

**MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

In the Matter of the Application of Great River Energy,
Northern States Power Company and others for
Certificates of Need for the Cap X
345-kV Transmission Projects

OAH Docket No. 15-2500-19350-2
PUC Docket No. CN-06-1115

TO: Judge Beverly Jones Heydinger
Office of Administrative Hearings
PO Box 64620
St. Paul, MN 55164-0620

or capx2020.oah.state.mn.us

Comments due September 26, 2008

PUBLIC COMMENT AND AFFIDAVIT OF ALAN J. MULLER

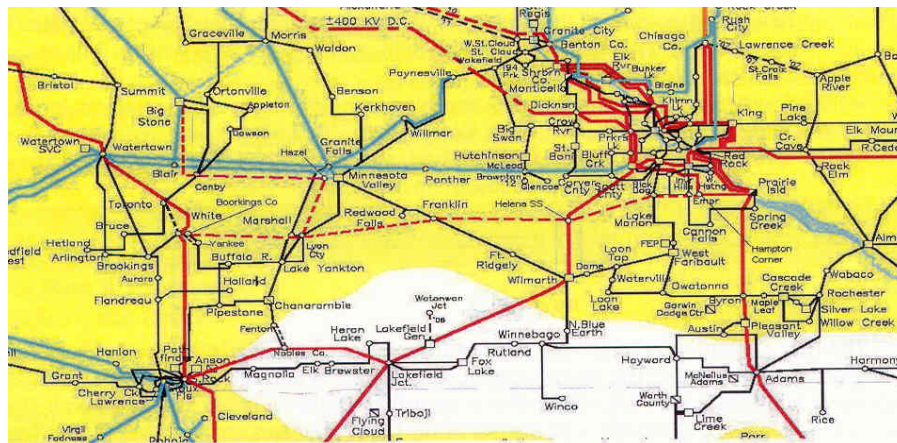
Alan J. Muller, after being duly sworn on oath, states and deposes as follows:

1. I am Executive Director of Green Delaware. I am making this comment on my own behalf as an individual, a part-time resident of Minnesota very concerned with energy issues. I am not retained by or representing any party in this proceeding.
2. In December, I attended many of the scoping meetings held by the Department of Commerce around Minnesota, and heard the presentations of Commerce staff and CapX 2020 over the course of many days. I was also present during several days of the evidentiary hearing in St. Paul.
3. On the evening of July 2, 2008, I testified at the public hearing in Rochester, and entered several exhibits at that time. I make this Comment to supplement my prior testimony in this docket.

CONNECTION OF BIG STONE II WITH THE CAPX 2020 BROOKINGS LINE

4. CapX 2020 and the Big Stone II coal plant are inextricably connected. The CapX 2020 application, and the Dept. of Commerce "Environmental Report" do not address the fact that the Big Stone II plant's transmission, as applied for in Minnesota, will connect into CapX 2020's "Brookings" line. Exhibit 1, CapX 2020 Application, Map of CapX 2020 Brookings line, showing radial line extending northwest from the Brookings line to the Hazel Creek substation and the Minnesota Valley substation; Ex. 28, Big Stone II transmission map. This connection was established in testimony in the evidentiary hearing.
5. This connection of Big Stone II into CapX 2020's Brookings line is also present in a September 6, 2005, letter from CapX 2020 to Burl Haar of the PUC, which contained

this map, where both the Big Stone II transmission and the CapX 2020 transmission are represented with a dashed red line:



6. Attached as Muller Exhibit A is a true and correct copy of the September 6, 2005 letter from William Kaul, of Great River Energy, as a partner in CapX 2020. This letter, in addition to presenting the above map, directly states the connection of CapX 2020 to transmission for Big Stone II. On p. 2, the Big Stone II Transmission is included as part of Project Group I:

Project Group 1		Expected CON Filing	Expected In-Service
Big Stone II Transmission	CapX West	3rd qtr 05	2011
Buffalo Ridge Outlet		4th qtr 05	2009
Buffalo Ridge – Metro 345		4th qtr 05	2010
Boswell – Wilton 230	CapX Northwest	1st qtr 06	2010
Fargo – Alexandria – Benton County 345		4th qtr 06	2012
Prairie Island – Rochester – LaCrosse 345	CapX Southeast	1st qtr 06	2011

7. The Big Stone II interconnection transmission is announced, in this Sept. 6, 2005, letter as “the first element to be presented” and specifically addresses direct connection with CapX 2020 in narrative and in a map:

CapX West

The first element to be presented for certificate of need approvals will be transmission facilities associated with the Big Stone generation project. While the Big Stone II partners include some non-CapX members, those of us responsible for transmission associated with Big Stone II have been working closely with the rest of the CapX members and with MISO. As was outlined in the Big Stone notice plan, MISO interconnection studies show that a second unit at Big Stone requires a minimum of two 230 kV interconnection lines. The Big Stone partners now intend to propose constructing the line connecting Big Stone and Granite Falls to 345 kV standards to better meet and be integrated with CapX, state, and regional objectives. As a result, the Big Stone transmission project, in addition to providing interconnection facilities for a

second unit at Big Stone, is now being planned as the first phase of a 345 kV line between southwestern Minnesota and the Twin Cities metro area. The Big Stone transmission partners expect to file a certificate of need for these facilities in September.

Id. p. 3-4.

8. The Big Stone II Recommendation in the Minnesota PUC transmission docket, 06-619, has been entered into the record of the CapX 2020 proceeding, Exhibit 20, and raises the environmental and interconnection issues.
9. Connecting Big Stone II, and thereby allowing the Big Stone II plant to operate, will have significant implications, both in CO2 emissions and costs associated with CO2 emissions. Both the planet and our picketbooks will suffer.
10. CO2 emissions have a market value/cost addressed in range by the Minnesota PUC and established by the various markets world wide.
11. Big Stone II output is not deliverable with either of the transmission alternatives proposed by Big Stone II. Thus far, five studies have been completed and shown that the energy generated by Big Stone II cannot be delivered, and now Phase 6 studies have been done, assuming CapX is completed and that Big Stone II is connected to CapX 2020, which is expected to mitigate the lack of deliverability.
12. Attached as Muller Exhibit B is a true and correct copy of the Big Stone II Phase 5 Draft Deliverability Study, labeled **G392 Deliverability Study Report - Draft 11-6-06** which shows that the generation is not deliverable, even after five attempts to find a way. This report is also available online at:
http://www.midwestmarket.org/publish/Document/3c9065_10e9e96031d_7fa70a48324a/Draft_Deliverability%20Study%20Result%20Report_G392_11-6-2006.pdf?action=download&_property=Attachment

This generator is not fully deliverable without system upgrade. The following upgrades are necessary to make it fully deliverable (600 MW):

Project G392 was studied for both alternative 1 and 2, the constraints limiting the full deliverability of this unit are listed above. The details on these constraints are listed in section 7 below.

The Grant County -- Morris 115kV is the most limiting constraint, it was also identified in the System Impact Study and the delivery service studies.

The Wilmar -- Granite Falls 230kV is undergoing upgrades, CT's are being replaced during Granite Falls fall outage. This work may already be complete. This should give a short-term rating of 318 MVA for an 800 Amp Wavetrap. GRE has a wavetrap of 800 Amp that is planned to be replaced early next year achieving the full conductor rating (383 MVA) -- (Per GRE). The short term rating of 318 MVA would allow for enough capacity to completely relieve this constraint for both alternatives.

Without any upgrades, G392 is 262.1 MW deliverable via alternative 1 and 267.7 MW deliverable using alternative 2

Muller Exhibit B, G392 Deliverability Study Report - Draft 11-6-06, Conclusion, p. 3.

13. Attached as Muller Exhibit C is a true and correct copy of Draft Big Stone II Deliverability Study, August 18, 2006.
14. This Big Stone II deliverability study continues to recite the problems with deliverability in this later version of that study:

This report focuses on flagging any potential constraints. More study work will be completed in Phase 6 in particular to address the impacts from Tables 1-1 through 1-4. Phase 6 is also considering the effect of projects such as those announced by the CapX 2020 group, and other projects that have matured since the Big Stone II delivery studies were started. Verification of ratings and limitations of various facilities will also be an ongoing task, as well as determining how operating guides might help resolve some constraints.

Muller Exhibit C, Draft Big Stone II Deliverability Study, August 18, 2006, p. 21.

15. The study concludes:

While being constructed for operation at 345 kV, the Big Stone to Granite Falls line would initially be operated at 230 kV until new 345 kV facilities are constructed in the Granite Falls area. Additional analysis has been completed with the "southern" line from Big Stone to Granite Falls operated at 345 kV and connecting into the Hazel substation, which is part of the CapX SW MN TC EHV study. The results indicate that operating the Big Stone to Granite Falls line at 345 kV in conjunction with the EHV facilities doesn't cause any existing Big Stone outlet facilities to overload beyond their applicable ratings for either system intact and N-1 conditions.

Building the Big Stone II transmission plan with the Big Stone – Granite Falls line at 345 kV integrates well into the regional transmission needs identified through the CapX 2020 Vision Study, the MISO Northwest Exploratory Study, and the SW MN TC EHV study.

Id., p. 78

16. Attached as Muller Exhibit D is a true and correct copy of Draft Big Stone II Deliverability Service Study (123 pps). More extensive than Exhibit C, again the general conclusion of this Big Stone II deliverability study specifically implicates CapX 2020 as necessary for Big Stone II:

8.3 General Conclusion

Sections 8.1 and 8.2 summarize constraints on the system that the Big Stone II project will have to mitigate for obtaining transmission service and not degrade the reliability of the transmission system.

For many of the constraints observed, there has not yet been a determination made as to what the mitigating step will be. Many concerns are expected to be addressed by load serving efforts that are currently underway at the time this report is being written and the BSP II project will need to wait for study work to be completed before reasonable and likely assumptions can be made for future studies to verify that the constraints will be addressed.

There are also larger scale efforts underway in Minnesota and bordering areas that might address many of the concerns identified. The CapX effort is currently looking at the following facilities to be built within the next several years:

- 345 Kv from Brookings County (near White, SD) – Lyon County – Helena (tap on Wilmarth – Blue Lake 345 Kv) – Lake Marion – Hampton Corner, with a 345 Kv line from Lyon County – Hazel Run (near Granite Falls). Likely with this line in-service the Big Stone – Canby – Granite Falls 230 Kv line will be converted to a Big Stone – Canby – Hazel Run 345 Kv line. The Hazel Run substation will have connections to the Granite Falls and Minnesota Valley substations.*
- 345 Kv from Fargo – Alexandria – St. Cloud – Monticello*
- 345 Kv from Hampton Corner – Rochester – Lacrosse*
- 230 Kv from Boswell – Wilton*

This list is referred to as CapX Group 1. The first line listed above is expected to help address many of the constraints found in this Delivery Study as it will likely interconnect with the new transmission line common to both transmission alternatives. Phase 6 of Big Stone II studies is scheduled to be started in early 2007, and will look at the effect of the planned and proposed CapX lines, as well as other planned and proposed system upgrades. It should also be noted that with these major new power lines being proposed by CapX, a separate study is underway by the CapX team to accommodate these high voltage lines and to identify what underlying (230 Kv and below) system changes would have to be done. There are also other Extra High Voltage (EHV) lines under investigation beyond CapX Group 1. (For more information visit www.capx2020.com).

Muller Exhibit D is a true and correct copy of Draft Big Stone II Deliverability Service Study (123 pps), 119-121

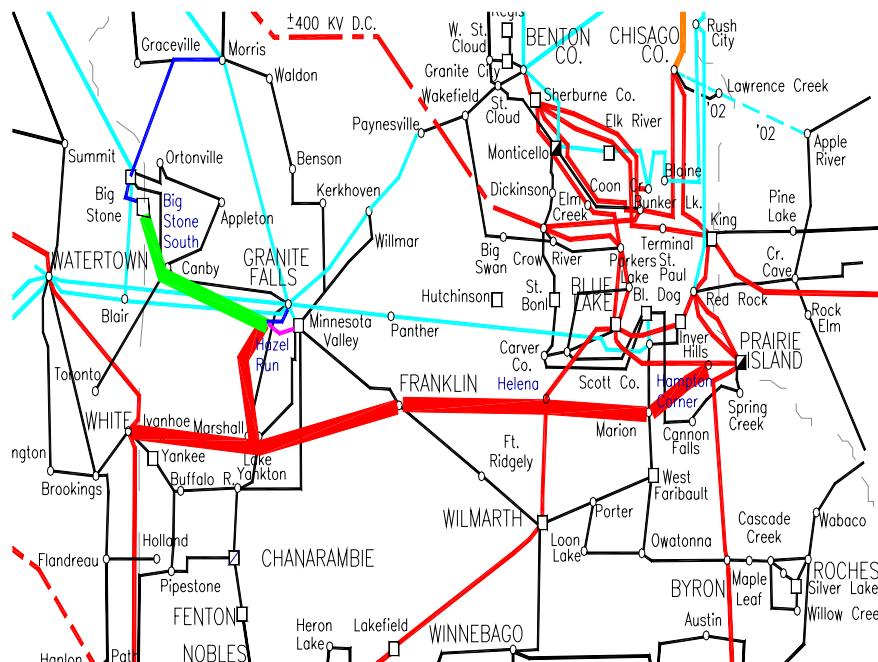
17. Without CapX 2020, according to the Midwest ISO studies, Big Stone II output is not deliverable, and studies are proceeding to determine what additional mitigation might be necessary. At this point, interconnection plans and deliverability studies overtly turn to CapX to address these problems.
18. Attached as Muller Exhibit E is a true and correct copy of “Phase 6 and Supplemental #2,” a MAPP (now MRO) SPG PowerPoint presentation authored by Dean Pawlowski of Otter Tail Power, and presented April 4, 2007, which noted:

Converting Big Stone – Canby – Granite Falls 230 Kv to 345 Kv

- *The line conversion would mean that there would be a 345 Kv line from Big Stone area tying into the Brookings County, SD – SE Twin Cities CapX project.*
- *The termination point for the 345 Kv would be at the proposed Hazel Run substation near Granite Falls.*
- *Only studied in a post-CapX world (the one project only).*

Id., Slide 7.

19. This same presentation shows the transmission map for Big Stone II (thick green line from Big Stone to Granite Falls) and its relation to CapX (thick red line from White eastward to Hampton Corners and then going northward to Hazel Run), the same as proposed above by CapX above in its September 6, 2005 letter:



20. The PowerPoint goes on to say that CapX mitigates many of the Big Stone II interconnection and delivery problems:

- CapX helps constraints found earlier
 - Kerkhoven Tap 115 kV bus voltage within criteria
 - Granite Falls – Minnesota Valley 230 kV loading well below normal rating at 56%
 - Fargo – Moorhead 230 kV loading below normal rating
 - Fargo 115/69 kV xfmr #2 loading down to emergency rating for relevant contingencies (as opposed to above emergency rating previously).
 - Belfield 345/230 kV xfmr loading below emergency rating. Contingency is loss of large Leland Olds 345/230 kV xfmr with cross-trip of the smaller one. Winter scenario sees the highest flows.
 - New Ulm area bus voltages is helped somewhat with the new Franklin 345/115 kV substation. However 115 and 69 kV is still a constraint for serving load in the area. Study on how to enhance load serving in this area is being performed w/ Xcel as lead.

Id., Slide 12.

21. Attached as Muller Exhibit F is a true and correct copy of G392 Deliverability Study Report - Final_1-22-08, available online at

http://www.midwestmarket.org/publish/Document/6871db_117a25bcaa6_-7ff70a48324a/Deliverability%20Study%20Result%20Report_G392_1-22-2008.pdf?action=download&_property=Attachment

22. Attached as Muller Exhibit G – Big Stone II Generator Interconnection Study, Supplemental IC Report - May 8, 2007, and available online at:

http://www.midwestmarket.org/publish/Document/9e2b5_112683a3cb8_-7fe80a48324a?rev=1
(one of many files in zip file)

In conclusion, this additional follow-up work has shown that Big Stone II does not create any new system performance concerns or worsen any existing system performance issues. However, existing operating guides and/or new operating guides will have to be developed for Big Stone generation to ensure the system meets steady state reliability criteria during prior outage conditions.

Exhibit G, Big Stone II Generator Interconnection Study, Supplemental IC Report, Executive Summary, p. 3. The problems have not been resolved:

3.6 Conclusion of Steady State Prior Outage Analysis

This analysis considered simultaneous failure of two transmission outlets from the Big Stone plant (N-2 contingencies). This analysis only monitored transmission facility loadings in the immediate area of Big Stone. The objective of this additional study work is to give some indication of if, and to what extent, additional reductions at Big Stone will be necessary in order to keep facility loading levels within acceptable limits during prior outage conditions.

Reviewing the results of this analysis have indicated that generator reductions will be necessary at the plant due to thermal overload problems on the system following outage of 2 transmission outlet from Big Stone.

Consideration of the existing operating procedure in place for Big Stone Unit 1 helps unload the transmission system at Big Stone for certain contingencies, but that operating procedure will need to be updated or a new operating procedure for Big Stone II will need to be developed in addressing the thermal overloads at Big Stone that appear during this analysis. It appears that in some cases, reductions that are in place today for Unit 1 will be relaxed by Big Stone II, while in other cases, there will need to be additional generator reductions from Big Stone II. Detailed operating studies will be required prior to Big Stone II being placed into service. These operating studies will include a detailed N-2 contingency analysis defining the operating restrictions that need to be placed on Big Stone generation. Big Stone Unit 1 is currently included as part of the North Dakota Operating Guides and any changes to the reduction scheme for Unit 1 or the development of a new reduction scheme for Big Stone II will be reflected in the appropriate documents (i.e. ND Operating Guide, etc...).

Exhibit G, Big Stone II Generator Interconnection Study, Supplemental IC Report, Executive Summary, p. 15.

MARKET ISSUES ARE A DRIVING FORCE IN CAPX2020 PROPOSAL

23. A primary driver of the CapX 2020 project is the market (deregulated profit) opportunities it will bring the generators with access to CapX 2020. Midwest ISO is the centralized dispatch entity, and has begun a Day-2 Market.
24. Midwest ISO and PJM are connected and negotiating to determine whether and how the entities might merge or be interconnected more directly, and should they join, it is possible that coal generation in the Dakotas could be sold to markets in Delaware.
25. Generators can sell surplus electricity in the Day-2 market, where prices are higher due to the nature of the Day-2 market with short notice and short term sales.
26. What isn't taken into account is the surplus of generation, which will be exacerbated by the many new generators waiting to come on line.
27. As I write this comment, the Midwest ISO Market Announcement page is headed with this announcement of surplus:

Friday, September 26, 2008 01:09 AM

Midwest ISO Market Footprint Minimum Generation Emergency ALERT in effect from 00:30 to 05:00 EST on Friday, September 26, 2008.

Based on the medium term Load Forecast, current scheduled interchange, on-line Resources, and transmission security requirements the Midwest ISO (MISO) is anticipating a supply surplus condition on a market footprint-wide basis and is requesting MISO Generation Operators and Market Participants to prepare for a Minimum Generation Emergency Event between 00:30 to 05:00 EST on Friday,

September 26, 2008. The currently forecasted Dispatchable down-room to the economic minimums of on-line resources is projected to be 480 MW during these hours. The event may result in utilization of the Emergency ranges of on-line Generation Resources, the decommitment of Generation Resources, requests to reduce purchases, or other Emergency actions.

MISO Market Announcement: <http://www.midwestiso.org/page/Market+Announcements>

28. Midwest ISO and CapX 2020 have not completed sufficient market analysis to support the magnitude of additions of transmission proposed.
29. Attached as Muller Exhibit H is a true and correct copy of ICF's February 28, 2007, Independent Assessment of Midwest ISO Operational Benefits. The copy provided with my testimony on July 2, 2008, in Rochester was found on midwestiso.org, and is identical to the copy attached here as Exhibit G, which was found at http://www.icfi.com/Markets/Energy/doc_files/midwest-iso-report.pdf.
30. The purpose of the MISO Midwest Market is to displace natural gas generation with coal generation. As explained in the study:

The focus was on production cost savings associated with centralized operations, and hence, primarily reflects estimation of the displacement of relatively more expensive generation with relatively less expensive generation made possible by centralized operations. In most cases the simulation indicated the potential displacement of gas-fired generation with coal-fired generation. This inter-fuel optimization is particularly important in the Midwest because the natural gas generation fleet includes a disproportionate level of expensive gas-fired peaking units as opposed to intermediate or less costly gas-fired combined cycle or gas-steam facilities. Further, Midwest ISO coal plants have very low operating costs even compared to other US coal-fired power plants. Thus, any displacement of natural gas generation with coal generation can greatly decrease operating costs. Put another way, the use of a gas plant when somewhere else inside or outside of the Midwest ISO a coal plant with spare capacity and the needed transmission is available to displace the gas plant would increase costs significantly. As such, an important goal of grid optimization is to minimize these occurrences.

Id. at 9.

31. The primary conclusion of the report states:

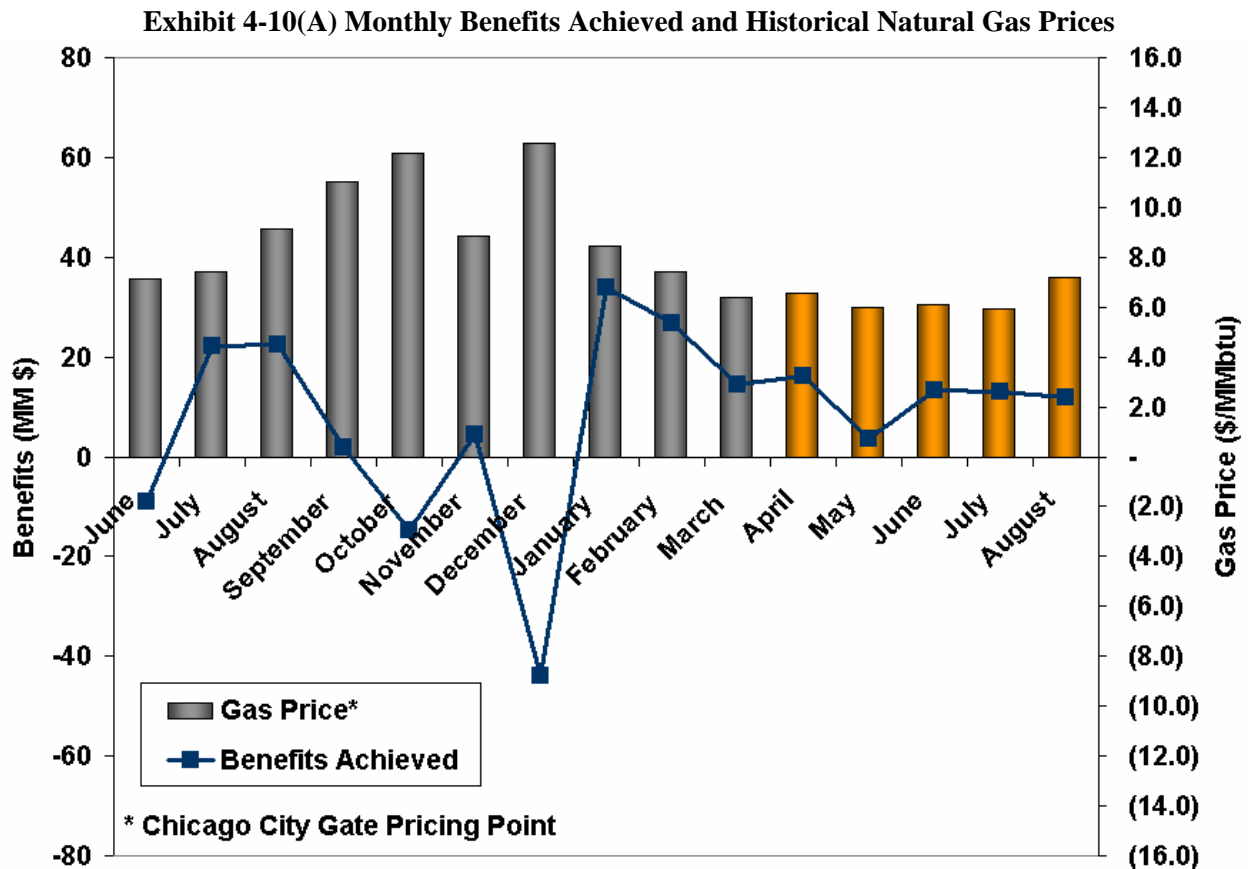
RTO operational benefits are largely associated with the improved ability to displace gas generation with coal generation, more efficient use of coal generation, and better use of import potential.

