Buffalo Ridge Incremental Generation Outlet
Electric Transmission Study

DRAFT

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

(0 – 600 MW beyond "825 MW")

Volume 1

February 28, 2005

Prepared by:
Xcel Energy

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Transmission Reliability & Assessment

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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
March 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 likely 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 future 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") 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). 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.

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 develpments 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 vague 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)

<u>Big Stone 2</u> is proposed to be a 600 MW coal-fired addition at the existing Big Stone site. [add comment on queue position of Big Stone 2 relative to Buff Ridge gen] MISO has completed the "Interconnection" Study for this unit, but not "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 likely be relaxed. It is not possible to determine which outcome would be more likely to occur 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.

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 & Recommended 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.

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 MB SPG meeting)
March 3, 2005	Sioux Falls, SD	MRES Offices	(adjacent to 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 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.

A draft of this study report (dated February 28, 2005) was reviewed at the March 3, 2005 meeting; this final version reflects the comments received at that meeting and at the MAPP Missouri Basin Sub-Regional Planning Group meeting held on March 3, 2005.

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.

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 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

					Net generation, MW					
Condition	load level	NDEX[1]	MHEX[2]	MWSI[3]	Wind	Anson	Path-finder	Minn Valley	Lake-field	Fibrominn
Peak	100 %	xxxx	xxxx	xxxx	918	232	0	0	550	50
Off-peak	70 %	1850	1982	1051	918	232	0	0	550	50

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

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. This Anson sensitivity analysis is provided in Appendix K.

1) NDEX = sum of flows on the 17 lines comprising the North Dakota Export Boundary;
2) MHEX = sum of flows on the 3 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 <u>Options Evaluated</u> (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 Sub. This would be 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 into 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 upgrades 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.

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. 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.

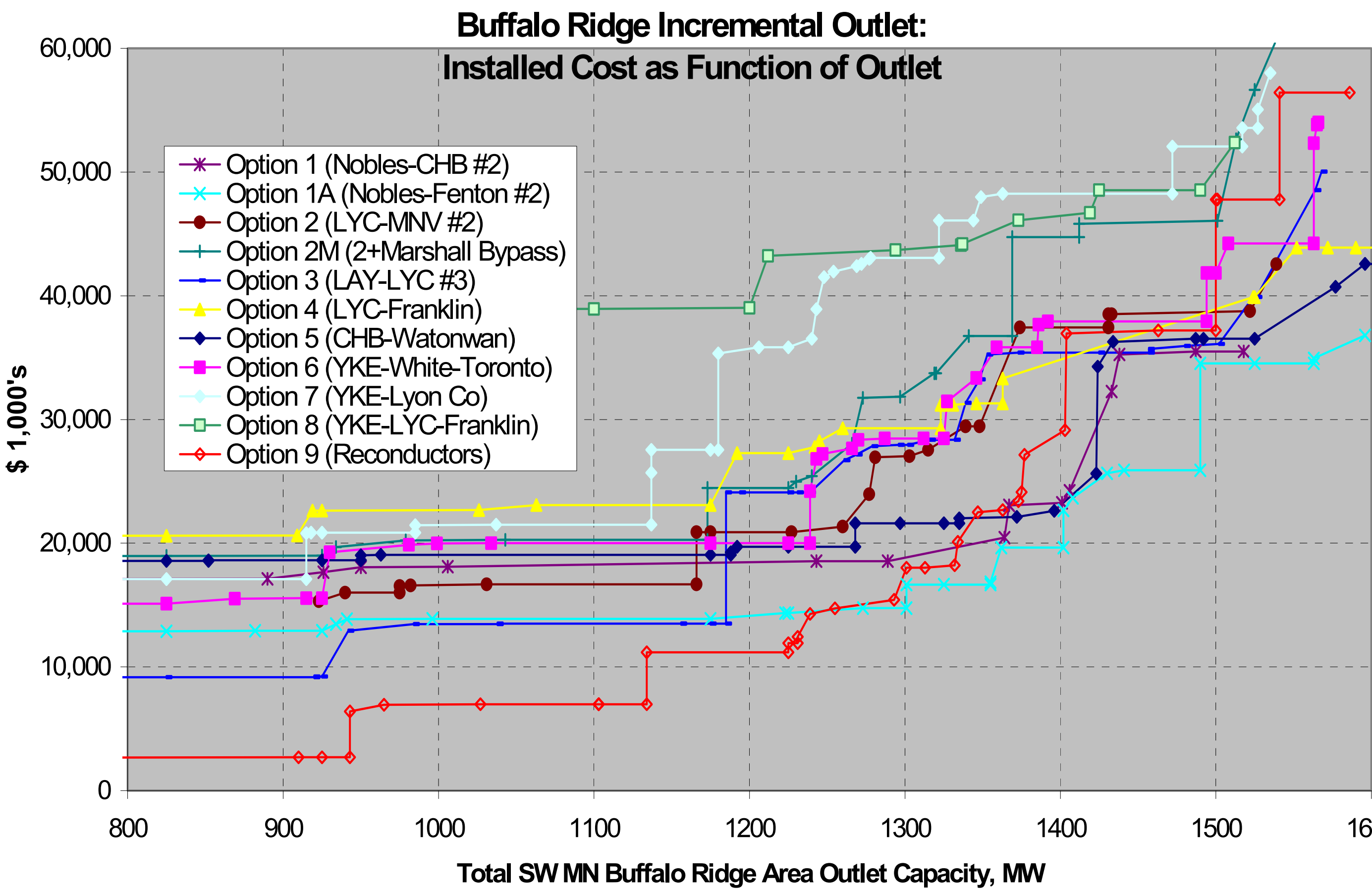
4.4 "First Cut" Screening

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 2 shows each Option's evaluated cost, taking into account installed cost and losses. (Refer to Section xx.yy for details of loss value derivation).

Graph 1



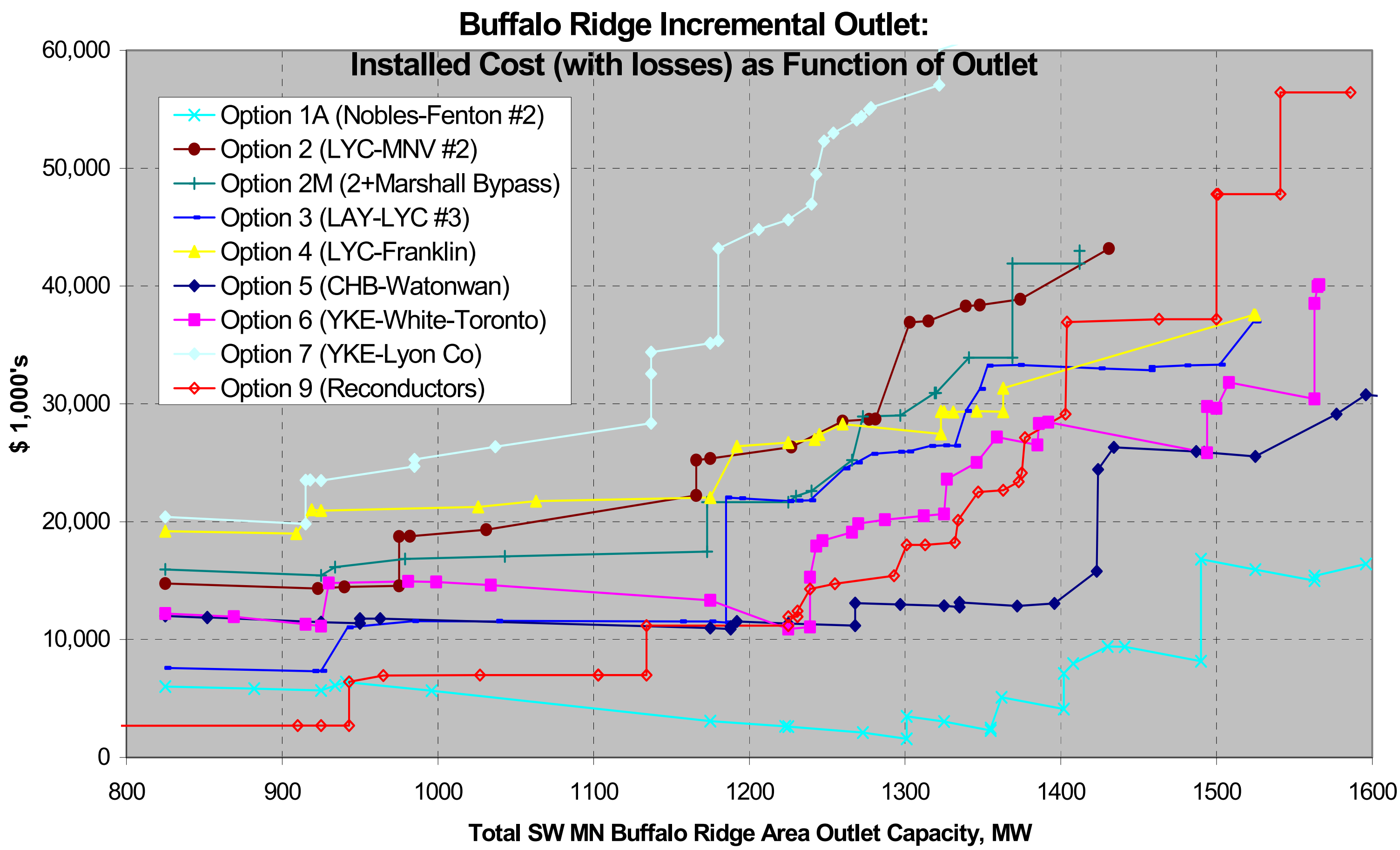
Graph 1 shows that

- 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 xx.yy for details of loss value derivation).

