PSC REF#:158023

Public Service Commission of Wisconsin
RECEIVED: 01/09/12, 10:48:51 AM

4.5.4: Brookings-Split Rock Project

The Brookings – Split Rock project is a new double-circuit 345 kV line that connects the existing Brookings County Substation to Split Rock Substation. From Brookings County Substation, 45 miles of new double-circuit 345 kV transmission line would be constructed to the existing Pipestone Substation.

One of the significant benefits to this project is that Pipestone Substation, an existing 115 kV substation, would be expanded to become a new injection point into the 345 kV transmission grid. With the addition of 345/115 kV transformation, Pipestone would join Brookings County, Nobles County, and Lyon County as significant injection points that enable generation resources to reach load centers. This expansion becomes increasingly necessary as the amount of wind generation that depends on transformation at Brookings County continues to grow.

From Pipestone Substation, 50 miles of new double-circuit 345 kV line would be constructed to Split Rock Substation near Sioux Falls, South Dakota. The completion of this circuit would expand the reliability benefits of the Fargo – Brookings County project to include the recently-constructed Split Rock – Lakefield Junction 345 kV transmission line. With a Fargo – Brookings County – Split Rock 345 kV transmission line in place, all four 345 kV lines between the Twin Cities and points to the west would be connected.

Figure 4.5.4.A – Brookings County-Split Rock Project

4.5.5: Lakefield-Adams Project

Lakefield and Adams Substations are currently connected via a single-circuit 161 kV transmission line that serves a number of communities in southern Minnesota. ITC Midwest has announced tentative plans to increase the capacity of this line, but this study assumed the upgrade of this path to double-circuit 345 kV.

From Lakefield Substation, the 161 kV line to Winnebago Substation was replaced with 55 miles of double-circuit 345 kV line. Winnebago Substation was assumed to be upgraded to 345/161 kV in order to ensure it would still be able to serve load in the surrounding area. Leaving Winnebago Substation, the existing 161 kV line to Hayward Substation was replaced with 50 miles of new double-circuit 345 kV line. Similar to Winnebago Substation, Hayward Substation was also converted to include 345/161 kV transformation. Each of these transformations is significant because it also provides a new injection point for generation to reach the high-voltage transmission grid.

From Hayward Substation, the existing Hayward – Adams 161 kV line was replaced with 37 miles of 345 kV double-circuit line.

Figure 4.5.5.A – Lakefield-Adams Project

4.5.6: Adams-La Crosse Project

With the significant interest in siting generation in southeastern Minnesota, it was necessary to investigate projects sited to enable additional generation to develop in that area. The Adams – North La Crosse project was designed with that in mind. From the existing Adams 345/161 kV substation, the existing Adams – Harmony 161 kV line was replaced with approximately 35 miles of new double-circuit 345 kV line. This construction would require the expansion of Harmony to include 345/161 kV transformation.

From Harmony Substation, the existing Harmony – Genoa 161 kV line would be replaced with approximately 45 miles of double-circuit 345 kV line. Similar to Harmony Substation, Genoa Substation would be expanded to include 345/161 kV transformation. From Genoa, approximately 20 miles of double-circuit 345 kV line would be constructed to the north, ultimately tying into the existing North La Crosse 345 kV substation.

This project would also have the dual benefit of bringing a new injection point into the La Crosse area. As load in the La Crosse area grows, the existence of a single 345 kV transmission source at North La Crosse will eventually strain the ability of the transmission grid to serve area load for loss of the 161 kV circuit extending south of North La Crosse into the La Crosse area. Inserting this 345/161 kV injection point at Genoa Substation will provide a new injection point remote from North La Crosse Substation.

Figure 4.5.6.A – Adams-La Crosse Project

4.5.7: Additional Projects Initially Reviewed

Beyond the six facilities previously discussed, seven other facilities were initially evaluated. These projects were studied as possible alternatives for the Minnesota RES evaluation. These projects include the following:

- Dorsey-Prairie-Maple River 500 kV line
- Center-Jamestown-Maple River 345 kV line #2
- Center-Jamestown-Prairie 345 kV line
- Broadland-Brookings Co 345 kV line
- Wilmarth-North Rochester 345 kV line
- Genoa-Salem 345 kV line

The Dorsey-Prairie-Maple River 500 kV line was evaluated due to the current Manitoba Hydro Transmission Service Request (TSR) which is currently being studied to deliver future hydro generation in Manitoba to load centers in the United States. Due to the timing of these two studies and unknown facilities required by the TSR, future studies will be required to evaluate its impact.

Both the Center-Jamestown-Maple River 345 kV line #2 and Center-Jamestown-Prairie 345 line are potential options currently being studied by Minnkota Power Cooperative for their load serving and existing generation outlet capability needs. A new line from Center will be required to provide outlet capability when they take solo ownership of Young 2 and release their ownership of Square Butte DC line. Both lines provide an opportunity for generation outlet from central North Dakota but only get to the Red River Valley for load serving needs. An additional line would be required to provide power to the Midwest ISO market.

The Broadland-Brookings Co 345 kV line provides great opportunity for East Central South Dakota, but has the biggest impacts on the Intergrated System[3] (IS) in the MAPP region. Due to adversely impacting the IS system, a large number of underlying facilities would be required and the cost of the faculties would increase as a result. This project would work better if invoked internally by the IS.

The Wilmarth-North Rochester 345 kV line provided marginal improvements to the system beyond the CapX 2020 facilities. This line provides minimal benefit for Lakefield Junction, Pleasant Valley, and Adams Substations which are all common generation interconnection facilities.

The Genoa-Salem 345 kV line would be a great Phase 2 project for RES, but the La Crosse-Madison 345 kV provides greater benefit overall. Since the King-Eau Claire-Arpin 345 kV line is an existing limiter of the Corridor Study, adding the Genoa-Salem 345 kV line would be less successful at off-loading the King-Eau Claire-Arpin line than the La Crosse-Madison 345 kV line. This is due to the Genoa-Salem line's electrical distance from Eau Claire and Madison.

[3] Intergrated System in the MAPP region include the intergrated transmission system of Western Area Power Administration, Basin Electric Power Cooperative, and Heartland Consumers Power District.

4.6: Performance Evaluation Methods

4.6.1: Steady State

The primary method of analysis for the steady-state (power-flow) simulations was the use of DC contingency analysis in PSS/E. This was the quickest way to study using the Midwest ISO market as a sink and with generation inside Minnesota at such high levels. Future studies will need to further refine the details of how much generation can be supported and the increased reactive losses from serving the load from a great distance. This study used a much wider footprint of generators as a sink than the Corridor Study; this allowed fewer generators in any one area to be turned down and helped reduce the potential of voltage issues.

The table below shows the areas monitored for violations. Branches 100 kV and above within and emanating from those areas were monitored for overloads.

Table 4.6.A – Monitored 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

4.6.2: Dynamics

To understand the impact of the proposed generation and transmission additions upon the performance of the northern MAPP transmission system, an extensive set of transient stability simulations was performed. Voltage profiles and system damping were reviewed to ensure that the transmission grid will function within acceptable levels following a transient event on the transmission system.

4.6.3: Market Dispatch

The North American electrical system is a complex interconnected grid in which power generators are interconnected through many miles of transmission lines comprising a high voltage grid that transports electric power to consumers. The bulk transmission system with limited access points acts like the interstate highway system, moving electric power long distances.

The market-wide dispatch model used for the analysis of this RES Update Study mirrors the way electricity is generated and moves through the system.

Another concern with the traditional or more localized study methodology is that it has the effect of "hiding" transmission violations like low voltage that occur during Midwest ISO market dispatch by not allowing the generation to participate in true market dispatch. The study team sought to ensure adding the generation would not constrain the transmission system with something that is masked by the Midwest ISO market dispatch model. At the same time, some violations can occur that would not normally occur in market dispatch based on increased transmission flows through areas created by traditional dispatch.

Market dispatch methodology better enables generation to interconnect and be delivered by studying transmission projects in the manner they will be used once in operation.

