

# **Buffalo Ridge Incremental Generation Outlet Electric Transmission Study**

*DRAFT #2*

Transmission Outlet Analysis  
for  
Southwest Minnesota/Eastern South Dakota  
(Buffalo Ridge Area)  
Generation Additions

(0 – 600 MW beyond “825 MW”)

Volume 1

May 9, 2005

Prepared by:  
Xcel Energy

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Prepared by:  
Xcel Energy  
Transmission Reliability & Assessment

Principal Contributors:

Richard Gonzalez, PE  
Jason Standing

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## 0.0 Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of Minnesota

Richard Gonzalez  
Registration Number 18938  
May xx , 2005

## 1.0 Background & Scope of Study

This electric transmission study addresses the development of transmission outlet capacity for additional electric generation capacity which may be constructed on the Buffalo Ridge in Southwestern Minnesota or adjacent South Dakota and Iowa portions of the 'Ridge. The study effort concentrated on developing and evaluating transmission options that could

- provide several hundred MW of incremental outlet capacity
- be implemented by the 2008-2009 timeframe.

It is recognized that continued generation development on the Buffalo Ridge will ultimately require addition of major transmission facilities to enable reliable and efficient transport of large blocks of power to the load centers located to the east. This Study is for the purpose of identifying smaller-scale improvements that can be implemented while those larger transmission plans are developed.

The existing transmission system and several transmission system improvement options were evaluated to identify the steady-state (thermal and voltage) limitations which would be successively encountered if additional increments of generation capacity were installed on the Buffalo Ridge, subject to the following principal assumptions:

- a total of 825 MW of generation (nameplate rating) has already been installed prior to the period of interest;
- the pre-existing 825 MW of generation has been integrated into the power system by construction of the Southwest Minnesota "825 MW" transmission facilities:
  - Split Rock-Nobles Co-Lakefield Jct 345 kV
  - Nobles Co 345/115 kV substation
  - Nobles Co-Fenton-Chanarambie 115 kV
  - Lakefield Jct-Fox Lk 161 kV #2
  - Troy 69 kV Switching Station
  - Buffalo Ridge-Yankee-White 115 kV
  - 60% series compensation of Wilmarth-Lakefield Gen 345 kV
  - various 161, 115 & 69 kV line reconductors & rebuilds
  - various substation upgrades
- it is desired to identify the limiters which would be incrementally encountered with additions ultimately aggregating to several hundred MW of additional nameplate generation capacity.
- under both system intact and first-contingency (n-1) conditions, facility loadings and bus voltage levels will be maintained within applicable established performance criteria, for both peak and off-peak load conditions, without resorting to tripping of generation or curtailment of deliveries to load.
- all new generation located on the Buffalo Ridge will have dynamic and steady-state reactive power control characteristics (power factor controllable in range of .90 lead to .90 lag) in conformance with the 1999-vintage NSP reactive power/voltage control standard.

- Present MAPP and MISO standards and policies will continue to apply with respect to constrained interface impacts, non-degradation of existing transfer capabilities, and generation accreditation procedures.

This study's analysis does not address transient or dynamic stability. Parallel studies (MISO "Buffalo Ridge Group II Interconnection") have identified local and regional stability limitations associated with installations of additional generation in this area. The local stability limitations identified by MISO are actually of a voltage collapse nature, and are addressed in this analysis (Section 5.2 & Appendix E). The regional stability limitations identified by the MISO studies appear to only require reactive power supply facility additions remote from the Buffalo Ridge to mitigate dynamic voltage dip violations. Consequently, these dynamic stability considerations are not considered critical with respect to selection of transmission options under evaluation in this Buffalo Ridge Incremental Generation Outlet Study.

This study's analysis also does not address mitigation of all remote interface impacts. Although interfaces traditionally of relevance to the Buffalo Ridge area were monitored, it is possible that incremental loading of remote interfaces, (either existing or defined in the future) may require mitigation. In this study, it has been noted that all transmission options studied exhibit 8 - 10% incremental flow ("circulating", "inadvertent", or "loop" flow) through the Manitoba Hydro system, from west to east; this increases loading on the Winnipeg-Twin Cities 500 kV interconnection.

The technical and economic analyses were performed for the purpose of identifying a preferred plan to achieve the specific goal of providing generation outlet capacity for several hundred MW of additional generation development on the Buffalo Ridge. It is recognized that many other potential generation developments--possibly aggregating to thousands of MW--are in preliminary stages of study by various entities; these may significantly affect overall future transmission requirements in this region. Many of these hypothetical generation projects are in the Dakotas, distant from the Ridge, but would in most cases require transmission to the Twin Cities or locations beyond, and therefore may involve transmission developments passing near the Ridge. Other postulated developments are within 100 - 150 miles of the Ridge, and therefore may offer opportunities for joint outlet development. In either case, however, although those projects could involve new or upgraded transmission through or near the Ridge, those hypothetical generation proposals would be implemented after the time period of interest for the increment of Buffalo Ridge generation outlet capacity addressed in this study.

Two specific generation proposed developments are electrically close to the Buffalo Ridge, or are located between the Ridge and the Twin Cities load center. These are

- Big Stone II (600 MW)
- Mankato Calpine Phase 2 (341 MW; 667 MW total)

Big Stone 2 is proposed to be a 600 MW coal-fired addition at the existing Big Stone site. MISO has completed the "Interconnection" Study for this unit, but not a "Delivery" (Transmission Service) study. The MISO interconnection study has concluded that there are two feasible interconnection options, each of which involves developing two 230 kV outlet lines to the east. Both options involve rebuilding the Big Stone-Canby-Granite Falls 115 kV circuit to 230 kV.

For the second 230 kV outlet, one option establishes a Big Stone-Morris circuit (via rebuild or double-circuiting on existing 115 kV route), while the other option establishes a new Big Stone-Willmar 230 kV circuit.

The Big Stone-Canby-Granite Falls 230 kV development would affect the performance of Option 6 (Yankee-White-Toronto) and related options (61A and 31A6) because Toronto is connected to Canby. A significant portion of the incremental Buffalo Ridge generation outlet achieved by Option 6's connection to Toronto is by virtue of increased loading which it causes on the Canby-Granite Falls 115 kV. If this line were rebuilt to 230 kV capability, the Buffalo Ridge outlet limit arising from overload of the Canby-Granite Falls line (1490 MW for Option 6 and 1430 MW for Option 61A) would almost certainly be relaxed. However, transmission system power flow patterns would change due the

- changes in network impedance arising from the Big Stone interconnection facility improvements, and
- the addition of the Big Stone generation output.

Consequently, it is not possible to determine the degree to which the Big Stone generation addition would affect Buffalo Ridge generation outlet capability until the outlet plans for Big Stone 2 are identified in greater detail.

The outlet plans for Big Stone 2 will not be finalized until after completion of the "delivery" study later in 2005; that study will likely identify the need for significant additional transmission system improvements (beyond those identified in the interconnection study) to accommodate delivery of the output of the Big Stone 2 generation addition.

Mankato Calpine is a multi-unit gas-fired plant proposed to be connected to the Wilmarth 345 and 115 kV buses. The first stage (326 MW) is proposed for a 2006 in-service date, while the timing of the second stage is unknown. This Buffalo Ridge study presumed the Stage 1 installation is in service, and it is further presumed that the transmission outlet improvement for this facility consists of a 115 kV line from Wilmarth to Carver Co, anticipated to consist of rebuild to double circuit 115/69 kV of an existing 69 kV line. The Stage 2 development is not modeled in this study. Stage 2, if it should ever be constructed, will require significant transmission improvements, the characteristics of which are not known at this time.

Other than the Big Stone 2 and Mankato Calpine Stage 1 projects, it is not possible to accurately predict the timing, size, and number of generation projects which may actually be implemented in the region. Accordingly, this Buffalo Ridge generation outlet study was performed presuming that transmission requirements for any such additional projects will be addressed by other power system improvements, the characteristics of which would be determined through future transmission studies.

## 2.0 Conclusions & Preferred Plan

The Preferred Plan is Option 31A, which adds the following facilities:

- Nobles Co-Fenton 115 kV line #2
- Nobles Co 345/115 transformer #2
- Lake Yankton-Marshall SW 115 kV line
- Shunt capacitors at Panther, Lk Yankton, and Winnebago Jct.

This option appears to offer the best overall results with respect to

power system performance (system intact & contingent loadings & voltages)  
power and energy losses (MW and MWh)  
practicality (logistics of construction and operation)  
price (cumulative present worth cost)

This study further identified that it may also be advantageous to add the Option 6 facilities (Yankee-White 115 kV line #2 and White-Toronto 115 kV line), particularly if more than 400 MW of incremental outlet were desired. These Option 6 facilities create additional Buffalo Ridge outlet capability, and also

- effectively address the Yankee voltage stability limitation;
- yield a beneficial reduction in power system losses;
- “open up” more of the northern portion of the Buffalo Ridge to generation development;
- provide some incidental load-serving benefit to the Toronto/Hetland Jct area
- reduce Buffalo Ridge area generation power injection into the WAPA 345 kV system.

If the Option 6 facilities are not implemented, a separate “Yankee fix” is needed if the total demand for Yankee generation outlet exceeds approximately 250 MW.

### 3.0 Study History & Participants

Following a kick-off meeting in October, 2004, progress review meetings were held periodically during the study's progress:

October 28, 2004	Sioux Falls, SD	MRES Offices	(kickoff meeting)
November 23, 2004	Minneapolis, MN	Xcel Energy Offices	
December 20, 2004	Sioux Falls, SD	MRES Offices	
January 14, 2005	Sioux Falls, SD	MRES Offices	(adjacent to MAPP MB SPG meeting)
March 3, 2005	Sioux Falls, SD	MRES Offices	(adjacent to MAPP MB SPG meeting)

In addition to the Study Group meetings, updates were also presented to the MAPP Missouri Basin (MB) and Northern MAPP (NM) Sub-regional Planning Groups (SPGs) during their regularly-scheduled meetings.

The Buffalo Ridge Incremental Generation Outlet study group benefited from participation of technical staff of the following transmission entities:

ALT	Alliant Energy	Dubuque, IA
BEPC	Basin Electric Power Coop	Bismarck, ND
EREPC	East River Electric Power Coop	Madison, SD
GRE	Great River Energy	Elk River, MN
HCPD	Heartland Consumers Power District	Madison, SD
MDU	Montana-Dakota Utilities	Bismarck, ND
MRES	Missouri River Energy Services	Sioux Falls, SD
NWPS	Northwestern Public Service	Huron, SD
OTP	Otter Tail Power Co	Fergus Falls, MN
WAPA	Western Area Power Administration	Billings, MT
XEL	Xcel Energy	Minneapolis, MN

Participation was also solicited and received from state (Minnesota, North Dakota, and South Dakota) regulatory bodies and interested environmental and energy policy advocacy groups. Also in attendance at some meetings were representatives of generation development entities, trade groups, and representatives or consultants for transmission service customers.

Xcel Energy technical staff and consultants performed the powerflow simulations, economic analyses, and tabulation of results. These results were presented and reviewed at the study group's meetings, at which comments, conclusions, and recommendations were developed to guide each successive stage of analysis.

The first draft of this study report (dated February 28, 2005) was reviewed at the March 3, 2005 meeting; based on the comments received at that meeting and at the MAPP Missouri Basin Sub-Regional Planning Group meeting also held on March 3, 2005 a second draft (dated May 9, 2005) was distributed to the Study Group and reviewed at the May 17, 2005 MB SPG meeting.

## 4.0 Analysis

### 4.1 Models Employed

The powerflow models employed were developed by the SW MN/SE South Dakota transmission study group. The models are based on the 2001 Series MAPP models, as updated

- 1) by MISO for the Buffalo Ridge Combined Study Group II (CS-2) interconnection evaluation studies;
- 2) by the Study Group to reflect any additional system improvements (primarily reconductors, shunt capacitors additions, and station equipment upgrades) which have either already been completed, or are planned to be in service by 2007 summer.

Appendix M provides a detailed listing of modeling assumptions employed.

### 4.2 Conditions Studied

The technical analysis was performed based upon Year 2007 powerflow models. The base models were adjusted to represent the latest available forecast data for summer season peak (100%) and off-peak (70%) load conditions. The off-peak model simulates a high transfer condition corresponding to approximately 90 - 95% of the presently-recognized simultaneous North Dakota/Manitoba transfer limit as established by the Northern MAPP Operating Review Working Group (NMORWG), while the on-peak model represents only identified firm power transactions.

Table 1

Condition	load level	NDEX <sup>1</sup>	MHEX <sup>2</sup>	MWSI <sup>3</sup>	Net generation, MW					
					Wind	Anson	Path-finder	Minn Valley	Lake-field	Fibrominn
Peak	100 %	1167	1681	1058	918	232	0	0	550	50
Off-peak	70 %	1850	1982	1051	918	232	0	0	550	50
NMORWG Limit:		1950	2175	1480						

Powerflow diagrams for the base cases and relevant contingencies are provided in Appendix C.

Some sensitivity analysis was also performed with Anson generation at the 232 + 170 MW level, to investigate incremental effect of the Year 2005 addition of Anson Unit 4. Although this is a peaking unit, the Anson site is sufficiently near the Buffalo Ridge generation locations to warrant an examination of simultaneous operation during off-peak “pool emergency” conditions when Anson may be called upon to operate at full capacity, to “deliver reserves to the pool”. This Anson sensitivity analysis is provided in Section 5.7.

#### Notes

- 1) NDEX = sum of flows on the 18 lines comprising the “North Dakota Export” Boundary;
- 2) MHEX = sum of flows on the 4 Manitoba Hydro-U.S. 230 & 500 kV tie lines;
- 3) MWSI = sum of flows on Minnesota-Wisconsin Stability Interface (Prairie Island-Byron, Eau Claire Arpin 345 kV)

### 4.3 Options Evaluated (Maps in Appendix A)

The following transmission improvement options were evaluated:

Option 1 “Nobles Co-Chanarambie 115 kV #2”

This option establishes a second Nobles Co-Chanarambie 115 kV line and installs a second 345/115 kV transformer at the Nobles Co Substation.

Option 1A “Nobles Co-Fenton 115 kV #2”

This option establishes a second Nobles Co-Fenton 115 kV line and installs a second 345/115 kV transformer at the Nobles Co Substation.

Option 2 “Lyon Co-Minn Valley 115 kV #2”

This option establishes a second 115 kV line from Lyon Co Sub to Minn Valley. This is achieved by rebuilding the existing Lyon Co-Yellow Medicine-Minn Valley 69 kV line at 115 kV.

Option 3 “Lake Yankton-Marshall 115 kV”

This option establishes a new Lake Yankton-Marshall SW 115 kV line.

“Marshall SW” is a new 115 kV substation proposed to be added in southwest Marshall by Marshall Municipal to address future distribution system supply needs. It is envisioned to be connected to an extension of the existing Marshall 115 kV loop between the existing Saratoga and “Southeast” substations.

Option 4 “Lyon Co-Franklin 115 kV”

This option establishes a new outlet line from the Marshall area eastward to the Redwood Falls/New Ulm vicinity by constructing a new Lyon Co-Franklin 115 kV circuit. All but 8 miles of this 44-mile route would consist of rebuild of existing 69 kV to 115 kV or double-circuit 115/69 kV configuration.

Option 5 “Chanarambie-Watonwan Jct 115 kV”

This option constructs a new Chanarambie-Watonwan Jct 115 kV line. This development presumes the Lakefield Gen-Watonwan Jct 115 kV line (presently proposed for 2007 in service) has already been installed for load-serving purposes. If not already installed, it would need to be added (at additional cost) to this option’s facilities.

Option 6 “Yankee-White-Toronto 115 kV”

This option upgrades establishes a second Yankee-White 115 kV line, and adds a White-Toronto 115 kV line.

Option 7 “Yankee-Lyon Co 115 kV”

This option establishes a new Yankee-Marshall SW-Lyon Co 115 kV line.

Option 8 “Yankee-Lyon Co-Franklin 115 kV”

This option establishes a new Yankee-Marshall SW-Lyon Co-Franklin 115 kV line.

Option 9 “Reconductors only”

This option upgrades all existing facilities as necessary to alleviate overload conditions. This tactic consists of reconductoring any overloaded lines and addressing any transformer overloads by replacement with a higher-capacity unit, or installation of an additional unit.

For Options 1 – 8, any overloads still observed following addition of the new facilities are generally addressed by upgrading the affected lines or transformers as required. In one case (Option 3) an additional 115 kV circuit (Nobles Co-Fenton 115 kV #2) and an additional transformer (Nobles Co 345/115 #2) were added because such an addition economically eliminates the need for multiple other projects.

For Option 9, all overload conditions are addressed by reconductoring the affected lines and replacing/augmenting overloaded transformers.

The above transmission Options were designed to be representative of a broad range of theoretically possible power system improvement strategies within the range of the “modest, quickly implementable” concept. In addition to these “simple” options, several “combination” options were also developed, following the “first cut” evaluation of the above Options. The combination options were developed and examined to determine whether it may be advantageous to implement more than one of the originally-identified transmission options.

Although a large number of other combinations of improvements could be concocted, their individual performance characteristics would not differ substantially from that of one of the of the representative options studied.

#### Note on “White Substation”.

Throughout this report, reference is made to the White 345/115 kV substation. During the course of this study, engineering work was begun on design of the Buffalo Ridge-Yankee-White 115 kV facilities which are part of the “825 MW” Buffalo Ridge outlet development plan. Due to certain WAPA concerns and MISO suggestions, it was decided to install a separate 345/115 kV transformer at “White” as a dedicated step-up for the Yankee-White 115 kV line. Subsequent site investigation led to the conclusion that these new 345/115 kV facilities would best be accommodated in a separate Xcel Energy substation adjacent to the existing WAPA White Substation. This new Xcel Energy 345/115 kV substation has been named *Brookings County Substation* (“Brookings Co”).

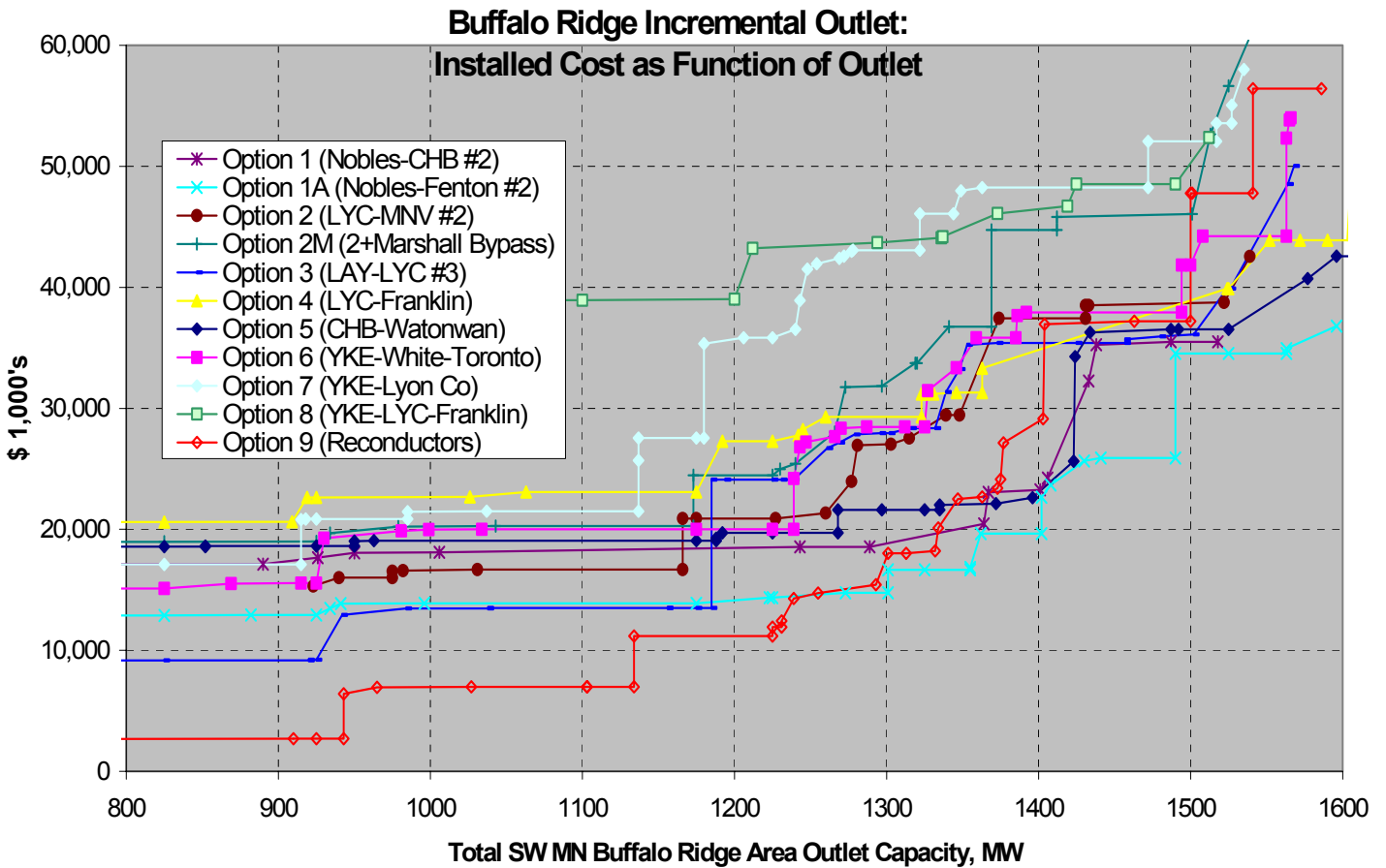
Accordingly, all references in this Report to new lines or transformers connecting to “White” should be interpreted as referring to the proposed new Brookings Co Substation.

#### 4.4 "First Cut" Screening

To keep the amount of technical analysis required at a manageable level, a "first cut" screening analysis was undertaken in an attempt to identify any facility addition Options which were technically or economically significantly weaker than the others, and for which further detailed analysis would not be warranted. Graphs 1, 2, and 3 show the results of the initial screening analysis.

Graph 1 shows each Option’s installed cost as a function of total Buffalo Ridge outlet capacity achieved.

Graph 1

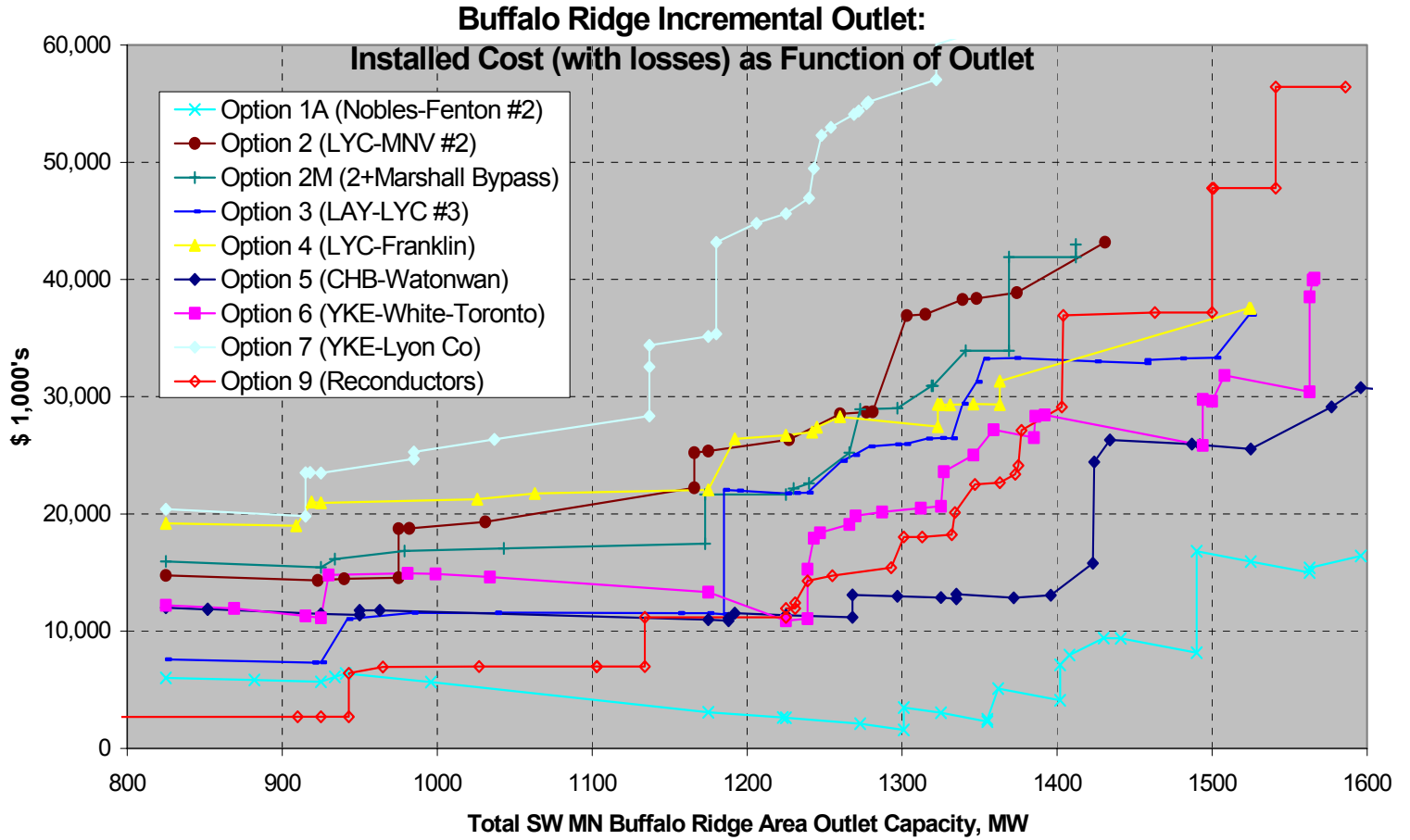


Graph 1 shows that

- Option 9 (Reconductors) is least-cost until approximately 1240 MW of Buffalo Ridge total outlet; Option 1A is least-cost beyond this level;
- Options 7 and 8 are highest-cost;
- Option 3 is relatively economical until approximately 1180 MW, at which point it suffers a large step increase in cost.