Graph 2

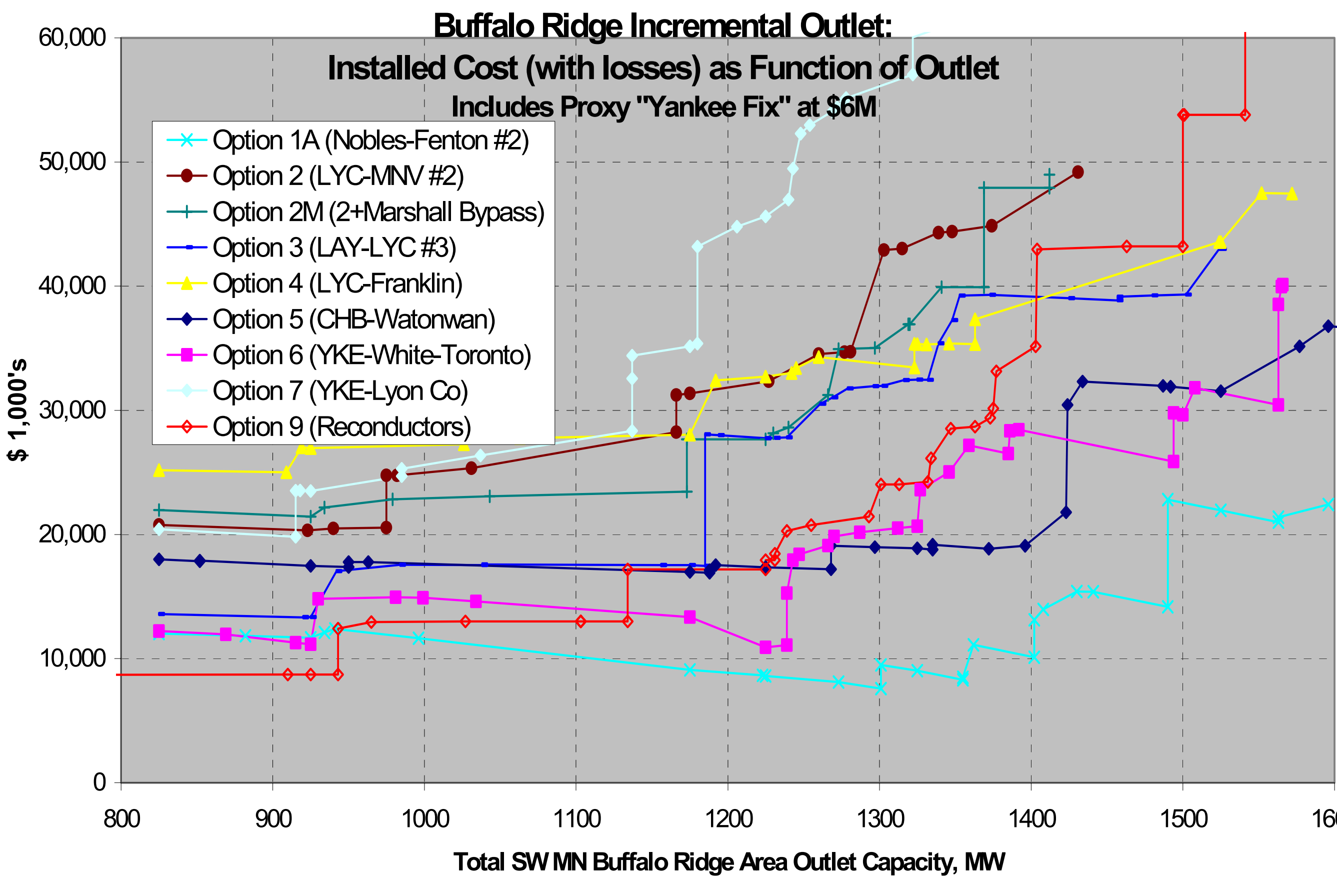


Graph 2 shows that adjusting for losses,

- 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	SMMPA
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	SMMPA
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 a LODF 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.

(Add MISO criteria; show less restrictive than 2%; PTDF =5%, OTDF = 3%)

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 provided 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.

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 to have a rating of approximately ± 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.

5.3 Constrained Interface Analysis *[Need to add latest version of MISO criteria]*

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).

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.

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. This result was anticipated because since none of the Options involves addition of major transmission facilities, 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".

It should be noted that 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 actual 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 Twind Cities.

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 power system dynamic performance for the regional EHV disturbances which presently establish the NDEX limit.

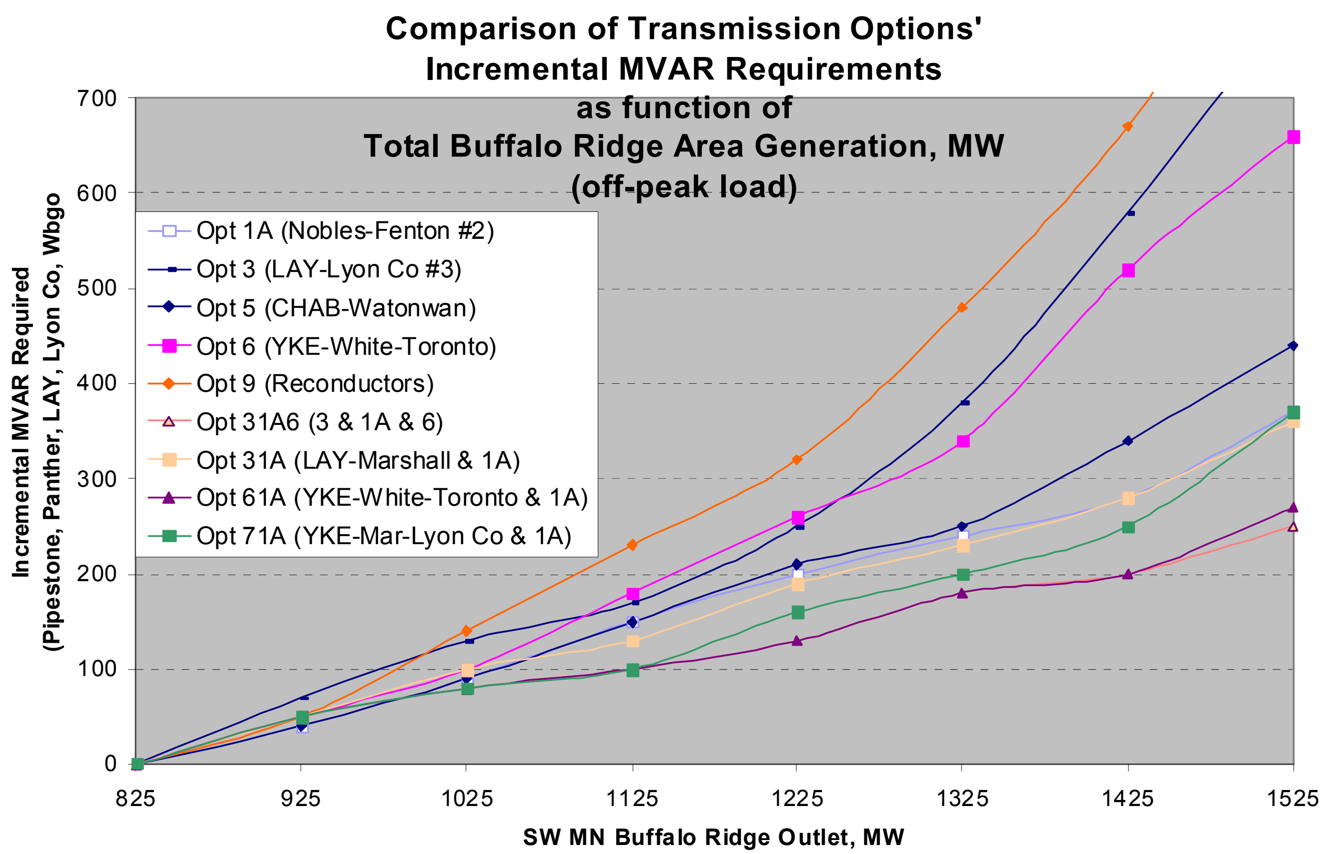
5.4 Reactive Power Requirements

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 2 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 2
Incremental Reactive Power Requirements
(Evaluated at 825 + 600 = 1425 MW)

		Reactive Requirement, MVAR					
Option	Buffalo Ridge Generation (MW)	Pipestone	Panther	Lake Yankton	Lyon Co	Winnebago Jct	Total
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 3 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 (2nd Nobles Co-Fenton 115 kV), which was chosen as the reference. More-detailed information on losses is provided in Appendix H.

Table 3
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	2nd 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 3 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 3 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 [Needs update yet]

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 the xxx, and yyy MW total Buffalo Ridge generation levels. These values are provided in Table 1 of Appendix I, and displayed in Graph 1. The MW values used were those from the on-peak (100% load) condition series of simulations. Although MW losses are potentially higher during the off-peak condition, capacity is presumed to have no value during such periods due to the ample supply of generation resulting from the lower load-serving requirement during such intervals.

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 7, the 20-year cumulative present value of the demand losses is $1,185,500 per on-peak 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 7, the 20-year cumulative present value of the energy losses resulting from each (off-peak) MW loss difference is $567,600.

Table 7

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 Annual	Cum PW
Capacity value:					FCR	Revenue Rqmt	
	50 % peaking @		$400 /kW		0.15	$30,000	
	50 % baseload @		$1,000 /kW		0.15	$75,000	
						$ 105,000	$
add 15% reserve requirement:						120,750	1,185,541
Energy Value:	1.00	8760 hr/yr	0.30	$22 /MWh		57,816	$ 567,646
			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 xx Buffalo Ridge area generation levels for which powerflow simulations were performed (xx, yy, and zz 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 7.

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 xx has losses that are higher than Option 1A (the lowest-loss option) by xxx MW on-peak and yyy MW off-peak.

Cumulative present value of the capacity is	(aa.a MW) ($1,185,500) =	$ xx,xxx,000
Cumulative present value of the energy is	(bbb.b MW) ($567,600) =	yy,yyy,000
Total cumulative present value of losses is	=	$ zzz,zzz,000
Equivalent capitalized value of losses is	($zzz,zzz,000) (0.5365) =	$ uu,uuu,000
Installed cost of Option 5 at the 825 MW level	(value displayed on Graph 2)	$ vv,vvv,000
Evaluated cost of Option 5 at the 825 MW level	(value displayed on Graph 3)	$ www,www,000