The power system is operated in real-time via security-constrained economic dispatch. What this means is that the transmission system operators work to run the most reliable and low-cost generation units first and then the higher cost generation units as needed to accommodate the electricity demand. This minimizes cost of generation that runs while avoiding contingent system violations. Therefore, the RES Update Study's use of market-wide dispatch provided more accurate results. Generally, higher cost generation is east of Minnesota, lower cost generation is west of Minnesota, so often a west-to-east bias of power flow occurs until facilities within the system limit that bias.

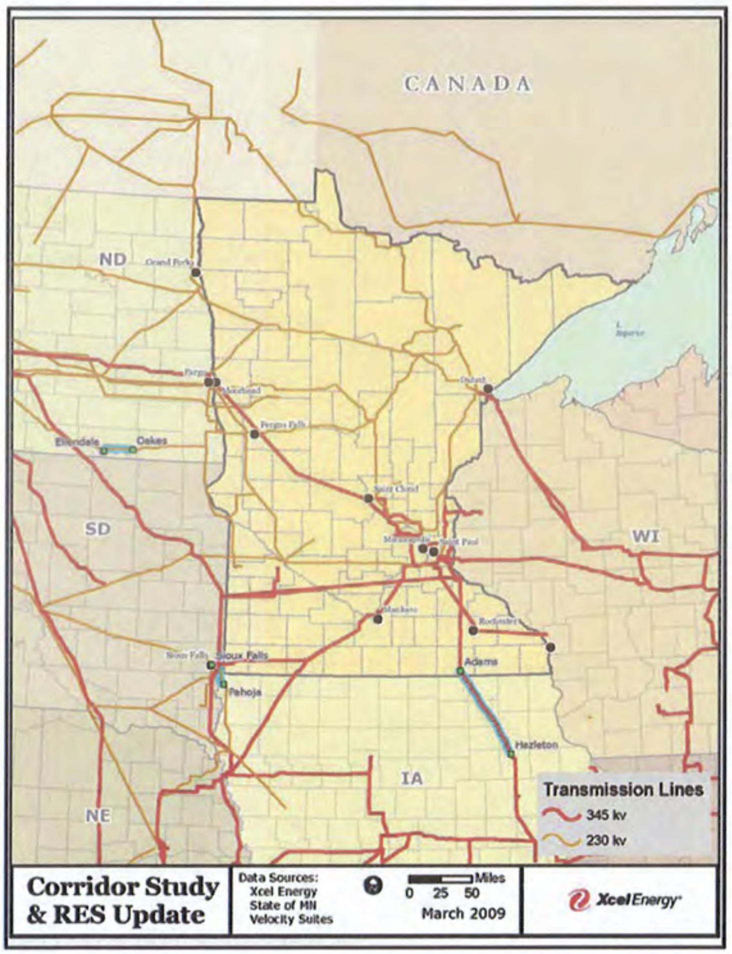
5.0: Results

5.1: Steady-State Analysis

The RES Update Study not only identified the different facilities' upgrades necessary to increase generation output but also investigated the impact the various improvements have on each other in each zone. This sensitivity analysis provided useful data for the RES Update and Corridor Study recommendations.

Figure 5.1.A provides a map of the three most common limiters that were deemed to be significant enough to limit additional generation delivery within a given sensitivity. A short description of each limitation is provided below.

Table 5.1.A – "Stopping Point" Limiters



- Ellendale – Oakes 230 kV Line – this line is the primary limit in cases without the Ashley – Hankinson 345 kV line. The interest in new generation development in the Ellendale area is the primary driver for this line overload.

- Hazleton – Adams 345 kV Line – this line limits generation delivery in a number of cases. Based on commitments made by ITC Midwest, it is anticipated that a new 345 kV line from Hazleton to Salem Substation will be constructed. This helps to provide generation outlet from southeastern Minnesota and northern Iowa. However, at higher levels of generation loss of 345 kV circuits between the Rochester area and La Crosse or Madison causes significant additional power to flow on the Hazleton – Adams 345 kV line as it attempts to reach the Hazleton – Salem line.

- Sioux Falls – Pahoja 230 kV Line – as generation interest in southwestern Minnesota and the Dakotas increases, loss of the Split Rock – Sioux City 345 kV line will overload the Sioux Falls – Pahoja line. This line runs

Figure 5.1.B shows a map of the underlying system limiters that were common throughout most, if not all scenarios studied. A short description of the limiters is provided below.

- Stone Lake 345/161 kV Transformer – this transformer is located along the recently completed Arrowhead – Gardner Park 345 kV line. The overload generally shows up for contingencies that involve loss of the Stone Lake – Gardner Park. In addition, a 345 kV breaker failure contingency that causes loss of both the Arrowhead – Stone Lake and Stone Lake – Gardner Park line segments causes overload of the King – Eau Claire – Arpin 345 kV line. Adding a second transformer at Stone Lake would eliminate the breaker-failure contingency concern.

- Eau Claire 345/161 kV Transformer – this overload occurs for a stuck breaker contingency on the 161 kV bus at Eau Claire Substation. Alleviating this overload would require either upgrading both 345/161 kV transformers or constructing a breaker-and-a-half scheme on the 161 kV bus at Eau Claire.

- Adams 161 kV Bus – overload of this bus segment occurs due to loss of the Byron – Pleasant Valley – Adams 345 kV line or a 345 kV breaker failure at Hazleton Substation that causes loss of the Hazleton – Adams line. Both of these contingencies force more power through the 161 kV system at Adams.

- White Substation 345 kV Relay Settings – the relay settings at White Substation are set in such a way that flow on the White – Split Rock 345 kV line is limited. This overload occurs for loss of the Brookings County – Lyon County 345 kV line, as this contingency forces power at Brookings County to flow south to Split Rock Substation.

Table 5.1.B – Common Underlying System Limiters

- Sioux City Substation 345 kV Relay Settings – the relay settings at Sioux City Substation are set in such a way that flow on the Sioux City – Split Rock 345 kV line is limited. This overload occurs for loss of the Lakefield – Nobles 345 kV line, as this contingency forces power at Split Rock to flow north to White Substation and south to Sioux City Substation.

- Adams 345/161 kV Transformer – this transformer is located in southeastern Minnesota and its overload mainly occurs for loss of the Byron – Pleasant Valley – Adams line.

- King 345 kV Bus Arrangement – the bus arrangement at King Substation northeast of the Twin Cities currently makes it possible that a single contingency could cause the loss of the King – Chisago, King – Red Rock, and King – Eau Claire 345 kV lines. Loss of King – Eau Claire also initiates tripping of the Eau Claire – Arpin 345 kV line. This contingency was shown to trigger several overloads throughout the system. By adding 345 kV breakers at King Substation, this contingency can be eliminated so only one facility is lost due to any contingency.

- Plymouth – Sioux City 161 kV Line – this overload occurs for loss of the Brookings County – Lyon County 345 kV line, as additional power is forced to flow south through Sioux Falls and Sioux City and then back up to the Twin Cities.

In the following off-peak tables, the rows RES Update Study transmission facilities configurations. Within each cell, the first line represents the generation level that can be reached with particular transmission assumptions. The second line represents the facility whose overload represents the system limit. The third line represents the contingency that limits the generation delivery under that off-peak scenario.

For example, referring to Table 5.1.1A, in a case with La Crosse – Columbia in service and the existing Minnesota Valley – Blue Lake 230 kV line in service, 2394 MW of outlet can be obtained. This is limited by overload of the Hazleton – Adams 345 kV line for loss of the Byron – North Rochester 345 kV line. If you move to the next column, installing the Corridor Upgrade results in 3600 MW of outlet. Again this is limited by overload of Hazleton – Adams this time for system intact. Full detail of all underlying and overloaded facilities can be found in Appendix D.

