ATTACHMENT D

WIRES PHASE II STUDY

WISCONSIN INTERFACE RELIABILITY ENHANCEMENT STUDY

WIREs PHASE II

A REPORT TO THE
WISCONSIN RELIABILITY
ASSESSEMENT ORGANIZATION
(WRAO)

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

This document is a report of the technical analyses performed by the Wisconsin Interface Reliability Enhancement study (WIREs) group. The WIREs group was formed under the auspices of the Wisconsin Reliability Assessment Organization (WRAO) in the spring of 1998 in response to transmission reliability concerns stemming from events in 1997 and 1998 which caused reliability margins to drop below historically observed levels. The WIREs group consists of participants from utilities in Illinois, Iowa, Minnesota, Wisconsin, and the Canadian Province of Manitoba and the Mid-Continent Area Power Pool (MAPP) and Mid-America Interconnected Network (MAIN) reliability councils. Regulatory agencies in Illinois, Iowa, Minnesota, and Wisconsin also participated as ex officio members.

This report represents the second phase of a two-phase study effort designed to identify transmission constraints on the regional bulk power transmission system and to evaluate transmission reinforcement alternatives to alleviate those constraints. The Phase I study effort, culminating in August of 1998 with the release of the *Wisconsin Interface Reliability Enhancement Study Phase I* report, consisted of a screening analysis to determine regional transmission constraints and the identification of a set of representative transmission reinforcement alternatives that would increase the simultaneous transfer capability into Wisconsin to 3000 MW. The 3000 MW simultaneous import capability was achieved by importing 2000 MW across transmission interconnections to the west and 1000 MW across transmission interconnections to the south or 1000 MW from the west and 2000 MW from the south. To the north and east Wisconsin has no transmission interconnections because of Lakes Superior and Michigan.

The Phase I study effort also constituted the basis for a report developed by the Public Service Commission of Wisconsin (PSCW) for the Wisconsin Legislature on the regional electric transmission system.

The WRAO, in its *Report of the Wisconsin Reliability Assessment Organization on Transmission System Reinforcement in Wisconsin*, has considered the technical analyses of the WIREs group along with environmental screening studies, policy considerations, geographical diversity, and ability to construct to formulate a recommended transmission reinforcement plan.

Alternative Transmission Reinforcement Plans Considered

The Phase II study effort refined the Phase I study results by further defining relative performance differences between alternative transmission reinforcement plans. The set of twelve original representative system reinforcements, which were identified in the Phase I study effort, were refined into seven transmission reinforcement plans. The reinforcements are referred to as “plans” because several projects, in addition to a major high voltage transmission line, are required to achieve the transfer capability objective. All of the projects associated with a particular “plan” are included in the cost estimates detailed in Chapter 8 of this report.

The major transmission system additions associated with each of the seven reinforcement plans evaluated in this study are:

- Plan 1c (Salem – Fitchburg 345 kV)
- Plan 2e (Prairie Island – Columbia 345 kV)
- Plan 3j (Arrowhead – Weston 345 kV)
- Plan 5a (Chisago – Weston 345 kV)
- Plan 5b (Apple River – Weston 230 kV)
- Plan 9b (Lakefield – Columbia 345 kV)
- Plan 10 (King – Weston 345 kV)

PERFORMANCE EVALUATION

The relative performance differences of the reinforcement alternatives were established with multiple evaluation techniques. Those evaluation techniques included the following:

- *Detailed power flow simulations*
- *Generator response to transmission line switching operations*
- *Dynamic stability*
- *Voltage stability*
- *Impact on the MAPP transmission system*
- *Construction cost estimates*
- *Impact on system losses*
- *Evaluated cost proxy*

The study group utilized a 2002 summer power flow model to evaluate the characteristics of each reinforcement plan. The 2002 model was chosen due to the lead time required to evaluate, license, engineer, and construct a transmission reinforcement of these magnitudes.

Detailed Power Flow Simulations

Several detailed power flow simulations were performed on each reinforcement plan to determine:

- the reactive voltage support required to achieve the 3000 MW simultaneous import capability
- the maximum transfer capability
- the sensitivity of the 3000 MW import capability to modeling assumptions

The detailed power flow simulations verify that each of the reinforcement plans is capable of supporting 3000 MW of simultaneous import capability. However, some plans provide more incremental transfer capability above the 3000 MW target than others. In addition, the maximum transfer capability of some plans is more sensitive to changes in modeling assumptions than others. The Table ES-1 (rows a-d) summarizes the power flow simulation results and shows the maximum transfer capability of each reinforcement plan under different modeling assumptions.

Generator Response to Transmission Line Switching Operations

The ability to transfer power across the western interface is currently limited by the Arpin phase angle. The Arpin phase angle limitation is a proxy for the maximum amount of stress introduced to the Weston generators when any portion of the King – Eau Claire – Arpin 345 kV line is switched. A sudden loss of any portion of the King – Eau Claire – Arpin 345 kV line results in a system “separation” between MAPP and eastern Wisconsin. When the line is re-closed across this “separation” an instantaneous change in power output is experienced on the Weston generator units which places mechanical stress on the shaft of each unit. The Weston units experience this phenomena due to their physical proximity to the western interface. The current Arpin phase angle limitation is 60 degrees (the maximum “separation”).