A more revealing comparison is achieved if one also takes into consideration the economic value of energy and capacity loss differences between the Options. Graph 2 shows each Option's evaluated cost, taking into account installed cost and losses. (Refer to Section 5.6 for details of loss value derivation).

Graph 2

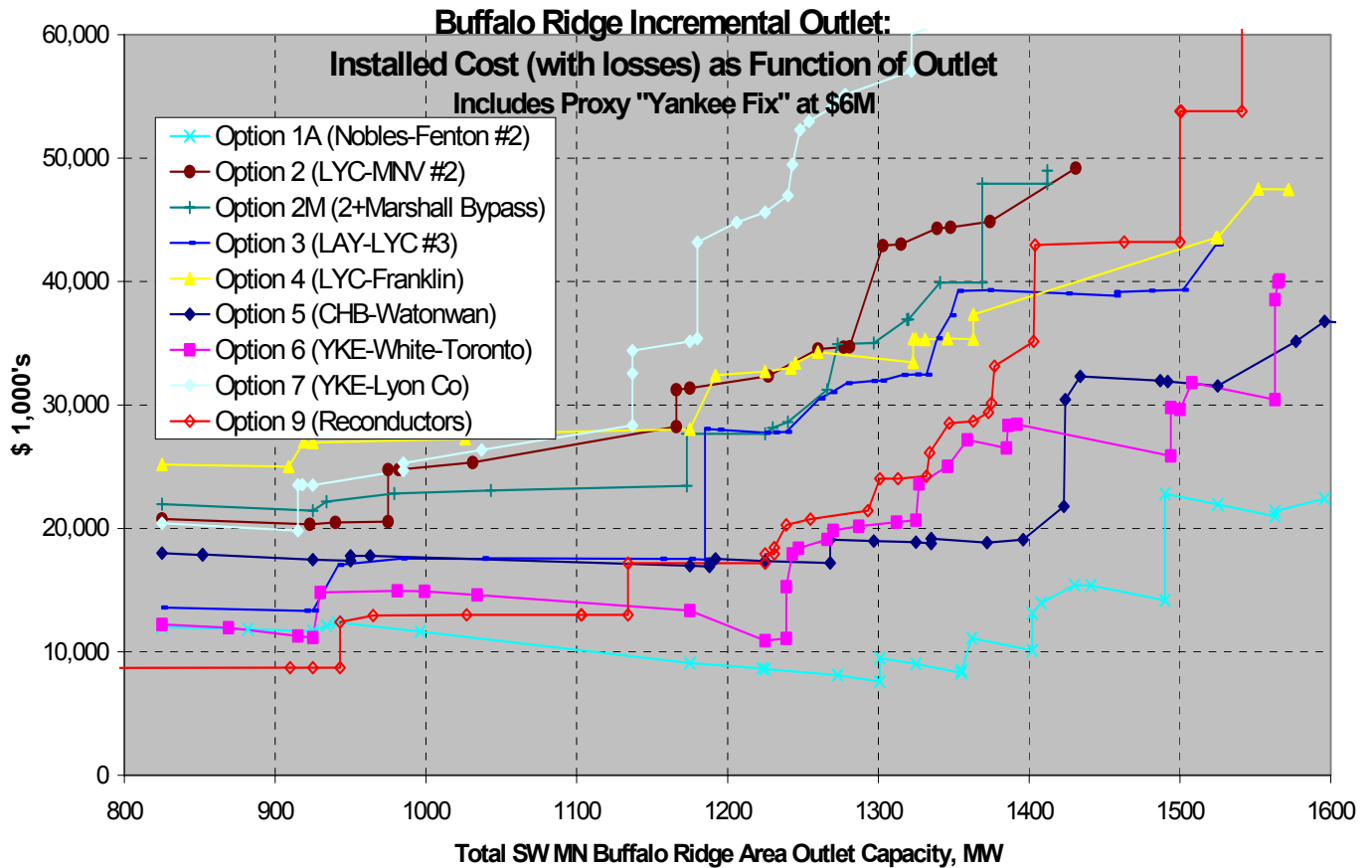


Graph 2 shows that adjusting for losses,

- Option 1A becomes least-cost at approximately 940 MW;
- Option 5 is more economical than Option 9 at outlet levels greater than 1240 MW;

Graph 3 shows the effect of taking into account also the cost of “Yankee” and “Marshall” fixes. (Refer to Sections 5.2 and 7.11 for details of Yankee and Marshall considerations.)

Graph 3



Graph 3 shows that considering installed cost, losses, and Yankee fix:

- Option 1A is least-cost at all levels beyond approximately 940 MW;
- Options 2, 2M, 7, and 8 are substantially more costly than the other Options

It was also observed that Option 1 (Nobles Co-Chanarambie) is always higher-cost than Option 1A (Nobles Co-Fenton). Since 1A could later be extended from Fenton to Chanarambie if desired, it was decided that Option 1 should be dropped from further explicit analysis.

Accordingly, it was decided to drop Options 1, 2, 2M, 3, 4, 7, 8 from further consideration.

The remaining Options retained for further evaluation were 1A, 3, 5, 6, and 9.

#### 4.5 Performance Evaluation Methods

Power system performance simulation was performed with the aid of the PSS/E digital computer powerflow program (Version 29) as supplied by Power Technologies, Inc. System intact and first-contingency analysis was performed primarily via the PSS/E activity TLTG (“Transfer Limit Table Generator”). TLTG performs automated contingency analysis while progressively incrementing power transfer between a defined “source” and “sink” location.

For both the TLTG analyses, the following apply:

Monitored facilities:

All transmission lines and transformers 69 kV and above in the model areas:

NSP (Xcel)	WAPA
Alliant	OTP
MEC	SMPMA
GRE	

Study area (facilities subject to outage):

All transmission lines and transformers 69 kV and above in the model zones:

NSP (Xcel) SW Minnesota/SD & NW Region	WAPA
Alliant	OTP
MEC	SMPMA
GRE (SW Minnesota)	

Appendix G contains the input data file describing the above facilities.

Activity TLTG achieves computational efficiency by extensive use of Power Transfer Distribution Factors (PTDFs) and Line Outage Distribution Factors (LODFs), concepts applicable to linear, time-invariant systems. These methods are appropriate for power system analysis, provided it is recognized their accuracy is constrained by their inherent limitations arising from non-linear effects such as exhaustion of reactive power supply and LTC transformer range limits. Consequently, the resultant reported transfer limits from TLTG are thus approximate.

Facilities identified in the TLTG outputs are considered valid limiters if they...

- ◆ have a PTDF of 2.0% or greater (system intact) or
- ◆ have an OTDF of 2.0% or greater (outage condition).

This 2.0% criterion was selected in accord with the MAPP Design Review Subcommittee (DRS) preliminary selection of this cutoff level for system impact analyses, and also independently in recognition that at PTDFs or OTDFs lower than 2%, very large reductions in generation (over 50:1) are required in order to achieve a perceptible amount of loading relief. Consequently, PTDFs/OTDFs lower than 2% strongly indicate that other power system adjustments are likely to be much more effective in producing the desired ameliorative effect than would generation adjustments in the study area. Refer to Section 5.3 for further discussion on evaluation of incremental loadings on constrained interfaces (“flowgates”) and non-flowgate facilities.

## 5.0 Results of Detailed Analyses

### 5.1 Powerflow (System Intact & Contingency)

Appendix C provides the "raw" TLTG outputs for the transmission Options.

Appendix B contains summary tables derived from the "raw" TLTG output tables in Appendix C. These tables in Appendix B list only limiting facilities exceeding the 2% PTDF/OTDF cutoff.

For each limiting facility identified, the proposed corrective action is listed in the "Remedy" column. In most instances, an overloaded line is proposed to be reconductored and an overloaded transformer is proposed to be replaced with a larger unit. However, in some cases rather than upgrade the overloading facility, it was determined advantageous to instead neutralize the contingency causing the overload. This is accomplished by constructing another circuit either directly in parallel with the circuit whose outage is the limiting condition, or by adding a new transmission path which provides loading relief to the affected line or transformer.

For example, in Option 3 from the raw TLTG output it was observed that outage of the new 345/115 kV transformer at the Nobles Co substation, or the 115 kV line from Nobles Co to Fenton would result in overload of the Marshall East River-Granite Falls 115 kV line at the  $918 + 238 = 1156$  MW level, Pipestone-Pathfinder 115 kV line at  $918 + 267 = 1185$  MW, and Erie Rd-S3 115 kV at  $918 + 313 = 1231$  MW. Furthermore, overload of the Nobles Co 345/115 kV transformer is possible during system intact conditions at the  $918 + 321 = 1239$  MW level. To address all these overload potentials in the most economical manner, rather than reconductor all the potentially affected circuits, it is logical to instead install a second Nobles Co-Fenton 115 kV line and a second Nobles Co 345/115 kV transformer at the 1156 MW level.

### 5.2 Yankee Voltage Stability Analysis

The "825 MW" set of Buffalo Ridge area transmission improvements presently being implemented are designed to increase generation outlet capability from the Southwest Minnesota portion of the Buffalo Ridge to 825 MW. Recent MISO generation interconnection study reports ("Buffalo Ridge Group 2") have confirmed that if additional increments of generation in excess of this 825 MW design level were to be installed, several power system performance limitations would be encountered. One of the limiting conditions is voltage collapse (or dynamic instability) in the Yankee/Buffalo Ridge Substation vicinity following tripout of either the Brookings Co 345/115 kV transformer or the Yankee-White (Brookings Co) 115 kV line.

A similar voltage collapse potential also exists (at Fenton generation levels beyond 200 MW) on the southern portion of the Buffalo Ridge, at Fenton/Chanarambie following outage of either the Nobles Co 345/115 kV transformer or the Nobles Co-Fenton 115 kV line. Option 1A and related "combination" Options (31A, 61A, 71A, 31A6) directly address this limitation by adding a second Nobles Co 345/115 kv transformer and by establishing a second Nobles Co-Fenton 115 kV line, while Option 5 creates an additional Chanarambie outlet line (Chanarambie-Watonwan Jct 115 kV).

The analysis provided in Appendix L provides an evaluation of three transmission options formulated to address the Yankee voltage stability limitation. In addition to the three “add wires” options, another option that may be feasible is the installation of a Static VAR Compensator (SVC) at the Buffalo Ridge Substation. Confirming the feasibility of the SVC solution would require additional technical analysis; however, based on the reactive study work summarized in Appendix L, it is already known that an SVC designed to permit installation of at least 100 MW of additional generation at Yankee (total of 300 MW) would need to have a rating of approximately  $\pm 80 - 100$  MVAR and would likely have an installed cost of 5 - \$6 million. This is comparable to the estimated cost of the least-cost “wires” option, which is addition of a second Buffalo Ridge-Lk Yankton 115 kV line.

Identification of the preferred “Yankee fix” is not necessary during the initial comparison of the Buffalo Ridge Area transmission Options; rather, it is only necessary to add a \$6 million cost assessment to any Buffalo Ridge area generation outlet options that do not provide a “Yankee fix” by dint of establishing an additional Yankee 115 kV outlet line (to White/Toronto as in Options 6, 61A, and 31A6, or to Marshall as in Options 7 and 71A). This \$6 million cost assessment is a proxy for the cost of implementing a Yankee fix (of undetermined type; either “wires” or SVC) for those Options requiring it.

It is important to note that for Yankee outlet levels over 300 MW, the SVC option would quickly become more expensive than a “wires” option, and for levels significantly beyond 300 MW, the addition of a second Buffalo Ridge-Lk Yankton 115 kV line is also not adequate. Consequently, for very high levels of Yankee generation outlet (approximately 350 MW or more) it is necessary to construct a second Yankee-White 115 kV line, plus either a second White 345/115 kV transformer (option 31AB), or a White-Toronto 115 kV line (Option 31A6).

### 5.3 Constrained Interface Analysis

#### 5.30 General

Presently the MAPP criteria relating to constrained interfaces are:

1. Increased loading of identified interfaces is permitted, provided adequate ATC (Available Transmission Capacity) exists to accommodate the incremental interface loading.
2. If the ATC is already zero or negative, or would become negative due to the transaction, incremental loading is permitted, provided that
  - ◆ the incremental loading is less than 5% of the transaction amount (PTDF less than 0.05), --or--
  - ◆ the incremental impact is 1.0 MW or less,
  - ◆ --or--
  - ◆ a mitigation plan is provided.
3. For facility additions (no incremental generation or power transfers) the incremental loading must not exceed 1.0% of the interface's TTC (Total Transfer Capability).

MISO Criteria are similar, but different; a comparison of applicable MISO and MAPP criteria for power transfers is provided in the table below.

Table 2  
Impact Assessment Criteria for Incremental Power Transfers

<u>Affected Facility type</u>	<u>Distribution Factor, %</u>		<u>Threshold</u>	
	<u>MAPP</u>	<u>MISO</u>	<u>MAPP</u>	<u>MISO</u>
Line or Transformer (non-flowgate) system intact	2.0	5.0	1 MW	0 MW
Line or Transformer (non-flowgate) outage	2.0	3.0	1 MW	0 MW
Flowgate (PTDF type)	5.0	5.0	1 MW or 2% of TTC	0 MW
Flowgate (OTDF type)	3.0	3.0	1 MW or 2% of TTC	0 MW

The above criteria apply to new power transactions, and generation additions, or more precisely, the deliveries of power from such generation additions.

Different criteria apply to addition of transmission facilities without associated new transactions or generation additions. Since there is no power transfer involved, it is not possible to compute a distribution factor (PTDF or OTDF). Rather, only the MW incremental facility loading is examined. MAPP’s criterion is 2.0% of a non-flowgate’s rating, and 1% of a flowgate’s TTC, each with a 1 MW threshold.

Appendix F provides tables summarizing

- ◆ the incremental system-intact interface flows (MW) for the line additions, and
- ◆ the resultant PTDFs for the generation additions, presuming the line additions to have already been completed.

The entries in Table F include the effect of the addition of 60% series compensation to the Wilmarth-Lakefield 345 kV line, as this is component of the “825 MW” SW Minnesota transmission upgrades, and is incorporated in all the powerflow models used in this Buffalo Ridge Incremental Generation Outlet Study.

From these tables it is concluded that the transmission Options are not expected to create any new concerns with regard to incremental loading of constrained interfaces in the MAPP region. All incremental flows and distribution factors are below the applicable acceptance criteria. This result was anticipated because none of the Options involves addition of major transmission facilities; consequently, the power flow patterns through the transmission network are not significantly affected. All the Options yield reduced loading on the MWSI interface, due to the presumed Twin Cities “sink”.

Despite the above review of incremental loadings, two interfaces must nevertheless be given special consideration: NDEX and MHEX.

### 5.31 NDEX (North Dakota Export)

The North Dakota Export interface (NDEX) consists of eighteen 345, 230, and 115 kV lines. The NDEX Total Transfer Capability (TTC) MW loading limit is based on dynamic stability considerations.

#### Option 6: White-Toronto 115 kV line

The White-Toronto 115 kV line, which is a feature of Option 6 and the related “combination” Options (61A and 31A6) creates a new North Dakota Export (NDEX) tie line. No significant change in total NDEX loading occurs, as all incremental flows into NDEX on the new tie line have compensating flows out of NDEX, since all incremental generation is modeled as delivered to the Twin Cities. The small changes observed in NDEX are due to changes in system losses; any noted increase (decrease) in NDEX loading is caused by reduced (increased) losses within the NDEX boundary.

The addition of a new NDEX tie line does not imply or guarantee achievement of any increase in NDEX capability. NDEX is a stability-constrained interface; accordingly, dynamic stability analysis is required in order to evaluate whether any NDEX increment might have been achieved. Any such improvement is apt to be relatively small, as addition of a 115 kV tie line will not significantly affect bulk system loadings and resultant power system dynamic performance for the regional EHV disturbances which presently establish the NDEX limit.

#### Impact of recent NDEX increase to 2080 MW

Section 5.8 addresses the principal incremental impacts of the recently-approved (by MAPP DRS) 130 MW increase in North Dakota Export limit (from 1950 MW to 2080 MW). The effect of the increased NDEX limit is to accelerate the need for the Granite Falls-Minn Valley-Panther 230 kV reconductors. A more subtle effect is increased post-contingent loading on the Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV line, which has already been identified as in need of upgrade due to the considerations covered in Section 5.9 and Appendix N.

### 5.32 MHEX (Manitoba Hydro Export)

The Manitoba-U.S. transmission interface (MHEX) consists of one 500 kV and three 230 kV lines:

- Dorsey-Roseau Co-Forbes 500 kV
- Letellier-Drayton 230 kV
- Glenboro-Rugby 230 kV
- Richer-Roseau Co-Moranville 230 kV

The permissible interface MW loading in the southward direction is limited by the thermal ratings of the various circuits, and also by power system dynamic stability considerations.

Referring to Table 3, it is observed that regardless of which Buffalo Ridge “incremental” outlet improvement plan is implemented, approximately 8 - 10% of the Buffalo Ridge-->Twin Cities

power delivery flows northward to Manitoba on the Rugby-Glenboro and Letellier-Drayton 230 kV lines, and then southward on the Dorsey-Roseau Co-Forbes-Chisago Co 500 kV.

Although this throughflow does not increase the measured MHEX value (since the flow is measured both incoming and outgoing), it does increase loading on the Dorsey-Roseau Co-Forbes-Chisago 500 kV line segments. This increased loading is a concern because the existing 2175 MW TTC value for the MHEX interface loadability limit is based, in part, on the loading limit of the 500 kV interconnection, which is presently dictated by the 2000 amp (1732 MVA) continuous rating of the Roseau Co series capacitors.

Table 3  
Incremental flows on Winipeg-Twin Cities 500 kV System  
(PTDFs for Buffalo Ridge-->Twin Cities Power Transfers)

<u>Option</u>	<u>% of Buffalo Ridge--&gt;Twin Cities delivery</u>	
	<u>Dorsey-Forbes</u>	<u>Forbes-Chisago</u>
0	8.1	9.9
1A	8.0	9.7
2	8.1	9.9
3	8.1	9.9
4	7.9	9.7
5	7.8	9.5
6	8.2	10.1
7	8.0	9.9
31A	8.0	9.8
61A	8.1	9.9
71A	7.9	9.7
31A6	8.1	9.9

During periods of high NDEX loading, the MHEX interface flows are biased more heavily onto the Dorsey-Forbes 500 kV line. Incremental Buffalo Ridge--> Twin Cities power deliveries cause further loading of the Dorsey-Forbes 500 kV line, and also the Forbes-Chisago 500 kV line. Since the present 2175 MHEX TTC value is based upon the series capacitors being at their 2000 amp loading limit, any incremental loading due to throughflows would be expected to result in a reduction in MHEX TTC value, unless provision were made for accommodating such incremental loadings.

Preventing deterioration of MHEX TTC would require either prevention of the Buffalo Ridge throughflow, or increase in 500 kV system loadability; these options are discussed in the following paragraphs.

Prevention of Buffalo Ridge-instigated throughflow

This option would involve installation of phase shifting transformers on the Glenboro-Rugby and Letellier-Drayton 230 kV lines. These transformers would have the ability to prevent the incremental northward flows on these two 230 kV circuits which combine to form the incremental southward flow on Dorsey-Forbes 500 kV. To coordinate with the lines' winter ratings, these transformers would each need to have a continuous rating of approximately 550

MVA; installed cost would be approximately \$5 - 7 million each, for a total cost of approximately \$10 - 14 million.

#### Increase 500 kV loadability

This option would accommodate increased loading on the Winnipeg-Twin Cities 500 kV system. This involves

- upgrading the Roseau Co and Chisago Co 500 kV series capacitors. The 500 kV series capacitor banks were designed to facilitate future upgrade from 2000 to 2500 amps; this upgrade would increase their MVA “through” rating from 1732 to 2165 MVA.
- Installing additional shunt capacitors on or adjacent to the 500 kV system to compensate for the incremental reactive power consumption on the 500 kV system.

Upgrade of the three series capacitor banks (2 at Roseau Co, 1 at Chisago Co) would cost a total of \$3 - 6 million. Provision of additional shunt capacitors would cost \$3 - 5 million, depending on the amount of MVAR required, and the voltage at which it would be installed (500 vs. 345, 230, or 115 kV). In addition to facilitating Buffalo Ridge generation outlet, there would likely be some relatively minor incidental benefits achieved with regard to MHEX and NDEX capabilities.

#### 5.33 Constrained interface considerations for Yankee Fix

In addition to the principal transmission options under evaluation in this study, the Tables in Appendix F also have entries for a version of Option 31A which incorporates a “Yankee fix” option proposed by MISO. This “Option 31AB” is based on Option 31A, with the addition of a second Yankee-White 115 kV line and a second White (Brookings Co) 345/115 kV transformer. Consequently, this Option is similar to Option 31A6, but with a second White 345/115 kV transformer instead of the White-Toronto 115 kV line.

The distribution factor table in Appendix F shows that Option 31AB causes increased loading on the Ft Cal S flowgate but that the resultant distribution factor of 3.2%, although the highest of all Options studied, is still below the applicable 5.0% criterion. In contrast, Option 31A has a distribution factor of 2.9% and Option 31A6 has a distribution factor of 3.0%. Considering variability in results which can result from differing modeling assumptions and future generation and transmission facility additions, Option 31AB presents more risk of exceeding the 5.0% criterion (or any future replacement value for the present 5.0% cutoff) than the other “Yankee fixes” studied.

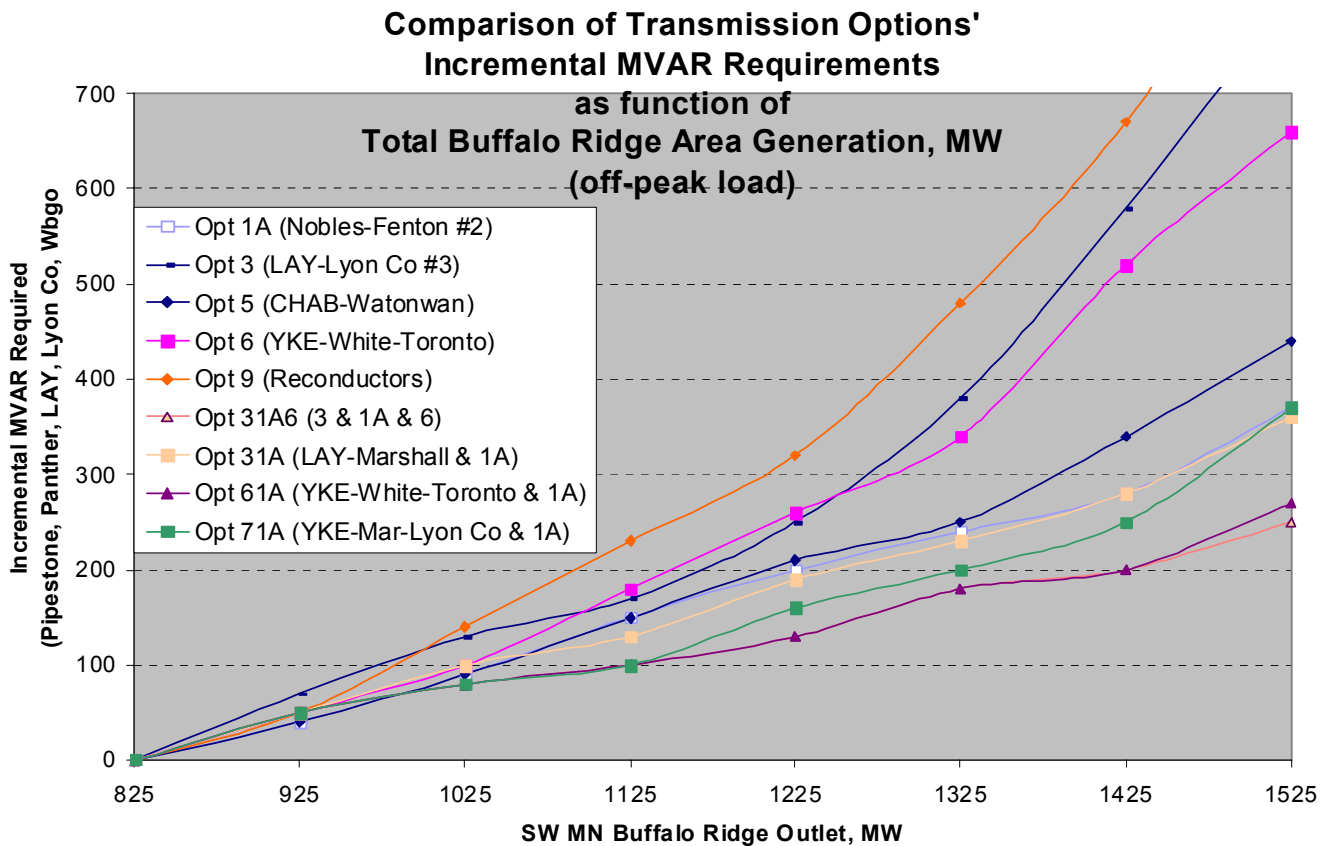
## 5.4 Reactive Power Requirements

Individual powerflow simulations were performed at the 925, 1225, and 1425 MW outlet levels to determine reactive requirements for each Option. The four most-severe Buffalo Ridge outlet contingencies were examined:

- Nobles Co 345/115 transformer
- White (Brookings Co) 345/115 kV transformer
- Lakefield Gen-Wilmarth 345 kV
- Wilmarth-Blue Lk 345 kV

A full tabulation of the reactive results is provided in Appendix D. Graph 4 summarizes these results; it shows that the transmission Options under evaluation exhibit significant differences with respect to reactive power requirements.

