	2.6	2.7
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.8	1.1	4.1	1.2	2.9	4.0	0.0	2.2	4.1	1.2	4.0	2.4
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.5	2.7	2.9	2.0	2.9	2.5	1.0	1.6	2.9	1.9	2.4	1.2
	p.u. Voltage	Council Cr 138kV	at Base collapse		1.25	2.9	4.0	4.3	3.8	4.4	4.4	1.7	2.4	4.2	3.8	4.3	1.8
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.2	3.1	2.8	3.2	3.7	2.5	1.7	0.0	2.8	3.3	2.5	1.9
	p.u. Voltage	Bell Center 161kV	at Base collapse		1.25	2.7	3.4	3.6	3.7	3.3	2.8	1.5	1.6	3.6	3.7	2.8	2.0
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	2.6	2.3	2.4	3.2	3.0	2.0	0.0	0.0	2.3	3.2	2.0	1.2
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.0	3.3	3.6	3.8	3.2	2.6	1.5	2.0	3.6	3.8	2.7	1.9
	p.u. Voltage	W. Middleton 138kV	at Base collapse		1.25	2.3	1.7	3.2	1.9	3.3	1.7	1.0	2.7	3.2	1.9	2.0	2.8
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.7	0.0	4.4	1.3	3.3	3.8	0.0	2.3	4.4	1.3	4.0	2.6
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.0	2.7	3.0	2.1	3.1	2.4	0.0	1.3	3.0	2.0	2.5	1.4
MW & MVAR LOSS 30%	**MW loss**	**ATC**	w/o transfer		2.5	5.0	4.3	3.9	3.2	4.6	3.4	1.8	1.1	4.0	3.3	3.4	2.0
	MW loss	ATC	at Base collapse		2.5	5.0	3.6	3.7	2.9	4.1	3.7	1.3	1.4	3.7	2.9	3.7	1.8
	MW loss	**External_WWI**	w/o transfer		2.5	0.0	0.0	0.0	2.0	1.3	4.9	0.0	1.1	0.0	2.0	5.0	0.0
	MW loss	External_WWI	at Base collapse		2.5	2.0	2.6	2.6	1.9	3.4	5.0	0.0	1.2	2.6	1.9	5.0	0.0
	MVAR line loss	ATC	**w/o transfer**		2	5.0	3.7	3.5	1.4	2.6	1.1	3.2	1.1	3.5	1.4	1.2	3.5
	MVAR line loss	**ATC**	**at Base collapse**		2	5.0	2.1	2.1	1.4	1.7	0.0	2.3	1.6	2.1	1.4	0.0	3.0
	MVAR line loss	ATC	at Base collapse		2	5.0	1.9	2.1	1.6	2.2	0.0	2.1	1.3	2.1	1.6	0.0	3.0
	MVAR line loss	ATC	at Base collapse		2	5.0	2.7	2.7	2.4	3.1	1.6	1.7	2.1	2.7	2.4	1.6	3.1
	MVAR line loss	ATC	at Base collapse		2	5.0	2.3	2.2	1.5	1.9	0.0	2.3	1.8	2.3	1.5	0.0	3.0
	MVAR line loss	**External_WWI**	w/o transfer		2	0.0	0.0	0.0	1.7	0.0	4.8	0.0	1.2	0.0	1.7	5.0	0.0
	MVAR line loss	**External_WWI**	at Base collapse		2	0.0	2.3	2.2	1.9	3.1	4.9	0.0	1.3	2.3	1.9	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse		2	0.0	2.3	2.2	1.8	2.7	4.9	1.1	1.1	2.3	1.8	5.0	1.2
	MVAR line loss	External_WWI	at Base collapse		2	0.0	2.3	2.2	2.0	3.2	4.9	0.0	1.3	2.3	2.0	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse		2	0.0	2.6	2.5	2.2	3.2	4.9	0.0	1.4	2.6	2.2	5.0	0.0
	Transfer 2 - Transfer Score		**Weighted Average**		40	3.2	2.9	2.7	3.4	5.0	4.5	1.2	1.3	3.3	3.4	4.6	1.7
	Transfer 2 - Voltage Score		**Weighted Average**		30	2.7	2.5	3.5	2.7	3.4	3.1	0.7	1.5	3.5	2.7	3.1	2.2
	Transfer 2 - Losses Score		**Weighted Average**		30	2.7	2.4	2.3	2.0	2.7	3.2	1.1	1.3	2.3	2.0	3.3	1.4
	Transfer 2 TOTAL		**Weighted Average**		100	2.9	2.6	2.8	2.8	3.8	3.7	1.0	1.3	3.1	2.8	3.8	1.8
						1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV

Table 5.10 - Summary of SUPK Transfer 3 Results

Badger Coulee Planning Analysis - Addendum

7/31/2013

	Description				Wt	Score (0=Worse, 1=No Change, 5=Best)											
	Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	[redacted]		Opt 1	Opt 1a	**Opt 1b**	**Opt 8**	Opt 7c	**Opt HV**	**Opt LV**	Base + caps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
	Transfer 3 -- SUPK to Gen			[redacted]													
TRANSFER 40%	**Incremental Transfer**	**Source Transfer**	at collapse level	[redacted]	10	3.5	2.6	2.5	3.9	5.0	3.0	1.0	2.3	3.9	3.9	4.5	3.9
	Transfer Limit	**ATC West Ties**	at collapse level	[redacted]	10	2.9	2.4	2.4	3.8	5.0	3.4	1.1	1.5	3.1	3.8	4.2	2.3
	Transfer Limit	**ATC Import**	at collapse level	[redacted]	10	3.5	2.6	2.4	3.9	5.0	3.0	1.0	2.3	3.9	3.9	4.5	4.0
	Differences in Regional Flow Through ATC			[redacted]													
	Regional Flow	(W. Ties) - (Imports)	at Base collapse	[redacted]	3.333	2.7	2.5	2.8	4.1	5.0	4.0	1.2	1.3	2.8	4.1	4.0	1.2
	Regional Flow	(W. Ties) - (Imports)	at Base collapse	[redacted]	3.333	2.6	2.4	2.7	4.2	5.0	3.7	1.2	1.1	2.7	4.2	3.7	1.3
	Regional Flow	(W. Ties) - (Imports)	at Base collapse	[redacted]	3.333	2.5	2.4	2.6	4.2	5.0	3.4	1.1	1.3	2.6	4.2	3.4	1.2
VOLTAGE PROFILE 30.0%	**p.u. Voltage**	Spring Green 138kV	at Base collapse	[redacted]	1	1.9	1.3	3.3	1.0	2.7	2.9	1.6	2.0	3.3	1.0	3.1	2.2
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1	3.3	2.5	2.7	2.4	3.2	2.6	1.4	1.3	2.7	2.4	2.7	1.6
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1	3.6	3.4	3.2	3.8	4.5	3.0	2.4	1.8	3.2	3.8	3.1	2.8
	p.u. Voltage	Richland Ctr 69kV	at Base collapse	[redacted]	1	4.3	3.7	4.0	4.0	4.5	3.8	3.2	3.1	4.0	4.0	4.0	3.5
	p.u. Voltage	**Verona 138kV**	at Base collapse	[redacted]	1	1.7	1.5	1.8	1.5	2.0	1.4	0.0	1.3	1.8	1.5	2.2	2.5
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	1.7	1.1	3.0	1.3	2.7	2.7	0.0	1.6	3.0	1.3	2.8	2.1
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	3.0	2.5	2.6	2.4	3.1	2.6	1.3	1.4	2.6	2.4	2.6	1.7
	p.u. Voltage	Hillsboro 161kV	at Base collapse	[redacted]	1.25	4.0	2.8	2.9	3.0	3.6	2.9	1.6	1.7	2.9	3.0	2.9	2.0
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1.25	3.5	3.3	3.3	3.7	4.3	3.1	1.9	1.6	3.3	3.7	3.1	2.5
	p.u. Voltage	Richland Ctr 69kV	at Base collapse	[redacted]	1.25	3.4	2.8	3.2	3.2	3.9	3.1	1.8	1.8	3.2	3.2	3.1	2.5
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	3.4	3.0	3.7	3.0	3.7	3.7	1.4	2.4	3.7	3.0	3.8	3.5
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	3.7	3.3	3.3	3.4	3.8	3.4	1.5	2.0	3.3	3.4	3.5	2.8
	p.u. Voltage	Hillsboro 161kV	at Base collapse	[redacted]	1.25	4.4	3.4	3.5	3.8	4.2	3.5	1.7	2.0	3.5	3.8	3.6	2.8
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1.25	4.1	3.9	3.7	4.2	4.5	3.7	1.9	2.2	3.8	4.2	3.8	3.4
	p.u. Voltage	Richland Ctr 69kV	at Base collapse	[redacted]	1.25	4.1	3.7	3.8	4.0	4.3	3.8	2.0	2.4	3.9	4.0	3.9	3.5
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	1.6	0.0	2.9	0.0	2.3	2.5	0.0	1.7	2.9	0.0	2.7	1.8
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	3.2	2.1	2.4	2.2	2.9	2.3	1.1	1.2	2.4	2.2	2.3	1.4
	p.u. Voltage	Council Cr 138kV	at Base collapse	[redacted]	1.25	3.7	4.2	4.4	4.4	5.0	4.6	3.0	3.4	4.4	4.3	4.7	3.1
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1.25	3.4	3.1	2.9	3.6	4.2	2.7	1.7	1.5	2.9	3.6	2.7	2.3
	p.u. Voltage	Bell Center 161kV	at Base collapse	[redacted]	1.25	3.8	2.9	3.0	3.5	3.7	3.0	1.5	2.1	3.0	3.5	3.0	1.8
	p.u. Voltage	Boscobell 69kV	at Base collapse	[redacted]	1.25	3.2	2.8	2.8	3.4	3.8	2.6	1.1	1.4	2.8	3.4	2.6	1.6
	p.u. Voltage	Richland Ctr 69kV	at Base collapse	[redacted]	1.25	3.8	3.1	3.4	3.7	4.1	3.3	1.6	2.5	3.5	3.7	3.4	2.1
	p.u. Voltage	Hilltop 69kV	at Base collapse	[redacted]	1.25	3.5	2.2	2.3	2.1	2.5	2.4	0.0	1.1	2.4	2.2	2.4	1.1
	p.u. Voltage	Hillsboro 161kV	at Base collapse	[redacted]	1.25	4.1	2.2	2.4	2.4	2.8	2.4	1.2	1.0	2.4	2.4	2.4	1.3
	p.u. Voltage	Spring Green 138kV	at Base collapse	[redacted]	1.25	1.9	1.3	3.1	1.2	2.6	2.7	1.2	1.6	3.1	1.2	2.9	1.8
MW & MVAR LOSS 30%	**MW loss**	**ATC**	w/o transfer	[redacted]	2.5	3.8	3.5	1.7	4.7	5.0	1.6	1.7	0.0	1.8	4.7	1.8	1.5
	MW loss	ATC	at Base collapse	[redacted]	2.5	5.0	3.9	3.3	3.8	4.9	1.7	0.0	1.2	3.4	3.8	1.8	1.4
	MW loss	**External_WWI**	w/o transfer	[redacted]	2.5	1.3	0.0	0.0	1.7	2.0	5.0	0.0	0.0	0.0	1.7	5.0	1.0
	MW loss	External_WWI	at Base collapse	[redacted]	2.5	1.6	1.7	1.7	2.1	2.8	5.0	1.4	1.0	1.8	2.1	5.0	1.4
	MVAR line loss	ATC	**w/o transfer**	[redacted]	2	4.4	3.7	2.0	4.8	5.0	1.2	1.4	0.0	2.0	4.7	1.5	0.0
	MVAR line loss	**ATC**	**at Base collapse**	[redacted]	2	5.0	3.0	2.4	2.6	3.4	0.0	0.0	1.1	2.4	2.6	0.0	1.5
	MVAR line loss	ATC	at Base collapse	[redacted]	2	5.0	3.0	2.7	3.3	3.7	0.0	1.1	1.9	2.7	3.3	0.0	1.8
	MVAR line loss	ATC	at Base collapse	[redacted]	2	5.0	3.9	3.6	4.1	4.6	2.5	1.5	2.4	3.7	4.1	2.6	3.1
	MVAR line loss	ATC	at Base collapse	[redacted]	2	5.0	3.0	2.5	3.1	3.6	0.0	1.0	1.7	2.5	3.1	0.0	1.7
	MVAR line loss	**External_WWI**	w/o transfer	[redacted]	2	1.2	0.0	0.0	1.2	1.6	5.0	1.2	0.0	0.0	1.3	5.0	1.2
	MVAR line loss	**External_WWI**	at Base collapse	[redacted]	2	0.0	1.4	1.4	2.0	2.5	5.0	1.3	0.0	1.4	2.0	5.0	1.3
	MVAR line loss	External_WWI	at Base collapse	[redacted]	2	0.0	0.0	0.0	2.4	1.5	5.0	1.5	2.0	0.0	2.4	4.8	1.5
	MVAR line loss	External_WWI	at Base collapse	[redacted]	2	0.0	1.9	1.8	3.1	3.0	5.0	1.4	1.4	1.9	3.1	5.0	1.9
	MVAR line loss	External_WWI	at Base collapse	[redacted]	2	0.0	1.4	1.4	2.9	2.8	5.0	1.3	1.9	1.4	2.9	5.0	1.4
	Transfer 3 - Transfer Score		**Weighted Average**		40	3.1	2.5	2.5	4.0	5.0	3.3	1.1	1.8	3.4	4.0	4.2	2.9
	Transfer 3 - Voltage Score		**Weighted Average**		30	3.3	2.7	3.1	2.9	3.6	3.0	1.4	1.9	3.1	2.9	3.1	2.3
	Transfer 3 - Losses Score		**Weighted Average**		30	2.7	2.2	1.8	3.0	3.3	3.0	1.0	1.0	1.8	3.0	3.1	1.5
	Transfer 3 TOTAL		**Weighted Average**		100	3.0	2.5	2.5	3.3	4.1	3.1	1.2	1.6	2.8	3.3	3.5	2.3
						1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV

To be comparable, some characteristics are measured at a common transfer level. The base case collapse transfer amount is considered the highest comparable point. At comparable transfer levels, the ATC import measure will be equivalent for each project, but the ATC West Ties interface flow will differ for each project.

The Transfer category examines the limits before collapse for the ATC West Ties interface, the ATC Import interface and the Source Transfer. The Source Transfer measures the amount of power transferred from source generation to sink location. As described above, the Source Transfer sinks mostly to ATC and partly to systems in the eastern part of the MISO region. A final measure of "ATC West Ties minus the ATC Imports" was included in the Transfer category to give a measure of regional value. This measure was evaluated at the base collapse point to give an indication of the amount of incremental power that can flow through the ATC system and out the ATC southern ties and Upper Peninsula Straits ties. It can also be described as a reduced dependency on the ATC southern (+Straits) ties for serving ATC imports. An ATC southern interface was not directly monitored, but rather it is calculated from the ATC West Ties and ATC Imports interfaces.

Figure 5.15 – Regional flow evaluation (ATC West Ties minus ATC Imports)

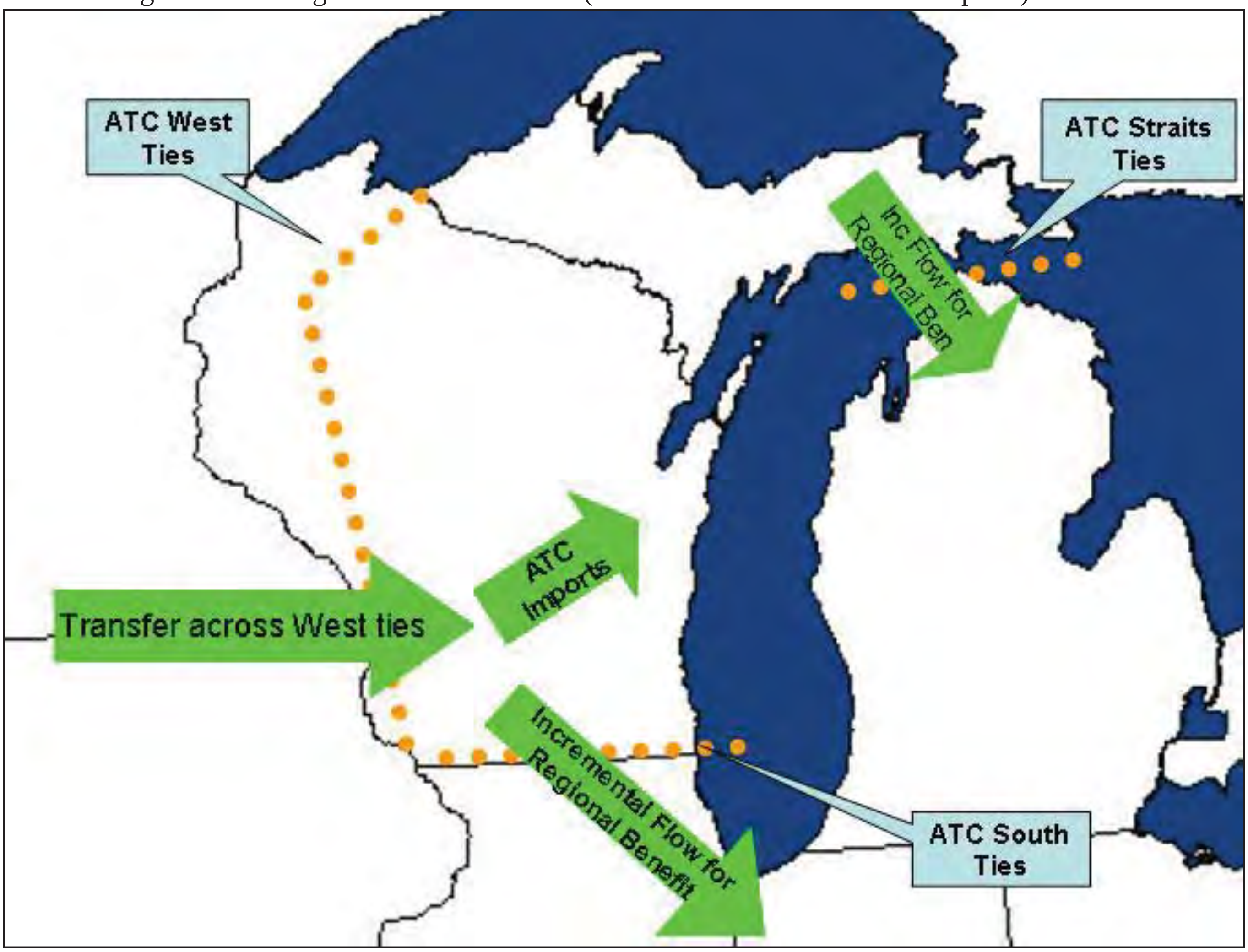

Table 5.11 shows the scoring category breakdown and the overall scoring of each project. Each transfer is weighted equally to determine the overall score.

Table 5.11 - Overall Summary of Voltage Performance

Description				Score (0=Worse, 1=No Change, 5=Best)											
Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	Outage	Opt 1	Opt 1a	**Opt 1b**	**Opt 8**	Opt 7c	**Opt HV**	**Opt LV**	Base + caps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
Transfer 1 - Transfer Score		**Weighted Average**		2.5	2.5	2.5	3.0	3.9	4.6	0.5	2.0	2.6	3.0	4.8	2.8
Transfer 1 - Voltage Score		**Weighted Average**		2.9	2.9	3.8	3.0	3.3	3.4	1.8	2.8	3.8	3.1	3.4	2.9
Transfer 1 - Losses Score		**Weighted Average**		2.6	2.3	2.2	2.1	2.7	3.8	1.0	1.4	2.3	2.2	3.8	1.5
Transfer 1 TOTAL		**Weighted Average**		2.7	2.6	2.8	2.8	3.4	4.0	1.1	2.1	2.9	2.8	4.1	2.4
Transfer 2 - Transfer Score		**Weighted Average**		3.2	2.9	2.7	3.4	5.0	4.5	1.2	1.3	3.3	3.4	4.6	1.7
Transfer 2 - Voltage Score		**Weighted Average**		2.7	2.5	3.5	2.7	3.4	3.1	0.7	1.5	3.5	2.7	3.1	2.2
Transfer 2 - Losses Score		**Weighted Average**		2.7	2.4	2.3	2.0	2.7	3.2	1.1	1.3	2.3	2.0	3.3	1.4
Transfer 2 TOTAL		**Weighted Average**		2.9	2.6	2.8	2.8	3.8	3.7	1.0	1.3	3.1	2.8	3.8	1.8
Transfer 3 - Transfer Score		**Weighted Average**		3.1	2.5	2.5	4.0	5.0	3.3	1.1	1.8	3.4	4.0	4.2	2.9
Transfer 3 - Voltage Score		**Weighted Average**		3.3	2.7	3.1	2.9	3.6	3.0	1.4	1.9	3.1	2.9	3.1	2.3
Transfer 3 - Losses Score		**Weighted Average**		2.7	2.2	1.8	3.0	3.3	3.0	1.0	1.0	1.8	3.0	3.1	1.5
Transfer 3 TOTAL		**Weighted Average**		3.0	2.5	2.5	3.3	4.1	3.1	1.2	1.6	2.8	3.3	3.5	2.3
				1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV
Overall Weighted Average (of Transfer 1, 2, 3)				2.9	2.6	2.7	3.0	3.8	3.6	1.1	1.7	2.9	3.0	3.8	2.2
Overall Weighted Average (of Transfer 2, 3) to Gen				3.0	2.5	2.6	3.1	4.0	3.4	1.1	1.5	2.9	3.1	3.6	2.0

For overall evaluation, the scoring is shown with and without the impact of Transfer 1 included.

PV Analysis - Additional Observations

Option 1 (NLAX-HLT-SPG-CDL) performed well with regard to voltage performance at common transfer levels and losses in the Hilltop area. This can be attributed in part to the Hilltop transformer and Hilltop low voltage outlet facilities. While Option 1 reduces MW and MVAR losses within the ATC portion of the study region, it increases MW and MVAR losses in the study region external to ATC. The external loss differences can be attributed in part to the impact of the additional power that is channeled through the ATC West Ties interface.

For the 765 kV Option, voltage performed well in Transfer 1. [redacted] includes a 765 kV line to North Monroe and double circuit 345 kV from North Monroe to Paddock. [redacted].

The non-ATC MW and MVAR losses for the 765 kV Option performed well, while the ATC MVAR losses in the ATC region performed poorly. Examining the detail of the ATC MVAR losses shows that loss efficiencies at higher voltage levels are partially offset by higher losses on facilities below 100 kV. The higher ATC losses can be attributed in part to some of the losses associated with the 765 kV and 345 kV facilities placed in the ATC region for the analysis and the additional flow pressure that is placed on the 138 kV in the vicinity of North Monroe. The external loss differences can be attributed in part to the additional 345 kV facilities in eastern Iowa that are included as part of the complimentary facilities that channel power into the 765 kV line. In doing so, they likely relieve losses on non-ATC lower voltage facilities.

The Low Voltage Option mainly consists of rating increases of existing facilities that do not aid in increasing the voltage stability characteristics of the region. Although they may help prevent line overloads, as expected the Low Voltage Option did not perform much better than the base case option. When the Low Voltage Option was tested with additional reactive resources, it performed better, but still not as well as the other options.

Figure 5.8 – 5.11 indicate that the dual 345kV line Option 7C and the 765kV option were among the projects showing the best combined MW and Mvar loss performance. The Hilltop connection to the 69kV and 138 kV in Option 1a was largely responsible for the good MW and Mvar loss performance for that option. The 765kV option performed particularity well under the Mvar loss conditions under pre and post-contingency. The 765kV option performed well for MW losses external to ATC, in part because the option includes additional 345kV connections in Iowa that are not in the other tested options. As anticipated, the Low Voltage option did not reflect good MW performance. The Mvar performance for the Low Voltage option was poor, but improved with ATC with reactive resource additions. Loss evaluation contributes to the ranking reflected in Table 5.12.

PV Analysis - Conclusion

Based on the overall scoring shown in Table 5.11, option rankings were created for comparison purposes. The scores for the average of three transfers were used for ranking purposes to take into account all three transfer scenarios. The scores for the EHV options without added reactive supports were used. The score for the Low Voltage Option with the reactive support was considered. Even with the reactive support, the Low Voltage Option still performs much worse than the EHV options. The option rankings for supporting voltage stability and robustness are shown in Table 5.12 below. A ranking of “1” represents the worst performance and “5” represents the best performance.

Table 5.12 – Option rankings for voltage stability and robustness performance

Options	**Option rankings**
Low Voltage	1
NLAX-HLT-SPG-CDL (1)	3
NLAX-SPG-CDL (1a)	2
NLAX-NMA-CDL (1b)	2
DBQ-SPG-CDL (8)	3
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5
Genoa-NOM 765 kV	4

5.9 Transient Stability Analysis

The transient stability analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-30 (PSS/E, Version 30.5.1) program from Power Technologies, Inc (PTI). This program is accepted industry-wide for dynamic stability analysis. The study model is a 2014 light load model. See *Section* 2.1.1 for discussions of the study model.

Stability Analysis - Studied generating stations

Six generating stations in the western Wisconsin study area were selected for transient stability analysis: Columbia, Nelson Dewey, Prairie Island, Alma, JPM and Arnold.

These are some of the largest non-wind generating stations in the study area. The objective is to investigate the transient stability of these representative units in the study area under the conditions of light load and relatively high wind penetration. These conditions represent the worst system conditions with respect to generator transient stability.

Stability Analysis - Simulated Contingencies

Category B, C and D contingencies were chosen at the six generating stations for transient stability simulations. Detailed descriptions of these contingencies can be found in Tables G.1, G.2 and G.3 in Appendix G. An outline of the contingencies is provided below.

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

Stability Analysis - Simulation Results

The Critical Clearing Times (CCT's) for the studied Category B, C and D faults and the seven transmission options were obtained through transient stability simulations. The results are listed in Tables G.4 through G.6 in Appendix G.

For the Category B contingencies the system was stable under all simulated faults for all cases with at least a 1.0 cycle stability margin. The results show that for faults near [redacted] Option 7c (NLAX-NMA-CDL + DBQ-SPG-CDL) provided the most stability margins, followed by Option 1b (NLAX-NMA-CDL). The other options seemed to have comparable performance. For some faults near [redacted], the Low Voltage Option provided better stability margins than the other options, largely due to the added facilities of [redacted] Option 1b was shown to provide slightly less stability margins than the other 345 kV options for some faults near [redacted]. Since all cases are stable with at least a 1.0 cycle stability margin, no supporting facilities are recommended based on the Category B results.

For the Category C contingencies the system was stable under all simulated faults for all cases with at least a 1.0 cycle stability margin, except for one fault associated with the base case. The same trends identified from the Category B results continued with the Category C results. The results show that for faults near [redacted], Option 7c provided the most stability margins, followed by Option 1b. The other options seemed to have comparable performance. For some faults near [redacted], the Low Voltage Option performed better, largely due to the added facilities of [redacted] Option 8 (DBQ-SPG-CDL) did show slightly larger stability margins than the other 345 kV options for some faults near [redacted]. Option 1b was shown to provide slightly less stability margins than the other options for some faults near [redacted]. Since all studied transmission options provided stability for all simulated faults with at least a 1.0 cycle margin, no supporting facilities are recommended based on Category C results.

For the Category D contingencies, the system is unstable for [redacted] ATC has observed the stability issues in the [redacted] and is currently performing a separate study for this area, which may lead to recommendations of system reinforcements, such as relay upgrades and/or breakers replacement, that will improve equipment clearing time. It is anticipated that with these potential improvements, [redacted] identified in this study will be mitigated. This is considered an existing system issue. Therefore no supporting facilities will be recommended in this study for the [redacted] As a sensitivity test, [redacted] The simulation results are shown in Table G.7 in Appendix G. The results show improvement to CCTs for a number of tested Category B, C and D contingencies. This sensitivity test is for informational purposes only.

Instability issues were also identified for Category D faults in [redacted]. For the non-transformer fault (D2-01), relay adjustments were identified that will improve the equipment clearing time and will mitigate the instability with at least a 1.0 cycle stability margin for Options 1, 1b and 7c. For the other options (1a, 8, 765 kV and Low Voltage) additional reinforcements are needed to meet the stability criteria. One set of facilities were tested as an example, which includes a [redacted]. The simulation results are included in Table G.8 in Appendix G. The results show that with these additions, Options 1a, 8, the 765 kV Option and the Low Voltage Option will meet the stability criteria with at least a 1.0 cycle margin. These fixes are not likely the least expensive fixes solely for the instability issue. This study does not present conclusions on the preferred fixes. Rather, the focus of the stability analysis is comparing between the studied options and is more for informational purposes. For the Category D [redacted] [redacted] 2-cycle breaker replacements would reduce the equipment clearing time and provide at least a 1.0 cycle stability margin for all studied options.

Stability Analysis - Summary

Based on the study results, the studied transmission options are ranked for their ability to support system transient stability, e.g., improving stability margins. More importance is given to stability at [redacted], since unacceptable Critical Clearing Times were identified under two Category D contingencies and small (still acceptable) stability margins were identified for one prior outage Category C contingency in the area. Improvement in stability margins for [redacted] is shown to be important. The rankings are shown in Table 5.16 below. A ranking of “1” represents the worst performance and “5” represents the best performance.