6.0 Economic Analysis

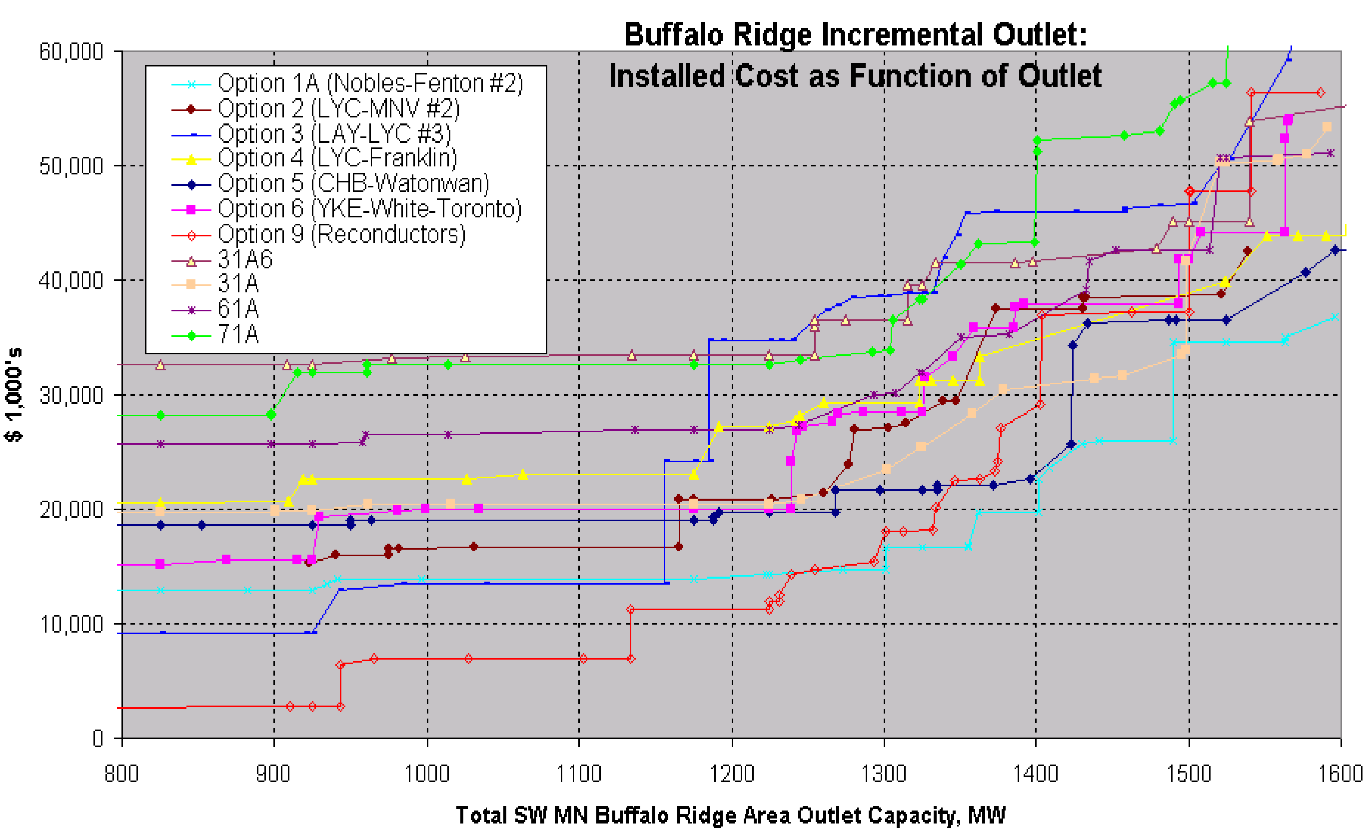
For the transmission Options which survived the "first cut", economic analyses were performed
1) on the basis of installed cost of required facilities;
2) also considering the effect of power and energy losses;
3) also considering the cost of Yankee and Marshall "fixes"
4) also considering the cost of 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) among the options.

6.1 Installed Cost

Graph 5 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 5. No consideration of losses is represented in this graph.

Graph 5



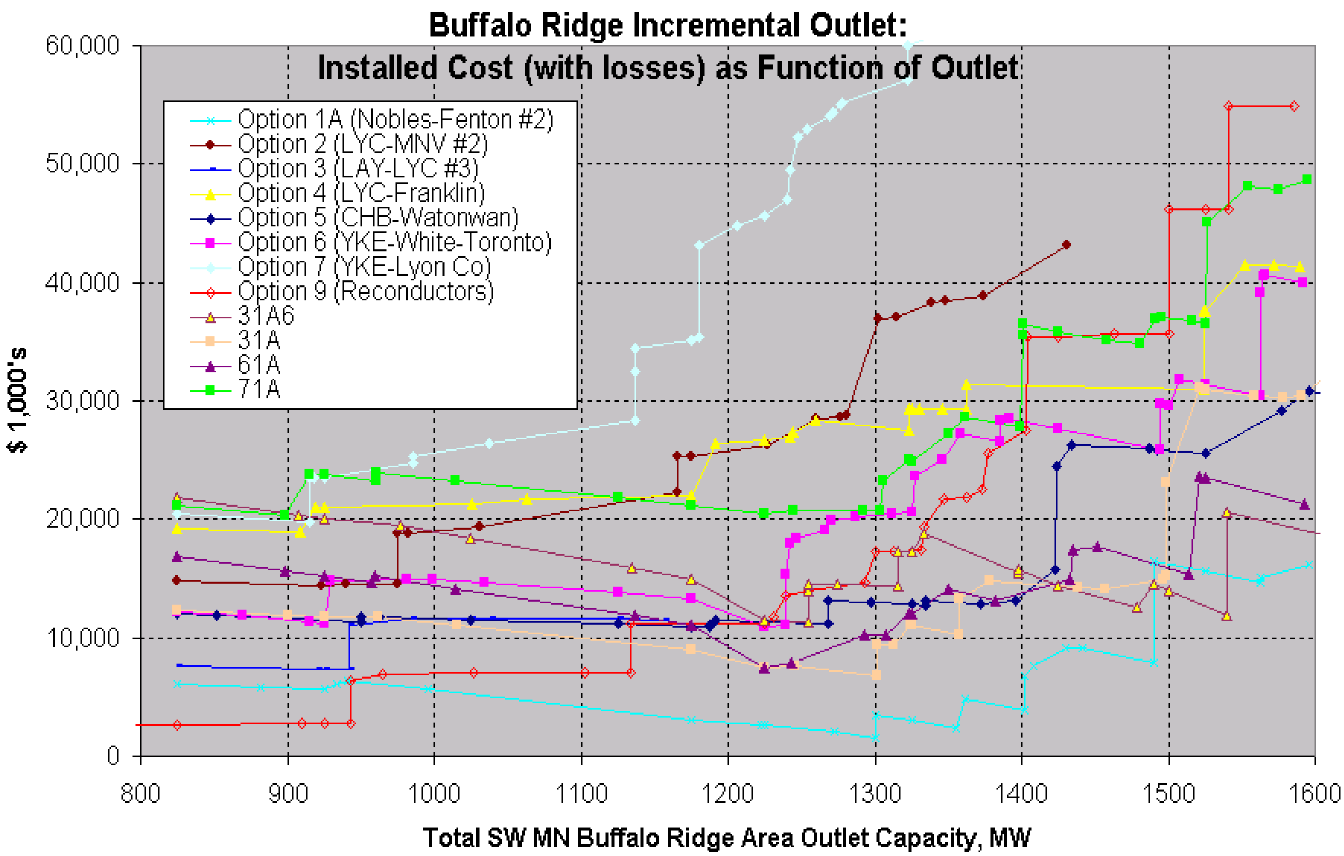
From Graph 5, it is observed that

- Option 9 (“reconductor only”) is the least expensive if less than 1240 MW of outlet is required.
- Options 1A and 3 (“2^{nd} 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 6 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 6



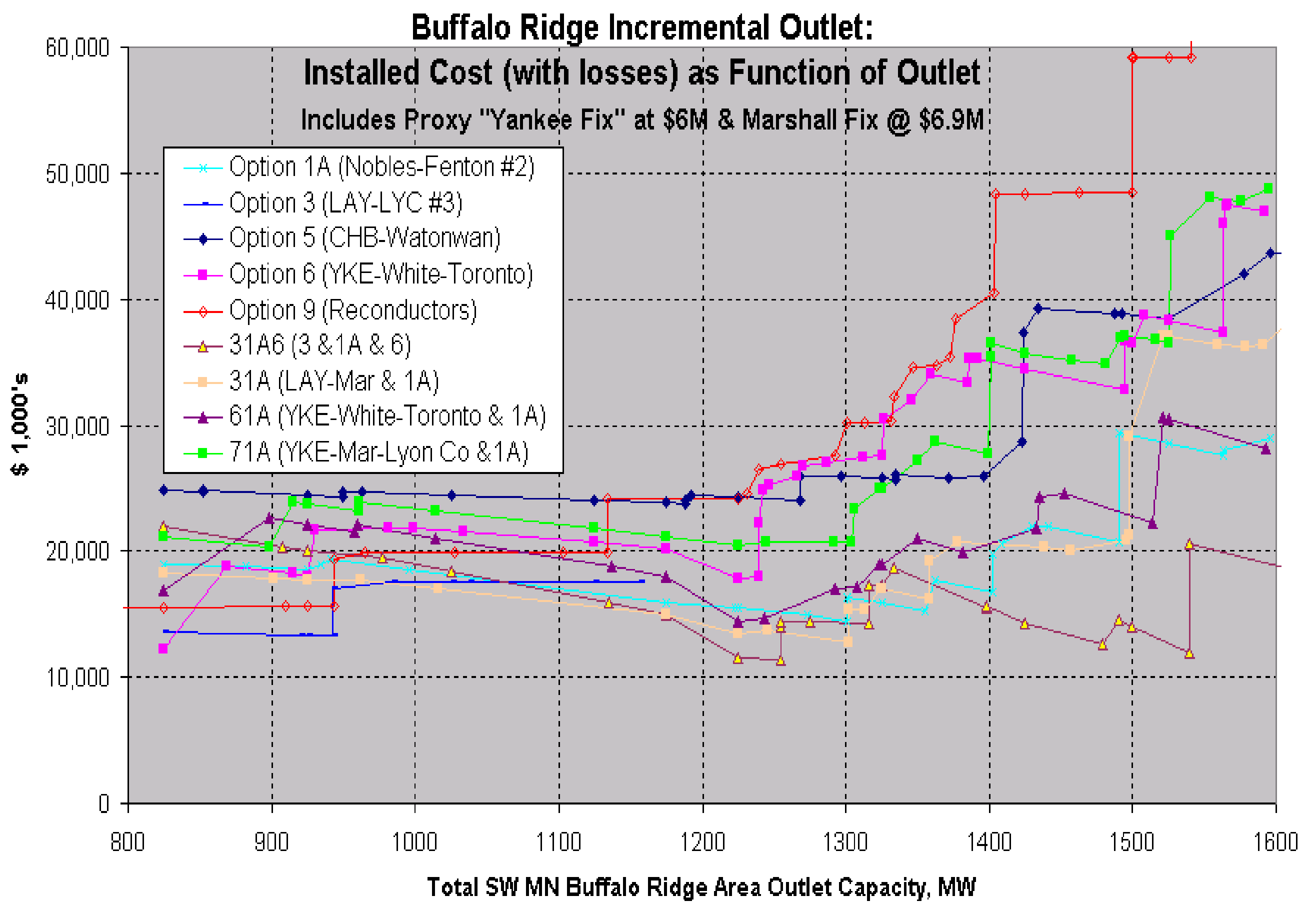
From Graph 6 it is observed that

- Beyond 950 MW, Option 1A ("2nd 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.