Graph 4



The options which rely principally on increased loading of existing or upgraded circuits (Options 9, 3, and 6) have relatively high incremental reactive requirements due to the lines' and transformers'  $I^2X$  reactive power consumption, whereas lower reactive requirements are noted for the Options which establish a new (Option 5) or reinforced 115 kV path (Option 1A) from the Buffalo Ridge area. The “combination” Options, which add two or three new 115 kV circuits, have the lowest reactive requirements.

Table 4 provides detail of the reactive requirements summarized on Graph 4, for the 1425 MW outlet level. Further detail is provided in the tabulation in Appendix D.

**Table 4**  
**Incremental Reactive Power Requirements**  
**(Evaluated at 825 + 600 = 1425 MW)**

Option	Buffalo Ridge Generation (MW)	Reactive Requirement, MVAR					Total
		Pipestone	Panther	Lake Yankton	Lyon Co	Winnebago Jct	
0 (existing system)	825	0	0	0	0	0	0
1A (Nobles Co-Fenton #2)	1425	0	120	80	0	80	280
3 (Lk Yankton-Lyon Co #3)	1425	240	120	100	60	60	580
5 (CHB-Watonwan Jct)	1425	40	120	100	0	80	340
6 (Yankee-White-Toronto)	1425	180	150	100	30	60	520
9 (Reconductors)	1425	300	120	100	90	60	670
31A	1425	0	120	100	0	60	280
61A	1425	0	120	20	0	60	200
71A	1425	0	150	40	0	60	250
31A6	1425	0	120	20	0	60	200

Notes:

1. Post-contingent reactive requirements based on holding post-contingent bus voltages to 0.95 pu.
2. Lk Yankton requirements listed are MVAR in excess of the existing 4 x 20 MVAR capacitor banks.
3. Lyon Co requirements listed are MVAR in excess of the existing 2 x 30 MVAR capacitor banks.

Regardless of which transmission option is selected for implementation, additional shunt capacitive compensation must be provided. Selecting Option 31A or Option 31A6 requires 100 MVAR of shunt compensation in order to achieve the 1125 MW level of Buffalo Ridge outlet, and at least 200 MVAR to achieve the 1425 MW level. All other Options require yet-higher levels, as shown on Graph 4.

A further conclusion is that it is highly desirable that generation additions have dynamic and steady-state voltage regulating capability similar to that previously required by NSP's ".90 lead/lag power factor" technical specification. Absent this feature, an equivalent amount of supplemental reactive

power supply equipment must be provided in order to ensure adequate transmission system voltage regulation.

Regardless of which transmission option is implemented, the design of the reactive compensation installations will require further detailed analysis, taking into consideration factors such as flicker, switching transients, ratings of existing equipments, capacitor bank availabilities, and operational margins required to guard against voltage collapse conditions. The numbers and sizes of capacitor banks required to satisfy the reactive requirements identified in Table 4 therefore are subject to further adjustment. Table 4 should therefore be used as a comparative guide as to the relative quantities of reactive compensation required, rather than a definitive statement of the exact characteristics of the installations involved.

### 5.5 Losses: technical evaluation

Table 5 compares the predicted incremental MW losses for the Options, under off-peak load conditions, for the 1325 MW generation scenario, which represents a 500 MW Buffalo ridge area generation increment over the existing 825 MW. The “normalized” column shows the losses relative to Option 1A (2<sup>nd</sup> Nobles Co-Fenton 115 kV), which was chosen as the reference. More-detailed information on losses is provided in Appendix G.

Table 5  
Power System Losses, MW (2007 Summer)  
at 1325 MW Buffalo Ridge Area Generation Level compared to  
825 MW generation level  
(off-peak load condition)

Option	Description	Buffalo Ridge area Generation, MW	Losses, MW	Incremental Losses		
				MW	% Normalized	
0	Existing System	825	13171.0	--	--	--
1A	2 <sup>nd</sup> Nobles Co-Fenton 115	1325	13308.2	137.2	27.4	1.00
3	Lk Yankton-Marshall SW 115	1325	13320.7	149.7	29.9	1.09
5	Chanarambie-Watonwan Jct 115	1325	13313.4	142.4	28.5	1.04
6	Yankee-White-Toronto 115	1325	13314.4	143.4	28.7	1.05
9	Reconductors	1325	13322.7	151.7	30.3	1.11
31A	3 + 1A	1325	13307.4	136.4	27.3	1.00
61A	6 + 1A	1325	13301.5	130.5	26.1	0.95
71A	7 + 1A	1325	13308.4	137.4	27.5	1.00
31A6	3 + 1A + 6	1325	13299.0	128.0	25.6	0.93
345 kV	(White-Lyon Co-Franklin-Twin Cities)	1325	13259.0	88.0	17.6	0.64

From Table 5 it is concluded the 115 kV transmission Options studied have noticeably different loss characteristics. The loss difference between the most efficient Option (31A6) and the lossiest (9) is nearly 24 MW. All options, however, have relatively high losses (25 -30%) due to lack of new transmission between the generation and the presumed Twin Cities “sink”.

The “345 kV” entry shows what the incremental losses would be if a new 345 kV single-circuit line were constructed from the Buffalo Ridge area to the Twin Cities. Its resultant losses are 40 MW (128.0 - 88.0) lower than the most efficient 115 kV Option under study. Further loss reductions could be achieved via optimization studies, which would examine double-circuit construction, different conductor sizes, series compensation, etc. Additional loss reduction would also be achieved if the 345 kV development were combined with one of the 115 kV Options presently under study. A 345 kV development is beyond the scope of this Incremental study, but its performance is shown here for comparison purposes.

From Table 5 it is seen that during the off-peak condition analyzed, the most efficient 115 kV transmission options are 1A and the “combination” options which include 1A. The worst performance is offered by Option 9 (Reconductors).

Regardless of which 115 kV transmission Option is chosen, the incremental losses will be high--approximately 25 - 30%. This is because all the Options (by design) make only relatively modest, local, transmission improvements. Achieving better incremental loss results will require construction of higher-voltage transmission between the Buffalo Ridge area and the Twin Cities load center, as demonstrated by the “345 kV” example.

## 5.6 Losses: Economic Evaluation

Losses were taken into account in the economic evaluation of the Options by computing an "equivalent capitalized value" of the loss differences between each option and the least-loss option. This equivalent capitalized value of the loss differences was then applied as an adjustment to the installed cost of each option to arrive at a loss-adjusted or "evaluated cost" for each option. The capitalized value of the losses has two components: Demand Losses, and Energy Losses. The following paragraphs describe

- ◆ the method by which cumulative present worth of each of these components was computed;
- ◆ how the resultant sum was converted to an equivalent capitalized value;
- ◆ the financial parameters applied (discount rate, energy & capacity values, fixed charge rates, etc.).

The economic value of losses was evaluated presuming a 20-year period for the duration of the loss differences, and a discount rate of 8.0%/yr. The 20-year study period was selected because loss differences change over time as transmission system additions are made and as use of the transmission system is modified due to both changes in generation pattern and changes in load levels and locations.

Demand losses (MW) were determined by performing powerflow simulations at various Buffalo Ridge generation levels between 825 and 1525 MW. These values are provided in Table 1 of Appendix I, and displayed in Graph 1.

The demand loss differences computed from the powerflow simulations were then multiplied by a factor of 1.15 to account for the 15% generation reserve requirement which all MAPP members must maintain in excess of their total system demand (load + losses). It is these adjusted MW figures whose economic value was determined.

The demand losses' value was computed presuming that 50% of the capacity would consist of base-load capacity with an installed cost of \$1,000/kW and the remaining 50% would consist of peaking capacity with an installed cost of \$400/kW. These values are considered representative, respectively, of contemporary costs for a coal-fired steam plant and a gas-fired combustion turbine installation.

Referring to Table 5, the 20-year cumulative present value of the demand losses is \$1,185,500 per MW.

Energy losses were evaluated based upon the off-peak MW loss figures, presuming a 30% annual loss factor (load factor of the losses). The resultant annual MWh figures were then converted to dollar values by multiplying by a presumed average annual energy cost of \$22/MWh. This \$22/MWh energy cost is based on an estimated cost of replacement energy from the "pool"; if the replacement energy were instead priced against purchasing additional wind-derived energy to compensate for the losses, the per-MWh cost would be considerably higher (up to approximately \$50 - 55/MWh).

Referring to Table 5, the 20-year cumulative present value of the energy losses resulting from each (off-peak) MW loss difference is \$567,600.

Table 5

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

Term of loss reduction	20 yrs	Present Value of annuity factor	9.82			
Assumed life, xmsn	35 yrs		11.65			
Discount rate	8 %/yr					
Energy value	\$22 /MWh					
Loss Factor	0.30					
FCR, xmsn	0.16					
				Levelized	Cum PW	
				Annual		
Capacity value:			FCR	Revenue Rqmt		
	50 % peaking @	\$400 /kW	0.15	\$30,000		
	50 % baseload @	\$1,000 /kW	0.15	\$75,000		
				<u>\$ 105,000</u>	\$	
	add 15% reserve requirement:			120,750	1,185,541	
Energy Value:	1.00	8760 hr/yr	0.30	\$22 /MWh	<u>57,816</u>	<u>\$ 567,646</u>
				Total annual cost, capacity & energy: \$	178,566	1,753,187
				Present Value factor	9.82	
				Cum PV	\$ 1,753,187	
				Equivalent investment \$	940,182	

For each option, the cumulative present value of the demand and energy losses was computed for the six Buffalo Ridge area generation levels for which powerflow simulations were performed (825, 925, 1175, 1225, 1325, and 1525 MW). The composite demand (MW) + energy loss (MWh) cost values were then converted to an equivalent capitalized value by the method described in the following paragraphs and in Table 5.

In order to determine the equivalent capitalized value of the losses, it is necessary to determine the amount of transmission investment which would cause a cumulative present worth cost (cumulative present worth of revenue requirements) equivalent to the cumulative present worth costs computed from the "pricing of the losses" exercise described in the preceding paragraphs. The following is a step-by-step example of the derivation of the equivalent capitalized value of losses.

Applying a 16% fixed charge rate, a \$1,000,000 investment in transmission facilities yields a levelized annual revenue requirement of \$160,000. Next applying a discount rate of 8.0% and a 35-year assumed life for transmission facilities, the "present value of annuity" factor is 11.65.

A \$1,000,000 transmission investment, whose annual revenue requirement is \$160,000 therefore has a 35-year cumulative present worth of revenue requirements of  $(\$160,000)(11.65) = \$1,864,000$ . Consequently, it can be observed that for transmission facilities the ratio between "cumulative present worth of annual revenue requirements" and "installed cost" is  $\$1,864,000/\$1,000,000 =$

1.864. The reciprocal of this number (0.5365) is therefore the factor by which to multiply the "cumulative present worth of the losses" to obtain the "equivalent capitalized value of the losses".

Example: At the 1325 MW generation level, Option 1A has losses that are lower than Option 9 by 14.5 MW.

Cumulative present value of the capacity is	(14.5 MW) (\$1,185,500) =	\$ 17,190,000
Cumulative present value of the energy is	(14.5 MW) (\$567,600) =	<u>8,230,000</u>
Total cumulative present value of losses is		= \$ 25,420,000

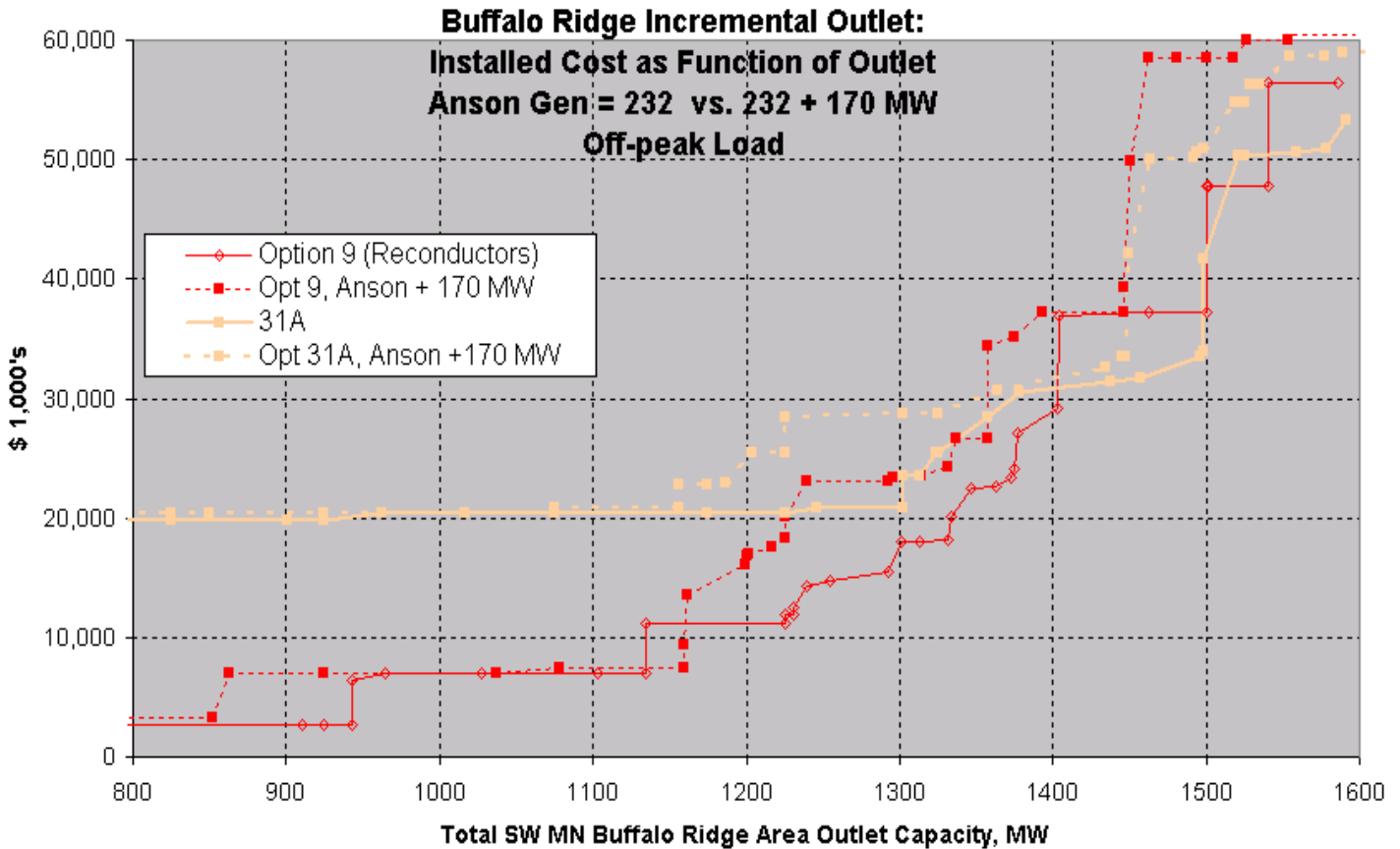
Installed cost of Option 1A at the 1325 MW level (value displayed on Graph 1)	\$ 16,660,000
Equivalent capitalized value of loss reduction: - (\$25,420,000) ( 0.5365) =	\$ <u>-13,630,000</u>
Evaluated cost of Option 1A at the 825 MW level (value displayed on Graph 2)	\$ 3,030,000

## 5.7 Anson Generation Sensitivity

The analysis described in the balance of this Report presents results obtained from TLTG simulations performed on powerflow base case models which represent Anson generation at 232 MW (existing two units of 116 MW each). This Sensitivity Analysis examines the 170 MW Unit 4 addition scheduled for Summer 2005, to determine whether the new Anson unit (connected to Split Rock Sub) would have any effect on the outlet capabilities achieved by the various transmission Options being studied for Buffalo Ridge generation outlet.

Graph 5 addresses this question. For Options 9 (reconductors) and 31A (2nd Nobles Co-Fenton 115 kV & Lk Yankton-Marshall 115 kV), additional simulations were run with the new Anson generation on line (total of 232 + 170 MW Anson generation). This graph shows the effect on installed cost; no adjustments for losses or other considerations.

Graph 5



Comparing the "before" (solid line) and "after" (dashed line) results, it is seen that for the off-peak condition studied, adding the 170 MW of Anson generation affects both Options in a roughly similar manner. Several conclusions can be made:

- There is no effect at Buffalo Ridge outlet levels below approximately 1130 MW;
- Anson generally causes limiting facilities to be encountered at Buffalo Ridge outlet levels 50 - 150 MW lower than in the base (232 MW Anson gen) case.
- Within the range 1200 -1400 MW total Buffalo Ridge output, the incremental effect of the new Anson generation is to increase the cost of achieving any given output level by \$4 -9 million for Option 9, and \$0 - 8 million for Option 31A.
- The general relationship between the Options' costs is not affected, but the crossover point where Option 31A becomes the less expensive option (considering only installed cost) occurs approximately 50 MW earlier (1360 vs. 1405 MW).

## 5.8 Big Stone #1/NDEX Sensitivity

The technical and economic evaluations of the transmission options presented in the balance of this report are based upon results from an extensive set of powerflow simulations, focusing on the off-peak load condition. These simulations represent one set of possible flow patterns resulting from the selected combination of load level, power transfers, and generation pattern.

Following completion of most of the technical analysis, it was noted that the base case models employed inadvertently had the existing Big Stone Unit 1 at only 122 MW net output. Although this is a possible "minimum load" scenario, operation of Big Stone at or near full output is more common, and must be accommodated. Increased generation at Big Stone will tend to increase loading on the Granite Falls-Minn Valley-Panther-McLeod-Blue Lk 230 kV line. Since this line is also an important outlet path for Buffalo Ridge area generation, incremental loading on this path is of concern.

Another matter of interest is that in recent months the MAPP Design Review Subcommittee (DRS) has accepted technical studies supporting an increase in NDEX limit of 130 MW (from 1950 to 2080 MW). This increase has been shown to be achievable with the combination of a capacitor addition proposed for Watertown, SD (by WAPA) and a generator addition at Groton, SD (by Basin Electric). The powerflow models used in the balance of this Report's analyses have NDEX at 1850 MW. Similar to Big Stone, increased NDEX loading also contributes to increased power flow on the Granite Falls-Minn Valley-Panther-McLeod-Blue Lk 230 kV line.

The sensitivity analysis provided in Appendix J evaluates the incremental effect of Big Stone generation level and the planned increase in NDEX operating limit. The powerflow modeling also reflects an update to the 69 kV system configuration in the Troy, MN vicinity; this affects Panther area 69 and 230 kV loadings.

Based on the analysis in Appendix J, the effect of the Big Stone #1/NDEX increase is to accelerate the need for the Granite Falls-Minn Valley and Minn Valley-Panther 230 kV reconductors.

Increased loadings on these 230 kV line segments leave less capacity for accommodating incremental loadings arising from Buffalo Ridge generation increases. Most transmission options studied suffer relatively similar impacts due to this change in base case conditions.

The exception to this general rule is Option 31A6. Presuming at least 1200 MW of total Buffalo Ridge outlet capability is desired (825 + 375 MW), Option 31A6 would incur the significant cost (approximately \$10 million) for the Canby-Granite Falls 115 kV rebuild if it (Option 31A6) were implemented prior to the Big Stone Unit 2 interconnection facility improvements. If this Option were implemented later, (such as by initially implementing Option 31A and later--after Big Stone #2 addition--adding the White-Toronto 115 kV line segment) no such penalty is suffered.

Except for the Option 31A6 considerations discussed above, the differences in incremental impact observed among the Options are not significant, and therefore do not affect the conclusion that Option 31A is the Preferred Plan. Similarly, the conclusion that the addition of the White-Toronto 115 kV line also appears to be advantageous--particularly if a relatively large increment of Buffalo Ridge area generation outlet capacity is desired--remains correct, but tempered by the timing considerations described above.

## 5.9 Paynesville 69 kV Sensitivity

The existing Paynesville-Roscoe Tap-Munson Tap-Farm Tap 69 kV line is equipped with 4/0 ACSR conductor having a nominal Summer rating of 47 MVA. Based upon the results of the Southwest Minnesota/Southeast South Dakota Electric Transmission Study (November, 2001), the resultant "825 MW" Buffalo Ridge series of projects originally included the rebuild of this line to higher capacity.

At a later date, it was determined that this particular rebuild did not appear to be necessary for achieving the 825 MW target outlet capability, but would likely be needed at a somewhat higher outlet level. Consequently, it was removed from the list of "825 MW projects".

During the time between the initial identification of this project and its later de-listing, it was reported during the normal powerflow model building process, as among the "planned facilities". Consequently, in recent years some powerflow models have been issued which represent the Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV as having been rebuilt to higher capacity. This includes the base case models used for the powerflow simulations performed for this Buffalo Ridge Incremental study.

To address the possible impact of this modeling discrepancy, a sensitivity analysis was performed with the correct (existing) Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV impedances and ratings. This analysis, which is provided in Appendix N, shows that regardless of which transmission option is implemented, the Paynesville-Roscoe Tp-Munson TP-Farm Tp 69 kV line upgrade is required in order to achieve Buffalo Ridge area total generation outlet levels of over 1200 MW.

Since the need for (and cost of) the Paynesville-Farm Tp 69 kV upgrade is common to all transmission options studied, this consideration will not affect selection of the Preferred Plan.

## 6.0 Economic Analysis

For the transmission Options which survived the “first cut”, economic analyses were performed

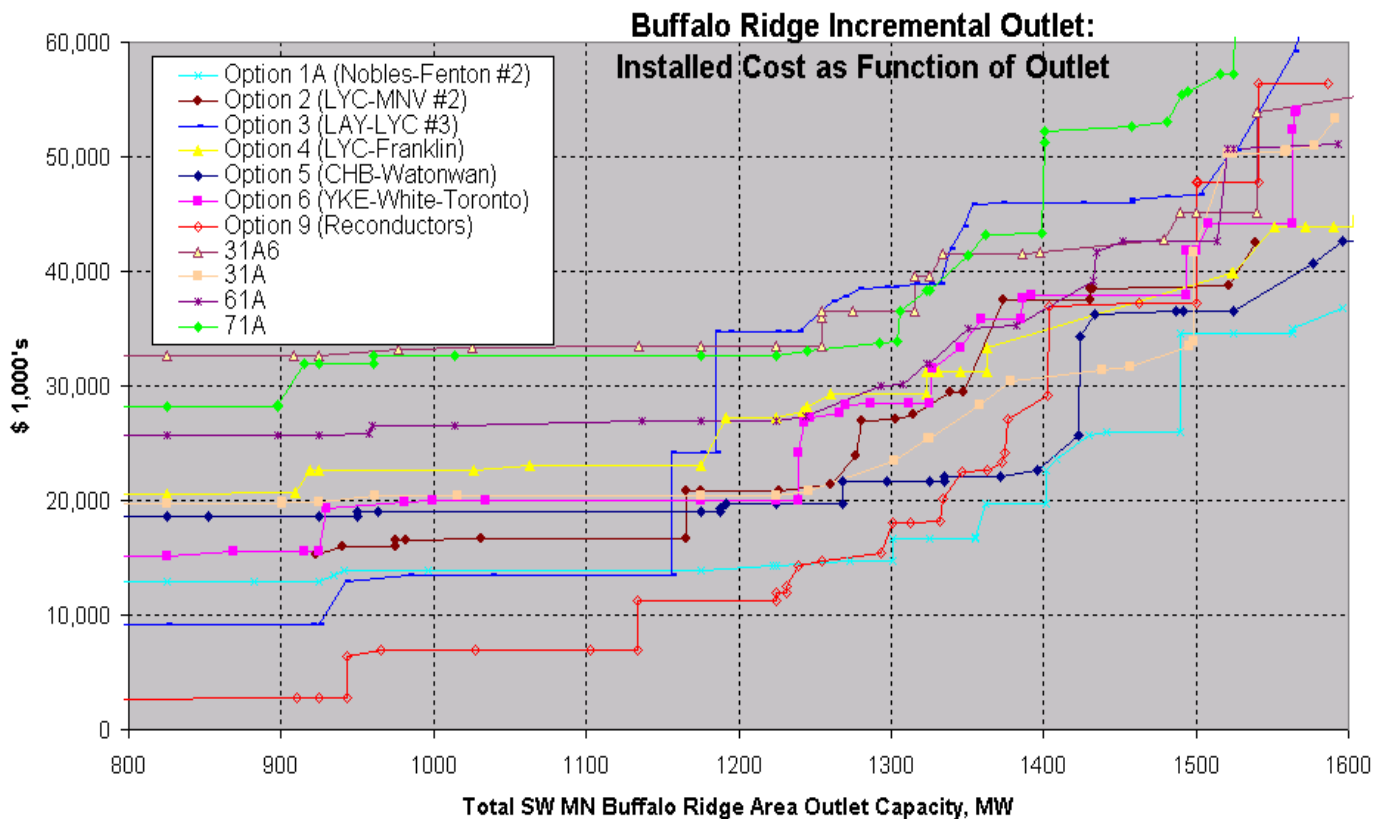
- 1) on the basis of installed cost of required facilities;
- 2) also considering the effect of power and energy losses;
- 3) also considering the cost of Yankee and Marshall “fixes”
- 4) also considering the cost of satisfying reactive power requirements.