Table 5.16 – Option rankings for supporting system transient stability

Options	Rankings
Low Voltage	1
NLAX-HLT-SPG-CDL (1)	3
NLAX-SPG-CDL (1a)	1
NLAX-NMA-CDL (1b)	4
DBQ-SPG-CDL (8)	1
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5
Genoa-NOM 765 kV	1

6. Conclusions

The Western Wisconsin Transmission Reliability Study identified thermal and voltage limitations (including potential voltage collapse) in the base case without any studied transmission options. Out of the initial 15 transmission options, seven were chosen for detailed analysis. Monetized (costs) and non-monetized measures were used for evaluating different aspects of the reliability performance and for comparing between the seven options. Table 6.1 provides a summary of the comparisons of all aspects discussed in the previous sections, including costs and performance rankings.

The results as summarized in Table 6.1 show that the Low Voltage Option has the lowest rankings for all aspects of the reliability performance evaluated using non-monetized measures. These aspects include system voltage performance under Category B and C contingencies, severe local low voltages under a Category C2 contingency, voltage stability and robustness and system transient stability. For these aspects, the Low Voltage Option consistently performs at inferior levels compared to the EHV options. For the reliability aspects evaluated using the monetized measure, the Low Voltage Option is less costly than the EHV options. However, because of its inability to support system voltages, voltage stability and transient stability, the 345 kV options are preferred over the Low Voltage Option.

The 765 kV Option would represent the first 765 kV element in the western Wisconsin area. The results show that the overall rankings are lower for the 765 kV Option than the 345 kV options for those aspects evaluated using non-monetized measures. For the reliability aspects evaluated using the monetized measure, the 765 kV Option is shown to have the highest cost.

A 345 kV reinforcement in the western Wisconsin area from La Crosse to Madison would strengthen the transmission networks in the area and would be expected to enhance the performance of any potential future 765 kV and/or HVDC facilities through the area should the need drivers for such projects be established.

Three of the seven options were in the corridor between North LaCrosse to Madison. These options (Options 1, 1a, and 1b) are comparable from an overall reliability performance perspective and Option 1b (NLAX_NMA-CDL) option has the lowest overall cost of the three options. A 345kV line in this corridor provides the voltage stability and interconnection to Minnesota which is one of the desired benefits of this study.

Option 8 (DBQ-SPG-CDL) also performs well from a reliability perspective. It has a slightly lower cost than Option 1b (NLAX-NMA-CDL) but does not provide the transient stability that is desired. Option 7c (NLAX-NMA-CDL & DBQ-SPG-CDL) performed the best across all aspects of the reliability analyses, and is expected to provide additional benefits over and above any of the singular 345 kV options including a higher increase in transfer capability for additional wind generation in MN and IA.

The conclusion of this study is that Option 7c provides the most reliability benefit to the western Wisconsin area and that Option 1b provides a portion of the benefit realized in Option 7c and includes the additional interconnection to Minnesota. Option 8 provides significant reliability benefits to western Wisconsin as well but not the needed reinforcements for Minnesota ATC believes that the total combination of benefits versus costs, as well as information from the Midwest ISO's Regional Generator Outlet Study, should be taken into account in making a choice to pursue any of the options listed above. ATC has been analyzing the combined reliability, economic, and policy benefits of these options for approximately two years and has determined that a 345 kV project from the La Crosse area to the greater Madison area (the Badger Coulee Project) would provide multiple benefits. ATC has recently announced its intention to finalize its evaluation of these combined benefits and to begin public outreach on the Badger Coulee Project.[16]

[16] Further information about this announcement is located at: http://www.atc-projects.com/BadgerCoulee.shtml

Table 6.1 – Summary of the comparisons of the reliability performance using monetized and non-monetized measures

Summary of project costs in 2010 dollars			Low Voltage	NLAX-HLT-SPG-CDL (1)	NLAX-SPG-CDL (1a)	NLAX-NMA-CDL (1b)	DBQ-SPG-CDL (8)	NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	Genoa-NOM 765 kV
EHV projects			Opt LV	Opt1	Opt1a	Opt1b	Opt8	Opt7c	Opt 765
			$0	$454,492,920	$377,454,200	$357,590,989	$304,187,200	$672,785,400	$880,598,000
Category B Supporting Facilities	Loading	ATC Facilities	$173,768,164	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
	Loading	Non-ATC Facilities	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	$269,165,514	$156,943,463	$183,640,721	$188,698,156	$205,393,188	$143,951,649	$180,046,843
Category C Supporting Facilities	Loading	ATC Facilities	$0	$0	$0	$0	$0	$0	$0
	Voltage	ATC Facilities	$82,758,813	$0	$0	$0	$0	$0	$0
	Loading	Non-ATC Facilities	$0	$0	$0	$0	$0	$0	$0
	Voltage	Non-ATC Facilities	$0	$0	$0	$0	$0	$0	$0
		Total	$82,758,813	$0	$0	$0	$0	$0	$0
Category B & C Supporting Facilities		ATC Facilities	$256,526,977	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
		Non-ATC Facilities	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	$351,924,327	$156,943,463	$183,640,721	$188,698,156	$205,393,188	$143,951,649	$180,046,843
Total cost estimates for project packages (main + support)			$351,924,327	$611,436,383	$561,094,921	$546,289,145	$509,580,388	$816,737,049	$1,060,644,843
Rankings - benefits not captured by cost analysis									
Voltage performance under Cat-B contingencies			1	4	4	4	4	5	3
Voltage performance under converged Cat-C contingencies			1	5	4	3	4	5	2
Alleviate Cat-C2 severe local low voltages			1	5	5	1	5	5	1
Support voltage stability and robustness			1	3	2	2	3	5	4
Support system transient stability			1	3	1	4	1	5	1

Appendices

Appendix A. Details of the Studied Transmission Options

Appendix B. Maps of the Studied Transmission Options

Appendix C. ATC Severity Index Tool Write-Up

Appendix D. Supporting Facilities for the EHV (345 kV and 765 kV) Options- Category B Loading Limitations

Appendix E. List of Non-Converged N-2 Contingencies

Appendix F. Voltage Stability Tables

Appendix G. Transient Stability Analysis Contingencies and Results

B. One-Line Diagrams of Project Alternatives

Project one-line diagrams for four of the alternatives are presented. Badger Coulee, Spring Green 345-kV, 345-kV to Iowa and High Voltage are the alternatives that have a project one-line. The Combination 345-kV alternative is the combination of Badger Coulee and 345-kV to Iowa. Therefore, joining these project one-lines together would create this alternative. The Low Voltage alternative does not have a project one-line associated with it because this alternative primarily upgrades or rebuilds existing transmission facilities with higher capacity equipment.

[redacted]

[redacted]

[redacted]

[redacted]

C. Economic Analysis - PROMOD Study Assumptions

Load, Interruptibles, and Direct Control Load Management Forecasts

Load Forecasts

The weather normalized peak load and energy usage forecasts used in the analysis for the ATC footprint were developed by Clearspring Energy Associates and are based on information collected from the Load Distribution Companies (LDCs) within the ATC footprint. The load and energy information provided by the LDCs includes the projected summer peaks and the projected annual energies needed to develop the forecasts. The forecasts include data on the following control areas: Alliant Energy East (ALTE), Madison Gas and Electric (MGE), Upper Peninsula Power Company (UPPC), We-Energies (WEC), and Wisconsin Public Service Corporation (WPS).

Only the 2008 energy and peak load data was used from the LDC information and data. To these starting values, various annual growth rates were applied (as specified for each Future in Tables C1 to C5) to come up with the loads for 2020 and 2026. Due to the area setup in PROMOD and its supporting database, it was necessary to adjust the data for use in the analyses. UPPCo is not explicitly modeled as its own area in PROMOD. Its information is accounted for in the WEC control area.

The control areas within ATC are predicting somewhat different annual load growth rates. To capture these differences, starting in 2009, the percentages for each control area of ATC's total load were used to develop different growth rates for each control area within ATC, but still provide an overall load growth rate for the entire ATC footprint. The peak load and energy usage forecasts used in the analyses can be found in Tables C1 through C5.

Table C1: 0.2% Peak Load Growth / 0.1% Energy Growth Forecasts for 2020 & 2026

	2009 Weather Normalized ATC Projections		2020 Company Percentage of ATC		2020 Forecast		2026 Company Percentage of ATC		2026 Forecast		Average Annual Growth Rates (2009 - 2026)	
Company	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Demand (%)	Energy (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATC	13,062	69,103	100.00%	100.00%	13,352	69,867	100.00%	100.00%	13,513	70,287	0.20%	0.10%

Table C2: 1.0% Peak Load Growth / 0.7% Energy Growth Forecasts for 2020 & 2026

	2009 Weather Normalized ATC Projections		2020 Company Percentage of ATC		2020 Forecast		2026 Company Percentage of ATC		2026 Forecast		Average Annual Growth Rates (2009 - 2026)	
Company	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Demand (%)	Energy (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATC	13,062	69,103	100.00%	100.00%	14,689	75,059	100.00%	100.00%	15,592	78,267	1.00%	0.70%

Table C3: 1.4% Peak Load Growth / 2.2% Energy Growth Forecasts for 2020 & 2026

	2009 Weather Normalized ATC Projections		2020 Company Percentage of ATC		2020 Forecast		2026 Company Percentage of ATC		2026 Forecast		Average Annual Growth Rates (2009 - 2026)	
Company	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Demand (%)	Energy (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATC	13,062	69,103	100.00%	100.00%	15,402	89,625	100.00%	100.00%	16,742	102,126	1.40%	2.20%

Table C4: 1.7% Peak Load Growth / 1.4% Energy Growth Forecasts for 2020 & 2026

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	2009 Weather Normalized ATC Projections		2020 Company Percentage of ATC		2020 Forecast		2026 Company Percentage of ATC		2026 Forecast		Average Annual Growth Rates (2009 - 2026)	
Company	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Demand (%)	Energy (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATC	13,062	69,103	100.00%	100.00%	15,957	81,563	100.00%	100.00%	17,656	88,658	1.70%	1.40%

Table C5: 2.5% Peak Load Growth / 2.2% Energy Growth Forecasts for 2020 & 2026

	2009 Weather Normalized ATC Projections		2020 Company Percentage of ATC		2020 Forecast		2026 Company Percentage of ATC		2026 Forecast		Average Annual Growth Rates (2009 - 2026)	
Company	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Load (%)	Energy (%)	Peak Load (MW)	Energy (GWh)	Peak Demand (%)	Energy (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ATC	13,062	69,103	100.00%	100.00%	17,530	89,625	100.00%	100.00%	20,329	102,126	2.50%	2.20%

Interruptible Load and Direct Control Load Management

Interruptible Load and Direct Control Load Management were modeled together in PROMOD as Interruptible Loads. The 2020 forecast data for these items was taken from the MISO MTEP 09 PowerBase database with data based on Module E submittals to MISO. The data for Interruptible Load and Direct Control Load Management was summed to represent the total load management available for each area. This value was then divided and distributed over several locations in each control area. The locations were chosen based on engineering judgment, as actual locations are unavailable. The information used in the analyses is shown in Table C6.

Table C6: Interruptible Loads and Direct Load Control Assumed for the Analyses

Name	Area	Maximum Capacity (MW)	Location
MGE Direct Load Control:1	Madison Gas & Electric Co.	[redacted]	[redacted]
MGE Direct Load Control:2	Madison Gas & Electric Co.	[redacted]	[redacted]
MGE Direct Load Control:3	Madison Gas & Electric Co.	[redacted]	[redacted]
MGE Interruptible:1	Madison Gas & Electric Co.	[redacted]	[redacted]
MGE Interruptible:2	Madison Gas & Electric Co.	[redacted]	[redacted]
MGE Interruptible:3	Madison Gas & Electric Co.	[redacted]	[redacted]
WEC Direct Load Control:1	We Energies	[redacted]	[redacted]
WEC Interruptible:1	We Energies	[redacted]	[redacted]
WEC Interruptible:2	We Energies	[redacted]	[redacted]
WEC Interruptible:3	We Energies	[redacted]	[redacted]
WPL Direct Load Control:1	Alliant East	[redacted]	[redacted]
WPL Interruptible:1	Alliant East	[redacted]	[redacted]
WPL Interruptible:2	Alliant East	[redacted]	[redacted]
WPL Interruptible:3	Alliant East	[redacted]	[redacted]
WPPI Interruptible:1	Wisconsin Public Power Inc. System	[redacted]	[redacted]
WPS Direct Load Control:1	Wisconsin Public Service Corp.	[redacted]	[redacted]
WPS Interruptible:1	Wisconsin Public Service Corp.	[redacted]	[redacted]
WPS Interruptible:2	Wisconsin Public Service Corp.	[redacted]	[redacted]
WPS Interruptible:3	Wisconsin Public Service Corp.	[redacted]	[redacted]
WPS Interruptible:4	Wisconsin Public Service Corp.	[redacted]	[redacted]

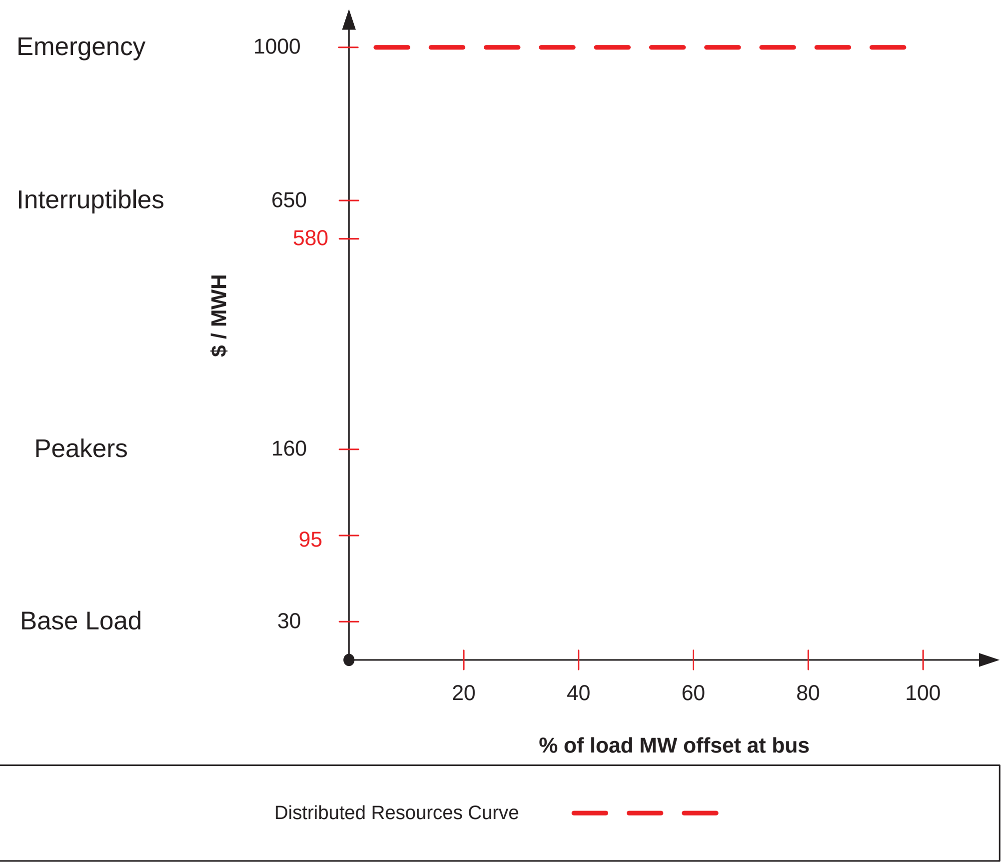
Distributed Resources (DR)

ATC utilizes a modeling technique comprised of "Distributed Resources" which mimics demand response and other distributed technologies that may serve to offset load in the future. In addition, these units serve to prevent unrealistic PROMOD results such as "buying through" constraints or dispatching "emergency" generation. The following detail provides background and descriptions of how ATC has modeled these units in past analysis and how they have been modeled for the Badger Coulee analysis.

Assumptions in 2008 PROMOD analysis

- DR units modeled to mimic demand response actions and other distributed technologies that may serve to offset load in the future
- Serve to prevent unrealistic PROMOD results such as "buying through" constraints or dispatching "emergency" generation
- DR units placed at every load 5 MW and higher within ATC (736 units in 2008)
- DR unit capacity set equal to peak load value at location
- Dispatch cost of $1,000/MWH in 2008 ($1,336 in 2024)
- Model units as fast-starting Combustion Turbines

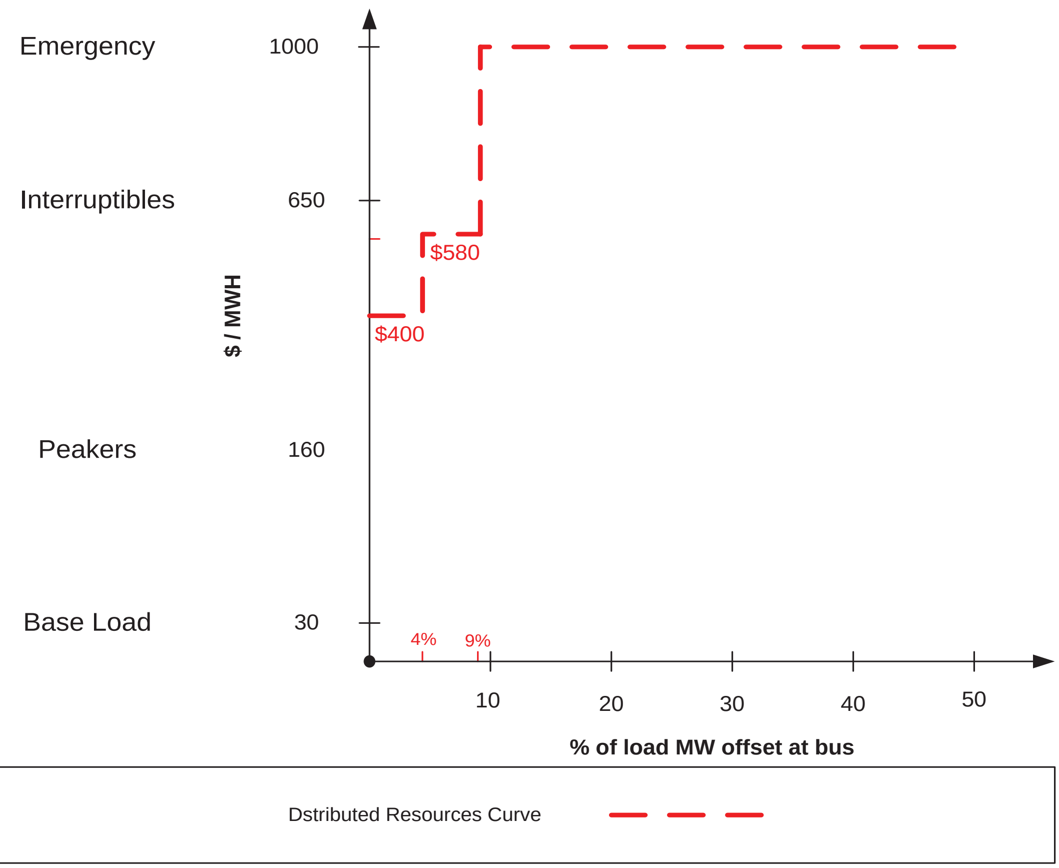
Figure C1: 2008 Distributed Resources Cost Curve for Demand Response



DR Units for Badger Coulee Analysis

- DR capacity set equal to 50% of bus load
- Use increasing cost curves on DR units
    - Price of DR dispatch is higher as more DR output is demanded to mimic increased resistance from consumers
    - Dispatch in 0.5 MW increments
- "FERC on Smart Grid" scenarios and expected reduction in peak demand from demand response:
    - Business-as-usual: 4% reduction
    - Expanded Business-as-Usual: 9% reduction (Assume this for WI)
    - Achievable Participation: 14% reduction
    - Full Participation: 20% reduction
- Since 9% reduction in peak demand is the maximum expected yield due to demand response, set any dispatch above that level to the emergency cost of energy.
- Pilot demand response programs show customer response begins at prices between 26¢ and 40¢ per kilowatt-hr (about $260 - $400 per MW-hr)

Figure C2: 2009 Distributed Resources Cost Curve for Demand Response



Modeling Distributed Renewable Generation

Issues and Proposed Assumptions for inclusion of Distributed Renewables

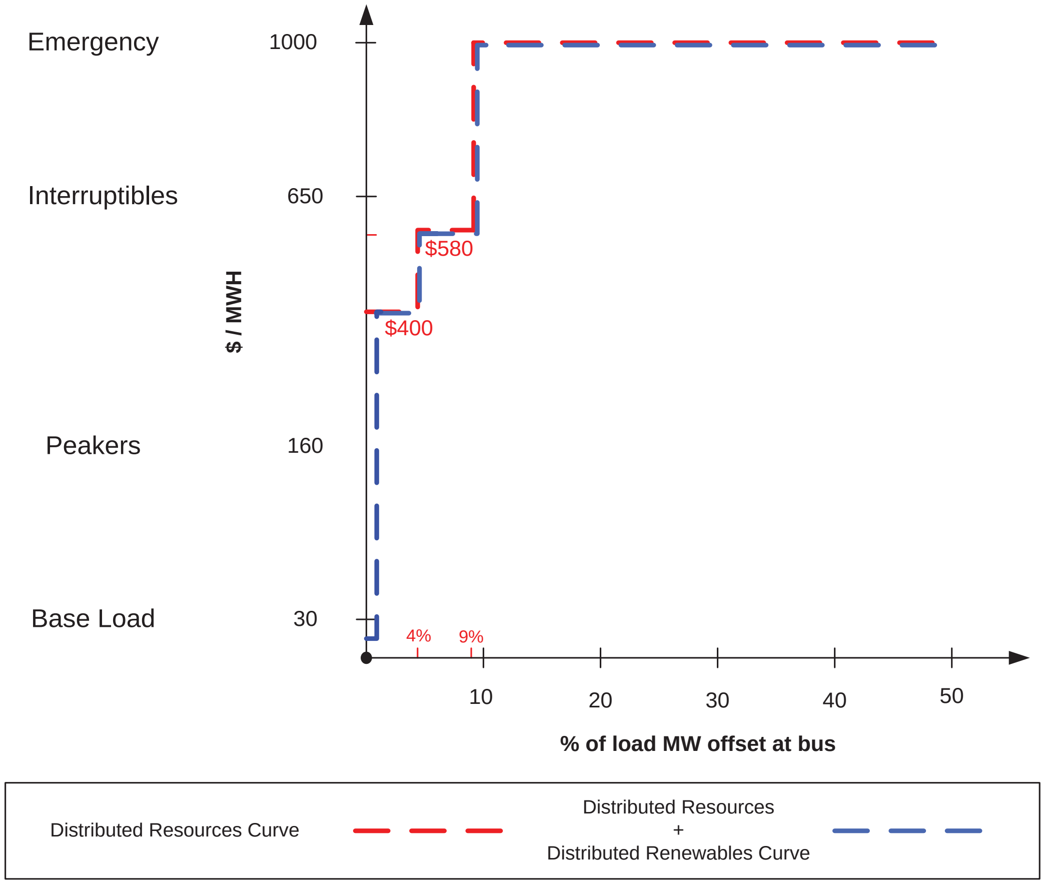
- Issue 1: Limit to number of units allowed in database
    - Use a sampling of existing DR units
    - At these units, add low-cost segment to the cost curve
    - Pricing of low-cost segment below baseload average
    - Set units as "must run" to ensure they are always dispatched

- Issue 2: Need to determine amount of MWs to be on at all times
    - Capacity of distributed renewable generation (DRG) to be equal to 0.4% of total energy
        - This doubles the current level of DRG in WI
            - "Always on" output determined through PSCW assumptions on capacity factors and installed capacity of biogas, wind, and solar (weighted average gives capacity factor of 70.56%).

- Issue 3: Need to choose diverse locations for distributed generation
    1) Divide loads into 10 groupings of approximately equal size (quantity-wise)
    2) For each grouping, sort loads from smallest to largest
    3) Choose every 14^{th} load for placement of a DRG
    4) Choose every 12^{th} load if there are less then 70 loads in the grouping

- Issue 4: Additional units may skew carbon emissions numbers
    - Set emissions of DR units to zero to imitate renewable generation

Figure C3: DR Cost Curve for Distributed Renewables



The blue dotted line shows the addition of the DRGs to the cost curve of some Distributed Resources. The DRGs will be dispatched at a value below base load generation and will eat into the first segment of the DR cost curve (leaving less MW for dispatch at $400/MW-hr.)

- $30 is the baseload dispatch cost. This value is calculated based on the average cost of ST Coal generators in the PROMOD model.
- $160 is the peaker dispatch cost. This value is calculated based on the average cost of CT gas units in the PROMOD model.
- $400 is the first dispatch point for DR units. This value is the equivalent of the 40 cent/kw-hr value that leads to customer action in demand response pilot programs. The first 4% of bus load is offset at this price.
- $580 is the second dispatch point for DR units. This value is the midpoint between peaker dispatch costs and emergency dispatch costs. An additional 5% of bus load is offset at this price (total of 9% of bus load).
- $1000 is the emergency dispatch cost. PROMOD dispatches emergency generation at this price. An additional 41% of bus load is dispatchable at this level.

Generation
Generation within the ATC Footprint

Table C7 contains a list of currently existing generation inside the ATC footprint that were included in all models for the analyses. The maximum capacity listed is the emergency maximum capacity for the units, and is only achievable under specific conditions for short periods of time.

