Table 5.1e: Do Nothing Underlying Facilities

Facility	contingency	remedy	Rating required for desired FCITC	rating achieved/ MVA	cost/ $	FCITC
Eau Claire-Presto Tap 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	325.3	434	-	1589
Boundary Dam phase shifter V	67STK	solution error	309.2	9999	-	1600
Hankinson-Wahpeton 230 kV	63369 JAMESTN3 345 66791 CENTER 3 345 1	reconductor 230 kV 795 ACSS	365.9	687	7,256,200	1622
Parkers Lake-Basset Creek 115 kV	917 1	rebuild 115 kV 2x795 ACSS	420.8	598	1,252,800	1666
Minn Valley Tap-Granite Falls 230 kV	60383 BRKNGCO3 345 60500 LYON CO3 345 C1	rebuild 230 kV line 840 MVA	439.3	840	-	1844
Inver Hills 345/115 9	60505 LKMARN 3 345 62234 LKMARN 7 115 C1	existing 633 MVA rating is sufficient	563.5	633	-	1855
Lakefield 345/161 1	60331 LKFLDXL3 345 60364 FIELD_N3 345 1	replace with 345/161 672 MVA transformer	338.6	773	8,920,000	1909
Lakefield 345/161 2	60331 LKFLDXL3 345 60364 FIELD_N3 345 1	replace with 345/161 672 MVA transformer	338.6	773	8,920,000	1909
Arrowhead Phase Shifter-Arrowhead 230 kV	NSP STK 8P5 BKR KING	phase shifter control will reduce flow	807.5	9999	-	1946
	total				175,990,345	2000

5.2: Constrained Interface Analysis

All of the constrained interfaces commonly monitored by Midwest ISO were monitored for violations of their limits. The Appendix for Constrained Interface results shows the detailed results of the analysis performed for constrained interfaces. The following table summarizes those results. (Constrained Interfaces are also commonly referred to as "flowgates".)

- The off-peak cases for both the Corridor-Base option and the System Alternative show no flowgate violations.
- The peak cases for both the Corridor-Base option and the System Alternative show the Forbes-Chisago System Intact flowgate. In both cases that flowgate is not overloaded in the models.
- The peak case for the System Alternative also shows the Arnold-Hazleton 345 kV For Loss Of Montezuma-Bondurant 345 kV. This flowgate is not overloaded in the models.

While performing analyses of the electric transmission system, it is important to monitor constrained interfaces. The constrained interfaces have been developed in part to prevent generation changes in one geographic area from causing overloads of transmission facilities in other areas. Since the AC transmission system in Minnesota is interconnected with the AC transmission systems all the way to the Atlantic ocean and to the Gulf of Mexico, generation increases in Minnesota can cause overloads in Iowa or Wisconsin or further away.

The general rules for flowgates are as follow.

- If a generation addition causes less than 3% flow increase on any given contingent flowgate (like the Arnold-Hazleton 345 kV For Loss Of Montezuma-Bondurant 345 kV), that generation is exempted from having to address that flowgate.
- If a generation addition causes less that 5% flow increase on any given system-intact flowgate (like Forbes-Chisago 500 kV System Intact), that generation is exempted from having to address that flowgate.
- If either of the 3% or 5% above criteria are violated for any flowgate, but there is sufficient Available Transfer Capability (ATC) on that flowgate to accommodate the new generations impact on that flowgate, no facility upgrades to that flowgate are required; however, the generation owners will likely have to purchase transmission service on that flowgate.

The Available Transfer Capabilities on the bulk transmission facilities are generally known only out as many as three years. Beyond that time, the postings of Available Transfer Capability are generally not available. Due to the fact the facilities in this study are recommended to be in service by the end of year 2015, there is no good way to determine the actual Available Transfer Capability on either of the flowgates with violations of the distribution-factor cutoff (3% or 5% as applicable).

Therefore, the next best option is to use the flows in the power-flow models as obtained from Midwest ISO. The peak model obtained from Midwest ISO was the basis for both the peak and off-peak models (load in the peak model was decreased to create the off-peak model). In the peak model were the firm transfers as set by Midwest ISO. So with those firm transfers and the 2000 MW of study generation, no flowgates overloaded in the peak models. Even with the high transfers added to the off-peak model – the high MHEX and NDEX and MWEX – there were no flowgate violations shown.

The fact none of the constrained interfaces are overloaded is important. That result indicates with the study generation of 2000 MW, the transmission options chosen were both good at transferring that generation to the study sink – the Twin Cities-area generators – with no need to either improve flowgate facilities or purchase transmission service on a flowgate.

Case	Constrained Interface	Power Transfer Distribution Factor cutoff	Power Transfer Distribution Factor	Resolution
Corridor-Base Off-peak	none			
Corridor-Base Peak	Forbes-Chisago 500 kV system intact	5.0%	5.8%	not overloaded (loading @ 2000 MW study generation is 1020 MVA with a 1655 MVA rating)
System Alternative Off-peak	none			
System Alternative Peak	Forbes-Chisago 500 kV system intact	5.0%	5.5%	not overloaded (loading @ 2000 MW study generation is 1005 MVA with a 1655 MVA rating)
System Alternative Peak	Arnold-Hazleton 345 kV for loss of Montezuma-Bondurant 345 kV	3.0%	3.0%	not overloaded (loading @ 2000 MW study generation is 178 MVA with a 601 MVA rating)

5.3: Reactive Power Requirements

The voltage results of this study showed there is not a great deal of need for adding reactive power facilities to support voltage under system-intact and contingent conditions. The below table shows the reactive-support facilities required for the 2000 MW level of study-source generation transfer to load. As is customary in bulk transmission studies, voltage changes less than 1% were ignored.

5.3.1: Corridor-Base Voltage Underlying Facilities

The Corridor-Base voltage underlying facilities are shown in detail in the Appendix for voltage results. The below table shows the summary.

Bus name	Contingency	Remedy	Location	units required	cost per unit	Cost/ $
Eden -138	ASK-ARP	Add 40 MVAr 138 kV capacitor	Eden	1	935000	935,000
Arrowhead 345-345	ASK-ARP	Add 80 MVAr 345 kV capacitor	Arrowhead	1	1500000	1,500,000
Council Creek -138	ASK-ARP	Add 14 MVAr 138 kV capacitor	Council Creek	2	935000	1,870,000
Frazee-115	1275STK1	Add 14 MVAr 115 kV capacitor	Frazee	1	935000	935,000
Miltona-115	1625STK	Add 14 MVAr 115 kV capacitor	Miltona	1	935000	935,000
total						6,175,000

5.3.2: System Alternative Voltage Underlying Facilities

The System Alternative voltage underlying facilities are shown in detail in the Appendix for voltage results. The below table summarizes those facilities.

Bus	Contingency	Remedy	Location	units required	cost per unit	Cost
Frazee-115	1275STK1	Add 14 MVAr 115 kV capacitor	Frazee	1	935000	935000
Miltona-115	1625STK	Add 14 MVAr 115 kV capacitor	Miltona	1	935000	935000
total						1870000

5.3.3: Light-load Charging Mitigation

During periods of light loading on any high-voltage transmission line, the charging current tends to increase the voltage at the endpoints of the line; this effect can lead to voltages outside of criteria if no mitigating facilities are installed. It is customary, therefore, to add reactors to the tertiary buses of the transformers involved in upgrade of a line to a higher voltage. This tends to be the most inexpensive way to keep the voltage within criteria during light-load periods.