Except for the economic evaluation of the electrical losses, present value analysis was not necessary, as it is presumed that the in-service dates (and hence expenditure patterns) do not vary significantly (more than 1 year) amongst the options.

### 6.1 Installed Cost

Graph 6 shows the estimated installed cost of each option as a function of incremental outlet capacity desired beyond the pre-existing 825 MW of outlet capacity. This graph was developed based on the data in Appendix B; as each successive power system limitation is encountered, the cost of the required "remedy" (reconductor, replace transformer, build new line, etc.) is added to the running total. These incremental investments are denoted by the individual data points displayed in Graph 6. No consideration of losses is represented in this graph.

Graph 6



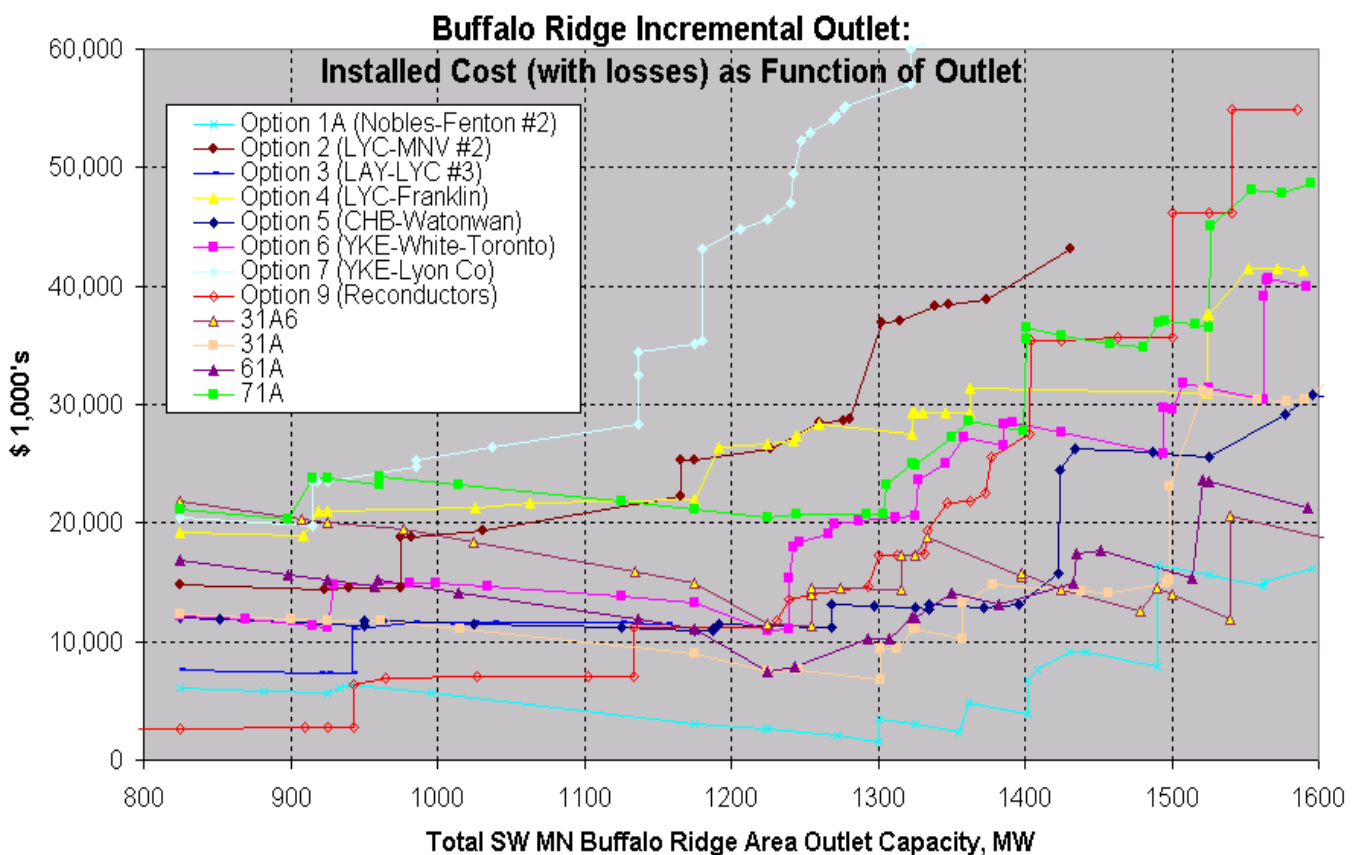
From Graph 6, it is observed that

- Option 9 (“reconductor only”) is the least expensive if less than 1240 MW of outlet is required.
- Options 1A and 3 (“2<sup>nd</sup> Nobles Co-Fenton 115 kV” and “Lk Yankton-Lyon Co 115 #3”) have essentially identical installed cost throughout the range of 950 –1150 MW of Buffalo Ridge area outlet capacity. At higher levels, 1A is significantly lower cost;
- At outlet levels beyond 1250 MW, Option 1A has the lowest installed cost.

## 6.2 Evaluated Cost (Adjusted for Losses)

Graph 7 is based on the installed cost data from Graph 5, with the data for all Options adjusted for each option’s higher power and energy losses relative to Option 1A. Section 5.5 contains detailed information regarding the computation of the equivalent capitalized value of the loss differences.

Graph 7



From Graph 7 it is observed that

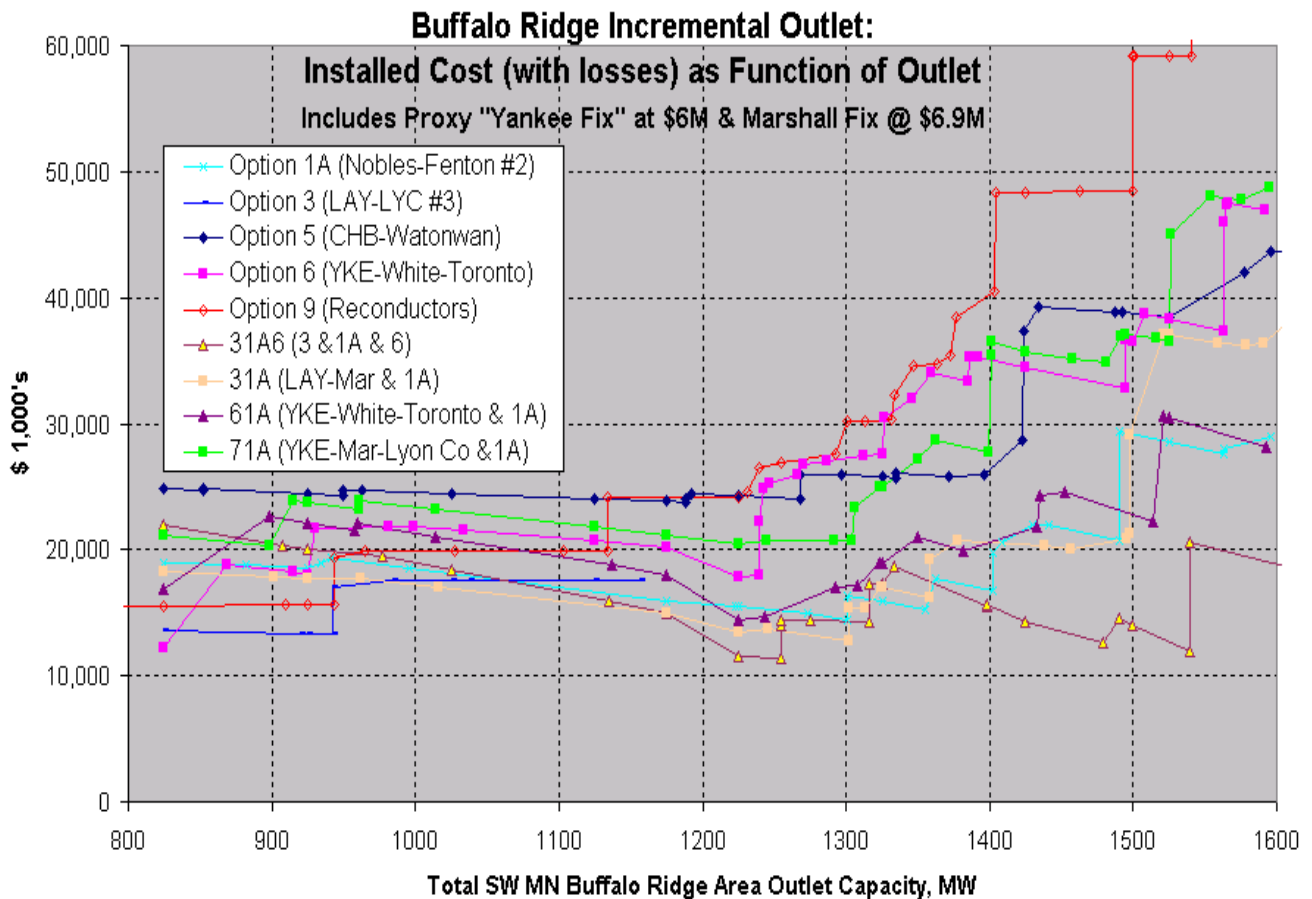
- Beyond 950 MW, Option 1A (“2<sup>nd</sup> Nobles Co-Fenton 115 kV”) is consistently the least-cost option.
- In the range 1200 - 1400 MW, the next-lowest-cost options are 31A, 61A, and 5.

Note: Option 3 is graphed only up to the 1156 MW level because beyond this point, it is most economical to implement the Option 1A facilities rather than individually address the Option 3 overloads directly.

### 6.3 Evaluated Cost (Adjusted for Losses, Yankee, and Marshall fixes)

Graph 8 shows the effect of taking into consideration the need for addressing the Yankee voltage stability limitation (described in Section 5.2), and the need for an additional transmission supply to Marshall (Section 7.11).

Graph 8

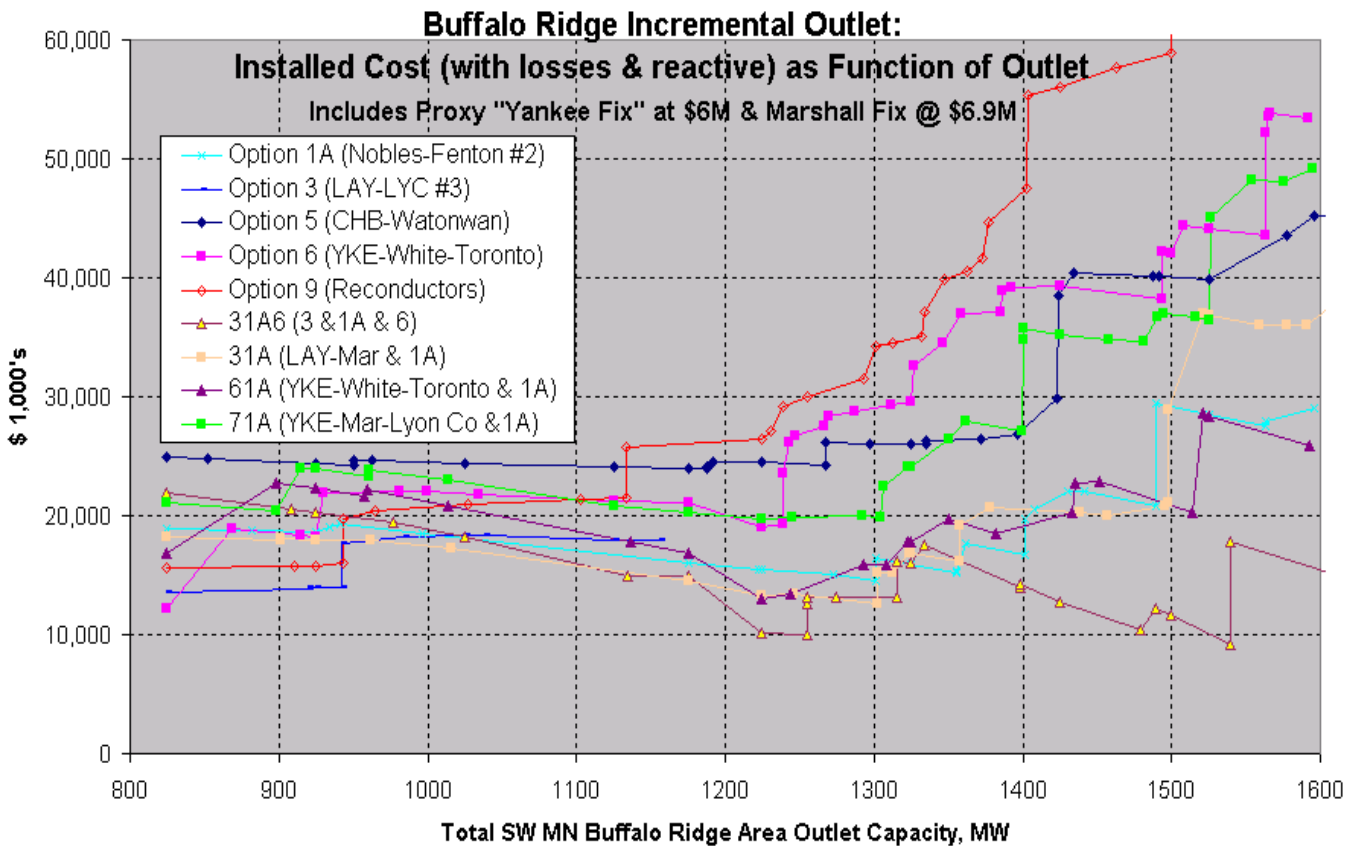


As expected, the Options which lack Yankee or Marshall “fixes” become higher cost than was previously observed in Graph 7. Beginning at approximately 1200 MW, a separation or “break” is developing between most of the “1A” options (1A, 31A, 61A, 31A6) and the remaining options (5, 6, 9, 71A).

#### 6.4 Evaluated Cost (Adjusted for Losses, Yankee/Marshall fixes, & Reactive)

Graph 9 shows the effect of taking into consideration the Options’ differences with respect to reactive power requirements. The evaluation of reactive power needs is described in Section 5.4, and further documented in Appendix D.

Graph 9



As expected, the Options which have the highest incremental reactive requirements become comparatively less economical than those which need fewer capacitor additions. Specifically, the “break” between the “1A” group of options and the others becomes more noticeable, while Option 9 (reconductors) becomes distinctly more expensive than all other options at all Buffalo Ridge outlet levels above 1130 MW.

From Graph 9 the following observations can be made:

- Option 9 (Reconductors) is never the most economical, and is the most expensive option at all Buffalo Ridge Area generation outlet levels beyond 1130 MW.
- Beyond 1130 MW, there is a group of four transmission options (1A, 61A, 31A, 31A6) which have total evaluated cost consistently lower than the other five options.
- The group of four lowest-cost options all include the "1A" transmission facilities.
- Option 5 (Chanarambie-Watonwan Jct 115 kV) is the most expensive option up to the 1130 MW level. Beyond that level, it is in the “middle of the pack”. However, it is never among the "lowest-cost" group.
- Option 71A (Yankee-Marshall-Lyon Co 115 kV & 1A) is the only “combination” option studied that does not fall within the “lowest-cost” group.
- Option 6 (Yankee-White-Toronto 115 kV) is a mid-cost option up to approximately 1230 MW. Beyond this level, its cost escalates rapidly.
- Option 31A6 becomes least-cost at approximately 1180 MW, but there are several cross-overs with Option 31A between 1255 and 1360 MW, at which point 31A6 breaks away from the pack.
- At levels above 1360 MW, Option 31A6 is consistently the lowest-cost option.

Based on the above observations, the following conclusions can logically be drawn:

- The Option 1A facilities will be part of the optimal transmission development.
- Addition of the Option 3 facilities (this creates Option 31A) generally does not impose any additional net cost on Buffalo Ridge outlet development, yet provides the Marshall load-serving benefits desired. Consequently, the Option 3 facilities (as part of Option 31A) also appear to be a desirable component of the Buffalo Ridge outlet plan.
- Addition of the Option 6 facilities to the Option 31A development (Option 31A6) generally reduces the total cost of Buffalo Ridge outlet beyond the 1180 MW level, provides the required “Yankee fix”, and offers some incidental load-serving benefits. However, the benefit of adding the Option 6 facilities is most evident at Buffalo Ridge outlet levels beyond 1360 MW.

## 7.0 Relevant Concerns

### 7.1 Load serving issues

Several load serving issues exist or are imminent in southwestern Minnesota and eastern South Dakota. These are summarized below and described in the following paragraphs.

<u>Load center</u>	<u>Critical Contingencies</u>
Marshall, MN	Lyon Co-Marshall Switching Station 115 kV
New Ulm/Redwood Falls	Minn Valley-Redwood Falls-Franklin 115 kV or Wilmarth-Franklin 115 kV
Olivia/Bird Island	Minn Valley-Sacred Heart 69 kV or Panther 230/69 kV source (Panther 230/69 kV transformer or Panther-Bird Island 69 kV line)
Dotson/Lamberton	Heron Lk-Storden 69 kV
Toronto/Hetland Jct	Burr Jct-Toronto 115

Detailed examination of these load-serving issues is beyond the scope of this study; however, some comparative performance characteristics can already be divined based on results of previous studies, and consideration of the transmission system topology.

#### 7.11 Marshall, MN

During periods of low (or zero) wind generation, the Marshall area load center is reliant on deliveries from

- the north via the two 30-mile 115 kV lines originating from the WAPA Granite Falls and the Xcel Energy Minn Valley 230/115 kV transformations;
- the south via the two Lk Yankton-Lyon Co lines from the Split Rk and future Nobles Co 345/115 kV transformations (distances of approximately 80 - 100 miles).

Only one of these transmission sources connects directly to the Marshall 115 kV load-serving loop; the other three are connected to the Lyon Co Substation, whose only connection to the Marshall 115 kV loop is the Lyon Co-Marshall Switching Station 115 kV line.

Consequently, presently there are only two transmission sources to the Marshall 115 kV loop. Continued load growth at Marshall has rendered the existing two 115 kV sources inadequate for first-contingency conditions. Any Option which constructs a new 115 kV line into the Marshall 115 kV loop would provide additional load-serving capability.

Option 3 establishes a new Lake Yankton-Marshall Southwest (“Marshall SW”) 115 kV line. The Lk Yankton-Marshall SW line establishes a new path into Marshall from the south, thereby providing loading relief for the existing two Lk Yankton-Lyon Co 115 kV lines; this

is relevant because with increased Buffalo Ridge generation, loss of the newer Lk Yankton-Lyon Co 115 kV circuit can cause overload of the older circuit, which has smaller conductor.

A special benefit of the Lk Yankton-Marshall 115 kV line addition is that the Lk Yankton SVS is brought electrically closer to the Marshall load center. This results in improved voltage regulation for the Marshall area, in addition to increased load-serving capability.

A future extension of this new Lk Yankton-Marshall SW 115 kV line, from Marshall SW approximately 12 - 15 miles to Lyon Co Substation, could also provide further load-serving capacity and assist in establishing additional wind outlet capacity, particularly if a future EHV transmission development were implemented connecting to the Lyon Co Substation. This is consistent with results of MISO “exploratory” studies which have indicated the need for higher-voltage transmission development from the Buffalo Ridge to the Twin Cities, and with this Incremental study’s losses analysis, which indicates that incremental power and energy losses will be rather high until a higher-voltage development is implemented.

The potential future Marshall SW-Lyon Co 115 kV line section also would provide a second connection from Lyon Co Substation to the Marshall 115 kV load-serving loop, thereby minimizing any “prior outage” Buffalo Ridge outlet limitations associated with the Marshall 115 kV loop segments.

“Combination” Options 31A & 31A6 include Option 3’s Lk Yankton-Marshall 115 kV line.

Option 2 establishes a second Lyon Co-Minn Valley 115 kV line, while Option 4 establishes a new Lyon Co-Franklin 115 kV line. With either option, to fully address the Marshall load-serving need it would be necessary to add another 115 kV line from Lyon Co to the Marshall 115 kV loop.

Options 7 and 71A establish a Yankee-Marshall SW-Lyon Co 115 kV line. Option 8 extends this line from Lyon Co eastward to the Franklin 115 kV station. Any of these Options would yield a new 115 kV transmission source to Marshall, although significant amounts of future shunt capacitor additions would likely eventually be required with these options to ensure adequate post-contingent Marshall 115 kV voltage.

#### 7.12 New Ulm/Redwood Falls, MN & Olivia/Bird Island

Options 4 and 8 establish a new Lyon Co-Franklin 115 kV circuit. This partially addresses the New Ulm/Redwood Falls load-serving issues because the present load-serving limitation is due to loss of either end of the Minn Valley-Redwood Falls-Franklin-Swan Lk-Wilmarth 115 kV line. The Lyon Co-Franklin line segment brings a new 115 kV source into the center of this line (Franklin). With a future extension of the new 115 kV to Ft Ridgely, this would likely be adequate for the foreseeable future load serving needs in the Redwood Falls/New Ulm area.

The improved Franklin 115 kV situation would also benefit the Olivia/Bird Island due to the resultant stronger 69 kV source at Franklin, and the recently-rebuilt Franklin-Bird Island 69 kV line. However, additional load serving improvements would still be required for the

Olivia/Bird Island area because this improved Franklin 69 kV source cannot fully mitigate the two most critical Olivia/Bird Island area transmission contingencies:

- Outage of Panther 230/69 kV transformer
- Outage of Panther-Bird Island 69 kV line

7.13 Dotson/Lamberton

Options 4 and 8 establish a Lyon Co-Franklin 115 kV line. This creates the opportunity for addition of a 115/69 kV substation approximately midway, in Sheridan Township. Such a station would provide a new 69 kV source approximately 20 miles closer to the Dotson/Lamberton area than the existing Franklin 115/69 kV source.

7.14 Toronto/Hetland Jct

The Toronto and Hetland Jct 115/41 kV substations are supplied radially by the Burr Jct-Toronto 115 kV line. Option 6 and the related “combination” options 61A and 31A6 establish a White (Brookings Co)-Toronto 115 kV line. This provides a second 115 kV supply to the Toronto Substation, thereby immunizing Toronto and Hetland Jct substations against the Burr Jct-Toronto 115 kV outage contingency. Presently, this line outage causes interruption of supply to all load normally served from the Toronto and Hetland Jct 41 kV sub-transmission systems, requiring that recovery be effected by use of an emergency 69/41 kV connection to East River Electric Power Coop near Lake Preston and start-up of Otter Tail Power’s Lake Preston diesel plant.

The new Brookings Co-Toronto 115 kV line established by Option 6 (and the related “combination” options 61A and 31A6) also facilitates routine maintenance or future upgrades and rebuilds of the Toronto/Burr/Canby area 115 kV transmission lines.

## 7.2 Constructability & Schedule Considerations

The transmission Options under evaluation differ significantly with respect to the number and type of construction activities required. These differences have ramifications with respect to the lead times involved in implementing the series of improvements required. Simpler Options are easier to build.

Options which require large amounts of reconductoring and rebuilding require disproportionately more time. This arises because power system reliability considerations limit the number of circuits within a geographical sub-area that can be simultaneously out of service for upgrade or replacement, since many of the circuits involved are to some degree electrically in parallel. This dictates that construction cannot be undertaken simultaneously on more than a few existing circuits per season; rather, sequential construction is required. In contrast, Options which rely less heavily on reconductors and rebuilds encounter fewer construction outage constraints.

Table 8 summarizes the types of transmission line work involved and gives an estimated duration of work, based on a January, 2007 start date.

Table 8  
Constructability & Schedule Considerations  
For achieving 500 MW Buffalo Ridge Area Generation Outlet Increment  
(825-->1325 MW total outlet)

Option	Description	miles of transmission					Capacitors	Years
		New	Recond	Rebuild	YKE/Marsh	Total		
1A	Nobles Co-Fenton 115 kV #2	18	32	19	25	94	10	2.0
3	Lk Yankton-Marshall-Lyon Co 115 kV	48	9	48	10	115	17	2.0
5	Chanarambie-Watonwan Jct 115	50	28	19	25	122	11	2.5
6	Yankee-White-Toronto 115	30	48	49	15	142	15	3.5
9	Reconductors	0	51	60	25	136	21	4.0
31A	3 + 1A	48	24	19	10	101	10	2.5
61A	6 + 1A	48	29	19	15	111	7	2.5
71A	7 + 1A	73	24	49	0	146	7	3.0
31A6	3 + 1A + 6	78	36	19	0	133	6	2.5

Notes:

1. Options that do not include Option 6 or Option 7 facilities need to address Yankee voltage collapse condition; presumed to be 10-mile Yankee-White 115 kV #2.
2. Options that do not include Option 3, 4, or 7 facilities will need to address Marshall load-serving requirements; presumed to be 15-mile Lk Yankton-Marshall SW 115 kV.
3. "Option 3" has Option 1A facilities added at 1150 MW (refer to Sections 5.1 & 6.2).

The extreme is Option 9, which relies exclusively on the reconductoring or rebuilding of existing lines, except for the Yankee and Marshall fixes. The construction time for these line projects and associated substation projects is estimated to be approximately 4 years. Similarly, Options 6 and

71A are nearly as laggard, at 3.5 and 3 years, respectively; again due to the large number of reconductor and rebuild miles involved.

The 4 years' implementation time indicated in Table 9 for Option 9 presumes all circuits to be reconducted can be taken out of service when requested. Although some preliminary effort has been made to take into consideration the logistics of implementation, it is anticipated a more-detailed construction scheduling analysis would indicate a somewhat longer implementation time would actually be required, due to outage scheduling constraints.

The other Options (1A, 3, 5, and the “combinations” other than 71A) are characterized by a more balanced blend of new facility additions and upgrades to existing lines and transformers. Accordingly, although significant coordination of construction outages is still required, implementation times are shorter than for Options 9, 6, and 71A. Consequently, the remaining Options (1A, 3, 5, and the “combinations” other than 71A) are predicted to be capable of implementation in under 3 years.