Rather than focus on the Arpin phase angle as a proxy measurement for the impact on the Weston generating units, the WIREs group focused on a direct measurement; the instantaneous change in power output of the Weston units upon the closure of the Eau Claire – Arpin 345 kV line. Analysis of the present day system calculated the Weston "delta P" corresponding to the re-close of the Eau Claire - Arpin 345 kV line with a phase angle difference of 60 degrees demonstrated that Weston Unit #3 would experience a “delta P” of 37.2% (or 0.372 per unit).

Analysis of each of the seven reinforcement plans at the target simultaneous transfer capability of 3000 MW (2000 MW west/1000MW south) indicates that each plan except for Plan 1c (Salem – Fitchburg 345 kV) results in a “delta-P” less than 37.2% limit. The Weston “delta-P” results for each of the seven reinforcement plans are shown in Table ES-1 (row e)

Dynamic Stability

Dynamic stability is the measure of the system’s ability to react to a major system disturbance such as a short circuit on a transmission line, the opening of a line, the loss of a large generator, or the switching of a major load. Dynamic stability evaluates the ability of the system’s generation units to remain synchronized and to “recover” from a system disturbance.

The dynamic stability analyses performed in this study considered the following:

1. WUMS and MAPP area disturbances
2. New facility disturbances
3. Maximum Columbia & Weston generation output sensitivities
4. Breaker failure performance (Rocky Run area)
5. Damping of the ¼ Hertz mode of oscillation
6. Incremental transfer capability assessment based on ¼ Hertz mode of oscillation.
7. Dynamic reactive support requirements

In general, all plans met established transient voltage and rotor angle criteria for the WUMS 2000 MW west – 1000 MW south import transfer condition. No additional reactive voltage support (VAr) requirements, over and above those identified through the power flow analyses, were identified.

The most pronounced difference between the reinforcement plans was observed for disturbances involving a loss of a major Twin Cities 345 kV outlet facility. For a loss of either the King – Eau Claire – Arpin 345 kV or the Prairie Island – Byron 345 kV transmission line, differences in transient voltage performance within MAPP and WUMS and damping of the MAPP/MAIN ¼ Hertz mode of oscillation were observed. Damping of the ¼ Hertz mode of oscillation is currently a stability limiting condition for the Twin Cities export (TCEX) limitation.

The damping of the ¼ Hertz (Hz) oscillation mode is dependent on transfer levels. To determine the maximum transfer capability at which the ¼ Hz mode is a limit, an incremental transfer capability (ITC) number was calculated based on the loss of either the King or Prairie Island 345 kV lines. The dynamic stability results of the ¼ Hz mode of oscillation are shown in Table ES-1 (row f).

Some generator stability problems were identified in the Rocky Run area for delayed clearing breaker failure cases studied with maximum generation at the Weston generating plant. These were found to be problems inherent in the base case and can be corrected with reduced failed breaker clearing times.

Voltage Stability

Voltage stability is the measure of a system's ability to maintain adequate voltage profiles following a major system disturbance such as the loss of a critical transmission line. Without adequate voltage support, a system could experience "voltage collapse", a condition characterized by declining voltages that cannot support customer load. The results of this analysis show that voltage instability is not encountered at a western interface transfer of 2000 MW.

The WIREs group undertook the voltage stability assessment with the MAPP Transmission Reliability Assessment Working Group and Power Technologies Inc. (PTI), a power system study consultant. The consultant's study work focused on western interface transfers because the western interface is more susceptible to voltage collapse than the southern interface. Past operating experience indicates that the southern interface is limited by thermal overload constraints rather than by voltage stability concerns.

In order to determine the maximum western interface transfer at which voltage instability is encountered, transfers were increased beyond the 2000 MW level (all other limitations were ignored). Results of this sensitivity are shown in Table ES-1 (row g) and demonstrate that some reinforcement plans provide more western interface transfer capability before voltage instability is exhibited.

Impact on the MAPP Transmission System

The impact of the seven reinforcement plans on the neighboring MAPP system was evaluated by considering the change in flow on the MAPP flowgates. Flowgates are a set of transmission lines with a single flow capability that define a thermal, voltage, or stability limitation. The geographical areas represented by the MAPP flowgates are shown in the figure below.

The change in flow on each flowgate due to the addition of a reinforcement plan to the system was determined by measuring the before and after reinforcement flow at a transfer level of 3000 MW (2000 MW western transfer / 1000 MW southern transfer). These results demonstrate that most reinforcement plans reduce flow on the MAPP flowgates as they are defined today[1]. The results are shown in Table ES-1 (rows h-l).