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

Graph 7 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 7

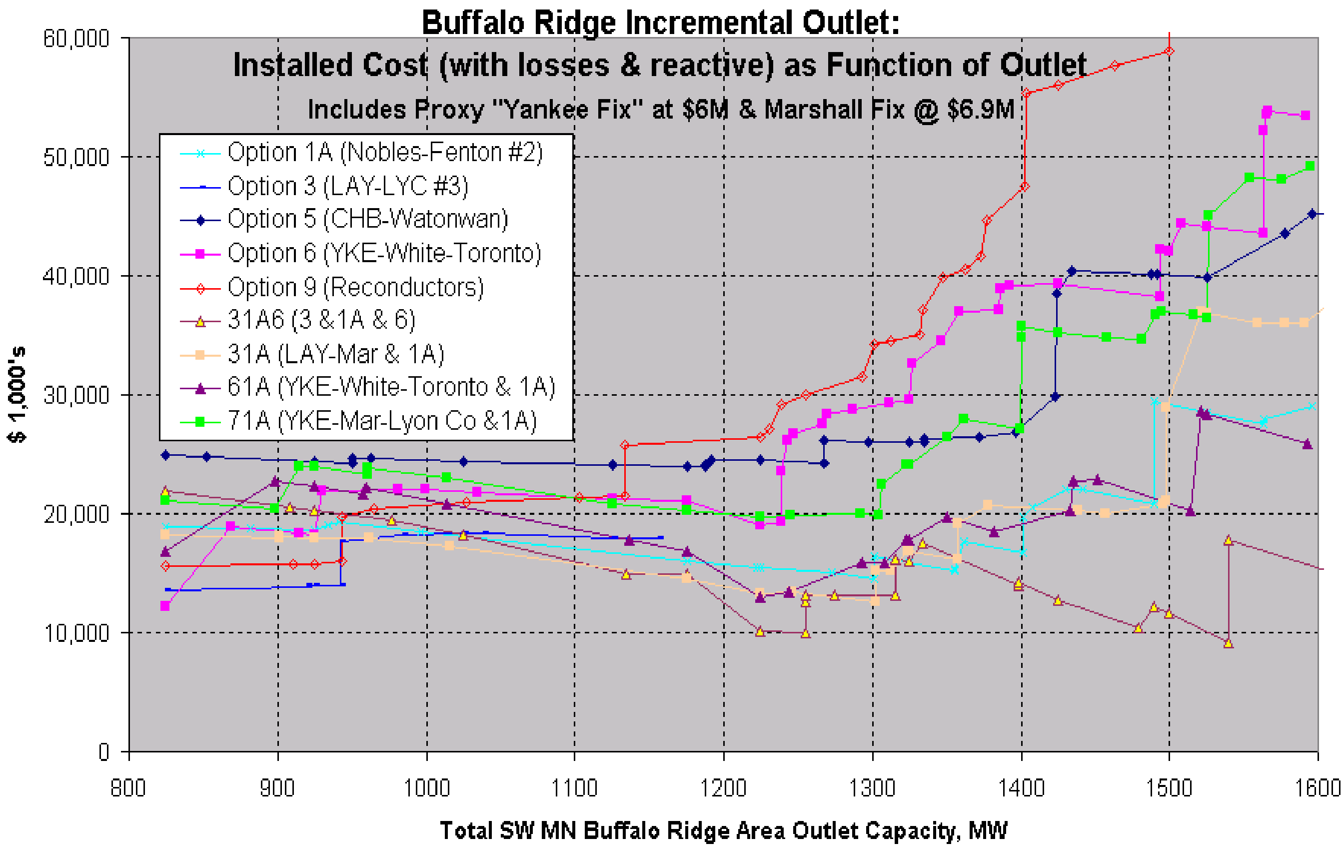


As expected, the Options which lack Yankee or Marshall "fixes" become higher cost than was previously observed in Graph 6. Beginning at approximately 1200 MW, a separation or "break" is developing between most of the "1A" options (1A, 31A, 61A, 31A6) and the remaining options (5, 6, 9, 71A).

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

Graph 8 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 8



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 8 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 southeastern South Dakota. These are summarized below and described in the following paragraphs.

Load center	Critical Contingencies
Marshall, MN	Lyon Co-Marshall SS 115 kV
New Ulm/Redwood Falls	Minn Valley-Redwood Falls-Franklin or Wilmarth-Franklin 115 kV
Olivia/Bird Island	Minn Valley-Sacred Heart 69 kV or Panther 230/69 kV source
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.

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 Minn Valley 230/115 kV transformations, and
- the south via the two Lk Yankton-Lyon Co lines from the Split Rk and Nobles Co 345/115 kV transformations (distances of approximately 80 - 100 miles).

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 SW-Lyon Co 115 kV line. The Lk Yankton-Marshall SW section establishes a new path into Marshall from the south, while the Marshall SW-Lyon Co section provides a second connection from Lyon Co Substation to the Marshall 115 kV load-serving loop. 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.

The “combination” options 31A and 31A6 incorporate 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 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 area to a slight degree due to the stronger source at Franklin. However, additional improvements would still be required for the Olivia/Bird Island area.

7.13 Dotson/Lamberton

Options 4 and 8 establishe 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'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 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

		miles of transmission						
Option	Description	New	Recond	Rebuild	YKE/Marsh	Total	Capacitors	Years
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 Section xx.yy).

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 reconductored 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.

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

February 25, 2005

Prepared by:
Xcel Energy

Appendix C

TLTG Outputs

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

Reactive Requirement Data

Appendix	Item
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

Outages	
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

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2/14/2005

SVC_output.xls

Appendix D-2

Buffalo Ridge Incremental Generation Outlet Study
Reactive additions required, MVAR

Buff Ridge MW:	825	925						1025						1125					
Option		PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT
1A	0	0	40	0	0	0	40	0	50	20	0	20	90	0	70	40	0	40	150
3	0	0	50	20	0	0	70	20	60	30	0	20	130	40	70	40	0	20	170
5	0	0	40	0	0	0	40	0	50	20	0	20	90	0	70	40	0	40	150
6	0	0	50	0	0	0	50	0	60	20	0	20	100	20	80	40	0	40	180
9	0	0	40	10	0	0	50	20	50	20	30	20	140	60	60	40	30	40	230
31A	0	0	50	0	0	0	50	0	60	20	0	20	100	0	70	40	0	20	130
61A	0	0	50	0	0	0	50	0	60	0	0	20	80	0	80	0	0	20	100
71A	0	0	50	0	0	0	50	0	60	0	0	20	80	0	80	0	0	20	100
31A6	0	0	50	0	0	0	50	0	60	0	0	20	80	0	80	0	0	20	100

Buff Ridge MW:	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
1A	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	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	90	60	0	60	210	20	90	80	0	60	250	40	120	100	0	80	340	60	150	120	30	80	440
6	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	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	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	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	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	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)

Option	825	PIP	PTH	LAY	LYC	WBG	TOT	PIP	PTH	LAY	LYC	WBG	TOT		PIP	PTH	LAY	LYC	WBG	TOT	
1A	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	0	30	20	10	10	0	0	40		40	0	0	0	-20	20	
	$M at $20/kVAr						$0.6						$0.8							$0.4	
5	0	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	
	$M at $20/kVAr						$0.0						$0.0							$0.0	
6	0	0	10	0	0	0	10	0	10	0	0	0	10		20	10	0	0	0	30	
	$M at $20/kVAr						$0.2						$0.2							$0.6	
9	0	0	0	10	0	0	10	20	0	0	30	0	50		60	-10	0	30	0	80	
	$M at $20/kVAr						$0.2						$1.0							$1.6	
31A	0	0	10	0	0	0	10	0	10	0	0	0	10		0	0	0	0	-20	-20	
	$M at $20/kVAr						$0.2						$0.2							-$0.4	
61A	0	0	10	0	0	0	10	0	10	-20	0	0	-10		0	10	-40	0	-20	-50	
	$M at $20/kVAr						$0.2						-$0.2							-$1.0	
71A	0	0	10	0	0	0	10	0	10	-20	0	0	-10		0	10	-40	0	-20	-50	
	$M at $20/kVAr						$0.2						-$0.2							-$1.0	
31A6	0	0	10	0	0	0	10	0	10	-20	0	0	-10	0	0	10	-40	0	-20	-50	0
	$M at $20/kVAr						$0.2						-$0.2							-$1.0	

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
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
3	60	0	10	0	-20	50	140	-30	20	30	-20	140	240	0	20	60	-20	300	360	30	20	60	-40	430
						$1.0						$2.8						$6.0						$8.6
5	0	0	10	0	0	10	20	-30	20	0	0	10	40	0	20	0	0	60	40	30	20	0	-20	70
						$0.2						$0.2						$1.2						$1.4
6	40	30	10	0	-20	60	100	0	20	0	-20	100	180	30	20	30	-20	240	280	30	20	0	-40	290
						$1.2						$2.0						$4.8						$5.8
9	100	0	10	30	-20	120	180	0	20	60	-20	240	300	0	20	90	-20	390	420	30	40	90	-20	560
						$2.4						$4.8						$7.8						$11.2
31A	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						$0.0						-$0.2
61A	0	0	-50	0	-20	-70	0	0	-60	0	0	-60	0	0	-60	0	-20	-80	-20	30	-60	-30	-20	-100
						-$1.4						-$1.2						-$1.6						-$2.0
71A	0	30	-50	0	-20	-40	0	0	-40	0	0	-40	0	30	-40	0	-20	-30	0	60	-40	0	-20	0
						-$0.8						-$0.8						-$0.6						$0.0
31A6	0	0	-50	0	-20	-70	0	0	-40	0	-20	-60	0	0	-60	0	-20	-80	-20	30	-60	-30	-40	-120
						-$1.4						-$1.2						-$1.6						-$2.4

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

Appendix E

Powerflow Diagrams & Logsheets

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

Appendix F

Interface PTDF 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	2.0	-4.6	
3	1.0	-0.4	0.3	0.4	0.4	1.8	0.8	5.1	
5	1.4	-0.8	-0.8	-0.4	-3.0	0.9	1.1	2.9	
6	52.8	-0.2	0.0	0.1	0.2	0.4	-0.1	2.0	(Note 1)
9	0.0	0.0	0.0	-0.1	-0.1	0.7	0.7	-0.1	
31A	1.0	-0.6	0.0	0.7	-0.6	4.0	3.6	4.8	
31A6	51.2	-0.6	-0.1	0.4	-0.6	2.6	2.1	4.4	(Note 1)
61A	52.9	-0.3	-0.3	0.3	-0.9	2.5	2.7	1.9	(Note 1)
71A	1.3	-0.5	-0.1	0.3	-1.0	2.3	2.4	3.3	