Table C7: Existing Generation within the ATC Footprint included in the models for all analyses

PowerBase Name	Category	Area	Maximum Capacity (MW)
Appleton (WEP):HYOP3	Hydro Run-of-River	We Energies	1.0
Autrain:HYOP2	Hydro Run-of-River	We Energies	1.0
Berlin (WPL):ALL	CT Gas	Alliant East	2.0
BHP Copper White Pine Ref. Inc .:GEN1	ST Coal	We Energies	20.0
BHP Copper White Pine Ref. Inc .:GEN2	ST Coal	We Energies	20.0
Big Quinnesec 61:HYOP2	Hydro Run-of-River	We Energies	3.0
Big Quinnesec 92:HYOP2	Hydro Run-of-River	We Energies	16.0
Blount:6	ST Gas	Madison Gas & Electric Co.	49.0
Blount:7	ST Gas	Madison Gas & Electric Co.	48.0
Blue Sky Wind Farm:44	Wind	We Energies	72.6
Brule:HYOP3	Hydro Run-of-River	We Energies	5.3
BTM Alliant East	CT Oil	Alliant East	2.0
BTM WE Energies	CT Oil	We Energies	2.0
BTM Wisconsin Public Service	CT Oil	Wisconsin Public Service Corp.	8.0
Castle Rock:HYOP5	Hydro Run-of-River	Alliant East	21.0
Cataract (UPP):HYOP1	Hydro Run-of-River	We Energies	1.0
Chalk Hill:HYOP3	Hydro Run-of-River	We Energies	7.8
Columbia (WPL):1	ST Coal	Alliant East	563.0
Columbia (WPL):2	ST Coal	Alliant East	546.0
Combined Locks Energy Center:WPS Power Development Inc	CT Gas	Wisconsin Public Service Corp.	53.0
Concord:1	CT Gas	We Energies	100.0
Concord:2	CT Gas	We Energies	100.0
Concord:3	CT Gas	We Energies	100.0
Concord:4	CT Gas	We Energies	100.0
CP Node WPS.JUNEAUC31	CT Oil	We Energies	18.0
Custer Energy Center:1	CT Gas	Wisconsin Public Service Corp.	24.0
Dafter:GTOL5	CT Oil	We Energies	4.0

Table C7: Existing Generation within the ATC Footprint included in the models for all analyses

PowerBase Name	Category	Area	Maximum Capacity (MW)
De Pere Energy Center:GT	CT Gas	Wisconsin Public Service Corp.	175.0
Detour:GTOL2	CT Oil	We Energies	10.6
Dewey:1	ST Coal	Alliant East	108.0
Dewey:2	ST Coal	Alliant East	112.0
Eagle River:GTOL2	CT Oil	Wisconsin Public Service Corp.	4.0
Edgewater (WPL):3	ST Coal	Alliant East	71.0
Edgewater (WPL):4	ST Coal	Alliant East	335.0
Edgewater (WPL):5	ST Coal	Alliant East	423.0
Edison Sault:HYOP73	Hydro Run-of-River	We Energies	30.0
Escanaba:STCL2	ST Coal	We Energies	18.0
Fitchburg (MGE):1	CT Gas	Madison Gas & Electric Co.	22.0
Fitchburg (MGE):2	CT Gas	Madison Gas & Electric Co.	22.0
Forward Wind Energy Center:WND1	Wind	We Energies	129.0
Fox Energy Center (Kaukauna):CC	Combined Cycle	Wisconsin Public Service Corp.	603.0
Germantown:1	CT Oil	We Energies	63.0
Germantown:2	CT Oil	We Energies	63.0
Germantown:3	CT Oil	We Energies	63.0
Germantown:4	CT Oil	We Energies	63.0
Germantown:5	CT Gas	We Energies	93.0
Gladstone - UPP:1	CT Oil	We Energies	27.0
Grandfather Falls:HYOP2	Hydro Run-of-River	Wisconsin Public Service Corp.	17.0
Green Field Wind Farm:44	Wind	We Energies	72.6
Hemlock Falls:HYOP1	Hydro Run-of-River	We Energies	2.8
Hoist:HYOP3	Hydro Run-of-River	We Energies	3.0
Janesville:4	CT Oil	Alliant East	7.0
John H. Warden:1	ST Gas	We Energies	36.0
Kaukauna (WPPI):GT	CT Gas	Wisconsin Public Power Inc. System	60.0
Kaukauna:GT1	CT Gas	Wisconsin Public Power Inc. System	16.0
Kewaunee:1	Nuclear	Wisconsin Public Service Corp.	578.0
Kilbourn:HYOP4	Hydro Run-of-River	Alliant East	6.0
Kingsford:HYOP3	Hydro Run-of-River	We Energies	6.0
Lincoln Turbines/ Kewaunee County:WIOP1	Wind	Wisconsin Public Service Corp.	2.0
Manistique:GTOL2	CT Oil	We Energies	5.0
Manitowoc:5	ST Coal	Wisconsin Public Service	24.0

Table C7: Existing Generation within the ATC Footprint included in the models for all analyses

PowerBase Name	Category	Area	Maximum Capacity (MW)
		Corp.	
Manitowoc:6	ST Coal	Wisconsin Public Service Corp.	30.0
Manitowoc:GTGS1	CT Gas	Wisconsin Public Service Corp.	5.5
Manitowoc:GTGS2	CT Gas	Wisconsin Public Service Corp.	5.0
Manitowoc:ST	ST Coal	Wisconsin Public Service Corp.	58.0
Marshfield CT (MEWD):GT	CT Gas	Wisconsin Public Service Corp.	55.2
McClure (UPP):HYOP2	Hydro Run-of-River	We Energies	8.0
Michigamme Falls:HYOP2	Hydro Run-of-River	We Energies	9.6
Montfort Wind Farm:WIOP1	Wind	We Energies	31.0
Neenah:GT1	CT Gas	We Energies	168.0
Neenah:GT2	CT Gas	We Energies	168.0
Nine Springs:GT1	CT Gas	Madison Gas & Electric Co.	15.0
Oak Creek South:5	ST Coal	We Energies	262.0
Oak Creek South:6	ST Coal	We Energies	265.0
Oak Creek South:7	ST Coal	We Energies	298.0
Oak Creek South:8	ST Coal	We Energies	314.0
Oneida Casino:GTOL2	CT Oil	Wisconsin Public Service Corp.	4.0
Paris (WEP):1	CT Gas	We Energies	100.0
Paris (WEP):2	CT Gas	We Energies	100.0
Paris (WEP):3	CT Gas	We Energies	100.0
Paris (WEP):4	CT Gas	We Energies	100.0
Peavy Falls:HYOP2	Hydro Run-of-River	We Energies	16.0
Petenwell:HYOP4	Hydro Run-of-River	Wisconsin Public Service Corp.	21.0
Pine:HYOP2	Hydro Run-of-River	We Energies	4.0
Pleasant Prairie:1	ST Coal	We Energies	617.0
Pleasant Prairie:2	ST Coal	We Energies	617.0
Point Beach:1	Nuclear	We Energies	617.0
Point Beach:2	Nuclear	We Energies	619.0
Point Beach:5	CT Oil	We Energies	19.0
Port Washington (Wep):CC	Combined Cycle	We Energies	635.0
Port Washington (Wep):CC2	Combined Cycle	We Energies	635.0
Portage - UPP:1	CT Oil	We Energies	27.0
Prairie Du Sac:HYOP8	Hydro Run-of-River	Alliant East	12.0
Presque Isle:5	ST Coal	We Energies	88.0
Presque Isle:6	ST Coal	We Energies	88.0

Table C7: Existing Generation within the ATC Footprint included in the models for all analyses

PowerBase Name	Category	Area	Maximum Capacity (MW)
Presque Isle:7	ST Coal	We Energies	88.0
Presque Isle:8	ST Coal	We Energies	88.0
Presque Isle:9	ST Coal	We Energies	88.0
Prickett:HYOP2	Hydro Run-of-River	We Energies	2.0
Pulliam:5	ST Coal	Wisconsin Public Service Corp.	52.0
Pulliam:6	ST Coal	Wisconsin Public Service Corp.	60.0
Pulliam:7	ST Coal	Wisconsin Public Service Corp.	86.0
Pulliam:8	ST Coal	Wisconsin Public Service Corp.	134.0
Pulliam:GT	CT Gas	Wisconsin Public Service Corp.	85.0
Riverside Energy Center:CC	Combined Cycle	Alliant East	655.0
Rock River:3	CT Oil	Alliant East	26.0
Rock River:4	CT Oil	Alliant East	14.0
Rock River:5	CT Oil	Alliant East	55.0
Rock River:6	CT Oil	Alliant East	55.0
Rockgen Energy Center:1	CT Gas	Alliant East	178.8
Rockgen Energy Center:2	CT Gas	Alliant East	190.7
Rockgen Energy Center:3	CT Gas	Alliant East	193.8
Rosiere (MGE):WIOP1	Wind	Madison Gas & Electric Co.	11.2
Saint Marys Falls:HYOP5	Hydro Run-of-River	We Energies	20.0
Sheboygan Falls:CT 1	CT Gas	Alliant East	145.0
Sheboygan Falls:CT 2	CT Gas	Alliant East	145.0
Sheepskin:1	CT Oil	Alliant East	37.0
South Fond Du Lac:GT1	CT Gas	Alliant East	88.0
South Fond Du Lac:GT2	CT Gas	Alliant East	88.0
South Fond Du Lac:GT3	CT Gas	Alliant East	88.0
South Fond Du Lac:GT4	CT Gas	Alliant East	88.0
Sycamore (MGE):1	CT Gas	Madison Gas & Electric Co.	15.0
Sycamore (MGE):2	CT Gas	Madison Gas & Electric Co.	21.0
Twin Falls (WEP):HYOP5	Hydro Run-of-River	We Energies	6.2
Valley (WEP):1	ST Coal	We Energies	120.0
Valley (WEP):2	ST Coal	We Energies	140.0
Valley (WEP):3	CT Oil	We Energies	3.0
Victoria (UPP):HYOP2	Hydro Run-of-River	We Energies	12.0
Way:HYOP1	Hydro Run-of-River	We Energies	1.8
West Campus Cogeneration Facility:CC	Combined Cycle	Madison Gas & Electric Co.	130.2
West Marinette (Mge):34	CT Gas	Madison Gas & Electric Co.	88.0
West Marinette:31	CT Gas	Wisconsin Public Service	41.0

Table C7: Existing Generation within the ATC Footprint included in the models for all analyses

PowerBase Name	Category	Area	Maximum Capacity (MW)
		Corp.	
West Marinette:32	CT Gas	Wisconsin Public Service Corp.	40.0
West Marinette:33	CT Gas	Wisconsin Public Service Corp.	76.0
Weston (WPS):1	ST Coal	Wisconsin Public Service Corp.	62.0
Weston (WPS):2	ST Coal	Wisconsin Public Service Corp.	87.0
Weston (WPS):3	ST Coal	Wisconsin Public Service Corp.	339.0
Weston (WPS):31	CT Gas	Wisconsin Public Service Corp.	20.0
Weston (WPS):32	CT Gas	Wisconsin Public Service Corp.	50.0
Weston (WPS):4	ST Coal	Wisconsin Public Service Corp.	545.9
White Rapids:HYOP3	Hydro Run-of-River	We Energies	8.0
Whitewater Cogeneration Facility:CC	Combined Cycle	We Energies	257.0
Winnebago County Landfill Gas (Sunnyview):1	CT Gas	Wisconsin Public Service Corp.	2.0
WPL Small Hydros:HYOP10	Hydro Run-of-River	Alliant East	2.4
WPPI Small Hydros:HYOP6	Hydro (existing)	Wisconsin Public Power Inc. System	7.3

Tables C8 and C9 contain lists of planned and possible future units which were included for the 2020 and 2026 analyses respectively.

Table C8: Planned Units included for all 2020 Analyses

PowerBase Name	Category	Area	Maximum Capacity (MW)
Cedar Ridge Wind Farm:WND1	Wind	Alliant East	68.0
Elm Road Generating Station [Oak Creek North]:ST1	ST Coal	We Energies	650.0
Elm Road Generating Station [Oak Creek North]:ST2	ST Coal	We Energies	650.0
Green Lake Wind Farm:WND1	Wind	Alliant East	160.0
Glacier Hills Wind Park:WND1	Wind	We Energies	99.0
Darlington Wind Farm:WND1	Wind	Alliant East	99.0
Randolph Wind Farm:WND1	Wind	Alliant East	80.0
EcoMet Wind Farm:WND1	Wind	We Energies	100.5

Table C9: Planned Units included for all 2026 Analyses

PowerBase Name	Category	Area	Maximum Capacity (MW)
Cedar Ridge Wind Farm:WND1	Wind	Alliant East	68.0
Elm Road Generating Station [Oak Creek North]:ST1	ST Coal	We Energies	650.0
Elm Road Generating Station [Oak Creek North]:ST2	ST Coal	We Energies	650.0
Glacier Hills Wind Park:WND1	Wind	We Energies	162.0
Darlington Wind Farm:WND1	Wind	Alliant East	99.0
EcoMet Wind Farm:WND1	Wind	We Energies	100.5
G749 EcoMont	Wind	Alliant East	50.0
G773 Ledge Wind Energy Center	Wind	Wisconsin Public Service Corp.	150.0
G590 Stony Brook Wind Farm	Wind	Wisconsin Public Service Corp.	98.0
G427 Lake Breeze Wind Farm	Wind	We Energies	98.0

Tables C10 and C11 contain generators that were added within the ATC footprint for particular 2020 and 2026 analyses respectively. The proposed new units are based on expansion plans performed by MISO using EGEAS software as a part of the MTEP 09 planning process. EGEAS was used to determine generation needs by area, type, size, and timing (in-service date) for the various MISO MTEP 09 expansion planning scenarios. The peak demand growth rates used in ATC's Futures models vary from those used by MISO. As such, adjustments to the MISO expansion plan were necessary based on the demand growth rates detailed in Tables C1 to C5. The expansion generators used in the ATC 2020 and 2026 PROMOD models, which were necessary to maintain appropriate planning reserve levels within the model, are detailed in Tables C10 and C11.

Table C10: Expansion Generating Unit Additions within ATC for the Various Analyses for 2020

Unit Type	Unit Size	Location	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
CT Gas	600 MW	Rockdale	X	---	---	---	---	---
CT Gas	600 MW	Rocky Run	X	---	---	X	---	---
ST Coal	600 MW	Columbia	X	---	---	---	---	---

Table C11: Expansion Generating Unit Additions within ATC for the Various Analyses for 2026

Unit Type	Unit Size	Location	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Biomass	200 MW	North Madison	---	---	---	---	---	X
CT Gas	600 MW	Rockdale	X	---	---	---	---	---
CT Gas	600 MW	Rocky Run	X	X	---	X	---	---
CT Gas	600 MW	Rockdale	X	X	---	X	---	---
Combined Cycle	600 MW	Cedarsauk	X	---	---	---	---	---
Combined Cycle	600 MW	North Appleton	X	---	---	X	---	---
Combined Cycle	600 MW	Racine	X	---	---	---	---	---
Combined Cycle	600 MW	Werner West	X	---	---	---	---	---
Photovoltaic	10 MW	Rockdale	---	---	---	---	---	X
Photovoltaic	30 MW	Rockdale	---	---	---	---	---	X
Photovoltaic	110 MW	Rockdale	---	---	---	---	---	X
ST Coal	600 MW	Columbia	X	---	---	X	---	---
ST Coal	600 MW	Gardner Park	X	---	---	---	---	---

Generation additions outside ATC – description of the need to meet planning reserves

For future study years, like 2020 and 2026, sufficient generation must be included in PROMOD to meet the minimum planning reserve requirements set by the regional North American Electric Reliability Council (NERC) Reliability Councils. These planning reserve requirements are normally set based on a Loss of Load Expectation (LOLE) analysis. The LOLE is defined as the fraction of time that electricity demand is likely to exceed available sources of power (including internal generation, load control measures and imported power) for a given system. The LOLE criterion is typically loss of load no more than 0.1 days per year or one day in ten years. The LOLE only considers electricity shortfalls on the bulk, high-voltage power system.

Two methods can be used for meeting the minimum planning reserve requirements in PROMOD. One method is to add generators for future study years. This was done for MISO, non-MISO MRO areas, and the Commonwealth Edison (CE) portion of PJM based on EGEAS expansion analysis performed by MISO in their MTEP 09 process. The specific expansion generators used by ATC came from the EGEAS expansion lists developed by MISO. ATC then calculated the necessary capacity requirements for each of its 2020 and 2026 futures based on the load growth assumptions presented in Tables C1 to C5. The generation and load assumptions embedded by MISO in their PROMOD model were maintained without modifications for all modeled portions of the Eastern Interconnect outside of the MISO, non-MISO MRO, and CE footprints.

Generation additions outside ATC – MISO & Commonwealth Edison

Generation additions were made to the model in an effort to simulate enough generation to meet the load demands of the region in both 2020 and 2026.

ATC worked to determine how many megawatts of generation were necessary throughout the MISO, non-MISO MRO, and Commonwealth Edison regions along with the optimal mix of generation types needed to attain the generation levels described below. This optimal mix was developed by analyzing the mix of generation that existed in the base MISO model and carrying that mix forward as an assumption for how the expansion generation needs would vary by generation type.

In addition, all MISO EGEAS expansion generators were essentially ranked by level of need according to their in-service date. Therefore, units identified with an earlier in-service were included in the model first, followed sequentially in order of in-service date. This was done until the total required generation capacity and generation mix was obtained based on the calculated need levels.

The MISO EGEAS expansions included various types of generation. The “Reference” expansion included Combustion Turbine (CT) Gas units, Combined Cycle units, and Steam Turbine (ST) Coal units. The “Gas Only” expansion included CT Gas units and Combined Cycle units. Finally, ATC utilized the Organization of MISO States (OMS) CARP generator expansion plan for its 2026 Carbon Constrained Future. This expansion was driven by significant environmental regulations and included CT Gas units, Combined Cycle units, hydro units, photovoltaic units, biomass units, Integrated Gasification Combined Cycle (IGCC) units, and nuclear units. Each unit modeled by MISO was placed at specific grid points throughout the region that would be best suited to locate new generation. The full MISO EGEAS expansion analysis provided lists of reasonable generation types and locations for addition to the PROMOD models.

The generation capacity needs, as calculated by ATC, were based on the load growth rates and corresponding generation levels which vary across the futures. As such, calculations were done to adjust the necessary megawatt levels of generation both by type and regional location to meet the reserve margin requirements of the regions (based on the different forecasted load levels assumed in each future). Generating units were placed into the model to match what the calculations indicated was needed for adequate generation in both MISO, non-MISO MRO, and Commonwealth Edison.

Tables C12 through C14 show the details of the total megawatts of generation along with the area where that generation was sited for the 2020 PROMOD models. Tables C15 through C22 shows the details of the total megawatts of generation along with the area where that generation was sited for the 2026 PROMOD models.

Table C12: 2020 Combustion Turbine Additions

	Total Capacity (MWs)					
PowerBase Area	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
AmerenCIPS	1,200	---	---	1,200	---	---
AmerenUE	600	600	---	600	600	---
Commonwealth Edison Co.	600	---	---	600	---	---
Consumers Energy Co.	1,800	1,200	1,200	1,800	1,200	1,200
Detroit Edison Co.	600	600	600	600	600	600
Duke (Cinergy)	1,200	600	---	1,200	600	---
First Energy Ohio	1,800	1,200	1,200	1,800	1,200	600
Hoosier Energy Rural Electric Coop Inc.	1,200	---	---	1,200	---	---
Indianapolis Power & Light Co.	---	1,200	---	---	1,200	---
Northern Indiana Public Service Co.	600	600	---	600	600	---
Northern States Power Co.	600	600	---	600	600	---
Total	**10,200**	**6,600**	**3,000**	**10,200**	**6,600**	**2,400**

Table C13: 2020 Coal-fired Additions

	Total Capacity (MWs)					
PowerBase Area	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Alliant West	1,200	---	---	1,200	---	---
AmerenCIPS	600	---	---	600	---	---
AmerenIP	600	---	---	600	---	---
AmerenUE	600	---	---	600	---	---
Consumers Energy Co.	4,800	---	1,200	4,800	---	---
Duke (Cinergy)	1,200	---	---	1,200	---	---
First Energy Ohio	1,800	---	600	1,800	---	---
Northern Indiana Public Service Co.	600	---	---	600	---	---
Northern States Power Co.	1,200	---	---	1,200	---	---
Otter Tail Power Co.	1,800	---	---	1,800	---	---
Total	**14,400**	**0**	**1,800**	**14,400**	**0**	**0**

Table C14: 2020 Combined Cycle Additions

	Total Capacity (MWs)					
PowerBase Area	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Consumers Energy Co.	---	600	---	---	600	600
Detroit Edison Co.	---	1,800	---	---	1,800	1,200
First Energy Ohio	---	600	---	---	600	---
Northern Indiana Public Service Co.	600	600	---	600	600	600
Total	**600**	**3,600**	**0**	**600**	**3,600**	**2,400**

Table C15: 2026 Combustion Turbine Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
AmerenCIPS	1,200	---	---	1,200	---	---
AmerenUE	600	600	---	600	600	---
Commonwealth Edison Co.	1,800	1,200	600	1,800	---	600
Consumers Energy Co.	2,400	1,800	1,200	2,400	1,800	1,200
Detroit Edison Co.	600	600	600	600	600	600
Duke (Cinergy)	2,400	1,800	---	2,400	1,800	600
First Energy Ohio	2,400	1,800	1,200	2,400	1,800	1,200
Hoosier Energy Rural Electric Coop Inc.	1,200	600	---	1,200	600	---
Indianapolis Power & Light Co.	---	1,200	---	---	1,200	---
Northern Indiana Public Service Co.	600	600	---	600	600	---
Northern States Power Co.	1,200	1,200	---	1,200	1,200	---
Total	**14,400**	**11,400**	**3,600**	**14,400**	**10,200**	**4,200**

Table C16: 2026 Coal-fired Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
Alliant West	1,200	---	---	1,200	---	---
AmerenCIPS	1,200	---	---	1,200	---	---
AmerenIP	1,800	---	600	1,800	---	---
AmerenUE	1,200	---	---	1,200	---	---
Commonwealth Edison Co.	1,200	---	---	1,200	---	---
Consumers Energy Co.	6,600	---	1,800	6,600	---	---
Duke (Cinergy)	2,400	---	---	2,400	---	---
First Energy Ohio	2,400	---	600	2,400	---	---
Northern Indiana Public Service Co.	1,200	---	---	1,200	---	---
Northern States Power Co.	3,000	---	---	2,400	---	---
Otter Tail Power Co.	2,400	---	---	1,800	---	---
Total	**24,600**	**0**	**3,000**	**23,400**	**0**	**0**

Table C17: 2026 Combined Cycle Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
AmerenUE	---	600	---	---	600	---
Consumers Energy Co.	600	600	---	600	600	600
Detroit Edison Co.	---	2,400	---	---	2,400	1,200
First Energy Ohio	---	1,200	---	---	1,200	600
Minnesota Power Inc.	600	600	---	600	600	---
Northern Indiana Public Service Co.	600	600	---	600	600	600
Northern States Power Co.	600	---	---	---	---	---
Total	**2,400**	**6,000**	**0**	**1,800**	**6,000**	**3,000**

Table C18: 2026 Hydro Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
AmerenCIPS	---	---	---	---	---	300
AmerenUE	---	---	---	---	---	550
Commonwealth Edison Co.	---	---	---	---	---	250
First Energy Ohio	---	---	---	---	---	400
Northern States Power Co.	---	---	---	---	---	50
Total	**0**	**0**	**0**	**0**	**0**	**1,550**

Table C19: 2026 Photo Voltaic Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
AmerenCILCO	---	---	---	---	---	170
AmerenCIPS	---	---	---	---	---	230
AmerenIP	---	---	---	---	---	200
AmerenUE	---	---	---	---	---	340
Commonwealth Edison Co.	---	---	---	---	---	3,200
Consumers Energy Co.	---	---	---	---	---	280
Dairyland Power Coop.	---	---	---	---	---	10
First Energy Ohio	---	---	---	---	---	320
Northern States Power Co.	---	---	---	---	---	160
Southern Minnesota Municipal Power Agency	---	---	---	---	---	80
Total	**0**	**0**	**0**	**0**	**0**	**4,990**

Table C20: 2026 Biomass Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
AmerenCIPS	---	---	---	---	---	200
Commonwealth Edison Co.	---	---	---	---	---	400
Duke (Cinergy)	---	---	---	---	---	400
First Energy Ohio	---	---	---	---	---	200
Hoosier Energy Rural Electric Coop Inc.	---	---	---	---	---	200
Northern States Power Co.	---	---	---	---	---	400
Total	**0**	**0**	**0**	**0**	**0**	**1,800**

Table C21: 2026 IGCC Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
Alliant West	---	---	---	---	---	600
AmerenCIPS	---	---	---	---	---	600
Duke (Cinergy)	---	---	---	---	---	1,200
Great River Energy	---	---	---	---	---	600
Indianapolis Power & Light Co.	---	---	---	---	---	600
Total	**0**	**0**	**0**	**0**	**0**	**3,600**

Table C22: 2026 Nuclear Additions

	Total Capacity (MWs)					
PowerBase Area	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
Detroit Edison Co.	---	---	---	---	---	1,200
Duke (Cinergy)	---	---	---	---	---	1,800
Total	**0**	**0**	**0**	**0**	**0**	**3,000**

Generation additions outside MISO, non-MISO MRO, and CE

For PJM, not including CE, ATC maintained the generator expansion and load growth levels that were embedded in the MISO MTEP 09 PROMOD model. This is based on the assumption that the expansions included in these external areas were suited to meet the associated load growth and therefore additional modifications were not necessary since ATC did not modify the load growth assumptions for these external areas.

Retirements inside ATC

Tables C23 and C24 contain existing generating units that were retired for the 2020 and 2026 futures respectively.

Table C23: Existing Generation Retirements within ATC for the Various Futures for 2020

Unit Name	Maximum Capacity (MW)	Commission Date	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
BHP Copper White Pine Ref. Inc .:GEN1	20	12/1/1955	---	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
BHP Copper White Pine Ref. Inc .:GEN2	20	12/1/1955	---	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Blount:4	21	1/1/1938	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Blount:6[1]	49	6/1/1957	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Blount:7[1]	48	7/1/1961	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Edgewater (WPL):3	71	7/1/1951	---	**Retired**	---	**Retired**	---	**Retired**
Escanaba:STCL2	18	5/1/1958	---	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Manitowoc:5	24	1/1/1956	---	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Manitowoc:6	30	1/1/1964	---	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Presque Isle:3	58	1/1/1964	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Presque Isle:4	58	12/1/1966	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Presque Isle:5	88	12/1/1974	---	**Retired**	---	**Retired**	---	**Retired**
Pulliam:3	27	1/1/1943	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Pulliam:4	28	8/1/1947	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Pulliam:5	52	9/1/1949	---	**Retired**	**Retired**	**Retired**	**Retired**	**Retired**
Pulliam:6	60	11/1/1951	---	**Retired**	---	**Retired**	---	**Retired**
Pulliam:7	86	11/1/1958	---	**Retired**	---	**Retired**	---	**Retired**
Weston (WPS):1	62	11/1/1954	---	**Retired**	---	**Retired**	---	**Retired**
Weston (WPS):2	87	9/1/1960	---	**Retired**	---	**Retired**	---	**Retired**

[1] Blount Units 6 and 7 were converted from coal fired units to natural gas fired steam turbines units

Table C24: Existing Generation Retirements within ATC for the Various Futures for 2026

Unit Name	Maximum Capacity (MW)	Commission Date	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
BHP Copper White Pine Ref. Inc .:GEN1	20	12/1/1955	---	Retired	Retired	Retired	---	Retired
BHP Copper White Pine Ref. Inc .:GEN2	20	12/1/1955	---	Retired	Retired	Retired	---	Retired
Blount:4	21	1/1/1938	Retired	Retired	Retired	Retired	---	Retired
Blount:6[1]	49	6/1/1957	Retired	Retired	Retired	Retired	---	Retired
Blount:7[1]	48	7/1/1961	Retired	Retired	Retired	Retired	---	Retired
Nelson Dewey:1	108		---	---	---	---	---	Retired
Nelson Dewey:2	112		---	---	---	---	---	Retired
Edgewater (WPL):3	71	7/1/1951	---	Retired	---	Retired	---	Retired
Escanaba:STCL2	18	5/1/1958	---	Retired	Retired	Retired	---	Retired
Manitowoc:5	24	1/1/1956	---	Retired	Retired	Retired	---	Retired
Manitowoc:6	30	1/1/1964	---	Retired	Retired	Retired	---	Retired
Oak Creek South:5	262		---	---	---	---	---	Retired
Oak Creek South:6	265		---	---	---	---	---	Retired
Oak Creek South:7	298		---	---	---	---	---	Retired
Presque Isle:3	58	1/1/1964	Retired	Retired	Retired	Retired	---	Retired
Presque Isle:4	58	12/1/1966	Retired	Retired	Retired	Retired	---	Retired
Presque Isle:5	88	12/1/1974	---	Retired	---	Retired	---	---
Pulliam:3	27	1/1/1943	Retired	Retired	Retired	Retired	---	Retired
Pulliam:4	28	8/1/1947	Retired	Retired	Retired	Retired	---	Retired
Pulliam:5	52	9/1/1949	---	Retired	Retired	Retired	---	Retired
Pulliam:6	60	11/1/1951	---	Retired	---	Retired	---	Retired
Pulliam:7	86	11/1/1958	---	Retired	---	Retired	---	Retired
Pulliam:8	134		---	---	---	---	---	Retired
Weston (WPS):1	62	11/1/1954	---	Retired	---	Retired	---	Retired
Weston (WPS):2	87	9/1/1960	---	Retired	---	Retired	---	Retired

[1] Blount Units 6 and 7 were converted from coal fired units to natural gas fired steam turbines units

Fuel Costs

Table C25: Natural Gas and Fuel Oil Price Forecasts (Annual Averages)

Year	Natural Gas ($ per mmBtu)	No. 2 Distillate Oil ($ per mmBtu)	No 2 Residual Oil ($ per mmBtu)
2009	4.22	11.25	7.52
2010	5.81	13.77	8.87
2011	6.59	15.10	9.73
2012	6.81	16.27	10.48
2013	6.97	18.23	11.74
2014	7.13	20.26	13.05
2015	7.30	21.91	14.11
2016	7.46	23.38	15.06
2017	7.62	24.82	15.99
2018	7.77	26.25	16.91
2019	7.92	27.50	17.71
2020	8.06	28.59	18.42
2021	8.21	29.45	18.97
2022	8.44	30.35	19.55
2023	8.42	31.40	20.23
2024	8.63	32.29	20.80
2025	8.75	33.01	21.26
2026	9.09	33.92	21.85

The natural gas prices from January of 2009 to July of 2009 are the averages of the monthly spot market prices as of July 20, 2009. The prices from August of 2009 through the end of 2021 are the annual monthly averages of the NYMEX futures prices. The prices from 2022 through 2026 use the 2021 natural gas price and escalate the price at the nominal natural gas price change assumed in the Energy Information Administration *Annual Energy Outlook 2009* as shown in Table C26.

The No. 2 distillate oil prices from January of 2009 to July of 2009 are the averages of the monthly spot market prices as of July 20, 2009. The prices from August of 2009 through the July of 2012 are the annual monthly averages of the NYMEX futures prices. The prices from August of 2012 through 2026 use the mid-2012 distillate oil price and escalate the price at the nominal distillate fuel oil price change assumed in the Energy Information Administration *Annual Energy Outlook 2009* as shown in Table C26.

The No. 2 residual oil prices from January of 2009 to July of 2009 are the averages of the monthly spot market prices as of July 20, 2009. The prices from August of 2009 through 2026 are based on spread analysis. This is done by using the mid-2009 residual oil price and escalating the price at the nominal residual fuel oil price change assumed in the Energy Information Administration *Annual Energy Outlook 2009* as shown in Table C26.

Table C26: US Energy Price and Inflation Escalation Prices

		Natural Gas			No. 2 Distillate Oil			No. 2 Residual Oil		
Year	Inflation (2)	Real	Nominal	% Change	Real	Nominal	% Change	Real	Nominal	% Change
2006	0.974	6.91	6.73	---	264.27	257.34	---	126.11	122.80	---
2007	1.000	6.96	6.96	3.42%	274.46	274.46	6.65%	140.22	140.22	14.18%
2008	1.022	8.67	8.86	27.30%	353.70	361.48	31.70%	212.23	216.90	54.69%
2009	1.032	4.20	4.33	-51.13%	208.36	215.04	-40.51%	97.36	100.48	-53.67%
2010	1.038	5.11	5.30	22.37%	186.85	193.90	-9.83%	103.51	107.41	6.90%
2011	1.050	5.48	5.75	8.58%	221.09	232.14	19.72%	137.74	144.62	34.63%
2012	1.063	5.60	5.96	3.55%	247.33	262.94	13.27%	162.55	172.81	19.49%
2013	1.082	5.74	6.21	4.26%	275.79	298.44	13.50%	184.95	200.14	15.82%
2014	1.105	5.92	6.54	5.24%	294.89	325.89	9.20%	203.13	224.48	12.16%
2015	1.130	6.16	6.96	6.54%	309.49	349.66	7.29%	223.89	252.95	12.68%
2016	1.156	6.38	7.37	5.82%	321.38	371.38	6.21%	235.86	272.55	7.75%
2017	1.182	6.60	7.80	5.89%	333.40	394.15	6.13%	245.79	290.57	6.61%
2018	1.210	6.82	8.26	5.80%	343.44	415.62	5.45%	255.82	309.59	6.55%
2019	1.239	7.12	8.82	6.78%	349.54	433.07	4.20%	259.97	322.09	4.04%
2020	1.270	7.47	9.49	7.66%	353.97	449.48	3.79%	263.30	334.34	3.80%
2021	1.302	7.72	10.06	5.95%	353.25	459.98	2.34%	267.17	347.89	4.05%
2022	1.335	7.74	10.34	2.81%	357.29	477.06	3.71%	268.12	358.00	2.91%
2023	1.367	7.55	10.32	-0.19%	360.10	492.32	3.20%	270.07	369.23	3.14%
2024	1.398	7.56	10.57	2.47%	361.07	504.78	2.53%	271.13	379.06	2.66%
2025	1.428	7.51	10.72	1.39%	360.59	514.79	1.98%	267.38	381.72	0.70%
2026	1.457	7.64	11.14	3.91%	365.26	532.32	3.41%	270.16	393.72	3.14%
2027	1.488	7.92	11.78	5.76%	364.00	541.46	1.72%	274.43	408.21	3.68%
2028	1.519	8.29	12.59	6.87%	370.29	562.44	3.88%	279.22	424.11	3.89%
2029	1.551	8.54	13.24	5.18%	379.89	589.04	4.73%	281.98	437.22	3.09%
2030	1.583	8.83	13.97	5.46%	380.17	601.65	2.14%	287.22	454.55	3.96%

Source: Energy prices are from US Energy Information Administration *Annual Energy Outlook 2009* Tables 12 and 13.