5.1.1: Southeast Zone Source

Table 5.1.1.A – Southeast Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2394 MW Hazleton-Adams 345 Byron-N. Roch. 345	3600 MW Hazleton-Adams 345 Base Case	3682 MW Hazleton-Adams 345 Base Case
Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3551 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3418 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	3000+ MW	2861 MW Hazel-Granite Falls 230 Base Case	3805 MW Hilltop-N. LAX 345 ECL-ARP & ARR-SLK 345

Table 5.1.1.B – Southeast Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2761 MW Hazleton-Adams 345 Byron-PV-Adams 345	3000+ MW	4340 MW Hazleton-Adams 345 Byron-N Roch. 345
Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3000+ MW
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3000+ MW
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	3000+ MW	3000+ MW	3000+ MW

5.1.2: Southwest Zone Source

Table 5.1.2.A – Southwest Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2572 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2435 MW Hazel-Granite Falls 230 Base Case	2645 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Adams - La Crosse La Crosse - Columbia	2566 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2433 MW Hazel-Granite Falls 230 Base Case	2651 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Columbia	2700 MW Split Rock-Nobles 345 Nobles-Lakefield Jct.	2473 MW Hazel-Granite Falls 230 Base Case	2728 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	1998 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2150 MW Hazel Creek 345/230 Parallel Outage	2285 MW Sioux Falls-Pahoja 230 SPK-NOB & SPK-SXC 345

Table 5.1.2.B – Southwest Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2188 MW Blue Lake-Helena 345 Helena-Lake Marion 345	3000+ MW	4058 MW Blue Lake-Helena 345 McLeod-Panther 345 dbl
Adams - La Crosse La Crosse - Columbia	2224 MW Blue Lake-Helena 345 Helena-Lake Marion 345	3000+ MW	4108 MW Blue Lake-Helena 345 McLeod-Panther 345 dbl
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Columbia	2986 MW Blue Lake-Helena 345 Helena-Lake Marion 345.	3000+ MW	4637 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. - Madison	3000+ MW	3000+ MW	4545 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345

5.1.3: North Dakota Zone Sources

Table 5.1.3.A – North Dakota Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Brookings	490 MW Ellendale-Oakes 230 Center-Jamestown 345	1501 MW Ellendale-Oakes Jamestown-Maple River 345	2022 MW Hazleton-Adams 345 ECL-ARP & ARR-SLK
Maple River - Brookings Ashley - Hankinson	1049 MW ARR Phase Shifter Base Case	1530 MW ARR Phase Shifter Base Case	2006 MW Hazleton-Adams 345 ECL-ARP & ARR-SLK
Maple River - Brookings Ashley - Hankinson La Crosse - Columbia	1440 MW ARR Phase Shifter Base Case	1581 MW ARR Phase Shifter Base Case	2688 MW ARR Phase Shifter Base Case
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	1588 MW ARR Phase Shifter Base Case	1653 MW Hazel-Granite Falls 230 Base Case	2285 MW Sioux Falls-Pahoja 230 SPK-NOB & SPK-SXC 345

Table 5.1.3.B – North Dakota Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Brookings	490 MW Ellendale-Oakes 230 Center-Jamestown 345	922 MW Ellendale-Oakes 230 Center-Jamestown 345	2828 MW Ellendale-Oakes 230 Center-Jamestown 345
Maple River - Brookings Ashley - Hankinson	1443 MW Ellendale-Oakes 230 Base Case	2225 MW Ellendale-Oakes 230 Ashley 345/230 Tx	3284 MW Ellendale-Oakes 230 Ashley 345/230 Tx
Maple River - Brookings Ashley - Hankinson La Crosse - Columbia	1436 MW Ellendale-Oakes 230 Base Case	3000+ MW	3275 MW Ellendale-Oakes 230 Ashley 345/230 Tx
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	1511 MW Ellendale-Oakes 230 Base Case	2296 MW Ellendale-Oakes 230 Ashley 345/230 Tx	3300 MW Ellendale-Oakes 230 Ashley 345/230 Tx

5.1.4: All Sources

Table 5.1.4.A – Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Split Rock Ashley - Hankinson La Crosse - Columbia	3215 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK	3110 MW Sioux Falls-Pahoja SPK-NOB & SPK-SXC 345	3379 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK
Maple River - Split Rock Ashley & Broadland Lines La Crosse - Columbia	3181 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK	3000 MW Sioux Falls-Pahoja SPK-NOB & SPK-SXC 345	3369 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	3536 MW Hazleton-Adams 345 Hilltop-NLAX 345	3453 MW Hazleton-Adams Hilltop-NLAX 345	3465 MW Adams-Pleasant Valley 345 N.Roch-NLAX 345

Table 5.1.4.B – Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Split Rock Ashley - Hankinson La Crosse - Columbia	5000 MW	5000 MW	6202 MW Hazleton-Adams 345 NLAX-Columbia 345
Maple River - Split Rock Ashley & Broadland Lines La Crosse - Columbia	5000 MW	5000 MW	6190 MW Hazleton-Adams 345 NLAX-Columbia 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	5000 MW	5000 MW	6350 MW Hazleton-Adams 345 NLAX-Columbia 345

5.1.5: Dispersed Renewable Generation

A generation scenario was run that generally mimicked the process used in the DRG Phase I study and attempted to model 2000 MW of new generation facilities on the lower voltage transmission system assuming no new transmission facilities beyond the CapX2020 Group I projects. Under a Midwest ISO market dispatch scenario, it was concluded that using DRG projects to meet the 2016 RES milestone was not feasible for several reasons.

Constraints in Wisconsin prevented the Midwest ISO market from being able to accept 2000 MW without the addition of new bulk transmission facilities. In response to this result, the Midwest ISO market dispatch was changed to mimic the dispatch used in the DRG Phase I study. This dispatch turned down generation in the greater Twin Cities metro area and also at Lakefield and Pleasant Valley in order to allow additional generation on the system. This shift in dispatch is noteworthy, because it does not reflect the methods by which the Midwest ISO studies and thus approves generation interconnection requests. In addition, this is not indicative of how power is dispatched in the real-time Midwest ISO market. Thus, this wider Twin Cities dispatch simply assumes that 2000 MW of DRG capacity will replace 2000 MW of existing Minnesota capacity under the real-time market dispatch. It is debatable whether adding this amount of new generation without additional bulk transmission and utilizing the unusual dispatch scenario described is realistically feasible. This scenario would result in significant existing generation in Minnesota that could not operate.

The analysis started with the summer off-peak case containing the Corridor Upgrade. All buses within the state of Minnesota were initially selected to run first contingency incremental transfer capability sinking to the Twin Cities generation. The output for each bus, limited by its first violation, was sorted to remove any negative transfers and buses over 100 kV. From this short list, the sites to be used in the final analysis were derived based on the incremental transfer capability determined for each site.

The green squares in Figure 4.3.1.E earlier in this report indicate the locations of DRG substation sites. In all, 42 sites were used in the final analysis. Due to the new transmission facilities in the model being fully subscribed and to avoid impacting transmission facilities, most of these sites were modeled just outside the Twin Cities metro area. Modeling these sites closer to the sinks in the Twin Cities area generally enables greater levels of generation capacity. Whether this is a realistic locational assumption is open for debate, as the population density in these areas is much greater than in more remote areas studied (e.g., Buffalo Ridge, Western Minnesota, Southeastern Minnesota). No attempt was made to evaluate the availability of appropriate terrain or availability of un-restricted land at these sites. In addition, attempts to site generation in these areas may be met with public opposition, as there will be more affected landowners per project.[4]

Another locational consideration is the impact that capacity factor will have on the number of wind projects that must be installed to meet the 2016 RES milestone. Where wind projects on the Buffalo Ridge may have capacity factors approaching 40% or more, the capacity factor closer to the Twin Cities is approximately 30%. This means the wind turbines located in the Twin Cities area are producing less of the time and more turbines would be required to produce an equivalent amount of energy as those in more favorable wind areas. This is important because the investment cost of wind

[4] Two examples of this public opposition can be found in the exhaustive permitting process experienced by Great River Energy to site a small wind turbine at their corporate headquarters in a commercial area of Maple Grove, Minnesota and an effort by East Ridge High School in Woodbury, Minnesota to site a small wind turbine on its property. In both cases, opposition focused on safety, land values, and noise concerns among other issues. The GRE wind turbine was approved, while the Woodbury wind turbine was not.

turbines is much greater than the investment cost of transmission on a cost per MW basis.[5]

One key finding of the DRG scenario was that turning down the Twin Cities generation to enable DRG to come online resulted in an overload of the 345/115 kV transformers at Terminal Substation northeast of Minneapolis. This overload occurred at roughly 900 MW of DRG penetration. A solution for this overload is not known. What is known is that the transformers at Terminal Substation cannot be any larger. The two transformers are already 672 MVA units. Due to the size of units that are larger than 672 MVA, increasing the size of the transformers would require the use of single-phase transformers. Doing this would require six single-phase transformers – a solution for which space at Terminal Substation does not exist. Compounding this problem is the fact that the 115 kV fault current levels are nearing 63 kA – the interrupting limit of the 115 kV circuit breakers at Terminal.