Id. at 14.

32. The report notes that the benefit will grow as “[t]ransmission upgrades which could increase the geographic scope of optimization within the Midwest ISO footprint.” Transmission upgrades anticipated are of a magnitude consistent with CapX 2020, “regional transmission investment initiatives such as MTEP 06 which will bring \$3.6 billion in transmission investments to market by 201 and targets elimination of 22 of the top 30 constraints in the footprint.

Id.

33. Attached as Muller Exhibit J is a true and correct copy of the May, 2007, Addendum to Independent Assessment of Midwest ISO Operational Benefits.
34. Below is a graph taken from the Addendum, which shows the “benefits” of displacing natural gas with coal (a scenario expressly not included in the Environmental Report):



Id. p. 10.

35. The emphasis on market drivers as a driver for the CapX 2020 proposal are a concern because the market, when functioning as designed, can have detrimental

consequences to participants and consumers. Worse, markets can be manipulated, as evidenced in our current economic quagmire.

36. An example of market manipulation is found in Minnesota. Otter Tail Power, the primary promoter of Big Stone II, has been subject to a Consent Order from FERC regarding market transactions using the designation of “Network Resources” for market transactions, resulting in a \$500,000 disgorgement of profits.
37. Attached as Muller Exhibit J is a true and correct copy of the FERC Stipulation and Consent Agreement with Otter Tail Power dated May 29, 2008. The issue is misuse of the designations that lower costs and give priority for transmission to serve its native load.
38. From the Stipulation, the first of two issues

Use of Network Service to Facilitate Off System Sales

5. Section 28.6 of MISO’s OATT states as follows:

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated Loads, or (ii) direct or indirect provision of Transmission Service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Module B of this Tariff for any Third-Party Sale which requires use of the Transmission Provider’s Transmission System except for service where the purchaser is a Network Customer of the Transmission Provider.¹

6. Enforcement determined that during the study period Otter Tail used network transmission service under MISO’s OATT to import power that later was sold off-system. Enforcement determined that portions of these purchases were made to service the off-system sales, and thus violated section 28.6 of MISO’s OATT. Taking into account only those purchases made from non-MISO members, staff determined that Otter Tail improperly utilized network transmission service for this purpose in 3,306 operating hours, representing approximately 250,000 MWh of purchased energy. Enforcement calculated that Otter Tail received \$546,832 in profits from the resultant off-system sales. These profits arose from the difference in the purchase and sale prices of transactions scheduled into and out of Otter Tail’s control area. The purchases were ultimately sold off-system and the sales were not from Otter Tail-owned generation.

Id. p. 2.

39. The second violation found by FERC was improper use of the curtailment priority for the transactions:

Curtailment Priority

8. Section 28.4 of MISO's OATT states as follows:

The Network Customer may use the Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, with no additional charges imposed under Schedules 7, 8, or 9, or the applicable ITC Rate Schedule. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff or under any applicable ITC Rate Schedule.²

9. Section 28.4 of MISO's OATT provides that if a network customer imports energy from a non-designated network resource to serve its network loads, it may use network service, but at a lower curtailment priority than for firm transmission service. Enforcement determined that on some occasions Otter Tail scheduled delivery of energy from non-designated resources using the curtailment priority for firm transmission service (7F or 7FN) associated with designated resources, instead of secondary network service (6NN), in violation of section 28.4 of MISO's OATT.

Id. at 3.

THE ENVIRONMENTAL REPORT IS INADEQUATE

40. The Environmental Report is inadequate and should be deemed so by the Public Utilities Commission.
41. An initial problem is that there is no clear procedure for challenging the scoping decision, thanks to statutory changes and rules that have not caught up with the statute.
42. The particular issue that should have been addressed, because this report is to address potential impacts, is the impact of the system focus on transmission, through which new coal generation is enabled. If there was not large transmission, the coal would not be built.

Conclusion

43. Based on what I have heard at various public meetings, a public hearing, and evidentiary hearings, I conclude that the CapX 2020 promoters are not being straightforward regarding their motives. I recall a statement to the effect that “we need to do this to keep your lights on,” and numerous claims that reliability would suffer if all the CapX proposals aren’t approved. The record does not support these claims and does not support their different claims of need. The Minnesota Department of Commerce appears to be aligned with the promoters and, in effect, giving the color of agency approval to dubious promotional materials and statements.
44. The record does not support the vaguely and indirectly implied claims that the projects are needed to enable growth of wind capacity.
45. Rather, the record indicates that the real motives for the proposals are:
 - a. enabling construction of new coal capacity and expanded use of existing coal capacity, and
 - b. enabling expanded profits through “bulk power transfer” market transactions.
46. The inclusion of so many line proposals in one Docket, with deficient public notice, greatly reduces the opportunity for adequate public participation and proper evaluation of the schemes.
47. Expanded coal use is incompatible with the critical need to reduce carbon emissions and other harmful impacts from burning coal. It is incompatible with often-stated and legislated public policies of the State of Minnesota that global warming must be addressed by reducing carbon emissions.
48. Increased bulk power transfer activities are not likely to benefit Minnesota or regional ratepayers and are likely to discourage the development of locally-sited wind and solar capacity, and supply-side (conservation and efficiency) investments.
49. Thus, the Cap/x 2020 proposals are likely to have more negative than positive impacts. I recommend:
 - 1) The the environmental review be upgraded to fully evaluate the impacts of consequent increased coal burning, to include all the impacts of the entire coal “life cycle” or “supply chain” including mining, transport, combustion, ash disposal, and health/environmental impacts.
 - 2) The ALJ should recommend denial of the application and CapX 2020 proposals should be rejected by the PUC.
50. Any further transmission proposals should be docketed by the PUC only on a line-by-line bases, with the real proposers clearly identified, the real motive declared, and more careful attention paid to the adequacy of public notice and the correctness of information provided to the public.

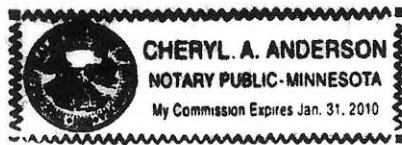
Thank you for the opportunity to Comment on the need for CapX 2020 and the adequacy of the Environmental Report.

Dated: September 26, 2008

Alan J. Muller

Signed and sworn to before me this
22 day of September, 2008.

Cheryl A. Anderson
Notary Public



**Central Minnesota
Municipal Power
Agency**



Minnkota Power
MPC COOPERATIVE, INC.



September 6, 2005

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East
St. Paul, MN 55101

Mr. Edward Garvey
Assistant Commissioner
Minnesota Department of Commerce
85 7th Place, Suite 500
St. Paul, MN 55101

Re: CapX Project Group 1 Implementation Plan

Dear Messrs. Haar and Garvey:

On behalf of the CapX 2020 participating utilities, I want to thank both of you and your agencies for the time and energy devoted to transmission issues, particularly during the recent legislative session. Those efforts have helped lay the groundwork for developing needed transmission infrastructure in the state, a critical component of our state's energy future.

As you know, the CapX 2020 utilities have worked to develop a long-term vision for transmission infrastructure to meet growing regional needs, and have made significant progress. We are now moving from the planning and study stage to implementation of Project Group 1. To ensure you are aware of our plans, which will result in regulatory filings in the near future, we wanted to provide you this update.

The information in this letter is general in nature and does not require either a docket or comment period; however, we are copying it to those on the service list the Commission maintains for the Biennial Transmission Projects Report to ensure that interested parties are likewise aware of our efforts.

Background

Over the last year, transmission planners have worked to develop a comprehensive framework for much needed transmission infrastructure for the state of Minnesota. Instead of a piecemeal approach in which each individual electrical issue is studied and addressed separately, we endeavored to integrate our planning efforts and identify common improvements to the high voltage transmission system over a broad spectrum of possible futures.

Our effort focused on the growing demand for electricity in Minnesota over the next fifteen years, through the year 2020. We understand from resource planners at utilities serving customers in Minnesota and surrounding states that the demand for electricity could increase by roughly 6300 megawatts by around 2020. To deliver that much power, substantial improvements to the bulk power transmission system serving the state will be required. Even using lower growth estimates (e.g., 4,500 MW), our studies identify that a significant amount of backbone transmission infrastructure will be required.

We named this joint planning effort "CapX 2020" in recognition that substantial capital investments will be needed to meet electrical demand projections of the planning period. We published our draft plan in May, have been talking to parties, and refining it since. An overview and update was presented to the Commission and the Department on July 18, 2005.

Vision Study Overview

As noted in our preliminary study report and at the July presentation, our Vision Study, in conjunction with other regional transmission studies, has identified a number of significant transmission projects as necessary to meet anticipated load by 2020. The projects have been put into four different "groups," based generally on need, the amount and detail of study work performed to date, and coordination with other regional planning efforts. Listed below is Project Group 1, with expected CON filing and in-service dates.

Project Group 1		Expected CON Filing	Expected In-Service
Big Stone II Transmission	CapX West	3rd qtr 05	2011
Buffalo Ridge Outlet		4th qtr 05	2009
Buffalo Ridge – Metro 345		4th qtr 05	2010
Boswell – Wilton 230	CapX Northwest	1st qtr 06	2010
Fargo – Alexandria – Benton County 345		4th qtr 06	2012
Prairie Island – Rochester – LaCrosse 345	CapX Southeast	1st qtr 06	2011

Projects in the other three groups were listed in the July presentation. Further study work and detailed analysis on these projects is ongoing.

Near-Term Actions

To move these study results to project proposals, the CapX utilities have been working to prepare regulatory filings for Project Group 1. We intend to make a number of regulatory filings in the coming months seeking approvals to build three major 345 kV components of our plan. In those filings, we will continue to emphasize that projects should not be viewed in isolation but as parts of an integrated whole needed to meet both regional and local reliability needs. Toward that end we intend to be presenting our plans in more detail as part of the November 1 Minnesota Transmission Planning Report. However, you will see filings before then to get the regulatory process started for a number of elements of the plan.

The initial three regional solutions to be proposed through Certificate of Need filings and routing applications are:

- **CapX West** consists of several projects including a new 345 kV line connecting western Minnesota and the Twin Cities, an upgrade of a 115 kV line from Big Stone to Morris to a 230 kV line and two new 115 kV lines in the Buffalo Ridge area. These projects have been closely coordinated with Big Stone generation interconnection requests and Buffalo Ridge transmission requirements.
- **CapX Northwest** consists of a 345 kV line between the Fargo and St. Cloud and a 230 kV line from Bemidji to the Grand Rapids area. These lines will establish a second new spoke in the bulk power expansion plan while also providing reliability upgrades in the Red River Valley and the St. Cloud areas. Combined, these first two elements of our plan will complete the key western Minnesota components of the Vision Study.
- **CapX Southeast** is a 345 kV line connecting the high voltage system in Red Wing to Rochester and the La Crosse area. This project will provide another spoke in the bulk power system and provide support for growing electrical demand in communities in southeastern Minnesota.

Additional description of each of these near-term actions is provided below.

CapX West

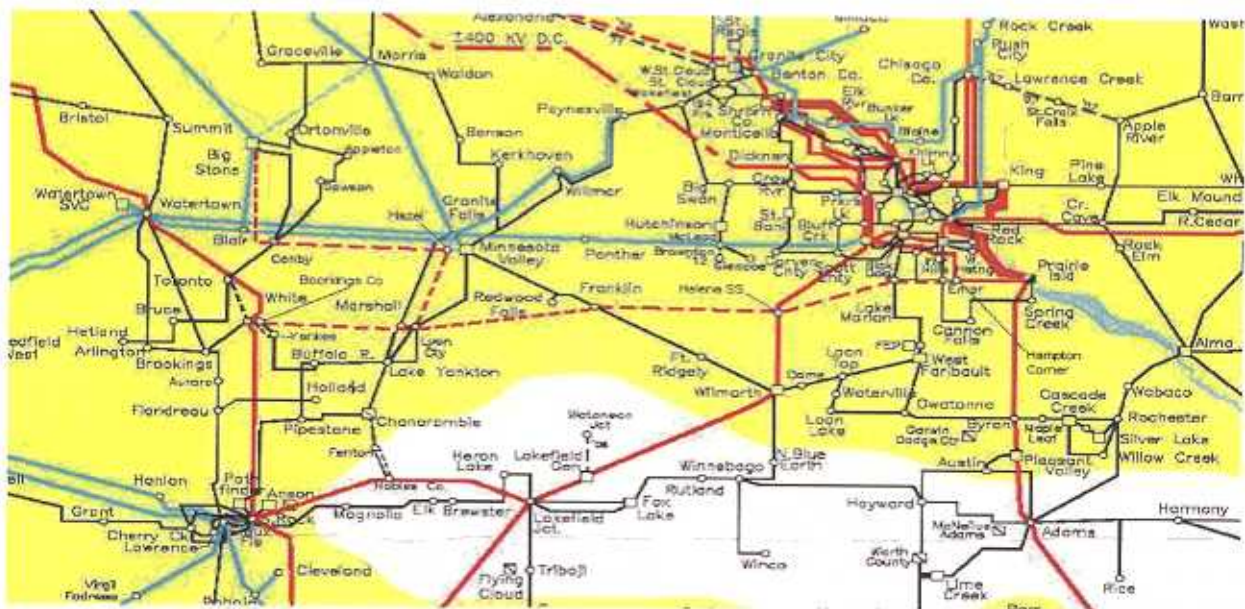
The first element to be presented for certificate of need approvals will be transmission facilities associated with the Big Stone generation project. While the Big Stone II partners include some non-CapX members, those of us responsible for transmission associated with Big Stone II have been working closely with the rest of the CapX members and with MISO. As was outlined in the Big Stone notice plan, MISO interconnection studies show that a second unit at Big Stone requires a minimum of two 230 kV interconnection lines. The Big Stone partners now intend to propose constructing the line connecting Big Stone and Granite Falls to 345 kV standards to better meet and be integrated with CapX, state, and regional objectives. As a result, the Big Stone transmission project, in addition to providing interconnection facilities for a

second unit at Big Stone, is now being planned as the first phase of a 345 kV line between southwestern Minnesota and the Twin Cities metro area. The Big Stone transmission partners expect to file a certificate of need for these facilities in September.

Next we intend to file for approval of the rest of the components of CapX West, which consist of 345 kV lines connecting substations near Brookings, Marshall, and Granite Falls to the bulk power supply system in the southern part of the Twin Cities area. The 345 kV plan is needed to meet the growing demand for electricity under a number of future power demand and generation scenarios. It also strengthens system reliability in parts of western and south central Minnesota. Our application will also include the 115 kV lines necessary to increase power delivery capability from the Buffalo Ridge area.

CapX and other utilities are now conducting the detailed studies to provide the design information required for certificate of need filings and are actively sorting out proposed ownership and other implementation details. We anticipate making a notice plan filing in September and a certificate of need application as soon thereafter as the process allows, likely in November or December.

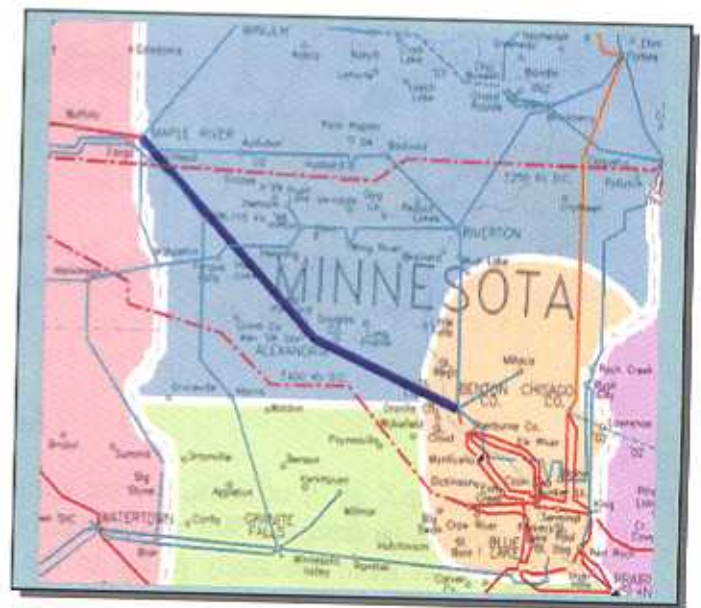
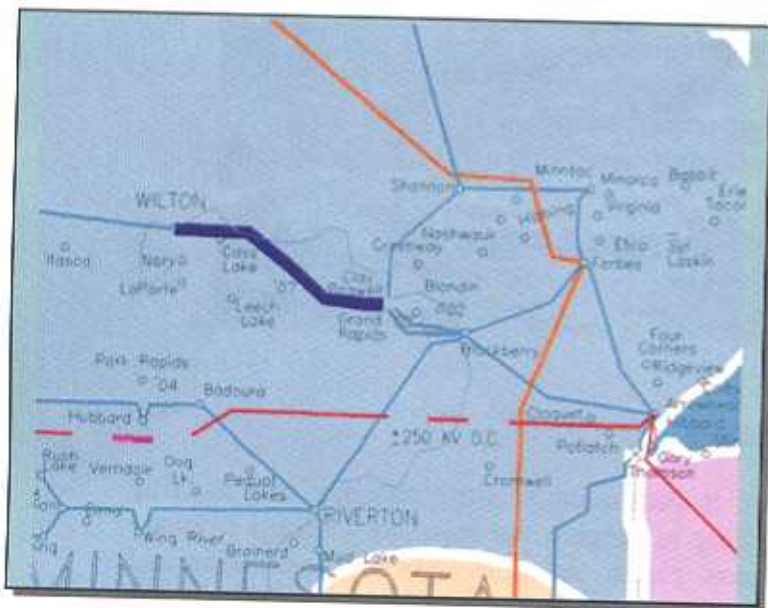
We believe that when viewed as an integrated package, these projects establish one of the key spokes in the overall plan for enhanced transmission infrastructure for the southwestern and western parts of the state. A simple schematic of the project on an integrated basis is provided below.



CapX Northwest

The next component of the overall implementation plan is a 345 kV transmission line between the Red River Valley and St. Cloud, the northern terminus of the 345 kV system surrounding the Twin Cities. Studies demonstrate that this line would support a number of possible statewide electrical growth scenarios and address identified electrical reliability issues in the Red River Valley and the St. Cloud area. This element of the CapX plan also acts in concert with CapX West to efficiently deliver power from western Minnesota where interest in renewables based generation is high. Studies have also identified the need for a 230 kV line connecting the Grand Rapids and Bemidji areas (Boswell-Wilton project). We plan to make notice plan filings and certificate of need applications for these facilities likely sometime in the first quarter of 2006 for the Boswell-Wilton 230 kV project and later in 2006 for the Red River Valley-Benton County 345 kV project.

Schematics of these projects are also presented below.



CapX Southeast

A third element of the near-term CapX plan is a proposal for a 345 kV addition between Prairie Island, Rochester and the La Crosse, Wisconsin area. Studies have shown the need for a large infrastructure addition in this area. A 345 kV facility will provide a third spoke into western Wisconsin and form the likely interconnection with a new 345 kV LaCrosse – Columbia, Wisconsin facility being considered by the American Transmission Company. We are working with ATC and at this point anticipate making a notice plan filing in January or February 2006 and a certificate of need application as soon as possible thereafter.

A schematic of that project is provided below (the red-dotted line indicates CapX facilities; the blue line identifies ATC facilities).



Conclusion

As CapX 2020 utilities, we are committed to continuing to work cooperatively to bring these projects to fruition. We are currently working to prepare the regulatory filings to move these projects from the study phase to the proposal phase, and ultimately to construction and completion. We are on an aggressive timeline, but also recognize our burden in proving the need for these facilities and will work within all regulatory processes to complete these proceedings. In doing so, however, we will continue to refer back to the backbone studies that identified these critical common elements to Minnesota's energy future. We appreciate your consideration of that information, and hope it is useful to you as you plan upcoming workload. As always, we are willing to work with interested parties in providing needed information as these filings proceed.

Messrs. Haar and Garvey
September 6, 2005
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Feel free to contact either me or any of the below CapX 2020 utilities' representatives if you have any questions or require any additional information regarding this letter or our plans for upcoming filings. I can be reached at (763) 241-2380.

Very truly yours,



William R. Kaul
Vice President, Transmission
Great River Energy
On Behalf of the Cap-X Utilities

c: Donald Jones, Xcel Energy
Tom Ferguson, Minnesota Power
Rod Scheel, Otter Tail Power Company
Ray Wahle, Missouri River Energy Services
Donald Kom, Central Minnesota Municipal Power agency
David Geschwind, Southern Minnesota Municipal Power Agency
Al Tschepen, Minnkota Power Cooperative

Deliverability Study Report for Project G392

1. Project Description

MISO Interconnection Queue Number	38020-01
Requested Maximum Output level (MW)	600
County	Grant
State	SD
Control Area / Transmission Owner	OTP

2. Introduction

Generator interconnection projects have to pass Generator Deliverability Study to be granted Network Resource Interconnection Services (NRIS). Interconnection projects that had not filed an Interconnection Agreement (IA) by 9/1/2004 are studied in their interconnection queue order to determine their deliverability.

For projects that have already signed IA but are still waiting for the deliverability study results, this report will be attached to its IA or System Impact Study report. If the generator is determined as not fully deliverable and wants to pursue full deliverability, the customer has to submit a new interconnection to MISO to do so.

For projects that are still in study mode, this report is attached to its system impact study report. If the generator is determined as not fully deliverable, the customer can choose either to change his project to an Energy Resource (ER) project or proceed with the system upgrades that will make the generator fully deliverable.

Since Generator Deliverability Study is to ensure Resource Adequacy during system peak condition, wind generators are tested at 20% of its maximum output level, and this is the maximum level that can be used to meet Resource Adequacy under Module E of the Midwest ISO Transmission and Energy Market Tariff (TEMT), unless the generator owner can demonstrate that the generator's capacity factor during SUMMER PEAK is greater than 20%.

3. Study Methodology

MISO Generator Deliverability Study whitepaper describing the algorithm can be found at "http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-767f0a48324a"

4. Determining the MW restriction

If one facility is overloaded based on the assessed "severe yet credible dispatch" scenario described in the study methodology, and the generator under study is in the

“Top 30 DF List” (see white paper for detail), part or all of its output is not deliverable. The restricted MW is calculated as following:

$$(\text{MW restricted}) = (\text{worst loading} - \text{MW rating}) / (\text{generator sensitivity factor})$$

If the result is larger than the maximum output of the generator, 100% of this generator’s output is not deliverable.

The generator is also responsible for any NEW base case (pre-shift) overload or NEW “severe yet credible dispatch overload” where the generator is not in the “Top 30 DF List”, if the generator’s DF is greater than 5%. Please see white paper for detail. The formula above also applies to these situations.