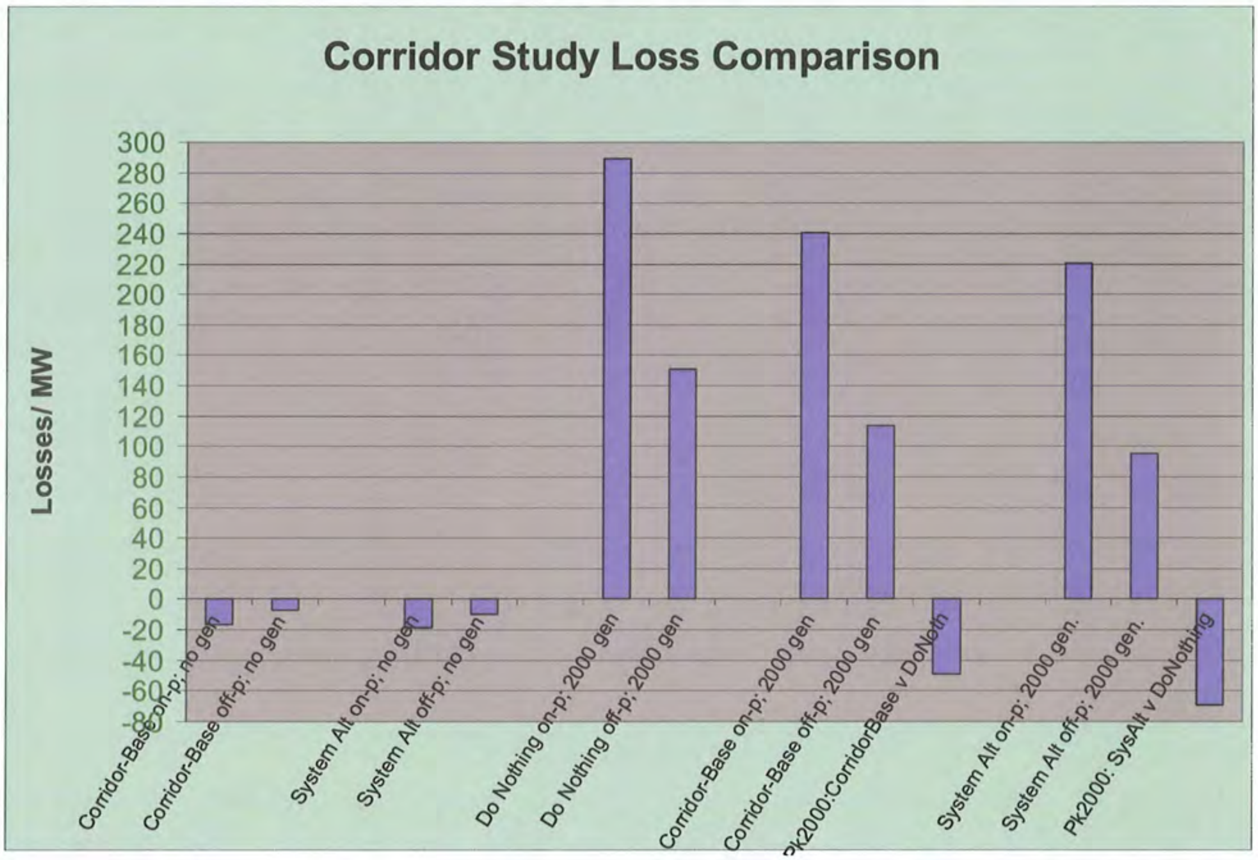
The charging from a 345 kV circuit is generally .86 MVAr per mile. The design for this project includes installing enough shunt reactance to absorb all the 345 kV lines' charging during light-load periods. Each reactor would be automatically switched based on the voltage on the primary or secondary of the transformer connected to the reactor. This way the reactors will only be energized at times they are needed, so extra capacitors would not have to be installed to compensate for the reactors being always energized.

The total 345 kV line mileage for the project is expected to be approximately 122 miles per circuit. This results in approximately 200 MVAr -- 100 MVAr per circuit -- at the .86 MVAr/mile rate. This works out nicely to four 50 MVAr reactors. To give as flat a voltage profile as possible, the proposal is to add one 50 MVAr reactor to the tertiary of a transformer at Hazel Creek and Panther and McLeod and Blue Lake.

For 765 kV lines, the charging is 4.2 MVAr/mile. For the 86 mile 765 kV line in the System Alternative, 361 MVAr would have to be absorbed during light-load periods. Also, the 36 mile double-circuit 345 kV line from West Waconia to Blue Lake would result in the need to absorb another 62 MVAr. The total reactors needed for the System Alternative would be approximately 420 MVAr.

5.4: Losses: Technical Evaluation

The losses benefits are significant for both the Corridor-Base option and the System Alternative. The following chart shows the relative losses from varying scenarios of transmission option implemented and level of study generation – 0 MW or 2000 MW.



The below table summarizes the losses for cases studied. The chart above is based on the following table.

Case	Condition	Losses/ MW	Loss increase/ MW	Portion of 2000 gen.	Explanation of difference
1a	Off-peak base case	17564			
1b	Case 1a with 2000 MW new generation	17715	151	8%	2000 MW source generation
2a	Peak base case	17488			
2b	Case 2a with 2000 MW new generation	17777	289	14%	2000 MW source generation
5a	Off-peak base case with Corridor-Base	17558	-7		Added Corridor-Base
5b	Case 5a with 2000 MW new generation	17671	114	6%	2000 MW source generation
6a	Peak base case with Corridor-Base	17472	-17		Added Corridor-Base
6b	Case 6a with 2000 MW new generation	17712	240	12%	2000 MW source generation
7a	Off-peak base case with System Alternative	17554	-10		Added System Alternative
7b	Case 7a with 2000 MW new generation	17650	96	5%	2000 MW source generation
8a	Peak base case with System Alternative	17469	-19		Added System Alternative
8b	Case 8a with 2000 MW new generation	17689	220	11%	2000 MW source generation

Concentrating on the peak losses, one can make a few observations from the above table.

- Adding 2000 MW of generation in the "Do Nothing" option results in loss of 14% of that generation.
- If the Corridor-Base option is built, only 12% of that generation is lost.
- If the System Alternative option is built, only 11% of that generation is lost.
- Adding the Corridor-Base option with no new generation results in a peak loss reduction of 17 MW.
- Adding the System Alternative option with no new generation results in a peak loss reduction of 19 MW.

5.5: Losses: Economic Evaluation

The below worksheet shows the derivation of the loss benefit in terms of the amount of transmission investment able to be supported by a loss savings. One important result on that worksheet is the 4.4 M$/MW of Cumulative Present Value of Losses. This value represents the result that any transmission improvement causing 1 MW of loss savings saves the electric system 4.4 M$ of present value generation cost that would otherwise be incurred to supply the capacity and energy for that 1 MW of losses.

The installed capacity values used for base-load and peaking generation are from the latest estimates by resource planners. The energy value used is from the 2008 average real-time energy price for the "MINNHUB" pricing point in the Midwest ISO market. That value was used because it is a good indication of the actual average energy price of the most-expensive block of 1 MW served during that year. If losses were reduced by 1 MW, that is a good indication of the energy cost avoided.

The key result on the following worksheet for this study is the 3.1 M$/MW of Equivalent Transmission Investment. This is the amount of "supportable transmission investment" per MW of loss savings. For example, a good investment would be to install an additional 20 M$ of transmission facilities to save 10 MW of losses, as that would require 2.0 M$/MW, and is below the 3.1 M$/MW point of economic indifference.

Computation of Equivalent Capitalized Value for Losses
(based on 1.00 MW loss on -peak)
(pool reserve requirement of 15%)

Input Assumptions

Term of loss reduction	40	yrs	Present Value of Annuity factor	11.92	< Losses
Assumed life, xmsn	35	yrs	Present Value of Annuity factor	11.65	< Transmission
Discount rate	8	%/yr			
Energy value	$46.19	MWh			
Loss Factor	0.30				
Transmission FCR	0.15				

Calculation

						Generation FCR	Levelized Annual Revenue Rqmt	Cum PW of Rev Req
Capacity value:	50	% peaking @		$800	/kW	0.15	$60,000	
	50	% baseload @		$3,000	/kW	0.15	$225,000	
						$	285,000	$
add 15% reserve requirement:							327,750	3,908,292
Energy Value:	1.00	8760 hr/yr	0.30	$46	/MWh		121,387	$ 1,447,497
				Total annual cost, capacity & energy:		$	449,137	5,355,789
				Present Value Annuity factor Losses			11.92	
				Cum PV Losses		$	5,355,789	
				Equivalent Transmission investment		$	**3,063,628**	
				is Cum PV Losses / FCR trans / PVA trans				

Xcel Energy Services

Based on the 3.1 M$/MW value, the "loss reduction" investment credit for building the Corridor-Base plan with no added study source generation is 53 M$ (17 MW loss savings multiplied by 3.1 M$/MW). This amount is a credit to the total installed cost of the Corridor-Base plan. The investment credit for building the System Alternative with no added generation is 59 M$ (19 MW loss savings multiplied by 3.1 M$/MW).

5.6: Dynamic Stability

The dynamic stability analyses showed one criteria violation for the Corridor-Base option with 2000 MW of added study generation. The System Alternative was not studied in the dynamics realm since its initial cost is so great. As stated elsewhere, the System Alternative is not viable without a wider 765 kV proposed development. If such a development were to materialize, it would be studied in detail in the dynamics realm.

However, since the Corridor-Base dynamics analysis showed only one violation in northern Wisconsin, it was assumed the same violation would appear for the System Alternative. The violation is remote from the study generation, and it is caused by loss of the King-Eau Claire-Arpin 345 kV line and the King-Chisago 345 kV line. With loss of that line from Minnesota to Wisconsin, power flow from Minnesota to Wisconsin is diverted to flow from the Duluth area southeast into Wisconsin. This causes a low-voltage violation at Minong Substation. This effect is expected to be independent of the voltage class built (345 kV or 765 kV) between Hazel Creek Substation and Blue Lake

Substation. Therefore the same cost of an SVC – 10 M$ -- has been assigned to the stability facility costs for both the Corridor-Base option and the System Alternative.

The same Minong Substation low-voltage violation appears in the Do Nothing option, but the Do Nothing option also has a violation at Jamestown, North Dakota; for the Do-Nothing option, an SVC at each of Minong Substation and Jamestown Substation are required. The total cost for those two SVCs is expected to be 20 M$.

The detailed results for the dynamic simulations are in the Appendix showing dynamics simulation results.

5.7: Production Cost Modeling Results

Production-cost and load-cost modeling was done with the computer program called PROMOD.

The below table shows the summary of the 40-year present value savings from constructing the Corridor-Base transmission with 2000 MW of new study generation; if that transmission is built, the 40-year present value of weighted production-cost savings (70% weight) and load-cost savings (30% weight) is 214 M$ versus the Do Nothing option.