The project that was assumed to resolve this issue has not been fully vetted to ensure it will resolve the transformer overload. It represents the best judgment of planning engineers based on currently available information to devise a solution to a problem that has challenged engineers for several years.

Considering all of these qualifications and while using all of the assumptions noted in this section, the DRG analysis showed that approximately 2000 MW of generation could be modeled using a Twin Cities dispatch.

Modeling this DRG primarily spread around the greater Twin Cities area would require approximately $85 million in transmission upgrades under these location and dispatch assumptions.

A specific loss analysis was not undertaken as part of the DRG scenario, however, the DRG Phase I study showed mixed results between summer peak and summer off-peak models. The summer off-peak models, due to the reduced loads and high wind generation, result in power needing to travel greater distances. Doing so on lower-voltage systems (where DRG tends to be installed) results in a loss increase. The DRG Phase I results are indicative of the loss results that could be expected from the DRG scenario in this study. This is important because, where several of the projects examined in this study introduce significant loss savings that dramatically impact the total cost of the project, the DRG scenario either would not introduce any savings or would only introduce very small savings and would likely result in greater generation installation costs.

[5] For example, 2000 MW at 30% capacity factor would produce approximately 5.25 million MWh per year. In order to produce the same amount of energy at 25% capacity factor, approximately 2400 MW of wind turbines would be necessary. Information from Windustry for wind generation projects in 2007 indicates installed costs can range from $1.2 million to $2.6 million per MW. At those costs, this extra 400 MW results in an additional cost of $480 million to $1.04 billion.

A specific loss analysis was not undertaken as part of the DRG scenario, however, the DRG Phase I study showed mixed results between summer peak and summer off-peak models. The summer off-peak models, due to the reduced loads and high wind generation, result in power needing to travel greater distances. Doing so on lower-voltage systems (where DRG tends to be installed) results in a loss increase. The DRG Phase I results are indicative of the loss results that could be expected from the DRG scenario in this study. This is important because, where several of the projects examined in this study introduce significant loss savings that dramatically impact the total cost of the project, the DRG scenario either would not introduce any savings or would only introduce very small savings and would likely result in greater generation installation costs.

5.2: Dynamic Stability

An indicative stability assessment was also performed. The inputs and faults studied are discussed above in Chapter 4. This assessment confirmed that as load serving entities approach final compliance with current renewable energy standards requirements, significant new reactive capability will be necessary. This is due in large part to generation being located a significant distance from load centers. At the same time, some larger generators are being turned down to make room for the new wind generators.

The power system relies on the inertia of generators to "weigh" the system down and absorb the voltage and power swings that follow a system fault. Larger generators have more inertia than smaller generators and are typically better at absorbing those swings. Smaller units tend to be more susceptible to swings, as their lesser inertia makes it easier for the units' power output to change. As the generation in the system increasingly shifts to smaller units further from load centers, there will be increased sensitivity to faults on major regional lines and large generation units.

With the addition of the Corridor Upgrade and its associated 2000 MW of generation, low voltages are observed on the 161 kV system between Stinson and Stone Lake for the PCS disturbance (SLGBF on King-Eau Claire 345 kV line). This issue has been showing up in other recent studies as well. The issue appears to only be a transient voltage issue since the steady-state voltages are relatively good. A potential fix would be to add a Static Var Compensator (SVC) in the Minong or Stone Lake region. The Lakefield-Columbia 345 kV line does mitigate the issue at 4800 MW, but it re-appears at the 6800 MW level.

The most significant stability-related result was a significant occurrence of instability for the region is for loss of Sherco Unit 3 (MQS). This is the largest single unit in the area and its loss causes an instantaneous reversal of direction on regional tie lines to fill the void left by the unit. This shift in regional transmission flow causes the system to go unstable. The increased penetration of wind generators (over 7300 MW of Minnesota and nearby wind) contributes to these swings as they are unable to absorb these swings as effectively as other regional generators. The voltage swing issues for loss of Sherco Unit 3 were resolved by removing 500 MW of generation at several buses in the system. The voltage swings at Watertown 345 kV show the instability at 7300 MW of wind in Figures 5.2.1.A and 5.2.1.B.

These plots show the potential of interconnecting large amounts of wind turbines and turning of synchronous generators with higher inertia values. The possibility the system reaches instability during various disturbances becomes more and more likely to happen if not transmission is built to strengthen the tie between Chicago and the Twin Cities.