5. Study Result

☐ This generator is determined to be fully deliverable (MW). No constraint found.

☒ This generator is not fully deliverable due to the following constraint(s):
Alternative 1

63050 WILLMAR4 230 66550 GRANITF4 230 1

For the loss of

63314 BIGSTON4 230 63325 BROWNSV4 230 1

63219 GRANTCO7 115 66555 MORRIS 7 115 1

For the loss of

63329 WAHPETN4 230 63331 FERGSFL4 230 1 (262.1 MW deliverable)

Alternative 2

63050 WILLMAR4 230 66550 GRANITF4 230 1

For the loss of

63314 BIGSTON4 230 63325 BROWNSV4 230 1

63219 GRANTCO7 115 66555 MORRIS 7 115 1

For the loss of

63329 WAHPETN4 230 63331 FERGSFL4 230 1 (267.7 MW deliverable)

6. Conclusion

☐ MW from this generator is deliverable based on MISO Generator Deliverability Study result.

- ☒ This generator is not fully deliverable without system upgrade. The following upgrades are necessary to make it fully deliverable (600 MW):
- Project G392 was studied for both alternative 1 and 2, the constraints limiting the full deliverability of this unit are listed above. The details on these constraints are listed in section 7 below
 - The Grant County -- Morris 115kV is the most limiting constraint, it was also identified in the System Impact Study and the delivery service studies.
 - The Wilmar -- Granite Falls 230kV is undergoing upgrades, CT's are being replaced during Granite Falls fall outage. This work may already be complete. This should give a short-term rating of 318 MVA for an 800 Amp Wavetrap. GRE has a wavetrap of 800 Amp that is planned to be replaced early next year achieving the full conductor rating (383 MVA) -- (Per GRE). The short term rating of 318 MVA would allow for enough capacity to completely relieve this constraint for both alternatives.
 - Without any upgrades, G392 is 262.1 MW deliverable via alternative 1 and 267.7 MW deliverable using alternative 2

7. Appendix A: Constraints for this project's deliverability

A description of the format of the constraint information can be found in Appendix B.

Alternative 1

Branches	Contingencies	line rating	pre-shift flow	post_shift flow	DFAX	Worst loading	MW restricted
63050 WILLMAR4 230 66550 GRANITF4 230 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	231.5	228.4	234.9	8.1%	234.9	41.4
63050 WILLMAR4 230 66550 GRANITF4 230 1	63325 BROWNSV4 230 63327 HANKSON4 230 1	231.5	229.3	236.5	8.9%	236.5	56.2
63050 WILLMAR4 230 66550 GRANITF4 230 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	231.5	230.2	237.4	8.9%	237.4	66.4
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	102.3	113.9	116.7	7.1%	116.7	202.5
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	102.3	117.2	119.8	6.2%	119.8	280.8
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 63331 FERGSFL4 230 1	102.3	120.1	122.6	6.0%	122.6	337.9

Constraint 1:

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 63331 FERGSFL4 230 1	102.3	120.1	2.5	-0.1	122.6
Gen #	Gen	Pgen	Pmax	Sensitivity	(add.) flow contribution	NR/ER
60374	FIBROMN7 115	49.0	50.0	10.2%	0.1	NR
62013	BENSON 941.6	0.0	12.2	10.2%	1.2	NR
63315	BIGSTN1G24.0	493.5	495.0	6.0%	0.1	NR
66666	BIGSTN2G25.0	654.6	655.0	6.0%	0.0	NR
63215	HIWY12 7 115	1.5	6.0	5.9%	-0.1	ER
63209	HETLAND7 115	0.0	21.2	5.4%	1.2	NR

Constraint 2:

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63050 WILLMAR4 230 66550 GRANITF4 230 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	231.5	230.2	7.2	-0.1	237.4
Gen #	Gen	Pgen	Pmax	Sensitivity	(add.) flow contribution	NR/ER
63209	HETLAND7 115	0.0	21.2	10.4%	2.2	NR
63215	HIWY12 7 115	1.5	6.0	9.2%	-0.1	ER
63315	BIGSTN1G24.0	493.5	495.0	8.9%	0.1	NR
66666	BIGSTN2G25.0	654.6	655.0	8.9%	0.0	NR
60148	MINVALY7 115	0.0	45.4	8.5%	3.8	NR

60691	GRNFLCY869.0	0.0	7.4	6.7%	0.5	NR
60858	HADLEY 869.0	1.0	2.0	5.3%	0.1	NR
1116	G252_80 69.0	0.0	8.0	5.2%	0.0	ER
1117	G252_20 69.0	0.0	2.0	5.2%	0.1	NR
1272	G272_80 69.0	0.0	8.0	5.1%	0.4	NR
1273	G272_20 69.0	0.0	2.0	5.1%	0.0	ER
61956	R.FALLS7 115	5.1	6.1	5.0%	0.1	NR

Alternative 2

Branches	Contingencies	line rating	pre-shift flow	post shift flow	DFAX	Worst loading	MW restricted
63050 WILLMAR4 230 66550 GRANITF4 230 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	231.6	227.7	234.6	8.1%	234.6	36.6
63050 WILLMAR4 230 66550 GRANITF4 230 1	63325 BROWNSV4 230 63327 HANKSON4 230 1	231.6	228.5	236.1	8.9%	236.1	51.1
63050 WILLMAR4 230 66550 GRANITF4 230 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	231.6	229.4	237.0	8.9%	237.0	61.3
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	102.3	113.4	116.6	7.1%	116.6	200.5
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63327 HANKSON4 230 63329 WAHPETN4 230 1	102.3	116.7	119.6	6.2%	119.6	277.9
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 63331 FERGSFL4 230 1	102.3	119.7	122.5	6.0%	122.5	336.3

Constraint 1

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63219 GRANTCO7 115 66555 MORRIS 7 115 1	63329 WAHPETN4 230 63331 FERGSFL4 230 1	102.3	119.7	2.8	-0.1	122.5
Gen #	Gen	Pgen	Pmax	Sensitivity	(add.) flow contribution	NR/ER
60374	FIBROMN7 115	49.0	50.0	10.2%	0.1	NR
62013	BENSON 941.6	0.0	12.2	10.2%	1.2	NR
63315	BIGSTN1G24.0	493.0	495.0	6.0%	0.1	NR
66666	BIGSTN2G25.0	650.0	655.0	6.0%	0.3	NR
63215	HIWY12 7 115	1.5	6.0	5.9%	-0.1	ER
63209	HETLAND7 115	0.0	21.2	5.4%	1.2	NR

Constraint 2

Branch	Contingency	MW rating	PreShift Loading	Add. flow from top 30 list	ER flow adjustment	Worst loading
63050 WILLMAR4 230 66550 GRANITF4 230 1	63314 BIGSTON4 230 63325 BROWNSV4 230 1	231.6	229.4	7.6	-0.1	237
Gen #	Gen	Pgen	Pmax	Sensitivity	(add.) flow contribution	NR/ER
63209	HETLAND7 115	0.0	21.2	10.4%	2.2	NR
63215	HIWY12 7 115	1.5	6.0	9.2%	-0.1	ER
63315	BIGSTN1G24.0	493.0	495.0	8.9%	0.2	NR
66666	BIGSTN2G25.0	650.0	655.0	8.9%	0.4	NR
60148	MINVALY7 115	0.0	45.4	8.5%	3.8	NR

60691	GRNFLCY869.0	0.0	7.4	6.7%	0.5	NR
60858	HADLEY 869.0	1.0	2.0	5.3%	0.1	NR
1116	G252_80 69.0	0.0	8.0	5.2%	0.0	ER
1117	G252_20 69.0	0.0	2.0	5.2%	0.1	NR
1272	G272_80 69.0	0.0	8.0	5.1%	0.4	NR
1273	G272_20 69.0	0.0	2.0	5.1%	0.0	ER
61956	R.FALLS7 115	5.1	6.1	5.0%	0.1	NR

8. Appendix B: How to read the generator deliverability study result.

A typical deliverability result looks like the following table (Flow and output are all in MW):

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	A		B		C		D		E		F		G	
1	Branch		Contingency		MW rating		preShift Loading		Add. flow from Top 30 List		ER flow adjustment		Worst loading	
2	18403 5SHAW G9 161 18038 5C-37A 161 1		18401 8SHAWNEE 500 18406 8MARSHAL 500 1		342.6		347.8		1.72		0		349.52	
3	Gen #		Gen		Pgen		Pmax		Sensitivity		(add.) flow contribution		NR/ER	
4		32936	OLBEN G122.0		580.1		585		6.0%		0.29		NR	
5		31890	VIAD 1 34.5		0		25		5.7%		1.42		NR	

1. The name of the branch that is limiting.

2. The bus number in the “deliverability case”.
3. The name of the contingency.
4. Bus name.
5. Branch MW rating, estimated by MUST. Although the first screening was done using DC algorithm by MUST, all violations were then checked using full AC powerflow and using branch MVA rating.
6. Generator initial output in “deliverability case”.
7. The branch loading before generator output adjustment.
8. Maximum MW output capacity from this bus in this deliverability case.
9. The generator’s sensitivity on the limiting branch. The sink is all MISO generation when MUST calculates this number.
10. Total incremental MW flow on branch by adjusting generator output levels: NRs in the “Top 30 DF List” are run up to their Pmax; Offline NRs outside of the “Top 30 DF List” but with 20% line rating impact are run up to their Pmax; ERs with larger than 5% sensitivity (contributing flow only) are turned down to 0MW. Please refer to the MISO generator deliverability procedure for detail. (In the example shown, $E2 = \text{SUM}(F4:F5)$)
11. Total branch flow from impact of ER units. This number is already included in calculating the number in 10. Please refer to the MISO generator deliverability procedure for detail.
12. This generator’s additional contribution on the branch flow by running it up to Pmax. If this is an ER with positive sensitivity, the contributions is from turning off the generator.
13. (worst loading) = (pre-shift loading) + (flow adjustment). $G2 = D2 + E2$.
14. The status of this generator: Network Resource (NR) or Energy Resource (ER).

DRAFT

Big Stone II Generator Interconnection Study



Performed by



Delivery Planning Department

For the

MAPP Design Review Subcommittee (DRS)

August 18, 2006

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V Disclaimer

The information contained in this study report is in draft form and may be subject to revision, verification, and/or additional evaluation. The person receiving such information from the Midwest ISO or Otter Tail Power Company may use this information only with the full knowledge that this draft information cannot be relied upon as accurate.

1.0 Preface

The Big Stone II interconnection study has been on-going since the beginning of 2004 with various aspects of the interconnection and system impact studies being performed simultaneously. In November of 2004, the steady state contingency analysis results from the Big Stone II interconnection study were released in a draft report from the Midwest Independent System Operator (MISO). This draft report included system limitations identified within the area of interconnection during contingency analysis of a 2007 summer peak and 2007 summer off-peak case. Within this report, two interconnection alternatives were identified to facilitate the interconnection of the proposed Big Stone II unit. These interconnection alternatives were:

Table 1-1: Big Stone II Interconnection Alternatives

1. New 230 kV line from Big Stone to Ortonville with an upgrade of the Ortonville to Johnson Junction to Morris 115 kV line to 230 kV with a new 230 kV line from Big Stone to Canby and an upgrade of the Canby to Granite Falls 115 kV line to 230 kV.
2. New 230 kV line from Big Stone to Willmar with a new 230 kV line from Big Stone to Canby with an upgrade of the Canby to Granite Falls 115 kV line to 230 kV.

Since the release of the draft report that documented the steady state contingency analysis results, alternative 1 has been modified to eliminate the proposed Ortonville 230/115 kV transformer due to physical substation size limitations and the 1.25-mile corridor that leads to and from the substation.

As part of the MISO interconnection study, transient stability and short circuit analysis were completed back in February 2006. This effort back in February included the Post Group 2 stability cases from MISO that included a massive amount of prior queued generation within the MAPP region without adequate transmission reinforcements to accommodate these prior queued projects. As a result, the pre-disturbance case was overly stressed with several critical lines and interfaces loaded well beyond their thermal limits.

After a detailed stability analysis, it was determined that the condition of the pre-disturbance model was so degraded that it was not suitable for the Big Stone II stability analysis. However, the analysis procedure on this overly stressed case did allow for some insight into what is considered to be the most critical contingencies in the local vicinity of Big Stone.

During this same timeframe there were several other generation interconnection studies underway. Most notable was the Excelsior Energy (Mesaba) study for a new unit up in northern Minnesota. The interconnection study for Mesaba included an effort by Minnesota Power to develop a new stability model with prior queued generation projects loaded into the case to more accurately match the capability of the transmission system. Many of the prior queued generation projects in SW MN were not included in this model since there was not adequate transmission proposed yet to accommodate the amount of queued generation. As a result of building this new stability model with more accurately matched generation patterns, the loadings on critical transmission lines and interfaces were held within their thermal limits.

After the stability analysis of the 230 kV alternatives on the Post Group 2 model, MISO determined that this later stability model developed for the Mesaba study was more appropriate for the Big Stone II interconnection study. Siemens PTI was hired as a sub-contractor to OTP to perform the transient stability analysis since they were most familiar with the study models and stability package used in the Mesaba studies.

The initial stability analysis (completed back in February) included an investigation of the two 230 kV alternatives identified above in Table 1-1. In response to regional study efforts going on within this region, (i.e. SW MN → TC EHV Study, CapX 2020 Vision Study, MISO Northwest Exploratory Study), the Big Stone II participants have submitted a Certificate of Need Application to the State of Minnesota stating that their preferred transmission alternative includes constructing the southern portion of their transmission plan (i.e. Big Stone – Granite Falls) to 345 kV standards, but initially operate the line at 230 kV until a time in which a 345 kV transmission path can be extended from western Minnesota into the Twin Cities. This external 345 kV transmission project considered to trigger the Big Stone to Granite Falls line to be upgraded to 345 kV is the SW MN → TC EHV project. This project is currently proceeding through the permitting phase and is expected to be in-service in the 2011 to 2012 timeframe. Since the timing of the Big Stone II transmission plan is so closely aligned with the expected in-service date of this 345 kV EHV line, studies have been completed for both the 230 kV alternatives and the 345 kV alternatives.

With the knowledge of this modified transmission plan, the transient stability analysis has been performed for both the 230 kV transmission alternatives and for these same alternatives with the southern line at 345 kV to interconnect with the proposed SW MN → TC EHV line at a new substation called Hazel Run.

This study is intended to serve a dual purpose in that it is intended to meet the study requirements of both the MAPP DRS and the Midwest ISO (MISO). Due to the differences in study requirements, the transient stability analysis considered two different export levels across the North Dakota Export (NDEX) interface. MISO requires the NDEX interface to be maintained at the current level of 2080 MW while the MAPP DRS requires an increase in the NDEX interface limit if the Big Stone II project desires to deliver power across the interface. Due to the current make-up of the project, approximately 370 MW of the 600 MW project was assumed to be delivered to those project participants with load outside NDEX. The new NDEX level with Big Stone II deliveries across NDEX was assumed to be 2450 MW based on the current definition of NDEX. The transient stability analysis has been completed at both the 2080 MW and 2450 MW NDEX levels to meet the requirements of both MAPP and MISO.

To also assess the impact of operating the southern line at 345 kV, additional steady state analysis has also been completed for the Morris alternative since it is the preferred project by the Big Stone II participants.

This report will document the results for the 230 kV and 345 kV variations of the Morris option and the Willmar option for the steady state, transient stability, and short circuit analyses completed as part of the Big Stone II interconnection study.

2.0 Executive Summary

A Generator Interconnection Evaluation Study (hereas referred to as “Study” or “Big Stone II Study”) has been completed for a 600 MW coal-fired base-load generating facility to be located at the existing Big Stone plant site in Grant County, South Dakota. The proposed in-service date for this project is early 2011.

This Study has identified possible impacts that this proposed generator may have on the existing transmission system. The objectives of this Study were to:

- Identify thermal overloads and voltage violations resulting from the interconnection of Big Stone II
- Identify unstable conditions or transient voltage concerns that may result from the interconnection of Big Stone II
- Identify potentially increased fault duties to existing equipment from the interconnection of Big Stone II

In order to meet the objectives of this Study, steady state power flow analysis, transient stability analysis, and short circuit analysis have been completed. While performing these different types of analyses, two different transmission alternatives were evaluated independently to determine the impact of the proposed generator interconnection on the existing transmission system. Both of these alternatives have one common aspect, which is the addition of a new 230 kV line (capable of operating at 345 kV) from Big Stone to Canby with an upgrade from 115 kV to 230 kV of the existing line from Canby to Granite Falls.

The two 230 kV alternatives studied for this interconnection request are shown below in Table 2-1.

Table 2-1: 230 kV Interconnection Alternatives for Big Stone II Study

1. New 230 kV line from Big Stone to Ortonville with upgrade of Ortonville to Johnson Junction to Morris 115 kV line to 230 kV with new 230 kV line from Big Stone to Canby and an upgrade of the Canby to Granite Falls 115 kV line to 230 kV.
2. New 230 kV line from Big Stone to Willmar with new 230 kV line from Big Stone to Canby with an upgrade of the Canby to Granite Falls 115 kV line to 230 kV.

2.1 Steady State Analysis of 230 kV Alternatives

Steady state analysis for this Study focused on the 2007 timeframe with analysis focusing on summer peak and summer off-peak conditions. These steady state cases were derived from the 2002 series MAPP models and have been used in several previous studies, including the “Group 1” and “Group 2” MISO/WAPA coordinated interconnection studies for the numerous wind generation requests in the Buffalo Ridge area. The Group 1 and Group 2 interconnection requests are ahead of this project in the MISO interconnection queue. These Group studies analyzed the feasibility of connecting approximately 1750 MW’s of wind generation within the Buffalo Ridge area of southwest Minnesota, northwestern Iowa, and southeastern South Dakota.

The Group 1 projects totaled approximately 916 MW's while the Group 2 projects totaled about 825 MW's.

Loading violations encountered during steady state contingency analysis of the 2007 summer off-peak case are shown below in Table 2-2. The quantities displayed within Table 2-2 represent the percent loading on each facility based on its normal continuous rating. The quantities shown below in yellow represent facility loadings not exceeding emergency ratings while those in red represent those loadings that did exceed emergency ratings.

Table 2-2: Overloaded Elements for Summer Off-peak Conditions

Overloaded Facility	Summer Off-peak	
	Alt #1	Alt #2
Big Stone 230/115/13.8 kV Transformer	103.5%	
Morris 230/115 kV Transformer	155.2%	
Ortonville - Johnson Jct. 115 kV Line		131.1%

Summer peak contingency analysis results are summarized below in Table 2-3. Once again, the quantities shown represent the percent loading on each facility based on the facility's normal continuous rating. As was shown in Table 2-2, quantities given in yellow represent facility loadings not exceeding emergency ratings while those in red represent those loadings that did exceed emergency ratings.

Table 2-3: Overloaded Elements for Summer Peak Conditions

Overloaded Facility	Summer Peak	
	Alt #1	Alt #2
Big Stone 230/115/13.8 kV Transformer	119.2%	111.8%
Morris 230/115 kV Transformer	177.0%	
Ortonville - Johnson Jct. 115 kV Line		141.7%
Big Stone - Browns Valley 230 kV Line	128.7%	114.1%
Big Stone - Highway 12 115 kV Line	112.6%	
Highway 12 - Ortonville 115 kV Line	106.9%	
Johnson Jct. - Morris 115 kV Line		118.2%

Voltage violations identified during contingency analysis of the 2007 summer off-peak case indicated that a decrease in voltage is caused by implementing interconnection alternative 2 with the proposed interconnection. A summary of the post-contingent voltage levels is given below in Table 2-4 in per unit voltage. Quantities shown in red indicate those post-contingent voltage levels that are below post-contingent voltage criteria set by transmission owners in this Region.

Table 2-4: Voltage Violations for Summer Off-peak Conditions

Voltage Violation	Summer Off-peak	
	Alt #1	Alt #2
Willmar 115 kV Bus		0.88
Willmar 230 kV Bus		0.91

Contingency analysis of the summer peak case has very similar voltage results as that shown for summer off-peak conditions. The Willmar bus voltage problems are evident for interconnection alternative 2 as shown below in Table 2-5. Once again, quantities shown in red indicate those post-contingent voltage levels that are below post-contingent voltage criteria set by transmission owners in this Region.

Table 2-5: Voltage Violations for Summer Peak Conditions

Voltage Violation	Summer Peak	
	Alt #1	Alt #2
Willmar 115 kV Bus		0.90
Willmar 230 kV Bus		0.90

Based on the overall system performance during steady state conditions, this Study has identified that the following upgrades will be necessary on the existing system for connecting the proposed project with interconnection alternative 1. These upgrades are in addition to the new facilities (described in Table 2-1) that are included as part of interconnection alternative 1.

Table 2-6: Required Upgrades for 230 kV Interconnection Alternative 1

1. Increase capacity of Morris 230/115 kV Transformer
2. Increase capacity of Big Stone to Browns Valley 230 kV Line

Implementing interconnection alternative 2 to connect the proposed project to the system will require the following upgrades (shown in Table 2-7) to the existing system. These upgrades are in addition to the new facilities (described in Table 2-1) that are included as part of interconnection alternative 2.

Table 2-7: Required Upgrades for 230 kV Interconnection Alternative 2

1. Increase capacity of Ortonville to Johnson Jct. 115 kV Line
2. Increase capacity of Johnson Jct. to Morris 115 kV Line
3. Increase capacity of Big Stone to Browns Valley 230 kV Line
4. Install capacitor bank in Willmar area to mitigate low voltages

2.2 Steady State Analysis of 345 kV Alternatives

The Big Stone II interconnection studies have identified that two new 230 kV lines provide adequate capability for the interconnection of the Big Stone II generator given that a few system upgrades are completed on the existing transmission system.

Regional studies have shown the need for 345 kV lines stretching from the Dakotas to the Twin Cities. The proposed Big Stone to Granite Falls 345 kV line represents a piece of the overall 345 kV lines from the Dakota's to the Twin Cities. In order to integrate the Big Stone II transmission plan into these regional transmission plans, the Big Stone II participants have decided to construct the southern portion of the transmission project from Big Stone to Granite Falls to 345 kV capability with the intent that it will be operated at 345 kV in the future.

While being constructed for operation at 345 kV, the Big Stone to Granite Falls line would initially be operated at 230 kV until new 345 kV facilities are constructed in the Granite Falls area. Additional analysis has been completed with the “southern” line from Big Stone to Granite Falls operated at 345 kV and connecting into the Hazel substation, which is part of the CapX SW MN→TC EHV study. The results indicate that operating the Big Stone to Granite Falls line at 345 kV in conjunction with the EHV facilities doesn’t cause any existing Big Stone outlet facilities to overload beyond their applicable ratings for either system intact and N-1 conditions.

Building the Big Stone II transmission plan with the Big Stone – Granite Falls line at 345 kV integrates well into the regional transmission needs identified through the CapX 2020 Vision Study, the MISO Northwest Exploratory Study, and the SW MN→TC EHV study.

2.3 Transient Stability Analysis

Transient stability analysis has been performed for both the 230 kV alternatives and the 345 kV alternatives at NDEX levels of 2080 MW and 2450 MW. A list of the interconnection alternatives included in the transient stability analysis is included in Table 2-8.

Table 2-8: Alternatives Included in the Transient Stability Analysis

1. Alternative 1: Big Stone – Morris 230 kV line with Big Stone – Granite Falls 230 kV in-service.
2. Alternative 2: Big Stone – Willmar 230 kV line Big Stone – Granite Falls 230 kV in-service.
3. Alternative 3: 345 kV upgrade of Big Stone Granite Falls with Big Stone – Morris 230 kV line with Buffalo Ridge – Metro (SW MN → TC EHV) 345 kV line.
4. Alternative 4: 345 kV upgrade of Big Stone Granite Falls with Big Stone – Willmar 230 kV line with Buffalo Ridge – Metro (SW MN → TC EHV) 345 kV line.