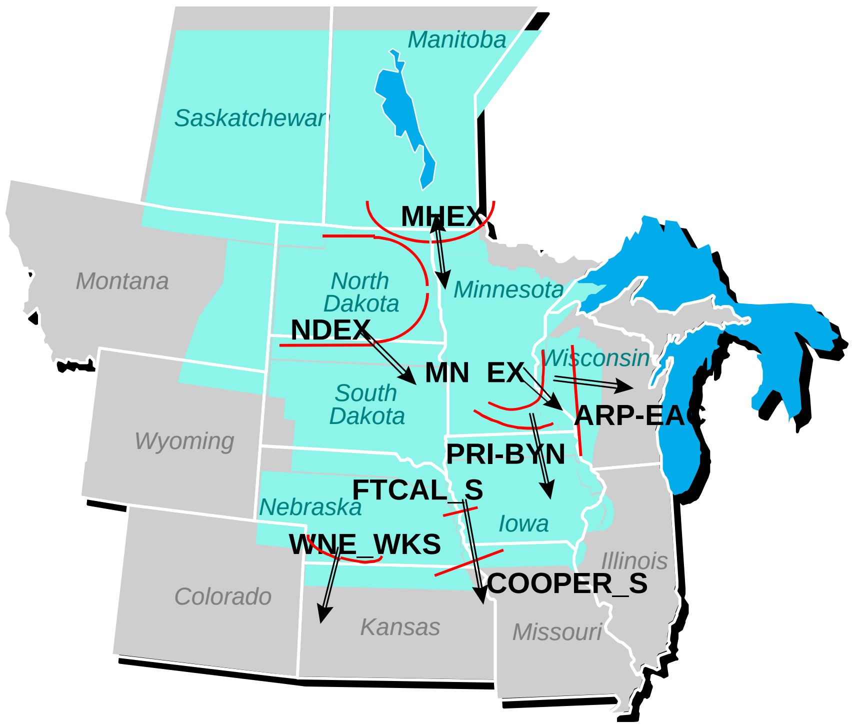

Figure ES- 1

Impact of System Losses

An analysis was undertaken to quantify the relative cost of system losses among the reinforcement plans. The costs associated with losses are summarized as an equivalent capital investment adjustment to the initial capital construction cost for each alternative. An equivalent capital cost adder is calculated for each reinforcement plan that is relative to the plan with the least losses. The capital cost adder for each reinforcement plan is shown in Table ES-1 (row m).

[1] It is important to note that some flowgate definitions and ratings may change when a major transmission reinforcement is added to the system.

The process computes the lifetime costs for the installed generating capacity and associated energy to serve the losses that would prevail for each alternative. Transmission losses are included for the MAPP, MAIN, and SPP Regions. The cost adder is based on subtracting the life time costs of the lowest cost alternative, from the cost of all alternatives. Three components of adjusted capital cost were computed. These are due to generation capacity to supply the losses, annual energy losses to serve load, and annual energy losses due to point-to-point transactions.

Capacity Cost
Each plan causes the greatest demand for losses at some anticipated transfer level condition. In the cost evaluation, the maximum amount of loss caused by a plan is assigned a cost of 400 $/kW. The resulting cost represents the cost for installed generating capacity that would be required to serve the losses.

Energy Loss for Load
Each plan has energy losses associated with the annual hourly loss that occurs as the load pattern is served. An annual load pattern is sufficiently predictable, so that the resulting cost for Energy Loss for Load is a constant for each plan. The annual energy to serve load in each plan has been set at 30 % of the energy that would be lost if the peak load occurred all hours in the year. The annual energy lost as a consequence of serving load is priced out at 15 $/MWh. The resulting annual energy cost is equated to a levelized annual carrying charge. The annual carrying charge dollars are then converted to an equivalent capital investment, by dividing by 15 %.

Energy Loss for Transactions
Each plan has energy losses that are required to support the various point-to-point transactions that are planned. After determining the annual energy associated with the point-to-point transactions, a capital investment is computed by dividing by 15 %. Due to the varying degrees that future point-to point usage can occur, the annual Energy Loss for Transactions have been computed over a range of operating conditions. For example 5% of the time a 2000 MW import into WUMS from the West and a 1000 MW import from the South is one operating point along with, 40% of the time at a 1000 MW West import and 0 MW South import, etc.

Construction Cost Estimates

The cost estimates for the WIREs reinforcement plans are comprised of three parts. These three parts are cost of transmission lines, cost of substation terminal additions, and the cost of associated projects. The total construction cost, expressed as a range of values for each reinforcement plan, is shown in Table ES-1 (rows n and o). The construction cost estimates contain a range to account for discrete “study areas” between substation end-points. A team of environmental analysts retained by the WRAO to examine the seven reinforcement plans developed the “study areas”.

The three segments of the construction cost estimates are discussed below.

Cost of Transmission Lines
Black & Veatch, an engineering consultant retained by WRAO for this purpose, developed the cost estimates for the transmission lines. The transmission line

cost estimates were based on the study areas defined for each plan by an environmental consultant working with WRAO and the WIREs group. For each study area, a single circuit cost estimate and a cost estimate that utilized all potential double circuiting opportunities were developed. In most cases, four cost estimates were developed for each reinforcement plan (two study areas times two cost estimates).

Cost of Substation Terminal Additions
The cost estimates for the substation terminal additions and enhancements required for each WIREs plan were developed by the utilities whose service territories contained the substations under consideration. Black & Veatch supplied standard substation "component costs" which were used by each utility in determining the estimated cost for these improvements. The component costs used are listed in a subsequent section.

Cost of Associated Projects
The associated projects are various system improvements which were required enhancements in order for the WIREs plan under consideration to achieve the stated power transfer goals. The cost estimates for these projects were developed by the utilities whose service territories contained the system elements under consideration.

Evaluated Cost Proxy

An evaluated cost proxy, which merged the construction cost, the equivalent capital cost adder for losses, and other savings from avoided local load serving projects is included in Table ES-1 (row p and q). The evaluated cost proxy is a portrayal of the overall economic impact of each reinforcement plan based on construction cost, the cost of losses, and a credit for avoided facilities. As with the construction cost estimates, the evaluated cost proxy is shown as a range to account for the different "study areas" for each reinforcement plan (the "study areas" were developed by the WRAO's environmental team).