Figure 5.2.1.A – Watertown 345 kV Voltage without Big Stone II

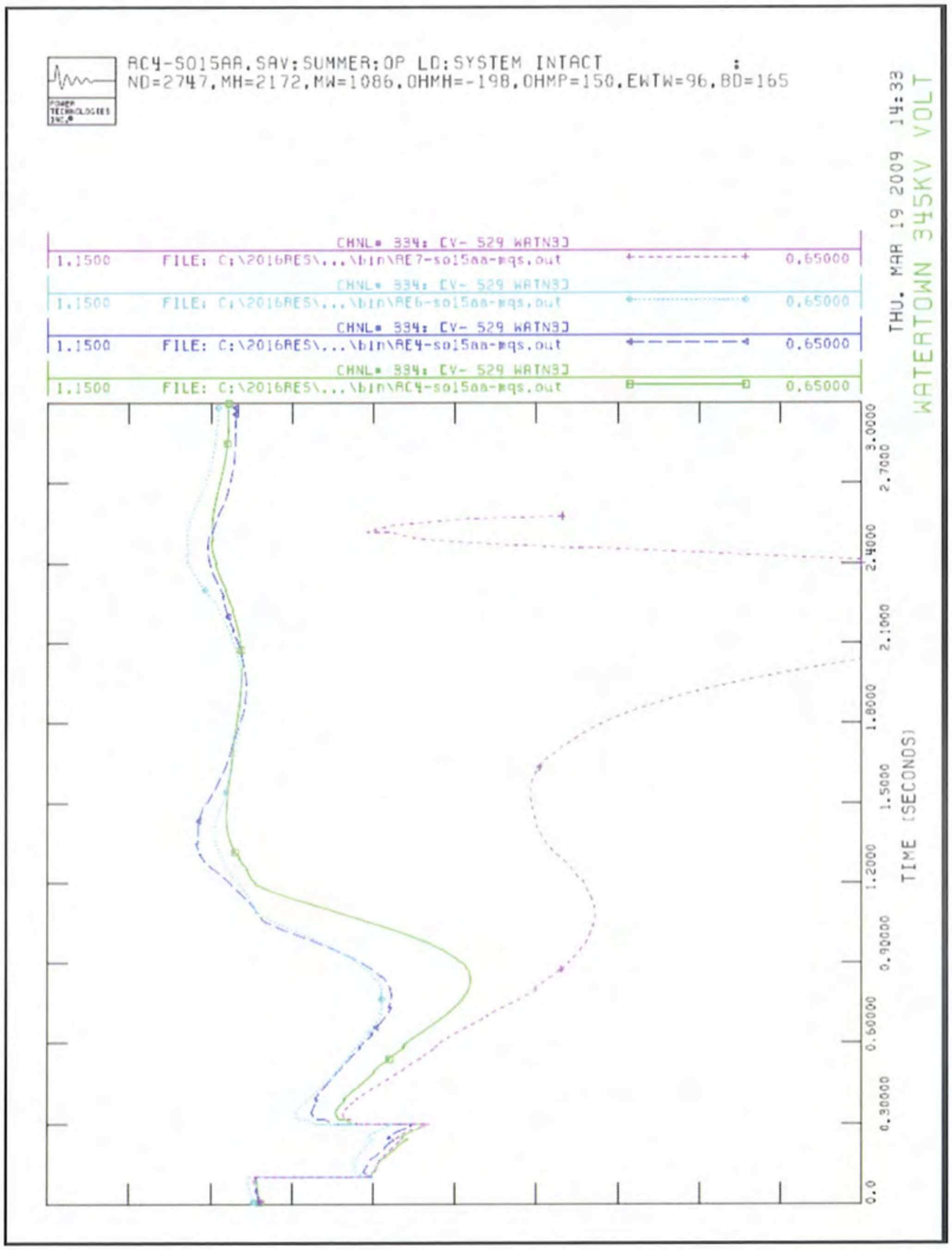
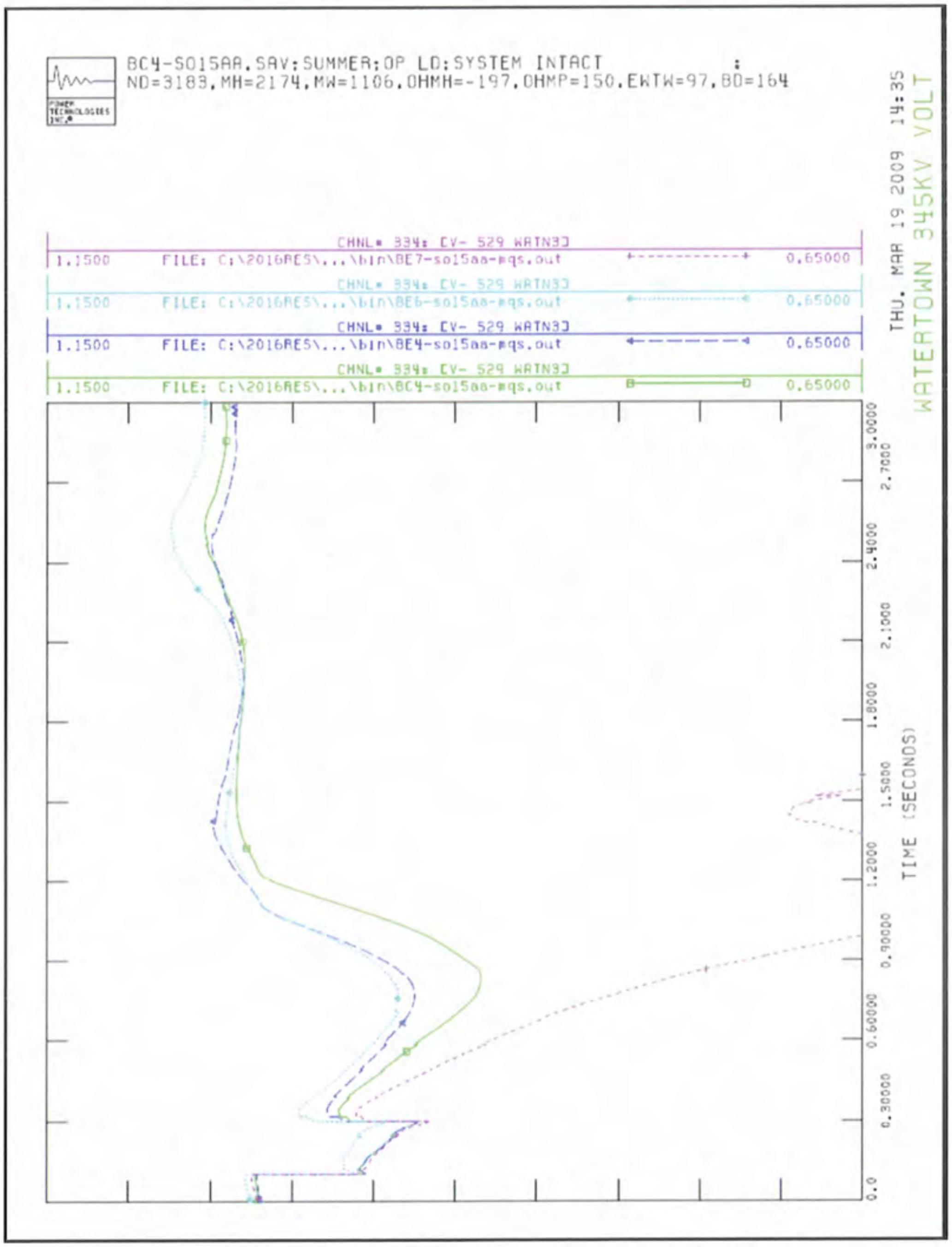


Figure 5.2.1.B – Watertown 345 kV Voltage with Big Stone II



The figures above show the voltage at the Watertown 345 kV bus during the loss of Sherco Unit 3. The colors of the lines represent various system configurations. Watertown is shown here because it has been shown to be the limiting bus with respect to voltage swings in many regional studies – as was the case in this study. Note that several of the configurations remain stable. The pink line shows rapidly decaying voltage represents the case with 7300 MW of generation. Both of these cases demonstrated dynamic system voltage collapse. Voltage (and frequency) swings proved to be too much for units to maintain operation.

In real-time, these graphs indicate that loss of Sherco Unit 3 would result in a first swing voltage that fell well below 60%. This is notable, because NERC first-swing voltage criteria requires that first-swing voltage remain above 70%. In fact, some cases showed first-swing voltage as low as 29%. With a voltage swing this substantial, the frequency would increase significantly, generators would trip based on their overfrequency protection, and within a matter of seconds, the collapse would cascade throughout the region.

At the reduced generation level of 6800 MW, the system was shown to be able to ride through the loss of Sherco Unit 3. System voltage fluctuations were still evident, but remained within the limits provided by NERC standards. Voltage violations were still observed for the PCS disturbance. These issues would still be required to be resolved – most likely through the addition of a SVC at Stone Lake Substation.

Both the 6800 and the 7300 MW cases required significant capacitor additions (1740 MVAR) just to raise the steady-state voltage of the system prior to performing any fault simulations. This was done primarily by adding capacitors on the new 345 kV lines. Table 5.2.1.C shows the size and placement of these caps. Full details of stability tables and plots can be found in Appendix E.

These capacitors were assumed to be placed on the 345 kV bus at the substation in question. However, due to the cost of 345 kV capacitors, it may be desirable to place this reactive support on the lower voltage (115 or 161 kV) buses. While this possibility was not explicitly studied, these capacitor additions would likely increase in size to account for losses through the transformer. In addition transformer increases may be necessary as these reactive power additions may result in transformer overloads.

Figure 5.2.1.C – Capacitor Additions

Location	Size (MVAR)
North La Crosse	4 x 60
Brookings Co	4 x 60
Helena	4 x 60
Hampton	3 x 60
Lyon Co	3 x 60
Lakefield Jct	4 x 60
Adams	4 x 60
Hazleton	3 x 60

In general, the message these results portray is that wind penetration beyond the levels studied in conjunction with the Corridor Upgrade must be pursued with the utmost caution. As the stabilizing influence of larger generators is reduced or those units are replaced by smaller generators that are more susceptible to voltage swings, additional bulk transmission lines will be needed in order to effectively absorb the impacts of regional faults and generator outages. The 7300 MW case for this stability study included approximately 800 miles of new transmission (beyond the CapX2020 Group I lines) and represented a significant expansion in the generation delivery capability of the regional transmission grid. Despite the inclusion of a significant amount of new transmission infrastructure to increase regional stability, observable limits to wind penetration in the upper Midwest were observed.

As this 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.