In order to identify if the Big Stone II project has an impact on the transient stability performance of the transmission system, the study was performed for all the transmission alternatives under consideration with transfers of 2080 MW and at 2450 MW across the North Dakota Export interface (NDEX). These NDEX levels represent the current definition of NDEX augmented to include the Canby – Granite Falls 230 kV line for alternatives 1 and 2, the Big Stone – Willmar 230 kV line for alternatives 2 and 4, and the Canby – Hazel (Run) 345 kV line for alternatives 3 and 4.

Two benchmark cases were developed representing 2009 summer off-peak conditions without the Big Stone II project. The benchmark case for the 345 kV alternatives included approximately 1500 MW of wind generation in southwest MN, while for the 230 kV alternatives this SW MN wind generation was reduced approximately to 825 MW.

Regional and local disturbances were simulated during the transient stability analysis. The regional disturbances included in the analysis are the worst known disturbances within the northern MAPP region. Local three-phase and single line-to-ground faults were performed on new facilities included as part of the four alternatives.

Regional disturbances simulated during the transient stability analysis resulted in high transient voltages for some buses in the Manitoba Hydro transmission system, specifically for faults MAT, OAS and NBZ. These overvoltages are not due to the interconnection of Big Stone II since they also show up for the benchmark cases. These overvoltages are more related to the HVDC reduction scheme following a trip of the 500 kV line.

For local faults, three phase and single line to ground with delayed clearing were performed within the Big Stone area for the existing and new interconnection facilities. Initially for all the cases both units at Big Stone (existing and new) were delivering full output (475 MW net for Big Stone Unit 1 and 600 MW net for Big Stone II).

Under this generation condition and for both NDEX transfers (worst condition 2450 MW):

For the 230 kV alternatives:

Alternative 1: all the local faults with the exception of FTS performed poorly showing low transient voltage violations mainly on 115 kV buses extending from Big Stone to Appleton to Canby and back around to Marietta.

Alternative 2: of the eight local faults, five showed low transient voltages mainly at these same 115 kV buses.

Additional stability simulations of alternatives 1 and 2 have determined that reducing the power output at Big Stone by 150 MW mitigated these voltage issues.

For the 345 kV alternatives, results for NDEX set at 2450 MW indicated:

Alternative 1: No voltage violations for local three phase local faults, but low voltage transient violations were present for 10 out of the 15 single line to ground local faults under evaluation. The performance of the benchmark case only had two single line to ground faults with voltage violations.

Alternative 2: No voltage violations were evident for local three phase faults, but low voltage transient violations were present for 9 out of the 15 single line to ground local faults under evaluation. The performance of the benchmark case only had two single line to ground faults with voltage violations.

When power output of Big Stone II was reduced by 150 MW for each alternative, five of the local single line to ground faults still had low voltage transient violations.

For prior outage conditions and with generation at Big Stone I reduced to 250 MW (net output as per existing operating guide) and Big Stone II delivering its full capacity, some local faults are showing low voltage violations for all the alternatives. However, the Big Stone II

interconnection does not seem to aggravate the existing transient low voltages violations for the three phase faults or the single line to ground faults under consideration as compared to those violations encountered when simulating the same fault on a comparable system intact case. This is likely due to the modeling of the operating guide for Big Stone I, which reduced the output of the plant from nearly 475 MW (net) to 250 MW (net).

As noted above, transient stability analysis has identified local low transient voltage violations when the Big Stone II plant is in service with either transmission interconnection alternative for local faults. Special operation procedures and/or system protection would need to be implemented after a more detailed and specific study is completed. Furthermore, the stability analysis has indicated that Big Stone II does not have an impact on the transient stability performance of the transmission system at either the 2080 MW NDEX level or the 2450 MW NDEX level.

2.4 Short Circuit Analysis

Short circuit analysis has identified that the continuous currents through the proposed 230 kV ring-bus at Big Stone may be higher than the 2000 Amp continuous rating of the existing 230 kV breakers. Further investigation into the actual bus flows will be necessary during the facilities study. Short circuit analysis has also determined that fault currents at Big Stone will double with the addition of the proposed Big Stone II unit. However, the fault currents are still within the applicable ratings of existing equipment at Big Stone. A review of the fault currents farther from Big Stone also indicate that fault currents will be increased to a lesser degree. The fault currents at more remote locations from Big Stone are expected to be within the interrupting capability of the existing equipment. Coordination with neighboring transmission owners will be necessary to determine if the expected fault currents with Big Stone II in-service will cause concern with the capability of existing substation equipment.

Since new transmission lines are associated with alternatives 1 and 2 for the Big Stone II project, it will be necessary to install new protective relaying at new and existing substations in order to insure that adequate protection is in place to detect faults on the new transmission lines. Since the existing 115 kV transmission system will have a different configuration with transmission alternatives 1 and 2, it will also be necessary to upgrade the existing protection schemes to insure that the local 115 kV lines are adequately protected.

Short circuit analysis of the 345 kV alternatives indicated that expected fault currents are still within acceptable fault interrupting capability of the existing circuit breakers on the system.

2.5 Loss Analysis

A brief loss analysis during this Study has indicated that alternative 1 is more effective in delivering the generation to the existing transmission system during summer off-peak conditions while alternative 2 is has more loss savings during summer peak conditions. The interconnection models used for this analysis are highly stressed due to several prior queued generation projects included in the model without adequate transmission, thus providing an unrealistic view of losses.

2.6 General Conclusion

Four transmission alternatives for the Big Stone II interconnection request have been evaluated during this interconnection study and the results of this analysis have been summarized above with more detailed information being contained within the body of the report to follow.

Overall, it appears that in order to reliably connect Big Stone II to the transmission system:

- Thermal upgrades will be necessary for any Big Stone II interconnection alternative;
- Additional studies will be necessary to effectively address local stability concerns at Big Stone;
- Existing 230 kV circuit breakers at Big Stone will need to be verified that the 2000 Amp continuous rating is not exceeded; and
- System protection schemes will be need to be updated on the transmission system to adequately protect the new transmission facilities as well as the existing facilities that will remain in-service with the Big Stone II transmission plan.

3.0 Introduction

3.1 Study Scope

The scope of this Generator Interconnection Evaluation Study (hereas referred to as the “Study” or the “Big Stone II Study”) is to determine the most efficient method of integrating a second generating plant into the existing system at Big Stone, SD. Through the generation interconnection process, a potential generation developer, hereas referred to as “the Customer”, has submitted a request for a new 600 MW generator at the existing site of the Big Stone generator. The current transmission system is not adequate to support the requested generator. This report outlines the results of the Study that has been completed to determine the necessary transmission additions to accommodate this interconnection request.

This Study has evaluated two different transmission alternatives to determine the impact of the proposed generator on the existing transmission system. These impacts have been identified by performing steady state power flow analysis, transient stability analysis, and short circuit analysis.

3.2 Existing Big Stone Transmission Facilities

The site of the generator interconnection request is at the same location as the existing Big Stone unit in extreme northeastern South Dakota. The existing unit at Big Stone is co-owned by Otter Tail Power Company, Northwestern Energy, and Montana-Dakota Utilities. The unit was initially installed during May of 1975. Over the years, generation equipment within the plant has been upgraded to get its accredited generation level within the MAPP Region to a net output of 475 MW.

The current transmission system supporting this unit is two 230 kV lines and two 115 kV lines. The 230 kV lines go north and south of the Big Stone site. The north line is from Big Stone to Browns Valley and ultimately terminates at Hankinson, ND. The south line from Big Stone terminates at Blair, SD. The 115 kV lines from the plant also go north and south. The north 115 kV line terminates at the Graceville tap (or Johnson Junction) where it intersects the Graceville – Morris 115 kV line. This line serves loads around Ortonville and Appleton. The south 115 kV line terminates at Granite Falls. This line serves loads around Canby, Marietta, and Toronto. Figure 3-1 is shown below and illustrates the outlet lines from Big Stone and Big Stone’s relative location within the MAPP region.

Figure 3-1: Existing Transmission Facilities around Big Stone Plant

[Figure 3-1 removed for public posting]

4.0 230 kV Interconnection Alternatives

In order to interconnect the proposed generator without detrimental impacts to the existing transmission system, two separate interconnection alternatives have been analyzed. Both of these alternatives have one common aspect, which is the addition of a new 230 kV line from Big Stone to Canby with an upgrade of existing 115 kV line from Canby to Granite Falls.

The two alternatives studied for this interconnection request are shown below in Table 4-1. Further explanation of these alternatives can be found in subsequent sections of this report.

Table 4-1: 230 kV Interconnection Alternatives for Big Stone II Study

1. New 230 kV line from Big Stone to Ortonville with upgrade of Ortonville to Johnson Junction to Morris 115 kV line to 230 kV with new 230 kV line from Big Stone to Canby with upgrade of the Canby to Granite Falls 115 kV line to 230 kV.
2. New 230 kV line from Big Stone to Willmar with new 230 kV line from Big Stone to Canby with upgrade of the Canby to Granite Falls 115 kV line to 230 kV.

4.1 230 kV Interconnection Alternative 1

New 230 kV line from Big Stone – Ortonville and from Big Stone to Canby with a 115 kV to 230 kV upgrade of Ortonville – Johnson Jct. – Morris line and Canby – Granite Falls line

The first interconnection alternative considered for this Study involved utilizing existing 115 kV line routes from the Big Stone plant.

A new 6.5-mile, 230 kV line was considered from Big Stone to Ortonville. At Ortonville, a new 230/115/13.8 kV transformer was added to tie back into the existing 115 kV system feeding the radial line out to Appleton as well as looping back into the Highway 12 substation. From Ortonville, it was assumed that the existing 24.6 mile, 115 kV line was converted to 230 kV into the existing Johnson Junction substation. At Johnson Junction, another 230/115 kV transformer was installed to tie into the existing 115 kV line to Graceville (and eventually to Wahpeton). From Johnson Junction, interconnection alternative 1 included upgrading the existing 15.5-mile, 115 kV line to Morris to 230 kV and connecting into the existing 230 kV bus at Morris.

In addition to the “northern” 230 kV line, interconnection alternative 1 also assumed a new 50.5 mile, 230 kV line from Big Stone to Canby with a new 230/115 kV transformer added at Canby to connect back to the existing 115 kV system feeding towards Toronto and Marietta. From Canby, it was assumed that the existing 39.2 mile, 115 kV line to Granite Falls was upgraded to 230 kV and terminated into the existing 230 kV bus at Granite Falls.

After this study was well underway, permitting efforts for the Big Stone II project identified constraints into and out of the Ortonville substation. It was determined that the Ortonville 230/115 kV transformer addition would be eliminated for alternative 1 based on a congested corridor into the Ortonville substation and physical space limitations within the Ortonville substation for a new 230/115 kV transformer.

The following figure illustrates a geographic representation of interconnection alternative 1 that was considered for this Study. Changes or additions to the existing transmission system are shown with dotted lines and circled in gray boxes.

Figure 4-1: Geographic Map of Interconnection Alternative 1

[Figure 4-1 removed for public posting]

4.2 230 kV Interconnection Alternative 2

New 230 kV line from Big Stone to Willmar and from Big Stone to Canby with a 115 kV to 230 kV upgrade of Canby – Granite Falls line

The second interconnection alternative considered for this Study still uses the same “southern” 230 kV line introduced within alternative 1, but includes a new 102 mile, 230 kV line from Big Stone to Willmar instead of taking advantage of the existing 115 kV route from Big Stone to Morris. From Willmar, existing 230 kV lines head northeast towards Paynesville, and southwest towards Granite Falls. This new 230 kV line from Big Stone to Willmar did not require the need for any additional transformers.

As mentioned previously, besides the new line from Big Stone to Willmar, the same Big Stone to Granite Falls line, as discussed as part of interconnection alternative 1, was also included as part of alternative 2.

Figure 4-2 illustrates a geographic representation of interconnection alternative 2 that was studied for this interconnection request. Changes or additions to the existing transmission system are shown with dotted lines and circled in gray boxes.

Figure 4-2: Geographic Map of Transmission Alternative 2

[Figure 4-2 removed for public posting]

5.0 Steady State Model Development

5.1 Modeling of Prior Queued Generation

Steady state analysis for this Study focused on summer peak and summer off-peak conditions for the 2007 timeframe. The Customer does not project an in-service date until 2011 for this generator, but the 2007 cases were most readily available for analysis. These steady state cases were taken from the Group 2 WAPA/MISO coordinated interconnection study. These cases were initially developed from the 2002 series MAPP models for 2007 and then modified by ABB to include the Group 1 interconnection projects from the MISO/WAPA interconnection queues. Upon completion of the Group 1 coordinated study, these models were modified once again to include all of the Group 2 projects. Through the coordinated study process, transmission owners in the northern MAPP region have reviewed the models and submitted numerous updates that ABB has included in the base case models. More documentation about the base case model development for the coordinated studies can be obtained from MISO.

In addition to these Group 1 and 2 projects included within the models, other previously queued generation projects were added to the base case models. These included MISO projects G261, G267, G370, and G380. A description of these projects is listed below in Table 5-1.

Table 5-1: Previously Queued Generation Projects Added to Models

Project	MW Size	Location	Point of Interconnection	Sink Information
G261	667.4 MW	Mankato, MN	Wilmarth 345 kV and 115 kV	Xcel Energy
G267	190.5 MW	McLeod, MN	McLeod 230 kV	Xcel Energy
G370	160 MW	Sioux Falls, SD	Anson 115 kV	Xcel Energy
G380	150 MW	Rugby, ND	Rugby 115 kV	Manitoba Hydro

5.2 Modeling of Existing Generation

In order to further stress the existing transmission system out of Big Stone and identify all of the potential system constraints during this Study, generation levels at Lake Preston (Toronto), Hoot Lake (Fergus Falls), and the existing Big Stone unit were modeled at their maximum accredited capacity. These generators have the potential for sharing some of the same transmission capacity as the proposed interconnection, therefore having this existing generation on-line further stresses the local transmission outlet out of Big Stone.

After all the previously mentioned base case model alterations were completed, the proposed interconnection of the new Big Stone unit with each associated interconnection alternative was added to the models.

5.3 Big Stone II Dispatch Assumptions

During the kick-off meeting, the Customer stated that the final size and final allocations for this particular project were not definite between the potential partners. However, the Customer brought forward some assumptions in studying this interconnection request of 600 MW. The Customer preferred the following dispatch for this Study.

<u><i>Sink</i></u>	<u><i>Amount</i></u>
Otter Tail Power Company (OTP)	100 MW
Missouri River Energy Services (MRES)	100 MW
Great River Energy (GRE)	100 MW
Minnesota Municipal Power Agency (MMPA)	100 MW
Central Minnesota Municipal Power Agency (CMMPA)	76 MW
Heartland Consumers Power District (HCPD)	74 MW
Hutchinson Utilities Commission (HUC)	50 MW

5.4 Steady State Study Models

The final models that were developed for the steady state portion of this Study are listed below in Tables 5-2 and 5-3 and illustrate the following export levels (in MW's) over the known interfaces in the northern MAPP region:

NDEX:	North Dakota Export Interface
MHEX:	Manitoba Hydro Export Interface (Manitoba to US)
MWSI:	Minnesota Wisconsin Stability Interface
MHOH:	Manitoba Hydro/Ontario Hydro Interface
OHMP:	Ontario Hydro/Minnesota Power Interface
EWTW:	Ontario East-West Transfer (East to West)
BD:	Boundary Dam/Tioga 230 kV Line

Table 5-2: 2007 Summer Peak Steady State Analysis Models

Case Name	Description	Big Stone II	NDEX	MHEX	MWSI	OHMH	OHMP	EWTW	BD
bas-sp07aa-g392.sav	Base Case Model All prior queued interconnections	0	491.3	1494.9	235.2	0.1	0.4	107.7	0.6
alt1-sp07aa-allgr2.sav	Big Stone - Morris 230 kV Big Stone - Granite Falls 230 kV	600	952.8	1505.5	289.7	0.1	0	107.3	0.2
alt2-sp07aa-allgr2.sav	Big Stone - Willmar 230 kV Big Stone - Granite Falls 230 kV	600	947.2	1502.1	290.9	0.1	0.2	107.5	0.6

The base case Group 2 summer off-peak models obtained from MISO included maximum simultaneous export levels over MHEX, NDEX, and MWSI. During development of the summer off-peak cases for this Study, the appropriate changes were made to include all of the prior queued generation projects. In the process of making these changes to the base case models, these maximum simultaneous export levels were altered across these critical interfaces. Therefore, in order to restore the maximum simultaneous transfer levels, the setexports IPLAN within the Northern MAPP Operating Review Working Group (NMORWG) stability package was utilized to restore these interfaces back to their base case levels. Once the interface flows were close to the base case level, the Big Stone II interconnection was added to the model. This interconnection did increase the NDEX quantity since alternative #1 included an upgrade of an existing 115 kV line to 230 kV (Canby – Granite Falls) and alternative #2 included a new 230 kV line across the existing NDEX interface (Big Stone – Willmar). The Study models derived

for the summer off-peak analysis are listed below and list the new export levels with Big Stone II added to the models.

Table 5-3: 2007 Summer Off-peak Steady State Analysis Models

Case Name	Description	Big Stone II	NDEX	MHEX	MWSI	OHMH	OHMP	EWTW	BD
bas-so07aa.uyv0020.sav	Base Case Model All prior queued interconnections	0	1948.9	2174	1480.9	0.4	0	106.1	0.1
alt1-so07aa-allgr2.sav	Big Stone - Morris 230 kV Big Stone - Granite Falls 230 kV	600	2420.4	2183.2	1503.8	0.4	0	106.1	0.1
alt2-so07aa-allgr2.sav	Big Stone - Willmar 230 kV Big Stone - Granite Falls 230 kV	600	2420.1	2179.9	1508.3	0.4	0	106.1	0

Machine characteristics for modeling the proposed interconnection for steady state analysis were obtained from the Customer. These machine characteristics and the assumptions used for modeling this proposed generator are given in Appendix A in PSS/E format.

6.0 Study Procedure

All aspects of this Study utilized the Power System Simulator for Engineers (PSS/E) software program distributed by Power Technologies Incorporated (PTI). PSS/E version 29.4 on the PC platform has been used during this Study.

Steady state analysis utilized the PSS/E activity ACCC, which simulates branch outages in a user-defined area while monitoring voltage and loading within another user-defined area. For this Study, the following areas had all single contingencies on branches of 69 kV and higher simulated during ACCC analysis:

- Area 331 – Alliant West (ALTW)
- Area 600 – Xcel Energy (XEL)
- Area 608 – Minnesota Power (MP)
- Area 613 – Southern Minnesota Municipal Power Agency (SMMPA)
- Area 618 – Great River Energy (GRE)
- Area 626 – Otter Tail Power Company (OTP)
- Area 635 – MidAmerican Energy Company (MEC)
- Area 652 – Western Area Power Administration (WAPA)
- Area 667 – Manitoba Hydro (MH)

In addition, valid multiple contingencies from the 2003 series MAPP contingency file were applied during ACCC analysis. The contingency file used for this Study was the same as that used during the Group 2 MISO/WAPA coordinated study.

In flagging violations during contingency analysis, the following areas were monitored during ACCC analysis:

- Area 331 – Alliant West (ALTW)
- Area 600 – Xcel Energy (XEL)
- Area 608 – Minnesota Power (MP)
- Area 613 – Southern Minnesota Municipal Power Agency (SMMPA)
- Area 618 – Great River Energy (GRE)
- Area 626 – Otter Tail Power Company (OTP)
- Area 635 – MidAmerican Energy Company (MEC)
- Area 640 – Nebraska Public Power District (NPPD)
- Area 645 – Omaha Public Power District (OPPD)
- Area 650 – Lincoln Electric System (LES)
- Area 652 – Western Area Power Administration (WAPA)
- Area 667 – Manitoba Hydro (MH)

6.1 Study Criteria

During steady state contingency analysis, branch loadings and bus voltages were monitored. Study criteria for contingency analysis monitored normal branch ratings (Rate A) for system

intact and contingency conditions. Voltage criteria used during contingency analysis was taken from the latest version of the *MAPP Members Reliability Criteria and Study Procedures Manual*.

All impacts created or worsened by the addition of the proposed interconnection were flagged. Facility impacts within the following bounds were not considered a violation during contingency analysis:

- Any bus voltage outside specific Transmission Owner criteria that had a change in voltage of less than 1%
- An increase in loading of less than 2% of the proposed interconnection project size for non-MISO (MAPP member) facilities during “n-1” conditions
- An increase in loading of less than 3% of the proposed interconnection project size for MISO member facilities during “n-1” conditions
- An increase in loading of less than 5% of the proposed interconnection during system intact conditions
- Branch loadings not exceeding emergency ratings (Rate C) during a contingency condition that had a re-dispatch scenario evident for mitigation
- Branch loadings not exceeding normal ratings (Rate A) during a system intact condition

Any impacted facilities that were identified during steady state ACCC contingency analysis for 2007 summer peak and 2007 summer off-peak conditions that do not fall within these criteria are discussed in the following sections. In discussing the ACCC analysis results, the primary focus was on those facilities immediately surrounding the point of interconnection.

7.0 Steady State Power Flow Analysis Results for 230 kV Alternatives

7.1 2007 Summer Off-peak Conditions

7.1.1 Loading Violations

7.1.1.1 230 kV Interconnection Alternative 1

During ACCC contingency analysis of the 2007 summer off-peak case, there were two facilities identified as being overloaded for interconnection alternative 1. These facilities included the existing Big Stone 230/115/13.8 kV transformer and the Morris 230/115 kV transformer. The magnitude of the post-contingent loading on these facilities along with the corresponding contingencies is shown below in Table 7-1.

**Table 7-1: Loading Violations for 230 kV Alternative 1
for 2007 Summer Off-peak Conditions**

Overloaded Branch						Normal Rating	Existing System		Int. Alt. #1		Contingency
FromBus	kV	ToBus	kV	ckt			MVA	% Rate A	MVA	% Rate A	
63195	BIGSTONY	230	63214	BIGSTON7	115	1	233		239.6	102.8	63314 BIGSTON4230.00 63320 ORTNVLE4230.00 C1
63195	BIGSTONY	230	63314	BIGSTON4	230	1	233		241.2	103.5	63314 BIGSTON4230.00 63320 ORTNVLE4230.00 C1
66554	MORRIS 4	230	66555	MORRIS 7	115	1	100		105.2	105.2	BASE CASE
											NUMEROUS OTHER CONTINGENCIES
									136.8	136.8	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1

The existing Big Stone 230/115/13.8 kV transformer only loads up to 103.5% of the normal rating for loss of the new Big Stone to Ortonville 230 kV line, which is well below the 125% emergency rating of the Big Stone transformer. However, the Morris 230/115 kV transformer overloads for a multitude of system conditions. During summer off-peak, system intact conditions, the transformer exceeds its normal rating of 100 MVA and is only worsened by critical contingencies in the area of interconnection. The magnitude of the loading experienced by the Morris 230/115 kV transformer during summer off-peak conditions will require this interconnection project to upgrade the existing 230/115 kV transformer at Morris for interconnection alternative 1.

The Ortonville 230/115 kV transformer addition, which was originally assumed as part of alternative 1, has now been eliminated based on information gathered from the routing and permitting efforts underway as part of this project. With the “north” line of alternative 1 now configured as Big Stone to Johnson Jct. to Morris, the post-contingent flow on the Big Stone 230/115 kV transformer is now less than 102.8% of its normal rating.