Note 1: The natural gas, coal, and oil prices represent prices paid to produce electricity and are expressed in dollars per mmBtu.
Note 2: Inflation is measured by the GDP Chain-Type Price Index.

Coal forecasts in the PROMOD model are utilized in two separate manners. Existing coal fired generators included in the model have associated coal costs and forecasts which are plant specific and are provided by Ventyx. New expansion coal fired generators identified by the MISO EGEAS analysis utilize generic fuel forecasts. These forecasts are developed regionally within MISO to account for price variations that would exist due to coal sources and transportation costs within the MISO East, Central, and West regions. Table C27 details the coal price forecasts utilized for the 2020 and 2020 PROMOD models.

Table C27: Coal Price by MISO Regions for New Expansion Generators

Year	MISO East ($ per mmBtu)	MISO Central ($ per mmBtu)	MISO West ($ per mmBtu)
2009	1.53	1.25	0.95
2010	1.86	1.51	1.14
2011	2.22	1.81	1.37
2012	2.28	1.85	1.40
2013	2.33	1.89	1.43
2014	2.37	1.93	1.46
2015	2.42	1.97	1.49
2016	2.47	2.01	1.52
2017	2.52	2.04	1.55
2018	2.57	2.08	1.58
2019	2.62	2.13	1.61
2020	2.67	2.17	1.64
2021	2.72	2.21	1.67
2022	2.77	2.25	1.70
2023	2.83	2.30	1.74
2024	2.88	2.34	1.77
2025	2.94	2.39	1.81
2026	3.00	2.44	1.84
2027	3.06	2.48	1.88
2028	3.12	2.53	1.92
2029	3.18	2.58	1.95
2030	3.24	2.63	1.99

The coal price forecasts are derived from prices and escalations of delivered coal prices contained within the US Energy Information Administration *Annual Energy Outlook 2009*. These values are further detailed in Table C28.

Table C28: US Energy Price – Delivered Prices for Electric Power

	Coal Delivered Prices - Electric Power	
Year	Nominal	% Change
2006	1.69	---
2007	1.78	5.33%
2008	1.97	10.87%
2009	2.05	3.66%
2010	1.93	-5.54%
2011	1.97	1.78%
2012	1.97	0.40%
2013	2.04	3.11%
2014	2.10	3.35%
2015	2.15	2.39%
2016	2.22	2.81%
2017	2.28	2.78%
2018	2.35	3.16%
2019	2.41	2.67%
2020	2.48	3.01%
2021	2.56	2.86%
2022	2.64	3.22%
2023	2.71	2.69%
2024	2.78	2.48%
2025	2.84	2.34%
2026	2.91	2.42%
2027	2.99	2.64%
2028	3.07	2.76%
2029	3.15	2.76%
2030	3.24	2.61%

Source: Energy prices are from US Energy Information Administration *Annual Energy Outlook 2009* Table 15.

Forced Outages

Ventyx provides generator Forced Outage Rates (FORs) for use in PROMOD based on national averages for various plant sizes and types. These averages come from the NERC's Generator Availability Data System (GADS) database. Forced Outage Rate data are "Equivalent FORs" (EFORs) to account for partial outages (derates) as well as full generator outages.

Maintenance

PROMOD automatically schedules generator maintenance outages to maximize reliability (which is done by minimizing the LOLE). The only exception is that Ventyx hard wires nuclear plant maintenance outages in PROMOD. A maintenance outage "blackout" period is defined from Mid-June through August.

Generation additions – Renewable Energy and Renewable Portfolio Standards

Additional generation in the form of wind energy was added to the PROMOD models in an effort to represent renewable portfolio standards in Wisconsin and surrounding states. ATC calculated the necessary amounts of energy required to meet the future year renewable standards for the states of Illinois, Iowa, Minnesota, and Wisconsin in addition to any other MISO states with a current renewable standard. Wind expansion zones as identified in the MISO Regional Generation Outlet Study (RGOS) were utilized for inclusion of the necessary RPS wind energy in the PROMOD model. These units were scaled in accordance the required amounts of energy based on the renewable portfolio standard assumptions for each future as defined in Tables C1 to C5.

Some of the wind units external to ATC were scaled to help meet Wisconsin's renewable portfolio standard and to account for external renewable energy which could be available for import into Wisconsin. Since the required amount of renewable generation for the Wisconsin renewable portfolio standard differed along with the futures, the factor by which these units were scaled also changed. These factors made up the basis of the added wind generation in the 2020 PROMOD model as detailed in Table C29. The expansion wind generation totals as used in the 2026 PROMOD model are detailed in Table C30.

Table C29: 2020 MISO RGOS Wind Additions

	Total Capacity (MW)					
MISO RGOS Wind Zone	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
RGOS AMRN 2	287	0	0	0	0	220
RGOS AMRN 3	287	0	0	0	0	220
RGOS IA-B	287	956	170	840	200	220
RGOS IA-F	287	956	170	840	200	220
RGOS IA-G	287	956	170	840	200	220
RGOS IA-H	287	956	170	840	200	220
RGOS IA-I	287	956	170	840	200	220
RGOS IA-J	366	1,036	249	920	279	299
RGOS IL-B	287	574	0	504	0	220
RGOS IL-C	287	574	0	504	0	220
RGOS IL-D	287	574	0	504	0	220
RGOS IL-E	287	0	0	0	0	220
RGOS IL-F	287	0	0	0	0	220
RGOS IL-G	287	0	0	0	0	220
RGOS IL-J	287	0	0	0	0	220
RGOSI IL-K	0	574	0	504	0	0
RGOS IN-A	287	0	0	0	0	220
RGOS MN-B	287	956	170	840	200	220
RGOS MN-E	287	956	170	840	200	220
RGOS MN-H	359	1,028	241	912	272	291
RGOS MN-K	363	1,032	245	916	276	296
RGOS MN-L	361	1,030	244	914	274	294
RGOS ND-G	287	956	170	840	200	220
RGOS ND-K	287	956	170	840	200	220
RGOS ND-M	287	956	170	840	200	220
RGOS SD-H	287	956	170	840	200	220
RGOS SD-J	287	956	170	840	200	220
RGOS SD-L	287	956	170	840	200	220
RGOS WI-B	405	628	0	316	0	361
RGOS WI-D	387	600	0	302	57	344
RGOS WI-F	384	596	31	300	56	342
Total	**9,231**	**20,676**	**3,216**	**17,519**	**3,817**	**7,287**

Table C30: 2026 MISO RGOS Wind Additions

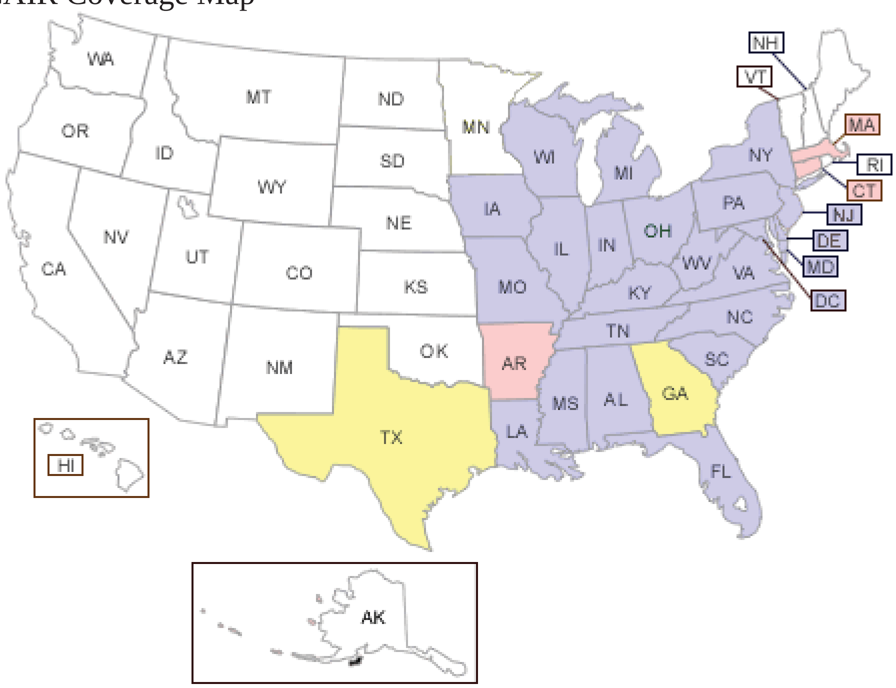
	Total Capacity (MW)					
MISO RGOS Wind Zone	**Robust Economy**	**Green Economy**	**Slow Growth**	**Regional Wind**	**Limited Investment**	**Carbon Constrained**
RGOS AMRN 2	485	0	267	0	321	300
RGOS AMRN 3	485	0	267	0	321	300
RGOS IA-B	485	1,256	267	1,092	321	300
RGOS IA-F	485	1,256	267	1,092	321	300
RGOS IA-G	485	1,256	267	1,092	321	300
RGOS IA-H	485	1,256	267	1,092	321	300
RGOS IA-I	485	1,256	267	1,092	321	300
RGOS IA-J	564	1,336	346	1,172	400	379
RGOS IL-B	485	754	267	655	321	300
RGOS IL-C	485	754	267	655	321	300
RGOS IL-D	485	754	267	655	321	300
RGOS IL-E	485	0	267	0	321	300
RGOS IL-F	485	0	267	0	321	300
RGOS IL-G	485	0	267	0	321	300
RGOS IL-J	485	0	267	0	321	300
RGOSI IL-K	0	754	0	655	0	0
RGOS IN-A	485	0	267	0	321	300
RGOS IN-E	0	677	0	611	0	0
RGOS IN-K	0	677	0	611	0	0
RGOS MI-B	0	737	0	688	0	0
RGOS MI-C	0	737	0	688	0	0
RGOS MI-D	0	737	0	688	0	0
RGOS MI-E	0	737	0	688	0	0
RGOS MI-F	0	737	0	688	0	0
RGOS MI-I	0	737	0	688	0	0
RGOS MN-B	485	1,256	267	1,092	321	300
RGOS MN-E	485	1,256	267	1,092	321	300
RGOS MN-H	556	1,328	338	1,164	392	372
RGOS MN-K	560	1,332	342	1,168	396	376
RGOS MN-L	559	1,330	341	1,166	395	374
RGOS OH-B	0	575	0	519	0	0
RGOS OH-C	0	575	0	519	0	0
RGOS OH-F	0	575	0	519	0	0
RGOS ND-G	485	1,256	267	1,092	321	300
RGOS ND-K	485	1,256	267	1,092	321	300
RGOS ND-M	485	1,256	267	1,092	321	300
RGOS SD-H	485	1,256	267	1,092	321	300
RGOS SD-J	485	1,256	267	1,092	321	300
RGOS SD-L	485	1,256	267	1,092	321	300
RGOS WI-B	510	765	0	361	0	333
RGOS WI-D	487	731	0	345	30	317
RGOS WI-F	484	726	0	342	30	315
Total	**14,869**	**34,392**	**7,505**	**29,444**	**9,022**	**9,375**

Environmental Regulations

The MISO MTEP 09 PowerBase database, as modified by ATC, which served as the Base Case for Badger Coulee analysis included representation of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). In response to court decisions the EPA has modified the CAIR and CAMR rules and regulations and the status of both is subject to change. However, ATC determined that environmental regulations of some form would exist and therefore proceeded to maintain the environmental regulations of generators which were embedded in the MISO MTEP 09 PowerBase model, including allowances and pricing related to CAIR Annual NOx, CAIR SO_2, Clean Air Act SO_2, CO_2, and Mercury. The following information provides additional details regarding the rules and regulations involved with CAIR and CAMR.

The CAIR program provides a basic framework for states in the CAIR region (see below) to achieve large reductions in SO_2 and NOx emissions utilizing a cap and trade approach beginning in 2009. For the Badger Coulee study, the state of Wisconsin and many of the surrounding states are included in the CAIR region, and the revised SO_2 and NOx restrictions were modeled for this study. In 2008 CAIR was remanded but not vacated by the courts. EPA then attempted to replace it by the Cross State Air Pollution Rule (CSAPR). CSAPR was vacated by the courts in 2012, and rehearing is pending. Thus, current status is that CAIR remains in effect and CSAPR has been vacated. For a detailed overview of the CAIR program, please refer to the EPA's website at http://www.epa.gov/cair/rule.html.

Figure C4: CAIR Coverage Map[17]



The CAMR rule proposed to permanently cap and reduce mercury emissions from coal-fired boilers in the U.S. CAMR was vacated by the courts in 2008. In 2012 EPA issued a new rule on

[17] Clean Air Interstate Rule Coverage Map (http://www.epa.gov/cair/where.html)

Mercury and Air Toxics Standards (MATS) and has partially stayed the rule while it reconsiders it. For a detailed overview of the CAMR rule, please refer to the EPA's website at http://www.epa.gov/camr/.

The EPA provides a snapshot of CAIR for 2010, 2015 and 2020, and a snapshot for CAMR for 2010 and 2020. These snapshots call for unit retrofits over these periods in order to meet the regulations outlined by the EPA.

In order to achieve these mandates, the retrofits on units are staggered prior to these dates in order to meet the prescribed regulations. The 2010 retrofits are placed in 2008 and 2009, the 2015 retrofits are placed in 2013 and 2014, and the 2020 retrofits are placed in 2016 and 2017. This allows the emissions control technology to be phased in, as opposed to having a dramatic effect at a single point in time.

Some units in the EPA studies have multiple emissions control technologies. For example, some units may get an SCR in 2010 and a scrubber in 2015. The emissions release rates will reflect this change through time. The emissions data through time will reflect the combined emission rate with all technology in service. In addition to adding all of the emission control technology, the heat rate and maximum capacities, as well as the variable and fixed operating and maintenance costs, are adjusted to account for the emissions changes.

Transmission

Transmission Models for 2020 and 2026

The transmission model used for this analysis was obtained from MISO. The 2020 and 2026 models are based on the 2019 MISO Transmission Expansion Plan model created by MISO as a part of its MTEP 09 analysis process. Updates to these models consisted of applying the MRO series model project list dated July 2009 to each model and adding in generation or transmission as described in the various scenarios and sensitivities. The major transmission projects in the 2020 and 2026 models are described below. Generation was dispatched according to control area merit order dispatch and load levels were set based on LSE forecasts.

Table C31: Major Changes in both the 2020 and 2026 Powerflow Models – 345-kV Projects

Gardner Park - Highway 22 345-kV	Werner West - Highway 22 345-kV
Highway 22 - Morgan 345-kV Project	Arpin - Rocky Run 345-kV rebuild
Paddock - Rockdale 345-kV Project	Point Beach - Sheboygan 345-kV uprate
Rockdale - West Middleton (Cardinal) 345-kV	Pleasant Prairie – Zion Energy Center 345-kV

Table C32: Major Changes in both the 2020 and 2026 Powerflow Models – 115-kV, 138-kV and 161-kV Projects

Lakota Road - Twin Lakes - Aspen - Plains 138-kV	Clintonville - Werner West 138-kV
Kansas - Norwich 138-kV looping Project	Whitcomb - Caroline 115-kV Rebuild
Gardner Park - Blackbrook 115-kV uprate	Oak Creek - Ramsey 138-kV uprate
Oak Creek - Allerton 138-kV uprate	North Madison - Huiskamp 138-kV
North Lake Substation	Rock River - Elkhorn 69 to 138-kV conversion
Badger - Clintonville 138-kV rebuild	Jefferson - Tyranena - Stony Brook 138-kV
Badger - West Shawano 138-kV rebuild	East Shawano - White Clay 138-kV rebuild
Oakridge - Verona 138-kV	Nicholson - Oak Creek 138-kV uprate
Root River - Oak Creek 138-kV rebuild	Kansas - Oak Creek 138-kV uprate
Bain - Kenosha 138-kV uprate	Canal - Dunn Road 138-kV
Council Creek - Petenwell uprate	Monroe County - Council Creek 161-kV and 69-kV rebuild

Table C33: Major Changes in both the 2020 and 2026 Powerflow Models – 69-kV Projects

Crivitz - High Falls 69-kV rebuild	Glenview - Shoto 69-kV uprate
Cornell - Chandler 69-kV uprate	Chandler - Lakehead - Masonville 69-kV uprate
Masonville - Gladstone – North Bluff 69-kV uprate	North Lake Geneva - Lake Geneva 69-kV uprate
Pine River 69-kV Ring Bus	Verona - Oregon 69-kV rebuild
DPC Hillsboro - Dayton rebuild	Walworth - North Lake Geneva 69-kV uprate
Royster - Femrite 69-kV uprate	McCue - Milton Lawns 69-kV uprate
Blount - Ruskin 69-kV underground project	Brodhead - South Monroe 69-kV rebuild
Gran Grae - Boscobel 69-kV uprate	Sheepskin - Dana 69-kV uprate
Metomen - Ripon - Mackford Prairie 69-kV	

Table C34: Major Changes in both the 2020 and 2026 Powerflow Models – Transformer Projects

Menominee 138/69-kV	West Marinette 138/69-kV
Oak Creek 345/138-kV	Metomen 138/69-kV
Verona 138/69-kV	2nd Kewaunee 345/138-kV
Bass Creek 138/69-kV	Metomen 138/69-kV

Table E35: Major Changes in both the 2020 and 2026 Powerflow Models – Generation Projects

Elm Road Generator Unit 1 Online	Elm Road Generator Unit 2 Online
Marshfield CT (G588) Online	

Table C36: Major Changes in both the 2020 and 2026 Powerflow Models – T-D Projects

Raymond T-D Project	Sauk City Phillps T-D Project
Norway T-D Project	Big Bay T-D Project
Oakridge T-D Project	Voss Road T-D Project
Maplewood T-D Project	7th St T-D Project
Sprecher T-D Project	Vienna T-D Project
Montana T-D Project	Sun Valley T-D Project
Fairwater T-D Project	Mazomanie West T-D Project
Warren T-D Project	Schofield T-D Project
Greenleaf T-D Project	SBU T-D Project
Beloit Gateway T-D Project	Powersbluff T-D Project
Richmond T-D Project	Nelson Dewey T-D Project
Arnett Road T-D Project	Iron Mountain T-D Project
MGE NE Cross Plains T-D Project	Southwest Verona T-D Project
Hanson T-D Project	River T-D Project

System topology used in this study reflects projects identified at the time of study. Since that time, some projects have changed status.

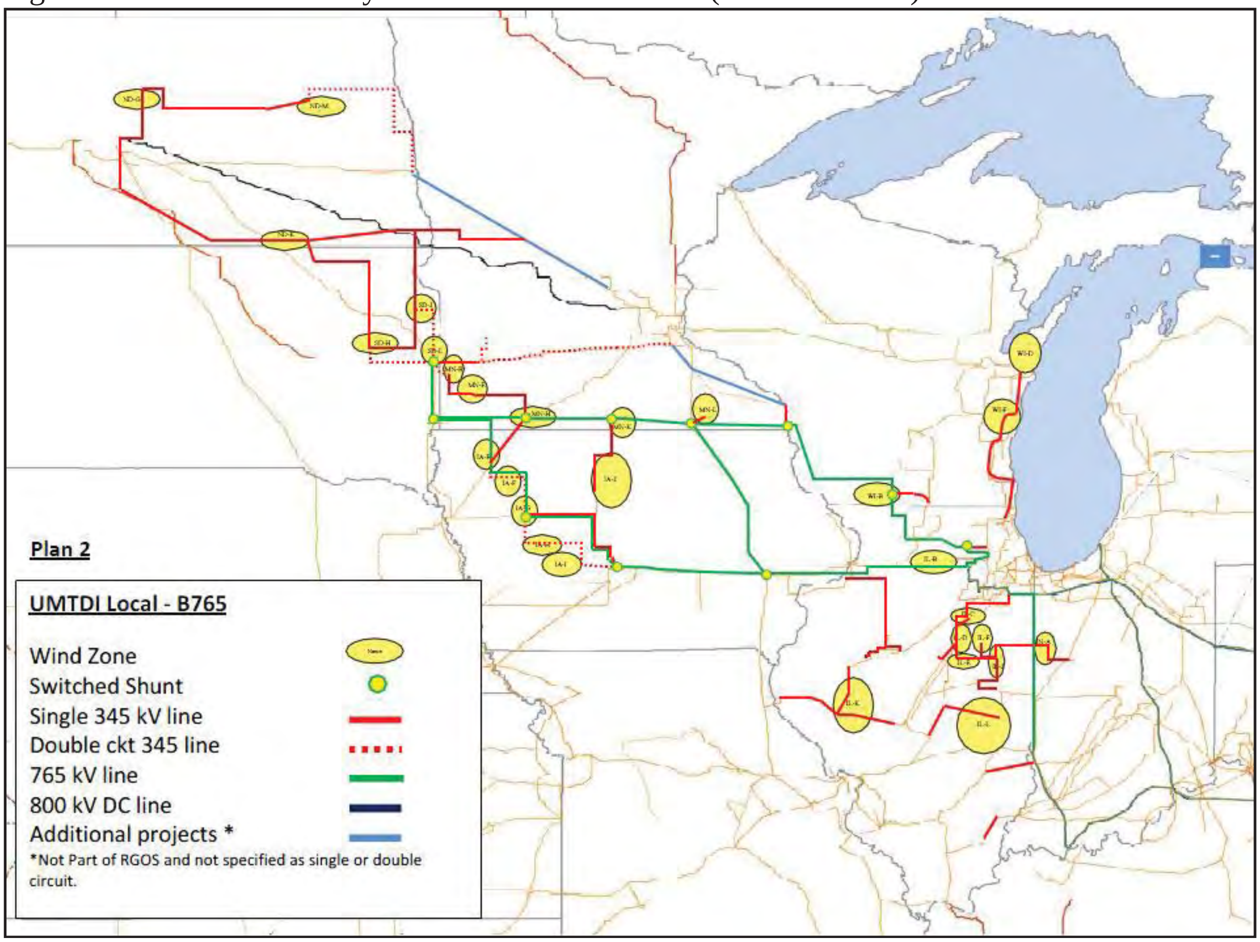
Transmission additions outside ATC – MISO RGOS and CapX 2020

In an effort to capture the actions of various MISO initiatives and regional stakeholder activities, the MISO Regional Generation Outlet Study transmission projects were included in the PROMOD models for the 2020 and 2026 study years. The RGOS transmission overlays consist of various plans utilizing combinations of 345-kV, 765-kV, and High Voltage DC transmission lines to move generation (primarily wind) from western sources to eastern loads. Additional information about the RGOS study and results can be found in the RGOS Phase I Executive Summary Report (December 2009) and the Regional Generation Outlet Study (November 2010). Below are additional details with regard to the ATC futures which specify the transmission overlays utilized in each.

Robust Economy (2020 and 2026)

The Robust Economy future utilized the RGOS Phase I 765-kV UMTDI Local transmission overlay plan for both the 2020 and 2026 study years.

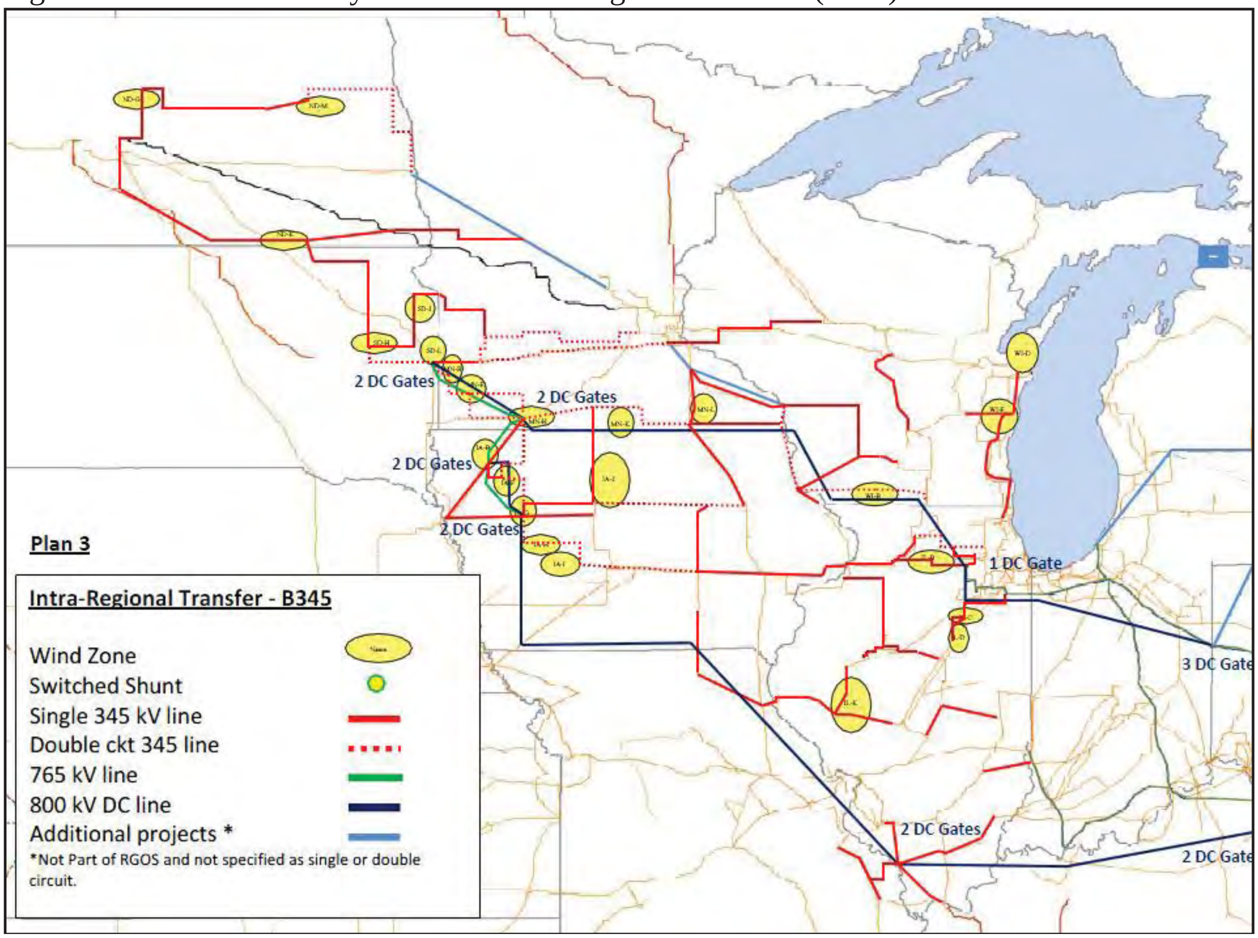
Figure C5: Robust Economy – 765-kV UMTDI Local (2020 and 2026)



Green Economy (2020)

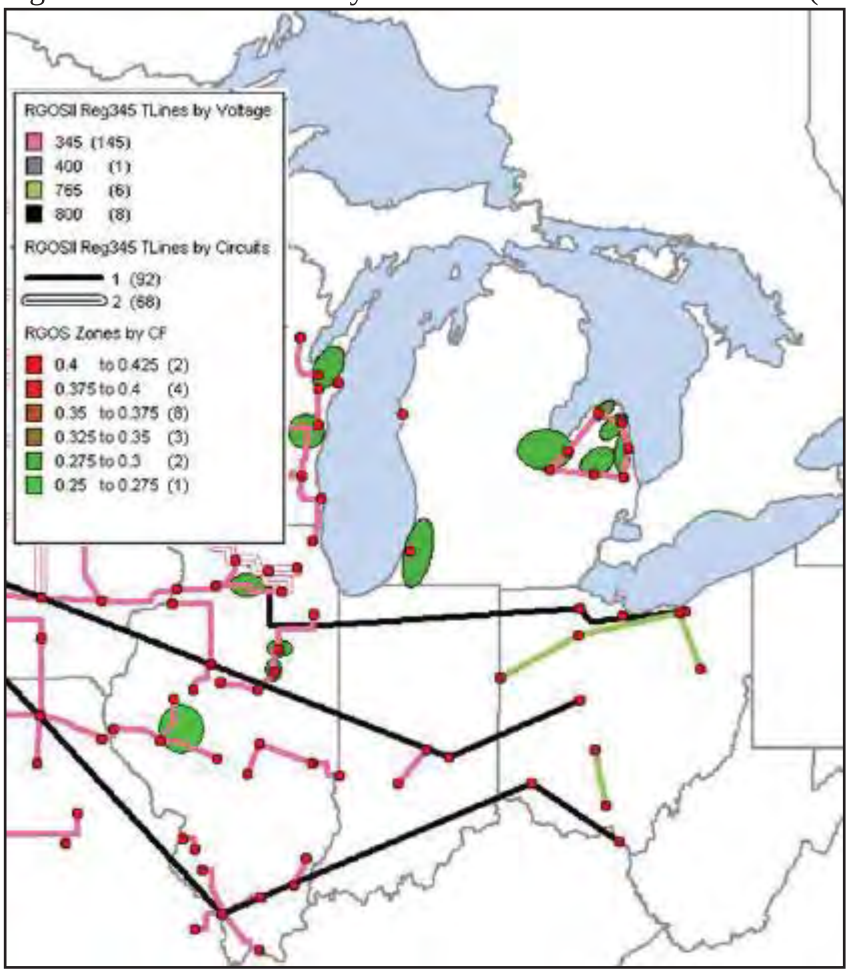
The Green Economy future utilized the RGOS Phase I 345-kV Intra-Regional Transfer transmission overlay plan for the 2020 study year.