While a specific stability assessment was not conducted for the DRG scenario, the no-build stability analysis conducted in conjunction with the Corridor and RES Update Studies is indicative of the type of results that can be expected from a DRG stability assessment. Installing 2000 MW of wind generation while not building any new transmission to tie the Twin Cities more closely with larger generators and then turning down greater Twin Cities generation to allow the 2000 MW of generation to come online would lower the system's inertia. With replacing the large generators that are capable of riding through system faults with a large number of smaller wind generating turbines results in degradation in the overall system stability in the upper Midwest.

The key finding of the RES Update Study is the realization of an operational limit to the extent to which wind penetration can be accepted into the transmission grid in the upper Midwest. In the steady state realm, this limit began to manifest itself as generation in the Twin Cities was turned down in order to enable increasing amounts of wind to be turned on. Some Twin Cities generators are natural gas units that can be turned on and off with relative ease, but others are fossil or nuclear units that cannot be rapidly taken offline and then brought back online. However, the Corridor and RES Update studies verified that beyond the renewable generation levels envisioned with the Corridor Upgrade, additional intermittent generation would require the larger fossil fuel generators near the Twin Cities to begin backing down.

5.3: Transmission System Losses

5.3.1: Technical Evaluation

The loss benefits are significant for justifying transmission projects. A MW of loss savings is equivalent to a MW that does not need to be produced by a generator. These results in lower fuel costs and, thus, a reduction in the costs passed on to ratepayers. The following table shows the relative losses from varying scenarios of transmission options implemented. The level of generation that was studied is also shown and matches the steady-state analysis in Section 5.1 with the Hazel-Blue Lake Corridor facilities. The loss values are based on the whole Eastern Interconnect losses during Summer Peak conditions. Details of the losses can be found in Appendix F.

Table 5.3.1.A – Losses Summary

Facilities	Generation	Source	Transmission Only			With Generation		
			Loss Without Facilities	Loss Without Facilities	Delta	Loss Without Facilities	Loss Without Facilities	Delta
	MW		MW	MW	MW	MW	MW	MW
Maple River-Brookings Ashley-Hankinson	1530	ND / Cord	17500.5	17491.6	-8.9	17686.1	17674.7	-11.4
Maple River-Brookings Ashley-Hankinson La Crosse-Madison	1581	ND / Cord	17500.5	17465.2	-35.3	17694.5	17652.8	-41.7
La Crosse-Madison	3600	ND / Cord	17500.5	17474.3	-26.2	18115.6	18072.2	-43.4
Adams-La Crosse La Crosse-Madison	3600	SE / Cord	17500.5	17468.3	-32.2	18115.6	18061.4	-54.2
Lakefield-Adams Adams-La Crosse La Crosse-Madison	3600	SE / Cord	17500.5	17460.3	-40.2	18115.6	18042.5	-73.1
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock La Crosse-Madison	3450	ALL / Cord	17500.5	17459	-41.5	18005.5	17945.4	-60.1
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock Lakefield-Adams Adams-La Crosse La Crosse-Madison	3450	ALL / Cord	17500.5	17440.3	-60.2	18005.5	17911.8	-93.7

The La Crosse-Madison 345 kV line creates the most MW loss savings as shown in the difference in the first two facilities Table 5.3.1.A. This large loss savings is created by the addition of a new 345 kV line to the Midwest ISO market outside Minnesota. Due to the general bias of transmission flows in the region, the lower-voltage system that this line spans carries a significant amount of through-flow beyond the load-serving needs for which it was primarily designed. Installing this new 345 kV line provides a more efficient path for that flow on the lower voltage system and results in fewer losses.

5.3.2: Economic Evaluation

Figure 5.3.2.A 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.

Figure 5.3.2.A – Equivalent Capitalized Value for Losses

Computation of Equivalent Capitalized Value for Losses
(pool reserve requirement of 15%)

Input Assumptions

Term of loss reduction	40	yrs	Present Value of Annuity factor	12.29	< Losses
Assumed life, xmsn	35	yrs	Present Value of Annuity factor	11.99	< Transmission
Discount rate	7.72	%/yr			
Energy value	$46	MWh			
Loss Factor	30.00		< ASK-ECL 345 loss factor (ave. 2000 and 2001). Proxy for MN to Western WI flows		
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	4,028,660
Energy Value:	1.00	8760 hr/yr	0.30	$46 /MWh		121,387 $	1,492,077
			Total annual cost, capacity & energy:		$	449,137	5,520,737

Present Value Annuity factor Losses	12.29
Cum PV Losses $	5,520,737
Equivalent Transmission investment $	**3,068,625**
is Cum PV Losses / FCR trans / PVA trans	

As an example, the table below demonstrates that, based on the 3.1 M$/MW value, the "loss reduction" investment credit for building the Maple River-Brookings Co and Ashley-Hankinson plan is 35 M$ (11.4 MW loss savings multiplied by 3.1 M$/MW). A full of loss savings can be found in Table 5.3.2.B.

Table 5.3.2.B – 40 Year Loss Savings

Facilities	Loss Savings MW	40-Year Loss Savings $
Maple River-Brookings Ashley-Hankinson	11.4	35,000,000
Maple River-Brookings Ashley-Hankinson La Crosse-Madison	41.7	128,000,000
La Crosse-Madison	43.4	134,000,000
Adams-La Crosse La Crosse-Madison	54.2	167,000,000
Lakefield-Adams Adams-La Crosse La Crosse-Columbia	73.1	225,000,000
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock La Crosse-Madison	60.1	184,000,000
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock Lakefield-Adams Adams-La Crosse La Crosse-Madison	93.7	288,000,000

6.0: PROMOD Simulations

6.1: Background

During the scoping phase of the RES Update, the TRC and other stakeholders expressed a desire for analysis of the economic performance of the facilities being studied. In response to this input, the study team worked with the Midwest ISO to perform analyses that tested the performance of the proposed facilities within the Midwest ISO's market dispatch. Short for PROduction MODeling, PROMOD is a software package developed by Ventyx that is capable of modeling the performance of the generation market. It can factor in transmission constraints, manipulate generation dispatch to avoid overloading constrained transmission interfaces, and minimizes the generation cost to do so.

PROMOD is a highly data-intensive program. A small selection of the type of information that is necessary to conduct an effective PROMOD study includes data such as fuel charges, fuel consumption rates for individual generators, possible generation increments for individual generators, and the startup time, shutdown time, and individual unit ramp rates for any generators that participate in a given market dispatch. PROMOD also requires a dependable transmission system model in order to determine with accuracy the amount of time a given interface is constrained and limits generation dispatch.

In addition, PROMOD is also a highly processor-intensive program. PROMOD uses its generation and transmission information, along with location-specific wind profile data to model the transmission system for every hour of an entire year. The wind farms modeled within PROMOD can be tied to the location-specific wind profile data so neighboring wind farms can theoretically see slightly different wind regimes. The extent to which each of these wind farms (and every other generator in the system) impacts every transmission line in the system is then recorded and that information is used to determine which units should be backed down to alleviate a transmission constraint.

PROMOD is highly detailed and highly intensive, with run-times on dedicated servers for cases with significant wind penetration spanning two full weeks.

Given the amount of confidential, market-sensitive information that is used in a PROMOD run, Midwest ISO engineers are widely-regarded as having some of the best-available production modeling information in the Midwest. For this reason, their assistance was sought to ensure the PROMOD study was conducted with the best information available.

While PROMOD can provide information such as Locational Marginal Prices (LMP) for various constraints and the value of alleviating that constraint, the information that bears the most relevance to this analysis is that of the production cost savings and load cost savings brought to bear by the projects under consideration.

6.2: Production Cost and Load Cost Explained

The production cost of a PROMOD study is the cost to produce sufficient generation to meet the demand being modeled. By running a "base case" and comparing the production cost of that case with one that includes the project in question, it is possible to determine the annual cost savings that will be realized by completing a particular project. The load cost of a PROMOD study is calculated by multiplying the LMP for each load center by the amount of load in that load center and then summing all the values for the various load centers in the market.