As mentioned in section 2.1, interconnection alternative #1 included 230 kV lines from Big Stone to Morris and from Big Stone to Granite Falls. These 230 kV lines were assumed to be composed of 954 ACSR conductor with a thermal rating of 390 MVA. During contingency analysis of interconnection alternative 1 for 2007 summer off-peak conditions, it appears that the 390 MVA rating of the new 230 kV lines between Big Stone and Morris will not be adequate in carrying the amount of post-contingent flow possible for loss of adjacent 230 kV outlet lines out

of the Big Stone plant. Table 7-2 indicates that up to 411 MVA of flow is possible on the Big Stone to Ortonville 230 kV line for loss of the Big Stone to Blair 230 kV line. Likewise, a 125 MVA, 230/115/13.8 kV transformer was added at Ortonville as part of interconnection alternative 1 for modeling purposes. It appears that 125 MVA will not be sufficient in handling the potential for up to 182 MVA during loss of the Big Stone to Ortonville 230 kV line during summer off-peak conditions. The expected loading on the new interconnection facilities that exceed their assumed capacity can be found below in Table 7-2.

**Table 7-2: Potential Loading on 230 kV Interconnection Facilities
for 2007 Summer Off-peak Conditions**

Overloaded Branch						Normal Rating	Existing System		Int. Alt. #1		Contingency
From Bus	kV	To Bus	kV	ckt			MVA	% Rate A	MVA	% Rate A	
63314	BIGSTON4	230	63320	ORTNVLE4	230	1	390.4		411.0	102.2	63314 BIGSTON4230.00 66503 BLAIR 4230.00 C1
63320	ORTNVLE4	230	63321	ORTNVLEY	230	1	125		181.4	145.1	63314 BIGSTON4230.00 63320 ORTNVLE4230.00 C1
63216	ORTONVL7	115	63321	ORTNVLEY	230	1	125		181.5	145.2	63314 BIGSTON4230.00 63320 ORTNVLE4230.00 C1
63320	ORTNVLE4	230	63337	JHNSNJT4	230	1	390.4		408.2	104.5	63314 BIGSTON4230.00 66503 BLAIR 4230.00 C1

Contingency analysis for interconnection alternative 1 also indicated that there were other, more remote facilities overloaded. Since these facilities are not in the direct area of interconnection, they are not required interconnection upgrades. However, upgrades to these facilities may be required at a later date if some of these same facilities appear in the delivery service study. A full listing of other facility overloads that appeared at locations more remote from the area of interconnection are shown in Appendix B.1.1.

One-line diagrams generated within PSS/E for 230 kV alternative 1 during system intact, N-1, and N-2 contingency conditions for the 2007 summer off-peak case can be found within Appendix H.

7.1.1.2 230 kV Interconnection Alternative 2

Contingency analysis for interconnection alternative 2 during summer off-peak conditions has only identified one overloaded facility. This is the Johnson Jct. to Ortonville 115 kV line that overloads for numerous contingencies. The highest post-contingent flow on the line was for loss of the Hankinson to Wahpeton 230 kV line. The following table illustrates this overload.

**Table 7-3: Loading Violations for 230 kV Alternative 2
for 2007 Summer Off-peak Conditions**

Overloaded Branch						Normal Rating	Existing System		Int. Alt. #2		Contingency	
From Bus		kV	To Bus		kV		ckt	MVA	% Rate A	MVA		% Rate A
62003	JOHNJCT7	115	63216	ORTONVL7	115	1	96.6	112.9	109.1	106.7	110.5	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1
											NUMEROUS OTHER CONTINGENCIES	

Since the post-contingent flow on this 115 kV line exceeds the emergency limit of 106 MVA, implementation of this interconnection alternative would trigger the need to upgrade this 115 kV line to handle this post-contingent flow.

Contingency analysis for interconnection alternative 2 also identified numerous other lines that were overloaded further away from the point of interconnection. These facility overloads could be a result of the assumed delivery of this generation, therefore these facilities are not required to be upgraded as part of the interconnection process, but may be required during a later stage of the delivery service study. A full listing of the contingency results for interconnection alternative 2 is available in Appendix B.1.1 for 2007 summer off-peak conditions.

One-line diagrams generated within PSS/E for 230 kV alternative 2 during system intact, N-1, and N-2 contingency conditions for the 2007 summer off-peak case can be found within Appendix H.

7.1.2 Voltage Violations

7.1.2.1 230 kV Interconnection Alternative 1

Contingency analysis of the 2007 summer off-peak case did not identify any voltage violations within the immediate area of interconnection for alternative 1. However, there were a multitude of voltage violations that did occur at locations far from the proposed interconnection. A full listing of these voltage violations can be found within Appendix B.1.2. The voltage violations within this Appendix are not required to be fixed during this Study, but may be required if later in the delivery service study these same voltage violations are shown to be further aggravated by the assumed delivery of the Big Stone II generator.

One-line diagrams generated within PSS/E for 230 kV alternative 1 during system intact, N-1, and N-2 contingency conditions for the 2007 summer off-peak case can be found within Appendix H.

7.1.2.2 230 kV Interconnection Alternative 2

Interconnection alternative 2 involved 230 kV lines from Big Stone to Willmar and from Big Stone to Granite Falls. Contingency analysis of the 2007 summer off-peak case has identified some potential voltage violations at both the Willmar 115 kV and 230 kV buses. Since these voltage violations are directly at the point of interconnection, mitigation of the voltage violations at Willmar will be necessary if interconnection alternative 2 goes forward in connecting Big Stone II to the system. Post-contingent voltage levels with the worst-case contingencies are shown below in Table 7-4.

**Table 7-4: Voltage Violations for 230 kV Alternative 2
for 2007 Summer Off-peak Conditions**

Voltage Violation			Existing System	Int. Alt #2		
Bus	kV	V-CONT	V-CONT	Δ V	Contingency	
62425	WILLMAR7	115		NEW	NUMEROUS CONTINGENCIES	
			0.8939	0.8848	-0.0091	62005 KERKHOT7115.00 62425 WILLMAR7115.00 CC1
63050	WILLMAR4	230		NEW	NUMEROUS CONTINGENCIES	
				0.9139	NEW	60108 WILMART3345.00 60331 LKFLDXL3345.00 C1
				0.9123	NEW	63050 WILLMAR4230.00 66550 GRANITF4230.00 C1

Since the post-contingent voltage at these two buses dropped below GRE's criteria of 0.92 p.u., mitigation of these voltages must be completed if interconnection alternative 2 is implemented when connecting the proposed generator to the system.

Interconnection alternative 2 also had numerous other voltage violations identified during contingency analysis of the 2007 summer off-peak case with all of the Group 2 projects modeled. A complete listing of these voltage violations can be found in Appendix B.1.2. Since these voltage violations occur at buses more remote from the point of interconnection, they do not have to be resolved during this interconnection Study. However, if some of these same voltage violations would happen to occur during the delivery service study, system upgrades would need to be added to mitigate the voltage violations that are aggravated by this proposed project.

One-line diagrams generated within PSS/E for 230 kV alternative 2 during system intact, N-1, and N-2 contingency conditions for the 2007 summer off-peak case can be found within Appendix H.

7.2 2007 Summer Peak Conditions

7.2.1 Loading Violations

7.2.1.1 230 kV Interconnection Alternative 1

Contingency analysis of the 2007 summer peak case has indicated that there are five potential overloads for interconnection alternative 1. These overloads appear on the Big Stone 230/115/13.8 kV transformer, the Big Stone to Browns Valley 230 kV line, the Morris 230/115 kV transformer, the Big Stone to Highway 12 115 kV line and the Highway 12 to Ortonville 115 kV line. The post-contingent loadings on these overloaded facilities are shown below in Table 7-5.

**Table 7-5: Loading Violations for 230 kV Alternative 1
for 2007 Summer Peak Conditions**

Overloaded Branch							Normal Rating	Existing System		Int. Alt. #1		Contingency
From Bus		kV	To Bus		kV	ckt		MVA	% Rate A	MVA	% Rate A	
63314	BIGSTON4	230	63325	BROWNSV4	230	1	291			298	102.4	60192 BLUE LK3345.00 60108 WILMART3345.00 C1
												60261 DEANLAK7115.00 60244 SCOTTCO7115.00 C1
										374.6	128.7	63337 JHNSNJT4230.00 66554 MORRIS 4230.00 C1
66554	MORRIS 4	230	66555	MORRIS 7	115	1	100			132.7	132.7	BASE CASE
										177	177	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1
												NUMEROUS OTHER CONTINGENCIES
63195	BIGSTONY	230	63214	BIGSTON7	115	1	233			277.7	119.2	63314 BIGSTON4 230.00 63320 ORTNVLE4 230.00 C1
63195	BIGSTONY	230	63314	BIGSTON4	230	1	233			277.7	119.2	63314 BIGSTON4 230.00 63320 ORTNVLE4 230.00 C1
63214	BIGSTON7	115	63215	HIWY12 7	115	1	216			243.3	112.6	63314 BIGSTON4 230.00 63320 ORTNVLE4 230.00 C1
63215	HIWY12 7	115	63216	ORTONVL7	115	1	216			230.8	106.9	63314 BIGSTON4 230.00 63320 ORTNVLE4 230.00 C1

According to the table above, post-contingent flow on the Big Stone to Browns Valley 230 kV line exceeds its emergency limit for outage of the Johnson Jct. to Morris 230 kV line. The Morris 230/115 kV transformer is overloaded for numerous contingencies with the highest amount of post-contingent loading occurring for outage of the Hankinson to Wahpeton 230 kV line. The corresponding post-contingent flow on this transformer was 177 MVA, which is well above the 125 MVA emergency transformer limit. Flows on the Big Stone 230/115/13.8 kV transformer were over the normal rating of the transformer, but did not exceed the emergency limit. The highest loading experienced on this transformer was 277.7 MVA when the Big Stone to Ortonville 230 kV line was out of service. In addition, the Big Stone to Highway 12 115 kV and the Highway 12 to Ortonville 115 kV line were overloaded for loss of the Big Stone to Ortonville 230 kV line. Facilities with post-contingent loadings above their respective emergency limits would need to be upgraded if interconnection alternative 1 is chosen to connect the proposed generator. These facilities include the Big Stone to Browns Valley 230 kV line, the Morris 230/115 kV transformer, and the Big Stone to Highway 12 115 kV line.

The Ortonville 230/115 kV transformer addition has now been eliminated from alternative 1 based on information gathered from the routing and permitting efforts underway as part of this project. With the “north” line of alternative 1 now configured as Big Stone to Johnson Jct. to Morris, the post-contingent flow on the Big Stone 230/115 kV transformer and the Big Stone – Highway 12 – Ortonville 115 kV line is now less their respective emergency ratings.

Contingency analysis results from the 2007 summer peak case also indicated that the assumptions used in adding the interconnection facilities to the model were not adequate in handling the amount of post-contingent flow possible on these facilities. Table 7-6 is shown below and illustrates the amount of post-contingent flow possible on the new interconnection facilities. If interconnection alternative 1 were implemented to connect the generator, the facilities associated with this interconnection alternative would have to be able to handle the following amount of post-contingent flow.

**Table 7-6: Potential Loading on 230 kV Interconnection Facilities
for 2007 Summer Peak Conditions**

Overloaded Branch						Normal Rating	Existing System		Int. Alt. #1		Contingency
From Bus	kV	To Bus	kV	ckt			MVA	% Rate A	MVA	% Rate A	
63314	BIGSTON4	230	63320	ORTNVLE4	230	1	390.4		412.2	105.6	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1
									431.2	110.4	63314 BIGSTON4230.00 63325 BROWNSV4230.00 C1
									426.5	109.2	63325 BROWNSV4230.00 63327 HANKSON4230.00 C1
63216	ORTNVLE4	115	63321	ORTNVLEY	230	1	125		202.8	162.3	63314 BIGSTON4230.00 63320 ORTNVLE4 230.00 C1
63320	ORTNVLE4	230	63321	ORTNVLEY	230	1	125		201.8	161.5	63314 BIGSTON4230.00 63320 ORTNVLE4 230.00 C1
63320	ORTNVLE4	230	63337	JHNSNJ4	230	1	390.4		418.6	107.2	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1
									438.6	112.3	63314 BIGSTON4230.00 63325 BROWNSV4230.00 C1
									433.5	111	63325 BROWNSV4230.00 63327 HANKSON4230.00 C1
63337	JHNSNJ4	230	66554	MORRIS 4	230	1	390.4		427.2	109.4	63314 BIGSTON4230.00 63325 BROWNSV4230.00 C1
									422.1	108.1	63325 BROWNSV4230.00 63327 HANKSON4230.00 C1
									407.3	104.3	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1

Numerous other overloads were identified for interconnection alternative 1 while performing contingency analysis on the 2007 summer peak case. A full listing of these overloads can be found in Appendix C.1.1. Since these overloads are more remote from the point of interconnection, they are not required fixes during the interconnection phase of this Study. However, if these facility overloads occur during the delivery service study, they would then be required upgrades.

One-line diagrams generated within PSS/E for 230 kV alternative 1 during system intact, N-1, and N-2 contingency conditions for the 2007 summer peak case can be found within Appendix I.

7.2.1.2 230 kV Interconnection Alternative 2

Analysis results from studying interconnection alternative 2 during summer peak conditions has identified four facilities that are overloaded. These facilities include the Big Stone 230/115/13.8 kV transformer, the Big Stone to Browns Valley 230 kV line, the Ortonville to Johnson Jct. 115 kV line and the Johnson Jct. to Morris 115 kV line. Post-contingent flows on these overloaded facilities are shown below in Table 7-7.

**Table 7-7: Loading Violations for 230 kV Alternative 2
for 2007 Summer Peak Conditions**

Overloaded Branch						Normal Rating	Existing System		Int. Alt. #2		Contingency
From Bus	kV	To Bus	kV	ckt			MVA	% Rate A	MVA	% Rate A	
63195	BIGSTONY	230	63214	BIGSTON7	115	1	233		259.1	111.2	63325 BROWNSV4230.00 63327 HANKSON4230.00 C1
									255.7	109.8	63314 BIGSTON4230.00 63325 BROWNSV4230.00 C1
									250.6	107.5	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1
63195	BIGSTONY	230	63314	BIGSTON4	230	1	233		260.5	111.8	63325 BROWNSV4230.00 63327 HANKSON4230.00 C1
									255.7	109.8	63314 BIGSTON4230.00 63325 BROWNSV4230.00 C1
									250.6	107.5	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1
62003	JOHNJCT7	115	63216	ORTONVL7	115	1	96.6		126.4	124.3	BASE CASE
									136.8	141.7	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1
											NUMEROUS OTHER CONTINGENCIES
63314	BIGSTON4	230	63325	BROWNSV4	230	1	291		289.8	100.6	BASE CASE
									326.1	112.1	60192 BLUE LK3345.00 60108 WILMART3345.00 C1
											NUMEROUS OTHER CONTINGENCIES
62003*	JOHNJCT7	115	66555	MORRIS 7	115	1	106		125.3	118.2	63327 HANKSON4230.00 63329 WAHPETN4230.00 C1

The post-contingent flow on the Big Stone 230/115/13.8 kV transformer never exceeds its emergency rating. However, the Ortonville to Johnson Jct. 115 kV line, the Johnson Jct. to Morris 115 kV line and the Big Stone to Browns Valley 230 kV line all exceed their emergency ratings, therefore an upgrade of these lines would be necessary if interconnection alternative 2 is implemented to connect this generator to the system.

There were also numerous other overloads that occurred during contingency analysis of interconnection alternative 2 during summer peak conditions. A full listing of the overloads encountered during contingency analysis of interconnection alternative 2 for summer peak conditions can be found in Appendix C.1.1. These overloads were not as close to the point of interconnection as the overloads shown above in Table 7-7. These overloads are most likely caused by the assumed delivery of Big Stone II and are therefore not required upgrades as part of this interconnection Study. The overloads shown within Appendix C.1.1 may require system upgrades if these same facility overloads occur during the delivery service study.

One-line diagrams generated within PSS/E for 230 kV alternative 2 during system intact, N-1, and N-2 contingency conditions for the 2007 summer peak case can be found within Appendix I.

7.2.2 Voltage Violations

7.2.2.1 230 kV Interconnection Alternative 1

Summer peak conditions seemed to cause more voltage violations than summer off-peak conditions. These voltage violations were widespread throughout the system. Analyzing the impacts that interconnection alternative 1 had on the summer peak case has identified that voltages within the area of immediate interconnection were improved by new 230 kV terminations at Morris and Granite Falls. Within the immediate area, voltages below 0.92 p.u.

were improved in all contingencies that were studied. The magnitude of this improvement along with the troublesome contingencies that caused these voltage violations is shown below in Table 7-8.

**Table 7-8: Voltage Violations for 230 kV Alternative 1
for 2007 Summer Peak Conditions**

Voltage Violation			Existing System	Int. Alt. #1		
Bus		kV	V-CONT	V-CONT	Δ V	Contingency
66550	GRANITF4	230	0.919	0.9194	0.0004	60192 BLUE LK3345.00 60108 WILMART 3345.00 C1 60215 HYLNDLK7115.00 60261 DEANLAK7115.00 C1 60261 DEANLAK7115.00 60244 SCOTTCO7115.00 C1
			0.9108	0.9162	0.0054	60192 BLUE LK3345.00 60108 WILMART 3345.00 C1 60215 HYLNDLK7115.00 60261 DEANLAK7115.00 C1
			0.9118	0.9168	0.005	60192 BLUE LK3345.00 60108 WILMART3345.00 C1 60261 DEANLAK7115.00 60244 SCOTTCO7115.00 C1
			0.9119	0.9175	0.0056	60108 WILMART3345.00 60192 BLUE LK3345.00 C1
			0.8744	0.9156	0.0412	60108 WILMART 3345.00 60331 LKFLDXL3345.00 C1
			0.8166	0.896	0.0794	60143 BENTON 7115.00 60146 GRANTCTY7115.00 C1 60143 BENTON 7115.00 60348 BENCTP7 115.00 C1 60348 BENCTP7 115.00 60157 STCLOUD7115.00 C1
66554	MORRIS 4	230	0.9057		ELIMINATED	60108 WILMART 3345.00 60331 LKFLDXL3345.00 C1
			0.8094		ELIMINATED	60143 BENTON 7115.00 60146 GRANTCTY7115.00 C1 60143 BENTON 7115.00 60348 BENCTP7 115.00 C1 60348 BENCTP7 115.00 60157 STCLOUD7115.00 C1
66555	MORRIS 7	115	0.8971		ELIMINATED	60108 WILMART 3345.00 60331 LKFLDXL3345.00 C1
			0.7689	0.9023	0.1334	60143 BENTON 7115.00 60146 GRANTCTY7115.00 C1 60143 BENTON 7115.00 60348 BENCTP7 115.00 C1 60348 BENCTP7 115.00 60157 STCLOUD7115.00 C1

Low voltage criteria at these WAPA buses is 0.90 p.u. As can be seen above, interconnection alternative 1 improves voltages to above 0.90 p.u. in nearly all cases.

Besides these voltage violations within the immediate area of interconnection, there was a multitude of other bus voltage violations spread throughout the system. A full list of these voltage violations can be found in Appendix C.1.2. These voltage violations are more remote from the area of interconnection and will not be required fixes during this interconnection Study. However, if some of these same voltage violations would happen to occur during the delivery service study, system upgrades would need to be added to mitigate the voltage violations that are aggravated by this proposed project.

One-line diagrams generated within PSS/E for 230 kV alternative 1 during system intact, N-1, and N-2 contingency conditions for the 2007 summer peak case can be found within Appendix I.

7.2.2.2 230 kV Interconnection Alternative 2

The implementation of interconnection alternative 2 indicated that two voltage violations are evident within the direct area of this project. These voltage violations are at the Willmar 115 kV and 230 kV buses. The number of contingencies that caused these voltage violations were numerous and are not all going to be shown here within the report, but if further information is desired about the contingencies that caused these voltage violations and the corresponding post-contingent voltage levels, refer to Appendix C.1.2.

**Table 7-9: Voltage Violations for 230 kV Alternative 2
for 2007 Summer Peak Conditions**

Voltage Violation			Existing System	Int. Alt. #1	ΔV	Contingency
Bus		kV	V-CONT	V-CONT		
62425	WILLMAR7	115			NEW	NUMEROUS CONTINGENCIES
63050	WILLMAR4	230			NEW	NUMEROUS CONTINGENCIES

Since the two voltage violations at Willmar are at the point of interconnection for alternative 2, the mitigation of these voltage violations will be required as part of this interconnection Study if alternative 2 is implemented to connect Big Stone II to the system.

Besides these voltage violations at Willmar, numerous other violations were found throughout the system for interconnection alternative 2. A complete listing of the violations can be found in Appendix C.1.2. Since these voltage violations are not directly within the area of interconnection, they are not required to be fixed during the interconnection Study. However, if some of these same voltage violations would happen to occur during the delivery service study, system upgrades would need to be added to mitigate the voltage violations that are aggravated by this proposed project.

One-line diagrams generated within PSS/E for 230 kV alternative 2 during system intact, N-1, and N-2 contingency conditions for the 2007 summer peak case can be found within Appendix I.

7.2.3 Steady State Analysis Conclusion of 230 kV Alternatives

Based on the overall system performance during steady state conditions, this Study has identified that the following upgrades will be necessary on the existing system for connecting the proposed project with 230 kV interconnection alternative 1. These upgrades are in addition to the new facilities (described in Table 2-1) that are included as part of interconnection alternative 1.

Table 7-10: Required Upgrades for 230 kV Interconnection Alternative 1

1. Increase capacity of Morris 230/115 kV Transformer
2. Increase capacity of Big Stone to Browns Valley 230 kV Line
3. Increase capacity of Big Stone to Highway 12 115 kV Line

The Ortonville 230/115 kV transformer addition, which was originally assumed as part of alternative 1, has now been eliminated based on information gathered from the routing and permitting efforts underway as part of this project. With the “north” line of alternative 1 now configured as Big Stone to Johnson Jct. to Morris, the post-contingent flow on the Big Stone to Highway 12 115 kV line is no longer over the emergency limit of the line and therefore is no longer a required upgrade for alternative 1.

Implementing interconnection alternative 2 to connect the proposed project to the system will require the following upgrades (shown in Table 7-11) to the existing system. These upgrades are in addition to the new facilities (described in Table 2-1) that are included as part of interconnection alternative 2.

Table 7-11: Required Upgrades for 230 kV Interconnection Alternative 2

1. Increase capacity of Ortonville to Johnson Jct. 115 kV Line
2. Increase capacity of Johnson Jct. to Morris 115 kV Line
3. Increase capacity of Big Stone to Browns Valley 230 kV Line
4. Install capacitor bank in Willmar area to mitigate low voltages

8.0 Steady State Analysis Results for 345 kV Alternative

8.1 Introduction

There are several regional transmission studies that have been completed that indicate a need for the addition of extra high voltage (EHV) transmission lines within this region in order to reliably serve the growing need for electricity. These include the CapX 2020 Vision Study, the Northwest Exploratory Study, and the Southwest Minnesota → Twin Cities Extra High Voltage (SW MN→TC EHV) study.

The CapX 2020 Vision Study has identified that multiple high voltage transmission lines will be required in order to reliably serve the anticipated load throughout the northern Midwest region in the year 2020. One of the high voltage lines identified within this study extends from southwestern North Dakota to the Twin Cities metro area.