Table ES-1 WIRE Study - Summary of Plans' Performance Evaluation

	Performance Results All Reinforcement Plans Satisfy 3000 MW Simultaneous Import Objective *ver3- 4/9/99*	Salem-Fitchburg 345 kV 1c	Prairie Island-Columbia 345 kV 2e	Arrowhead-Weston 345 kV 3j	Chisago-Weston 345 kV 5a	Apple River-Weston 230 kV 5b	Lakefield Jct-Columbia 345 kV 9b	King-Weston 345 kV 10
	Southern Interface Transfer Capability (with 1000 MW western bias)							
a	**Transfer Capability - Southern Interface**	**2450**	**2370**	**2130**	**2150**	**2010**	**2400**	**2140**
	Western Interface Transfer Capability (with 1000 MW southern bias)							
b	**Transfer Capability - Western Interface (MW)**	**2210**	**2580**	**2280**	**2270**	**2120**	**2750**	**2300**
c	**Transfer Capability - Source Sensitivity (MW)**	**2110**	**2550**	**2190**	**2190**	**2140**	**2810**	**2200**
d	**Transfer Capability - Sink Sensitivity (MW)**	**2160**	**2720**	**1860**	**1880**	**2160**	**2590**	**1890**
e	**Weston Delta P (per unit improvement from existing limit @ 2000 MW)**	**-0.013**	**0.015**	**0.036**	**0.166**	**0.064**	**0.009**	**0.247**
f	**Dynamic Stability - .25 Hz Damping (MW incremental xfer through WUMS)**	**50**	**720**	**450**	**670**	**220**	**120**	**480**
g	**Voltage Stability (western transfer level MW - no southern import)**	**2615**	**3245**	**2615**	**2865**	**2865**	**3105**	**2865**
	Other Factors							
h	**MAPP OPPD Flowgate Loading (avg % loading change from base case)**	**-1.2%**	**-9.3%**	**-7.9%**	**-8.6%**	**-5.5%**	**-12.4%**	**-7.9%**
i	**MAPP COOPER_S Flowgate Loading (% loading change from base case)**	**-7.9%**	**-18.1%**	**-14.7%**	**-16.1%**	**-11.6%**	**-22.3%**	**-15.4%**
j	**MAPP ECL-ARP Flowgate Loading (% loading change from base case)**	**-0.8%**	**-6.3%**	**-19.7%**	**-24.3%**	**-10.6%**	**-7.5%**	**-20.2%**
k	**MAPP PRI-BYR Flowgate Loading (% loading change from base case)**	**1.3%**	**-26.1%**	**-15.5%**	**-18.3%**	**-9.0%**	**7.0%**	**-16.5%**
l	**MAPP MN EX Flowage Loading (% loading change from base case)**	**0.3%**	**-17.6%**	**-17.0%**	**-20.6%**	**-6.7%**	**8.1%**	**-20.2%**
	Economic Factors							
m	**Losses (Capital Cost Adder w/r to Plan 3j - million $)**	**$50.2**	**$27.2**	**$0.0**	**$1.4**	**$38.7**	**$29.0**	**$20.8**
n	**Construction Cost Range (single ckt - million $)**	**$116 - $145**	**$169 - $176**	**$177 - $210**	**$172 - $205**	**$118 - $144**	**$227 -**	**$136 - $139**
o	**Construction Cost Range (doubl ckt - million $)**	**$158 - $227**	**$243 - $265**	**$266 - $310**	**$240 - $284**	**$171 - $208**	**$395 -**	**$210 - $262**
p	**Evaluated Cost Proxy Range (single ckt - million $)**	**$166 - $195**	**$195 - $202**	**$177 - $199**	**$126 - $149**	**$157 - $173**	**$256 -**	**$157 - $160**
q	**Evaluated Cost Proxy Range (double ckt - million $)**	**$208 - $277**	**$269 - $291**	**$266 - $299**	**$194 - $228**	**$210 - $237**	**$424 -**	**$231 - $283**

Table ES - 1

SUMMARY OF TECHNICAL STUDY RESULTS

The evaluation techniques utilized in this study demonstrate that each reinforcement plan, with the exception of Plan 1c, is capable of supporting a simultaneous transfer of 3000 MW over the western and southern interfaces into Wisconsin. The Weston delta-P performance of Plan 1c (Salem – Fitchburg 345 kV) is slightly less than criteria which indicates that Plan 1c could not sustain a simultaneous import of 3000 MW without adding additional facilities to the plan.

Each of the evaluation techniques considered in this study were considered in isolation. In other words, the voltage stability transfer capability did not consider thermal limitations and vice-versa. The absolute transfer capability of each reinforcement plan is a function of all potential limitations including thermal, voltage, dynamic stability, and Weston delta-P. The following "radar-plot" attempts to capture how a different type of system limitation limits the transfer capability of each reinforcement plan.