Because regulated utilities have customers with fixed rates, it is in the best interest of the utility to minimize the cost to deliver that energy. This promotes efficiency of production and minimizes the number of generators that must be run and the level at which those generators must run at any one time. In general, the production cost calculation within PROMOD tends to reflect more of a regulated market system.

On the other hand, a true market system will seek to minimize the cost observed by the load. When rates of service vary based on the constraints present on the transmission system, a utility will be most interested in what the cost to its loads would be. In this way, the load cost calculation within PROMOD reflects a more market-based system.

Given the mixture of regulated and market-based entities within the Midwest ISO footprint, the Midwest ISO typically considers 70 percent of the production cost savings and 30 percent of the load cost savings when evaluating the economic worth of a project. To maintain consistency with Midwest ISO methodologies, the same percentages were used for this analysis.

The PROMOD analysis of the RES Update Study facilities was conducted with the preferred Corridor facilities in service to ensure the most accurate post-project simulations occurred. The results of these analyses can be found in below.

6.3: Generation Siting

The first task in developing a base case PROMOD model was to ensure the locations of the "existing" modeled wind generation were accurate. Consistent with the steady state analysis, base case wind generation on the Buffalo Ridge was set at 1900 MW. The initially-planned RIGO facilities were also modeled, as was the associated 922 MW of generation. This brought the total "base case" wind generation in Minnesota to the same 2822 MW of generation included in the steady state power flow model.

The next task was to model the potential locations of generation that would be enabled by the projects being considered. Given the steady state results of the Corridor Upgrade, 2000 MW of potential generation (in addition to the 2822 MW in the base case) was modeled as shown in Table 6.3.A.

Table 6.3.A – PROMOD Generation Locations for 4822 MW

Substation	Generation Size
Base Generation	2822
Yankee	150
Fenton	150
Lyon Co.	300
Nobles	200
Brookings Co.	400
Granite Falls	300
Morris	200
Big Stone	300
TOTAL	**4822**

Table 6.3.B – PROMOD Generation Locations for 5822 MW "A"

Substation	Generation Size
Base Generation	4822
Hankinson	300
Ellendale	300
Maple River	400
TOTAL	**5822**

Table 6.3.C – PROMOD Generation Locations for 5822 MW "B"

Substation	Generation Size
Base Generation	4822
Adams	300
Byron	300
Split Rock	200
Lakefield	200
TOTAL	**5822**

Finally, initial steady state results indicated that a total of 7322 MW of generation may have been attainable with installation of the Corridor Upgrade, the Fargo to Split Rock project, and the Lakefield to Madison project. In order to model this, a specific generation source list was developed for this case. Those sources are shown in Table 6.3.D below.

Table 6.3.D – PROMOD Generation Locations for 7322 MW

Substation	Generation Size
Base Generation	4822
Hankinson	300
Ellendale	300
Maple River	400
Pipestone	300
Winnebago	200
Adams	300
Byron	300
Split Rock	200
Lakefield	200
TOTAL	**7322**

6.4: Project Selection

Based on the results of steady state analysis, a series of projects were presented for economic analysis. In order to determine the benefit of projects and minimize the number of cases to be run, some qualitative judgments were made regarding appropriate projects for analysis. Table 6.4.A shows a list of the projects that were analyzed and the generation levels that were studied. Unless noted otherwise, all scenarios include the recommended Corridor Upgrade facilities in the base case.

Table 6.4.A – PROMOD Case and Generation Levels

Case	Facilities Studied	Generation Level
1A	Base Case - Post CapX Group I	4822 MW
6A	Maple River - Brookings Ashley - Hankinson	4822 MW
7A	La Crosse - Madison	4822 MW
Base-1	Base Case - Corridor Upgrade	5822 MW "A"
6B	Maple River - Brookings Ashley - Hankinson	5822 MW "A"
7B	Maple River - Brookings Ashley - Hankinson La Crosse - Madison	5822 MW "A"
Base-2	Base Case - Corridor Upgrade	5822 MW "B"
8A	Lakefield - Adams	5822 MW "B"
8B	Lakefield - Adams La Crosse - Madison	5822 MW "B"
9A	Adams - La Crosse La Crosse - Madison	5822 MW "B"
9B	Lakefield - Adams Adams - La Crosse La Crosse - Madison	5822 MW "B"
Base-3	Base Case - Corridor Upgrade	7322 MW
10	Maple River - Brookings Ashley - Hankinson Brookings - Split Rock Lakefield - Adams Adams - La Crosse La Crosse - Madison	7322 MW

Note that each generation level contains what is labeled as a "base case." To serve as a basis for comparison, this case contains the recommended Corridor Upgrade facilities as the anticipated starting point for the generation development envisioned for these projects. The various transmission project combinations are then added, in turn, to the case and the simulation is run. By comparing the PROMOD output with these projects in the case to the output of the respective base case, an idea of the economic worth of a project can be ascertained. The full output of PROMOD can be found in Appendix G.

Consistent with the Midwest ISO methodology discussed above, the production cost savings and load cost savings associated with each of the projects studied are summarized in Table 6.4.B. The values given represent those for the entire Midwest ISO market since that is the sink to which the power is being dispatched. Note that the savings are based on the base case scenario at each respective generation level.

Table 6.4.B – PROMOD Production and Load Cost Savings

Case	Generation Level	70% Production Cost Savings	30% Load Cost Savings
6A	4822 MW	$28,000,000	$79,000,000
7A	4822 MW	$16,000,000	$50,000,000
6B	5822 MW "A"	$21,000,000	$40,000,000
7B	5822 MW "A"	$29,000,000	$55,000,000
8A	5822 MW "B"	$1,000,000	($12,000,000)
8B	5822 MW "B"	$2,000,000	($3,000,000)
9A	5822 MW "B"	$9,000,000	$21,000,000
9B	5822 MW "B"	$16,000,000	$34,000,000
10	7322 MW	$41,000,000	$64,000,000

Table 6.4.C gives the 40-year production and load cost savings and total economic benefit associated with these projects.

Table 6.4.C – PROMOD 40-Year Production and Load Cost Savings

Case	Generation Level	40-Year Production Cost Savings	40-Year Load Cost Savings	Total 40-Year Economic Benefit
6A	4822 MW	$347,000,000	$973,000,000	$1,320,000,000
7A	4822 MW	$191,000,000	$612,000,000	$803,000,000
6B	5822 MW "A"	$253,000,000	$494,000,000	$746,000,000
7B	5822 MW "A"	$356,000,000	$679,000,000	$1,034,000,000
8A	5822 MW "B"	$18,000,000	($154,000,000)	($136,000,000)
8B	5822 MW "B"	$28,000,000	($36,000,000)	($8,000,000)
9A	5822 MW "B"	$115,000,000	$265,000,000	$380,000,000
9B	5822 MW "B"	$203,000,000	$420,000,000	$623,000,000
10	7322 MW	$500,000,000	$791,000,000	$1,291,000,000

6.5: PROMOD Conclusion

Immediately, two cases jump out as having a negative 40-year economic benefit. These cases are the Lakefield-Adams and Lakefield-Adams-La Crosse projects. While perhaps surprising, this result is understandable, as the Lakefield-Adams and Adams-La Crosse projects would provide parallel paths to other 345 kV lines that are relatively unconstrained in the real-time market. With the installation of the Brookings-Twin Cities line, power can easily travel along the Lakefield-Wilmarth-Helena 345 kV line and then utilize the transmission system in the Twin Cities and existing transmission connecting to the Rochester area. Installing the Lakefield-Adams-La Crosse lines would serve to offload those facilities, but if they are not constrained to a great degree, then their installation will not provide a significant market benefit.

The benefit to installing the Lakefield-Adams and Adams-La Crosse lines lies mainly in regional reliability. The regional transmission system must be designed to serve load during peak and off-peak periods and under various contingencies during those conditions. Installing the Lakefield-Adams-La Crosse lines will provide a method for the existing transmission system to back itself up under those contingencies and avoid NERC criteria violations.