	Incremental Flows Due to Generation Additions in %								
	825 to 1225 MW Gen								
	NDEX	MHEX	GGS	WNE-WKS	GRIS-LINC	Cooper-S	FTCAL-S	MWSI	
Option									
1A	-0.4	0.1	0.1	0.2	1.1	-0.2	2.6	-10.9	
3	-0.4	0.2	0.1	0.1	1.1	-0.6	2.1	-10.7	
5	-0.4	0.2	0	0.1	1.0	-0.5	2.2	-10.6	
6	0.4	0.1	0.1	0.2	1.2	-0.4	2.3	-10.7	(Note 1)
9	-0.4	0.1	0.1	0.1	1.0	-0.6	2.1	-10.8	
31A	-0.4	0.2	0.1	0.2	1.1	-0.2	2.5	-10.7	
31A6	0.4	0.2	0.1	0.3	1.2	0.1	2.7	-10.5	(Note 1)
61A	0.4	0.2	0.1	0.3	1.2	0.1	2.7	-10.6	(Note 1)
71A	-0.4	0.2	0.1	0.2	1.1	-0.3	2.5	-10.8	

Note 1: Apparent increases in NDEX observed in Options that include "Option 6" facilities are fictitious; the power flow on the new White-Toronto 115 kV line (which is a new NDEX tie line) has not been taken into account in the NDEX tabulation. Since the flow on White-Troronto is northward (into NDEX) its contribution to total NDEX sum is a negative value.

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2/23/2005
Constrained.interfaces.xls

Appendix G

Input Data for TLTG & ACCC

Appendix H

Power System Loss Data

Total System Losses (MW)

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	82
0	13171.0	13201.0	13276.6	13292.4	13324.5	13399.8	
1A	13161.7	13191.4	13263.8	13278.5	13308.2	13378.4	
2	13167.1	13196.7	13273.5	13289.7			
2M	13165.8	13195.3	13272.3	13288.0			
3	13167.3	13197.1	13273.2	13288.5	13320.7	13395.1	
4	13167.5	13197.3	13274.2	13290.4	13320.7	13395.7	
5	13161.9	13191.5	13266.7	13282.1	13313.4	13386.5	
6	13165.9	13194.4	13268.2	13281.3	13314.4	13385.2	
7	13172.5	13201.9	13283.4	13301.4			
8	13164.0	13192.9	13269.3	13285.5			
9	13169.0	13199.1	13275.3	13291.0	13322.7	13398.2	
31A	13161.0	13190.5	13263.1	13277.3	13307.4	13377.6	
61A	13159.6	13187.9	13258.5	13270.3	13301.5	13368.7	
31A6	13157.6	13185.7	13255.7	13267.7	13299.0	13365.0	-
345kV	13115.3	13141.7	13213.9	13227.4	13259.0	13326.8	-5
71A	13161.4	13190.3	13263.1	13278.1	13308.4	13377.5	

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
61A	-11.4	16.9	87.5	99.3	130.5	197.7
31A6	-13.4	14.7	84.7	96.7	128.0	194.0
345kV	-55.7	-29.3	42.9	56.4	88.0	155.8

71A	-9.6	19.3	92.1	107.1	137.4	206.5

Appendix I

Schedules

Appendix J

Options’ Components and Indicative Costs

Buffalo Ridge Incremental Generation Outlet Transmission Study

Installed Cost Estimates for Transmission Options
("Base Plan" costs)
(not including reactive power needs)

				Installed Cost $1,000's	
Option 1	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
Option 1A	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
Option 2	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
Option 2M	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
Option 3	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

Option 4	Add Lyon Co-Franklin 115 kV						
	Rebuild Lyon Co-Milroy 69-Sheridan-Redwood-Franklin to 115/69 dckt		44	mi	400	17,600	
	(115 kV @ 310 MVA)						
	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	
Option 5	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	
Option 6	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	
Option 7	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	
Option 8	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		44	mi	400	17,600	
	(115 kV @ 310 MVA)						
	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	
Option 9	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 K

Anson Sensitivity Analysis

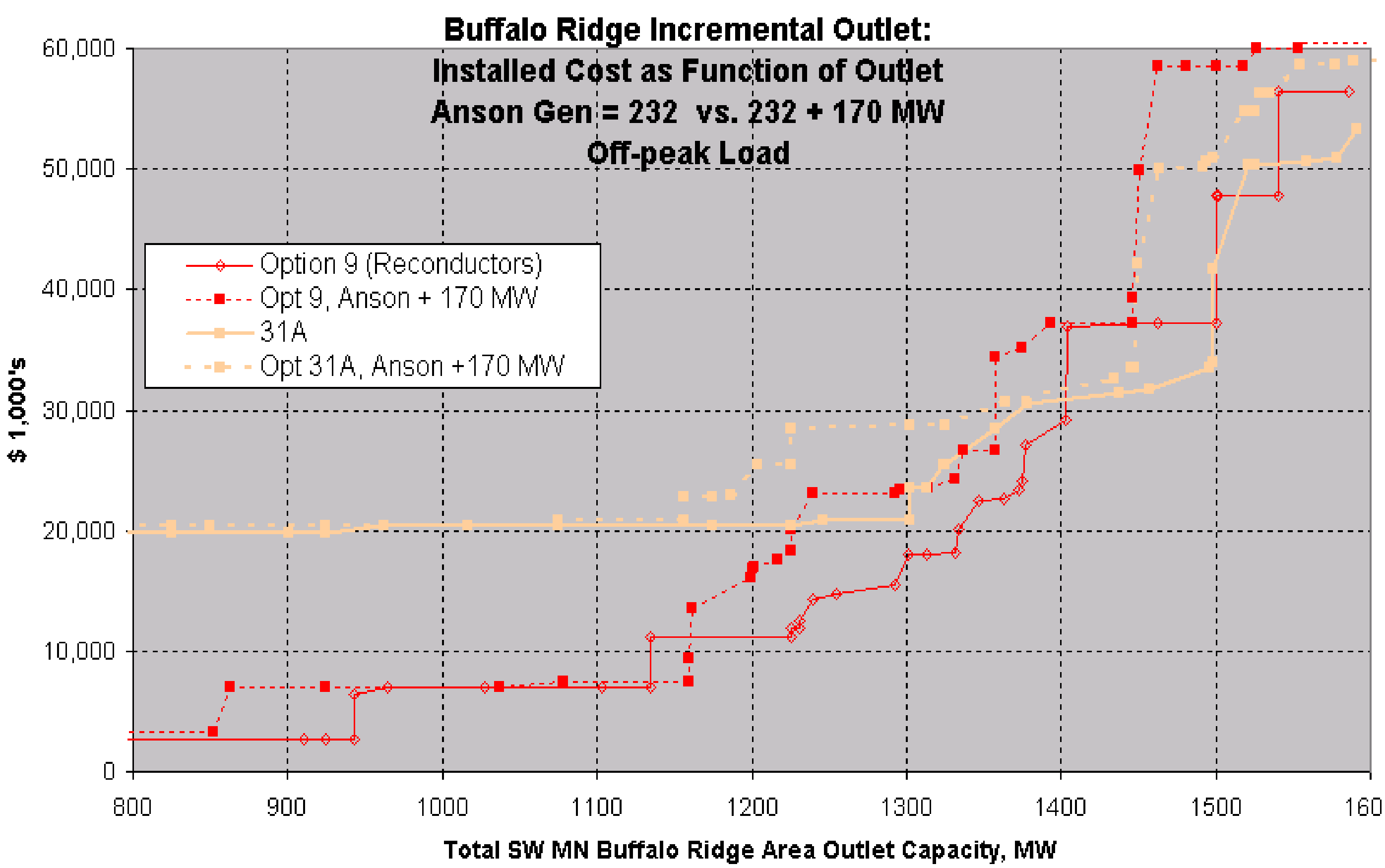
Buffalo Ridge Incremental Generation Outlet Study

Anson Generation Level Sensitivity Analysis

The Buffalo Ridge Incremental Generation Outlet Analysis described in the body 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 K-1 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 K-1



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).

Appendix L

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:

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

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.

Option	Description	Approx miles of 115 kV: new	Approx miles of 115 kV: rebuild	Installed Cost, $M
0.	Existing System	0	0	0.0
A.	Add 2nd 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 LakeYankton 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 2nd 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.

Option	Description	Est. Yankee outlet, MW	Buff Ridge Critical V @ Yankee = 400 MW	Cost $/kW
0.	Existing System	250	.96	--
A.	Add 2nd 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.