The Northwest Exploratory Study, which was conducted by MISO as part of MTEP-05, investigated the required transmission to allow for the interconnection and delivery of new generation sources located in the Dakotas and southwest Minnesota to the large load center of the Twin Cities. To accommodate the 2000 MW of generation considered within this study, the Northwest Exploratory Study identified two new 345 kV lines across the Dakotas and into the Twin Cities metropolitan area. This study further concluded that new 500 kV lines did not offer substantial benefits over new 345 kV lines due to limitations of the existing system for contingencies involving the new lines.

A third study completed by Xcel Energy, called the SW MN→TC EHV study, identified a transmission plan for accommodating up to 1900 MW of total generation in the Buffalo Ridge area. The preferred transmission plan included a 345 kV line from southwestern Minnesota to the Twin Cities.

In light of the information now available from these other regional studies, the Big Stone II participants have stated within their MN Certificate of Need Application that they prefer to build the “southern “ line of their transmission plan (Big Stone to Granite Falls) to 345 kV standards and initially operate it at 230 kV until other regional 345 kV lines are completed to connect with.

Steady state contingency analysis has been completed for 345 kV alternative 1 (Big Stone – Morris 230 kV and Big Stone – Hazel Run 345 kV) to examine the maximum loading levels on existing facilities in order to identify any new constraints not previously identified in the analysis of the 230 kV alternatives

8.2 Study Criteria

Steady state analysis that was performed as part of this study monitored branch loadings within the study area. Study criteria for facility loadings were set to align with the publications in the *MAPP Members Reliability Criteria and Study Procedures Manual*. General study criteria for system intact and contingency conditions were the same as what was discussed in section 6.1.

All impacts created or worsened by the addition of the proposed generation are documented within the various sections of this report.

8.3 Model Development

This study utilized the 2002 series MAPP models representing a 2007 summer peak scenario and a 2007 summer off-peak scenario. These models included several updates from regional utilities and were also used for the 230 kV analyses for Big Stone II. These models included all previously queued interconnection projects ahead of Big Stone II and were based on the MISO/WAPA Group 2 coordinated study.

All analysis within this study focused on Transmission Alternative 1 identified through the Big Stone II studies, which includes a new 230 kV line from Big Stone to Morris and from Big Stone to Granite Falls since this was the preferred transmission alternative indicated by the Big Stone II participants within the MN Certificate of Need Application.

8.3.1 Addition of Southwest Minnesota → Twin Cities EHV Facilities

The facilities identified through the SW MN→TC EHV study have been identified as the initiating event that would cause the Big Stone to Canby to Granite Falls line to be converted to 345 kV.

The preferred transmission alternative identified by the SW MN→TC EHV study is shown in the figure below. The preferred alternative includes a new 345 kV line from a new substation, called the Brookings County substation, which is adjacent to the Western Area Power Administration White substation east to a new substation along the Prairie Island to Blue Lake 345 kV line called Hampton Corners. The new west to east 345 kV line is proposing to tap into the existing substations of Lyon County, Franklin and Lake Marion along the way. In addition, this line is also proposing to tap into the existing 345 kV line at a new switching station called Helena. Also identified as part of these facilities is a 345 kV line running north from the Lyon County Substation to a new substation called Hazel, which is located just south of the Granite Falls and Minnesota Valley substations. The Hazel substation is intended to be located in close proximity to the existing Canby to Granite Falls line. In addition, the study also recommended that a portion of the proposed 345 kV line from Lyon County to Franklin to the Helena Switching Station be constructed as a double circuit.

Figure 8-1: New Facilities identified by the "SW MN → Twin Cities EHV" Study

[Figure 8-1 removed for public posting]

8.4 Model Assumptions

When adding the Big Stone to Granite Falls 345 kV line to the system, the proposed 230 kV line was replaced with a 345 kV line from Big Stone to Canby and ultimately to Hazel (a new substation that ties the Big Stone II outlet facilities to the proposed SW MN→TC EHV facilities). New 230 kV lines were assumed from Hazel to Granite Falls and from Hazel to Minnesota Valley as part of the EHV project. At Canby, a new 345/115 kV transformer was added in order to connect into the existing 115 kV system at Canby.

In order for the Big Stone to Granite Falls line to operate at 345 kV, changes were also assumed at the Big Stone end. It was assumed that a new 345/230 kV substation would be constructed approximately 1.25 miles south of the existing Big Stone substation. The existing substation at Big Stone is currently limited in physical size due to existing infrastructure in place for the operation of the existing unit. Due to operating the Big Stone to Granite Falls line at 345 kV, the development of a green field site into a new 345/230 kV substation is needed in order to allow for enough physical space to accommodate two new 345/230 kV transformers.

The 115 kV system that forms a loop from Big Stone to Canby was left unchanged from the original interconnection studies with the exception of a new 115 kV line being added from Toronto to the Brookings County substation, which is a previously identified outlet line from the Buffalo Ridge (Buffalo Ridge Incremental Generation Outlet Study). The models used in this analysis also included the proposed 115 kV upgrade of the existing Appleton to Canby 41.6 kV line.

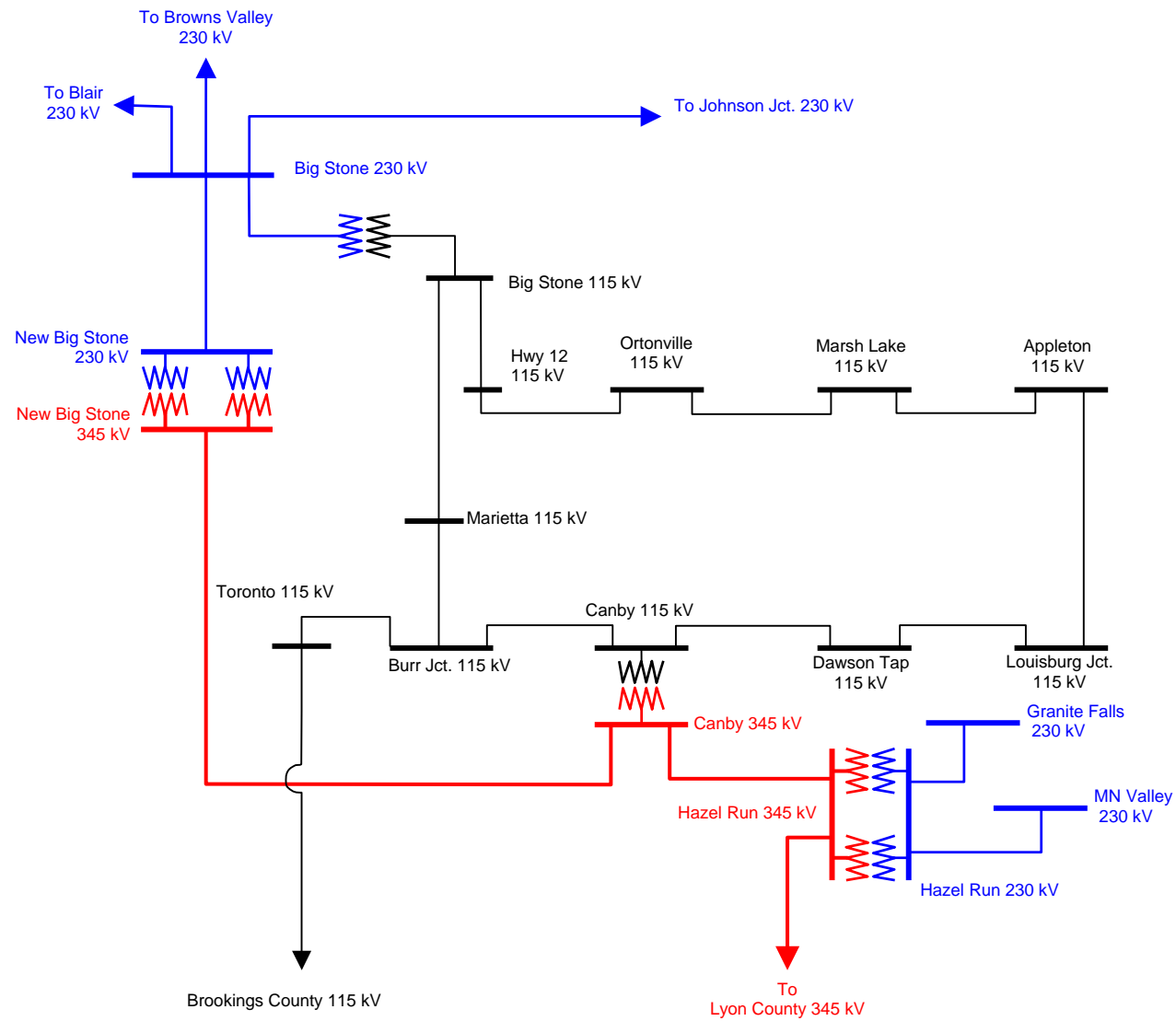
Since the release of the Big Stone II interconnection study report that documented the steady state analysis results, information about the existing Ortonville substation has resulted in a slight change of transmission alternative 1 from Big Stone to Morris. Due to physical space limitations within the existing Ortonville substation, the proposed Ortonville 230/115 kV transformer has been removed from transmission alternative 1. Therefore, this study considered the 230 kV line from Big Stone to Morris to only have one tap into the existing Johnson Jct. substation, which is approximately 14 miles west of the Morris substation.

For this study, it was also assumed that all proposed 230 kV lines are composed of 1272 ACSR conductor and all 345 kV lines are composed of bundled 1272 ACSR.

The new Big Stone 345 kV substation was connected back to the existing Big Stone 230 kV substation by a single 230 kV line. At the new Big Stone 345 kV substation, two new 345/230 kV transformers were assumed to step the voltage up to 345 kV. Once the voltage was at 345 kV, the line continued to Canby and eventually to Hazel Run where it interconnects with the EHV project.

The system configuration with the Big Stone 345 kV line in-service is shown in Figure 8-2.

Figure 8-2: One-Line Diagram of Big Stone 345 kV Alternative 1



8.5 Line Loading Results

8.5.1 Existing System Facilities

8.5.1.1 System Intact Conditions

Local contingency analysis identified no transmission line overloads during System Intact (SIT) conditions for either Summer Peak (SUPK) or Summer Off-Peak (SUOP) conditions. Table 8-1 summarizes maximum loadings of each existing outlet facility for system intact conditions.

One-line diagrams generated within PSS/E for system intact conditions are included in Appendix D.1.1 for summer peak and Appendix D.2.1 for summer off-peak.

Table 8-1: Maximum Loading on Existing Outlet Facilities for “System Intact” Conditions for Big Stone II 345 kV Alternative 1

EXISTING FACILITIES "SYSTEM INTACT" MAXIMUM LOADING SUMMARY					
Existing Facility	Normal Rating	New Big Stone 345 kV Substation - Option 2			
		Loading, (MVA)	Loading, (%)	Scenario	Outage
Big Stone to Browns Valley 230 kV	390 MVA	241 MVA	61.8%	SUPK	N/A
Browns Valley to Hankinson 230 kV	390 MVA	223 MVA	57.2%	SUPK	N/A
Hankinson to Wahpeton 230 kV	320 MVA	266 MVA	83.1%	SUPK	N/A
Wahpeton to Fergus Falls 230 kV	320 MVA	216 MVA	67.5%	SUPK	N/A
Big Stone to Blair 230 kV	480 MVA	320 MVA	66.7%	SUOP	N/A
Big Stone 230/115 kV Transformer	233 MVA	112 MVA	48.1%	SUOP	N/A
Big Stone to Highway 12 115 kV	216 MVA	70 MVA	32.4%	SUPK	N/A
Highway 12 to Ortonville 115 kV	216 MVA	62 MVA	28.7%	SUOP	N/A
Ortonville to Marsh Lake 115 kV	96 MVA	44 MVA	45.8%	SUOP	N/A
Marsh Lake to Appleton 115 kV	96 MVA	41 MVA	42.7%	SUOP	N/A
Appleton to Louisburg 115 kV	96 MVA	35 MVA	36.5%	SUOP	N/A
Louisburg to Dawson Tap 115kV	96 MVA	35 MVA	36.5%	SUOP	N/A
Dawson Tap to Canby 115 kV	94 MVA	29 MVA	30.9%	SUOP	N/A
Big Stone to Marietta 115 kV	96 MVA	47 MVA	49.0%	SUOP	N/A
Marietta to Burr Jct 115 kV	96 MVA	45 MVA	46.9%	SUOP	N/A
Burr Jct to Canby 115 kV	96 MVA	65 MVA	67.7%	SUPK	N/A
Toronto to Burr Jct. 115 kV	96 MVA	45 MVA	46.9%	SUPK	N/A

8.5.1.2 Contingency Conditions

Two existing Big Stone facilities experience loading that exceeds their normal ratings during N-1 contingency conditions. These lines are highlighted in light blue in Table 8-2. The Hankinson to Wahpeton 230 kV line overloads during summer peak conditions. The other line overload occurs on the Burr Jct. to Canby 115 kV line, which overloads by the same amount during both summer peak and off-peak conditions. It should be noted that this loading level is believed to occur as a result of the new transmission facilities added as part of the EHV study and is more a function of Buffalo Ridge wind generation than Big Stone II generation. Loading on the Burr Jct. to Canby

line drops below its normal rating without the Toronto to Brookings County 115 kV line in-service.

Table 8-2 summarizes the maximum loadings of each existing Big Stone II outlet facility for N-1 conditions. As shown within the table below, no existing facilities are loaded above their respective emergency limits.

One-line diagrams generated within PSS/E for N-1 contingency conditions for Option 2 are included in Appendix D.1.2 for the summer peak case and Appendix D.2.2 for the summer off-peak case.

Table 8-2: Maximum Loadings on Existing Outlet Facilities for “N-1” Conditions for Big Stone II 345 kV Alternative 1

EXISTING FACILITIES "N-1" MAXIMUM LOADING SUMMARY					
Existing Facility	Normal Rating	New Big Stone 345 kV Substation - Option 2			
		Loading, (MVA)	Loading, (%)	Scenario	Outage
Big Stone to Browns Valley 230 kV	390 MVA	330 MVA	84.6%	SUPK	Big Stone - Johnson Jct.
Browns Valley to Hankinson 230 kV	390 MVA	306 MVA	78.5%	SUPK	Big Stone - Johnson Jct.
Hankinson to Wahpeton 230 kV	320 MVA	339 MVA	105.9%	SUPK	Big Stone - Johnson Jct.
Wahpeton to Fergus Falls 230 kV	320 MVA	236 MVA	73.8%	SUOP	Big Stone - Blair 230 kV
Big Stone to Blair 230 kV	480 MVA	420 MVA	87.5%	SUOP	Big Stone - Johnson Jct. 230 kV
Big Stone 230/115 kV Transformer	233 MVA	179 MVA	76.8%	SUOP	Big Stone - New Big Stone 230 kV
Big Stone to Highway 12 115 kV	216 MVA	97 MVA	44.9%	SUOP	Big Stone - New Big Stone 230 kV
Highway 12 to Ortonville 115 kV	216 MVA	92 MVA	42.6%	SUOP	Big Stone - New Big Stone 230 kV
Ortonville to Marsh Lake 115 kV	96 MVA	75 MVA	78.1%	SUOP	Big Stone - New Big Stone 230 kV
Marsh Lake to Appleton 115 kV	96 MVA	71 MVA	74.0%	SUOP	Big Stone - New Big Stone 230 kV
Appleton to Louisburg 115 kV	96 MVA	65 MVA	67.7%	SUOP	Big Stone - New Big Stone 230 kV
Louisburg to Dawson Tap 115kV	96 MVA	64 MVA	66.7%	SUOP	Big Stone - New Big Stone 230 kV
Dawson Tap to Canby 115 kV	94 MVA	58 MVA	61.7%	SUOP	Big Stone - New Big Stone 230 kV
Big Stone to Marietta 115 kV	96 MVA	84 MVA	87.5%	SUOP	Big Stone - New Big Stone 230 kV
Marietta to Burr Jct 115 kV	96 MVA	81 MVA	84.4%	SUOP	Big Stone - New Big Stone 230 kV
Burr Jct to Canby 115 kV	96 MVA	103 MVA	107.3%	SUPK	Big Stone - New Big Stone 230 kV
Toronto to Burr Jct. 115 kV	96 MVA	78 MVA	81.3%	SUOP	Canby - Hazel 345 kV

8.5.2 New Facilities

In addition to identifying potential issues on the existing transmission system due to the Big Stone to Granite Falls line operating at 345 kV, the proposed facilities as part of the Big Stone II transmission project were monitored in order to determine the capacity necessary to reliably support the interconnection of the Big Stone II generator.

8.5.2.1 System Intact Conditions

Table 8-3 illustrates the maximum loading for each proposed facility as part of 345 kV transmission alternative 1 during system intact conditions.

One-line diagrams generated within PSS/E for system intact conditions for option 2 are included in Appendix D.1.1 for summer peak and Appendix D.2.1 for summer off-peak scenarios.

Table 8-3: Maximum Loadings on New Outlet Facilities for “System Intact” Conditions for Big Stone II 345 kV Alternative 1

NEW FACILITIES "SYSTEM INTACT" MAXIMUM LOADING SUMMARY			
New Facility	New Big Stone 345 kV Substation - Option 2		
	Loading	Scenario	Outage
Big Stone to Johnson Jct 230 kV	334 MVA	SUPK	N/A
Johnson Jct to Morris 230 kV	269 MVA	SUOP	N/A
Morris 230/115 kV Transformer	118 MVA	SUPK	N/A
Big Stone to New Big Stone 230 kV - Ckt 1	268 MVA	SUOP	N/A
Big Stone 345/230 kV Transformer #1	134 MVA	SUOP	N/A
Big Stone 345/230 kV Transformer #2	134 MVA	SUOP	N/A
New Big Stone to Canby 345 kV	268 MVA	SUOP	N/A
Canby 345/115 kV Transformer	72 MVA	SUOP	N/A
Canby to Hazel 345 kV	346 MVA	SUOP	N/A
Hazel 345/230 kV Transformer #1	64 MVA	SUPK	N/A
Hazel 345/230 kV Transformer #2	64 MVA	SUPK	N/A
Hazel to Granite Falls 230 kV	64 MVA	SUOP	N/A
Hazel to MN Valley 230 kV	90 MVA	SUPK	N/A
Hazel to Lyon County 345 kV	317 MVA	SUOP	N/A
Brookings County to Toronto 115 kV	39 MVA	SUPK	N/A

8.5.2.2 Contingency Conditions

Table 8-4 includes maximum loading for each proposed facility for “N-1” conditions including the contingency for which the loading occurs.

One-line diagrams generated within PSS/E for N-1 contingency conditions are included in Appendix D.1.2 for the summer peak case and Appendix D.2.2 for the summer off-peak case.

**Table 8-4: Maximum Loadings on New Outlet Facilities for “N-1” Conditions
for Big Stone II 345 kV Alternative 1**

NEW FACILITIES "N-1" MAXIMUM LOADING SUMMARY			
New Facility	New Big Stone 345 kV Substation - Option 2		
	Loading	Scenario	Outage
Big Stone to Johnson Jct 230 kV	425 MVA	SUPK	Big Stone - Browns Valley 230 kV
Johnson Jct to Morris 230 kV	325 MVA	SUPK	Big Stone - Browns Valley 230 kV
Morris 230/115 kV Transformer	135 MVA	SUPK	Big Stone - Browns Valley 230 kV
Big Stone to New Big Stone 230 kV - Ckt 1	328 MVA	SUOP	Big Stone - Johnson Jct. 230 kV
Big Stone 345/230 kV Transformer #1	250 MVA	SUOP	Big Stone 345/230 kV Transformer #2
Big Stone 345/230 kV Transformer #2	250 MVA	SUOP	Big Stone 345/230 kV Transformer #1
New Big Stone to Canby 345 kV	329 MVA	SUOP	Big Stone - Johnson Jct. 230 kV
Canby 345/115 kV Transformer	158 MVA	SUOP	Big Stone - New Big Stone 230 kV
Canby to Hazel 345 kV	416 MVA	SUOP	Big Stone - Johnson Jct. 230 kV
Hazel 345/230 kV Transformer #1	139 MVA	SUOP	Hazel - Lyon Cty 345 kV
Hazel 345/230 kV Transformer #2	139 MVA	SUOP	Hazel - Lyon Cty 345 kV
Hazel to Granite Falls 230 kV	110 MVA	SUOP	Hazel - Lyon Cty 345 kV
Hazel to MN Valley 230 kV	168 MVA	SUOP	Hazel - Lyon Cty 345 kV
Hazel to Lyon County 345 kV	353 MVA	SUOP	Big Stone - Blair 230 kV
Brookings County to Toronto 115 kV	89 MVA	SUOP	Canby - Hazel 345 kV

8.6 Steady State Analysis Conclusion for 345 kV Alternative

Due to the desire to integrate the Big Stone transmission plan with the regional planning needs, the project has proposed to construct the Big Stone to Granite Falls line to 345 kV standards, but operate it at 230 kV until other regional transmission plans are implemented. The operation of this Big Stone to Granite Falls line at 345 kV has required the need for this investigation, which included this new line connecting into other regional 345 kV projects; namely the Buffalo Ridge to Metro 345 kV line identified through the SW MN→TC EHV study.

System intact and first contingency (N-1) conditions were analyzed in order to identify inadequacies in the existing system once the Big Stone to Granite Falls line is operated at 345 kV.

Based on the loading results discussed in Section 8.5, no existing outlet facilities require upgrading as the heaviest N-1 loading on any existing facility does not exceed its emergency rating. Therefore, it is apparent that there are no further interconnection related upgrades beyond those already identified in the steady state contingency analysis of the 230 kV alternatives when operating the Big Stone to Granite Falls line at 345 kV with the proposed Buffalo Ridge to Twin Cities 345 kV line. Building the Big Stone II transmission plan with the Big Stone – Granite Falls line at 345 kV integrates well into the regional transmission needs identified through the CapX 2020 Vision Study, the MISO Northwest Exploratory Study, and the SW MN→TC EHV study.

9.0 Transient Stability Analysis

9.1 Introduction

As part of the MISO interconnection study, transient stability and short circuit analysis were completed back in February 2006. This effort back in February included the Post Group 2 stability cases from MISO that included a massive amount of prior queued generation within the MAPP region without adequate transmission reinforcements to accommodate these prior queued projects. As a result, the pre-disturbance case was overly stressed with several critical lines and interfaces loaded well beyond their thermal limits.

After a detailed stability analysis, it was determined that the condition of the pre-disturbance model was so degraded that it was not suitable for the Big Stone II stability analysis. However, the analysis procedure on this overly stressed case did allow for some insight into what is considered to be the most critical contingencies in the local vicinity of Big Stone.

During this same timeframe there were several other generation interconnection studies underway. Most notable was the Excelsior Energy (Mesaba) study for a new unit up in northern Minnesota. The interconnection study for Mesaba included an effort by Minnesota Power to develop a new stability model with prior queued generation projects loaded into the case to more accurately match the capability of the transmission system. Many of the prior queued generation projects in SW MN were not included in this model since there was not adequate transmission proposed yet to accommodate the amount of queued generation. As a result of building this new stability model with more accurately matched generation patterns, the loadings on critical transmission lines and interfaces were held within their thermal limits.

After the stability analysis of the 230 kV alternatives on the Post Group 2 model, MISO determined that this later stability model developed for the Mesaba study was more appropriate for the Big Stone II interconnection study. Siemens PTI was hired as a sub-contractor to OTP to perform the transient stability analysis since they were most familiar with the study models and stability package used in the Mesaba studies.