Figure C6: Green Economy – 345-kV Intra-Regional Transfer (2020)



Green Economy (2026)
In addition to the transmission overlay identified in Figure C6, the 2026 Green Economy future utilized additional transmission infrastructure in eastern MISO as depicted in Figure C7.

Figure C7: Green Economy – Eastern MISO RGOS additions (2026)



Slow Growth (2020 and 2026)
The lower growth rates and resulting lower wind and generation penetration levels in the Slow Growth future drive a decreased need for significant transmission infrastructure additions in the region. As such, the only major transmission project additions included in the 2020 and 2026 Slow Growth analysis consist are the CapX 2020 Group I projects.

This project group includes approximately 600 miles of 345-kV lines which connect across Minnesota, North Dakota, South Dakota, and Wisconsin along with a smaller 230-kV line in the Bemidji, Minnesota area. These projects are defined as follows:

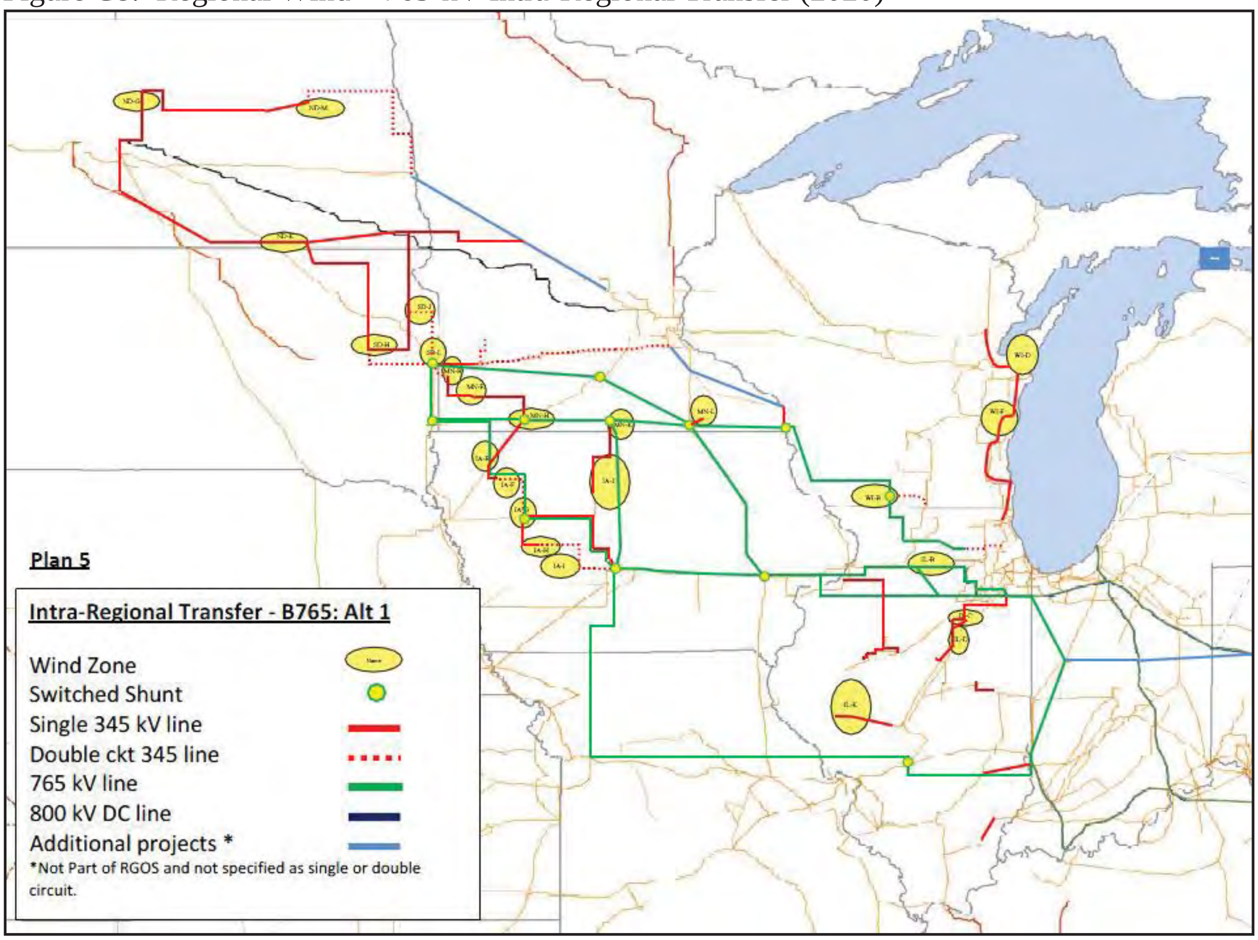
Table C37: CapX 2020 Project Group I Definitions

Project Description	Primary Voltage	Approximate Mileage	Targeted In-Service Year
Bemidji - Grand Rapids	230-kV	70	2011 - 2012
Fargo - St. Cloud	345-kV	210	2013 - 2015
Monticell - St. Cloud	345-kV	28	2011
Brookings County - Hampton	345-kV	240	2013 - 2015
Hampton - Rochester - La Crosse	345-kV	125	2013 - 2015

Regional Wind (2020)

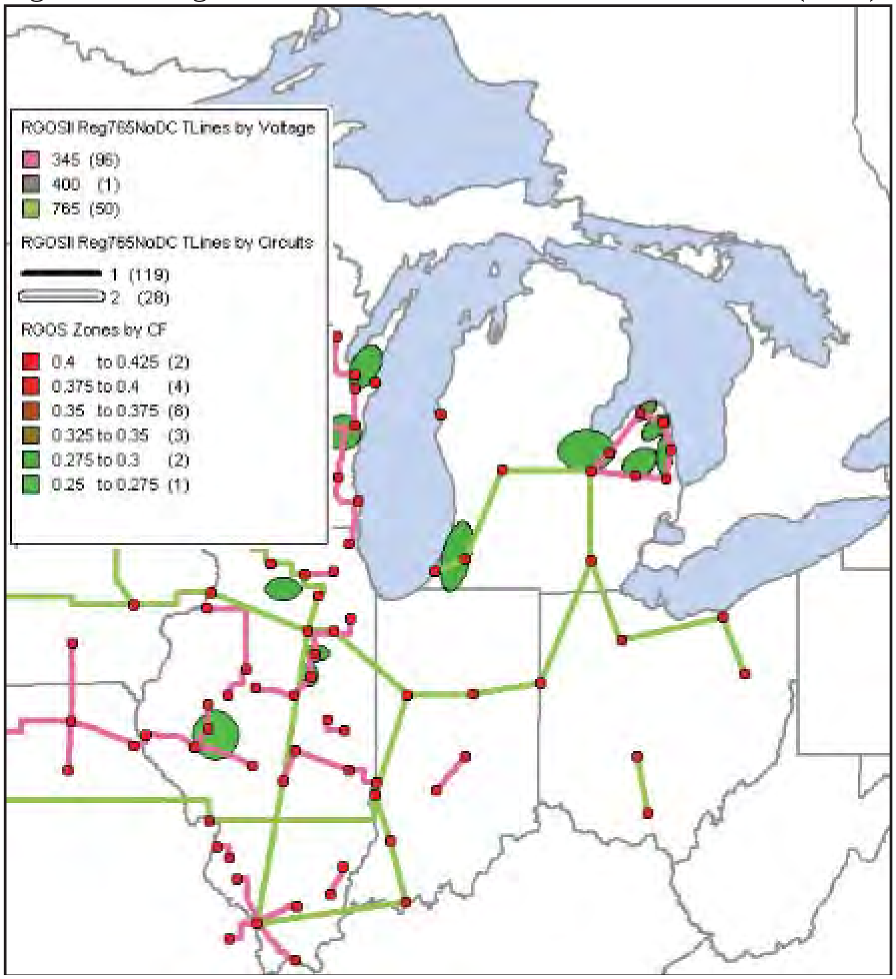
The Regional Wind future utilized the RGOS Phase I 765-kV Intra-Regional Transfer transmission overlay plan for the 2020 study year.

Figure C8: Regional Wind – 765-kV Intra-Regional Transfer (2020)



Regional Wind (2026)
In addition to the transmission overlay identified in Figure C8, the 2026 Regional Wind future utilized additional transmission infrastructure in eastern MISO as depicted in Figure C9.

Figure C9: Regional Wind – Eastern MISO RGOS additions (2026)



Limited Investment (2020 and 2026)

The moderate growth rates and resulting moderate wind and generation penetration levels in the Limited Investment future drive a decreased need for significant transmission infrastructure additions in the region. As such, the only major transmission project additions included in the 2020 and 2026 Limited Investment analysis consist are the CapX 2020 Group I projects.

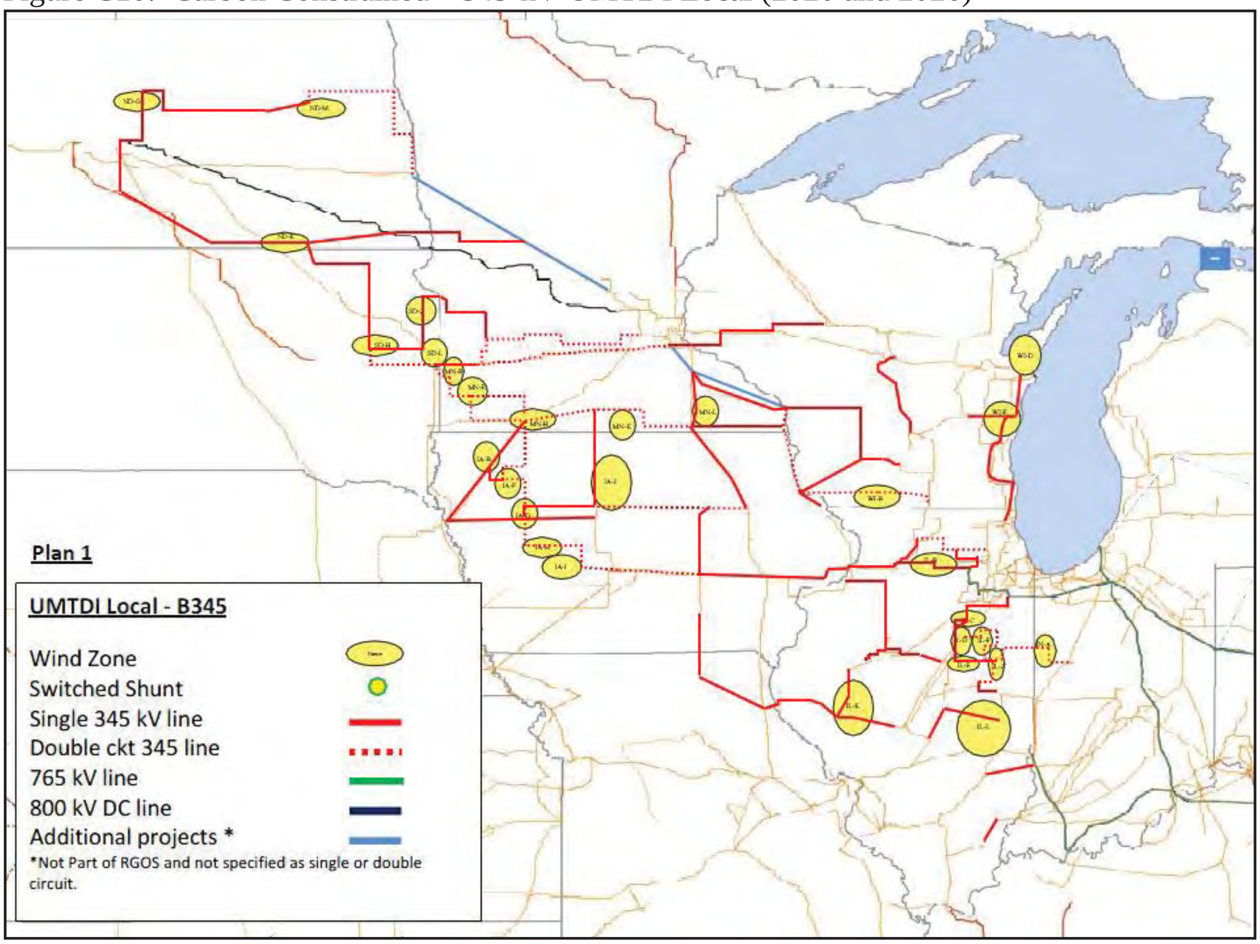
This project group includes approximately 600 miles of 345-kV lines which connect across Minnesota, North Dakota, South Dakota, and Wisconsin along with a smaller 230-kV line in the Bemidji, Minnesota area. These projects are defined as follows:

Table C38: CapX 2020 Project Group I Definitions

Project Description	Primary Voltage	Approximate Mileage	Targeted In-Service Year
Bemidji - Grand Rapids	230-kV	70	2011 - 2012
Fargo - St. Cloud	345-kV	210	2013 - 2015
Monticell - St. Cloud	345-kV	28	2011
Brookings County - Hampton	345-kV	240	2013 - 2015
Hampton - Rochester - La Crosse	345-kV	125	2013 - 2015

Carbon Constrained (2020 and 2026)
The Carbon Constrained future utilized the RGOS Phase I 345-kV UMTDI Local transmission overlay plan for both 2020 and 2026 study years.

Figure C10: Carbon Constrained – 345-kV UMTDI Local (2020 and 2026)



Transmission Constraints — Initial list and Updates

The constraints used in PROMOD cover the entire PROMOD study area, which includes transmission in the MISO and PJM systems. The constraints used in this analysis were originally supplied by the MISO as used in the MISO PROMOD studies for MTEP 09. These constraints were then augmented for the ATC 2020 and 2026 Futures with additional flowgates based on historical system constraints, projected future constraints from other studies and projected constraints based on analysis of a sampling of various hours simulated by PROMOD throughout the year.

D. Economic Analysis - PROMOD Analysis Methodology

General Description

PROMOD is a security constrained economic dispatch computer simulation program.[18] The program simulates both the electric generation and transmission systems. It determines the least-cost generation dispatch over a large area for every hour while simultaneously respecting all known transmission constraints (flowgates). This is the same approach that Locational Marginal Price (LMP) markets, like the MISO and PJM markets, use to dispatch generation. In short, PROMOD simulates LMP markets. As a result, PROMOD can be used to help evaluate the cost-effectiveness of transmission projects, like Badger Coulee, in a market environment.

For the Badger Coulee analysis, all of the transmission and generation within MISO and PJM were simulated in PROMOD (the combination of these areas will subsequently be referred to as the “PROMOD footprint”). Due to the large amount of information being processed, a one year PROMOD simulation typically takes about 24-48 hours.

The first step in the economic analysis of a new transmission project is to update the PROMOD input data to create a “reference” case (i.e. a case without the new project). This update includes all known transmission and generation changes for the study year including new and upgraded transmission lines, new and retired power plants, etc. This is followed by a one year reference case PROMOD run. The output from this run, including costs and key generator and transmission system characteristics, is reviewed for reasonableness for the study year. A new project, like Badger Coulee, is then added to PROMOD and the simulation is rerun. The corresponding PROMOD output from the “project” case is again reviewed for reasonableness.

The cost difference between the reference and project cases is then calculated to help determine the economic benefits associated with adding the project. Calculating the benefits, by using the cost differential, tends to reduce the impact of any inaccuracies in forecasts and input data because all of the inputs are identical except for the addition of the new project.

PROMOD utilizes a complete DC load flow model with impedance information for all elements of the transmission system. The model accounts for transmission losses and costs by determining how each generator impacts transmission losses and calculating a corresponding “dispatch penalty factor”. This factor is then included when PROMOD does its least-cost generation dispatch. For example, if a particular generator increases losses on the transmission system, PROMOD applies a higher dispatch penalty factor causing the generator to dispatch less relative to a plant that reduces overall transmission losses.[19]

A new transmission project may also reduce overall transmission system losses and as a result reduce the cost to serve load. To precisely capture this effect requires analysis of PROMOD output data to determine the change in energy losses on the system and the project’s impact on reduced system energy losses.

[18] PROMOD was developed by Ventyx, a subsidiary of ABB.
[19] The peak load data in PROMOD for each control area includes transmission losses, which is appropriate if the “single pass” technique for calculating losses is used in the model. This is MISO’s standard technique for accounting for the impact of losses on generation dispatch.

PROMOD uses generator operating costs rather than bid costs to dispatch generation.[20] As a result, PROMOD does not capture the impact of bidding behavior on costs and the ability of some new transmission lines to enhance competition. This is part of the reason why additional analyses need to be done to fully capture the benefits of new transmission facilities.

The PROMOD model requires a large amount of input data for the transmission and generation systems. The following discusses the sources of this information in general terms and how related information is developed, such as flowgates for new transmission topology. It also discusses in more detail the various steps involved in PROMOD economic analyses and some of the key study parameters.

Transmission System Data

Transmission system data, including ratings and impedances, come from a NERC Multiregional Modeling Working Group (MMWG) case in PSS/E RAW data format. An updated version of this case from MISO or Ventyx is often used. To ensure that the most current ATC system is modeled, ATC strips out its own transmission topology from the PSS/E case and replaces it with the latest footprint from ATC's 10-Year Assessment for the specific study year.

Transmission Constraints-Flowgates

The flowgate list (referred to as the "Event file" in PROMOD) typically starts with data supplied by MISO. However, the MISO flowgate list normally only reflects current transmission system topology and needs to be updated to reflect the transmission topology and ratings for future study years. The Event file must be manually updated to account for these topology and rating changes using data from the PSS/E RAW file.

The PROMOD Analysis Tool (PAT)[21] is used to help define any additional needed flowgates for a future study year. The PAT is used to do a contingency analysis for a select series of hours throughout the year that represent different peak load and "market" generator dispatch patterns. Varying generator dispatch patterns throughout the year change transmission flow patterns, which may require the addition of new flowgates to prevent transmission system overloads.

PAT's "Contingency Evaluator Tool" sequentially outages all transmission elements (e.g. line and transformers) to determine if any other transmission elements overload due to the outage. Contingency analyses must be done to meet NERC requirements that the transmission system be operated and planned to withstand the worst contingency without causing any overloads. The outaged element is referred to as the "contingency". If another element tends to overload under contingency it is referred to as the "limiting element". The most critical limiting element-contingency pairs found using PAT are translated into flowgates for inclusion in the Event file. For future study years, both new generation and transmission may change flow patterns on the transmission system and require that new flowgates be added to prevent overloads (particularly under contingency).

[20] Technically, in the MISO market, generators submit "offers" and Load-Serving Entities (LSEs) submit "bids".
[21] A companion tool to PROMOD used for detailed evaluation of hourly output from PROMOD.

Generator Input Data

Most of the generator input data is contained within PowerBase, which is the database provided for use with PROMOD. PowerBase contains generator data, such as summer and winter capacities, heat rates, forced outage rates, etc. which comes from Ventyx. They in turn get most of their data from the Platts database[22] and public information sources, like the EPA's Continuous Emission Monitoring System and NERC's GADS databases. Planned future generation is added to PROMOD as described in the following section.

Reserve Margins

For future study years, sufficient new generation needs to be included in PROMOD to meet applicable long term planning reserve margins. Minimum planning reserve requirements are set based on the assumption that other reliability regions will have generation reserves to help during a generation emergency. Emergencies can occur when, for example, a large plant breaks down and insufficient generation is available to replace it locally. In this case the system is designed to rely on neighboring reliability regions to make up the shortfall at least until additional generation can be brought on locally. Being able to rely on generation from neighboring reliability regions lowers the overall costs for everyone because each region can build less generation and still meet its NERC reliability requirements.[23] Please see the PROMOD Study Assumptions for more details about the methodology for adding new generation and the amount that was needed to meet the planning reserve margins.

Fuel Cost Forecasts

Ventyx gets plant-specific fuel forecasts for coal-fired units from the Platts database. Please see the PROMOD Study Assumptions for details about how the fuel forecasts for natural gas and fuel oil were developed.

Generator Forced Outage Rates

Ventyx provides generator Forced Outage Rates (FORs) in PowerBase based on national averages for various plant sizes and types. These averages come from the NERC's GADS database. Forced Outage Rate data included in PowerBase are "Equivalent FORs" (EFORs) to account for partial as well as full generator outages.

PROMOD Analysis Methodology

For major projects, like Badger Coulee, an iterative process is used to help determine the full project benefits in addition to assuring a properly constrained system within the PROMOD model. PROMOD is run and the most significant PROMOD transmission constraints are identified. If applicable, an appropriate transmission solution is developed to address the most significant constraint (that ATC has the ability to fix) and the analysis is rerun with the solution

[22] Formerly the Resource Data International (RDI) database.
[23] Minimum planning reserve margin requirements are typically based on a Loss of Load Expectation (LOLE) requirement, which is normally loss of load of no more than one day in ten years on the bulk power system.

implemented to determine the next most significant constraint.[24] In addition, the PROMOD cases are reviewed to determine if additional constraints are necessary in the event file. This process is repeated until it is apparent that resolving the next constraint is not cost-effective based on the PROMOD analysis (i.e. additional transmission projects are only added if sufficient additional production cost savings are obtained to cover the cost of fixing the constraint). The "project" includes the primary project, like Badger Coulee, plus any smaller cost-effective "fixes" identified as part of the iterative process. For Badger Coulee, no additional purely economic "fixes" were identified or utilized. The lower voltage "fixes" associated with the implementation of Badger Coulee and subsequently included in the PROMOD analysis were previously identified as a part of the Western Wisconsin Transmission Reliability Study.

Number of Draws

Because of their complexity, power plants are periodically forced out of service at various times. To simulate these breakdowns, PROMOD develops a random outage pattern for each generator based on each plant's EFOR. Different outage patterns (known as "draws") will result in somewhat different annual costs from PROMOD. A single draw is used for all PROMOD run combinations that are being compared to ensure that any cost difference is not the result of different generator outage patterns.

Scheduled Generator Maintenance

PROMOD automatically schedules generator maintenance outages to maximize reliability (which is done by minimizing the LOLE). The only exception is that Ventyx hard wires nuclear plant maintenance outages in PROMOD. A maintenance outage "blackout" period is defined from mid-June through August. A single maintenance outage schedule is used for all PROMOD run combinations that are being compared to ensure that any cost difference is not the result of different scheduled maintenance patterns.

PROMOD Benchmarking/Tuning

Both MISO and ATC have found that PROMOD tends to underestimate LMPs relative to the MISO market. Adjustments can be made to help "tune" PROMOD so that its output better mimics actual market prices. ATC has performed several PROMOD analyses in an effort to tune the model. In its tuning runs, ATC reduced the total coal-fired capacity on all coal-fired units included in the PROMOD model. This was done by reducing the capacities of each unit by the same percentage level on a monthly basis. This tuning percentage is in addition to any seasonal derates already included in the model.

ATC's tuning efforts have shown that coal derates in the range of 5% to 8% seem to be appropriate for greater alignment between PROMOD modeled LMPs and actual market LMPs. As such, ATC utilized a 6% coal derate for the Badger Coulee analysis. This value falls within

[24] Constraints are ranked for relief primarily based on their shadow price, but also to some degree on the number of hours they are constraining. Both of these are outputs from PROMOD. The shadow price is the production cost that could be saved if the constraint could be relieved by 1 MW.

the range of past tuning efforts and provides appropriate coal unit dispatch which more closely matches real world operating conditions.

E. Economic Analysis - Detailed Description of the "Drivers" for the Futures and Corresponding Matrices

Peak Demand and Energy Growth Assumptions

The peak demand and energy growth assumptions used in the PROMOD analysis were developed based on a comprehensive review of historical growth in both US energy and peak load, which suggests that Load Factors have been relatively stable.

In Table E1, the average growth of peak demand over the period 1990 to 2008 was 2.0 percent per year, while the annual growth in Total Sales over the same time period was 1.7 percent. While the growth in Peak and Total Sales were not exactly identical, the two growth rates were similar enough to produce a relatively flat Load factor, which was 60.3 percent in 1990 to 59.0 percent in 2008.

Table E1: US Peak, Energy and Load Factor Data

Year	Non-coincident Summer Peak (MW)	Total Sales (GWh)	Annual Peak Growth (%)	Annual Energy Growth (%)	Load Factor (%)
1990	546,331	2,728,690	---	---	60.3
1991	551,418	2,775,727	0.92	1.69	60.9
1992	548,707	2,776,978	-0.49	0.05	61.2
1993	575,356	2,880,572	4.63	3.60	61.0
1994	585,320	2,954,199	1.70	2.49	61.2
1995	620,249	3,032,458	5.63	2.58	59.8
1996	616,790	3,118,713	-0.56	2.77	62.0
1997	637,677	3,172,731	3.28	1.70	60.4
1998	660,293	3,277,887	3.43	3.21	59.9
1999	682,122	3,326,309	3.20	1.46	58.9
2000	678,413	3,436,243	-0.55	3.20	61.2
2001	687,812	3,410,931	1.37	-0.74	59.8
2002	714,565	3,481,262	3.74	2.02	59.8
2003	709,375	3,517,709	-0.73	1.04	59.7
2004	704,459	3,570,377	-0.70	1.48	61.5
2005	758,876	3,680,760	7.17	3.00	58.7
2006	789,475	3,694,190	3.88	0.36	56.6
2007	782,227	3,784,705	-0.93	2.39	58.6
2008	789,915	3,745,645	0.97	-1.04	59.0

Source: Peak and Load Factor data are from Table 2.1 and Total Sales data are from Table 6.1 EEI Statistical Yearbook

Total Sales are defined as Sales to Ultimate Customers plus Sales for Resale (Requirements and Non-Requirements Customers).

A similar analysis was done for ATC. In Table E2, the average growth of coincident peak demand over the period 2001 to 2009 was -0.5 percent per year, while the annual growth in Total Sales over the same time period was 0.4 percent, which resulted in a relatively variable Load factor (58.6 percent in 2001 to 61.0 percent in 2009.)

Table E2: ATC Peak, Energy and Load Factor Data

Year	Coincident Summer Peak (MW)	Total Sales (GWh)	Annual Peak Growth (%)	Annual Energy Growth (%)	Load Factor (%)
2001	12,216	62,692	---	---	58.6
2002	12,287	67,558	0.58	7.20	62.8
2003	12,708	66,333	3.31	-1.85	59.6
2004	11,570	65,046	-9.84	-1.98	64.0
2005	12,568	68,847	7.94	5.52	62.5
2006	13,059	67,661	3.76	-1.75	59.1
2007	12,660	69,459	-3.15	2.59	62.6
2008	11,794	68,162	-7.34	-1.90	65.8
2009	11,868	63,414	0.62	-7.49	61.0

Source: Coincident summer peak and Total Sales data are from ATC's 2001-2009 Annual Reports

Load Growth within ATC (MW and MWh)

To determine a forward-looking estimate for energy, a five-year moving average of the geometric mean for ATC energy was used. As Table E3 illustrates, the expected growth in energy for the ATC footprint is 1.9 percent, which was rounded to 2 percent.

Table E3: Forward-Looking Estimates for ATC Energy Growth

Year	Total Sales (GWh)	Annual Energy Growth (%)	5-Year Moving Average Standard Deviation	5-Year Moving Average Geometric Mean
2001	62,692	---	---	---
2002	67,558	7.20	---	---
2003	66,333	-1.85	---	---
2004	65,046	-1.98	---	---
2005	68,847	5.52	---	---
2006	67,661	-1.75	0.0454	1.0135
2007	69,459	2.59	0.0340	1.0046
2008	68,162	-1.90	0.0341	1.0045
2009	63,414	-7.49	0.0495	0.9929

Geometric Mean of the data	0 percent
Standard Deviation	5 percent
Lower Bound based on two standard deviations	-10 percent
Upper Bound based on two standard deviations	10 percent

Given the wide range of energy growth and based on feedback from ATC customers, it was determined that a more reasonable range would be 0.1 percent for the lower bound and 2.2 percent for the upper bound.

Load Growth outside ATC (MW and MWh)

As Table E4 illustrates, the neighboring states have a fairly high variability of annual growth rates (both high and low) in comparison to Wisconsin. It was, therefore, determined that the energy and peak demand growth rates used for ATC would also exhibit some variability as compared to external areas.