R Gonzalez, PE
J Standing
Xcel Energy Transmission Reliability & Assessment
11-17-2004
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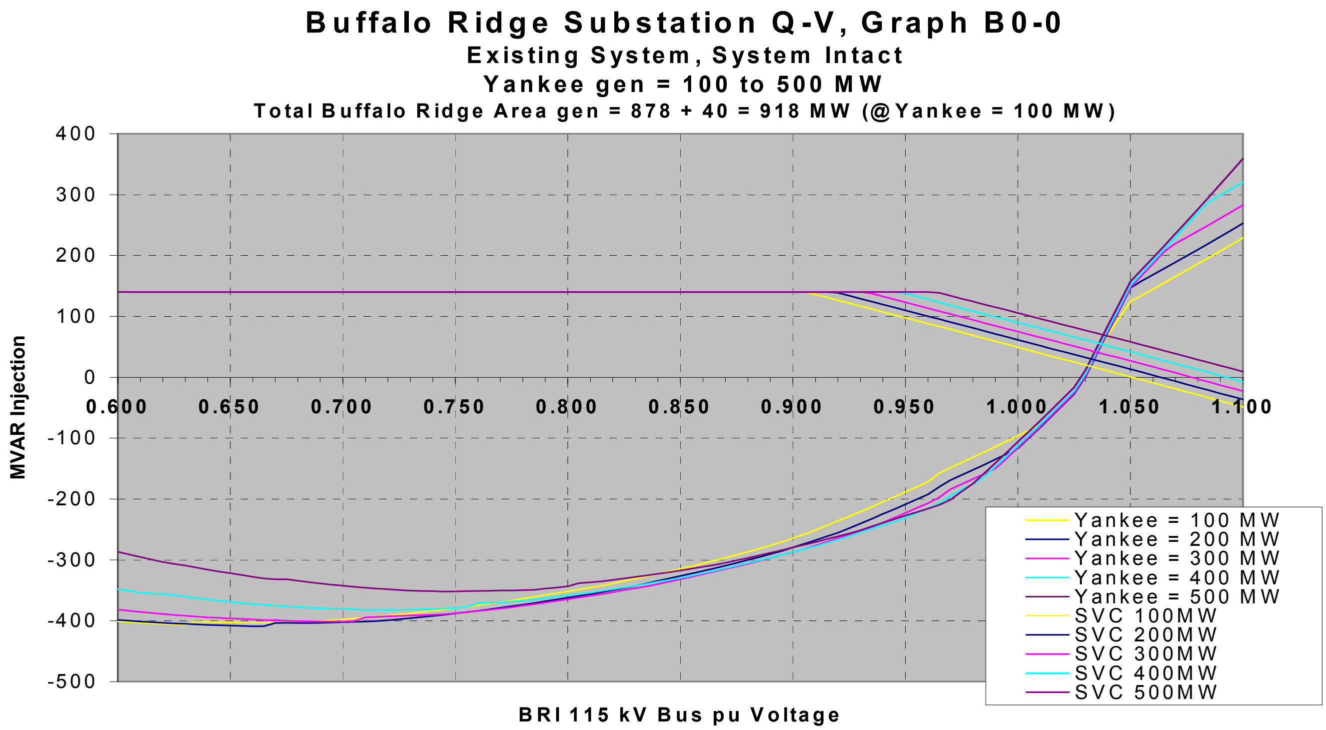
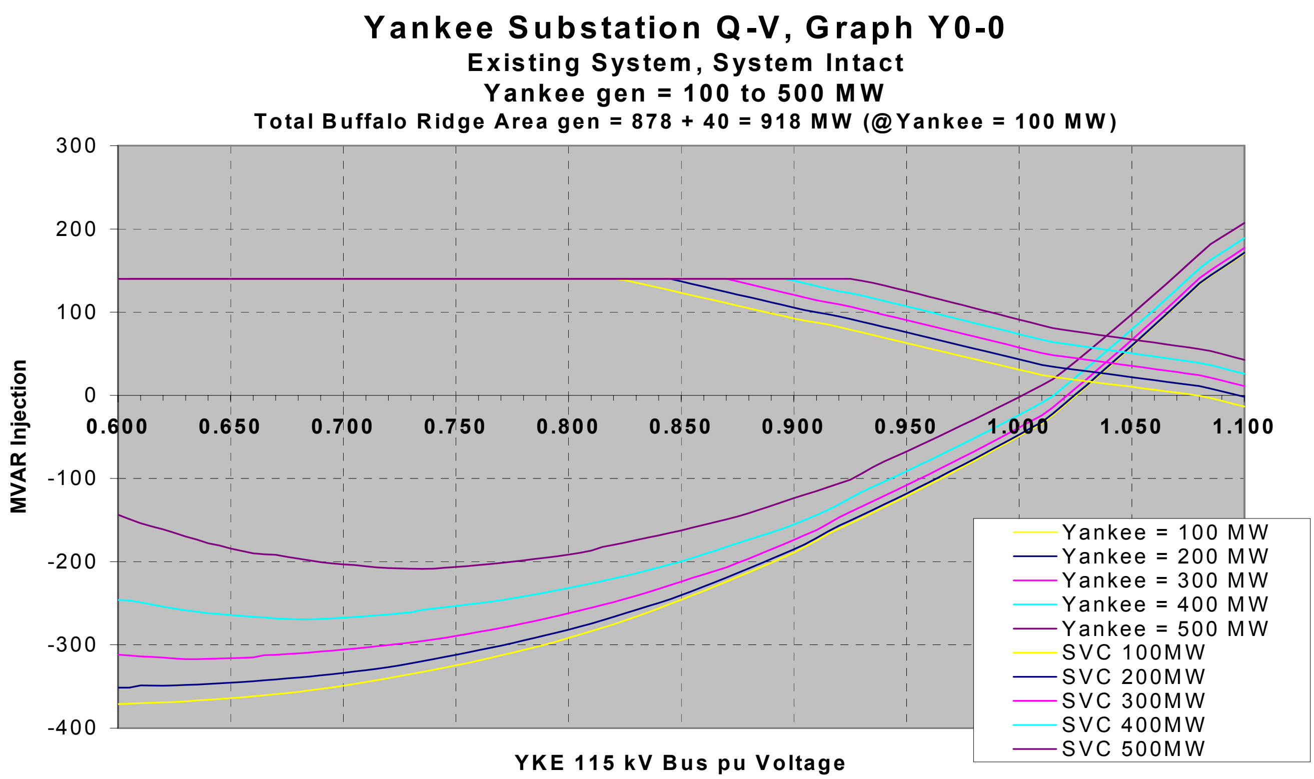

Buffalo Ridge Substation Q-V, Graph B0-0
Existing System, System Intact
Yankee gen = 100 to 500 MW
Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)
MVAR Injection
400
300
200
100
0
-100
-200
-300
-400
-500
0.600
0.650
0.700
0.750
0.800
0.850
0.900
0.950
1.000
1.050
1.100
BRI 115 kV Bus pu Voltage
Yankee = 100 MW
Yankee = 200 MW
Yankee = 300 MW
Yankee = 400 MW
Yankee = 500 MW
SVC 100MW
SVC 200MW
SVC 300MW
SVC 400MW
SVC 500MW

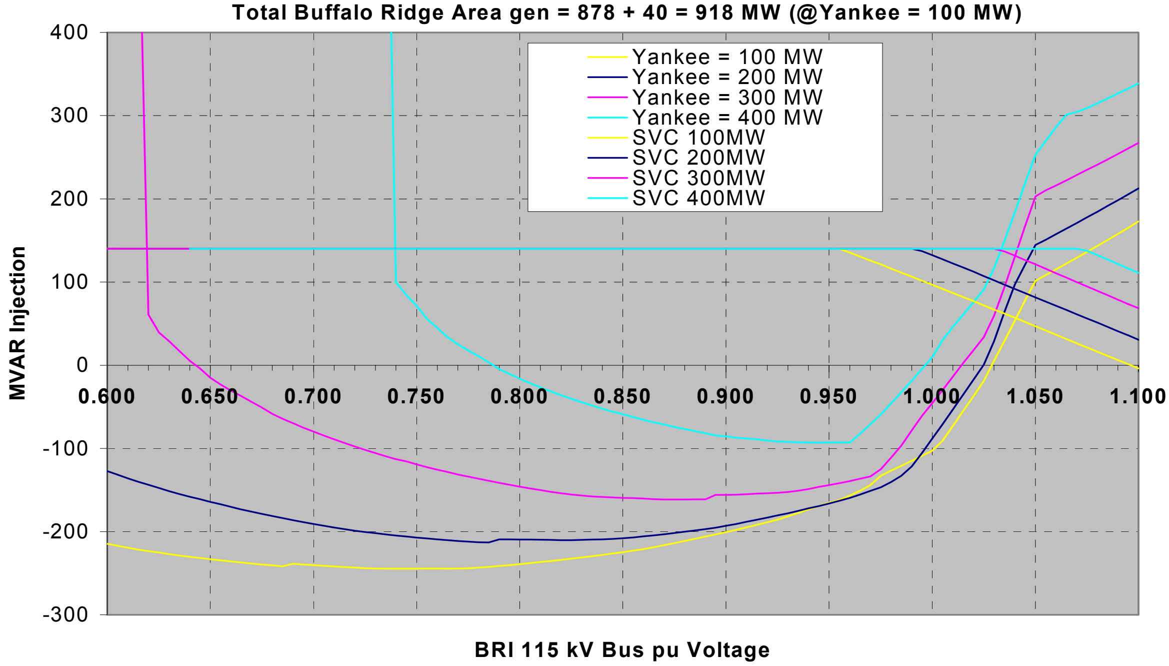

Yankee Substation Q-V, Graph Y0-0
Existing System, System Intact
Yankee gen = 100 to 500 MW
Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)
MVAR Injection
300
200
100
0
-100
-200
-300
-400
0.600
0.650
0.700
0.750
0.800
0.850
0.900
0.950
1.000
1.050
1.100
YKE 115 kV Bus pu Voltage
Yankee = 100 MW
Yankee = 200 MW
Yankee = 300 MW
Yankee = 400 MW
Yankee = 500 MW
SVC 100MW
SVC 200MW
SVC 300MW
SVC 400MW
SVC 500MW

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)