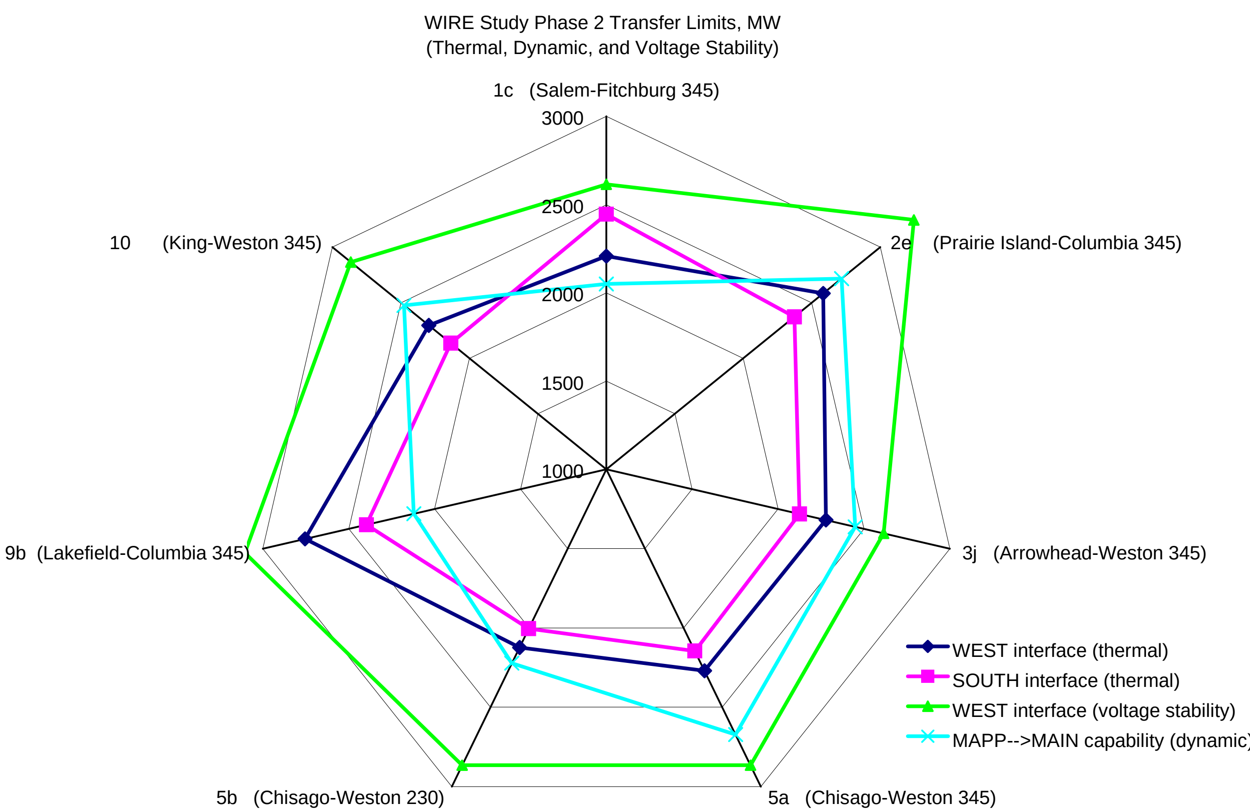

Figure ES- 2

Chapter 1 INTRODUCTION

1.1 Background

The Phase I study effort, culminating in August of 1998 with the release of the *Wisconsin Interface Reliability Enhancement Study Phase I* report, consisted of a screening analysis to determine regional transmission constraints and the identification of a set of representative transmission reinforcement alternatives. The Phase I screening analysis focused primarily on thermal overload constraints and transmission reinforcements indicative of the type of transmission additions necessary to alleviate those thermal constraints. The twelve transmission reinforcements considered in the Phase I analysis were:

1. Salem – Fitchburg 345 kV (1c)
2. Prairie Island – Columbia 345 kV (2e)
3. Salem – Paddock 345 kV (2f)
4. Arrowhead – Weston – S Fond du Lac 345 kV (3e)
5. Arrowhead – Weston 345 kV (3j)
6. Arrowhead – Weston 230 kV (3k)
7. Chisago – Weston 345 kV (5a)
8. Chisago – Rocky Run 500 kV (6c)
9. Wilmarth – Byron – Columbia 345 kV (8b)
10. Huron – Split Rock – Lakefield – Adams – Genoa – Columbia 345 kV (9a)
11. Plano – Plano Tap 345 kV (12)
12. Arrowhead – Plains 345 kV (13c)

The Phase I study effort did not consider transmission planning criteria such as voltage performance, dynamic stability, voltage stability, detailed construction costs, and the economic evaluation of loss estimates. Before considering these detailed planning criteria, the WIRE study team refined the twelve representative reinforcements into seven reinforcement plans. The reinforcement plans were developed by comparing the relative performance of the twelve original options and selecting those most representative of the reinforcements studied in the Phase I process.

Reinforcement Options 3j and 5a were selected for the Phase II study process because both plans met the 2000/2000/3000 MW transfer capability objective (based on thermal limitations) at a relatively reasonable cost. In addition, both options performed reasonable well based on the Phase I Arpin phase angle, Weston delta-P, and on-peak loss savings analyses.

Reinforcement Option 6c was eliminated from further analysis in the Phase II study process because the transfer capability objective (based on thermal limitations) was achieved with options that require lower voltages that do not require rather expensive 500 kV to 345 kV step-down transformers. In addition, the 500 kV operating voltage of this option limits the ability to enhance local load serving. This option is also relatively expensive when compared to other options.

Reinforcement Options 3e, 3k, and 13c were all eliminated from further analysis in the Phase II process because none of the options provided any additional benefit over Options 3j and 5a. Each performed inferior to Options 3j and 5a from a thermal transfer capability perspective, and from an Arpin phase angle/Weston delta-P perspective.

Reinforcement Option 12 was eliminated from further study as a stand-alone reinforcement plan. The Plano – Plano Tap 345 kV facility remains as an integral project contained within each of the Phase II reinforcement plans. However, on a stand-alone basis, Option 12 did not sufficiently address the Arpin phase angle/Weston delta-P issue and it is suspect to voltage collapse.