Table E4: Sales to Ultimate Customers for Total Electric Industry (GWhrs)

State	2000	2001	2002	2003	2004	2005	2006[1]	2007	2008	2001 - 2008 Annual Growth
Wisconsin	65,146	65,178	66,999	67,242	67,953	70,336	---	71,301	70,008	1.0%
Michigan	105,019	102,403	107,311	108,878	106,585	110,445	---	109,297	105,683	0.5%
Illinois	128,017	136,034	137,666	135,975	139,232	144,986	---	146,055	144,755	0.9%
Indiana	97,775	97,734	101,429	100,468	102,049	106,549	---	109,420	106,502	1.2%
Minnesota	59,782	60,224	62,162	63,087	63,323	66,019	---	68,231	67,630	1.7%
Iowa	39,088	39,216	40,898	41,207	40,888	42,757	---	45,270	44,768	1.9%

[1] EEI data for 2006 was not available at the time of study

Source: Tables 6.5 and 6.6 from the EEI Statistical Yearbook

Low-Cost Generation within ATC

A significant driver in evaluating the economic benefits of transmission projects that increase import capability into a congested area is the amount of low-cost generating capacity within the area. Approximately 1,300 MW of coal-fired capacity has been approved by the PSCW and is under construction or in-service, including Elm Road units 1 and 2. Elm Road 1 and 2 are thus included in all futures. Please see Tables C7 through C11 in previous sections for precise lists of which generator units were added or retired in the 2020 and 2026 cases.

Retirement of some smaller, older and less efficient coal-fired units within the ATC footprint is also included in some of the futures. Generation owners may choose to retire some older smaller coal-fired units rather than add costly pollution control equipment to meet the requirements of new and existing environmental regulations.

Renewable Energy in ATC and Wisconsin

To account for the additional renewable energy needed to meet the Wisconsin renewable energy percentage, it was necessary to first calculate the existing amount of renewable energy within the ATC footprint. Calculation of the renewable energy needs consists of two primary variables. Renewable energy needs under the Renewable Portfolio Standard are based on total energy sales within the ATC footprint. Incremental needs above and beyond existing and planned renewable generation were determined by multiplying the RPS percentage requirements against the total energy for each given future and each study year. This energy level was subsequently calculated against the capacity factors of the RGOS expansion units within Wisconsin to determine the total renewable energy needs for the ATC footprint. These numbers were used as a basis for determining the additional renewable resources that would be needed from both internal and sources external to the ATC footprint in order to meet the Wisconsin renewable portfolio standard. Table E5 shows a breakdown of the sources of renewable energy (inside/outside Wisconsin) that were necessary based on the previously calculated existing renewable generation:

Table E5: 2020 and 2026 ATC Renewable Source Percentages

Future	Inside ATC Renewable %	Outside ATC Renewable %
Robust Economy (20% Renewable Energy)	49.0%	51.0%
Green Economy (25% Renewable Energy)	50.0%	50.0%
Slow Growth (10% Renewable Energy)	74.0%	26.0%
Regional Wind (20% Renewable Energy)	48.5%	51.5%
Limited Investment (10% Renewable Energy)	72.0%	28.0%
Carbon Constrained (25% Renewable Energy)	49.6%	50.4%

CapX 2020 and RGOS Transmission

The CapX 2020 Group I projects as detailed previously were all added as a part of the 2020 and 2026 futures. Four of the futures (Robust Economy, Green Economy, Regional Wind, and Carbon Constrained) utilized MISO RGOS transmission overlays in addition to the CapX 2020 Group I projects. These overlays have been detailed previously in this report.

Natural Gas Price Forecast

Table E6: Natural Gas Prices

Year	US Wellhead Price ($ per 1,000 ft^3)	Annual Price Change (%)
1990	1.71	---
1991	1.64	-4.09%
1992	1.74	6.10%
1993	2.04	17.24%
1994	1.85	-9.31%
1995	1.55	-16.22%
1996	2.17	40.00%
1997	2.32	6.91%
1998	1.96	-15.52%
1999	2.19	11.73%
2000	3.68	68.04%
2001	4.00	8.70%
2002	2.95	-26.25%
2003	4.88	65.42%
2004	5.46	11.89%
2005	7.33	34.25%
2006	6.39	-12.82%
2007	6.25	-2.19%
2008	7.97	27.52%
2009	3.67	-53.95%

Source: Energy Information Administration Natural Gas Navigator

Geometric Mean of the price data	4 percent
Standard Deviation	30 percent
Lower Bound based on two standard deviations	-60 percent
Upper Bound based on two standard deviations	60 percent

Price volatility in 2009 led to a significant increase in volatility of the standard deviation calculations utilized to determine price bounds for natural gas. Utilization of data through 2008 limits this volatility and decreases the bounds.

Lower Bound based on two standard deviations (through 2008)	-45 percent
Upper Bound based on two standard deviations (through 2009)	50 percent

Coal Price Forecast

Table E7: Coal Prices

Year	Average Open Market Mine Price ($ per short ton)	Annual Price Change (%)
1990	21.76	---
1991	21.49	-1.24%
1992	21.03	-2.14%
1993	19.85	-5.61%
1994	19.41	-2.22%
1995	18.83	-2.99%
1996	18.50	-1.75%
1997	18.14	-1.95%
1998	17.67	-2.59%
1999	16.63	-5.89%
2000	16.78	0.90%
2001	17.38	3.58%
2002	17.98	3.45%
2003	17.85	-0.72%
2004	19.93	11.65%
2005	23.59	18.36%
2006	25.16	6.66%
2007	26.20	4.13%
2008	31.25	19.27%
2009	32.92	5.34%

Source: Energy Information Administration Coal Delivered Prices

Geometric Mean of the price data	2 percent
Standard Deviation	7 percent
Lower Bound based on two standard deviations	-10 percent
Upper Bound based on two standard deviations	20 percent

Environmental Regulations Driving Generation Portfolios outside ATC

Environmental regulation bounds were based upon proposed EPA rules under the Clean Air Act(CAIR and CAMR, or similar). The “upper” bound for levels of CO_2 regulation was originally set using information from MISO. The $44/ton CO_2 tax in 2020 and $50/ton CO_2 in 2026 were vetted with ATC Stakeholders through ATC’s Order 890 analysis process.

Generation Portfolios outside ATC

Generation portfolios for areas outside of ATC including MISO, non-MISO MRO and Commonwealth Edison were developed as described previously under the section titled "Generation additions outside ATC – MISO, non-MISO MRO & CE." As explained in that section, ATC worked to determine how many megawatts of generation were necessary throughout the MISO, non-MISO MRO, and Commonwealth Edison regions along with the optimal mix of generation types needed to attain the generation levels described below. This optimal mix was developed by analyzing the mix of generation that existed in the base MISO model and carrying that mix forward as an assumption for how the expansion generation needs would vary by generation type.

The generation capacity needs as calculated by ATC were based on the load growth rates and corresponding generation levels which vary across the futures. As such, calculations were done to adjust the necessary megawatt levels of generation both by type and regional location to meet the reserve margin requirements of the regions (based on the different forecasted load levels assumed in each future). From this point, generating units from the MISO EGEAS expansion set were placed into the model to match what the calculations indicated was needed for adequate generation in both MISO, non-MISO MRO, and Commonwealth Edison.

Table E8 shows the total megawatts of non-renewable generation which was added outside of the ATC footprint (as further detailed previously).

Table E8: 2020 and 2026 Non-Renewable Additions

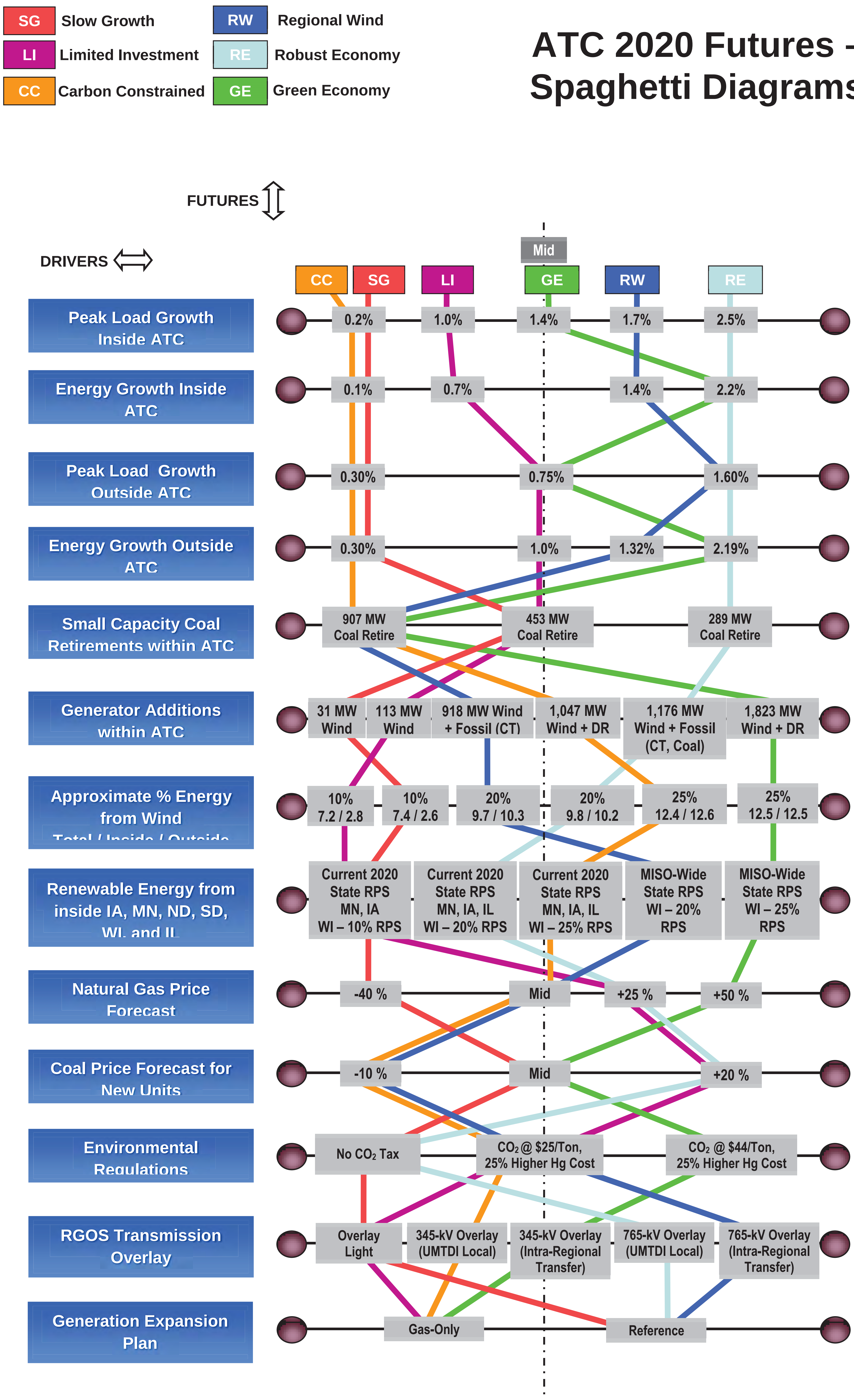
	Non-Renewable Generation Portfolios Outside ATC	
Future	**2020 Total Additions**	**2026 Total Additions**
Robust Economy	25,200 MW	41,400 MW
Green Economy	10,200 MW	17,400 MW
Slow Growth	4,800 MW	6,600 MW
Regional Wind	25,200 MW	39,600 MW
Limited Investment	10,200 MW	16,200 MW
Carbon Constrained	4,800 MW	15,600 MW

Futures Matrices

(The Futures Matrices which appear on the following pages are graphic representations of the information in the Planning Analysis)

The “spaghetti diagrams” as depicted on the following pages are utilized as a visual aid in the development and presentation of the ATC Futures. The diagrams help to visualize the relationship between the various drivers defined in the Futures Matrix. In addition, these diagrams help to ensure that the drivers are reasonably distributed throughout the futures and are logically spread based on the definition of each Future.

ATC 2020 Futures – Spaghetti Diagrams



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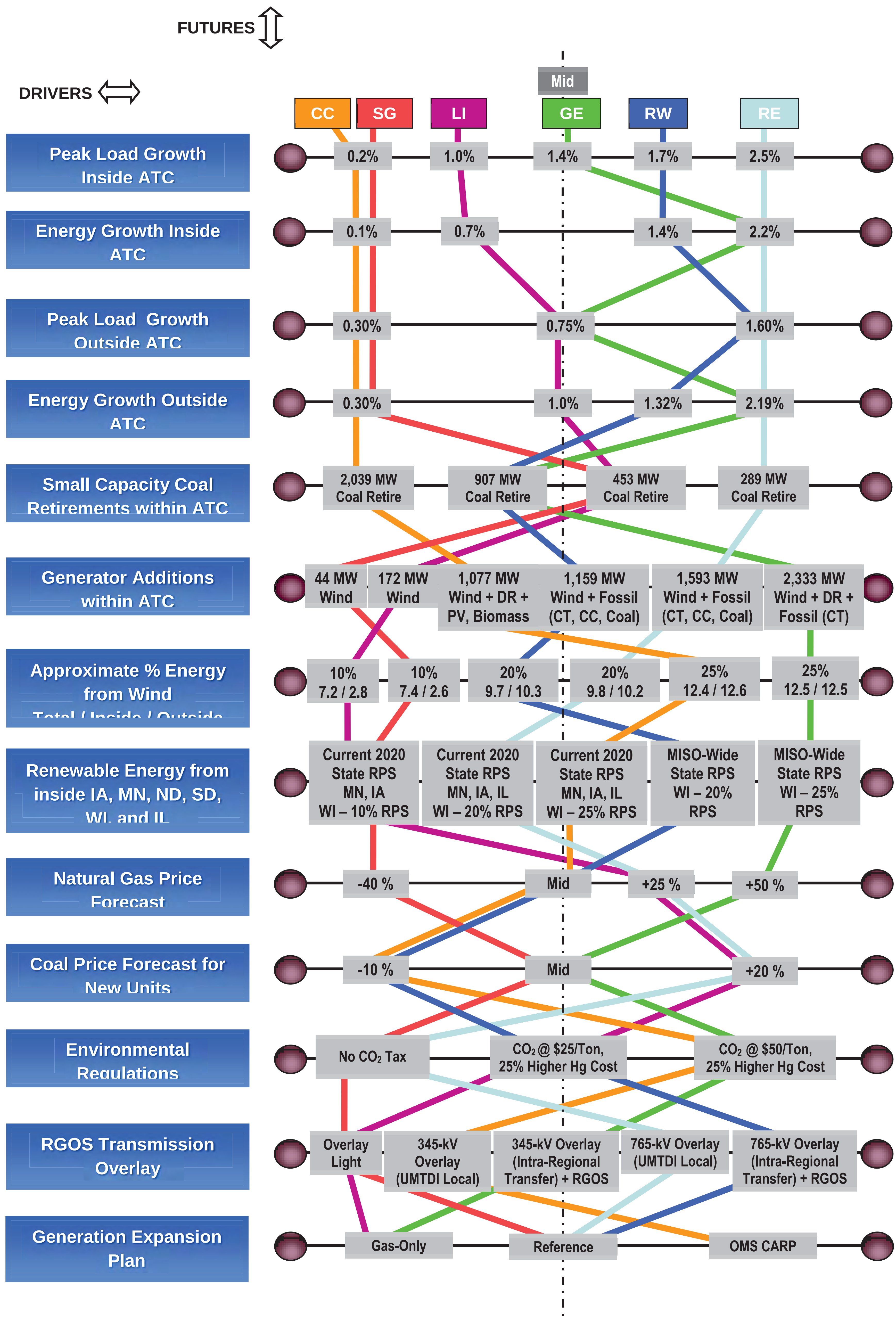
SG Slow Growth
LI Limited Investment
CC Carbon Constrained
RW Regional Wind
RE Robust Economy
GE Green Economy

ATC 2026 Futures – Spaghetti Diagrams



F. Badger Coulee Planning Analysis Sensitivity

MTEP 11 BUSINESS-AS-USUAL LOW FUTURE AS A SENSITIVITY

I. Introduction

ATC has been evaluating transmission alternatives in western Wisconsin (including Badger Coulee) in its Order 890 planning process since 2008. This planning process is part of the FERC-approved MISO Tariff and includes extensive public input, specific deadlines, and a high degree of transparency (Midwest ISO FERC Electric Tariff, Fifth Revised Volume No. 1, Attachment FF-ATCLLC.).

Evaluating transmission alternatives is a complex, lengthy process. It requires development of appropriate methodologies, computer simulations of the transmission system and other engineering and economic analyses of proposed alternatives. Detailed information about how these methods, models, and analyses were developed and applied to Badger Coulee and other projects is provided throughout the Planning Analysis and Planning Analysis Addendum (see especially Planning Analysis, Section 5.0 and Planning Analysis Addenda C, D, and E.

II. Rationale for this Addendum

There is inevitably a lapse of time between the date when the relevant data and models for a planning analysis are selected and the date when the CPCN application for the selected project is presented to the PSCW. While ATC's planning process is continuous, for any particular set of projects it must necessarily cut off its data-gathering and model selection in order to perform the analysis of those projects.

Because of this time lapse, ATC determined that it would be appropriate to perform an additional sensitivity analysis in order to test its previous results. It decided to focus this analysis on one of the key benefits of Badger Coulee, namely, its energy-cost savings for ATC customers.
The main reason for performing such a sensitivity is to test the predictive value of ATC's Strategic Flexibility construct. If the results show that the project yields benefits within the range of the previously established futures, one can be more confident that the original analysis was correct and that the project will provide net benefits across a wide range of likely future conditions. The key point is not whether the project still performs well under *current* conditions, since conditions will vary widely during the long useful life of the project. Rather it is whether the results of the sensitivity fall within the boundaries of the previous analysis and hence increase confidence in that analysis.

III. Selection of the Sensitivity

After considering various options, ATC selected as its sensitivity the Business as Usual (BAU) with Mid-Low Demand and Energy Growth Rates future from the 2011 Midwest ISO Transmission Expansion Plan (MTEP 11)(also known as the MTEP 11 BAU-Low future).

There were two main reasons for this selection. First, as ATC was developing its Planning Analysis based on the MTEP 09 model, MISO was evaluating potential "Candidate Multi-Value Projects" through its RGOS process and developing and securing FERC approval for its MVP tariff (MTEP 11, Section 4.1, p. 42-47). From the beginning, Badger Coulee was among these

MVP projects. All of the MVP projects were thoroughly analyzed by MISO using its MTEP 11 model and included in its MTEP 11 Report approved by the MISO Board in December, 2011 (MTEP, Section 4.1, p. 48-75). Thus it was logical for ATC to select for its sensitivity the same MTEP 11 model that MISO used for its analysis of the MVP portfolio including Badger Coulee. Secondly, the MTEP 11 model obviously uses more recent energy and load levels, forecasts, and regulatory information than the MTEP 2009 model.

IV. The MTEP 11 Business-As-Usual – Low Case

The MTEP 11 future scenarios and model assumptions were developed with extensive stakeholder involvement in accordance with FERC Order 890 (MTEP 11, p. 91). Four futures were developed: BAU-Low, BAU with Historic Demand and Energy Growth Rates, the Carbon Constraint Future, and the Combined Energy Policy Future (MTEP 11, p. 5).

BAU-Low is the most conservative of the MTEP 11 futures. For most reference values it models the regional power system as it exists today. It assumes no change in resource adequacy standards, renewables mandates, or environmental regulation. It also assumes a slow recovery from the current economic downturn and uses modest demand, energy, and inflation rates (MTEP 11, p. 5, 32, 92).

The starting point for the MTEP 11 model is the PROMOD 2016 summer peak power flow case. The BAU-Low database (including all the relevant generator, load, fuel, and environmental information) is then applied to this case.

The effective MISO demand growth rate for the BAU-Low scenario is 0.78% and the energy growth rate 0.79%. These values are derived by adjusting downward the forecasted MISO demand and energy growth rate of 1.26% to reflect increased Demand Response and Energy Efficiency. For the first time in MTEP 11 MISO included such resources in its EGEAS expansion modeling, based on a study by Global Energy Partners (MTEP 11, p. 93; Appendix E2, p. 16, 18).

These growth rates are also consistent with the growth rates reviewed in the PSCW's most recent Strategic Energy Assessment (*Final Strategic Energy Assessment: Energy 2018* (Docket No. 5-ES-106)(November, 2012). In this report the Wisconsin load-serving entities forecast annual load growth of .3% to 1.7% through 2018. and the PSCW noted that the average of these forecasts was consistent with the annual peak demand growth of 1% in the previous Strategic Energy Assessment (*Final SEA: Energy 2018*, p. 3, 9).

In the out years of the study period for the MISO BAU-Low scenario (beyond five years) MISO used the EGEAS model to select only the generation necessary to maintain the balance between load and generation and to meet the Planning Reserve Margin (PRM) target. This additional generation was sited in specific locations based on stakeholder-defined rules and criteria (for example, brownfield sites were preferred over greenfield sites)(Appendix E2, 15, 16).

Other key variables of the BAU-Low future include natural gas and coal costs, discount rates, and capital costs. For all these variables MISO used either its Low or Mid estimates, consistent with the premise of business as usual (see Appendix E2, Tables E2.1 and E2.2, p. 6-9 for details).

V. ATC's Application of the BAU-Low Case to Badger Coulee

ATC performed a PROMOD analysis of Badger Coulee using the MTEP 11 BAU Low database. Two PROMOD cases were developed: one with Badger Coulee and one without Badger Coulee. The sensitivity analysis measured net energy-cost savings as a result of Badger Coulee for ATC customers. It did not measure the savings across the MISO footprint, as does MISO's MTEP 11 analysis of the entire MVP portfolio including Badger Coulee.

In addition, the metric ATC employed in this analysis is its Customer Benefit metric, rather than MISO's Adjusted Production Cost (APC) or LMP measures. While energy-cost savings for ATC customers are largely dependent on the cost of generation supply, they are also affected by factors such as total congestion charges, FTR revenues, loss charges, and loss refunds. The ATC Customer Benefit metric takes into account these factors and calibrates the energy-cost savings to arrive at likely actual savings to ATC customers. The result is a value in between production-cost and LMP savings (Planning Analysis, Section 5.4.7.)

Finally, ATC's sensitivity compares only one of the major benefits of Badger Coulee (net energy-cost savings). It does not analyze other benefits such as insurance value, loss savings, Renewable Investment Benefit, or the avoided cost of necessary reliability projects.
The results of the sensitivity analysis are as follows:

Table F1: Badger Coulee Customer Benefit Savings – MISO MTEP11 BAU - Low

	MTEP 11 BAU-LOW
2021 Savings ($M - 2021)	3.58
2026 Savings ($M - 2026)	4.55
40-Year PV Savings ($M - 2012)	50.35

For comparison purposes the comparable results for the six futures in the Planning Analysis are:

Table F2: Badger Coulee Customer Benefit Savings – ATC Futures

	ATC – RE*	ATC – GE*	ATC – SG*	ATC – RW*	ATC – LI*	ATC – CC*
2020 Savings ($M - 2020)	18.87	9.34	2.61	6.98	7.65	5.75
2026 Savings ($M - 2026)	33.68	28.56	3.33	21.20	13.92	10.65
40-Year PV Savings ($M - 2012)	356.26	285.45	37.09	212.06	146.85	112.10

RE = Robust Economy
GE = Green Economy
SG = Slow Growth
RW = Regional Wind
LI = Limited Investment
CC = Carbon Constraint (Planning Analysis, Table 9, 10, 11)

The results show that the net energy-cost savings of Badger Coulee, in both study years and on a present-value basis, are greater in the MTEP 11 BAU-Low case than they are in the ATC Slow Growth Future. This outcome is consistent with the fact that the MTEP 11 BAU-Low case continues the effects of the current economic downturn while the ATC Slow Growth Future also assumes a sluggish economy inside and outside ATC. Thus, in the most conservative scenarios in both MTEP 11 and the ATC Planning Analysis Badger Coulee demonstrates substantial net energy-cost savings for ATC customers.

G. Badger Coulee – ATC's and NSPW's Wisconsin Customer Net Benefits and Costs

When NSPW became a co-applicant with ATC in seeking authorization to construct Badger Coulee, it was appropriate for ATC to consider whether and how it could calculate the benefits and costs of the project to ATC's and NSPW's Wisconsin customers. ATC's prior planning analysis covered benefits and costs in the ATC MISO pricing zone, formerly known as the Wisconsin-Upper Michigan System (WUMS). This zone includes eastern Wisconsin as well as the Upper Peninsula of Michigan, but does not include western Wisconsin and the areas served by NSPW and other load-serving entities.

Another relevant recent development was the final approval of the MISO MVP tariff and greater clarity from MISO about how the regional cost-sharing in the tariff would be applied to MVP projects like Badger Coulee.

Following these developments ATC consulted with various parties (including Xcel Energy and MISO) and developed a methodology to calculate the benefits and costs of Badger Coulee to ATC's and NSPW's Wisconsin customers.

Total ATC and NSPW Wisconsin costs for the project were determined by the following method:

1. allocating to ATC and Xcel Energy expenditures related to the project elements that they will own;
2. deploying these expenditures through the applicable provisions of the MISO Tariff (including the MVP and network service provisions of the Tariff); and in the case of Xcel Energy any applicable provisions of the state tariff,
3. allocating an appropriate share of ATC's total revenue requirements for the project to the Wisconsin portion of the ATC zone;
4. allocating an appropriate share of Xcel Energy's revenue requirements for the project to NSPW; and
5. deriving a present value for the combined ATC Wisconsin and NSPW revenue requirements associated with Badger Coulee.

Benefits for ATC's Wisconsin customers were developed by applying to the previously developed savings the percentage of ATC's total energy sales in Wisconsin. Wisconsin benefits for NSPW customers were developed by conducting PROMOD analyses of total adjusted production cost and energy loss savings for the Xcel Energy zone for each of the six futures, and then allocating the total savings from such results to NSPW according to the standard allocators applied by Xcel Energy under the Interchange Agreement between NSPW and NSPM.

A Net Present Value of total benefits or costs for ATC's and NSPW's Wisconsin customers was then calculated in 2012 dollars for each of the futures. The results of this supplemental analysis showed that these Wisconsin customers would receive substantial net benefits as a result of Badger Coulee in each of the six futures. The following graph and table provide detailed results of the combined net benefits for Badger Coulee.

Figure G1: Net Project Cost / Benefit for ATC's and NSPW's Wisconsin Customers

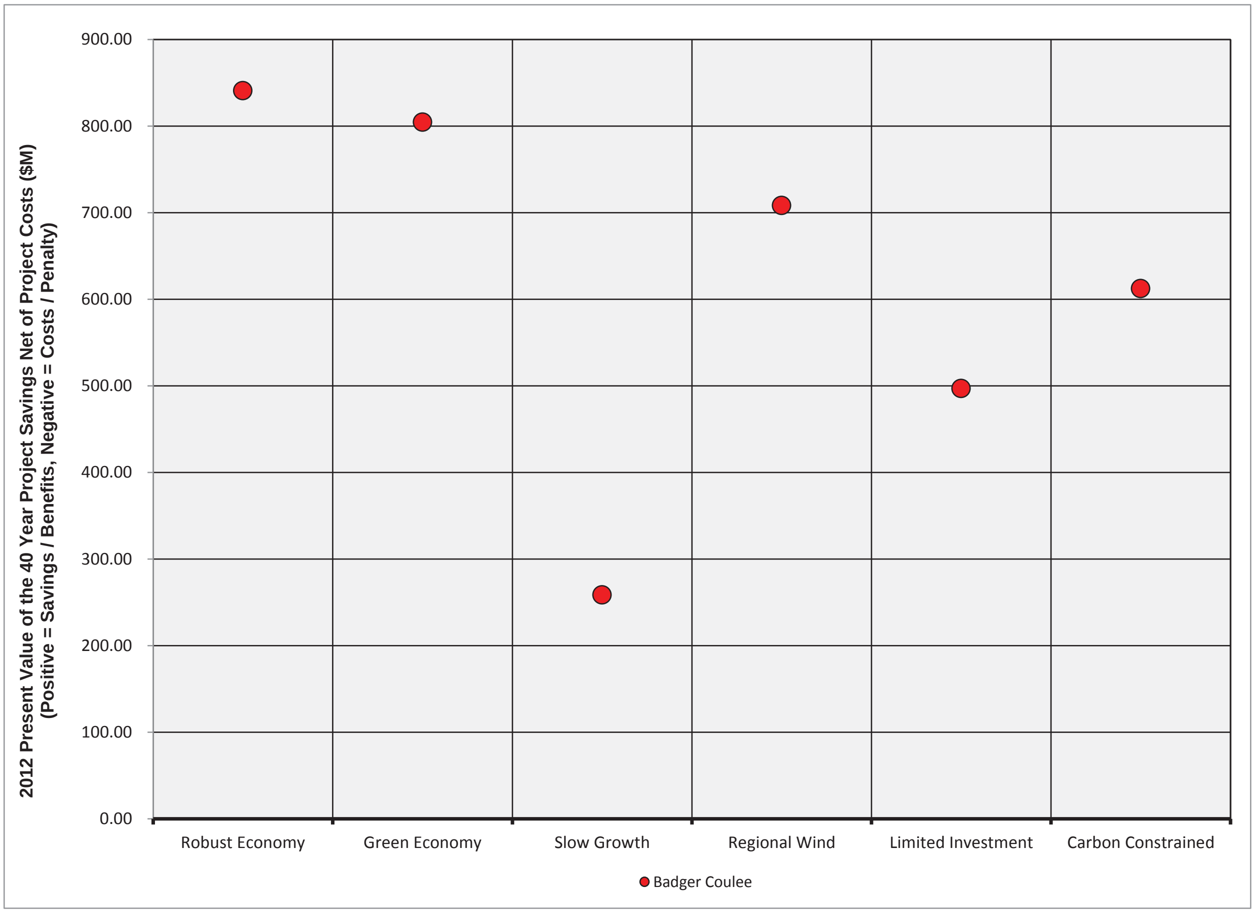


Table G1: Monetized Benefits of Badger Coulee for ATC's and NSPW's Wisconsin Customers

		Badger Coulee
PROJECT COSTS		
Total Project Cost ($M - Nominal)		($550.21)
WI 2012 Present Value of the Revenue Requirement(PVRR2012) -$M		($0.01)
PROJECT BENEFITS		
All Futures		
	Avoided Cost of Potential Projects - <345-kV (PVRR2012)	$135.54
	Insurance Value	$23.57
Robust Economy		
	Energy Benefits (PROMOD)	$336.88
	Loss Savings	$53.87
	RIB	$290.87
	NPV2012 ($M)	**$840.73**
Green Economy		
	Energy Benefits (PROMOD)	$277.48
	Loss Savings	$53.08
	RIB	$314.70
	NPV2012 ($M)	**$804.37**
Slow Growth		
	Energy Benefits (PROMOD)	$35.49
	Loss Savings	$14.38
	RIB	$49.57
	NPV2012 ($M)	**$258.54**
Regional Wind		
	Energy Benefits (PROMOD)	$200.78
	Loss Savings	$29.20
	RIB	$319.12
	NPV2012 ($M)	**$708.21**
Limited Investment		
	Energy Benefits (PROMOD)	$142.10
	Loss Savings	$49.61
	RIB	$146.02
	NPV2012 ($M)	**$496.84**
Carbon Constrained		
	Energy Benefits (PROMOD)	$95.52
	Loss Savings	$31.28
	RIB	$326.48
	NPV2012 ($M)	**$612.38**

ATC also calculated that the year of "first savings" for ATC's and NSPW's Wisconsin customers in which annual benefits first exceed annual revenue requirements is 2018 in all six futures analyzed. The "go ahead" year in which cumulative benefits first exceed cumulative revenue requirements is 2018 in all six futures analyzed.