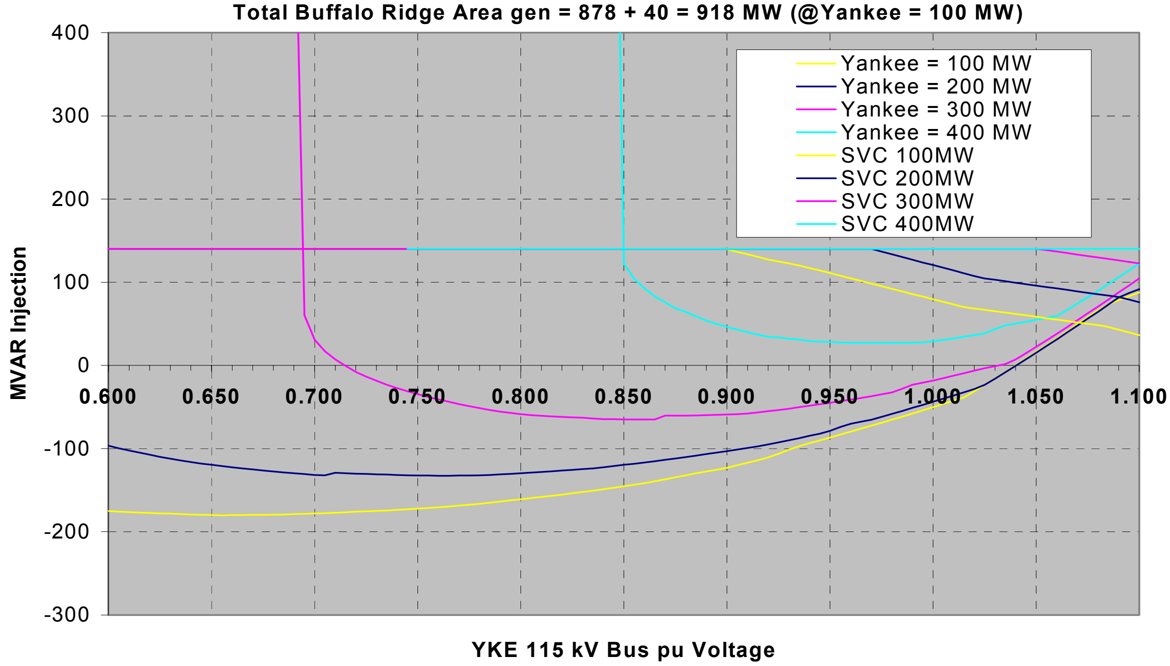


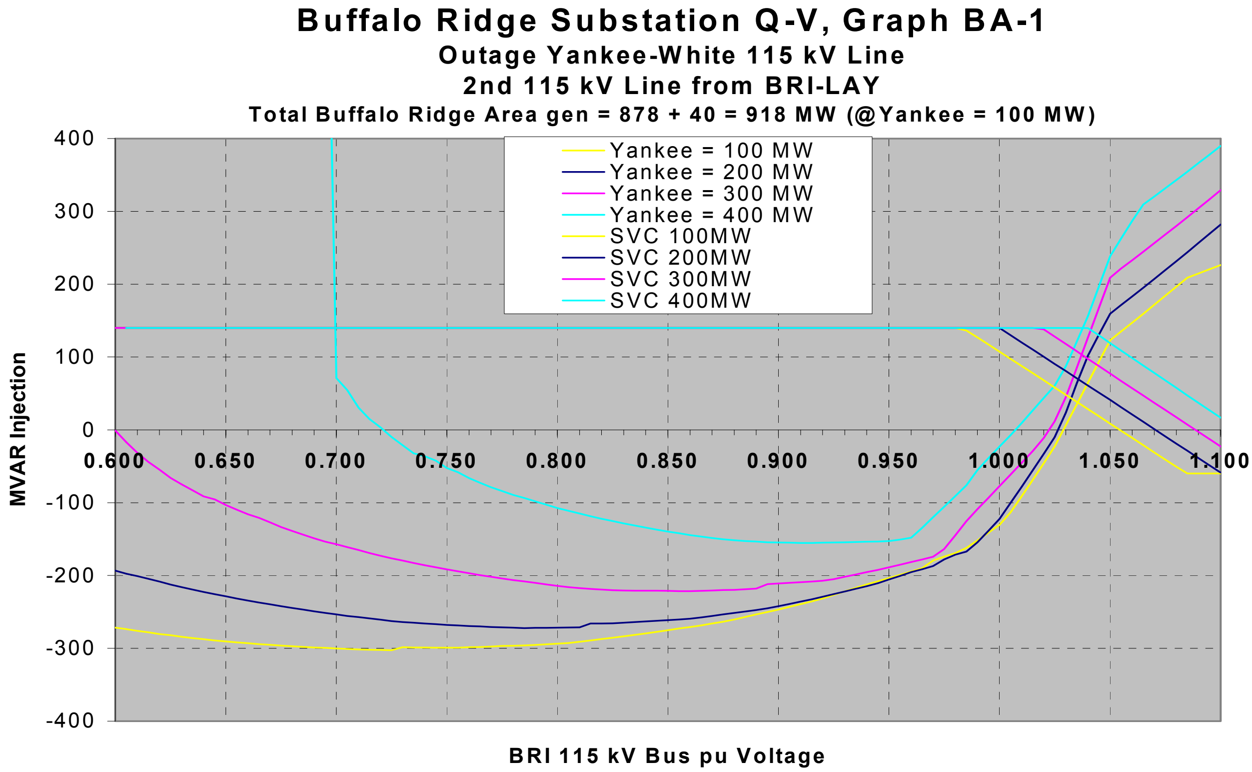
Yankee Substation Q-V, Graph Y0-1

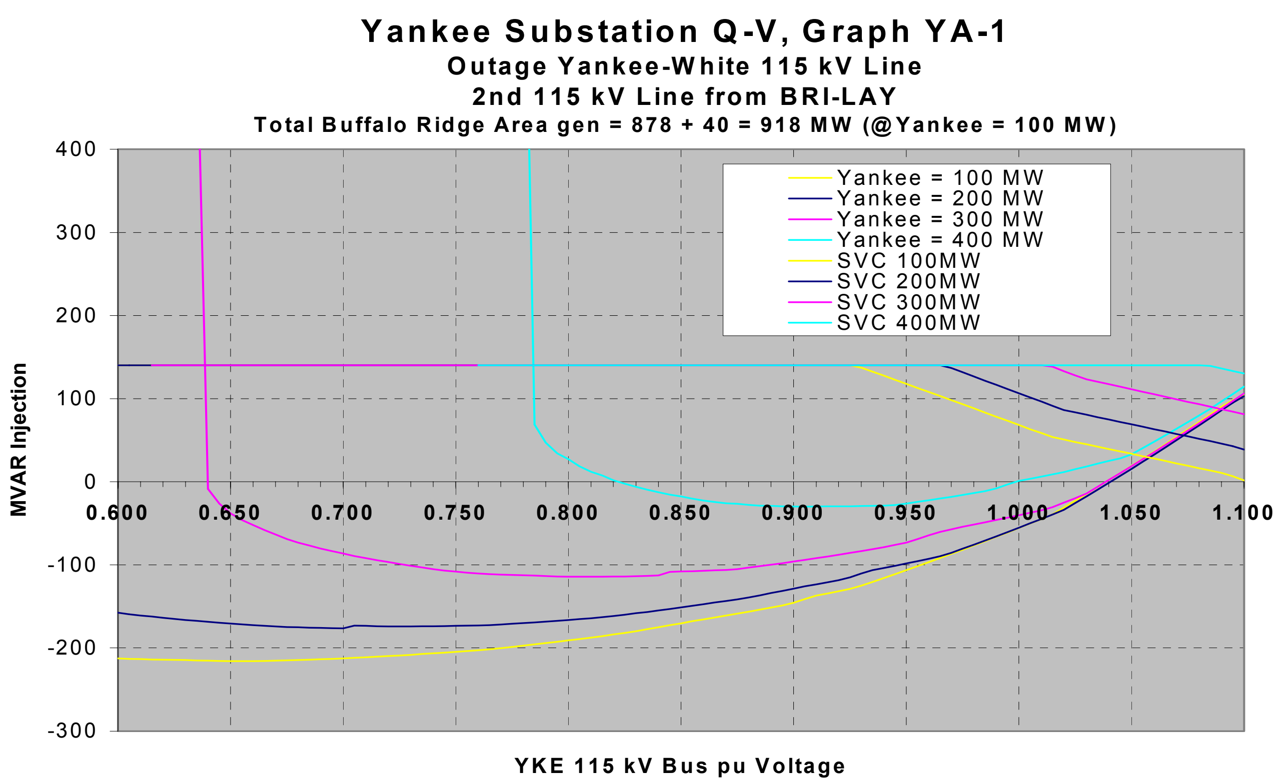
Existing System, Outage Yankee-White 115 kV Line