Corridor Project (Metro Sink for Underlying Costs)	
Description	***Cost***
70% Production Cost Savings (40-year)	$34,685,192
30% Load Cost Savings (40-year)	$179,723,682
total	$214,408,874

6: Economic Analysis

6.1: Total Evaluated Costs

The total evaluated costs for all options were compiled from the

- costs for the base facilities,
- the underlying-system costs,
- the facilities required to keep the power system within criteria following dynamic disturbances,
- the 40-year present value of load-cost and production-cost penalties,
- and the 40-year present value cost of losses.

Considering all the cost factors of the Corridor-Base option, the System Alternative, and the Do Nothing option, the Corridor-Base option is seen to be the least-cost option.

Not included are the costs of the central and eastern Wisconsin capacitors since those facilities are expected to be required even without any of the options analyzed as part of this study. The high transfers from Minnesota to eastern Wisconsin are the drivers for those capacitors.

The following table summarizes the options' total costs.

Table 6.1: Overall Cost Summary

Option	Base Project Installed Cost/ M$	Underlying System Installed Cost for 2000 MW delivery/ M$	Losses cost/ M$	Cost of Facilities for Dynamic Stability/ M$	Production-cost & load-cost penalty/ M$	Total Installed Cost for 2000 MW delivery/ M$
Corridor-Base	349	117	0	10	0	**476**
System Alternative	583	114	-61	10	0	**646**
Do Nothing	0	176	150	20	214	**560**

The following table shows the total evaluated cost for the Corridor-Base option.

Table 6.1a: Corridor-Base option total costs

Project	**Hazel-Blue Lake double 345 kV with 1 express**			
Sum of Facility cost/ M$				
Type	**Location**	**Facility**	**units**	**Total**
base project	Blue Lake	add 2 345 kV terminations	1	7,000,000
		tertiary shunt reactor	1	1,000,000
	Hazel Creek	add 2 345 kV terminations	1	7,000,000
		tertiary shunt reactor	1	1,000,000
	Hazel Creek-Minnesota Valley vicinity	string second circuit on existing double-circuit 345 kV towers	6	3,000,000
	McLeod	develop 345 kV yard with 2 345 kV terminations	1	10,000,000
		tertiary shunt reactor	1	1,000,000
	McLeod-Blue Lake	build 345 kV double circuit	56	151,000,000
	Minnesota Valley vicinity-Panther	build 345 kV double circuit	30	81,000,000
	Panther	develop 345 kV yard with 2 345 kV terminations	1	10,000,000
		tertiary shunt reactor	1	1,000,000
	Panther-McLeod	build 345 kV double circuit	28	76,000,000
base project Total				349,000,000
losses	various	Corridor-Base losses cost	1	0
losses Total				0
production cost penalty	various	no production cost penalty	1	0
production cost penalty Total				0
underlying facilities	Corridor-Base	Hazel Creek-Blue Lake double 345 kV one express underlying facilities	1	111,000,000
	various	Corridor-Base reactive support	1	6,000,000
underlying facilities Total				117,000,000
Grand Total				**466,000,000**

The following table shows the total evaluated cost for the System Alternative. Since the electrical performance of the System Alternative and Corridor-Base options are very similar, the load-cost and production-cost penalties for those options are assumed equal.

Table 6.1b: System Alternative total costs

Project	Hazel-West Waconia 765 kV			
Sum of Facility cost/ M$				
Type	Location	Facility	units	Total
base project	Blue Lake	add 2 345 kV terminations	1	7,000,000
		tertiary shunt reactor	2	3,000,000
	Hazel Creek	develop 765 kV ring bus, 2 terminations, 765/345 transformer	1	60,000,000
		tertiary shunt reactor	3	4,000,000
	Hazel Creek-West Waconia	build 765 kV line	93	372,000,000
	West Waconia	develop 765 kV ring bus, 2 terminations, 765/345 transformer	1	60,000,000
		tertiary shunt reactor	3	4,000,000
	West Waconia-Blue Lake	build 345 kV double circuit	27	73,000,000
base project Total				***583,000,000***
losses	various	System Alternative losses cost	1	-61,000,000
losses Total				***-61,000,000***
production cost penalty	various	no production cost penalty	1	0
production cost penalty Total				***0***
underlying facilities	System Alternative	Hazel Creek-West Waconia 765 kV line underlying facilities	1	112,000,000
	various	System Alternative reactive support	1	2,000,000
underlying facilities Total				***114,000,000***
Grand Total				**636,000,000**

The following table shows the total evaluated cost for the Do Nothing option.

Table 6.1c: Do Nothing total costs

Project	**Do Nothing**			
Sum of Facility cost/ M$				
Type	**Location**	**Facility**	**units**	**Total**
losses	various	Do Nothing Losses Cost	1	150,000,000
losses Total				150,000,000
production cost penalty	various	70% Production Cost Increase + 30% Load Cost Increase over Corridor-Base	1	214,000,000
production cost penalty Total				214,000,000
stability facilities	various	Do Nothing Stability Facilities	1	20,000,000
stability facilities Total				20,000,000
underlying facilities	various	Do Nothing Underlying System Costs	1	176,000,000
underlying facilities Total				176,000,000
Grand Total				**560,000,000**

7: Relevant Concerns

7.1: Load-Serving Issues

Though this study was not primarily focused as an analysis of the load-serving benefits from the options studied, load-serving benefit is expected from the Corridor-Base option. Installation of an in-and-out 345 kV arrangement at Panther and McLeod substations is expected to defer any load-serving facilities for those substations for many years.

7.2: Constructability & Schedule Considerations

7.2.1: Constructability

The main constructability issue is the existing need for the 230 kV line from Granite Falls to the Twin Cities versus the need to make use of that line's corridor in a more efficient way by building a new line (the Corridor-Base option) on that corridor. That 230 kV line is an integral part of the delivery to load of the existing wind generation in southwest Minnesota. If that 230 kV line needs to be taken out of service for construction of a new line on the same corridor, risk of curtailment of wind generation will ensue, and curtailment of wind generally results in higher costs for Minnesota electric customers. This study has not attempted to quantify the amount of potential curtailment or the cost allocation that may apply to such curtailments.

An alternative to taking that 230 kV line out of service for construction would be to build the new facilities alongside that 230 kV line. This possibility has been investigated and seems feasible for part of the route of the Corridor-Base option. Since the System Alternative does not involve any changes to that 230 kV line, the System Alternative avoids this constructability issue.

7.2.2: Schedule

The primary schedule consideration is the need to meet the 2016 milestone of the Minnesota Renewable Energy Standard. Therefore, the base-project facilities need to be in service by the end of year 2015. If the base-project and the required underlying-system facilities are not installed by this time, there is risk the Minnesota load-serving entities will not all be able to meet their portion of the Renewable Energy Standard. Curtailment of wind energy would be likely; such curtailment has been demonstrated in production-cost model (PROMOD) analyses for this study.

The other effect of not having the recommended facilities in place by 2016 is the risk of increased production cost and load cost to meet the energy needs of Minnesota electric customers. As shown in section 6.1, there is a substantial penalty (~200 M$ present value over 40 years) from not having the recommended facilities installed.

The underlying system facilities required must also be installed by the end of year 2015, though the actual facilities installed as underlying facilities may change between the time of this report and year 2016. Were the electric system loads and generation and transmission to develop exactly as modeled, the underlying-system facilities required to be built would be exactly as described in this document. However, many developments of transmission system changes or load changes or generation additions or retirements could affect the list of underlying-system facilities required by year 2016. A simple example of such a change would be a new large industrial load being added at a substation slated in this study for a new capacitor. If that load were added in year 2011, the need for that capacitor may be advanced to 2011. By the time the Corridor Study facilities would be added, that capacitor would no longer be on the list of needed underlying-system facilities.