Appendix I provides preliminary schedules for Options 9 and 31A, providing details on the anticipated staging of each Option's transmission line and substation components.

### 7.3 Double-Circuit Line Considerations

Option 31A, which has been identified as the “Preferred Plan”, involves addition of a second Nobles Co-Fenton 115 kV line, and possibly also a second White-Yankee 115 kV line, depending which “Yankee fix” option is selected. Implementation of the second Nobles Co-Fenton and White-Yankee 115 kV circuits requires consideration of whether it is desirable or acceptable to construct these pairs of circuits on double-circuit structures.

Appendix K provides a detailed analysis of the “double circuit” issue. The conclusion is that in the case of Nobles Co-Fenton 115 kV #2 and White-Yankee 115 kV #2, it is inappropriate to have these circuits on the same structures as the #1 circuit. This conclusion arises because the second circuit in each case is being installed for the purpose of providing back-up (redundancy) for failure of the first circuit. Consequently, the second circuit must be constructed in a manner that minimizes exposure to “common-mode” failures which would simultaneously render both circuits unusable.

Common-mode failure mechanisms for double-circuit lines include

- electrical failure of line insulation due to lightning strike;
- mechanical failure of one or more structures;
- broken shield wire falling into power conductors;
- wind-blown debris causing conductor-conductor short circuits;
- insulator contamination due to road salt, soot, or agricultural chemicals;
- wind/sleet/ice conditions
- contact with aircraft or construction equipment (crane, dump truck)
- protective relaying malfunction (“sympathetic tripping” due to fault on adjacent circuit)

These common-mode failure mechanisms have all been experienced on the Xcel Energy/NSP transmission system, on double-circuit lines at all voltage levels from 69 kV to 345 kV.

In consideration of these common-mode outage mechanisms, the NERC Planning Standards recognize double-circuit line outages as a “single-contingency” type of event (“Category C-5”). Consequently, evaluation of electric transmission system capability is performed considering failure of both circuits of a double-circuit line as being a single-contingency event. Double-circuit lines therefore are not appropriate in situations where two independent circuits are required for reliability purposes.

Double-circuit construction is acceptable if the power system can reliably withstand simultaneous failure of both circuits. Double circuit construction therefore can be appropriate in situations where the two circuits serve different functions, connect different pairs of substations, split away and proceed in different directions, or where high capacity (but not redundancy) is required.

In the case of the Nobles Co-Fenton and White-Yankee 115 kV #2 circuits, the second circuit is needed to provide back-up for the first circuit. Consequently, logic dictates that to achieve the intended benefit to be derived from adding the second circuit, the #1 and #2 circuits cannot be constructed as a double-circuit line.

#### 7.4 Tariff Considerations

The technical and economic analyses described in this Report were performed without regard to transmission tariff considerations. This procedure is appropriate for determining the least-cost transmission solutions with respect to installed cost and future electrical losses, but is somewhat simplistic (if not Pollyannaish and Panglossian) due to its ignorance of possible transmission tariff implications and costs.

The northwestern section of the Buffalo Ridge is on the MISO-WAPA interface. The White (Brookings Co) 345/115 kV facilities now being installed as part of the Buffalo Ridge “825 MW” series of improvements establish a new WAPA-MISO interconnection. This section describes some pertinent tariff considerations that should be recognized when assessing the Buffalo Ridge “incremental” transmission Options’ overall performance.

##### Northern Section of the Buffalo Ridge (South Dakota): access to MISO market

The transmission Options which include the White-Toronto 115 kV line (6, 61A, 31A6) “open up” the Toronto section of the Buffalo Ridge for wind developments whose intended market would be within MISO. The only existing MISO facility in the area is the radial Otter Tail Power 115 kV system at Toronto; in addition to voltage control challenges, it has the significant strategic disadvantage of being “trapped” inside the NDEX boundary. What little other transmission exists in the immediate area is non-MISO.

Absent a new Brookings Co-Toronto 115 kV line, generation developments in the Toronto area need to pay a significant transmission service charge for use of the WAPA/Basin/Heartland Integrated System (“IS”) for delivery of their output to the WAPA/MISO interface, in addition to

any local transmission upgrade costs. This present situation keeps potential eastern South Dakota wind generation developments at an economic disadvantage relative to their “inside MISO” competitors in Minnesota and elsewhere.

#### Reliance on White (Brookings Co) 345/115 kV substation

The transmission Options which include the White-Toronto 115 kV line (6, 61A, 31A6) result in less power injection into the WAPA 345 kV system at White than is the case for the Options lacking this 115 kV line segment. WAPA, which is not a MISO member, has already signaled their expectation that they should receive some significant type of compensation for power injections at White, regardless of whether such injections cause any adverse (or favorable) incremental loading conditions on the WAPA system. Consequently, with respect to MISO participants, it is evident that there is likely some non-trivial value to minimization of inflows onto the 345 kV system at White.

#### Selection of “Yankee Fix”

The “White 345 kV inflow” matter is also relevant to the selection of the “Yankee Fix” (Section 5.2). In addition to the constrained interface considerations described in Section 5.3, another relevant factor is the effect on White 345 kV inflow levels. The “Yankee fix” option of installing a second 345/115 kV transformer at the new Brookings Co Substation will increase slightly the inflows to the 345 kV system, while the alternate option of adding the Brookings Co-Toronto 115 kV line will reduce such inflows.

# Appendix A

## Maps

# Appendix B

TLTG Summary Tables  
(with cumulative cost data)

# **Buffalo Ridge Incremental Generation Outlet Electric Transmission Study**

## Transmission Outlet Analysis for Southwest Minnesota/Eastern South Dakota (Buffalo Ridge Area) Generation Additions

(0 – 600 MW beyond “825 MW”)

Volume 2

May 9, 2005

Prepared by:  
Xcel Energy

# Appendix C

## Powerflow Diagrams & Logsheets

<u>Appendix</u>	<u>Facility additions</u>	<u>Buffalo Ridge area gen, MW</u>
C-0	(Existing System)	825
C-1	Option 1	825
C-1A	Option 1	825
C-2	Option 2	825
C-2M	Option 2M	825
C-3	Option 3	825
C-4	Option 4	825
C-5	Option 5	825
C-6	Option 6	825
C-7	Option 7	825
C-8	Option 8	825
C-9	Option 9	825
C-31A	Option 31A	825
C-61A	Option 61A	825
C-71A	Option 71A	825
C-31A6	Option 61A	825

# Appendix D

## Reactive Requirement Data

<u>Appendix</u>	<u>Item</u>
D-1	Tabulation of MVAR requirements
D-2	Tabulation of corresponding capacitor requirements

The values in Appendix D-2 represent the amount of installed capacitance in nominal MVAR (rounded up to the next standard capacitor bank size) required to achieve the “actual” MVAR outputs indicated in D-1.

For example, referring to D-1, Option 9 at the 1425 MW outlet level is seen to need 264 MVAR. Since the modeled SVC bus voltage is .950, the corresponding amount of installed capacitance is  $264/.950^2 = 293$  MVAR; this rounds up to 300 MVAR, the value shown in Table 4.

# Appendix D-1

Buffalo Ridge Incremental Outlet Study							
Reactive Outputs Required to Maintain .95PU Voltages							
Option	Outage	MW Level	Pipestone SVC	Panther SVC	Lake Yankton SVC	Lyon Co CAP	Winnebago CAP
0	1	925	0.0	0.0	86.2	62.4	
0	2	925	0.0	0.0	43.1	63.6	
0	3	925	0.0	0.0	55.5	61.1	
0	4	925	0.0	0.0	19.9	63.9	
0	1	1225	94.9	49.9	140.0	52.7	
0	2	1225	0.0	0.3	140.0	59.8	
0	3	1225	0.0	96.4	102.0	60.4	
0	4	1225	0.0	35.9	61.4	62.4	
0	1	1425	294.0	115.0	140.0	42.5	
0	2	1425	0.0	30.5	140.0	54.4	
0	3	1425	0.0	48.0	129.0	59.4	45.9
1A	1	925	0.0	0.0	16.3	31.7	
1A	2	925	0.0	0.0	44.4	31.7	
1A	3	925	0.0	37.0	38.5	62.8	
1A	4	925	0.0	0.0	28.2	31.3	
1A	1	1225	0.0	0.0	53.2	31.1	
1A	2	1225	0.0	0.0	124.0	62.3	
1A	3	1225	0.0	76.8	87.0	61.1	39.2
1A	4	1225	0.0	18.4	48.8	63.0	
1A	1	1425	0.0	0.0	72.9	30.7	
1A	2	1425	0.0	0.0	140.0	58.5	
1A	3	1425	0.0	106.0	113.0	60.1	71.2
3	1	925	0.0	0.0	100.0	31.0	
3	2	925	0.0	0.0	53.5	31.4	
3	3	925	0.0	43.2	68.0	31.1	
3	4	925	0.0	0.0	35.2	31.4	
3	1	1225	45.3	32.7	140.0	56.1	
3	2	1225	0.0	0.0	140.0	62.5	
3	3	1225	0.0	79.3	102.0	62.3	30.6
3	4	1225	0.0	29.5	82.9	31.1	
3	1	1425	205.0	100.0	140.0	47.4	
3	2	1425	0.0	13.2	140.0	57.7	
3	3	1425	0.0	106.0	131.0	61.7	43.5

Option	Outage	MW Level	Pipestone SVC	Panther SVC	Lake Yankton SVC	Lyon Co CAP	Winnebago CAP
31A	1	925	0.0	0.0	11.4	31.9	
31A	2	925	0.0	0.0	37.0	31.8	
31A	3	925	0.0	40.0	57.7	31.2	
31A	4	925	0.0	0.0	24.8	31.7	
31A	1	1225	0.0	0.0	50.8	31.5	
31A	2	1225	0.0	0.0	138.0	31.1	
31A	3	1225	0.0	76.0	83.8	62.7	33.6
31A	4	1225	0.0	25.3	68.5	31.3	
31A	1	1425	0.0	0.0	71.9	31.3	
31A	2	1425	0.0	0.0	140.0	60.8	
31A	3	1425	0.0	99.2	111.0	62.1	47.8
31A6	1	925	0.0	0.0	1.8	32.0	
31A6	2	925	0.0	0.0	8.8	31.9	
31A6	3	925	0.0	42.9	47.1	31.3	
31A6	4	925	0.0	0.0	13.8	31.7	
31A6	1	1225	0.0	0.0	36.6	31.6	
31A6	2	1225	0.0	0.0	82.4	31.3	
31A6	3	1225	0.0	83.4	89.1	30.8	33.1
31A6	4	1225	0.0	27.7	53.5	31.4	
31A6	1	1425	0.0	0.0	52.6	31.4	
31A6	2	1425	0.0	5.8	121.0	30.9	
31A6	3	1425	0.0	104.0	86.8	62.4	46.1
5	1	925	0.0	0.0	53.5	31.2	
5	2	925	0.0	0.0	42.4	31.5	
5	3	925	0.0	34.0	39.7	62.8	
5	4	925	0.0	0.0	27.8	31.4	
5	1	1225	0.0	0.0	136.0	61.5	
5	2	1225	0.0	0.0	125.0	62.4	
5	3	1225	0.0	72.8	89.7	61.1	44.8
5	4	1225	0.0	17.6	51.2	62.9	
5	1	1425	34.7	20.8	140.0	56.3	
5	2	1425	0.0	0.0	140.0	58.3	
5	3	1425	0.0	97.3	116.0	60.1	57

Option	Outage	MW Level	Pipestone SVC	Panther SVC	Lake Yankton SVC	Lyon Co CAP	Winnebago CAP
6	1	925	0.0	0.0	69.1	63.1	
6	2	925	0.0	0.0	5.2	64.5	
6	3	925	0.0	42.2	33.8	62.8	
6	4	925	0.0	0.0	26.1	31.2	
6	1	1225	24.6	18.4	140.0	57.4	
6	2	1225	0.0	0.0	83.4	62.0	
6	3	1225	0.0	84.7	79.2	61.2	31.2
6	4	1225	0.0	27.6	44.6	62.8	
6	1	1425	148.0	65.6	140.0	51.0	
6	2	1425	0.0	15.1	127.0	60.6	
6	3	1425	0.0	109.0	101.0	60.3	43.3
61A	1	925	0.0	0.0	5.9	31.8	
61A	2	925	0.0	0.0	13.8	31.6	
61A	3	925	0.0	36.9	23.4	63.0	
61A	4	925	0.0	0.0	16.3	31.4	
61A	1	1225	0.0	0.0	38.1	31.2	
61A	2	1225	0.0	0.0	63.6	63.0	
61A	3	1225	0.0	80.2	66.6	61.6	36.0
61A	4	1225	0.0	28.4	53.3	30.8	
61A	1	1425	0.0	0.0	52.8	30.9	
61A	2	1425	0.0	1.9	100.0	61.9	
61A	3	1425	0.0	105.0	85.3	60.8	47.1
71A	1	925	0.0	0.0	5.1	31.7	
71A	2	925	0.0	0.0	13.4	31.5	
71A	3	925	0.0	39.3	19.9	62.8	
71A	4	925	0.0	0.0	13.6	31.3	
71A	1	1225	0.0	0.0	35.6	31.0	
71A	2	1225	0.0	0.0	63.1	61.3	
71A	3	1225	0.0	83.8	60.2	61.0	34.7
71A	4	1225	0.0	27.7	30.7	62.6	
71A	1	1425	0.0	0.0	33.6	62.6	
71A	2	1425	0.0	9.9	101.0	59.6	
71A	3	1425	0.0	112.0	79.8	59.9	46.9

Option	Outage	MW Level	Pipestone SVC	Panther SVC	Lake Yankton SVC	Lyon Co CAP	Winnebago CAP
9	1	925	0.0	0.0	85.6	62.4	
9	2	925	0.0	0.0	41.1	63.8	
9	3	925	0.0	37.3	48.4	62.4	
9	4	925	0.0	0.0	38.6	31.1	
9	1	1225	76.3	36.6	140.0	52.8	
9	2	1225	0.0	0.0	140.0	60.2	
9	3	1225	0.0	79.7	102.0	60.5	33.3
9	4	1225	0.0	21.3	62.4	62.4	
9	1	1425	264.0	106.0	140.0	42.4	
9	2	1425	0.0	12.4	140.0	54.8	
9	3	1425	0.0	105.0	131.0	59.4	46.1
<b>Outages</b>							
1	Nobles 115/345 kV transformer						
2	New White 115/345 kV transformer						
3	345 kV line from Lakefield Gen to Wilmarth						
4	345 kV line from Wilmarth to Blue Lake						
Jason Standing							
Xcel Energy							
2/14/2005							
SVC_output.xls							

# Appendix D-2

Buffalo Ridge Incremental Generation Outlet Study																																																
Reactive additions required, MVAR																																																
Buff Ridge MM	825						925						1025						1125						1225						1325						1425						1525					
Option	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT						
1A	0	0	40	0	0	40	0	50	20	0	20	90	0	70	40	0	40	150	0	90	50	0	60	200	0	120	60	0	60	240	0	120	80	0	80	280	20	120	100	30	100	370						
3	0	0	50	20	0	70	20	60	30	0	20	130	40	70	40	0	20	170	60	90	60	0	40	250	140	90	80	30	40	380	240	120	100	60	60	580	380	150	120	90	60	800						
5	0	0	40	0	0	40	0	50	20	0	20	90	0	70	40	0	40	150	0	90	60	0	60	210	20	90	80	0	60	250	40	120	100	0	80	340	60	150	120	30	80	440						
6	0	0	50	0	0	50	0	60	20	0	20	100	20	80	40	0	40	180	40	120	60	0	40	260	100	120	80	0	40	340	180	150	100	30	60	520	300	150	120	30	60	660						
9	0	0	40	10	0	50	20	50	20	30	20	140	60	60	40	30	40	230	100	90	60	30	40	320	180	120	80	60	40	480	300	120	100	90	60	670	440	150	140	120	80	930						
31A	0	0	50	0	0	50	0	60	20	0	20	100	0	70	40	0	20	130	0	90	60	0	40	190	0	110	80	0	40	230	0	120	100	0	60	280	0	150	120	30	60	360						
61A	0	0	50	0	0	50	0	60	0	0	20	80	0	80	0	0	20	100	0	90	0	0	40	130	0	120	0	0	60	180	0	120	20	0	60	200	0	150	40	0	80	270						
71A	0	0	50	0	0	50	0	60	0	0	20	80	0	80	0	0	20	100	0	120	0	0	40	160	0	120	20	0	60	200	0	150	40	0	60	250	20	180	60	30	80	370						
31A6	0	0	50	0	0	50	0	60	0	0	20	80	0	80	0	0	20	100	0	90	0	0	40	130	0	120	20	0	40	180	0	120	20	0	60	200	0	150	40	0	60	250						
Difference w/r to Option 1A (MVAR)																																																
1A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
3	0	0	10	20	0	30	20	10	10	0	40	40	0	0	0	-20	20	60	0	10	0	-20	50	140	-30	20	30	-20	140	240	0	20	60	-20	300	360	30	20	60	-40	430							
						\$0.6					\$0.8					\$0.4						\$1.0						\$2.8						\$6.0						\$8.6								
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	0	0	10	20	-30	20	0	0	10	40	0	20	0	0	60	40	30	20	0	-20	70						
						\$0.0					\$0.0					\$0.0						\$0.2						\$0.2						\$1.2						\$1.4								
6	0	0	10	0	0	10	0	10	0	0	0	10	20	10	0	0	0	30	40	30	10	0	-20	60	100	0	20	0	-20	100	180	30	20	30	-20	240	280	30	20	0	-40	290						
						\$0.2					\$0.2					\$0.6						\$1.2						\$2.0						\$4.8						\$5.8								
9	0	0	0	10	0	10	20	0	0	30	0	50	60	-10	0	30	0	80	100	0	10	30	-20	120	180	0	20	60	-20	240	300	0	20	90	-20	390	420	30	40	90	-20	560						
						\$0.2					\$1.0					\$1.6						\$2.4						\$4.8						\$7.8						\$11.2								
31A	0	0	10	0	0	10	0	10	0	0	0	10	0	0	0	0	-20	-20	0	0	10	0	-20	-10	0	-10	20	0	-20	-10	0	0	20	0	-20	0	-20	30	20	0	-40	-10						
						\$0.2					\$0.2					-\$0.4						-\$0.2						-\$0.2						\$0.0						-\$0.2								
61A	0	0	10	0	0	10	0	10	-20	0	0	-10	0	10	-40	0	-20	-50	0	0	-50	0	-20	-70	0	0	-60	0	0	-60	0	0	-60	0	-20	-80	-20	30	-60	-30	-20	-100						
						\$0.2					-\$0.2					-\$1.0						-\$1.4						-\$1.2						-\$1.6						-\$2.0								
71A	0	0	10	0	0	10	0	10	-20	0	0	-10	0	10	-40	0	-20	-50	0	30	-50	0	-20	-40	0	0	-40	0	0	-40	0	30	-40	0	-20	-30	0	60	-40	0	-20	0						
						\$0.2					-\$0.2					-\$1.0						-\$0.8						-\$0.8						-\$0.6						\$0.0								
31A6	0	0	10	0	0	10	0	10	-20	0	0	-10	0	10	-40	0	-20	-50	0	0	-50	0	-20	-70	0	0	-40	0	-20	-60	0	0	-60	0	-20	-80	-20	30	-60	-30	-40	-120						
						\$0.2					-\$0.2					-\$1.0						-\$1.4						-\$1.2						-\$1.6						-\$2.4								

R Gonzalez  
2/14/2005  
Reactive rqmts table1.xls



# Appendix E

## Yankee Voltage Stability Analysis

# Buffalo Ridge Incremental Generation Outlet Study

## Yankee Voltage Stability Analysis

### 0.0 Background

The Southwest Minnesota transmission improvements presently under way were designed to increase total generation outlet capacity from the southwest Minnesota portion of the Buffalo Ridge to 825 MW. Recent generation interconnection studies performed by MISO (“Buffalo Ridge Group 2”) have confirmed that if additional increments of generation in excess of this 825 MW design level were to be installed, several power system performance deficiencies would become evident. One of the limiting conditions is voltage collapse (or dynamic instability) in the Yankee/Buffalo Ridge Substation vicinity following tripout of the Yankee-White 115 kV line or the new White 345/115 kV transformer.

This analysis examines the voltage stability situation relating to the Yankee vicinity, and provides an evaluation of “modest-scale” transmission options available for ensuring local voltage stability, thereby enabling additional Yankee vicinity generation additions beyond the “825 MW” level.

### 1.0 Nature of Yankee/Buffalo Ridge Area Voltage Stability Limitation

The “825 MW” package of southwest Minnesota transmission improvements currently being implemented is for the purpose of increasing generation outlet capacity by 400 MW, to a total of 825 MW. Design of these system additions was based on the presumption that incremental generation additions would be split approximately 50/50 between the north end (Yankee) and the south end (Fenton) of the Ridge. The Buffalo Ridge-Yankee-White 115 kV line is for the purpose of allowing connection of the new generation on the northern portion of the Ridge.

The “825 MW” system design was for a total of 200 MW of generation interconnection at or near Yankee Substation. In contrast, Yankee interconnection requests being reviewed by MISO total at least 500 MW. As expected, power system performance at these elevated levels is unsatisfactory.

The voltage collapse situation being observed in the Yankee/Buffalo Ridge substation subarea is straightforward in nature. The Buffalo Ridge and Yankee substations can be considered a “generation island.” From this island there are three 115 kV outlet lines:

- Buffalo Ridge-Lk Yankton
- Buffalo Ridge-Pipestone
- Yankee-White

Upon outage of the Yankee-White 115 kV line--the shortest, and “strongest”, due to the White 345/115 kV transformation--Yankee is radially connected to Buffalo Ridge; all the Yankee and Buffalo Ridge generation output must be carried by the remaining two circuits: Buffalo Ridge-Pipestone and Buffalo Ridge-Lake Yankton. These circuits are each 20 miles in length, with an impedance of approximately 0.12 pu (100 MVA base). Even under a “best-case” scenario where these two lines were to be equally

loaded, as the Yankee generation is increased, the reactive consumption ( $I^2X$ ) of each Yankee/Buffalo Ridge line will be as follows:

<u>Injct. to 115kV, MW</u>			<u>Reactive Consumption, MVAR</u>				<u>Reactive Supply, MVAR</u>				<u>MVAR Deficit</u>
<u>Buffalo Ridge</u>	<u>Yankee</u>	<u>Total</u>	<u>Buff Ridge- Lk Yanktn</u>	<u>Buff Ridge- Pipestone</u>	<u>Yankee- Buff R</u>	<u>Total</u>	<u>Buffalo Ridge</u>	<u>Yankee</u>	<u>Lake Yanktn</u>	<u>Total</u>	
200	200	400	48	48	34	<b>130</b>	30	60	70	<b>160</b>	--
200	300	500	75	75	76	<b>226</b>	30	90	70	<b>190</b>	<b>36</b>
200	400	600	108	108	134	<b>350</b>	30	120	70	<b>220</b>	<b>130</b>
200	500	700	147	147	210	<b>504</b>	30	150	70	<b>250</b>	<b>254</b>

- Notes: 1. Lk Yankton SVS taken as ½ of 140 MVAR; remaining 50% reserved for Lk Yankton-Lyon Co 115 kV requirements.  
 2. Yankee generation pf capability presumed to be .96 lead/lag.  
 3. Yankee 115/34.5 tx reactive losses ignored.

It is evident that even under this “best-case” scenario, at the higher generation levels (Yankee at 300-500 MW) the resultant VAR consumption on the local transmission lines exceeds the local reactive power supply capability. This causes voltage collapse.

## 2.0 Description of Transmission Options Evaluated

Several transmission options were formulated to address the Yankee/Buffalo Ridge area voltage stability limitation. The candidate options, and their principal features are listed below.

<u>Option</u>	<u>Description</u>	<u>Approx miles of 115 kV</u>		<u>Installed</u>
		<u>new</u>	<u>rebuild</u>	<u>Cost, \$M</u>
0.	Existing System	0	0	0.0
A.	Add 2 <sup>nd</sup> Buffalo Ridge-Lk Yankton 115 kV	20	0	6.6
B.	Add Yankee-Lyon Co 115 kV	47	0	13.4
C.	Add Yankee-White-Toronto 115 kV	10	10	8.2

- Notes: 1. Line costs presumed to be \$250,000 mi for new or rebuild.  
 2. Includes substation allowance of \$800,000 per terminal  
 3. Costs are indicative, intended to be of + 30% accuracy, and were developed without regard to consideration of site-specific conditions.

Although many other transmission options could theoretically be formulated, Options A-C are believed to be representative of the basic “modest-scale” options available to improve Yankee/Buffalo Ridge voltage stability. Consequently, these Options should be considered representative of transmission improvement concepts; implementation details such as exact termination points, facility ratings, bus configurations, etc. would be determined in conjunction with consideration of other transmission system performance considerations and goals.

Study of larger transmission developments involving 230 or 345 kV transmission lines emanating from either Yankee or Buffalo Ridge substations was not within the scope of this analysis. It is probable that such larger developments would also be effective at providing improved Yankee/Buffalo Ridge area voltage stability, and it is also possible such projects may ultimately be justified on the basis of regional

generation outlet considerations beyond the scope of this localized (Yankee/Buffalo Ridge) voltage stability study.

### 3.0 Analysis

In order to better discern the nature of the voltage stability limitation, and to evaluate the effectiveness of possible transmission improvements, Q-V analyses were performed for both the Yankee and Buffalo Ridge 115 kV buses. The following sections describe each transmission option's performance relative to Yankee/Buffalo Ridge voltage stability.