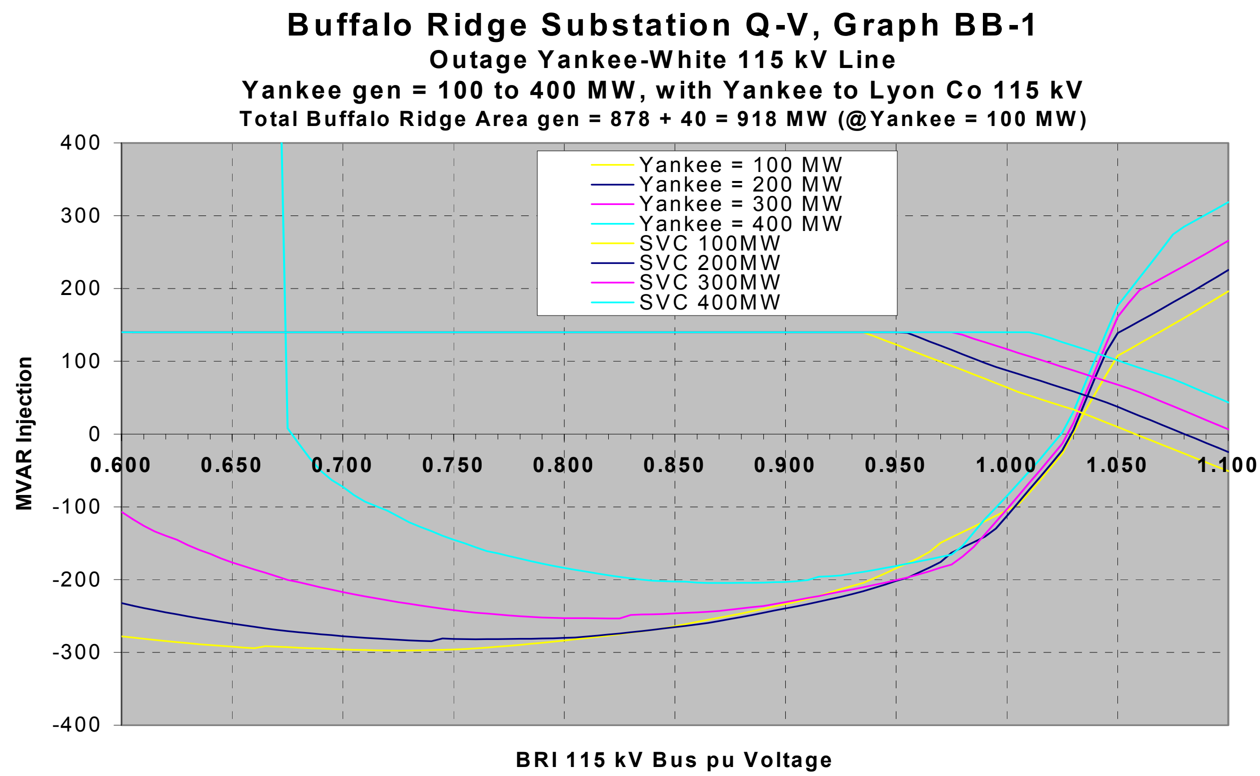
Yankee gen = 100 to 400 MW

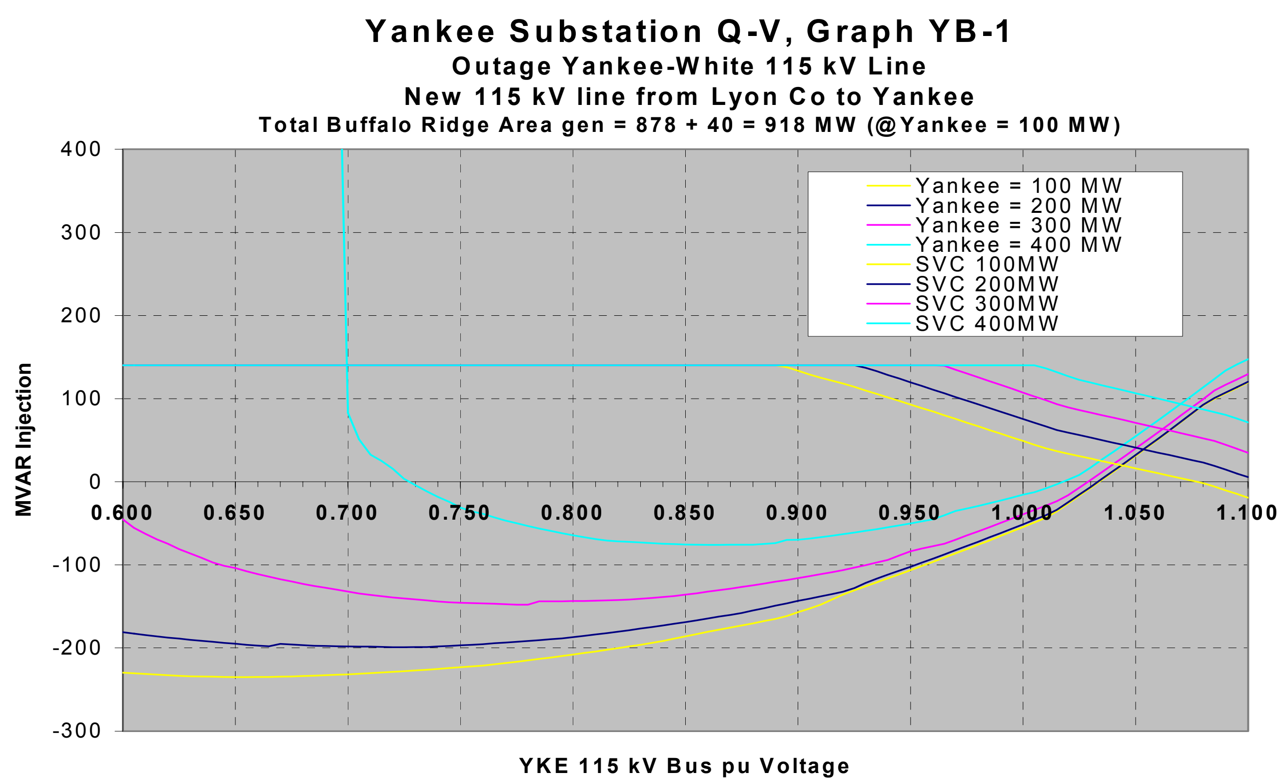
Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)




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 = 100 MW
Yankee = 200 MW
Yankee = 300 MW
Yankee = 400 MW
SVC 100MW
SVC 200MW
SVC 300MW
SVC 400MW
MVAR Injection
BRI 115 kV Bus pu Voltage
400
300
200
100
0
-100
-200
-300
-400
0.600
0.650
0.700
0.750
0.800
0.850
0.900
0.950
1.000
1.050
1.100


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)
Yankee = 100 MW
Yankee = 200 MW
Yankee = 300 MW
Yankee = 400 MW
SVC 100MW
SVC 200MW
SVC 300MW
SVC 400MW
MVAR Injection
YKE 115 kV Bus pu Voltage
400
300
200
100
0
-100
-200
-300
0.600
0.650
0.700
0.750
0.800
0.850
0.900
0.950
1.000
1.050
1.100


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)
MVAR Injection
BRI 115 kV Bus pu Voltage
Yankee = 100 MW
Yankee = 200 MW
Yankee = 300 MW
Yankee = 400 MW
SVC 100MW
SVC 200MW
SVC 300MW
SVC 400MW
400
300
200
100
0
-100
-200
-300
-400
0.600
0.650
0.700
0.750
0.800
0.850
0.900
0.950
1.000
1.050
1.100

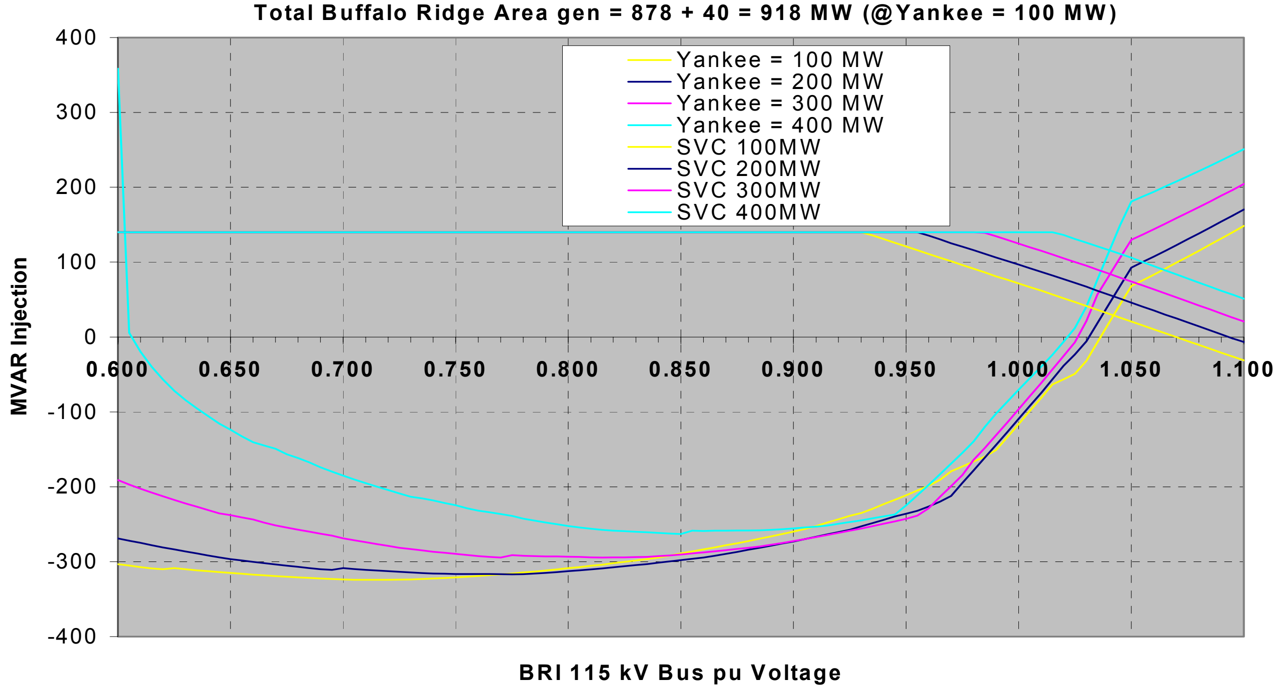

Yankee Substation Q-V, Graph YB-1
Outage Yankee-White 115 kV Line
New 115 kV line from Lyon Co to Yankee
Total Buffalo Ridge Area gen = 878 + 40 = 918 MW (@Yankee = 100 MW)
MVAR Injection
YKE 115 kV Bus pu Voltage
Yankee = 100 MW
Yankee = 200 MW
Yankee = 300 MW
Yankee = 400 MW
SVC 100MW
SVC 200MW
SVC 300MW
SVC 400MW
400
300
200
100
0
-100
-200
-300
0.600
0.650
0.700
0.750
0.800
0.850
0.900
0.950
1.000
1.050
1.100

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)

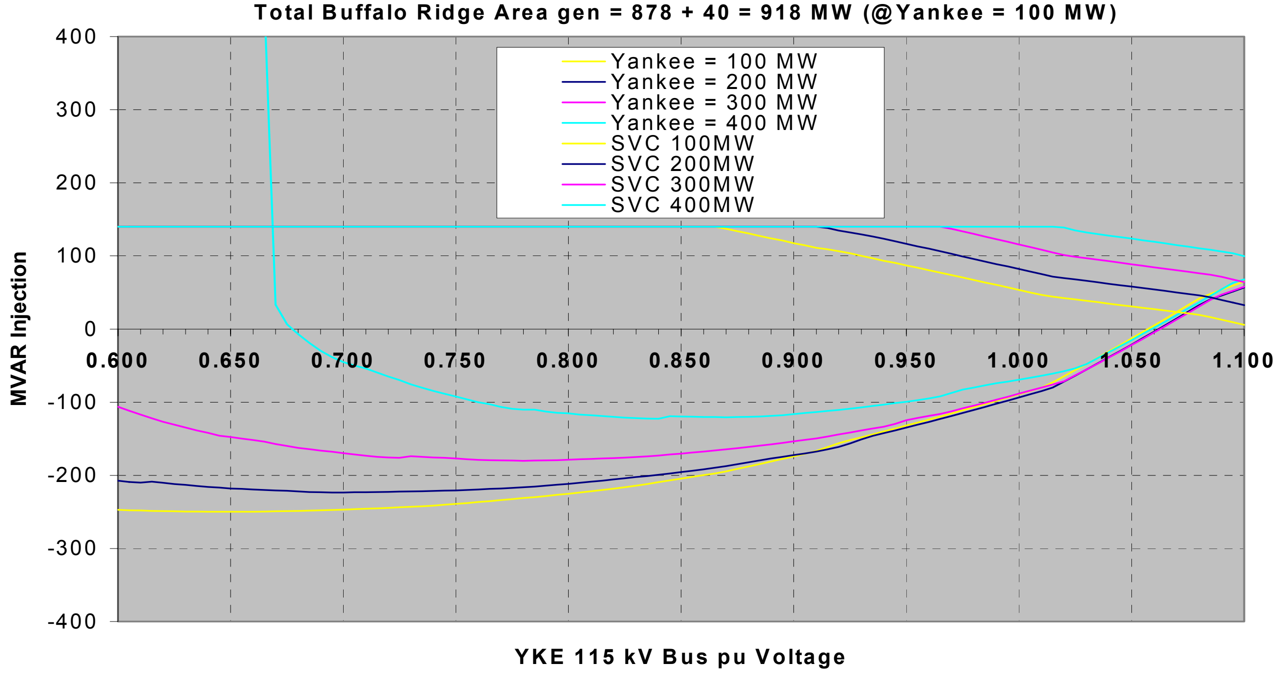


Yankee Substation Q-V, Graph YC-1

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

Modeling Assumptions
&
Input Parameters

Yankee generation reactive capability:	0.96 pf lead/lag (30 MVAR per 100 MW)
Lk Yankton SVS:	± 60 MVAR SVC, plus 4 x 20 MVAR shunt cap

Powerflow model is derived from MISO 2007 Summer Peak (Case A102II_07supk_c1.1NEW_DKD) used as “Buffalo Ridge Group II Study” base case.

Total SW MN wind gen in base case = 878 MW (918 MW nameplate installed capacity)

Load level (pk vs. off-peak) is unimportant for this local voltage collapse analysis, as this is a Yankee/Buffalo Ridge local generation outlet study, and there is no load at either substation.

“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

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