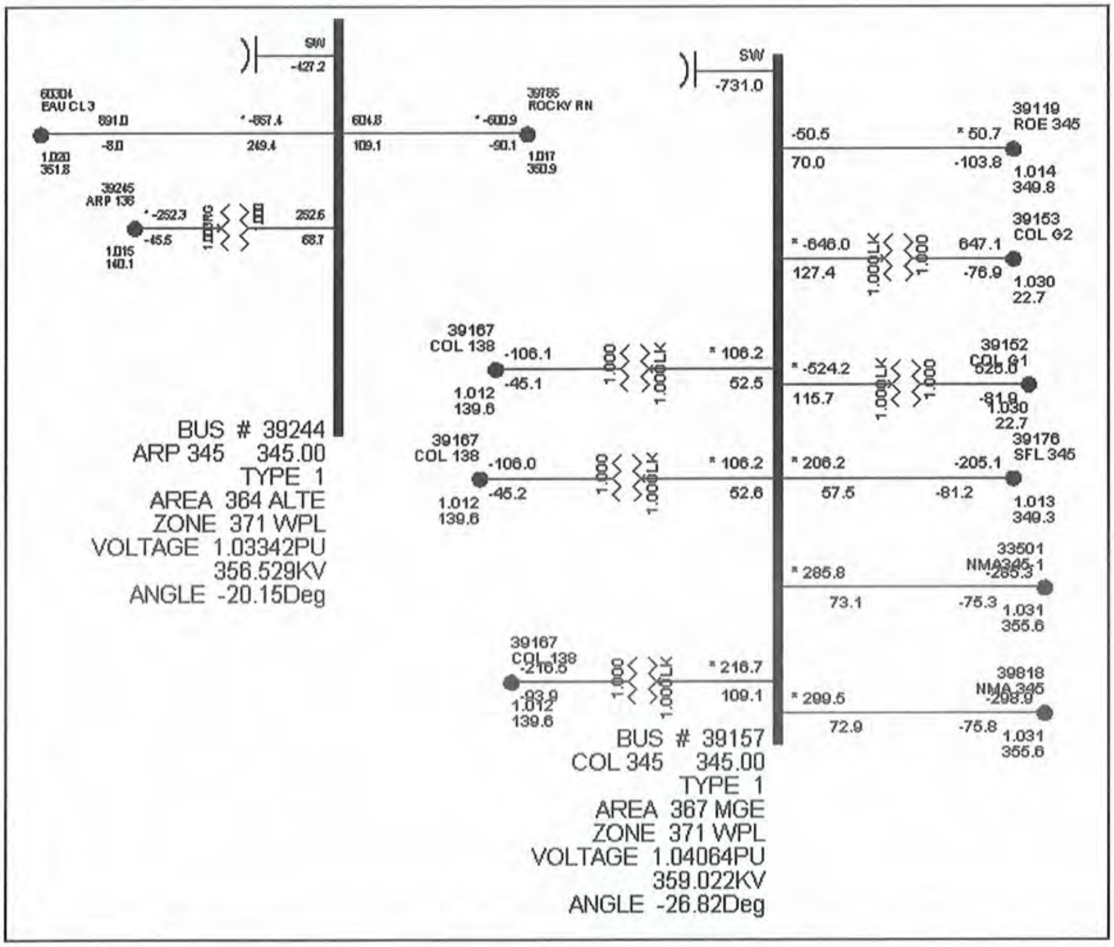
7.3: Facilities Assumed In Place

The modeling started out with the facilities noted in section 4 of this report modeled. As the study continued, those facilities were generally found to be sufficient to meet the needs they were designed to meet. However, with the Corridor-Base plan and 2000 MW of new generation sources, the Hazel Creek-Granite Falls 230 kV line (not yet built) loaded to over 500 MVA under contingency (loss of the Granite Falls-Willmar 230 kV line) and to over 450 MVA under system-intact conditions. Therefore, this line needs to be built for those loading levels. The cost of this is not included in the estimates in this report since this line has not yet been built, and the incremental cost over the present design should be small. Given the high system-intact loading, a large conductor such as 2312 kcm is recommended to minimize losses. Under the System Alternative, this line does not load as highly – 220 MVA under system-intact conditions and 480 MVA under contingency (loss of the Granite Falls-Minnesota Valley Tap 230 kV line).

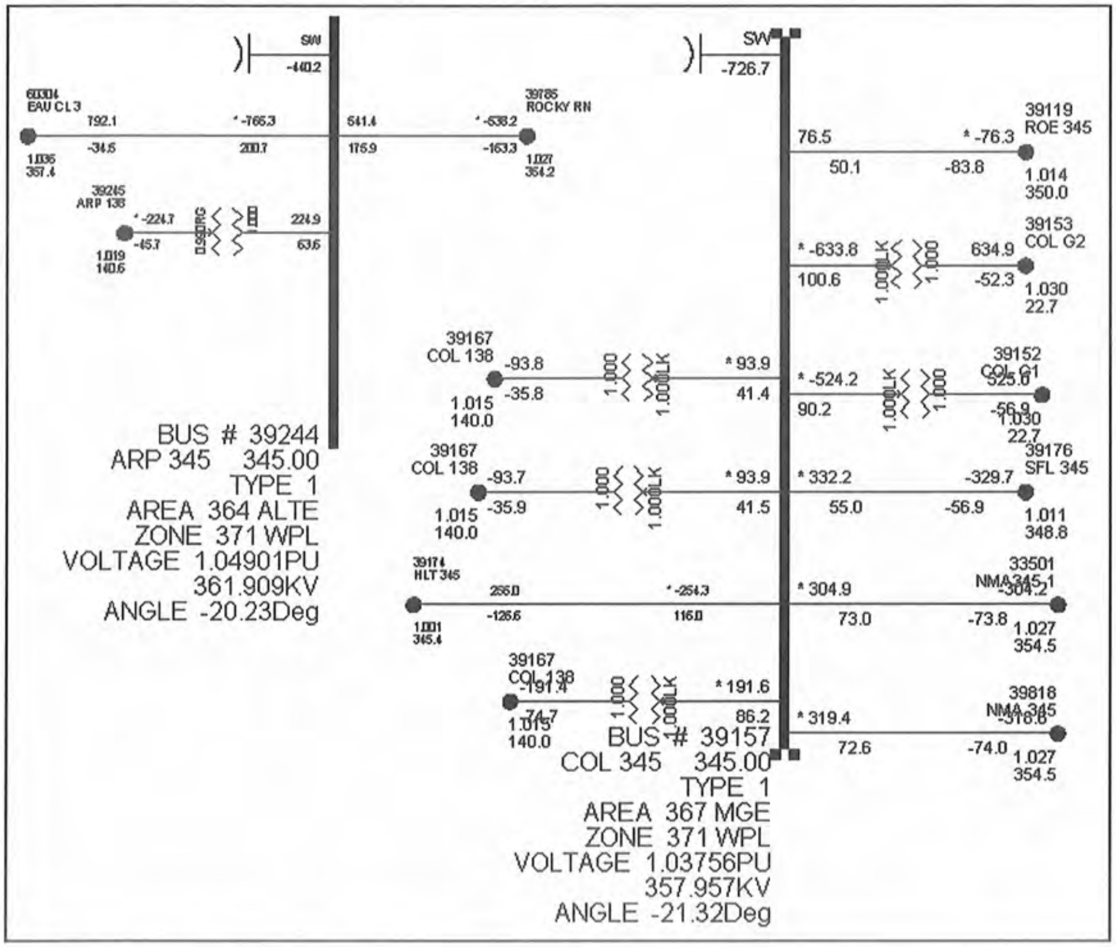
7.4: Underlying System Side Analyses

7.4.1: Side analysis of reactive requirements at Arpin

A small side analysis was performed to investigate the reactive requirements at Arpin and Columbia if a new La Crosse-Madison-area 345 kV line is added. The below diagram shows a Madison-area bus – Columbia 345 kV – and the Arpin 345 kV bus for the Corridor-Base option with 2000 MW new generation in southwest Minnesota and eastern South Dakota, off-peak loads, and MWEX at 1525 MW.

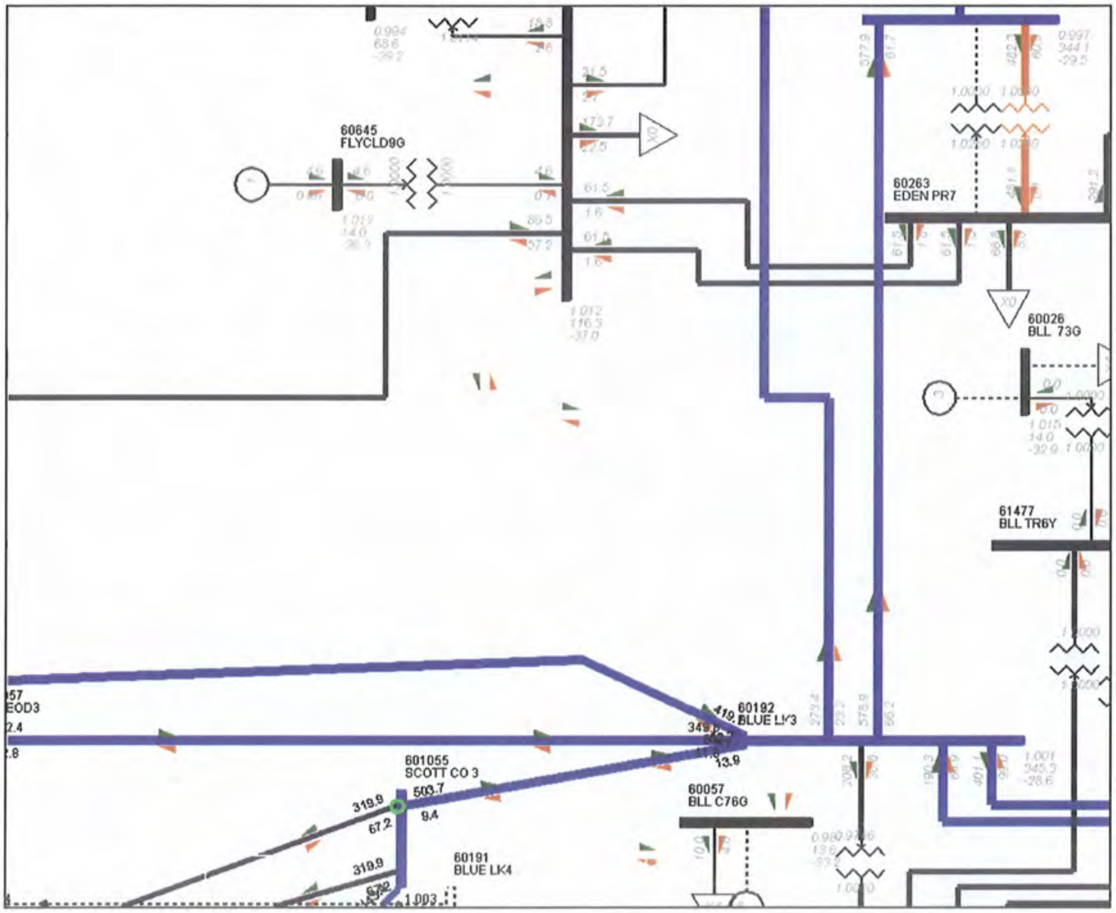


The following diagram shows the same conditions as the above diagram except with the North La Crosse-Columbia 345 kV line added. As can be seen, the reactive needs at Arpin and Columbia are not significantly reduced. This is due to the fact the flow on the 345 kV lines connecting at Arpin is not reduced much by adding the North La Crosse-Columbia 345 kV line.