The initial stability analysis (completed back in February) included an investigation of the two 230 kV alternatives. In response to regional study efforts going on within this region, (i.e. SW MN → TC EHV Study, CapX 2020 Vision Study, MISO Northwest Exploratory Study), the Big Stone II participants have submitted a Certificate of Need Application to the State of Minnesota stating that their preferred transmission alternative includes constructing the southern portion of their transmission plan (i.e. Big Stone – Granite Falls) to 345 kV standards, but initially operate the line at 230 kV until a time in which a 345 kV transmission path can be extended from western Minnesota into the Twin Cities. This external 345 kV transmission project considered to trigger the Big Stone to Granite Falls line to be upgraded to 345 kV is the SW MN → TC EHV project. This project is currently proceeding through the permitting phase and is expected to be in-service in the 2011 to 2012 timeframe. Since the timing of the Big Stone II transmission plan is so closely aligned with the expected in-service date of this 345 kV EHV line, studies have been completed for both the 230 kV alternatives and the 345 kV alternatives.

With the knowledge of this modified transmission plan, the transient stability analysis has been performed for both the 230 kV transmission alternatives and for these same alternatives with the southern line at 345 kV to interconnect with the proposed SW MN → TC EHV line at a new substation called Hazel Run.

This study is intended to serve a dual purpose in that it is intended to meet the study requirements of both the MAPP DRS and the Midwest ISO (MISO). Due to the slight differences in study requirements, the transient stability analysis considered two different export levels across the North Dakota Export (NDEX) interface. MISO requires the NDEX interface to be maintained at the current level of 2080 MW while the MAPP DRS requires an increase in the NDEX interface limit if the Big Stone II project desires to deliver power across the interface. Due to the current make-up of the project, approximately 370 MW of the 600 MW project was assumed to be delivered to those project participants with load outside NDEX. The new NDEX level with Big Stone II deliveries across NDEX was assumed to be 2450 MW based on the current definition of NDEX. The transient stability analysis has been completed at both the 2080 MW and 2450 MW NDEX levels to meet the requirements of both MAPP and MISO.

9.2 Modeling Assumptions (Substation One-Lines)

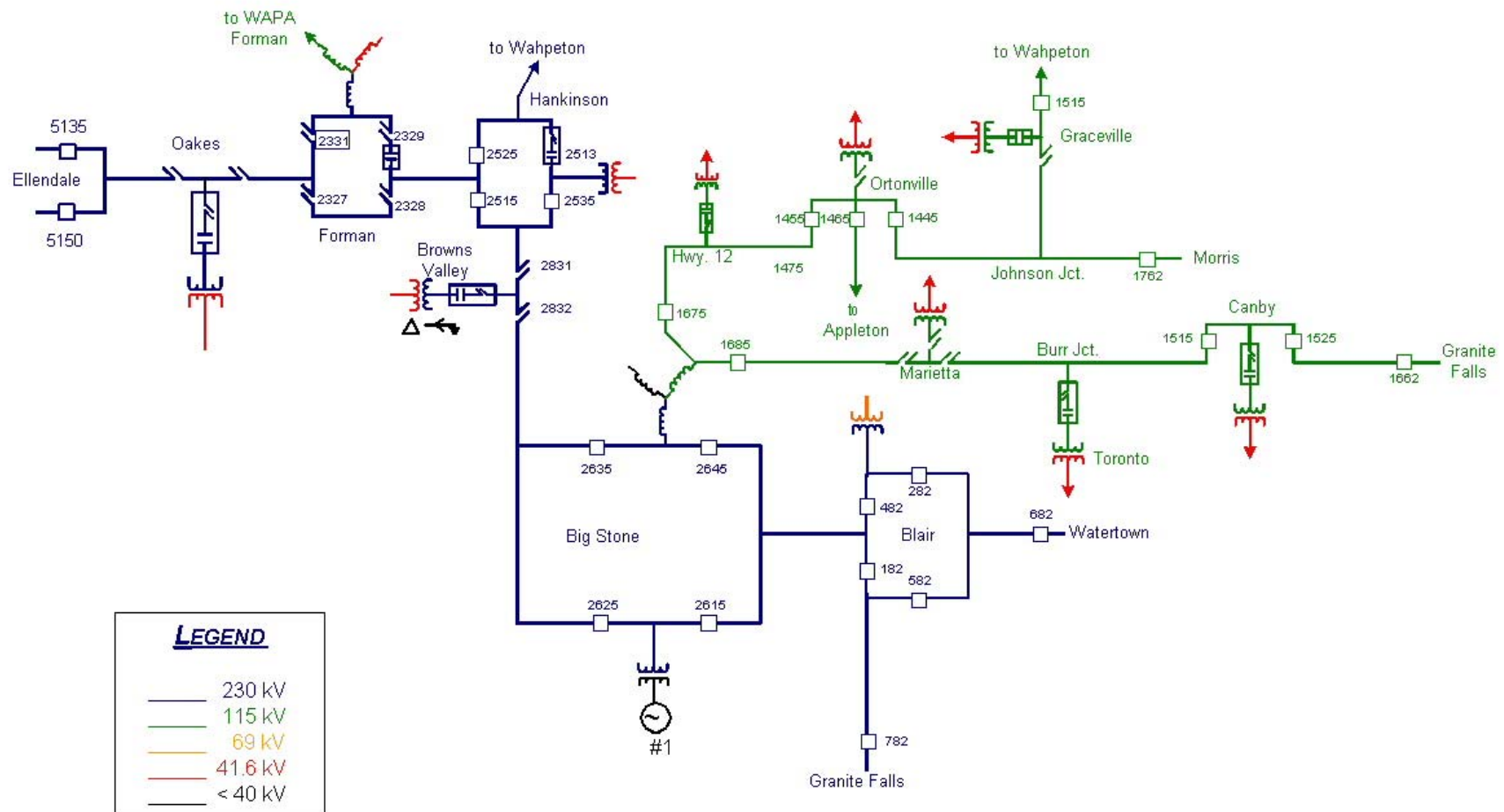
The Big Stone II transmission project includes the addition of new facilities to the existing transmission system. Existing infrastructure will need to be modified to accommodate the new facilities proposed with the transmission project. Preliminary engineering and design have been underway to find the most efficient way of connecting the new transmission facilities into the existing system. The latest information about substation configurations was taken into consideration during development of the local faults to simulate around Big Stone and on the new transmission facilities.

This section of the report will describe in detail the proposed configuration of the substations and how they will be modified to integrate the Big Stone II transmission plan into the system.

Transient stability analysis performed within this region considers single line-to-ground faults with delayed clearing and three-phase faults with normal clearing. The delayed clearing of single line-to-ground faults is typically performed by means of a stuck breaker simulation. The configuration and labeling of the circuit breakers on the transmission system are important to define the different types of single line-to-ground faults that can occur on the system. When referring to different faults or disturbances within this report, references will be made to certain circuit breaker numbers.

The following figure illustrates the existing breaker configuration on the outlet facilities at Big Stone. As shown below, 230 kV ring buses are present at Big Stone, Hankinson, and Blair while dedicated 115 kV line breakers are present at Big Stone, Ortonville, and Canby.

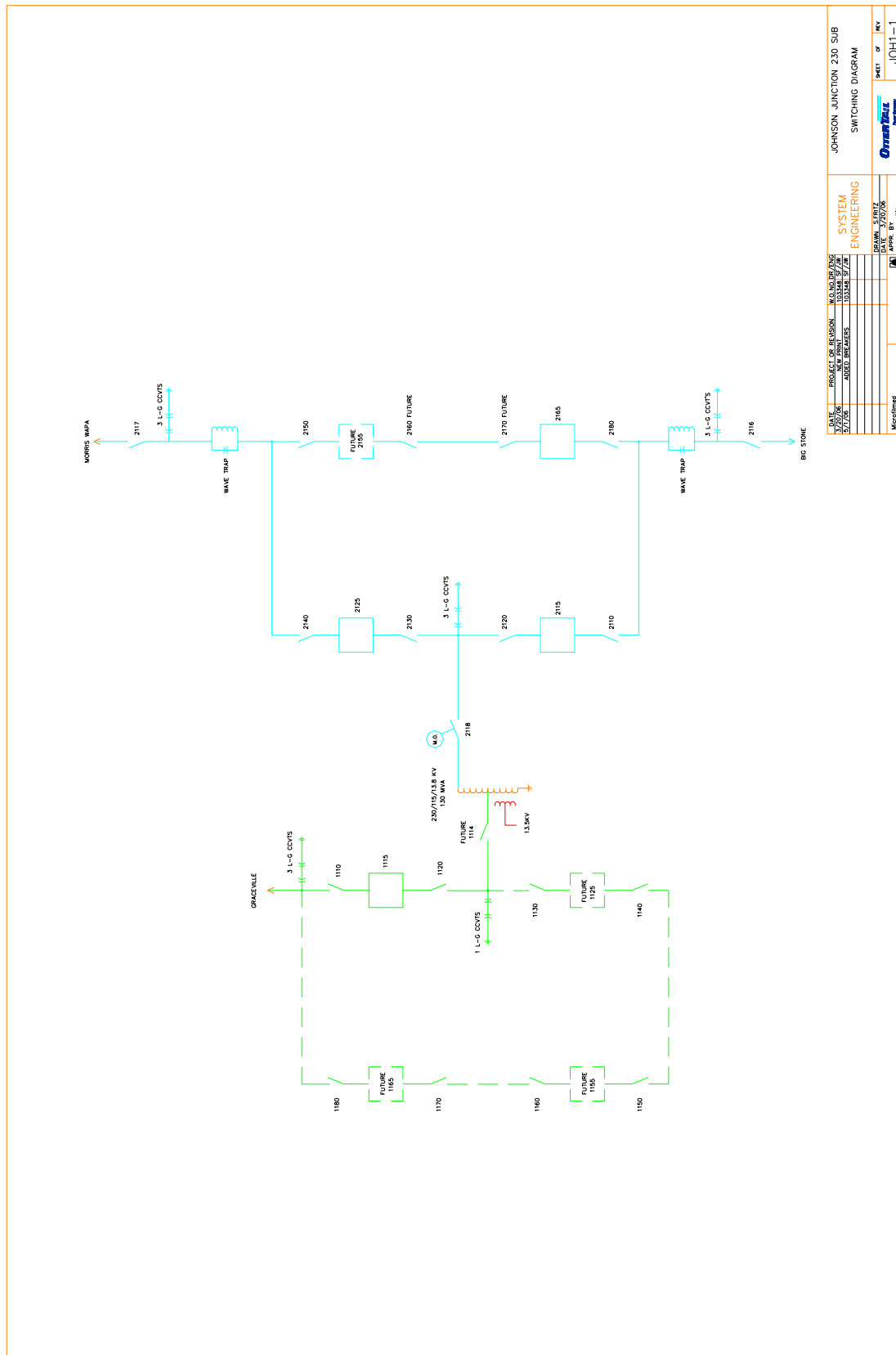
Figure 9-1: One-Line Diagram of Existing Transmission System



To include new line terminations at the existing Big Stone 230 kV substation, it has been determined that the substation will be modified to a “breaker and half” scheme by the addition of 5 new 230 kV breakers. Since the long-term plan for the southern line is to be operated at 345 kV, the current design of the substation includes provisions for the future 345 kV line. The current plan will be to modify the Canby 230 kV line to terminate into a new 345 kV substation approximately 1.25 miles south of the existing substation where 2 new 345/230 kV transformers will step the voltage up from 230 kV to 345 kV. From this substation, the proposed line will continue to Canby and ultimately to Hazel Run. The following figures include the proposed layout of the Big Stone 230 kV substation and the Big Stone 345 kV substation. As mentioned previously, the breaker numbers referenced within these figures will be used in describing faults in subsequent sections of this report.

Transmission alternative 1 will include a new termination into the Johnson Jct. switch station and the Morris substation. The Johnson Jct. switching station currently is a tap point connecting the Graceville 115 kV line into the Ortonville – Morris 115 kV line. It is proposed that the existing Ortonville – Johnson Jct. – Morris 115 kV line will be converted to 230 kV. This will require a new 230/115 kV transformer at Johnson Jct. to connect the new 230 kV line back into the 115 kV line that will still continue to Graceville. Since the Johnson Jct. substation is considered a “project” facility, preliminary design on the substation has been completed. The termination into the Morris substation (which is the endpoint of the “northern” line of alternative 1) will be coordinated with Western Area Power Administration in order to connect into the substation according to their specifications. A conceptual one-line diagram of the new Johnson Jct. substation is shown below. The future facilities are shown in dashed lines.

Figure 9-4: Proposed Layout of Existing Johnson Jct. Substation



The “northern” line of alternative 2 is proposed as a new 230 kV line from Big Stone to Willmar. The substation modifications necessary on the Big Stone end are proposed to be the same as that for alternative 1 except that the Johnson Jct. termination into the Big Stone sub will be replaced by the Willmar termination. The breaker configuration for this line on the Big Stone end can be found above in Figure 9-2. The Willmar end of this line will terminate into an existing substation jointly owned by Great River Energy (GRE), Xcel Energy (XEL), and Willmar Municipal Utilities (WMU). The termination into this substation will follow the guidelines as dictated by the existing owners. Therefore, no one-line diagram has been created for the Willmar termination for alternative 2.

Common to both transmission alternatives is the new transmission line from Big Stone to Granite Falls. There are currently plans to modify the existing Canby substation to accommodate the new 230 kV line into the substation from Big Stone. The current substation includes a 115/41.6 kV transformer with 115 kV terminations for the line from Big Stone and the line to Granite Falls. To accommodate the proposed line as part of the Big Stone II project, a new 230 kV bay will need to be created at the Canby substation with a new 230/115 kV transformer. A conceptual one-line diagram with breaker labels is included below. In anticipation of the southern line going to 345 kV, there have also been some high level thoughts on how the substation could look with the 345 kV line in-service. The modifications needed for the 345 kV line with the 345/115 kV transformer is shown as “future” facilities in dotted lines within Figure 9-5 below.

The last piece of the Big Stone II transmission plan is a termination into the Granite Falls substation. Again, this substation is owned by WAPA and the new termination into the substation will be done in accordance with their standards. Therefore, a one-line diagram has not been developed for this termination. Likewise, the 345 kV termination into the Hazel Run substation will also be owned by a third party and is not yet well enough defined to provide a one-line diagram of this termination.

9.3 Transient Stability Study Criteria

Transient events on the transmission system involve major disturbances such as a sudden loss of generation, line-switching operations, faults, or sudden load changes. Following a disturbance, synchronous machine frequencies undergo transient deviations from the synchronous frequency (60 Hz), and machine power angles change. The objective of a transient stability study is to determine whether or not the machines will return to synchronous frequency with new steady-state power angles. During recovery of the transmission system from these disturbances, certain criteria are applicable to measure the performance of the transmission system. This criterion is applicable to machine damping angles (to determine if generators remain stable), transient voltage levels, relay margins on critical transmission lines, as well as other system parameters.

The Mid-Continent Area Power Pool (MAPP) region has specific transient voltage criteria for high voltage buses following system disturbances. This criterion insures that power system performance is within NERC guidelines. The default transient voltage criterion within MAPP requires that voltages do not swing below 0.70 p.u. or above 1.20 p.u. after a disturbance clears (is extinguished). Specific buses defined in the *MAPP Members Reliability Criteria and Study Procedures Manual* have voltage limits outside those defined by the MAPP default criteria and are identified below in Table 9-1.

Table 9-1: Transient Voltage Criteria for Specific Buses (in p.u. voltage)

Bus	Transient Voltage	
	Max	Min
Dorsey 230	1.25	0.70
Forbes 230	1.15	0.82
Arrowhead 230	1.15	0.82
Riverton 230	1.15	0.82
Drayton 230	1.15	0.80
Wahpeton 115	1.18	0.80
Tioga 230	1.15	0.80

Bus	Transient Voltage	
	Max	Min
Dickinson 345	1.17	0.70
Coal Creek 230	1.18	0.70
Watertown 345	1.18	0.75
Boise 115	1.15	0.82
Ramsey 230	1.65 (5 cyc.)	0.70
Hubbard 230	1.20	0.82

Besides the specific transient voltage criteria identified in Table 9-1, there are additional criteria applied to other buses within the MAPP region. These specific transient voltage criteria are documented within the *MAPP Members Reliability Criteria and Study Procedures Manual*.

As well as monitoring transient voltages during stability studies, it is also important to insure that out-of-step (OOS) relay margins are maintained on transmission lines crossing the U.S. – Canadian border. These locations include Drayton, Fort Francis, Moranville, Rugby, and Tioga. MAPP has criteria in place to insure that cascade tripping of these interconnections does not

occur. Criteria for OOS relay margins on each of the U.S. – Canada tie lines are noted below in Table 9-2.

Table 9-2: Relay Margins for U.S. – Canada Tie Lines

	Steady State	Dynamic	
		South Flow	North Flow
OOS relay at 500 kV Dorsey bus monitoring the Dorsey-Forbes line	110%	50%	25%
OOS relay at 500 kV Forbes bus monitoring the Forbes-Dorsey line	110%	50%	25%
OOS at 230 kV Drayton bus monitoring the Drayton-Letellier line	110%	25%	25%
OOS relay at 230 kV Prairie bus monitoring the Prairie-Drayton line	110%	25%	25%
OOS relay #1 at 230 kV Moranville bus monitoring the Moranville-Richer line	110%	25%	25%
OOS relay at 230 kV Tioga bus monitoring the Tioga-Boundary Dam line	110%	25%	25%
OOS relay at 115 kV International Falls bus monitoring the Int. Falls-Fort Francis line	110%	25%	25%

Transient stability analysis for the Big Stone II interconnection study utilized a Northern MAPP Operating and Review Working Group (NMORWG) stability package, which has features enabled to identify any violations of the previously mentioned criteria during transient stability simulations.

9.4 Transient Stability Analysis Results

Siemens PTI was hired as a sub-contractor to OTP to perform the transient stability analysis of Big Stone II. Detailed results in the form of a report can be found in Appendix E. PSS/E output reports and plots from the NMORWG stability package for each fault simulated can be found within Appendices F and G, respectively.

9.5 Transient Stability Analysis Conclusion

Transient stability analysis performed for the Big Stone II interconnection study included the following interconnection alternatives:

Table 9-3: Interconnection Alternatives Included in the Transient Stability Analysis

1. Alternative 1: Big Stone - Morris 230 kV line with Big Stone-Granite Falls 230 kV in-service.
2. Alternative 2: Big Stone - Willmar 230 kV line Big Stone-Granite Falls 230 kV in-service.
3. Alternative 3: 345 kV upgrade of Big Stone Granite Falls with Big Stone – Morris 230 kV line with Buffalo Ridge – Metro (SW MN → TC EHV) 345 kV line.
4. Alternative 4: 345 kV upgrade of Big Stone Granite Falls with Big Stone – Willmar 230 kV line with Buffalo Ridge – Metro (SW MN → TC EHV) 345 kV line.

In order to identify if the Big Stone II project has an impact on the transient stability performance of the transmission system, the study was performed for all the transmission alternatives under consideration with transfers of 2080 MW and at 2450 MW across the North Dakota Export interface (NDEX). These NDEX levels represent the current definition of NDEX augmented to include the Canby – Granite Falls 230 kV line for alternatives 1 and 2, the Big Stone – Willmar 230 kV line for alternatives 2 and 4, and the Canby – Hazel (Run) 345 kV line for alternatives 3 and 4.

Two benchmark cases were developed representing 2009 summer off-peak conditions without the Big Stone II project. The benchmark case for the 345 kV alternatives included approximately 1500 MW of wind generation in southwest MN, while for the 230 kV alternatives this SW MN wind generation was reduced to approximately 825 MW.

Regional and local disturbances were simulated during the transient stability analysis. The regional disturbances included in the analysis are the worst known disturbances within the northern MAPP region. Local three-phase and single line-to-ground faults were performed on new facilities included as part of the four alternatives.

Regional disturbances simulated during the transient stability analysis resulted in high transient voltages for some buses in the Manitoba Hydro transmission system, specifically for faults MAT, OAS and NBZ. These overvoltages are not due to the interconnection of Big Stone II since they also appeared for the benchmark cases. These overvoltages are more related to the HVDC reduction scheme following a trip of the 500 kV line.

For local faults three phase and single line to ground with delay clearing were performed within the Big Stone area for the existing and new interconnection facilities. Initially for all the cases both units at Big Stone (existing and new) were delivering full output (Big Stone Unit 1 at 475 MW net and Big Stone II at 600 MW net).

Under this generation condition and for both NDEX transfers (worst condition 2450 MW):

For the 230 kV alternatives:

Alternative 1: all the local faults with the exception of FTS performed poorly showing low transient voltage violations mainly on 115 kV buses extending from Big Stone to Appleton to Canby and back around to Marietta.

Alternative 2: of the eight local faults, five showed low transient voltages mainly at these same 115 kV buses.

Additional simulations have identified that reducing the power output at Big Stone by 150 MW mitigated these transient voltage issues.

For the 345 kV alternatives, results for NDEX set at 2450 MW have shown:

Alternative 1: No voltage violations were apparent for local three phase faults, but low voltage transient violations were evident for 10 out of the 15 local single line to ground faults under evaluation. Transient stability performance of the

benchmark case indicated that only two local single line to ground faults had transient voltage violations.

Alternative 2: No voltage violations were evident for local three phase faults, but low voltage transient violations were present for 9 out of the 15 local single line to ground local faults under evaluation. Performance of the benchmark case only had two local single line to ground faults with transient voltage violations.

When power output of Big Stone II was reduced by 150 MW, the following faults still had low voltage transient violations:

fes/ges: SLGBF at Big Stone on Blair 230 kV Line with Big Stone breaker 2645 stuck

fgs/ggs: SLGBF at Big Stone on Hankinson 230 kV Line with Big Stone breaker 2455 stuck

fis/gis: SLGBF fault at Big Stone on Canby 230 kV Line with Big Stone breaker 2465 stuck

fks/gks: SLGBF at Big Stone on Willmar 230 kV Line with Big Stone breaker 2635 stuck (on Johnson Jct. 230 kV line for fks)

fms/gms: SLGBF at Big Stone South 230 kV side on 345/230 kV Transformer #1 with Big Stone breaker 2715 stuck

Prior outage conditions of local Big Stone outlet lines was also included as part of the transient stability analysis. This analysis had generation at Big Stone I reduced to 250 MW (net output per existing operating guide) and Big Stone II delivering its full capacity. During this analysis, it was apparent that some local faults are showing low voltage violations for all the alternatives while only some of them are due to the new plant. Further reduction in generation was not tested during prior outage conditions.

As noted above, transient stability analysis has identified low transient voltage violations when the Big Stone II plant is in service with either transmission interconnection alternative. Special operation procedures and/or system protection would need to be implemented after a more detailed and specific study is completed.

10.0 Short Circuit Analysis

10.1 Introduction

Short circuit analysis has been completed by system protection engineers at Otter Tail Power Company in order to determine the impacts that the proposed Big Stone II interconnection will have on fault currents on the transmission system within the Big Stone area. Unlike the steady state power flow models, the short circuit analysis uses different transmission models to find fault currents on the transmission system. In order to determine the impact of the Big Stone II interconnection to the fault currents on the transmission system, faults were simulated on the existing system and compared with the same faults after the Big Stone II interconnection was added with either transmission alternative at 230 kV and 345 kV. Comparing the fault currents with and without the Big Stone II interconnection will identify the increase in fault currents caused by the Big Stone II interconnection along with each of the 230 kV and 345 kV transmission alternatives.