Further detail regarding this supplemental analysis is provided below.

The steps in calculating the net revenue requirement impacts for the Project are as follows:

1. Develop the cost estimates for each segment of the Project and allocate those costs to the respective owner as shown in the table below:

Table G2: Project Cost Estimates and Ownership Allocations

			[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

2. Calculate the incremental annual revenue requirement for the project prior to any allocation to specific rate schedules. ATC uses Attachment O in the MISO tariff while Xcel Energy uses its Wisconsin state tariff to calculate the incremental impacts. The results of these calculations are shown in column (a) for ATC and (g) for Xcel Energy in the table below. These calculations capture the change in the following revenue requirement component that results from the addition of the project:
   2.1. Return grossed up for the applicable income taxes, based on the annual adjusted rate base as calculated per the applicable tariff.
   2.2. O&M, this includes the maintenance costs on new right of way and new substations.
   2.3. Taxes other than Income Taxes, this includes property taxes, Environmental Impact fees and Gross Receipts taxes as applicable.

3. Calculate the proportionate share of the ATC and Xcel Energy Attachment O revenue requirement to be allocated to the Project under Attachment MM. Attachment MM proportionately allocates all of the expenses and required returns to the MVP projects and is not linked to the incremental costs associated with the Project. This is shown in column (b) for ATC and (h) for Xcel Energy in the table below.

4. Subtract the Attachment MM allocation from the Incremental Annual Revenue Requirement, and in Xcel Energy's case adjust for cost sharing under the Interchange Agreement to calculate the net change in the network revenue requirement as provided in columns (c) for ATC and (i) for Xcel Energy in the table below.

5. Allocate to each rate zone its proportionate share of the Schedule 26A revenue requirement as calculated in step 3 above. The estimated Schedule 26A charges to the ATC zone customers is shown in column (d) and to the NSPW customers in column (k) in the table below.

6. The total net revenue requirement for all rate schedules is the sum of the change in network revenue requirement calculated in step 4 above and the Schedule 26A charges calculated in step 5 above. For the full ATC zone this is shown in column (e) and for the ATC Wisconsin customers it is shown in column (f). The total net revenue requirement for NSPW is shown in column (i) and NSPW's Wisconsin-only customers in column (g) in the table below.

Table G3: Project Total Net Revenue Requirement

[redacted]

H. Wisconsin Energy Efficiency Programs and Impacts

Wisconsin has a long history of promoting energy efficiency, including provision of energy efficiency services and programs managed by utilities and third parties. Statewide energy efficiency programs have been coordinated through the Focus on Energy[25] program since 2001 and are the primary vehicle through which Wisconsin homes and businesses receive energy efficiency services. This section documents the Wisconsin statewide energy efficiency programs and impacts, and assesses the historic and potential future impacts of energy efficiency programs on load growth.

Load management and non-program energy conservation impacts (such as appliance efficiency standards and building codes) are qualitatively addressed, but are not quantitatively evaluated in this section. ATC does not offer load management programs to retail electric customers nor does it have the ability to curtail retail load (except via actions of load-serving entities under emergency conditions). Therefore, future load management impacts are beyond ATC's control. Non-program conservation, such as appliance efficiency standards and building codes, are continually being developed and implemented at the federal, state, and local levels. While particular standards may change in any given year, there has been a long and steady pace toward more efficient appliances, electrical equipment, and building envelopes for several decades. Those impacts are embedded in historic load data and are inherently included in load forecasts.

The impacts of energy efficiency, energy conservation, and load management have reduced historic load growth and are embedded in the historic load data. For this reason, they are also assumed to be included in the load forecasts to the extent that the programs are maintained at roughly the historic levels. Therefore, no specific manual adjustments to the historic data or load forecasts are required to capture these impacts. If future energy efficiency budgets, goals, or impacts are substantially changed from current levels, the incremental impacts of those increases or decreases could be manually added to, or subtracted from, the load forecasts.

I. Wisconsin Focus on Energy Programs

The Focus on Energy (FoE) programs encourage Wisconsin homes and businesses to reduce energy consumption by providing incentives for customers to purchase products and services that are energy efficient or to use renewable energy sources. The electric efficiency programs are designed to reduce the amount of electricity consumed, reduce peak demands, and/or shift electric demand from on-peak periods. The programs, impacts, and spending levels are documented in annual reports and evaluations developed as part of the program, and are publicly available. Detailed information regarding the programs offered, the estimated program impacts, and related information can be found in those reports and are summarized here.

[25] www.focusonenergy.com

A list of programs currently offered by Focus on Energy is summarized in the following table.

Table H1: Focus on Energy Program Offerings (as of May 2013)[26]

Focus on Energy Program Offerings (as of May 2013)	
Residential	**Non-Residential**
Appliance Recycling	Business Incentive
Assisted Home Performance	Chain Stores & Franchises
Express Energy Efficiency	Design Assistance
Home Heating Assistance	Large Energy Users
Home Performance	Retro-commissioning
Multifamily Energy Savings	Small Energy Users
New Homes	Renewable Energy Competitive Incentive
Residential Lighting and Appliance	(to be completed in future years)
Residential Rewards	

In addition to the Focus on Energy programs, Wisconsin utilities with retail customers retain the right to offer energy efficiency or load management programs independently, subject to the approval by the Public Service Commission of Wisconsin. These programs are varied in their target customer segment, objectives, availability, and duration. These programs are supplemental to the Focus on Energy programs, typically have much smaller impacts, and may have limited duration. For these reasons, independently-offered programs available now and in the past are not evaluated in this section.

Wisconsin's electric and gas utilities collectively fund Focus on Energy and recover their contributions from their customers through electric and gas rates. Focus on Energy programs are currently funded through a mechanism that collects 1.2 percent of retail energy revenues in Wisconsin, a funding level roughly equal to utilities' energy efficiency expenditures prior to the establishment of Focus on Energy.

II. Wisconsin Energy Efficiency Impacts

Focus on Energy develops annual reports that document the amount of energy and peak demand savings from the program, both incrementally for the most recent year and on a cumulative basis since the program's inception. For purposes of this evaluation, the energy and peak demand savings represent the "net verified" savings unless otherwise noted. The "net" savings adjusts for impacts not directly attributable to the Focus on Energy program, and reflect the incremental impacts of the programs compared to a no-program scenario. The "net-to-gross" ratios for each measure have been developed independently and are documented in Appendix C of the Focus on Energy 2011 Annual Report.

At the statewide level, a history of the annual Focus on Energy net verified energy and peak demand impacts along with approximate program spending is presented in the following graphs.

[26] Source: Focus on Energy 2012 Evaluation Report, April 2013, p. 2

The funding level was reduced by approximately 50 percent in fiscal years 2003 to 2007, after which it was restored to its previous statutory level. The decreased impact in 2011 is partially attributable to a transition period to a new program administrator, and may not be reflective of future impact levels. The spending and impacts represent the incremental impacts from the program in that year, and are not cumulative across all years of the program.

Figure H1: Focus on Energy Spending and Net Energy Impact

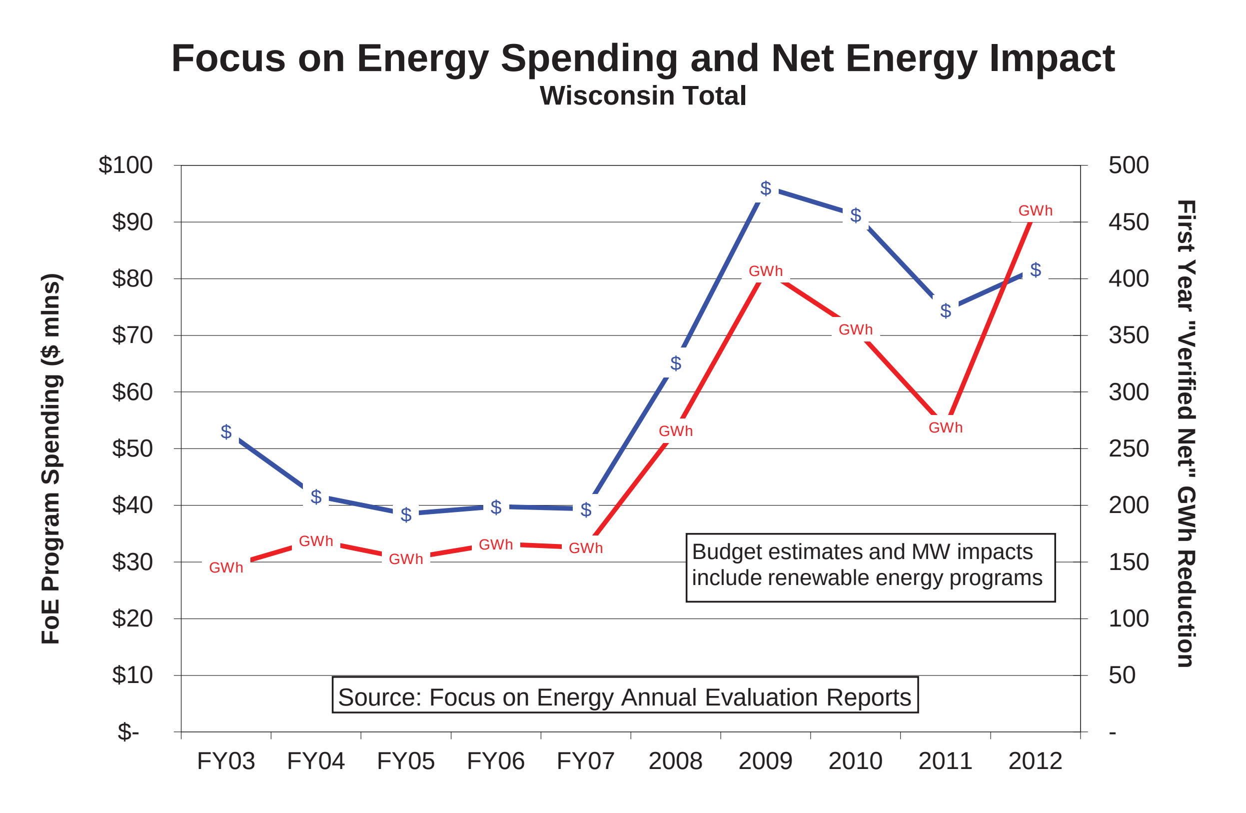
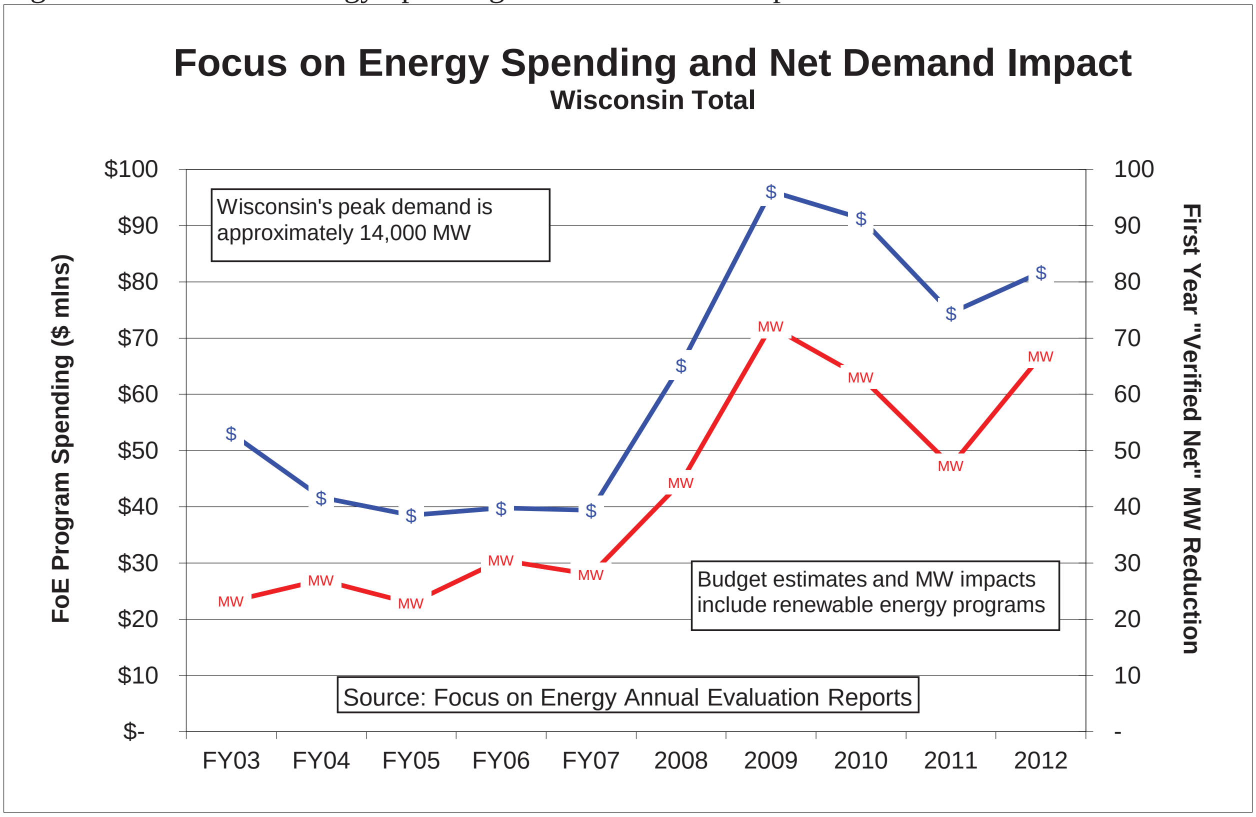


Figure H2: Focus on Energy Spending and Net Demand Impact

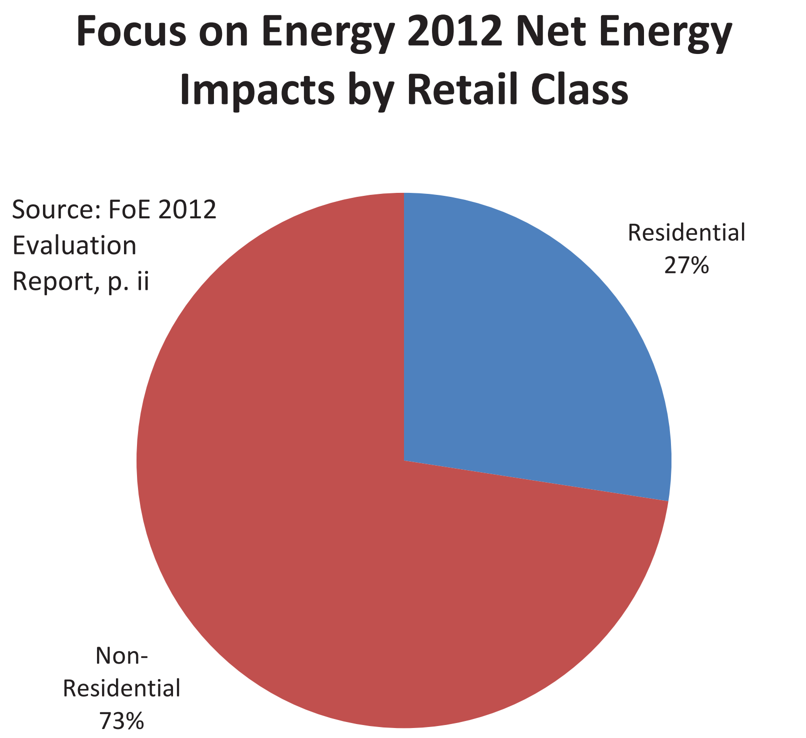


The verified net savings in 2012 of 66.8 MW and 461 GWh represents approximately 0.5 percent of Wisconsin's total electric load.[27] That is, the net impacts of the Focus on Energy programs are decreasing the electricity growth rate in Wisconsin by approximately 0.5 percent compared to what would be expected in the absence of the program. This level of savings is inherently embedded into the historic load data and growth trends at the statewide level. Program spending in 2012 was $81.7 million.

The distribution by retail class of the verified net energy savings from the 2012 Focus on Energy programs is illustrated as follows. Approximately 27 percent of the energy impacts were in the residential class while the remaining 73 percent was in non-residential classes. By comparison, 32 percent of Wisconsin's 2012 retail electric sales were to the residential class. This indicates that the Focus on Energy impacts across retail classes are roughly proportionate to the size of the classes, with a slightly greater share of impacts in the non-residential classes relative to the class size.

[27] As stated in the 2012 Wisconsin Strategic Energy Assessment, Wisconsin's non-coincident peak demand in July 2012 was 15,062 MW (p. 8), influenced by an extremely hot weather pattern. The "net" verified MW savings of 66.8 MW represents 0.44% of 2012 peak demand, while the "gross" verified MW savings of 95.4 MW represents 0.63% of 2012 peak demand.

Figure H3: Focus on Energy 2012 Net Energy Impacts by Retail Class



III. Estimated Future Energy Efficiency Impacts

The Focus on Energy program maintains relatively stable goals and anticipated impacts for 2013 and beyond, compared to 2012. Therefore, future energy efficiency impacts are expected to remain at the 2012 level each year into the foreseeable future, barring substantial changes in funding levels, goals, or program effectiveness. This anticipated level of savings depends on the following key assumptions:

- Energy and peak demand savings will persist at nearly constant levels. Since participation in energy efficiency programs is voluntary, no assurance can be made that electric customers will continue to take advantage of the incentives offered to make energy efficiency investments.
- Stable energy efficiency program budgets will translate to stable energy efficiency impacts. As programs mature, increasing incentives and/or new program offerings and spending may be required to maintain savings levels. At the same time, it is also possible that greater efficiencies or greater awareness associated with mature programs will provide greater future savings for the same program costs.

I. Glossary of Abbreviations

Glossary of Abbreviations

APC: Adjusted production cost(s)
Alliant: Alliant Energy
Alliant-WPL: Alliant Energy-Wisconsin Power & Light
ALTE: Alliant East Control Area
ATC: American Transmission Company
AWEA: American Wind Energy Association
BES: Bulk Electric System
BOD: Board of Directors
BTM: Behind-the-meter
CAIR: Clean Air Interstate Rule
CAISO: California ISO
CAMR: Clean Air Mercury Rule
CPCN: Certificate of Public Convenience and Necessity
COL: Columbia
ComEd: Commonwealth Edison
CVS: Capacity Validation Study
DLC: Direct Load Control
DOJ: Department of Justice (DOJ)
DPC: Dairyland Power Cooperative
ECCH: Expanded Congestion Cost Hedge
EHV: Extra High Voltage
EIA: Energy Information Administration
EMF: Electromagnetic field
ECAR: East Central Area Coordination Agreement
EUE: Expected Unserved Energy
FCITC: First Contingency Incremental Transfer Capability
FERC: Federal Energy Regulatory Commission
FTC: Federal Trade Commission
FTR: Financial Transmission Right
GADS: Generator Availability Data System [used by NERC]
GHG: Greenhouse Gas
GIQ: Generator Interconnection Queue
GRE: Great River Energy
GW: gigawatt
GWh: gigawatt-hour
HHI: Herfindahl-Hirschman Index
IGCC: Integrated Gasification Combined Cycle [coal plant]
IMM: Independent Market Monitor
ITCM: International Transmission Company Midwest
kV: kilovolt
kW: kilowatt
LBA: Local Balancing Authority
LLMP: Load-weighted Locational Marginal Price
LMP: Locational Marginal Price

LOLE: Loss of Load Expectation
LSE: Load-Serving Entity
LV: Low Voltage
MAIN: Mid-American Interconnected Network
MCC: Marginal Congestion Component
MEC: MidAmerican Energy Company
MGE: Madison Gas and Electric; also, Madison Gas and Electric Control Area
MLC: Marginal Loss Component
MISO: Midwest Independent System Operator
MP: Minnesota Power
MPW: Muscatine Power and Water
MTEP: MISO Transmission Expansion Planning
MVP: Multi-Value Project
MW: megawatt
MWh: megawatt-hour
NCA: Narrow Constrained Area
NED: Nelson Dewey
NERC: North American Electric Reliability Corporation
NLAX: North LaCrosse
NPV: Net Present Value
NREL: National Renewable Energy Laboratory
NSPW: Northern States Power of Wisconsin
O&M: Operations and Maintenance
OTP: Otter Tail Power
PAT: PROMOD Analysis Tool
PJM: PJM Interconnection
PRM: Planning Reserve Margin
PSCW: Public Service Commission of Wisconsin
PV: Present Value
RECB: Regional Expansion Criteria and Benefits
RES: Renewable Energy Standard
RGOS: Regional Generation Outlet Study
RIB: Renewable Investment Benefit
ROW: Rights-Of-Way
RPS: Renewable Portfolio Standard
RSI: Residual Supplier Index'
SMMPA: Southern Minnesota Municipal Power Agency
SVC: Static VAR Compensator
TCA: Tabors Caramanis and Associates
TYA: Ten Year Assessment
UMTDI: Upper Midwest Transmission Development Initiative
WE: We Energies
WEC: We Energies Control Area
WPPI: Wisconsin Public Power Inc.
WPS: Wisconsin Public Service Corp.; also, Wisconsin Public Service Control Area
WUMS: Wisconsin Upper Michigan System

WWTRS: Western Wisconsin Transmission Reliability Study
XEL-MN: Xcel-Minnesota
XEL-WI: Xcel-Wisconsin

BADGER COULEE 345 kV TRANSMISSION LINE PROJECT

5-CE-142

NORTHERN STATES POWER COMPANY, A WISCONSIN CORPORATION

NEED STUDY

Prepared by:

Amanda King

September 2013

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1.0 INTRODUCTION AND SUMMARY OF NEED

The La Crosse/Winona area, which has its highest electricity demand during the summer and reached a new coincident peak of 481 MW in 2012, is currently served by area 161 kV and 69 kV lines. The area includes the cities of La Crosse, Onalaska and Holmen, Wisconsin and extends east to include Sparta, Wisconsin; northeast to include Arcadia, Wisconsin; northwest to include the area of Winona/Goodview, Minnesota; and southwest to include La Crescent, Houston, and Caledonia, Minnesota. In recent years, the area has been experiencing population and business growth and associated increased demand for power.

In response to this demand, Northern States Power Company, a Wisconsin corporation ("NSPW"), WPPI Energy and Dairyland Power Cooperative ("DPC") proposed the Hampton-Rochester-La Crosse 345 kV Project ("La Crosse Project"). The Public Service Commission of Wisconsin granted a Certificate of Public Convenience and Necessity ("CPCN") for the La Crosse Project in May 2012. The project, scheduled to be in service in 2015, will provide a strong 345 kV source into a new Briggs Road Substation in the La Crosse area and provide load serving capability until area load reaches 750 MW.

The La Crosse area has reached a new peak each year since 2008, and between the years of 2010 and 2012 total load has grown 3.44%, considerably above the average load growth for the NSP and DPC control areas over the same time period. If load in the La Crosse area continues to grow at this rate, the 750 MW load level is forecasted to be reached as soon as the 2026 timeframe.

To serve load beyond 750 MW, another transmission source into the La Crosse area will be needed. This report documents the deficiency that arises at this load level and demonstrates that the proposed Badger Coulee Transmission Project would provide a second 345 kV high voltage source that will extend the load serving capability of the transmission system in the La Crosse area.

This report will also address transfer capability. Existing transfer limitations between Minnesota and Wisconsin limits delivery of power from west to east and affects system operators' ability in response to a critical contingency or shifts in variable resources such as wind generation. As previously detailed in the Supplemental Need Study submitted in Docket 05-CE-136 as PSC Ref#: 152526, the 345 kV La Crosse Project alone provides approximately 840 MW of transfer capability. With the addition of the Badger Coulee Transmission Project, an additional 360 MW of transfer capability is achieved, bringing the total to approximately 1,200 MW of additional transfer capability.

2.0 LA CROSSE AREA LOAD SERVING ANALYSIS

2.1 Existing Transmission System

The transmission system in Wisconsin is largely comprised of two systems that behave independently and are only minimally connected. The transmission system in western Wisconsin developed principally as the result of planning and coordination between Xcel Energy, Superior Water Light and Power ("SWLP"), and DPC. The transmission system in eastern Wisconsin, owned by American Transmission Company, LLC ("ATC"), developed separately, preliminarily focusing on the Madison and Milwaukee areas and expanding north into the Upper Peninsula of Michigan.

The eastern and western Wisconsin transmission systems have interconnected at only a handful of locations. Specifically, there are two 345 kV connections and one 115 kV connection. As a result, the transmission system in western Wisconsin is currently more closely linked with the transmission system in Minnesota than that in eastern Wisconsin.

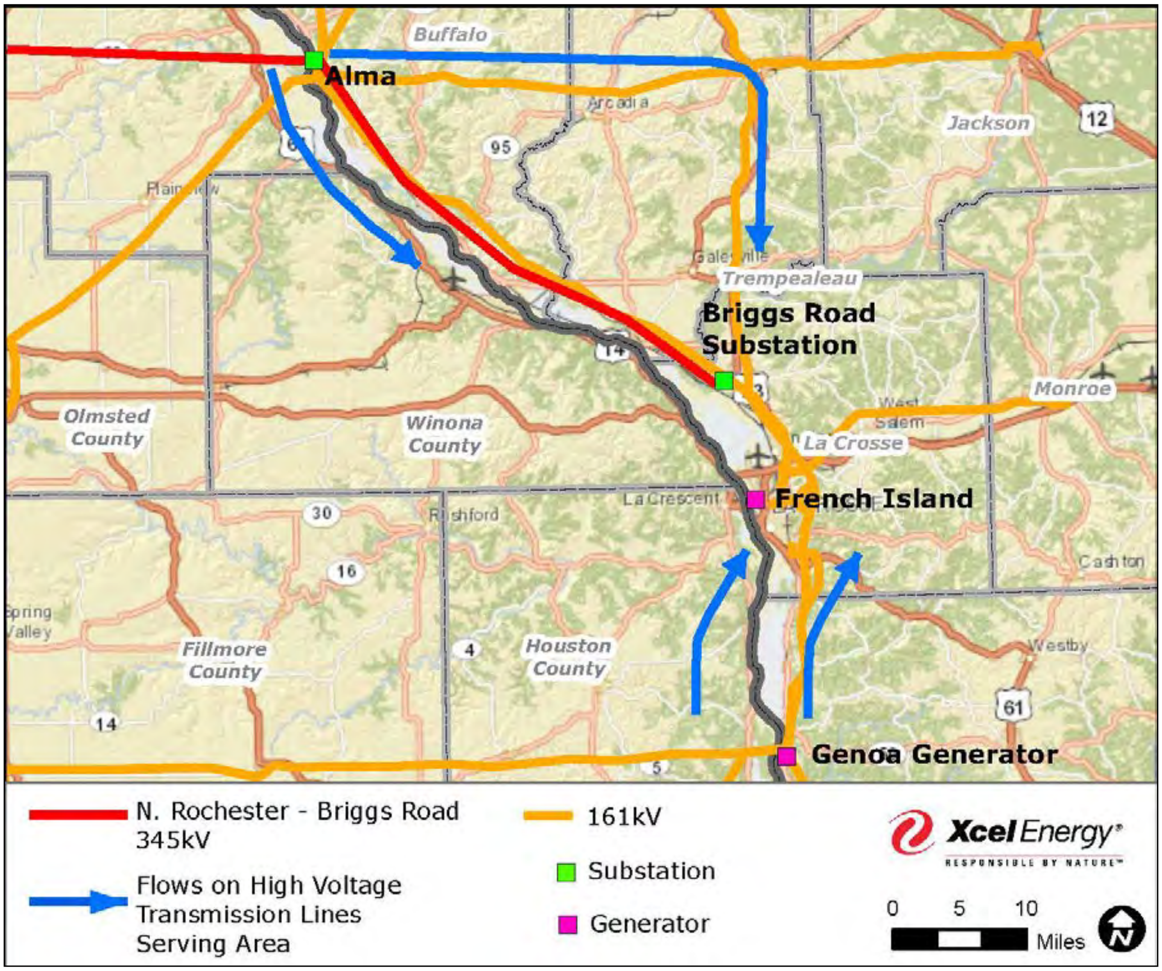
In the La Crosse/Winona areas, NSPW and DPC member distribution cooperatives—Vernon Electric Cooperative, Tri-County Electric Cooperative, Oakdale Electric Cooperative and Riverland Energy Cooperative—provide electric service. Power to the area is delivered by four 161 kV transmission lines:

- Alma–Marshland–La Crosse 161 kV (Dairyland)
- Alma–Tremval–La Crosse 161 kV (Dairyland and Xcel Energy)
- Genoa–Coulee 161 kV (Dairyland)
- Genoa–La Crosse 161 kV (Dairyland)

In 2015, the new 345 kV transmission line between Hampton, Rochester and La Crosse will also be in-service providing additional load serving support.