7.4.2: Eden Prairie 345/115 transformers

To fix the issue of the Eden Prairie 345/115 transformers overloading for loss of each other, the option of adding 345/115 transformation at Scott County was tested; this would be a 345 kV tap on the Blue Lake-Helena line; however, with 2000 MW of wind, Eden Prairie transformer 10 still loaded to 109% for loss of the other bank. The below excerpt from a map shows this effect.



Therefore the best plan for the Eden Prairie transformers appears to be to replace them.

7.5: Dorsey Forbes 500 kV line

As in most studies of added generation west of the Twin Cities with a sink of the Twin Cities or east of the Twin Cities, the power flow on the Dorsey-Forbes 500 kV line was shown to increase in this study. However, the distribution factor of the increase was less than 3% under system-intact conditions. Under outage conditions, the 500 kV line was not shown to overload in any situation. This shows the Corridor-Base option and System Alternative do a good job of efficiently moving the study generation to the Twin Cities area with little impact on the 500 kV line.

Minnesota RES Update Study Report

Volume 1

Prepared for the Minnesota Transmission Owners

Principal Contributors: Michael Cronier and Daniel Kline

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Minnesota Transmission Owners (MTO)*

Basin Electric Power Cooperative
(also representing East River Electric Power Cooperative and L&O Power Cooperative)
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
Great River Energy
Heartland Consumers Power District
Interstate Power and Light
Minnesota Municipal Power Agency
Minnesota Power
Minnkota Power Cooperative
Missouri River Energy Services
(also representing Hutchinson Utilities Commission and Marshall Municipal Utilities)
Northern States Power Company, a Minnesota Corporation (" Xcel Energy")
Otter Tail Power Company
Rochester Public Utilities
Southern Minnesota Municipal Power Agency
Willmar Municipal Utilities

- The Minnesota Transmission Owners are utilities that own or operate high voltage transmission lines within Minnesota. When originally formed, this group was made up of those utilities subject to 2001 legislation requiring transmission owners to file a biennial transmission report. Additional utilities have joined the MTO to collaborate on more recent transmission studies.

Great River Energy, Xcel Energy and Otter Tail Power provided leadership for the studies. The Minnesota Transmission Owners-member utility transmission planning engineers provided valuable input to the study process.

Table of Contents

Listing of Tables and Figures

1.0: Background & Scope of Study

In October 2007, a Work Scope was developed to define study work to be performed by Minnesota utilities. This work was intended to assess the transmission system in the upper Midwest for improvements necessary to develop a robust and reliable transmission system that (i) allows regional utilities to develop generation projects that satisfy the Renewable Energy Standard legislation milestones, and (ii) continues to enable reliable, low cost energy for our region, and (iii) continues developing a robust and reliable transmission system. That Work Scope "seeks to optimize delivery of reliable power, including renewable energy to Minnesota retail customers to build upon the analyses that have previously been done or that are in progress."

The Corridor Study was the first study to help enable the Minnesota utilities to meet the Renewable Energy Standard law. That study evaluated the upgrade of the 230 kV transmission line corridor from the Granite Falls area to the southwest corner of the Twin Cities metropolitan area to double-circuit 345 kV. Initially, it was surmised that the Corridor Upgrade would lead to an increment of 1000 MW of new generation delivery capability. According to calculations of expected wind generation potential at the time, it was believed an additional 1000 MW of generation delivery capability beyond the Corridor Upgrade would be necessary to meet the 2016 RES milestones. Initially, the RES Update Study was focused on identifying the appropriate project to enable that delivery capability.

Results from the Corridor Study demonstrated that the Corridor Upgrade provide sufficient additional generation outlet capacity to assist Minnesota load-serving entities to meet the 2016 milestones set out in the Renewable Energy Standard law through construction of the facilities associated with that study.

After realization that the Corridor facilities could facilitate achieving the 2016 milestones, the focus for this report evolved to determine what facilities should be pursued so load serving utilities can meet the next milestones set out in the Renewable Energy Standard law. One of the main focuses was to look at sending the power to the Midwest ISO market. This creates a realistic model of the transmission system in which "Locational Margin Pricing" (LMP) drives the dispatch of generation. In addition, utilities in neighboring states are signing power purchase agreements with wind projects located in the state of Minnesota to meet their renewable requirements. This drives a need for utilities to investigate additional options for increasing generation delivery to ensure sufficient capacity is available to allow new renewable generation projects to connect to the transmission grid.

As with the Corridor Study, this study aims to build a foundation to determine the best bulk transmission improvement plan for society. This is not an easy task, as different generation and transmission projects, philosophies, and requirements are constantly changing. Certain assumptions have to be made determining study sources and sinks. This involves creating transmission to enable a certain amount of delivery from the study generation sources to the study generation sinks. The generation sources and sinks used are intended to be indicative of general patterns. Where a particular bus is used as a source, it could represent a future project at that bus or at any bus nearby. Source and sink buses are typically chosen to minimize transmission system limitations in the immediate vicinity of the source bus.

After analysis, the best plan among studied alternatives is recommended. Along with the analysis of the options goes analysis of the underlying system facilities required with each option. The idea is to determine the best plan considering as many effects as possible. However, the inclusion of underlying facilities in this report serves only to aid in weighing the best plan. If new generation develops in a pattern differing from the patterns studied, the underlying facilities may change; those included in this report served only as a basis for determining the total possible costs of the options. With these costs and electrical system study results, a preferred plan can be developed to enable delivery of the new generation sources.

The stakeholders involved in the development of Minnesota-area electric transmission have a desire to maximize the use of existing rights-of-way to the extent possible given the need to meet NERC standards. To this end, transmission developers often look to upgrade the power-carrying capability of existing rights-of-way. But as the transmission system continues to change, new facilities on new right-of-way occasionally need to be developed to help optimize the power grid with these new renewable power resources.

2.0: Conclusion

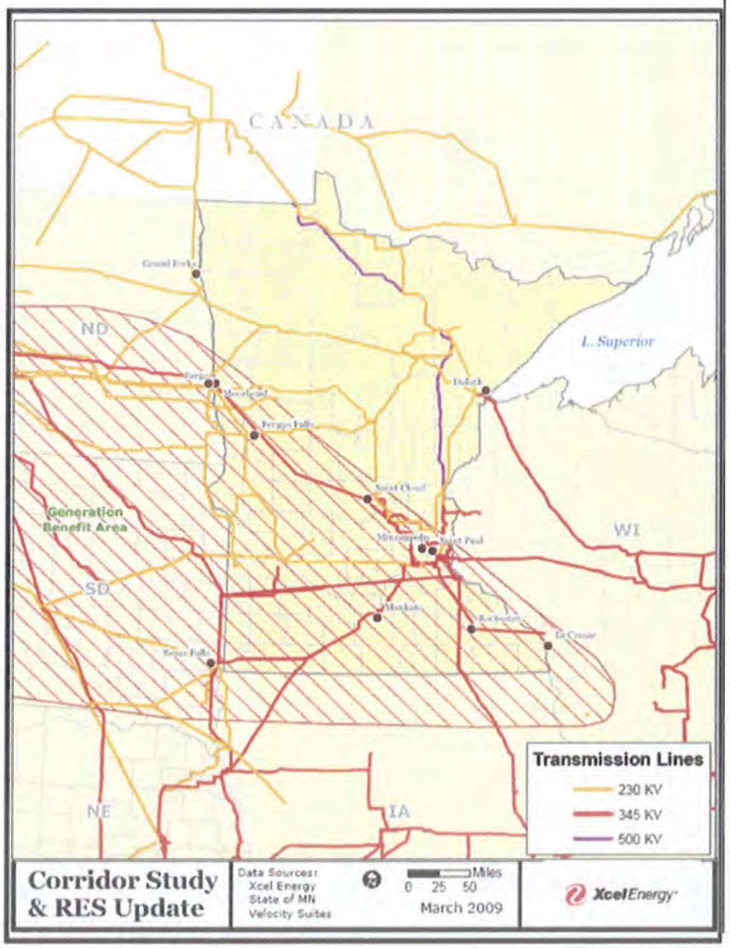
All the facilities studied provide some level of outlet capability. A few of the projects actually create a 40-year cost savings if the power is delivered to the Midwest ISO market.

The La Crosse – Madison 345 kV line provides the greatest overall system benefits in the studied time frame. This line creates a third path south and east of the Twin Cities towards Chicago. This is proven in the southwest zone thermal analysis by providing up to 3600 MW of generation delivery capability beyond the base model.

The Fargo – Brookings Co. and Ashley-Hankinson 345 kV lines provide great outlet capability for North Dakota and western Minnesota, but this outlet capability is limited for the Midwest ISO Market without the La Crosse – Madison line. The other lines that benefit the system are the Brookings Co – Split Rock, Lakefield – Adams, and Adams – L a Crosse 345 kV lines. Figures 2.0.A and 2.0.B show the full RES facilities and generation benefit area.