#### 3.10 Existing System

Examination of Graphs B0-0 and Y0-0 shows that under "system intact" conditions, there is no voltage collapse concern throughout the 100 - 500 MW range of Yankee generation.

Graphs B0-1 and Y0-1 (Outage of Yankee-White 115 kV) reveal that

- at the Yankee = 300 MW generation level, although the critical voltage is sufficiently low (approx. 0.85 pu at Yankee, 0.89 at Buffalo Ridge), the slope of the right-hand portion of the curve is very slight; this indicates that small changes in reactive supply will cause large voltage deviations. Operation at 300 MW is nearly certain to be unacceptable.
- At the Yankee = 300 MW generation level, the Lk Yankton SVS "runs out of VARs" at the point corresponding to a Buffalo Ridge voltage of 1.03 pu; this requires approximately 80 MVAR of reactive supply (which does not now exist) at Buffalo Ridge.
- At the Yankee = 300 MW generation level, the post-contingent Buffalo Ridge and Yankee voltages are acceptable (1.01 and 1.03 pu, respectively). However, the Lk Yankton SVS is at full output, and voltage is beginning to decay in that vicinity.
- At the Yankee = 400 MW generation level, critical voltages are 0.97 at Yankee and 0.96 pu at Buffalo Ridge; these are too high, as they are within the normal operating range. Also, Yankee requires at least 30 MVAR additional reactive supply (beyond presumed generation capability) to ensure existence of an operating point at .97 pu voltage.

Conclusions: Voltage performance of existing ("825 MW") system is adequate for the 200 MW Yankee generation level, and likely infeasible at 300 MW. Performance at 400 MW is clearly infeasible; even if additional reactive compensation were provided at Yankee (the location most in need), the critical voltage is too high (.97 pu).

Estimated total Yankee outlet capability: 250 MW.

### 3.12 Option A (Add Buffalo Ridge-Lk Yankton 115 kV #2)

Graphs BA-1 and YA-1 (Outage of Yankee-White 115 kV) reveal that

- at the Yankee = 300 MW generation level, the critical voltages are approx. 0.81 pu at Yankee, and 0.86 at Buffalo Ridge. This is an improvement of 3 - 4% (.03 - .04 pu voltage) compared to the “existing system” condition.
- at the Yankee = 300 MW generation level, slope of the right-hand side of the Q-V curve is improved for both Yankee and Buffalo Ridge.
- at the Yankee = 400 MW generation level, the Buffalo Ridge critical voltage is approx. .91 pu; this is too high for secure operation. Also, slopes of Q-V curves for both Yankee and Buffalo Ridge are essentially zero throughout voltage range of .90 - .95 pu.
- The Lake Yankton SVS VAR supply is depleted at a Buffalo Ridge voltage of 1.04 pu; this is higher than for any of the other Options. This is actually good, as the significance of this is that the Lk Yankton SVS now has greater “reach” toward Buffalo Ridge Sub. If the four existing Lake Yankton 20 MVAR shunt capacitors were upgraded (they are designed for ultimate 40 MVAR capability) the performance of this Option would be improved.

Conclusions: Addition of a 2<sup>nd</sup> Buffalo Ridge-Lk Yankton 115 kV line yields a modest improvement in Yankee/Buffalo Ridge voltage security. Yankee operation at 300 MW would be secure, while operation at 400 would be infeasible.

Estimated total Yankee outlet capability: 350 MW. Upgrade of the Lake Yankton shunt capacitors would likely provide additional capability.

### 3.13 Option B (Add Yankee-Lyon Co 115 kV)

Graphs BB-1 and YB-1 (Outage of Yankee-White 115 kV) reveal that

- at the Yankee = 300 MW generation level, the critical voltages are approx. 0.78 pu at Yankee, and 0.82 at Buffalo Ridge. This is an improvement of 7% compared to the “existing system” condition.
- at the Yankee = 400 MW generation level, the critical voltages are approx. 0.86 pu at Yankee, and 0.88 at Buffalo Ridge. This is an improvement of 1% compared to the “existing system, 300 MW” condition.
- at the Yankee = 400 MW generation level, slope of the right-hand side of the Q-V curve is marginally acceptable.

Conclusions: Addition of a Yankee-Lyon Co 115 kV line yields a noticeable improvement in Yankee/Buffalo Ridge voltage security. Yankee operation at 300 MW would be definitely secure, while operation at 400 MW would also likely be feasible.

Estimated total Yankee outlet capability: 400 MW.

### 3.14 Option C (Add Yankee-White-Toronto 115 kV)

Graphs BC-1 and YC-1 (Outage of White 345/115 kV transformer) reveal that

- at the Yankee = 300 MW generation level, the critical voltages are approx. 0.78 pu at Yankee, and 0.82 at Buffalo Ridge. This is an improvement of 7% compared to the “existing system” condition.
- at the Yankee = 400 MW generation level, the critical voltages are approx. 0.84 pu at Yankee, and 0.85 at Buffalo Ridge. This is an improvement of 3-4% compared to the “existing system, 300 MW” condition.
- at the Yankee = 400 MW generation level, slope of the right-hand side of the Q-V curve is acceptable.
- Throughout the Yankee = 100-400 MW generation range, post-contingent voltage at Yankee is approximately 1.06 pu if Yankee generation reactive output = 0. Approximately 10 - 20 MVAR of reactive absorption is required to keep the 115 kV voltage at 1.05 pu. Although this would increase loading of the Lk Yankton SVS, it does not present a problem, as the Lk Yankton SVS would still be within its regulating range.

Conclusions: Addition of a Yankee-White-Toronto 115 kV line yields a noticeable improvement in Yankee/Buffalo Ridge voltage security. Yankee operation at 400 MW would be definitely secure. Operation at higher levels would likely not be feasible due to near-zero slope of the Buffalo Ridge Q-V characteristic in the voltage range .85 - .94 pu. voltage.

Estimated total Yankee outlet capability: 400 MW.

### 3.2 Performance Summary

The following table summarizes the electrical results from Sections 3.10-3.13 and provides incremental \$/kW installed costs based on the incremental outlet capacities achieved and the indicative costs from Section 2.0.

<u>Option</u>	<u>Description</u>	<u>Est. Yankee outlet, MW</u>	<u>Buff Ridge Critical V @ Yankee = 400 MW</u>	<u>Cost \$/kW</u>
0.	Existing System	250	.96	--
A.	Add 2 <sup>nd</sup> Buffalo Ridge-Lk Yankton 115 kV	350	.91	66
B.	Add Yankee-Lyon Co 115 kV	400	.88	89
C.	Add Yankee-White-Toronto 115 kV	400	.85	55

#### **4.0 Conclusions/Recommendations**

From the standpoint of voltage stability, the “825 MW” “existing system” configuration is not adequate for Yankee generation levels exceeding approximately 250 MW. Since there is no steady-state post-contingency operating point at those higher generation levels, the “stability problem” identified in the MISO Group II studies has its roots in voltage stability--not dynamic stability.

The three transmission options analyzed are each capable of relaxing the “existing system” voltage stability-related Yankee/Buffalo Ridge Sub outlet limitation by approximately 100 to 150 MW. Further increments would be possible if more than one Option were implemented, or if further optimization of these transmission concepts were attempted.

Options A and C appear to offer the best value.

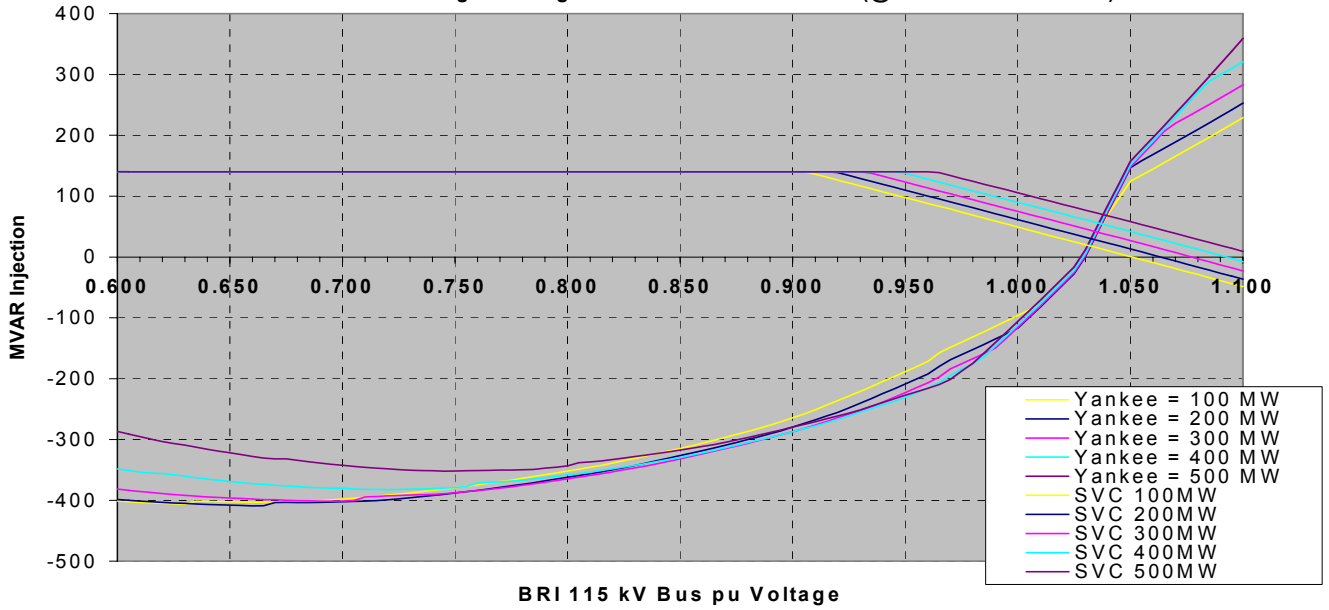
Option B, which involves significantly more new line construction, would appear to be desirable only if it were to offer other significant benefits, such as relaxation of “thermal” limits to Buffalo Ridge area generation outlet capability, or significant loss reductions.