Reinforcement Option 2e was selected for the Phase II study because it provides relatively good performance from an Arpin phase angle/Weston delta-P and construction cost standpoint. In addition, this option provides for another outlet from the Twin Cities area.

Reinforcement Options 9a and 8b were eliminated from further study. The construction cost of Option 9a is excessive when compared to Option 2e. Option 8b is suspect to increase loading on the Twin Cities southern ties when compared to Option 2e.

Reinforcement Option 2f was eliminated because of its similarity to Option 1c. Option 1c was carried into the Phase II analysis even though it performed only marginally well when compared to other options. Option 1c was retained to provide a measure against which to compare the dynamic stability performance of options electrically closer to the existing western interface.

Three new reinforcement plans were developed based on the options evaluated in the Phase I process. Plan 9b (Lakefield Jnc – Adams – Genoa – Columbia 345 kV) is a trimmed version of the Phase I Option 9a and is less costly from a construction cost standpoint. Plan 5b (Apple River – Weston 230 kV) was added to consider dynamic and voltage stability performance of a lower voltage version of Plan 5a. Plan 10 (King – Weston 345 kV) was added because of the potential dynamic stability differences between it and Plan 5a (Chisago – Weston 345 kV). The group discussed the King – Weston reinforcement in the Phase I process but noted that from a thermal standpoint, it is electrically similar to Plan 5a. However, potential dynamic and voltage stability differences prompted the group to add Plan 10 to the Phase II process.

1.2 SIGNIFICANCE OF PHASE II STUDY RESULTS

The performance criteria evaluated in this study represent a benchmark upon which the reinforcement plans are compared. Each performance evaluation is considered based upon a “snapshot” of system conditions. Therefore, the results presented in this report are not absolute values valid for all operating conditions. A change in any one of a number of modeling assumptions such as load level, load distribution, generation profiles, transmission system topology, and simultaneous transfers would likely impact the results detailed in this report. The WIRE study team notes that a change in any one of the modeling assumptions could lead to a ±10% change in the 3000 MW transfer capability of each plan.

The transfer capability limits and performance measures established in this report are not the same as, nor calculated on the same basis as, the available transfer capability (ATC) values posted on the Open Access Same-Time Information System (OASIS). The ATC values posted on the OASIS define the commercial availability of the transmission system on a firm and non-firm basis and include such factors as transmission reliability margin (TRM) and capacity benefit margin (CBM). The transfer capability limits within this report are not intended to establish the commercial availability of the transmission system and should not be used as such. The transfer capabilities within this report are analogous to those reported in the Transmission Assessment Study Guide (TASG) and Future System Study Guide (FSSG) reliability studies performed by MAIN.

CHAPTER 2 DETAILED POWER FLOW SIMULATIONS

The Phase I study effort consisted of a high-level screening analysis to identify thermal constraints on the regional transmission system during heavy transactions into Wisconsin. The Phase I study effort also identified a representative set of transmission reinforcement options to attain a simultaneous transfer capability of 3000 MW over Wisconsin's western and southern interfaces. The Phase I screening analysis utilized linearized power flow techniques ("DC" power flow analysis) that do not capture voltage limitations or heavy VAr (Volt-Amp reactive) flows.

The Phase II study effort refined the analysis conducted in Phase I by considering the transfer capability beyond the 3000 MW level, sensitivities to input assumptions, and the consideration of voltage limitations and VAr flow ("AC" power flow analysis). This section describes the Phase II power flow simulations and results.

2.1 TRANSFER CAPABILITY - BACKGROUND

The power flow simulations were conducted with the PSS/E power flow package, a nationally recognized tool for transmission system planning studies. The PSS/E activity TLTG evaluates a linearized network model (DC load flow) to estimate the import or export limits of a specified region. To develop power exports/imports, the activity identifies a "study" system in which generation is increased (sources) and an "opposing" system in which generation is decreased (sinks). Power transfer distribution factors (PTDF) relate the change in exports/imports to branch and interface flows. Maximum transfer capabilities are determined by extrapolating the line and interface flows using the PTDFs and comparing them to specified ratings.

Default Sources/Sinks

Base case imports into WUMS totaled approximately 375 MW from the west and 150 MW from the south respectively. In order to evaluate the reinforcement plans using TLTG and meet the study objective of 2000 MW non-simultaneous transfer capability on each WUMS interface, additional sources west of WUMS had to total 1625 MW and additional sources south of WUMS had to total 1850 MW. Conversely, sinks within WUMS had to be identified to facilitate the imports.

Due to the lack of available generation in the MAPP region, the study used a combination of load reduction in western MAPP and the addition of unplanned generating units in Nebraska and North Dakota to provide the 1625 MW exported to WUMS. Load was reduced to 90% of peak in the following control areas: Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), Lincoln Electric System (LES), Western Area Power Administration (WAPA), and Otter Tail Power (OTP). The load reduction method produced approximately 925 MW of available capacity. The remaining 700 MW was split between two 350 MW generators. One unit was added at the Gentleman facility located in Nebraska and another was added at the Antelope Valley facility in North Dakota.

The load reduction represents a shoulder peak condition in western MAPP in which cooler weather frees up generation for export to WUMS while that area experiences high temperatures and peak load conditions. This scenario has occurred several times in the past as weather systems move from west to east. The study did not consider load reduction in eastern MAPP (Minnesota, Iowa and western Wisconsin) because of its proximity to WUMS.