Figure 2.0.A – RES Transmission Facilities

Figure 2.0.B – RES Generation Benefit Area



One key finding was shown in stability analysis. The dynamic stability analysis showed that there could be an operational limit achieved with increased wind penetration. This operational limit is created due to backing off existing generation in the Twin Cities to allow wind generation to interconnect. This causes instability during various disturbances. This phenomenon is especially noticeable when Sherco 3 is tripped and the system spins out of control. Generally, wind generators do not have much inertia, unlike traditional generation plants. The overall system inertia allows the system to recover after a major disturbance.

This instability issue drives the need for new transmission out of the state – either to allow existing generation to remain in-service and provide stability to the system or to tie the system more closely to external generation sources. Additional studies will be needed to determine which transmission facilities will be required to achieve levels of renewable energy penetration beyond the 7000 MW studied here.

3.0: Study History & Participants

As mentioned, in October 2007 the Work Scope covering this study (and other studies) was issued. The following table shows the parties to that Work Scope.

Table 3.0.A – Study Participants

Basin Electric Power Cooperative	Minnesota Power
Central Minnesota Municipal Power Agency	Minnkota Power Cooperative
Dairyland Power Cooperative	Missouri River Energy Services
Heartland Consumers Power District	Northern States Power Company d/b/a Xcel Energy
Great River Energy	Otter Tail Power Company
Interstate Power & Light Company	Rochester Public Utilities
Minnesota Municipal Power Agency	Southern Minnesota Municipal Power Agency
	Willmar Municipal Utilities

In November 2007, initial meetings were held to introduce the study of the upgrade of the Granite Falls-Southwest Twin Cities Area 230 kV line. The study was referred to as the "Corridor Study". Project Managers, Transmission Planners, and Substation Engineers gathered within Xcel Energy to define roles and a draft scope.

In January 2008, meetings were held to discuss model development and better define the scopes of the RES and Corridor studies. Due to the RES legislation and the many interested stakeholders, it was known that the study would be a very public study. Therefore some parts of the study took longer than in traditional studies, but the time resulted in a better study. An example of this is the model building; as opinions resulted in assumptions changing, the models had to be changed, but the result was a set of accurate, dependable models. The model building was largely completed by April 2008.

In March 2008, anticipating the need to rebuild the existing 230 kV corridor and the difficulty in obtaining construction outages along this corridor, the scheduling of construction and the interaction between the proposed Corridor Study facilities and existing transmission facilities began to be considered. These issues are often referenced by the term "constructability". Since some transmission facilities may need to be out of service during construction of new facilities, some generation may need to be curtailed during construction. Issues like these have been investigated over the course of the study.

In September 2008, preliminary results were presented to the public at the joint Northern-MAPP Subregional Planning Group (NM-SPG) and Missouri-Basin Subregional Planning Group (MB-SPG) meeting in Duluth, Minnesota.

As part of a separately-legislated effort, the DRG Phase I Study, a group of engineers was assembled by the Minnesota Office of Energy Security. This group was called the

Technical Review Committee (TRC) and was formed to serve as an advisory group to the Dispersed Renewable Generation Study. Given the technical expertise collected in this group, the TRC served as a technical sounding board for the scope, assumptions, and results of the Corridor and RES Update studies. Meetings of this group were held in October 2007, December 2007, February 2008, April 2008, May 2008, September 2008, October 2008, February 2009, and March 2009. At each meeting, the status and findings of this study were presented.

4.0: Analysis

4.1: NERC Criteria

Transmission 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). If those criteria are met, the transmission system will remain stable, all voltage and thermal limits 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 constantly monitored and changed as deemed necessary to avoid large outages and blackouts. Most often, the criteria are made more rigorous in response to real-world events and as engineers learn better ways to ensure reliability of the transmission system. The criteria most applicable to transmission planning are listed in Appendix A.

4.2: Models Employed

4.2.1: Steady-State Models

The base models used for the steady-state (power flow) analysis are the models of the year 2013 summer peak load and summer off-peak load conditions from the MTEP07 series of models created by Midwest ISO for the Midwest ISO Transmission Expansion Plan (MTEP) process. These models were chosen for study work because

- they are consistent with the models most used by Midwest ISO for steady-state work,
- they afford the best topology available for the Eastern Interconnect – the electric system spanning all of the United States east of the Rocky Mountains and outside of Texas.,
- they are being used for other similar studies (the DRG study, for one),
- they are well documented and well understood.

In addition, any PROMOD analysis related to this study was created and performed by Midwest ISO on a PROMOD MTEP model which was best available. So there is good compatibility between the steady-state transmission (PSS/E) model chosen and the models to be used for PROMOD work.

4.2.2: Dynamics Models

The base model used for the dynamic analysis came from the NORDAGS (Midwest ISO's North Dakota Group Study) Group 1 models. The reasons for choosing this model were that it aligns well with the study timeframe of the year 2015 and is compatible with the NMORWG (Northern Mid-Continent Area Power Pool (MAPP) Operating Review Working Group) stability package. The NMORWG stability package is widely used for MRO and MAPP studies in the upper Midwest area. The NORDAGS model was built from the same base operating model used in the 2006 NMORWG package and updated for the recent System Impact Studies for NORDAGS. The validity of the stability model is also of particular importance because these models have been reviewed and documented quite extensively and their accuracy has been confirmed by utilities throughout the region. After the appropriate model from NORDAGS was selected, the topology had to be updated along with the corresponding files in the package to make the model used in the steady-state analysis. These changes include updates to the CapX 2020 Group 1, BRIGO[1], and RIGO[2] facilities.

4.3: Conditions Studied

4.3.1: Steady-State Modeling Assumptions

The in-service date planned for the conversion of the Minnesota Valley-Blue Lake 230 kV line corridor is 2016. This timing is due to the desire to have added transfer capability to support load serving entities' to satisfy the State of Minnesota's Renewable Energy Standard for 2016. This study piggy-backed the Corridor Study so therefore, the year 2016 was chosen as the year to study along with using the same models.

Due to the need to look at both load-serving ability and transfer capability, the decision was made to analyze system performance under both summer peak and summer off-peak load conditions. To accommodate the Minnesota Conservation Improvement Program (CIP), the decision was made to have the loads not quite as high as they would be otherwise. In the peak-load case, the loads in the 2013 case were scaled up to be not quite at the 2016 level with no Conservation Improvement Program. The off-peak load levels were 61% of those in the peak model based on a Midwest ISO analysis that showed the highest line loadings happened at 61.2%. The table below shows the control areas included in the Study Area

[1] The BRIGO (Buffalo Ridge Incremental Generation Outlet Study) focused on increasing wind outlet capacity of the transmission system in the Buffalo Ridge area.

[2] The RIGO (Regional Incremental Generation Outlet Study) focused on increasing wind outlet capacity of the transmission system in areas outside the Buffalo Ridge area. This transmission study looked at west-central Minnesota and southeastern Minnesota 115 kV or 161 kV line improvements with an in-service goal of 2011. Since the time models were developed, the number has decreased slightly and is a factor in the range of generation deliverability that will exist by 2016.

Table 4.3.1.A – Control Area for Load Scaling

Area Number	Area Name
331	Alliant West
600	Xcel Energy
608	Minnesota Power
613	Southern Minnesota Municipal Power Agency
618	Great River Energy
626	Otter Tail Power
633	Muscatine Power & Water
635	MidAmerican Energy
640	Nebraska Public Power District
645	Omaha Public Power District
650	Lincoln Electric System
652	Western Area Power Administration
667	Manitoba Hydro
672	SaskPower
680	Dairyland Power Cooperative

The generation levels used for previously planned projects are shown in the following Table 4.3.1.B. The sinks for generation added were the Black Dog, Blue Lake, Inver Hills, and Riverside generators in the Twin Cities.

Table 4.3.1.B – Additional Generation Added

BRIGO	MW Additional
Fenton	187.5
Yankee	187.5
TOTAL	**375**
RIGO	**MW Additional**
Pleasant Valley	722
Pleasant Valley	200
TOTAL	**922**
Brookings Study	**MW Additional**
Toronto	105
Canby	70
Yankee	105
Brookings Co.	105
Fenton	105
Nobles	105
Lakefield	105
TOTAL	**700**

The performance of any bulk electrical system is significantly affected by the power transfers across it. For the study, it was recognized the new facilities proposed would have to enable the system to carry existing firm transfers, new energy transfers, and possibly some non-firm transfers (to allow room for growth of future firm transfers). Therefore, in the off-peak case, transfers were changed to be consistent with the "maximum simultaneous" transfers often studied in the MAPP region. The existing transfer limits are

- North Dakota Export (NDEX) of 2080 MW,
- Manitoba Export (MHEX) of 2175 MW,
- Minnesota-Wisconsin Export (MWEX) of 1525 MW,
- Boundary Dam phase shifter southward flow of 150 MW,
- International Falls phase shifter southward flow of 100 MW.

In the peak-load case, the transfers in the base case were not changed for the study work. The Midwest ISO-supplied case already had firm transfers consistent with data submitted for on-peak modeling.