### Buffalo Ridge Substation Q-V, Graph B0-0

Existing System, System Intact

Yankee gen = 100 to 500 MW

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

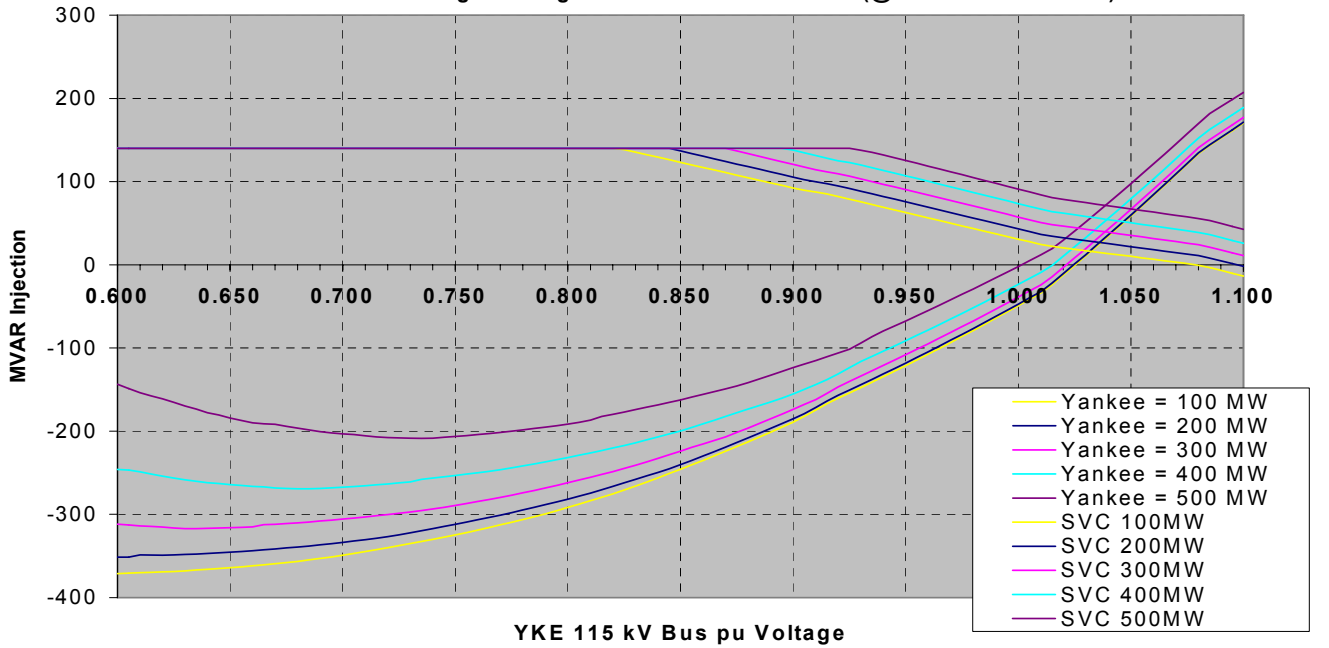


### Yankee Substation Q-V, Graph Y0-0

Existing System, System Intact

Yankee gen = 100 to 500 MW

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

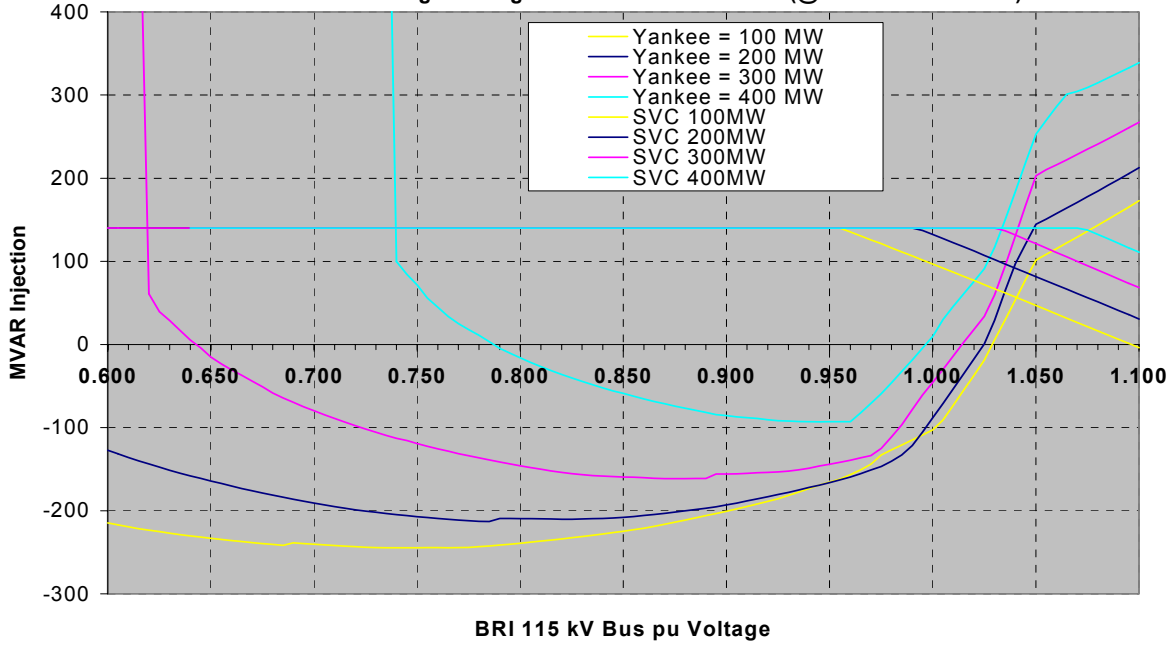


### Buffalo Ridge Substation Q-V, Graph B0-1

Existing System, Outage Yankee-White 115 kV Line

Yankee gen = 100 to 400 MW

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

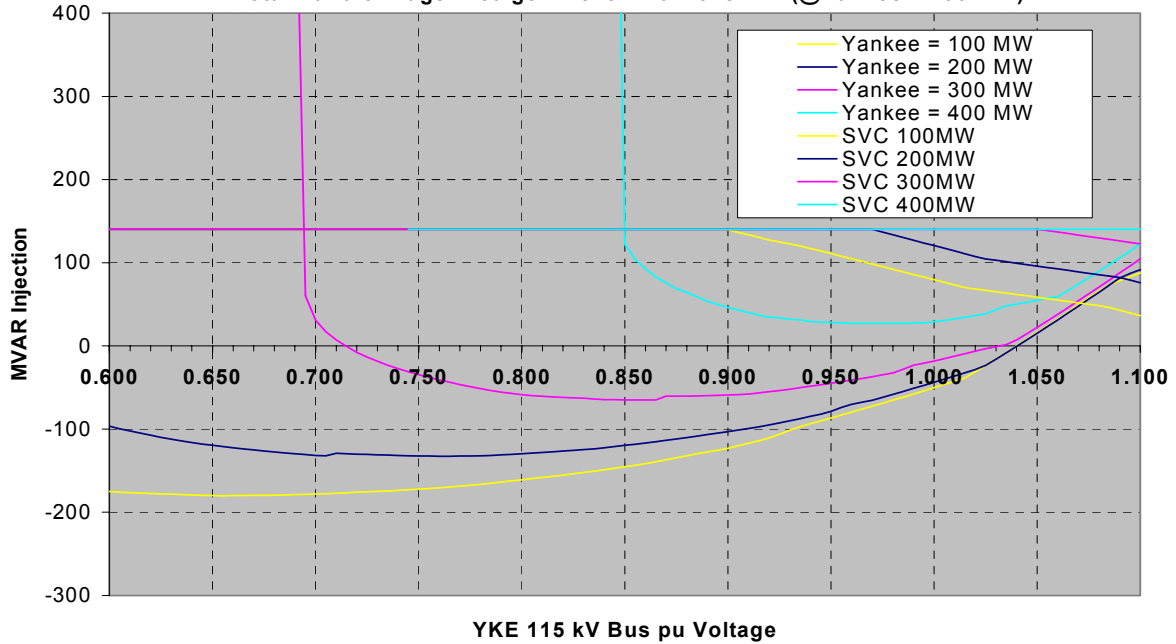


### Yankee Substation Q-V, Graph Y0-1

Existing System, Outage Yankee-White 115 kV Line

Yankee gen = 100 to 400 MW

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

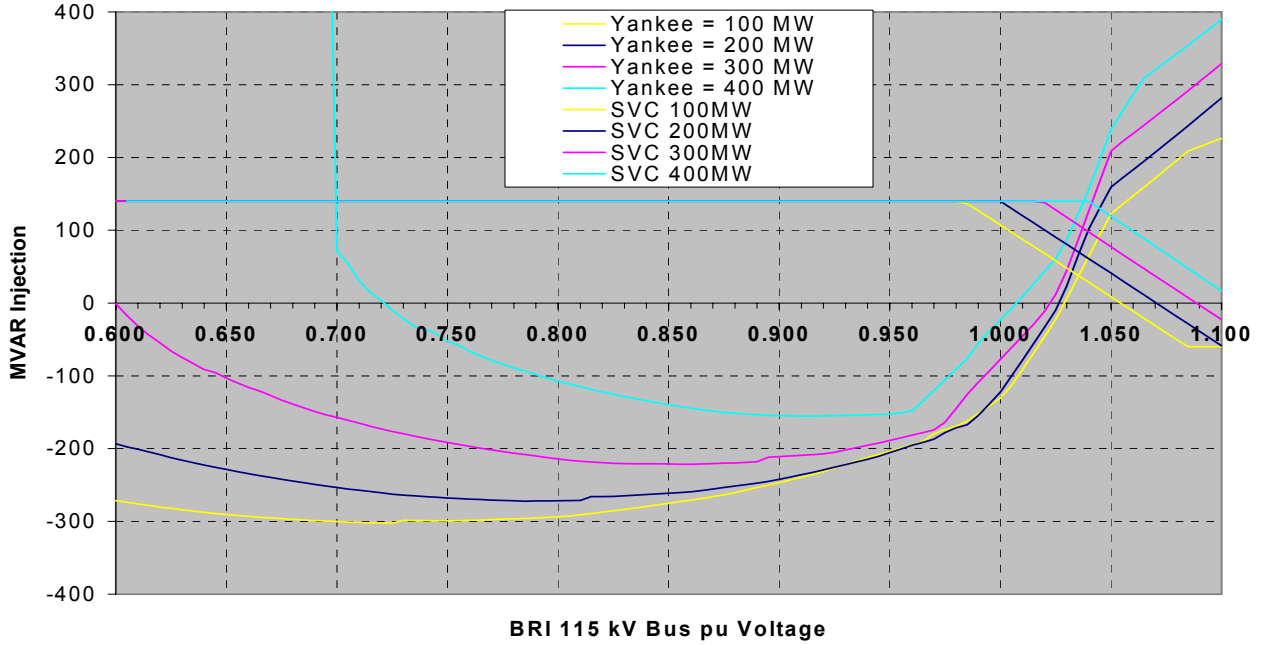


### Buffalo Ridge Substation Q-V, Graph BA-1

Outage Yankee-White 115 kV Line

2nd 115 kV Line from BRI-LAY

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

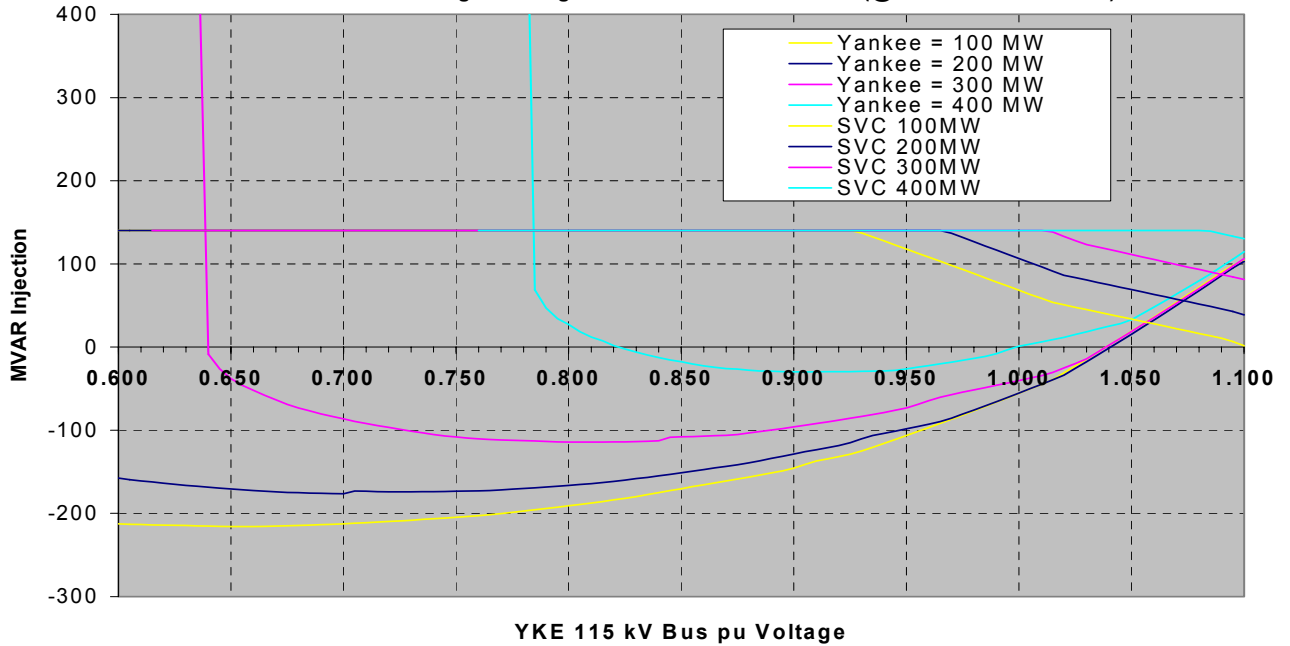


### Yankee Substation Q-V, Graph YA-1

Outage Yankee-White 115 kV Line

2nd 115 kV Line from BRI-LAY

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

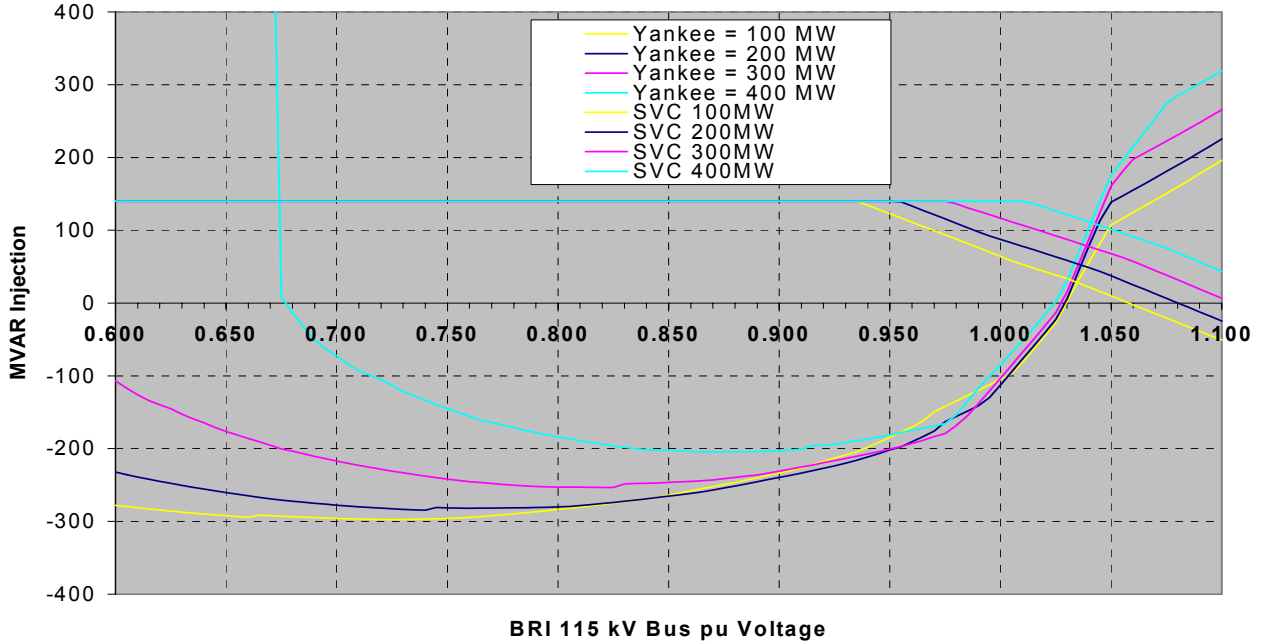


### Buffalo Ridge Substation Q-V, Graph BB-1

Outage Yankee-White 115 kV Line

Yankee gen = 100 to 400 MW, with Yankee to Lyon Co 115 kV

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

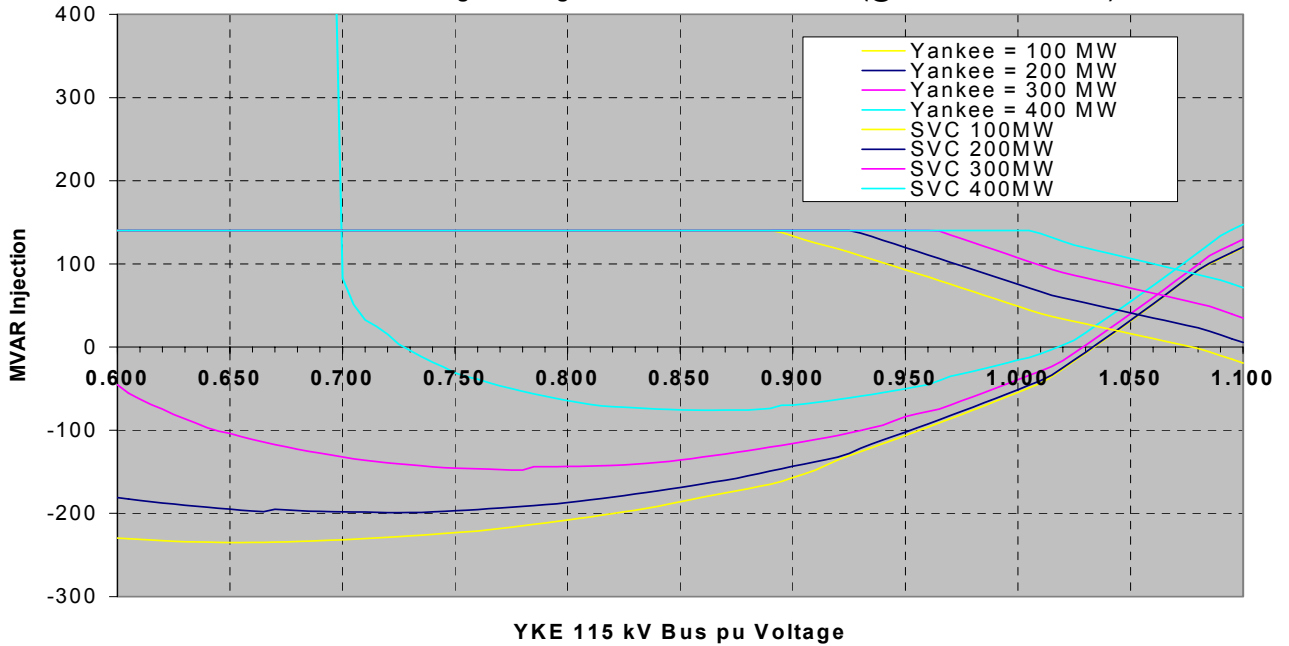


### Yankee Substation Q-V, Graph YB-1

Outage Yankee-White 115 kV Line

New 115 kV line from Lyon Co to Yankee

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

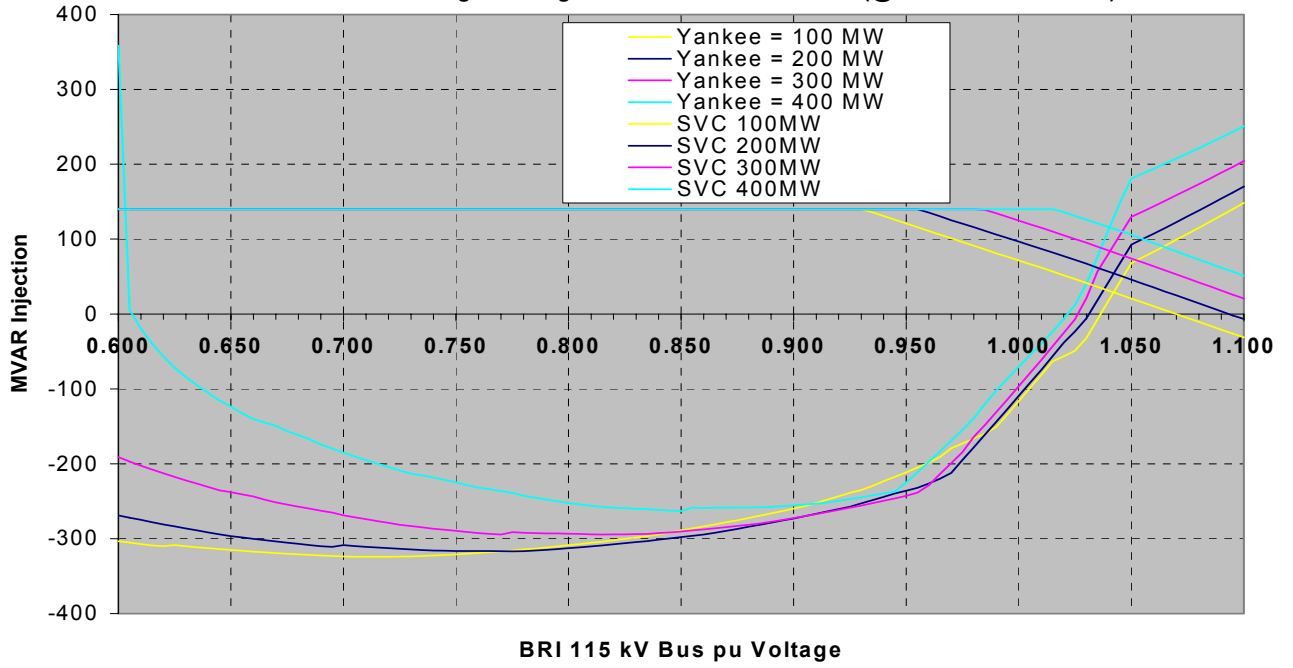


# Buffalo Ridge Substation Q-V, Graph BC-1

Outage White 115/345 kV transformer

Yankee gen = 100 to 400 MW, with Yankee to OTP 115 kV

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)

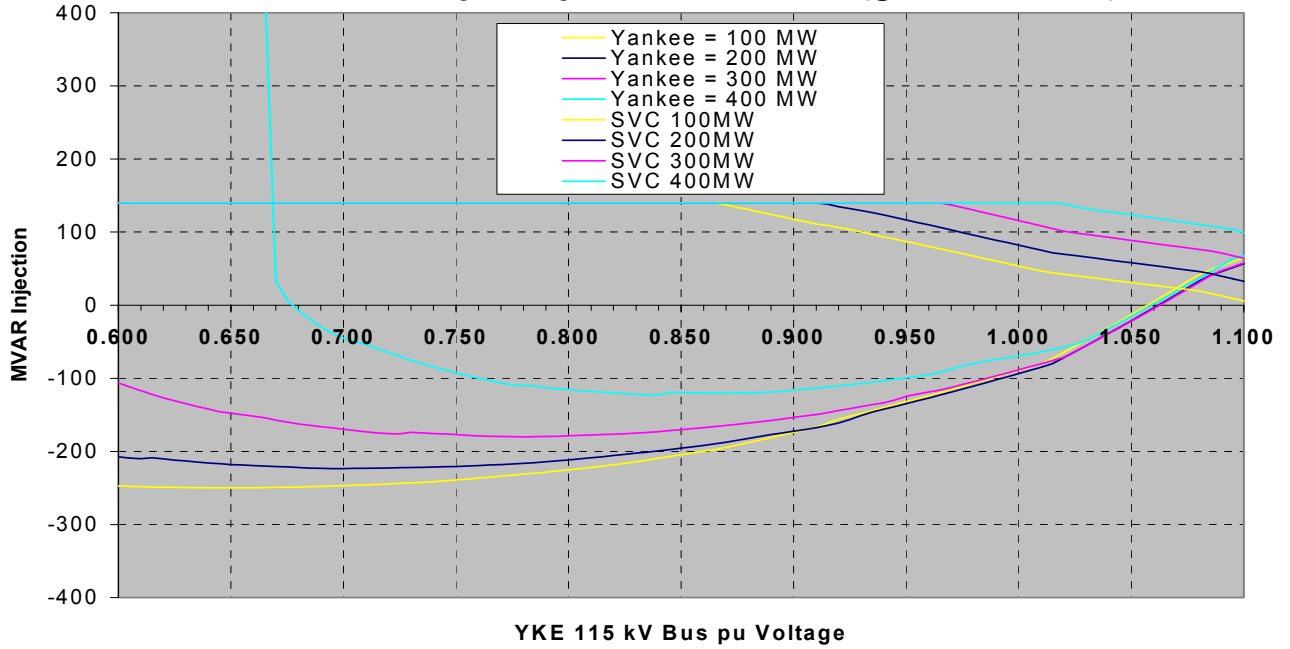


# Yankee Substation Q-V, Graph YC-1

Outage White 115/345 kV transformer

Yankee gen = 100 to 400 MW, with Yankee to OTP 115 kV

Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)



# Appendix F

## Constrained Interface Analysis

MW flow change

Facility Additions Only								
	NDEX	MHEX	GGs	WNE-WKS	GRIS-LINC	Cooper-S	FTCAL-S	MWSI
TTC:	2150	2175	1800	480	1010	1190	776	1480
Actual:	1850.3	1981.5	1429.8	329.4	500.4	420	454.8	1051.2
Option								
1A	-0.2	0.2	-0.9	-0.2	-1.7	0.5	2.1	-4.5
3	1.0	-0.5	0.2	0.5	0.4	1.7	0.8	5.1
5	1.4	-0.8	-0.9	-0.3	-0.3	0.9	1.1	2.9
6	2.1	-0.3	0.0	0.1	0.2	0.4	-0.1	2.1 (Note 1)
9	0.0	0.0	0.0	0.1	-0.1	0.6	0.7	0.0
31A	1.0	-0.6	-0.1	0.7	-0.6	3.9	3.6	4.8
31A6	3.0	-0.6	-0.2	0.4	-0.6	2.5	2.1	4.5 (Note 1)
61A	2.2	-0.4	-0.3	0.4	-0.9	2.5	2.7	2.0 (Note 1)
71A	1.2	-0.5	-0.2	0.3	-1.0	2.3	2.4	3.3
31AB	0.9	-0.6	0.0	0.9	-0.4	4.8	4.3	5.2

Incremental Flows Due to Generation Additions in % DF								
825 to 1225 MW Gen								
	NDEX	MHEX	GGs	WNE-WKS	GRIS-LINC	Cooper-S	FTCAL-S	MWSI
Option								
1A	-1.9	0.4	0.2	0.2	1.3	-0.2	2.9	-28.5
3	-1.8	0.5	0.2	0.1	1.4	-0.7	2.4	-28.6
5	-2.1	0.6	0.2	0.1	1.2	-0.7	2.5	-28.4
6	1.8	0.6	0.3	0.2	1.5	-0.4	2.5	-28.1 (Note 1)
9	-2.0	0.7	0.2	0.1	1.3	-0.7	2.4	-28.3
31A	-1.9	0.6	0.2	0.2	1.3	-0.2	2.9	-28.0
31A6	1.7	0.6	0.3	0.3	1.5	0.1	3.0	-27.7 (Note 1)
61A	1.8	0.5	0.3	0.3	1.5	0.0	3.0	-27.9 (Note 1)
71A	-1.8	0.6	0.2	0.2	1.3	-0.3	2.8	-28.1
31AB	-2.0	0.6	0.3	0.3	1.5	0.2	3.2	-27.8

Note 1: NDEX definition revised to include Toronto-White 115 kV line.  
Actual net effect on NDEX and MHEX, except for effect of losses, is zero since NDEX and MHE are closed contours and neither source nor sink is inside either area.

Note 2: Option "31AB" is Option 31A, with addition of 2nd Yankee-White 115 kV & 2nd White (Brookings Co) 345/115 kV tx.

J Standing  
R Gonzalez  
3/18/2005  
Constrained.interfaces.xls

# Appendix G

## Power System Losses Data

G-1 Total System Losses

G-2 Losses by Area

# Appendix G1

Total System Losses (MW)							Difference with respect to Option 9					
Option	825	(100MW @YKE) 925	(200MW @YKE & 150MW @FNT) 1175	(200MW @YKE & 200MW @FNT) 1225	(250MW @YKE & 250MW @FNT) 1325	(350MW @YKE & 350MW @FNT) 1525	825	925	1175	1225	1325	1525
0	13171.0	13201.0	13276.6	13292.4	13324.5	13399.8	2.0	1.9	1.3	1.4	1.8	1.6
1A	13161.7	13191.4	13263.8	13278.5	13308.2	13378.4	-7.3	-7.7	-11.5	-12.5	-14.5	-19.8
2	13167.1	13196.7	13273.5	13289.7			-1.9	-2.4	-1.8	-1.3		
2M	13165.8	13195.3	13272.3	13288.0			-3.2	-3.8	-3.0	-3.0		
3	13167.3	13197.1	13273.2	13288.5	13320.7	13395.1	-1.7	-2.0	-2.1	-2.5	-2.0	-3.1
4	13167.5	13197.3	13274.2	13290.4	13320.7	13395.7	-1.5	-1.8	-1.1	-0.6	-2.0	-2.5
5	13161.9	13191.5	13266.7	13282.1	13313.4	13386.5	-7.0	-7.6	-8.6	-8.9	-9.3	-11.7
6	13165.9	13194.4	13268.2	13281.3	13314.4	13385.2	-3.1	-4.7	-7.1	-9.7	-8.3	-13.0
7	13172.5	13201.9	13283.4	13301.4			3.5	2.8	8.1	10.4		
8	13164.0	13192.9	13269.3	13285.5			-5.0	-6.2	-6.0	-5.5		
9	13169.0	13199.1	13275.3	13291.0	13322.7	13398.2	0.0	0.0	0.0	0.0	0.0	0.0
31A	13161.0	13190.5	13263.1	13277.3	13307.4	13377.6	-8.0	-8.6	-12.2	-13.7	-15.3	-20.6
61A	13159.6	13187.9	13258.5	13270.3	13301.5	13368.7	-9.4	-11.2	-16.8	-20.7	-21.2	-29.5
31A6	13157.6	13185.7	13255.7	13267.7	13299.0	13365.0	-11.4	-13.4	-19.6	-23.3	-23.7	-33.2
345kV	13115.3	13141.7	13213.9	13227.4	13259.0	13326.8	-53.7	-57.4	-61.4	-63.6	-63.7	-71.4
71A	13161.4	13190.3	13263.1	13278.1	13308.4	13377.5	-7.6	-8.8	-12.2	-12.9	-14.3	-20.7
With Respect to Option 0, 825												
Option	825	925	1175	1225	1325	1525						
0	0.0	30.0	105.6	121.4	153.5	228.8						
1A	-9.3	20.4	92.8	107.5	137.2	207.4						
2	-3.9	25.7	102.5	118.7								
2M	-5.2	24.3	101.3	117.0								
3	-3.7	26.1	102.2	117.5	149.7	224.1						
4	-3.5	26.3	103.2	119.4								
5	-9.1	20.5	95.7	111.1	142.4	215.5						
6	-5.1	23.4	97.2	110.3	143.4	214.2						
7	1.5	30.9	112.4	130.4								
8	-7.0	21.9	98.3	114.5								
9	-2.0	28.1	104.3	120.0	151.7	227.2						
31A	-10.0	19.5	92.1	106.3	136.4	206.6		J Standing				
61A	-11.4	16.9	87.5	99.3	130.5	197.7		Xcel Energy				
31A6	-13.4	14.7	84.7	96.7	128.0	194.0		1/12/2005				
345kV	-55.7	-29.3	42.9	56.4	88.0	155.8		Total_System_Losses 01-12-05.xls				
71A	-9.6	19.3	92.1	107.1	137.4	206.5						

**Appendix G-2**  
**Loss Analysis - SW Minnesota**  
(Losses, MW, 2007 Summer off-peak)

	Option	SW MN Buffalo Ridge Generation		MW Increase	% of 500 MW
		825 MW	1325 MW		
<b>Marshall</b> (Note 1)	0	0.42	0.78	0.36	
	9	0.44	0.80	0.36	
	31A	0.62	1.09	0.47	
	31A6	0.51	0.85	0.34	
	31AM	0.61	1.08	0.47	
<b>WAPA</b>	0	321.27	334.45	13.18	
	9	321.37	334.48	13.11	
	31A	321.21	334.71	13.50	
	31A6	320.18	333.76	13.58	
	31AM	321.21	334.69	13.48	
<b>OTP</b>	0	91.62	93.39	1.77	
	9	91.63	93.32	1.69	
	31A	91.32	93.08	1.76	
	31A6	92.32	95.72	3.40	
	31AM	91.31	93.08	1.77	
<b>GRE</b>	0	98.38	101.41	3.03	
	9	98.35	101.37	3.02	
	31A	98.32	101.34	3.02	
	31A6	98.60	101.78	3.18	
	31AM	98.32	101.34	3.02	
<b>ALTW</b>	0	68.77	77.97	9.20	
	9	68.91	78.00	9.09	
	31A	69.18	79.08	9.90	
	31A6	68.89	78.74	9.85	
	31AM	69.18	79.08	9.90	
<b>XCEL/NSP</b>	0	471.89	546.40	74.51	
	9	469.62	544.55	74.93	
	31A	460.76	524.95	64.19	
	31A6	457.65	514.36	56.71	
	31AM	460.77	524.96	64.19	

(Note 3) **Sub Total**

0	101.7	20.3
9	101.8	20.4
31A	92.4	18.5
31A6	86.7	17.3
31AM	92.4	18.5

(Note 4) **Grand Total**

0	153.5	30.7
9	151.7	30.3
31A	136.4	27.3
31A6	128.0	25.6
31AM	136.4	27.3

Notes:

1. Marshall losses are stated as a breakout of the total WAPA losses.
2. Option "31AM" is Option 31A with the addition of a 115 kV line from Marshall SW to Lyon Co
3. Sub-total does not involve summation of "Marshall" loss figure because Marshall losses

# Appendix H

## Options' Components and Indicative Costs

<b>Buffalo Ridge Incremental Generation Outlet Transmission Study</b>							
	Installed Cost Estimates for Transmission Options ("Base Plan" costs) (not including reactive power needs)						
						Installed Cost \$1,000's	
<b>Option 1</b>	Add Chanarambie-Nobles Co 115 kV #2						
		qty	unit	each	total		
	New Chanarambie-Nobles Co 115 kV #2 (600 MVA)	26	mi	350	9,100		
	115 kV line term at Nobles Co	1	ea	850	850		
	115 kV line term at Chanarambie	1	ea	850	850		
	2nd 345/115 tx at Nobles Co (672 MVA)	1	ea	2,500	2,500		
	345 kV breaker & buswork at Nobles Co (for 2nd tx)	1	ea	800	800		
	115 kV breaker & buswork at Nobles Co (for 2nd tx)	1	ea	700	700		
	Total				14,800		
<b>Option 1A</b>	Add Fenton-Nobles Co 115 kV #2						
	New Fenton-Nobles Co 115 kV #2 (600 MVA)	14	mi	350	4,900		
	115 kV line term at Nobles Co	1	ea	850	850		
	115 kV line term at Fenton	1	ea	850	850		
	2nd 345/115 tx at Nobles Co (672 MVA)	1	ea	2,500	2,500		
	345 kV breaker & buswork at Nobles Co (for 2nd tx)	1	ea	800	800		
	115 kV breaker & buswork at Nobles Co (for 2nd tx)	1	ea	700	700		
	Total				10,600		
<b>Option 2</b>	Add Lyon Co-Minn Valley 115 kV #2						
	Rebuild Lyon Co-Yellow Med-Minn Valley 69-->115 kV (310 MVA)	30	mi	260	7,800		
	115 kV line term at Lyon Co	1	ea	850	850		
	115 kV line term at Minn Valley	1	ea	850	850		
	Reconfigure Minn Valley 115 kV bus to breaker-and-a-half	1	ea	3,000	3,000		
	Convert Yellow Med 69-23 kV sub to 115-23 kV	1	ea	500	500		
	Total				13,000		
<b>Option 2M</b>	Add Lyon Co-Minn Valley 115 kV #2 & Marshall Bypass						
	Rebuild Lyon Co-Yellow Med-Minn Valley 69-->115 kV (310 MVA)	30	mi	260	7,800		
	115 kV line term at Lyon Co	1	ea	850	850		
	115 kV line term at Minn Valley	1	ea	850	850		
	Reconfigure Minn Valley 115 kV bus to breaker-and-a-half	1	ea	3,000	3,000		
	Convert Yellow Med 69-23 kV sub to 115-23 kV	1	ea	500	500		
	115 kV line term at Lyon Co	1	ea	850	850		
	115 kV line term at Marshall East River	3	ea	600	1,800		
	Add Lyon Co-Marshall East River 115 kV (310 MVA)	4	mi	260	1,040		
	Total				16,690		
<b>Option 3</b>	Establish Lk Yankton-Lyon Co 115 kV #3						
	New Lk Yankton-Marshall SE 115 kV (310 MVA)	20	mi	260	5,200		
	115 kV line term at Lk Yankton	1	ea	850	850		
	115 kV line term at Marshall SE or equiv.	1	ea	850	850		
	Total				6,900		

<b>Option 4</b>	Add Lyon Co-Franklin 115 kV						
	Rebuild Lyon Co-Milroy 69-Sheridan-Redwood-Franklin to 115/69 dckt (115 kV @ 310 MVA)	44	mi	400	17,600		
	115 kV line term at Lyon Co	1	ea	850	850		
	115 kV line term at Franklin	1	ea	850	850		
	Reconfigure Franklin 115 kV bus to ring	1	ea	1,300	1,300		
	Total					20,600	
<b>Option 5</b>	Add Chanarambie-Watonwan Jct 115 kV						
	New Chanarambie-Watonwan Jct 115 kV (310 MVA)	50	mi	260	13,000		
	115 kV line term at Chanarambie	1	ea	850	850		
	115 kV line term at Watonwan Jct	1	ea	850	850		
	Develop 115 kV ring bus at Watonwan Jct	1	ea	1,000	1,000		
	Total					15,700	
<b>Option 6</b>	Add Yankee-White-OTP Toronto 115 kV						
	New Yankee-White 115 kV #2 (600 MVA)	10	mi	350	3,500		
	New White-Toronto 115 kV (310 MVA)	19	mi	260	4,940		
	115 kV line term at Yankee	1	ea	850	850		
	115 kV line terms at White	2	ea	850	1,700		
	115 kV line term and develop ring bus at Toronto	1	ea	1,850	1,850		
	Total					12,840	
<b>Option 7</b>	Establish Yankee-Lyon Co 115 kV						
	New Yankee-Marshall SE 115 kV (310 MVA)	40	mi	260	10,400		
	New Marshall SE-Lyon Co 115 kV (310 MVA)	6	mi	260	1,560		
	115 kV line term at Yankee	1	ea	850	850		
	115 kV line term at Marshall SE or equiv.	2	ea	850	1,700		
	115 kV line term at Lyon Co	1	ea	850	850		
	Total					15,360	
<b>Option 8</b>	Establish Yankee-Lyon Co-Franklin 115 kV						
	New Yankee-Marshall SE 115 kV (310 MVA)	40	mi	260	10,400		
	New Marshall SE-Lyon Co 115 kV (310 MVA)	6	mi	260	1,560		
	115 kV line term at Yankee	1	ea	850	850		
	115 kV line term at Marshall SE or equiv.	2	ea	850	1,700		
	115 kV line term at Lyon Co	1	ea	850	850		
	Rebuild Lyon Co-Milroy 69-Sheridan-Redwood-Franklin to 115/69 dckt (115 kV @ 310 MVA)	44	mi	400	17,600		
	115 kV line term at Lyon Co	1	ea	850	850		
	115 kV line term at Franklin	1	ea	850	850		
	Reconfigure Franklin 115 kV bus to ring	1	ea	1,300	1,300		
	Total					35,960	
<b>Option 9</b>	Reconductors Only						
	Reconductor Lyon Co-Marshall Sw Stn 115 kV	4	mi	100	400		
	Rebuild Svea Tp-Litch Tp 69 kV	24.7	mi	150	3,705		
	Reconductor Pipestone-Pathfinder 115 kV	42	mi	100	4,200		
	Total					8,305	
12/10/2004							
Option.cost.ests1.xls							

# Appendix I

## Schedules

# Appendix J

## Big Stone #1/NDEX Sensitivity Analysis

# Sensitivity of TLTG results to NDEX and Big Stone Generation Levels

## Background

The technical and economic evaluations of the transmission options presented in the body of this report are based upon results from an extensive set of powerflow simulations, focusing on the off-peak load condition. These simulations represent one set of possible flow patterns resulting from the selected combination of load level, power transfers, and generation pattern.