The study utilized available generating capacity in Southern Illinois and ECAR to provide exports totaling 1850 MW to WUMS. Southern Illinois generation participated in 10% of that total, with ECAR accounting for the remaining 90%.

The study used all on-line generating units within WUMS to sink imported power. The amount each unit participated in the specified transaction was directly proportional to its MW output in the base case.

Base Case Biasing

In an effort to simulate a 3000 MW simultaneous transfer into WUMS, the transfer capability limits on each WUMS interface were tested with a 1000 MW transfer “bias” on the opposite interface. The transfer capability analysis of the WUMS western interface was conducted with the 1000 MW “bias” on the southern interface; the southern interface transfer capability was tested with a 1000 MW “bias” on the western interface. When a 2000 MW transfer capability on a particular interface is achieved with the simultaneous 1000 MW “bias”, the total simultaneous import capability is 3000 MW.

Monitored Elements

The study monitored all transmission system elements above 100 kV in and emanating from the following regions: Wisconsin, Western Upper Peninsula of Michigan, Illinois, Eastern Missouri, Minnesota, Iowa and Eastern Nebraska.

The study also defined and monitored three “interfaces”:

1. Arpin -- Eau Claire 345 kV line.
2. Prairie Island -- Byron 345 kV line.
3. Twin Cities Exports

Contingencies

All single branches, 100 kV and up, contained within and tied to the monitored regions were taken as contingencies, with one exception; Commonwealth Edison submitted a separate contingency list for all facilities located in their service territory. The ComEd list included many multi-segment contingencies and operating guides. Several utilities also submitted operating guides to implement in association with various 345 kV system contingencies.

Participation Factor Cutoffs

The transfer capability output reports identified segments with Power Transfer Distribution Factors (PTDF) greater than 2%. The study group only considered PTDFs greater than 3% as significant. Generally, segments with PTDFs less than 3% that appear as limitations in transfer studies have high initial base case flows associated with local area load serving problems.

2.2 Transfer Capability Sensitivity Studies

The modifications of the default source and sink lists provide a method to test the transfer capability robustness of each plan with respect to thermal limitations. The sensitivity analysis focused on the WUMS western interface and utilized a base case biased with WUMS southern imports totaling 1000 MW to properly compare the projects against the 3000 MW simultaneous import design criteria.

Source Sensitivity

The base transfer capability study utilized 700 MW of unplanned generation at the Gentleman and Antelope Valley sites, combined with load scaling in western MAPP, as source points for WUMS imports. The source sensitivity replaced the unplanned generators with a generation unit at the Lakefield Junction 345 kV substation (in southwestern Minnesota) and continued to use load scaling in western MAPP to free up capacity for exports. Transfer capability limits were chosen in a manner consistent with the base study.

Sink Sensitivity

The base transfer capability study used all WUMS generation as sink points for transactions. The sink sensitivity utilized the following five generator sites:

Columbia Unit 1	514 MW
Edgewater Unit 5	372 MW
Oak Creek Unit 8	280 MW
Point Beach Unit 1	495 MW
Kewaunee Unit 1	530 MW

This sink methodology is consistent with past and present MAIN system capability studies and can summarize the impact of large unit outages on the eastern Wisconsin transmission system. Transfer capability limits were chosen in a manner consistent with the base study.

2.3 Transfer Capability Limit Results

The reinforcement of facilities limiting WUMS imports to levels below the 2000 MW/3000 MW design criteria were assumed to be part of the respective plan’s scope and subsequently included in the overall cost estimates. In an effort to identify the reasonable WUMS import level beyond the targeted criteria, all “simple” reinforcements were included in the plan scope until a “significant” limit was attained. “Simple” reinforcements included any or all of the following: terminal equipment upgrades, re-sagging of existing line conductor or the replacement of line conductor on existing structures. “Significant” limits generally required the complete reconstruction of an existing line or the addition of a new line to eliminate the transfer capability limitation identified in the transfer simulation.

The results of the maximum transfer capability with the default source/sink list and the maximum western interface transfer capability with the source and sink sensitivities are shown in the following tables. The results presented are based on thermal limitations only; other limitations (such as steady state voltage profiles, voltage stability, and dynamic stability) are discussed in subsequent sections of this report. The term FCTTC is the acronym for First Contingency Total Transfer Capability.

Plan	Description	Western Interface FCTTC With 1000 MW Southern Bias	
		(MW)	Limiting Element
1c	Salem-Fitchburg 345 kV	2208	Seneca-Genoa 161 kV
2e	Prairie Island-LaCrosse-Columbia 345 kV	2584	Wien-T Corners 115 kV
3j	Arrowhead-Highway 8 Tap-Weston 345 kV	2278	Nelson Dewey-Cassville 161 kV
5a	Chisago-Apple Rvr-Highway 8 Tap-Weston 345 kV	2269	Sand Lake-Port Edwards 138 kV
5b	Apple Rvr-Highway 8 Tap-Weston 230 kV	2123	Nelson Dewey-Cassville 161 kV
9b	Lakefield-Adams-Genoa-Columbia 345 kV	2753	Elk Mound-Barron 161 kV
10	King-Eau Claire-Weston 345 kV	2295	Nelson Dewey-Cassville 161 kV