Since the definition of export interfaces such as NDEX can change as future transmission lines are added, it is customary to set the transfer levels in a case prior to any major new transmission lines being added to that model. This was the case for this study. The CapX 2020 lines and future lines under study were not part of the model as the export levels were set. This avoids skewing the export levels under study.

Due to the fact the MTEP07 models contained the 2004 version of the Midwest Reliability Organization's (MRO's) electric power system for non-members of Midwest ISO, which system's representation had to be updated in the MTEP07 models by taking that system's representation from the MRO 2007 models and incorporating it into the MTEP07 models.

The major model modifications are as follow:

- The only Midwest ISO-planned facilities left in the models are those in Appendix A of the Midwest ISO Transmission Expansion Plan; those planned facilities with less certainty – such as those in Appendix B or C – were removed.
- Similarly uncertain facilities from MAPP's 10-year plan were removed.
- Facilities from the Buffalo Ridge Incremental Generation Outlet (BRIGO) study were included.
- Facilities from the Regional Incremental Generation Oultet (RIGO) study were included; this includes approximately 922 MW of new generation.
- The CapX 2020 Group 1 base facilities were added.
- Fictitious generators added by Midwest ISO and known as Strategist Units were removed.
- Generation in the southwest Minnesota area was set to be 1900 MW; this includes the "825 MW" plus the BRIGO generation up to approximately 1200 MW and another 700 MW enabled by the Brookings County-Twin Cities 345 kV development. Based on Midwest ISO interconnection queue information, all of this generation was assumed to be wind.
- The Lakefield Generation gas and wind units were assumed to be running at 550 MW total.

The models required addition of five 100 MVAR shunt capacitor banks on the Arpin 345 kV bus; without those capacitors, the high MWEX flows caused the system-intact voltage at Arpin Substation to be below 0.95 pu. The model showed the need for those capacitors to be on the 345 kV bus. The Arpin 138 kV bus already has two 50 MVAR capacitors; if more 50 MVAR capacitors were added there, the flow up to the 345 kV bus overloaded the Arpin 345/138 transformer. A similar bank of nine 75 MVAR shunt capacitor banks was added to the Columbia 345 kV bus; voltage at this bus under contingency was very low without those capacitors.

During the study, the study team became uncertain about the future of Big Stone II and whether it will proceed in light of current circumstances. Therefore, for the bulk of the study work, Big Stone II generation and transmission were not included in the models. Big Stone II generation and transmission were not included in the models used to arrive at the conclusions and recommendations stated in this report.

Modeling of the scenario of no Big Stone II generation or related transmission was accomplished by turning off the Big Stone II generator and the associated transmission. The replacement power for Big Stone II generation came from each of the Big Stone II partners' generation plans and existing generation not running in the models. The table below shows those replacement power sources. This study also performed sensitivity with respect to Big Stone II generation and transmission.

The three scenarios studied in the steady-state analysis included the following:

1. Existing 230 kV Corridor
    - Without Big Stone II
2. Corridor double circuit 345 kV Upgrade with from Hazel Creek to Blue Lake
    - Without Big Stone II
3. Corridor double circuit 345 kV Upgrade back to Big Stone
    - Big Stone II
    - Corridor generation

Table 4.3.1.C – Base Model Descriptions

Parameter	Peak model	Off-peak model
Generation Changes	• Black Dog and Blue Lake and Inver Hills and Riverside generators in the Twin Cities used as sinks for wind from "825", BRIGO, "Brookings", and RIGO studies.	• Black Dog and Blue Lake and Inver Hills and Riverside generators in the Twin Cities used as sinks for wind from "825", BRIGO, "Brookings", and RIGO studies. • Study area generation reduced to the levels needed for the 60% load level.
MHEX	Unchanged from Midwest ISO-supplied model	2175 MW
NDEX	Unchanged from Midwest ISO-supplied model	2080 MW
MWEX	Unchanged from Midwest ISO-supplied model	1525 MW
MN Wind	2582 MW	
ND Wind	411 MW	
SD Wind	160 MW	
IA Wind	770 MW	
WI Wind	95 MW	
MB Wind	0 MW	
Transmission Changes	• The only Midwest ISO-planned facilities left in the models are those in Appendix A of the Midwest ISO Transmission Expansion Plan; those planned facilities with less certainty – such as those in Appendix B or C – were removed.	

	• Similarly uncertain facilities from MAPP's 10-year plan were removed. • Facilities from the Buffalo Ridge Incremental Generation Outlet (BRIGO) study were included. • Facilities from the Regional Incremental Generation Oultet (RIGO) study were included; this includes approximately 922 MW of generation. • The CapX 2020 Group 1 base facilities were added. • Fictitious generators added by Midwest ISO and known as Strategist Units were removed. • Generation in the southwest Minnesota area was set to be 1900 MW; this includes the "825 MW" plus the BRIGO generation up to approximately 1200 MW and another 700 MW enabled by the Brookings County-Twin Cities 345 kV development. • The Lakefield Generation gas and wind units were assumed running at 550 MW total.
Facility Rating Changes	Xcel Energy ratings as of 2008.12.27 were used; other companies' ratings were mostly unchanged from the model supplied by Midwest ISO except for those changed in the "MRO model" transplant and as suggested by reviewers.
Study Timeframe	Year 2016.

In addition to the Corridor generation sources, the following tables show the sources under the various sensitivity scenarios.

Table 4.3.1.D – Corridor Generation Sources

Bus identifier	Bus name	Generation MW
60286	Nobles County 345 kV	235
60383	Brookings County 345 kV	471
60393	Fenton 34.5 kV	176
60394	Yankee 34.5 kV	176
60500	Lyon County 345 kV	353
66550	Granite Falls 230 kV	353
66554	Morris 230 kV	235
	Total	2000

Figure 4.3.1.E – Additional Sourcing Zones

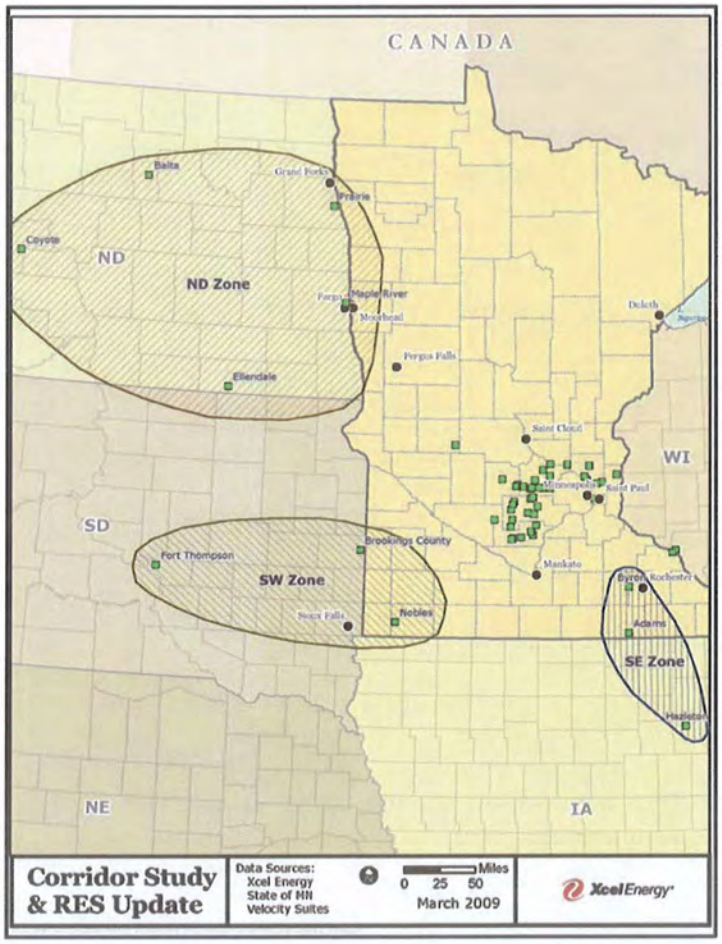


Table 4.3.1.F – SE Zone Sources

Bus identifier	Bus name	Generation Source
60102	Adams 345 kV	750
61950	Byron 345 kV	750
34018	Hazleton 345 kV	500
	Total	2000

Table 4.3.1.G – SW Zone Sources

Bus identifier	Bus name	Generation MW
60286	Nobles County 345 kV	750
60383	Brookings County 345 kV	750
60393	Big Bend 230 kV	500

	Total	2000

Table 4.3.1.H – ND Zone Sources

Bus identifier	Bus name	Generation MW
67315	Coyote 24 kV	200
63053	Balta 230 kV	300
66755	Prairie 230 kV	400
67326	Ellendale 230 kV	500
66754	Maple River 230 kV	600
	Total	2000

Table 4.3.1.I – Overall Sources

Bus identifier	Bus name	Generation MW
67315	Coyote 24 kV	100
63053	Balta 230 kV	100
66755	Prairie 230 kV	150
67326	Ellendale 230 kV	200
66754	Maple River 230 kV	250
60102	Adams 345 kV	300
61950	Byron 345 kV	300
34018	Hazleton 345 kV	250
60286	Nobles County 345 kV	300
60383	Brookings County 345 kV	300
60393	Big Bend 230 kV	250
	Total	2500

4.3.2: Dynamic Modeling Assumptions

Using the NORDAGS Study Package, the 2015 Summer off-peak "A04" model fits well with time frame of the this study. This case was updated to include all CapX 2020 Group 1, BRIGO, and RIGO facilities. As well as a few modeling changes to match the steady-state topology. A special sensitivity was also performed to evaluate the Big Stone II generation and transmission impacts. A total of eighteen scenarios were evaluated in this analysis. The table below shows a summary of the cases.