Following completion of most of the technical analysis, it was noted that the base case models employed inadvertently had the existing Big Stone Unit 1 at only 122 MW net output. Although this is a possible “minimum load” scenario, operation of Big Stone at or near full output is more common, and must be accommodated. Increased generation at Big Stone will tend to increase loading on the Granite Falls-Minn Valley-Panther-McLeod-Blue Lk 230 kV line. Since this line is also an important outlet path for Buffalo Ridge area generation, incremental loading on this path is of concern.

Another matter of interest is that in recent months the MAPP Design Review Subcommittee (DRS) has accepted technical studies supporting an increase in NDEX limit of 130 MW (from 1950 to 2080 MW). This increase has been shown to be achievable with the combination of a capacitor addition proposed for Watertown, SD (by WAPA) and a generator addition at Groton, SD (by Basin Electric). The powerflow models used in the Buffalo Ridge analysis to date have NDEX at 1850 MW. Similar to Big Stone, increased NDEX loading also contributes to increased power flow on the Granite Falls-Minn Valley-Panther-McLeod-Blue Lk 230 kV line.

The sensitivity analysis described in the following sections evaluates the incremental effect of Big Stone generation level and the planned increase in NDEX operating limit. The powerflow modeling also reflects an update to the 69 kV system configuration in the Troy, MN vicinity.

## Analysis

### Method & Results

This sensitivity analysis was performed to evaluate the effect of having Big Stone Unit #1 at full output, and the effect of the planned increase in NDEX dynamic limit. This was accomplished by increasing the Big Stone Unit #1 output to 415 MW and sending the 293 MW incremental output eastward (to Milwaukee [Oak Creek]). This action caused the NDEX loading to increase to 2135 MW, which is approximately 102% of the 2080 MW limit most recently recognized by the MAPP DRS. Consequently, this is a severe test of West-->East loading through western Minnesota.

Another model revision which was made for this sensitivity analysis relates to the Troy 69 kV switching station, which is being placed in service in late 2005. Troy is located on the 69 kV system between Minn Valley and Panther. The base case powerflow models were revised to correctly represent the 69

kV configuration in the Troy vicinity. This relatively minor model revision reduces pre- and post-contingent loadings on the Minn Valley-Panther 230 kV and the Panther 230/69 kV transformer.

Table 1 shows the incremental effect which the above-described Big Stone/NDEX changes to the base case powerflow models have on the limiting facilities encountered by four of the transmission options under study. These four options were chosen as representative of the full set of options, as they implement different transmission outlet upgrade strategies.

Table 1  
SW Minnesota Buffalo Ridge Area  
Total Generation Outlet Capacity, MW

Limiting Facility	Rating MVA	NDEX	Transmission Option							
			31A		31A6		5		9	
			low	high	low	high	low	high	low	high
Granite Falls-Minn Val 230	388		1457	<b>1148</b>	1398	<b>1139</b>	1487	<b>1195</b>	1463	<b>1143</b>
Minn Valley-Panther 230	388		1358	<b>1190</b>	1316	1185	1423	<b>1268</b>	1377	<b>1200</b>
Panther 230/69 tx	70		1302	1179*	1255	1165*	--	--	1301	1168*
Minn Valley 230/115 tx	187		1641	1473	1606	1473	--	1616	--	1464
Pipestone-Pathfinder 115	225		--	--	--	--	1577	1507	1134	1098
Canby-Granite Falls 115	96		--	--	1641	<b>1168</b>	--	--	--	--
Toronto-Burr 115	144		--	--	1490	1574	--	--	--	--
Johnson Jct-Ortonville 115	97		--	--	--	<b>641</b>	--	--	--	--

Notes:

1. The “low NDEX” values in Table 1 are from the corresponding tables in Appendix B. This represents the condition of NDEX = 1850 MW, Big Stone = 122 MW.

The “high NDEX” values are derived from new “TLTG” simulations performed for this sensitivity analysis. This corresponds to the condition of NDEX = 2135 MW, Big Stone = 415 MW.

The “raw” outputs for these new “high NDEX” TLTG simulations are provided in Appendix M-2. Since the base cases already have 918 MW of Buffalo Ridge generation represented, this amount is added to the MW limits indicated in the TLTG outputs to arrive at the “Buffalo Ridge Area Total Generation Outlet” MW limits displayed in Table 1.

2. “\*” indicates distribution factor is below 2.0%; due to Troy Switching Station-related model update.
3. Outlet limits are based on permissible post-contingent loading of 110% of continuous rating for lines & 130% for transformers.

Observations: (High increment; 500 - 575 MW)

From study of Table 1, it is observed that if a target Buffalo Ridge generation outlet level of approximately 1325 - 1400 MW were selected (825 plus 500 - 575 MW), the “new” limiters shown in **bold** would be encountered, due to the effects of the higher Big Stone/NDEX level.

The Granite Falls-Minn Valley 230 kV reconductor would therefore be added to each Option, and the Minn Valley-Panther 230 kV reconductor would be required for all the options studied, except for 31A6, which already includes it.

The Johnson Jct-Ortonville 115 kV overload appears as a new limiter, only for Option 31A6, because Buffalo Ridge generation increase has a distribution factor of over 2.0% on this facility for outage of the Granite Falls-Blair/Watertown 230 kV double circuit line. However, this overload would be addressed by the proposed Big Stone 2 interconnection improvements, and is actually also present for all other Options, but at levels slightly below the 2.0% reporting threshold.

The only other new limiter encountered in this 1325 - 1400 MW range is the Canby-Granite Falls 115 kV overload, in the case of Option 31A6. As with Johnson Jct-Ortonville 115 kV, the problematic contingency is loss of the Granite Falls-Blair/Watertown 230 kV double circuit line. The resultant overload is understandable, since both the NDEX/Big Stone increase and the added Buffalo Ridge generation cause incremental loading on this line.

Consequently, Option 31A6 has the relative advantage of not gaining the need for the 30-mile Minn Valley-Panther 230 kV reconductor but has the relative disadvantage of acquiring the need for the Canby-Granite Falls 115 kV rebuild (39 miles). The cost of the Canby-Granite Falls rebuild would be considerably higher than the avoided cost of the Minn Valley-Panther reconductor, so this represents a net penalty against the economics of Option 31A6, compared to what is encountered by the other Options.

Relationship to Big Stone 2 unit addition

Based on the results of the MISO interconnection study for this proposed generating unit, the Canby-Granite Falls 115 kV line is proposed to be rebuilt as a 230 kV line. Consequently, this “Canby-Granite Falls 115 kV rebuild” cost penalty against Option 31A6 would not be encountered if implementation of Option 31A6 were coordinated with the Big Stone 2 transmission improvements.

Observations: (Moderate increment; 375 MW)

If a lower Buffalo Ridge outlet capacity target level than 1325 - 1400 MW were chosen, the impacts would be slightly different. For example, at 1200 MW (825 + 375 MW) all Options would still need the addition of the Granite Falls-Minn Valley 230 kV reconductor, but Option 5 would not need the Minn Valley-Panther 230 kV reconductor, as it is not encountered until the 1268 MW Buffalo Ridge outlet level. Option 31A6 would suffer, as it gains (at 1185 MW) the need for the Minn Valley-Panther 230 kV reconductor, which previously was not needed until the 1316 MW Buffalo Ridge generation level. Consequently, Option 31A6 becomes less competitive at these lower Buffalo Ridge outlet levels.

## Conclusions

The effect of the Big Stone #1/NDEX increase is to accelerate the need for the Granite Falls-Minn Valley and Minn Valley-Panther 230 kV reconductors. Increased loadings on these 230 kV line segments leave less capacity for accommodating incremental loadings arising from Buffalo Ridge generation increases. Most transmission options studied suffer relatively similar impacts due to this change in base case conditions.

The exception to this general rule is Option 31A6. Presuming at least 1200 MW of total Buffalo Ridge outlet capability is desired (825 + 375 MW), Option 31A6 would incur the significant cost (approximately \$10 million) for the Canby-Granite Falls 115 kV rebuild if it (Option 31A6) were implemented prior to the Big Stone Unit 2 interconnection facility improvements. If this Option were implemented later, (such as by initially implementing Option 31A and later adding the White-Toronto 115 kV line segment) no such penalty is suffered.

Except for the Option 31A6 considerations discussed above, the differences in incremental impact observed among the Options are not significant, and therefore do not affect the conclusion that Option 31A is the Preferred Plan. Similarly, the conclusion that the addition of the White-Toronto 115 kV line also appears to be advantageous--particularly if a relatively large increment of Buffalo Ridge area generation outlet capacity is desired--remains correct, but tempered by the timing considerations described above.

R Gonzalez, PE  
3-28-2005  
NDEX Sensitivity1.doc

# Appendix K

## Double-Circuit Line Considerations

# Buffalo Ridge Area Transmission Projects for Increased Generation Outlet: Considerations Relating to Double-Circuit Transmission Lines

## **Background**

Transmission improvements presently under way on the Buffalo Ridge (“825 MW projects”) include addition of a Nobles Co-Fenton-Chanarambie 115 kV line, and a White-Yankee-Buffalo Ridge 115 kV line. These lines provide outlet from the Buffalo Ridge area generation sites to the Nobles Co and White 345/115 kV substations.

The “Buffalo Ridge Incremental Generation Outlet” transmission study has pursued the identification of feasible transmission options for increasing outlet capacity from the Buffalo Ridge by several hundred MW. The Options identified as most desirable all involve addition of a second Nobles Co-Fenton 115 kV line, and possibly also a second White-Yankee 115 kV line. This finding has prompted the question of whether it might be desirable to construct the Nobles Co-Fenton and White-Yankee lines with double-circuit structures, to accommodate future second circuits.

The following sections describe the considerations that must be taken into account in determining whether double-circuit construction may be advantageous or acceptable.

## **Discussion**

### Need

There are two needs with regard to increased outlet capability: ensure voltage stability, and prevent overloads; these are described in the following paragraphs.

### *Voltage Stability*

The “825 MW” facilities were designed to accommodate 400 MW of new generation on the Buffalo Ridge, presumed to be approximately 50% (200 MW) on the northern portion of the Ridge (Yankee Substation) and approximately 50% (200 MW) on the southern portion (Fenton Substation). In contrast, presently there are requests in the MISO Interconnection Queue totaling 500 MW at Yankee and well over 200 MW at Fenton/Chanarambie.

Buffalo Ridge “Group 2” interconnection studies performed by MISO indicated a post-contingent dynamic stability problem for the Yankee generation additions. The critical contingency is loss of the Yankee-White 115 kV circuit; this loss of access to the White 345/115 kV outlet causes high reactive power consumption on the remaining lines in the Yankee/Buffalo Ridge Sub vicinity. Subsequent detailed analysis performed by Xcel Energy as part of the Buffalo Ridge Incremental Generation Outlet Study has determined that the “stability” limitation identified by MISO is actually a “voltage stability” limitation: following outage of the Yankee-White 115 kV line, at Yankee generation levels higher than approximately 250 MW, there is inadequate reactive power supply available to maintain normal voltage levels; voltage collapse occurs.

There are two principal options available to address this Yankee voltage collapse vulnerability. One is to install a Static VAR Compensator (SVC) at the Buffalo Ridge Substation; the other option is to establish a second Yankee-White 115 kV circuit. Although at this time no decision has been made regarding which option to pursue, it should be noted that aside from the voltage stability benefits, the second Yankee-White 115 kV circuit also helps alleviate thermal outlet limitations, and therefore may be advantageous compared to the SVC option.

If a second Yankee-White 115 kV circuit is to be installed, it must be physically separate from the first circuit; otherwise, the desired Yankee-White redundancy will not be achieved, and generation outlet capacity will remain constrained by both voltage stability and post-contingent overloads.

The Fenton Substation situation is similar to that at Yankee. Upon loss of the Fenton-Nobles Co 115 kV line, voltage collapse is possible at high generation levels (beyond the initial 200 MW) due to loss of the Nobles Co 345/115 kV outlet. Establishing a second Fenton-Nobles Co 115 kV circuit will address this voltage collapse concern, provided that the second circuit is physically independent of the first circuit. Again, double-circuit construction is not appropriate.

Thermal limitations

Following completion of the “825 MW” set of Buffalo Ridge area transmission improvements, among the most severe contingencies with respect to limiting generation outlet capability are those involving loss of either of the 345 kV outlet paths: Nobles Co-Fenton and White-Yankee 115 kV. Outage of either line, or its associated 345/115 kV transformer (at Nobles Co or White) presents two limitations:

1. overload of other transmission lines or transformers;
2. voltage collapse at Yankee or Fenton

For example, in the Buffalo Ridge Incremental Generation Outlet Study the following “thermal” limiters were among those identified for the “825 MW” system:

**Buffalo Ridge**

<u>Outlet, MW</u>	<u>Limiting Facility</u>	<u>Contingency</u>
1134	Pipestone-Pathfinder 115 kV	Nobles Co-Fenton 115 or Nobles Co 345/115 tx
1231	Nobles Co 345/115 tx	(system intact)
1239	Lyon Co-Yellow Med 69	Nobles Co-Fenton 115 or Nobles Co 345/115 tx
1313	Nobles Co 345/115 tx	White-Yankee 115 or White 345/115 tx
1347	Minn Valley-Yellow Med 69	Nobles Co-Fenton 115 or Nobles Co 345/115 tx
1363	Marshall-Erie Rd 115	Nobles Co-Fenton 115 or Nobles Co 345/115 tx
1373	Chandler-Chandler Tp 69	Nobles Co-Fenton 115 or Nobles Co 345/115 tx
1403	Lk Yankton-Buffalo Ridge 115	White-Yankee 115 or White 345/115 tx
1404	Marshall Tp-Granite Falls 115	Nobles Co-Fenton 115 or Nobles Co 345/115 tx

It is evident that if another Nobles Co-Fenton 115 kV circuit (#2) were developed by constructing a second (independent) Nobles Co-Fenton line, this would neutralize all the generation outlet limitations listed above which arise from the Nobles Co-Fenton (#1) line outage.

In contrast, if this second Nobles Co-Fenton 115 kV circuit were instead installed as a second circuit on double-circuit structures carrying both the #1 and #2 circuits, the generation outlet benefit of having two

circuits would not be obtained, as the circuits would be subject to common-mode failures, and therefore the required redundancy would not be achieved.

Similar considerations apply to establishment of a second Yankee-White 115 kV circuit. The second Yankee-White circuit is required both for “thermal” (overload) reasons and also to prevent voltage collapse following outage of the #1 circuit. In order to achieve the generation outlet capacity increase for which the second circuit is intended, it must be physically independent of the first circuit.

The primary common-mode failures for multiple-circuit transmission lines are

- electrical failure of line insulation due to lightning strike;
- mechanical failure of one or more structures;
- broken shield wire falling into power conductors;
- wind-blown debris causing conductor-conductor short circuits;
- insulator contamination due to road salt, soot, or agricultural chemicals;
- wind/sleet/ice conditions
- contact with aircraft or construction equipment
- protective relaying malfunction (“sympathetic tripping” due to fault on adjacent circuit)

All the above failure scenarios have been experienced on the Xcel Energy/NSP transmission system.

#### NERC Planning Standards

The NERC Planning Standards for electric transmission systems considers loss of a double-circuit line as a “Category C” event: “Event(s) resulting in the loss of two or more (multiple) elements”.

Specifically, Contingency type C-5 is defined as “[a]ny two circuits of a multiple circuit towerline”. For such contingencies, it is required that system stability be maintained, voltages and facility loadings be within applicable ratings, and that no cascading outages of generation or transmission elements result.

The MISO Buffalo Ridge “Group 2” interconnection study showed that outage of the Yankee-White 115 kV line resulted in power system performance criteria violations. Giving proper consideration to the NERC Category C-5 definition, it is clear that if the second Yankee-White 115 kV circuit were installed as a second circuit on the same structures as the first circuit, both circuits would be presumed to fail simultaneously, and there would be no performance improvement attained.

#### MAPP DRS

Xcel Energy/NSP is a member of MAPP and consequently is subject to the MAPP Planning Standards. The MAPP Design Review Subcommittee (DRS) is responsible for evaluating proposed transmission and generation facility additions for compliance with these standards.

The MAPP *Planning Standards* are based upon the NERC standards, with certain extensions and clarifications added. Specifically, MAPP provides a definition of “double-circuit line”:

**Double-Circuit Line (MAPP)** - Two bulk transmission circuits constructed on common structures for a cumulative distance of more than one mile in length.

[MAPP Reliability Handbook, Section 3 (revised December, 2004)  
<http://www.mapp.org/content/reliabilityhandbook.shtml> ]

The “one-mile” exception is based primarily on the following probabilistic considerations:

- some double-circuiting is often necessary for short segments adjacent to substations, due to congested conditions, particularly in the case of large substations with many transmission circuits. Such exposures are typically on utility-controlled property, where conditions of maintenance and surveillance are superior;
- review of performance records shows that for short lines (less than 3 or 4 miles) transmission circuit outages are more often caused by substation equipment problems than by actual line failure. Consequently, the additional outage exposure added by 1 mile of double circuit is small compared to 1) the substations’ contributions to circuit unavailability in the case of short lines, or 2) the overall line contribution in the case of long lines.

In accord with the MAPP/NERC Planning Standards, DRS review of proposed transmission and generation additions is based on considering failure of double-circuit lines of over 1 mile in length as a single contingency.

## **Conclusions**

Double-circuit transmission lines are appropriate for applications where high power handling capacity is required, and the transmission system is designed to withstand failure of both circuits, per NERC and MAPP standards.

Double-circuit construction is not appropriate for the Nobles Co-Fenton 115 kV or the White-Yankee 115 kV circuits. In each case the second circuit would be intended for the purpose of providing redundancy for the first circuit, so as to achieve satisfactory post-contingency power system performance.

Considering the significant potential for common-mode failures, installation of the second circuit on the same structures as the first circuit would not yield the intended increases in Buffalo Ridge generation outlet capability. Consequently, double-circuit construction is not appropriate or advisable for these circuits.

# Appendix L

## TLTG Input /Output Data

L-00 Input parameters for TLTG simulations

	<u>Option</u>	<u>Facility additions</u>
L-0		(Existing System)
L-1	1	2 <sup>nd</sup> Nobles Co-Chanarambie 115 kV & 2 <sup>nd</sup> Nobles Co 345/115 tx
L-1A	1A	2 <sup>nd</sup> Nobles Co-Fenton 115 kV & 2 <sup>nd</sup> Nobles Co 345/115 tx
L-2	2	Lyon Co-Minn Valley 115 kV #2
L-2M	2M	2 + Marshall bypass (Lyon Co-Marshall East River 115 kV)
L-3	3	Lk Yankton-Lyon Co 115 kV #3
L-4	4	Lyon Co-Franklin 115 kV
L-5	5	Chanarambie-Watonwan Jct 115 kV
L-6	6	Yankee-White 115 kV #2 & White-Toronto 115 kV
L-7	7	Yankee-Marshall-Lyon Co 115 kV
L-8	8	Yankee-Marshall-Lyon Co-Franklin 115 kV
L-9	9	Reconductors
L-31A	31A	3 + 1A
L-61A	61A	6 + 1A
L-71A	71A	7 + 1A
L-31A6	31A6	3 + 1A + 6

- Notes:
1. The TLTG tabulations' base case Buffalo Ridge Area generation is 918 MW. Therefore, 918 MW must be added to the TLTG outputs' stated incremental outlet limits to arrive at the total Buffalo Ridge generation outlet limit.
  2. First page is "system intact" limits; following pages show "first contingency" limits.
  3. First column in "first contingency" listing is incremental outlet limit based on continuous ratings; second column is limit based on presumed emergency ratings (110% of continuous for lines, 130% for transformers)

# Appendix M

## Base Case Modeling Assumptions & Input Parameters

“Existing System” configuration includes “SW MN 825 MW” transmission improvements:

- Split Rock-Nobles Co-Lakefield Jct 345 kV
- Nobles Co 345/115 kV sub
- Nobles Co-Fenton-Chanarambie 115 kV
- Buffalo Ridge-Yankee-White 115 kV
- Xcel White 345/115 kV sub
- Lakefield Jct-Fox Lk 161 kV #2
- Various 115 & 69 kV reconductors, transformer replacements, shunt capacitor additions

Yankee generation reactive capability: 0.96 pf lead/lag (30 MVAR per 100 MW)

Lk Yankton SVS:  $\pm 60$  MVAR SVC, plus 4 x 20 MVAR shunt cap

Powerflow model is derived from MISO 2007 Summer Peak (“A102II\_07supk\_c1.1NEW\_DKD”) case used as MISO “Buffalo Ridge Group II Study” base case.

Total SW MN Buffalo Ridge area wind generation in base case = 878 MW  
(corresponds to approximately 918 MW nameplate installed capacity)

Wilmarth-Lakefield (LGS) 345 kV 60% series compensation included.

Anson generation at 2 x 116 MW

GRE Lakefield generation at 548 MW.

# Appendix N

## Paynesville 69 kV Sensitivity

### **Analysis of Paynesville-Roscoe Tap-Munson Tap-Farm Tap 69 kV Post-Contingent Line Loadings**

#### **Background**

The existing Paynesville-Roscoe Tap-Munson Tap-Farm Tap 69 kV line is equipped with 4/0 ACSR conductor, with a nominal Summer rating of 47 MVA. Based upon the results of the Southwest Minnesota/Southeast South Dakota Electric Transmission Study (November, 2001), the resultant “825 MW” Buffalo Ridge series of projects originally included the rebuild of this line to higher capacity.

At a later date, it was determined that this particular rebuild did not appear to be necessary for achieving the 825 MW target outlet capability, but would likely be needed at a somewhat higher outlet level. Consequently, it was removed from the list of “825 MW projects”.

During the time between the initial identification of this project and its later de-listing, it was reported during the normal powerflow model building process, as among the “planned facilities”. Consequently, in recent years some powerflow models have been issued which represent the Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV as having been rebuilt to higher capacity.

The powerflow analyses undertaken for the Buffalo Ridge Incremental Generation Outlet Study were performed using MISO 2001 Series powerflow models which represented the Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV as rebuilt to high capacity (795 kcm ACSR; 117 MVA). It was recently realized that this likely has resulted in “masking” of an overload which should be appearing in the powerflow analysis outputs. This Appendix summarizes the results of a sensitivity analysis performed for the purpose of evaluating the effect of this modeling discrepancy.

## Analysis

The “Option 31A6”, “Option 9”, and “Option 5” powerflow base case models used in the Buffalo Ridge Incremental Generation Outlet Study analysis were revised to reflect the existing impedance characteristics and rating associated with the Paynesville-Roscoe Tap-Munson Tap-Farm Tap 69 kV line’s existing 4/0 conductor. These three Options were chosen as representative of the spectrum of Options studied in the “Incremental” study effort.

As expected, the existing 4/0 conductor does become overloaded within the range of Buffalo Ridge outlet of interest. The following table shows the Buffalo Ridge total generation outlet levels (rounded to the nearest 10 MW) at which these line sections’ post-contingent loadings limit achievable Buffalo Ridge generation outlet.

<u>Option</u>	<u>Buffalo Ridge Area Total Generation Outlet, MW</u>	<u>Limiting Facility (outage = Paynesville-Wakefield 115 kV)</u>
31A (2 <sup>nd</sup> Nobles Co- Fenton 115 kV)	1120	Paynesville-Roscoe Tp 69 @ 110% of 48 MVA
	1210	Roscoe Tp-Munson Tp @ 110% of 48
	1310	Munson Tp-Farm Tp @ 110% of 48
9 (Reconductors)	1120	Paynesville-Roscoe Tp 69 @ 110% of 48 MVA
	1210	Roscoe Tp-Munson Tp @ 110% of 48
	1310	Munson Tp-Farm Tp @ 110% of 48
5 (Chanarambie- Watowan Jct 115)	1200	Paynesville-Roscoe Tp 69 @ 110% of 48 MVA
	1300	Roscoe Tp-Munson Tp @ 110% of 48
	1400	Munson Tp-Farm Tp @ 110% of 48

From this table is observed that the first section of this 69 kV line (Paynesville-Roscoe Tp) becomes subject to overload at approximately 1120 - 1200 MW SW MN Buffalo Ridge generation, regardless of transmission Option implemented. Similarly, the next two sections (Roscoe Tp-Muson Tp and Munson Tp-Farm Tp) become subject to overload at 1210 - 1300 MW, and 1310 - 1400 MW, respectively.

The similarity in results observed for the three transmission options is explained by observing that none of the “incremental” Options creates significant network impedance changes in the Paynesville/Wakefield vicinity, nor is there major transmission added which might divert power flows away from the Paynesville 230/115/69 kV transformation. This was confirmed by noting that on the TLTG simulation outputs the “outage transfer distribution factor” (“OTDF”) on the Paynesville-Farm Tp 69 kV line, for Buffalo Ridge-->Twin Cities power deliveries, is between 2.3 % and 2.4% regardless of which option is studied. Due to the similar pre-contingent loadings and this small variation in distribution factor, the post-contingent loadings experienced for the Paynesville-Wakefield 115 kV outage are similar, regardless of which “incremental” transmission option is implemented.

After rebuild with heavier conductor--which increases the OTDF slightly, to 2.6%--the post-contingent loadings would be approximately 66 MVA at the 1400 MW Buffalo Ridge generation level. Consequently, the new Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV conductor needs to be at least 477 kcm ACSR or equivalent.

## **Conclusions**

Achieving any target total Southwest Minnesota Buffalo Ridge Area generation outlet capability in excess of approximately 1200 MW will require increased capacity on the Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV line. This finding holds regardless of the particular Buffalo Ridge "Incremental" transmission Option chosen for implementation. The new line conductor should be at least 477 kcm ACSR or equivalent.

R Gonzalez  
J Standing  
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