The 2015 La Crosse area transmission system is shown graphically in Figure 1:

Figure 1: 2015 La Crosse Area Transmission System



2.2 Planning Criteria

Planning engineers are required to meet the needs of the stakeholders in the electric transmission system while adhering to all reliability criteria established and enforced by the North American Electric Reliability Corporation ("NERC"). The criteria are designed to ensure that the transmission system will remain stable, all voltages and thermal loadings of the transmission facilities will be within established limits, there will be no cascading outages, and only planned / controlled loss of demand or transfers will occur. These criteria have been developed over decades and are monitored and changed as deemed necessary to avoid large outages and blackouts. Most often, the criteria are made more rigorous as engineers learn better ways to maintain reliability of the transmission system. The full detail on all NERC Criteria is available at the following location:

http://www.nerc.com/page.php?cid=2%7C20

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2.3 Methodology and Assumptions

Steady State Models

The base models used for the steady-state (power flow) analysis were 2017 summer peak load condition models from the 2012 series of models created by Midwest Reliability Organization ("MRO").

Analytical Software Tools

The program used for this power flow was Power System Simulator for Engineering (PSS/E) Version 32 by Siemens PTI.

2.4 Analysis

Power flow methodology

One of the primary analyses performed as part of this local area load serving study is the amount of load able to be served under first-contingency conditions.

One of the methods used for determining the load level which could be served in the Winona and La Crosse areas was first-contingent incremental transfer capability ("FCITC") analysis into the area. Employing this analysis, the amount of power able to be transferred into an area under contingency before a transmission line or transformer overloads is established. This method can also be used to determine the level of load able to be served before any bus has a voltage violation.

Steady state modeling assumptions

The initial load level studied for the La Crosse area was 491 MW. Analysis was performed while increasing the load. As shown through the La Crosse CPCN proceeding, load can be reliably served in the Winona/La Crosse area after the addition of the La Crosse 345 kV line until the local area load reaches 750 MW. *See* **Appendix 1**. For purposes of this analysis, the La Crosse Project was assumed to be in-service.

As load levels in the area were increased, remote Twin Cities area generation was increased to serve the additional load. For simulation of the loss of Genoa generation or John P. Madgett generation, generation remote from the study area was increased to offset the generation loss.

All of this work was completed with a peak-load case; the transfers in the base case were not changed for the study work. The Midwest Reliability Organization-supplied case already had firm transfers consistent with data submitted by utilities for on-peak modeling.

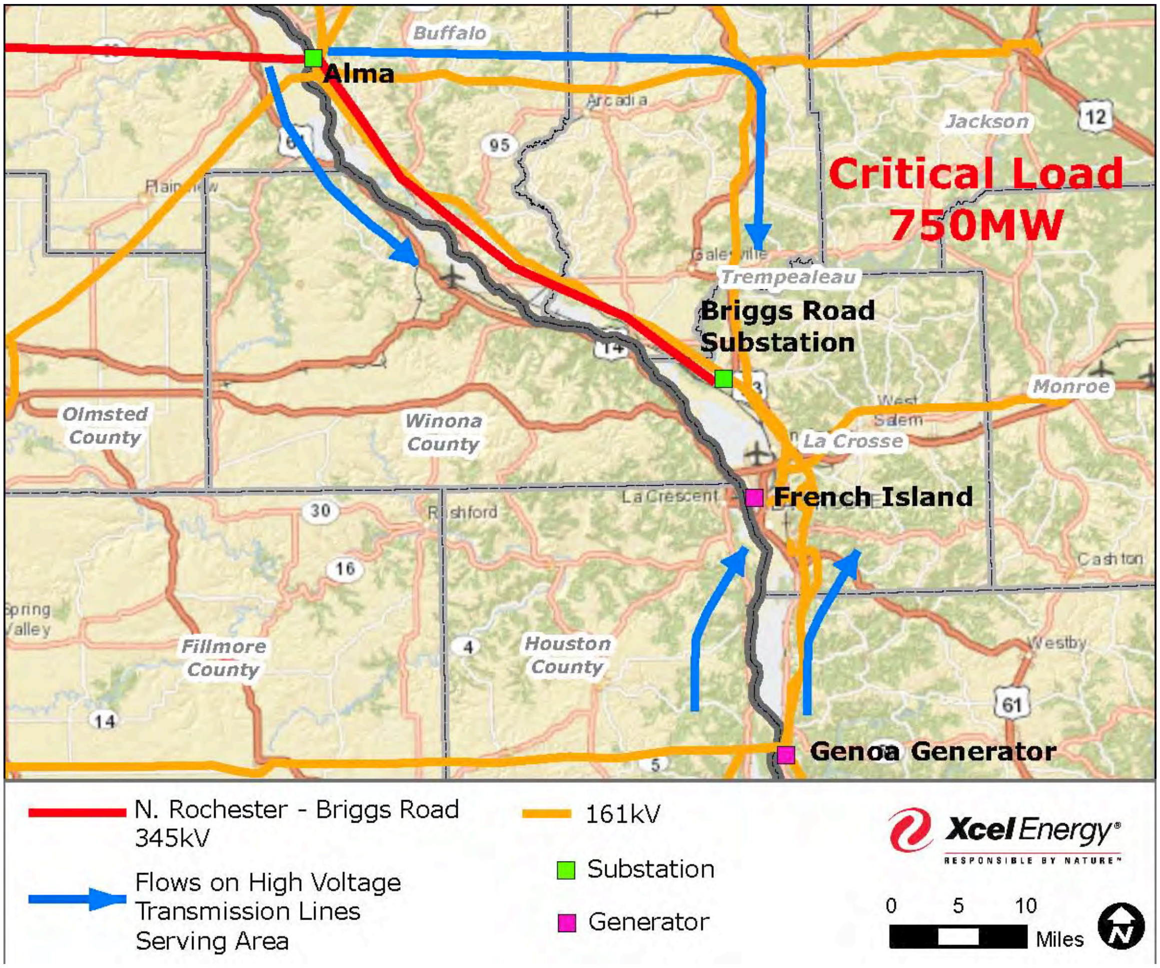
Steady state contingencies modeled

The contingencies studied are the relevant complex NERC Category B and Category C contingencies commonly used for bulk transmission studies in the La Crosse area. In addition, the following contingencies were taken; all branches (transformers and transmission lines) were taken as contingencies one at a time in the control areas of Xcel Energy (the lines in the La Crosse / Winona area and the wider region), Southern Minnesota Municipal Power Agency, DPC and Alliant Energy. Also, all the generators in those areas were taken off line one at a time, and all the transmission ties from those areas were taken as contingencies one at a time.

The primary methodology employed was to use the base load levels in the models and grow those loads to higher levels to determine the load level where facilities would experience overloads or low voltages. To do this, the load at each substation is grown in proportion to its initial load. For instance, if the La Crosse area load were to be grown from its estimated 2012 starting point of 491 MW to a 982 MW level (doubled), a substation with 4 MW of initial load would only increase 4 MW while a 40 MW substation would increase 40 MW. The La Crosse area loads included loads served by DPC and NSPW.

Based on this analysis it was determined that for loss of a generating unit at Alma, plus loss of the North Rochester – Briggs Road 345 kV line, the 161 kV sources into La Crosse overload at the 750 MW load level. Similarly, for loss of a Genoa unit and loss of the North Rochester – Briggs Road 345 kV line, the 161 kV sources into La Crosse also overload. Addition of the Badger Coulee Project into the models allowed for load in the greater La Crosse area to be reliably served through the planning horizon, or beyond 1400 MW.. Figure 2 illustrates the sources, generators and 750 MW critical load level.

Figure 2: La Crosse/Winona Areas Critical Load Level



Timing of Need

The La Crosse Project will serve area load levels up to 750 MW, after which an additional transmission source will be needed to meet customer demand. To assess the timing of this need, NSPW compiled historical load data for the area. Figure 3 shows that the La Crosse area has reached a new peak each year since 2008. Additionally, between the years of 2010 and 2012 the total load has grown 3.44%, or considerably above the average load growth for the NSP and DPC control areas over the same time period (just under 1 % and 1.1 % respectively).

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Figure 3: Historical La Crosse/Winona Area Non-Coincident Substation Loads

LA CROSSE AREA LOAD SERVING SUBSTATIONS	Actual Loads					
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2011	Load MW 2012
Bangor	4.08	4.17	3.46	3.30	3.10	4.43
Brice	5.12	6.93	6.36	3.50	3.52	3.52
Caledonia City	3.42	3.90	3.51	3.65	3.38	4.37
Cedar Creek	3.54	5.17	4.93	5.00	4.73	5.90
Centerville	2.79	3.34	4.20	3.05	4.73	5.57
Coon Valley	4.29	5.22	3.96	3.99	4.00	5.00
Coulee	53.50	60.30	52.91	54.60	56.00	55.80
East Winona	8.92	9.47	11.09	7.00	7.64	7.38
French Island	19.50	29.04	24.06	29.00	29.00	28.80
Galesville	6.91	6.89	5.50	5.79	6.00	6.92
Goodview	31.78	35.33	33.61	31.67	37.30	39.80
Grand Dad Bluff	1.67	1.91	1.63	1.68	1.75	1.97
Greenfield	2.85	3.43	3.06	2.93	3.62	3.76
Holland	-	-	-	4.74	4.78	5.33
Holmen	14.97	13.16	14.91	13.30	14.10	11.51
Houston	3.61	3.78	3.38	3.75	3.89	4.27
Krause	4.12	4.48	4.54	5.02	5.25	5.49
La Crosse	58.43	50.33	46.98	47.63	49.00	50.65
Mayfair	43.90	46.58	45.39	56.45	49.00	45.10
Mound Prairie	2.18	2.02	2.39	2.24	2.38	2.76
Mount La Crosse	1.64	2.00	2.09	2.15	2.29	2.44
New Amsterdam	3.88	4.66	4.46	3.47	3.84	4.84
Onalaska	11.73	12.93	10.48	13.77	13.50	14.32
Pine Creek	2.03	2.36	1.84	1.93	2.06	2.33
Rockland	4.18	4.14	3.10	3.66	3.70	3.11
Sand Lake Coulee	2.99	2.84	2.59	3.01	3.84	3.13
Sparta	29.65	32.47	31.74	30.90	33.00	34.80
Sparta (Dairyland)	1.15	1.36	1.16	1.14	1.15	1.38
Swift Creek	17.10	24.80	21.83	23.75	24.00	22.10
Trempealeau	4.43	3.94	3.68	2.68	3.20	3.55
West Salem	23.30	24.52	23.97	22.80	24.00	28.13
Wild Turkey	1.17	1.20	1.35	2.69	2.71	3.54
Winona	46.30	51.91	51.19	51.17	54.54	59.00
Total Load MW:	425.13	464.58	435.35	451.41	465.00	481.00

Using the 2012 peak as the base year, NSPW calculated total area load in the post 2020 timeframe based on several growth rates, 1%, 1.24%, 2% and 3.44%.

Figure 4: La Crosse Load Area Growth Post 2020

	1%	1.24%	2%	3.44%
2025	547 MW	565 MW	622 MW	746 MW
2030	575 MW	600 MW	687 MW	884 MW
2040	636 MW	680 MW	837 MW	1240 MW
2045	668 MW	722 MW	925 MW	1469 MW
2050	702 MW	768 MW	1020 MW	1740 MW

Depending on the actual growth rate, a new transmission source could be needed as soon as the 2026 timeframe (if load grows at a rate over 3% annually) or after 2050 (if load grows at a rate below 1.24% annually). The addition of the Badger Coulee Transmission Project would provide a second transmission source, creating a robust second 345 kV source to meet this need.

3.0 TRANSFER CAPABILITY ANALYSIS

3.1 Recognized Constraints

There is a lack of high voltage transmission, particularly 345 kV class, between Minnesota and Wisconsin which constrains regional movement of power. This constraint affects the efficiency and reliability of the regional electric transmission system.

There are two key constrained areas that limit power transfers between NSPW's system in Wisconsin and other states. These constrained areas not only affect economic dispatch of energy as discussed above, but create operational limitations. The two constraints are the Iowa/Minnesota/Wisconsin Narrow Constrained Area ("Minnesota NCA") and the Minnesota-Wisconsin Export ("MWEX").

The FERC designated the Minnesota NCA in 2007. As explained by the Independent Market Monitor in its 2013 report[1], a constrained area must meet certain criteria to warrant the NCA designation:

> A constrained area warrants designation as a NCA if it satisfies two tests under the FERC-approved market power mitigation measures contained in the MISO Tariff. First, the transmission constraint must have bound for more than 500 hours over the

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[1] Patton, David B., Informational Filing of Midwest Independent Transmission System Operator, Inc.'s Independent Market Monitor (Feb. 21, 2003).

> prior 12 months. These hours include those in which MISO made commitments or took other actions to manage the congestion. Second, one or more suppliers must frequently be pivotal – i.e., its resources are needed to meet the load and manage the congestion into the constrained area. An area that satisfies these two tests is particularly vulnerable to market power abuse. The NCA designation is necessary to assure that wholesale electricity prices will remain just and reasonable. A NCA designation alters the operation of the Day Ahead and Real Time energy market in the area from its designed mode. Generators in a NCA face restrictions on their offer price into the MISO energy markets because they can impact the affected transmission constraints in a NCA.

When an area is chronically constrained, there are increased market power concerns for generators in the constrained area making offers into the MISO energy market. In 2012, there were 2,700 hours of binding constraints in the Minnesota NCA, as the IMM reported:

> The Minnesota NCA transmission constraints are mainly associated with two dominant parallel electrical paths. The first is a set of 345 kV facilities in western Iowa to the Lakefield, Wilmarth and Blue Lake substations in Minnesota. The second is a set of 345 kV facilities in eastern Iowa to the Adams, Pleasant Valley and Prairie Island substations in Minnesota. Each of the constraints can restrict power flow into Minnesota from the south. Long-term forced outage of a large generator in MISO's West region contributed significantly to the increased Minnesota NCA congestion in 2012. This outage is continuing into 2013. Early in 2012 transmission outages resulting in reduced imports from Manitoba also increased congestion into Minnesota. In the addition, transmission outages related to significant upgrades in 2012, which are continuing into 2013, resulted in increased south-to-north congestion. Accordingly, we expect that the constraints that define the Minnesota NCA will continue to significantly surpass the 500-hour criteria during the next 12 months.

The MWEX interface constraint arises from the limited bulk transmission connecting Minnesota, Wisconsin and Iowa. There is presently a single extra high voltage transmission path from the Twin Cities to eastern Wisconsin, the King – Eau Claire – Arpin – Rocky Run 345 kV path, plus certain lower voltage facilities. Transfers across the MWEX interface are limited due to voltage stability and transient voltage recovery limitations. The constrained interface both limits the ability for lower cost energy resources to flow from generation to loads, and creates system reliability issues, particularly in terms of system stability, during either switching or outages (planned or unplanned) on the King – Eau Claire – Arpin – Rocky Run path. The NSP Companies own the portion of the King – Eau Claire – Arpin – Rocky Run path from the A.S. King Substation to the Arpin substation (approximately 183 miles), and ATC owns the portion from the Arpin Substation to the rest of the ATC system. At present, the only connection from Arpin Substation to the Madison area is a circuitous path that results in a weak connection.

This constrained interface between the NSP System (Minnesota and Wisconsin) and utilities to the west and north in the historic Mid-Continent Area Power Pool ("MAPP") region, and loads and generation in the eastern portions of Wisconsin, which are now served by the ATC transmission system, has been the focus of studies dating back several decades.

A new high voltage transmission link between the Twin Cities area in Minnesota to the Madison area in Wisconsin was studied as part of the Wisconsin Interface Reliability Enhancement, Phase II, Study ("WIRES Phase II Report") efforts. The WIRES Phase II Report identified a transmission line from the Prairie Island Substation, southeast of the Twin Cities, to the Columbia Substation, just north of the Madison area as a project that would address certain stability issues in the MWEX interface that arise during either switching or outages on the King—Eau Claire – Arpin – Rocky Run 345 kV path. This Prairie Island – Columbia line was one of several alternatives identified in the WIRES Phase II Report to mitigate this reliability issue. Of the identified alternatives, the Arrowhead – Weston 345 kV Line was ultimately constructed. The Arrowhead – Weston line runs from north of Duluth, Minnesota, to near Wausau, Wisconsin, and is owned by ATC.

A La Crosse to Madison transmission link was also proposed by the CapX2020 Initiative as part of their vision study work culminating in the 2005 CapX2020 Vision Study. The CapX2020 Initiative is a collaboration of 11 utilities in the upper Midwest, including NSPW, that was formed to study and propose transmission projects necessary to meet the needs of the region through 2020. The CapX2020 Vision Study identified transmission facilities electrically similar to the Prairie Island – Columbia transmission line identified in the WIRES Phase II Report. The CapX2020 Vision Study identified a 345 kV transmission line from a substation near the Prairie Island generating station in the Twin Cities area to a substation in the La Crosse area and a 345 kV transmission line extending from the La Crosse Project end point to the Columbia Substation.

Based on the results of the CapX2020 Vision Study, the CapX2020 utilities started earnest planning of the Twin Cities – La Crosse transmission facility identified in the Vision Study. This scoping work culminated in the La Crosse Project, approved in MTEP08 as a baseline reliability project.

The need for a La Crosse area to Madison area transmission line was also identified in the Minnesota RES Update Study ("RES Update") in 2009, submitted to the Minnesota Public Utilities Commission as part of the 2009 Biennial Transmission Projects Report. The RES

Update was a study performed collaboratively by various owners of transmission facilities in Minnesota, known as the Minnesota Transmission Owners ("MTO") group. The RES Update was performed so the MTO could identify transmission upgrades necessary for Minnesota electric utilities to meet their state-imposed renewable energy portfolio standards.

While the study work to that point had clearly identified making a 345 kV connection between La Crosse and the Madison area, a specific Madison connection had not been evaluated. To provide a more granular level study of this option as well as reliability needs in western Wisconsin, a separate study was commissioned.

The additional study work culminated in the 2010 Western Wisconsin Transmission Reliability Study ("WWTRS"), undertaken by ATC as the lead in cooperation with NSPW and other utilities. The WWTRS assessed the reliability needs in western Wisconsin in the eight to ten-year time frame, and also evaluated the extent to which different transmission options would meet these needs using various reliability measures.

The WWTRS concluded that the La Crosse – North Madison – Cardinal and the Dubuque – Spring Green – Cardinal 345 kV projects would provide the best reliability benefits in Wisconsin and would provide additional load serving benefits, energy and loss savings and other economic and policy benefits such as the ability to integrate and deliver renewable energy.

Based in part on the outcome of the WWTRS, the La Crosse – Madison Line and the Dubuque – Madison Line were designated as candidate Multi Value Projects ("Candidate MVPs") by MISO, subject to further study. These projects were then designated as MVPs by the MISO Board of Directors on December 8, 2011.

3.2 Thermal Transfer Analysis Between WI and MN

As part of the La Crosse Project proceeding, NSPW undertook an analysis of the thermal transfer capability between Minnesota and Wisconsin. This analysis examined the relative transfer capability achieved by the proposed La Crosse Project and a 161 kV alternative. The analysis included an evaluation of this capability assuming the 345 kV network were further extended to the east either from La Crosse to Madison or from La Crosse to North Appleton.

The transfer analysis was completed to evaluate how the proposed 345 kV project and one of the alternatives under consideration would impact system transfer capability from west to east across the Wisconsin/Minnesota border in the near term and the longer term, depending on future 345 kV build-out scenarios in Wisconsin. The areas in the west that were selected as sources were Great River Energy, Minnesota Power, Otter Tail Power Company, and Northern States Power Company-Minnesota. The areas in the east that were selected as sinks were Alliant Energy East, Madison Gas and Electric Co., Upper Peninsula Power Co., Wisconsin Energy Corp, and Wisconsin Public Service. Engineers selected these areas based on their judgment that these assumptions would provide a realistic network condition when transfers between Minnesota and western Wisconsin would be high.

The models used for the analysis were based on the 2011 MRO Series 2017 Summer 70% Peak base model. Figure 5 shows a description of the pedigree of each case used in the transfer analysis.

Figure 5: Cases Used in Transfer Analysis

Case	Model Changes
Base-MRO-2017SU70.sav	- Base MRO model - Without the North Rochester – Briggs Road 345 kV line
345-MRO-2017SU-CAPX_ONLY.sav	- Base MRO model
345-MRO-2017SU-MADISON.sav	- Base MRO model - With Briggs Road – North Madison 345 kV line added

The critical contingencies for the transfer levels with the Eau Claire-Arpin SPS in place are as follows:

- La Crosse 345 kV Line alone: Seneca- Genoa
- La Crosse 345 kV Line plus 345 kV line to Madison: North Rochester- North La Crosse 345 kV Line plus 345 kV line to North Appleton: Seneca- Genoa
- 2010 161 kV Alternative Option alone: Seneca- Genoa
- 2010 161 kV Alternative Option plus 345 kV line to Madison: Wabaco -Rochester
- 2010 161 kV Alternative Option plus 345 kV line to North Appleton: Wabaco-Rochester

Transfer analysis was performed by increasing the power flow between the source and sink areas until overloads were created. The results demonstrate that, based on the models and assumptions described above, the 345 kV La Crosse Project alone provides approximately 840 MW of transfer capability. With the addition of the Badger Coulee Transmission Project an additional 360 MW of transfer capability is achieved bringing the total to approximately 1,200 MW of additional transfer capability.

A PV analysis was completed using eight transfer cases to confirm the results of the transfer analysis.

Each of the eight 345 kV buses to be monitored was selected using engineering judgment and was picked to represent a geographically diverse area that would be representative of the bulk electric system in the eastern Minnesota/western Wisconsin area. The buses monitored were as follows:

Cordova 345 kV Bus => Quad Cities, IL (Davenport, IA)

Eau Claire 345 kV Bus => Eau Claire, WI

North La Crosse (Briggs Road) 345 kV => La Crosse, WI

Paddock 345 kV => Beloit, WI

Arpin 345 kV => Arpin, WI

North Appleton 345 kV => Appleton, WI

Kewaunee 345 kV => Kewaunee, WI

Gardner Park 345 kV => Wausau, WI.

The PV analysis was completed using models based on the 2011 MRO Series 2017 Summer 70% Peak base model. The Eau Claire – Arpin SPS was presumed to be in place. The power flow between the source and sink areas were then increased, ignoring overloads, until system stability problems occurred.[2] The PV analysis was stopped when the transfer levels exceeded those found in the transfer analysis, proving that the system remained stable at the 840 MW and 1200 MW transfer levels.

This additional transfer capability across a currently constrained interface will have multiple benefits for the region. These include both economic benefits and reliability benefits by allowing access to additional generation when needed. For example, the RES Update study concluded that a new high-voltage transmission facility is necessary between the La Crosse area and eastern Wisconsin to ensure reliable operation and full dispatch of new generation resources. Specifically, this study identified a project substantially similar to the La Crosse – Madison Line, which was shown to provide significant benefits in all cases studied, as the appropriate facility to provide this link.

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[2] Source (MN): Great River Energy, Minnesota Power, Otter Tail Power Co, and Northern States Power Company—Minnesota.

Sink (WI): Alliant Energy East, Madison Gas and Electric Co, Upper Peninsula Power Co, Wisconsin Energy Corp, and Wisconsin Public Service

The RES Study also discussed a potential "tipping point" on the regional transmission system which would require a bulk transmission line from the La Crosse area to the Madison area. In other words, without a line to the east of La Crosse the system will reach a tipping point where additional generation capacity additions to the west of the Twin Cities cannot be accommodated due to the need to keep Twin Cities generation online for steady state and dynamic system stability. The addition of the Badger Coulee project will allow Minnesota operational flexibility in dealing with any potential future generation additions.

Following a Commission approval of this project, MISO engineers, working with area utilities, would begin a study to formally determine the MWEX value with the addition of the Badger Coulee project.

4.0 CONCLUSION

A robust regional network to interconnect generation, transfer power between states, to source distribution systems and to minimize congestion will be required to meet the ever increasing demand for power and to reduce overall energy costs. The Badger Coulee Transmission Project will help address all of these needs.

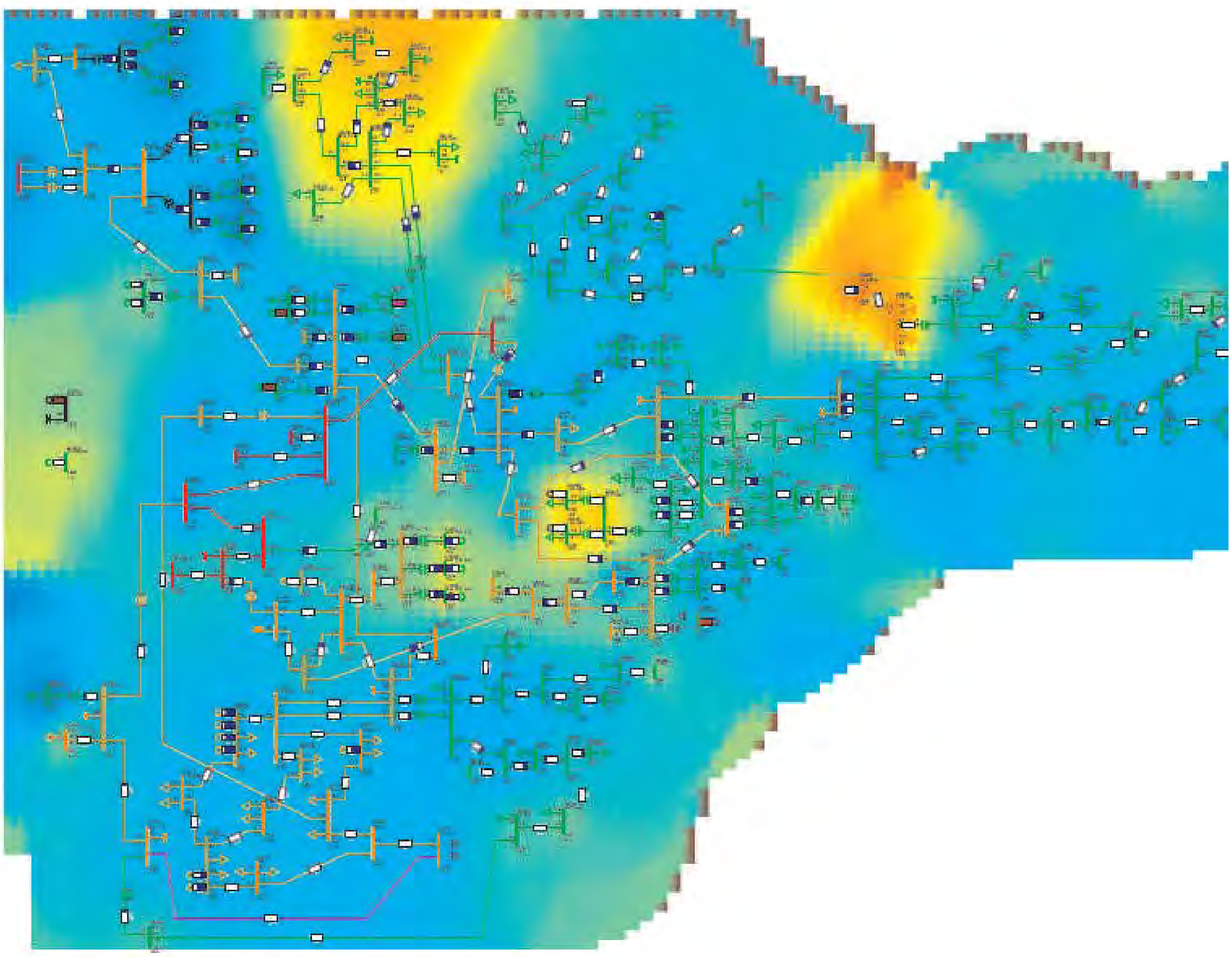
The Badger Coulee Transmission Project will enhance both local and regional reliability by creating a second 345 kV source into the La Crosse area. This second source will create sufficient load serving capability to meet anticipated load levels beyond 750 MW.

The Badger Coulee Transmission Project will also increase transfer capability across the historically constrained MWEX interface. The combination of the CapX Hampton – La Crosse and Badger Coulee Transmission Projects will add approximately 1200 MW of additional transfer capability to enable deliveries of additional generation, including renewable generation, into Wisconsin.

APPENDIX

Appendix 1: 345 kV Project Load Flow Output Comparison

Outage of Genoa Generation + Alma - Marshland 161 kV line
Thermal Loading and Voltage Levels at 750 MW



Outage of JPM Generation + Genoa - Coulee 161 kV line
Thermal Loading and Voltage Levels at 750 MW