Table 4.3.2.A – Dynamic Case Descriptions

Case Name	BS II Status	Transmission Additions	Generation Level
R00	OUT	CapX, BRIGO, RIGO facilities	Exising Modeled
R02	OUT	CapX, BRIGO, RIGO facilities	2822 MW
R04	OUT	CapX, BRIGO, RIGO facilities	4822 MW
RC2	OUT	R02, Corridor facilities	2822 MW
RC4	OUT	R02, Corridor facilities	4822 MW
RL4	OUT	RC2, La Crosse-Columbia 345 kV	4822 MW
RE4	OUT	RC2, RES facilities	4822 MW
RE6	OUT	RC2, RES facilities	6822 MW
RE7	OUT	RC2, RES facilities	7322 MW
B00	IN	CapX, BRIGO, RIGO facilities	Exising Modeled
B02	IN	CapX, BRIGO, RIGO facilities	2822 MW
B04	IN	CapX, BRIGO, RIGO facilities	4822 MW
BC2	IN	B02, Corridor facilities	2822 MW
BC4	IN	B02, Corridor facilities	4822 MW
BL4	IN	BC2, La Crosse-Columbia 345 kV	4822 MW
BE4	IN	BC2, RES facilities	4822 MW
BE6	IN	BC2, RES facilities	6822 MW
BE7	IN	BC2, RES facilities	7322 MW

The Corridor facilities include replacing the Minnesota Valley-Blue Lake 230 kV line with a double circuit 345 kV line from Hazel Creek to Blue Lake. The RES facilities include a Maple River-Hankinson-Big Stone-Brookings County 345 kV line, an Ashley-Ellendale-Hankinson 345 kV line, Brookings County-Pipestone-Split Rock 345 kV line, Lakefield-Winnebago-Hayward-Adams 345 kV line, Adams-Genoa-North La Crosse 345 KV line, and the North La Crosse-Hilltop-Columbia 345 kV line.

The generation additions added to the model incorporate user-written dynamic models for Clipper, GE, and Vestas turbines. The generation additions were split among the three at each source bus. These splits include 70% for GE (Type III), 15% for Clipper (Type IV), and 15% for Vestas (Type II). This division of wind turbines was developed in consultation with the TRC and was intended to provide an approximation of future generation projects required to fulfill the 2822, 4822, and 7322 MW levels.

4.4: Conditions Studied

4.4.1: Steady-state Contingencies Modeled

The contingency list used was produced by the Midwest Reliability Organization and Midwest ISO; it contains the complex NERC Category B and Category C contingencies commonly used for bulk transmission studies in the Minnesota area. A list of the approximately 7,000 complex contingencies can be found in Appendix B. The following table shows the control areas used for taking single contingencies; all 100 kV and above branches (transformers and transmission lines) were taken as contingencies one at a time. In addition, all the generators in those areas were taken out of service one at a time, and all the 100 kV and above ties from those areas were taken as contingencies one at a time.

Table 4.4.1.A – Contingency Areas

Area Number	Area Name
331	Alliant West
364	Alliant East
365	Wisconsin Energy
366	Wisconsin Public Service
367	Madison Gas & Electric
368	Upper Peninsula Power Company
600	Xcel Energy
608	Minnesota Power
613	Southern Minnesota Municipal Power Agency
618	Great River Energy
626	Otter Tail Power
633	Muscatine Power & Water
635	MidAmerican Energy
640	Nebraska Public Power District
645	Omaha Public Power District
650	Lincoln Electric System
652	Western Area Power Administration
667	Manitoba Hydro
680	Dairyland Power Cooperative

4.4.2: Dynamic Disturbances Modeled

The table below lists the regional disturbances that were analyzed for this system impact study. These disturbances have been used consistently when evaluating projects in the Northern MAPP region. Appendix C contains the description of all fault files that were included in the stability analysis and the dynamic models used for the new generation.

Table 4.4.2.A – Regional Disturbances

Fault Name	Faulted Bus	Fault Type	Clearing Time (cycles)	Initial Clearing	Backup Clearing (cycles)	Backup Clearing
AG1	Leland Olds 345kV	SLGBF	4	Leland Olds-Ft Thompson line	11	FLTD Line
AG3	Leland Olds 345kV	3-phase	4	Leland Olds-Ft Thompson line		
EI2	Coal Creek 230kV	fault	10	CU HVDC bipole	7	Coal Creek 1&2
EQ1	Coal Creek 230kV	SLGBF	4.5	CU HVDC #1	11	Coal Creek #2
FD9	Square Butte 230kV	3-phase	4	Square Butte-Stanton 230kV line		
MAD	Dorsey 500kV	3-phase	4	Dorsey – Forbes 500kV line		
MQS	Sherco	SLGBF	4	Sherco #3	9	Sherco-Benton Co
MSS	Sherco	SLGBF	4	Sherco-Coon Creek 345 kV line	9	Coon Ck 345/115 Tx
MTS	Monticello 345kV	SLGBF	5	Monticello-Elm Creek line	9	Monticello bus
NAD	Forbes 500kV	3-phase	4	Forbes – Dorsey 500kV line		100% DC reduction
NMZ	Chisago Co 500kV	3-phase	4	Chisago Co – Forbes 500kV line		100% DC reduction
PAS	Forbes 500kV	SLGBF	4	Forbes – Dorsey 500kV line	13	Forbes-Chisago Co
PCS	King 345kV	SLGBF	4	King – Eau Claire 345kV line	14	King-Chisago Co
PCT	King 345kV	Trip	-	King – Eau Claire 345kV line		
PYS	Prairie Island 345kV	SLGBF	4	Prairie Island - Byron 345kV line	14	PI 345/161 Tx
PYT	Prairie Island 345kV	Trip	-	Prairie Island - Byron 345kV line		

4.5: Options Evaluated

The transmission line projects studied for completion after the Corridor Upgrade included the following:

4.5.1: La Crosse - Madison Project

Due to constraints in the transmission system in Wisconsin, the possibility of a new facility extending further into Wisconsin was studied. The La Crosse – Madison project concept is currently being reviewed by engineers at several regional utilities to determine the most effective topology for the proposed facility. For purposes of this study, such a line was assumed to begin at North La Crosse and end at Columbia power plant north of Madison.

This assumption was made with the knowledge that it is difficult to route additional transmission facilities into Columbia Substation. However, given the existing transmission at the Columbia plant, it served as a desirable proxy for the line to avoid dealing with unforeseen transmission constraints at the Madison end of the proposed line that would likely be addressed by any ultimate project configuration. It is the opinion of the study team that any eventual La Crosse – Madison project topology would produce substantially similar electrical results as the proposal that was studied.

From North La Crosse Substation, the assumed project constructed 75 miles of new double-circuit 345 kV line to the existing Hilltop Substation. Expansion of Hilltop Substation to include 345 kV transformation was assumed. From Hilltop Substation, approximately 65 miles of double-circuit 345 kV line was constructed to Columbia Substation.

Figure 4.5.1.A – La Crosse-Madison Project

4.5.2: Fargo-Brookings County Project

The Fargo – Brookings County project is a double-circuit 345 kV line utilizing both new and existing right-of-way between Fargo, North Dakota and the existing Brookings County Substation in South Dakota. The project begins with approximately 60 miles of new double-circuit 345 kV line between Fargo and the existing Hankinson 230 kV Substation. At Hankinson, a new 345/230 kV transformation would be installed to serve as a high-voltage injection point for new generation sourced in North Dakota.

From Hankinson Substation, the existing Hankinson – Big Stone 230 kV line would be removed and replaced with a double-circuit 345 kV line. The total mileage of this segment is 70 miles. In the middle of this segment is the existing 230/41.6 kV Browns Valley Substation. This is a load-serving substation that serves a portion of Otter Tail Power Company load in South Dakota and Minnesota. As part of this project, Browns Valley would be converted to a 345/115/41.6 kV substation. The 41.6 kV load would be served off the transformer tertiary and the 115 kV secondary would be available to serve future load-serving or generation delivery projects.

Extending south from Big Stone, 75 miles of new double-circuit 345 kV line would be built to ultimately connect to the existing Brookings County Substation.

Figure 4.5.2.A – Fargo-Brookings County Project

4.5.3: Ashley-Hankinson Project

The Ashley – Hankinson 345 kV project is a 345 kV spur from eastern North Dakota extending into central North Dakota. The general territory through which this line would pass includes some of the most prominent wind regimes in the upper Midwest.

Where the existing Leland Olds – Groton 345 kV line crosses the Ellendale – Wishek 230 kV line, this project would propose to build Ashley Substation. Currently, the rich wind regime in this area is limited in delivery capability by the 230 kV line that was designed to serve load in the area. Ashley Substation would be a new 345/230 kV substation that would insert a new injection point into the 345 kV transmission system. From there, a 125-mile single-circuit 345 kV line would be constructed along new right-of-way to Hankinson Substation. New right-of-way would be necessary because the existing system in this area is limited by outage of Ellendale – Forman – Hankinson 230 kV line – the only possible double-circuit candidate.

Figure 4.5.3.A – Ashley-Hankinson Project