In addition, both of these lines follow existing 161 kV rights-of-way. The Lakefield-Adams line specifically has already been identified as being undersized and outdated; ITC Midwest has expressed a desire to improve the capacity and, so long as the existing 161 kV line is being updated, it makes sense to consider an upgrade that involves 345 kV.

The 40-year economic benefit totals generally show that the most significant benefits come in cases in which the Fargo-Brookings and Ashley-Hankinson lines are installed. This is logical, as the transmission system in North Dakota and South Dakota is constrained and the wind regime gives a very high capacity factor for those wind farms that are installed. As wind generation has no instantaneous production cost (i.e. fuel cost), enabling it to produce yields a significant production cost savings. It is noteworthy that three of the four cases in which the Maple River-Brookings and Ashley-Hankinson lines are included total more than $1 billion in 40-year net present value for their economic benefit.

Another project that shows significant economic value is the La Crosse-Madison line. Case 7A, which includes the La Crosse-Madison line in addition to the Corridor Upgrade provides a 40-year economic benefit of over $800 million – a dramatic economic benefit for two lines that are relatively short. The present value economic benefit of these projects, without including the value of loss savings, actually exceeds the installation cost of the lines by over $50 million.

These results are indicative of the magnitude of economic benefit that could be expected from installation of these facilities. Precise generation locations, sizes, fuel types, and dispatch would have an impact on which transmission constraints exist in any given model. Two of the same PROMOD models are actually capable of producing slightly different results – this accounts for the variability in wind generation and other market influences.

Based on the economic benefits demonstrated in the PROMOD results for the RES Update Study, the Fargo-Brookings, Ashley-Hankinson, and La Crosse-Madison projects are all recommended based on their economic performance and the benefits to the generation market.

7.0: Economic Analysis

7.1: Installed Cost

The following tables represent estimated planning cost for the various alternatives. These cost tables were created to provide a general installed cost bases on substation and line lengths.

7.1.1: La Crosse - Madison Project

	Acreage	Length	
Substations			
North La Crosse Substation	--		$8,000,000
Hilltop Substation	10		$20,000,000
Columbia Substation	5		$8,000,000
Lines			
North La Crosse-Hilltop 345 kV Dbl Ckt.		75	$180,000,000
Hilltop-Columbia 345 kV Dbl Ckt		65	$134,000,000
Total	15	140	**$350,000,000**

7.1.2: Fargo-Brookings County Project

	Acreage	Length	
Substations			
Flint Substation	15		$25,000,000
Hankinson Substation	10		$15,000,000
Browns Valley Substation	10		$20,000,000
Big Stone Substation	---		$15,000,000
Brookings County Substation	--		$8,000,000
Lines			
Sheyenne-Audubon 230 kV In-and-Out		2	$2,000,000
Maple River-Frontier 230 kV In-and-Out		1	$2,000,000
Alexandria SS-Bison 345 kV In-and-Out		1	$2,000,000
Bison-Flint 345 kV Ckt #2		20	$6,000,000
Flint Hankinson 345 kV Dbl Ckt.		60	$130,000,000
Hankinson-Browns Valley 345 kV Dbl Ckt.		35	$80,000,000
Browns Valley-Big Stone 345 kV Dbl Ckt.		35	$80,000,000
Big Stone-Brookings Co. 345 kV Dbl Ckt.		75	$165,000,000
Total	35	229	**$550,000,000**

7.1.3: Ashley-Hankinson Project

	Acreage	Length	
Substations			
Ashley Substation	10		$15,000,000
Hankinson Substation	--		$5,000,000
Lines			
Ashley-Hankinson 345 kV		125	$155,000,000
Total	10	125	**$175,000,000**

7.1.4: Brookings-Split Rock Project

	Acreage	Length	
Substations			
Brookings County	--		$8,000,000
Pipestone Substation	10		$20,000,000
Split Rock Substation	--		$8,000,000
Lines			
Brookings-Pipestone 345 kV Dbl Ckt.		50	$112,000,000
Pipestone-Split Rock 345 kV Dbl Ckt.		45	$100,000,000
Total	10	95	**$250,000,000**

7.1.5: Lakefield-Adams Project

	Acreage	Length	
Substations			
Lakefield Junction Substation	5		$8,000,000
Winnebago Substation	10		$20,000,000
Hayward Substation	10		$20,000,000
Adams Substation	5		$8,000,000
Lines			
Lakefield Jct.-Winnebago 345 kV Dbl Ckt.		55	$125,000,000
Winnebago-Hayward 345 kV Dbl Ckt.		50	$110,000,000
Hayward-Adams 345 kV Dbl Ckt.		37	$84,000,000
Total	30	142	**$375,000,000**

7.1.6: Adams-La Crosse Project

	Acreage	Length	
Substations			
Adams Substation	5		$8,000,000
Harmony Substation	10		$20,000,000
Genoa Substation	10		$20,000,000
North La Crosse Substation	--		$8,000,000
Lines			
Adams-Harmony 345 kV Dbl Ckt		35	$84,000,000
Harmony-Genoa 345 kV Dbl Ckt		45	$110,000,000
Genoa-North La Crosse 345 kV Dbl Ckt.		20	$50,000,000
Total	25	100	**$300,000,000**

7.2: Evaluated Cost (with losses)

The following tables show the total evaluated cost for the various alternatives evaluated. The evaluated cost include installed and underlying system costs including production cost savings, load cost savings, and loss savings

7.1.1: La Crosse - Madison Project with Corridor

Description	*Cost*
Project Cost	$700,000,000
Underlying System Cost	$35,000,000
70% Production Cost Savings Offset	($191,000,000)
30% Load Cost Savings Offset	($612,000,000)
Loss Savings Offset	($134,000,000)
Net Project Cost	($202,000,000)

7.1.2: Fargo-Brookings Co. & Ashley Hankinson Project

Description	*Cost*
Project Cost	$725,000,000
Underlying System Cost	$45,000,000
70% Production Cost Savings Offset	($253,000,000)
30% Load Cost Savings Offset	($494,000,000)
Loss Savings Offset	($35,000,000)
Net Project Cost	($12,000,000)

7.1.3: Fargo-Brookings Co., Ashley Hankinson, & La Crosse Madison Project

Description	*Cost*
Project Cost	$1,075,000,000
Underlying System Cost	$30,000,000
70% Production Cost Savings Offset	($356,000,000)
30% Load Cost Savings Offset	($679,000,000)
Loss Savings Offset	($128,000,000)
Net Project Cost	($58,000,000)

7.1.4: Adams-La Crosse & La Crosse Madison Project

Description	Cost
Project Cost	$650,000,000
Underlying System Cost	$20,000,000
70% Production Cost Savings Offset	($115,000,000)
30% Load Cost Savings Offset	($265,000,000)
Loss Savings Offset	($167,000,000)
Net Project Cost	$123,000,000

7.1.5: Lakefield-Adams-La Crosse & La Crosse Madison Project

Description	Cost
Project Cost	$1,025,000,000
Underlying System Cost	$15,000,000
70% Production Cost Savings Offset	($203,000,000)
30% Load Cost Savings Offset	($420,000,000)
Loss Savings Offset	($225,000,000)
Net Project Cost	$192,000,000

7.1.6: Fargo-Brookings Co-Split Rock, Ashley Hankinson, & La Crosse Madison Project

Description	Cost
Project Cost	$1,325,000,000
Underlying System Cost	$40,000,000
70% Production Cost Savings Offset	($356,000,000)
30% Load Cost Savings Offset	($679,000,000)
Loss Savings Offset	($185,000,000)
Net Project Cost	$145,000,000

7.1.7: Fargo-Brookings Co-Split Rock, Ashley Hankinson, Lakefield-Adams-La Crosse, & La Crosse Madison Project

Description	***Cost***
Project Cost	$2,000,000,000
Underlying System Cost	$30,000,000
70% Production Cost Savings Offset	($500,000,000)
30% Load Cost Savings Offset	($791,000,000)
Loss Savings Offset	($288,000,000)
Net Project Cost	$451,000,000