10.2 Continuous Currents

The existing Big Stone 230 kV bus is a 4-breaker ring bus. In order to accommodate the additional transmission and generator, the ring bus is planning to be expanded to include five more breakers to create a breaker and a half scheme. With this configuration and the injection of generation from unit 1 and the new unit, there is approximately 1100 MW of power being injected into the 230 kV bus work at Big Stone. The existing 230 kV breakers at the Big Stone substation have a continuous current capacity of 2000 Amps, which is approximately 800 MW. Depending on the power flows through the 230 kV bus work, there may be the need to upgrade the existing 230 kV breakers to a higher rating. A detailed analysis will be necessary during the facilities study to review the power flows around the proposed 230 kV bus in order to insure that the 2000 Amp continuous rating is not being exceeded.

10.3 Fault Currents

The fault currents obtained during the short circuit analysis considered two types of faults. One type was a three-phase fault, which is an event that results in a direct connection across all three phases of a transmission circuit. The other type of fault was a single line-to-ground fault, which is an event that results in one phase of a three-phase transmission circuit being faulted (connected) directly to ground.

10.3.1 230 kV Alternatives

10.3.1.1 Three-Phase Fault Currents

The results of simulating three-phase faults with and without the Big Stone II interconnection have indicated that the largest increase in fault current will be directly within the Big Stone substation. The resultant increase in fault currents where alternative 1 is proposed to terminate into the existing transmission system are approximately 2500 Amps at the Morris 230 kV bus, 1700 Amps at the Granite Falls 230 kV bus and 700 Amps at the Granite Falls 115 kV bus. Likewise, the increases in fault currents where alternative 2 is proposed to terminate into the

existing transmission system are approximately 1800 Amps at the Granite Falls 230 kV bus, 1450 Amps at the Willmar 230 kV bus, and 800 Amps at the Granite Falls 115 kV bus. Table 10-1 illustrates the three-phase fault currents on the existing system and compares them at various locations on the system to three-phase fault currents with Big Stone II in-service for each 230 kV transmission alternative.

Table 10-1: Three-Phase Fault Currents (in Amps) with 230 kV Alternatives 1 and 2

Location of 3 Phase Fault	Existing System	Interconnection Alternative #1	Increase in Fault Current	Interconnection Alternative #2	Increase in Fault Current
Big Stone 230 kV Bus	7400	14400	7000	14000	6600
Big Stone 115 kV Bus	4420	12000	7580	11000	6580
Ortonville 230 kV Bus	---	10440	---	---	---
Ortonville 115 kV Bus	5900	9400	3500	6900	1000
Johnson Jct. 230 kV Bus	---	6630	---	---	---
Johnson Jct. 115 kV Bus	4200	5461	1261	4400	200
Morris 230 kV Bus	3830	6340	2510	4050	220
Morris 115 kV Bus	6200	6330	130	6470	270
Canby 230 kV Bus	---	5500	---	5500	---
Canby 115 kV Bus	2800	5380	2580	5370	2570
Granite Falls 230 kV Bus	6962	8650	1688	8780	1818
Granite Falls 115 kV Bus	8990	9700	710	9800	810
Willmar 230 kV Bus	4000	4380	380	5450	1450
Willmar 115 kV Bus	3270	3370	100	3420	150
Willmar 69 kV Bus	6300	6550	250	6810	510
Marietta 115 kV Bus	3230	4090	860	4030	800
Toronto 115 kV Bus	1600	2180	580	2200	600

10.3.1.2 Single Line-To-Ground Fault Currents

Investigation into the single line-to-ground faults has revealed that fault currents are much higher at the various locations in the Big Stone area than was apparent for the three-phase faults. Again, the highest single line-to-ground fault currents are apparent right at the Big Stone substation. The increase in fault currents at the substations that will connect alternative 1 to the existing transmission system are approximately 2140 Amps at the Morris 230 kV bus, 1400 Amps at the Granite Falls 230 kV bus, and 800 Amps at the Granite Falls 115 kV bus. The increase in fault currents at the substations that will connect alternative 2 to the existing transmission system are approximately 1600 Amps at the Granite Falls 230 kV bus, 900 Amps at the Granite Falls 115 kV bus, and 1000 Amps at the Willmar 230 kV bus. The following table illustrates the single line-to-ground fault currents for the existing system as well as with the proposed Big Stone II interconnection for each transmission alternative.

**Table 10-2: Single Line-To-Ground Fault Currents (in Amps) with
230 kV Alternatives 1 and 2**

Location of Single Line To Ground Fault	Existing System	Interconnection Alternative #1	Increase in Fault Current	Interconnection Alternative #2	Increase in Fault Current
Big Stone 230 kV Bus	9150	18400	9250	18000	8850
Big Stone 115 kV Bus	4970	13006	8036	12440	7470
Ortonville 230 kV Bus	---	10380	---	---	---
Ortonville 115 kV Bus	5820	10900	5080	6500	680
Johnson Jct. 230 kV Bus	---	5990	---	---	---
Johnson Jct. 115 kV Bus	3200	6368	3168	3200	0
Morris 230 kV Bus	3130	5270	2140	3250	120
Morris 115 kV Bus	5750	6130	380	5930	180
Canby 230 kV Bus	---	4920	---	4900	---
Canby 115 kV Bus	2730	6430	3700	6410	3680
Granite Falls 230 kV Bus	5950	7350	1400	7550	1600
Granite Falls 115 kV Bus	9900	10670	770	10800	900
Willmar 230 kV Bus	2400	2570	170	3400	1000
Willmar 115 kV Bus	1500	1520	20	1530	30
Willmar 69 kV Bus	2100	2130	30	2150	50
Marietta 115 kV Bus	3460	4180	720	4130	670
Toronto 115 kV Bus	1140	1440	300	1440	300

10.3.2 345 kV Alternatives

10.3.2.1 Three-Phase Fault Currents

A similar short circuit analysis has been completed for the 345 kV alternatives associated with Big Stone II. Three-phase fault currents appear to be increased near the Big Stone plant and at the termination points of each of the alternatives as compared to the 230 kV alternatives. The three-phase fault currents for both 345 kV alternatives are shown below in Table 10-3.

Table 10-3: Three-Phase Fault Currents (in Amps) with 345 kV Alternatives 1 and 2

Location of 3 Phase Fault	Existing System	Interconnection Alternative #1	Increase in Fault Current	Interconnection Alternative #2	Increase in Fault Current
Big Stone 345 kV Bus	---	6808	---	6762	---
Big Stone 230 kV Bus	7420	15878	8458	15644	8224
Big Stone 115 kV Bus	8545	11324	2779	12232	3687
Ortonville 230 kV Bus	---	11015	---	---	---
Ortonville 115 kV Bus	6093	6813	720	8149	2056
Johnson Jct. 230 kV Bus	---	6978	---	---	---
Johnson Jct. 115 kV Bus	5136	5561	425	5536	400
Morris 230 kV Bus	3906	6747	2841	4365	459
Morris 115 kV Bus	6577	6515	-62	7063	486
Canby 345 kV Bus	---	5282	---	5292	---
Canby 115 kV Bus	2809	9777	6968	9828	7019
Granite Falls 230 kV Bus	7009	12323	5314	12500	5491
Granite Falls 115 kV Bus	9036	12542	3506	12639	3603
Hazel Run 230 kV Bus	---	12366	---	12523	---
Hazel Run 345 kV Bus	---	9068	---	9115	---
Willmar 230 kV Bus	4032	4920	888	6102	2070
Willmar 115 kV Bus	3286	3536	250	3582	296
Willmar 69 kV Bus	6334	6901	567	7150	816
Marietta 115 kV Bus	3249	4596	1347	4648	1399
Toronto 115 kV Bus	1612	8178	6566	8183	6571

10.3.2.2 Single Line to Ground Fault Currents

Single line to ground fault currents were also calculated at key locations on the transmission system near Big Stone for the 345 kV alternatives. The results from this analysis indicate that the single line-to-ground fault currents are higher than the three-phase fault currents for the 345 kV alternatives. The single line-to-ground fault currents for the 345 kV alternatives are included below in Table 10-4.

**Table 10-4: Single Line-To-Ground Fault Currents (in Amps) for
345 kV Alternatives 1 and 2**

Location of Single Line to Ground	Existing System	Interconnection Alternative #1	Increase in Fault Current	Interconnection Alternative #2	Increase in Fault Current
Big Stone 345 kV Bus	---	7416	---	7372	---
Big Stone 230 kV Bus	9170	20454	11284	20149	10979
Big Stone 115 kV Bus	10008	12721	2713	13449	3441
Ortonville 230 kV Bus	---	10075	---	---	---
Ortonville 115 kV Bus	5956	6341	385	7358	1402
Johnson Jct. 230 kV Bus	---	6036	---	---	---
Johnson Jct. 115 kV Bus	3755	6448	2693	3913	158
Morris 230 kV Bus	3174	5476	261	3435	261
Morris 115 kV Bus	6026	6255	229	6351	325
Canby 345 kV Bus	---	4929	---	4939	---
Canby 115 kV Bus	2742	11343	8601	11390	8648
Granite Falls 230 kV Bus	5976	10502	4526	10718	4742
Granite Falls 115 kV Bus	9925	13626	3701	13745	3820
Hazel Run 230 kV Bus	---	10498	---	10681	---
Hazel Run 345 kV Bus	---	7396	---	7464	---
Willmar 230 kV Bus	2401	2812	411	3684	1283
Willmar 115 kV Bus	1498	1556	58	1560	62
Willmar 69 kV Bus	2100	2172	72	2186	86
Marietta 115 kV Bus	3472	4523	1051	4559	1087
Toronto 115 kV Bus	1140	7098	5958	7100	5960

System protection engineers have determined that the existing equipment on the transmission system is capable of between 30,000 to 40,000 Amps at the Big Stone substation and other substations on the OTP system. The fault currents indicated above in Tables 10-1 through 10-4 do not exceed 30,000 Amps therefore not requiring any equipment upgrades due to the increase in the fault currents caused by the addition of the proposed Big Stone II interconnection. However, coordination with neighboring transmission owners will be necessary to determine if the expected fault currents with Big Stone II in-service will cause concern with the capability of existing substation equipment.

10.4 Protection Schemes

In addition to investigating the impacts that the proposed project will have on the fault currents within the transmission system, short circuit analysis also included an assessment of the existing protection schemes on the transmission system to determine if any changes would be necessary as a result of the proposed Big Stone II interconnection. Since new transmission lines are associated with the transmission alternatives, it will be necessary to install new protective relaying at new and existing substations in order to insure that adequate protection is in place to detect faults on the new transmission lines. Since the existing 115 kV transmission system will have a different configuration with the transmission alternatives, it will also be necessary to upgrade the existing protection schemes on the 115 kV system. Alternative 1 will require updating the protective relay schemes on the Big Stone to Ortonville 115 kV line as well as the Big Stone to Canby 115 kV line since they will be modified from the existing transmission system with alternative 1. Alternative 2 will require protective relaying schemes to be updated along the Big Stone to Canby 115 kV line since it will no longer extend to Granite Falls, as it does today.

10.5 Short Circuit Analysis Conclusion

Continuous current through the proposed 8-breaker 230 kV bus at the Big Stone 230 kV substation may over duty the 2000 Amp capability of the existing circuit breakers. Additional investigation during the facilities study will be necessary to determine the breaker flows through additional simulations.

Short circuit analysis has identified that fault currents at Big Stone will approximately double with the addition of the proposed Big Stone II unit. The fault currents are still below 21,000 Amps, which is within the applicable ratings of existing equipment on the OTP system. Coordination will be necessary with WAPA and GRE to insure that existing equipment at their respective substations will be able to withstand the increased fault currents due to the Big Stone II interconnection.

The protection schemes currently in place on the transmission system near Big Stone will have to be updated to accommodate the new configuration of the system once Big Stone II is in-service. In addition to upgrading existing protection schemes, it will be necessary to install new protection on the new transmission circuits. Each of the alternatives involve different transmission lines, which will define the ultimate line sections that must be protected once Big Stone II is in-service.

11.0 Loss Analysis of 230 kV Alternatives

11.1 Introduction

A brief loss analysis was conducted for this interconnection Study using the steady state power flow models developed for contingency analysis. Areas monitored for the loss analysis focused on those control areas within the immediate Study area and those just adjacent of it.

11.2 Summer Off-peak Conditions

Table 11-1 is shown below and illustrates the loss characteristics of each interconnection alternative for the summer off-peak case studied for this proposed interconnection.

Table 11-1: Loss Analysis Results by Control Area for Summer Off-peak Conditions

Control Area	Summer Off-peak Conditions				
	All Group 2				
	Base	Alt #1	Δ MW	Alt #2	Δ MW
ALTW	181.0	186.6	5.6	186.4	5.4
XEL	592.3	634.9	42.6	637.0	44.7
MP	91.5	99.7	8.2	96.9	5.4
SMMPA	2.8	3.0	0.2	3.0	0.2
GRE	48.7	56.3	7.6	70.3	21.6
OTP	93.8	112.7	18.9	107.6	13.8
MPW	1.6	1.6	0.0	1.6	0.0
MEC	328.6	333.6	5.0	333.5	4.9
NPPD	88.4	86.1	-2.3	85.9	-2.5
OPPD	48.7	51.0	2.3	51.1	2.4
LES	4.6	4.6	0.0	4.6	0.0
WAPA	298.0	318.4	20.4	306.7	8.7
MH	241.4	240.9	-0.5	241.1	-0.3
DPC	79.2	78.9	-0.3	79.1	-0.1
Total =	2100.6	2208.3	107.7	2204.8	104.2

As can be seen from the previous table, interconnection alternative 2 was most effective in reducing system losses when the proposed generator was added to the summer off-peak models.

11.3 Summer Peak Conditions

This same type of analysis was performed for summer peak conditions. The following figure illustrates the loss characteristics of each interconnection alternative for the summer peak case.

Table 11-2: Loss Analysis Results by Control Area for Summer Peak Conditions

Control Area	Summer Peak Conditions				
	All Group 2				
	Base	Alt #1	Δ MW	Alt #2	Δ MW
ALTW	120.6	127.6	7.0	127.4	6.8
XEL	489.9	504.9	15.0	506.1	16.2
MP	69.7	73.1	3.4	71.6	1.9
SMMPA	1.3	1.3	0.0	1.3	0.0
GRE	118.7	124.8	6.1	137.7	19.0
OTP	104.8	130.3	25.5	128.9	24.1
MPW	1.3	1.4	0.1	1.4	0.1
MEC	198.8	202.5	3.7	202.2	3.4
NPPD	95.8	91.2	-4.6	91.1	-4.7
OPPD	36.5	37.6	1.1	37.6	1.1
LES	9.5	9.5	0.0	9.5	0.0
WAPA	233.2	235.5	2.3	228.1	-5.1
MH	258.6	257.8	-0.8	258.1	-0.5
DPC	65.9	64.3	-1.6	64.4	-1.5
Total =	1804.6	1861.8	57.2	1865.4	60.8

As can be seen from the previous table, interconnection alternative 1 was most effective in reducing system losses when the proposed generator was added to the summer peak models.

11.4 Loss Analysis Conclusion

Loss performance is very similar between the two interconnection alternatives, however interconnection alternative 1 reduces losses more during summer peak conditions when power pool prices are typically higher than those in the off-peak times. However, it is important to note that the interconnection models used for this analysis are highly stressed since there are several prior queued generation projects included in the model without adequate transmission thus driving losses higher than expected.

12.0 Conclusion

This report has documented the steady state contingency analysis, transient stability analysis, and the short circuit analysis results of the proposed 230 kV and 345 kV interconnection alternatives being considered with the interconnection of a new 600 MW coal-fired generator in northeastern South Dakota at the existing Big Stone site in Grant County.

These two 230 kV transmission alternatives included:

Alternative #1: New 230 kV from

- a. Big Stone to Ortonville
- b. Big Stone to Canby

With an upgrade of existing 115 kV lines to 230 kV along the following routes:

- a. Ortonville to Johnson Jct.
- b. Johnson Jct. to Morris
- c. Canby to Granite Falls

Alternative #2: New 230 kV line from

- a. Big Stone to Willmar
- b. Big Stone to Canby

With an upgrade of existing 115 kV lines to 230 kV along the following routes:

- a. Canby to Granite Falls

The two 345 kV transmission alternatives included:

Alternative #1: New 230 kV from

- a. Big Stone to Ortonville
- b. Big Stone to Big Stone 345 kV substation
- c. Hazel Run to Granite Falls

New 345 kV from

- a. Big Stone to Canby

With an upgrade of existing 115 kV lines to 230 kV along the following routes:

- a. Ortonville to Johnson Jct.
- b. Johnson Jct. to Morris

With an upgrade of existing 115 kV lines to 345 kV along the following routes:

- a. Canby to Hazel Run to connect with Buffalo Ridge – Metro (SW MN → TC EHV) 345 kV line.

Alternative #2: New 230 kV from

- a. Big Stone to Willmar
- b. Big Stone to Big Stone 345 kV substation
- c. Hazel Run to Granite Falls

New 345 kV from

- a. Big Stone to Canby

With an upgrade of existing 115 kV lines to 345 kV along the following routes:

- a. Canby to Hazel Run to connect with Buffalo Ridge – Metro (SW MN → TC EHV) 345 kV line.

Based on the overall system performance during steady state conditions, this Study has identified that the following upgrades will be necessary for connecting Big Stone II with 230 kV alternative 1.

Table 12-1: Required Upgrades for 230 kV Interconnection Alternative 1

1. Increase capacity of Morris 230/115 kV Transformer
2. Increase capacity of Big Stone to Browns Valley 230 kV Line

Implementing 230 kV interconnection alternative 2 to connect Big Stone II to the existing system will require the following upgrades:

Table 12-2: Required Upgrades for 230 kV Interconnection Alternative 2

1. Increase capacity of Ortonville to Johnson Jct. 115 kV Line
2. Increase capacity of Johnson Jct. to Morris 115 kV Line
3. Increase capacity of Big Stone to Browns Valley 230 kV Line
4. Install capacitor bank in Willmar area to mitigate low voltages

The Big Stone II participants have decided to construct the southern portion of the transmission project from Big Stone to Granite Falls to 345 kV capability with the intent that it will be operated at 345 kV in the future.

While being constructed for operation at 345 kV, the Big Stone to Granite Falls line would initially be operated at 230 kV until new 345 kV facilities are constructed in the Granite Falls area. Additional analysis has been completed with the “southern” line from Big Stone to Granite Falls operated at 345 kV and connecting into the Hazel substation, which is part of the CapX SW MN→TC EHV study. The results indicate that operating the Big Stone to Granite Falls line at 345 kV in conjunction with the EHV facilities doesn’t cause any existing Big Stone outlet facilities to overload beyond their applicable ratings for either system intact and N-1 conditions.

Building the Big Stone II transmission plan with the Big Stone – Granite Falls line at 345 kV integrates well into the regional transmission needs identified through the CapX 2020 Vision Study, the MISO Northwest Exploratory Study, and the SW MN→TC EHV study.

The Big Stone II 600 MW coal fired project has been evaluated to assess stability impacts on the MAPP/MISO transmission system.

In order to identify if the Big Stone II project has an impact on the transient stability performance of the transmission system, the study was performed for all the transmission alternatives under consideration with transfers of 2080 MW and at 2450 MW across the North Dakota Export interface (NDEX).

Transient stability analysis has identified that for all the alternatives and under the different NDEX transfer scenarios, there are several local disturbances that result in transient low voltage violations around the Big Stone area that are due in most of the cases to the addition of Big Stone II. With respect to the regional disturbances, there are three faults that produce high voltage violations in the Base Case and the different Big Stone II alternative cases on several buses in the

Manitoba Hydro system, these regional faults have in common the opening of the 500 kV line between Dorsey and Forbes.

For local faults, three phase and single line to ground with delayed clearing were performed within the Big Stone area for the existing and new interconnection facilities. Initially for all the cases both units at Big Stone (existing and new) were delivering full output (Big Stone Unit 1 at 475 MW net and Big Stone II at 600 MW net).

Under this generation condition and for both NDEX transfers (worst condition 2450 MW):

For the 230 kV alternatives:

Alternative 1: all the local faults with the exception of FTS performed poorly showing low transient voltage violations mainly on 115 kV buses extending from Big Stone to Appleton to Canby and back around to Marietta.

Alternative 2: of the eight local faults, five showed low transient voltages mainly at these same 115 kV buses.

Additional simulations have identified that reducing the power output at Big Stone by 150 MW mitigated these transient voltage issues.

For the 345 kV alternatives, results for NDEX set at 2450 MW have shown:

Alternative 1: No voltage violations were apparent for local three phase faults, but low voltage transient violations were evident for 10 out of the 15 local single line to ground faults under evaluation. Transient stability performance of the benchmark case indicated that only two local single line to ground faults had transient voltage violations.

Alternative 2: No voltage violations were evident for local three phase faults, but low voltage transient violations were present for 9 out of the 15 local single line to ground local faults under evaluation. Performance of the benchmark case only had two local single line to ground faults with transient voltage violations.

When power output of Big Stone II was reduced by 150 MW, there were still five local single line-to-ground faults that had low voltage transient violations.

For prior outage conditions and with generation at Big Stone I reduced to 250 MW (net output as per existing operating guide) and Big Stone II delivering its full capacity, some local faults are showing low voltage violations for all the alternatives. However, the Big Stone II interconnection does not seem to aggravate the existing transient low voltages violations for the three phase faults or the single line to ground faults under consideration as compared to those violations encountered when simulating the same fault on a comparable system intact case. This is likely due to the modeling of the operating guide for Big Stone I, which reduced the output of the plant from nearly 475 MW (net) to 250 MW (net).

As noted above, transient stability analysis has identified local low transient voltage violations when the Big Stone II plant is in service with either transmission interconnection alternative for

local faults. Special operation procedures and/or system protection would need to be implemented after a more detailed and specific study is completed. Furthermore, the stability analysis has indicated that Big Stone II does not have an impact on the transient stability performance of the transmission system at either the 2080 MW NDEX level or the 2450 MW NDEX level.

Short circuit analysis identified some concerns with the existing 230 kV circuit breakers at Big Stone. With the addition of the proposed Big Stone II generator to the existing 230 kV bus work and breakers at Big Stone, the output from both units may over duty the continuous 2000 Amp rating of the existing circuit breakers within the substation. Further investigation into this matter will be necessary during the facilities study.

Big Stone II's impact to the fault currents on the transmission system were also included as part of the short circuit analysis. The highest increase in fault current was noted directly at the Big Stone 230 kV bus. The fault currents are nearly double of what is present on today's system. Since these fault currents are still below the interrupting capability of the existing equipment at Big Stone, there is no need for upgrades at the plant beyond the new facilities associated with each of the transmission alternatives. Fault currents further from the Big Stone plant are not increased as much as they were locally with the addition of Big Stone II and are not expected to be of concern. However, coordination with neighboring transmission owners will be necessary to determine if existing substation equipment at Morris, Granite Falls, and Willmar will be capable of the increased fault currents with Big Stone II in-service.

Existing protection schemes on the transmission system will also need to be updated for the new configuration of the transmission system with Big Stone II in-service.

A brief loss analysis of the 230 kV alternatives during this Study has indicated that alternative 1 is more effective in delivering the generation to the existing transmission system during summer off-peak conditions while alternative 2 is has more loss savings during summer peak conditions with the proposed interconnection added to the models. The interconnection models used for this analysis are highly stressed due to several prior queued generation projects included in the model without adequate transmission, thus providing an unrealistic view of losses.

Based on the results of this interconnection Study, it appears that either alternative used to connect this generator to the system will work from a steady state contingency analysis standpoint given that the proper system enhancements are made within the direct area of interconnection. In addition, more detailed studies are needed to mitigate the low transient voltage concerns identified during the stability analysis for the local single line-to-ground and three-phase faults at Big Stone. Furthermore, relaying schemes will need to be implemented with the Big Stone II project to ensure that adequate system protection is in place with the new transmission lines being constructed as part of the project.