Table 2.3- 1

Plan	Description	Southern Interface FCTTC With 1000 MW Southern Bias	
		(MW)	Limiting Element
1c	Salem-Fitchburg 345 kV	2445	Itasca-Tonne Blue 138 kV
2e	Prairie Island-LaCrosse-Columbia 345 kV	2373	Itasca-Tonne Blue 138 kV
3j	Arrowhead-Highway 8 Tap-Weston 345 kV	2125	Turkey River-Cassville 161 kV
5a	Chisago-Apple Rvr-Highway 8 Tap-Weston 345 kV	2145	Turkey River-Cassville 161 kV
5b	Apple Rvr-Highway 8 Tap-Weston 230 kV	2005	Turkey River-Cassville 161 kV
9b	Lakefield-Adams-Genoa-Columbia 345 kV	2396	Itasca-Tonne Blue 138 kV
10	King-Eau Claire-Weston 345 kV	2135	Turkey River-Cassville 161 kV

Table 2.3- 2

Plan	Description	Western Interface FCTTC With 1000 MW Southern Bias	
		Source Sensitivity (MW)	Sink Sensitivity (MW)
1c	Salem-Fitchburg 345 kV	2110	2160
2e	Prairie Island-LaCrosse-Columbia 345 kV	2550	2720
3j	Arrowhead-Highway 8 Tap-Weston 345 kV	2190	1860*
5a	Chisago-Apple Rvr-Highway 8 Tap-Weston 345 kV	2190	1880*
5b	Apple Rvr-Highway 8 Tap-Weston 230 kV	2140	2160
9b	Lakefield-Adams-Genoa-Columbia 345 kV	2810	2590
10	King-Eau Claire-Weston 345 kV	2200	1890*

* The Port Edwards - Sand Lake 138 kV limit removed with $6M expenditure to rebuild the line

* Next valid limit at 2150 MW

Table 2.3- 3

Tables 2.3-1 and 2.3-2 demonstrate that each reinforcement plan is capable of supporting simultaneous transfer capability of at least 3000 MW based on thermal limitations. Each plan is capable of at least 2000 MW of transfer capability across either the western or southern interface while simultaneously importing 1000 MW on the opposite interface (2000 + 1000 = 3000 MW). Some reinforcement plans support more incremental transfer capability above the 3000 MW objective than others do.

The western interface source/sink transfer capability sensitivity results shown in Table 2.3-3 show that all plans meet the 3000 MW objective when the sources are modified from the default. However, the sink sensitivity results show that Plans 3j, 5a, and 10 fall just short of the of the 3000 MW objective when the sink list is modified. The results demonstrate that the Port Edwards – Sand Lake 138 kV line is sensitive to changes in the sink (or import) participation point list. An expenditure of $6 million is required to remove the limitation and restore western interface transfer capabilities to the 2000 MW target. The $6 million estimate is not included in the construction cost estimates for Plan 3j, 5a, and 10 because the limitation surfaced in a sensitivity analysis to test for robustness.

2.4 AC ANALYSIS – DETERMINATION OF REACTIVE VOLTAGE SUPPORT REQUIREMENTS

All power transfer studies conducted in the Phase 1 evaluation utilized DC power flow techniques that identify thermal overload problems only. A DC power flow analysis assumes that system voltage profiles are held constant throughout the power flow simulation. However, voltage profiles throughout the transmission system are impacted when the system topology is changed due to the loss of a transmission element or when power transfers are initiated. In order to ascertain the voltage response of the system to these events, an AC power flow analysis is required.

The AC power flow analysis of the seven reinforcement plans was performed with PSS/E, a power system simulation package developed by Power Technologies, Inc. The AC power flow analysis considered transmission contingencies in Wisconsin and parts of Iowa, Minnesota, and Illinois. Resulting voltage profiles were monitored to determine voltage violations. Voltage profiles (especially voltages less than about 95% of nominal) can heavily impact the flow on the transmission system. For this reason, transmission system elements were monitored for thermal overload violations as well.

The WIREs 2002 summer base case, which was developed in Phase 1, was used for the AC power flow analysis. A small number of system modifications were made to the base case to correct minor modeling errors. The power flow model was then altered to simulate a western interface transaction of 2000 MW and a southern interface transaction of 1000 MW. Transactions from the west were simulated by reducing load within western MAPP companies and adding “unplanned” generation. Transactions from the south were simulated by increasing the output of existing generation in southern Illinois and ECAR. Section 2.1 of this report describes the default source/sink list used to simulate western and southern interface transactions.

An AC power flow analysis was conducted on this “3000 MW import” power flow case to determine first contingency voltage violations and to confirm the thermal transfer capabilities established with the DC power flow analysis. A second, yet highly critical, component of the AC power flow analysis is the identification and location of shunt capacitor banks required to support system voltage profiles. Shunt capacitor banks were added to the system in order to maintain a voltage of 90% of nominal during critical transmission contingencies.

2.5 AC ANALYSIS – REACTIVE VOLTAGE RESULTS

In general, the AC power flow analysis did not identify any thermal overload problems that were not observed in the DC power flow analysis. However, the 69 kV interface between Alliant-East and Dairyland Power Cooperative did exhibit thermal overloads for outages of the King – Eau Claire – Arpin 345 kV line. In particular, the Council Creek 69 kV interconnection and 69kV lines around the Tomah, Sparta, and Monroe Co. substations overloaded in the base case when a 3000 MW transaction is simulated. The implementation of regional accepted operating guides provided relief for the overloaded 69 kV interconnections. These 69 kV overloads were not identified in the DC power flow analysis because only those facilities 100 kV and above were monitored.

Shunt capacitor bank requirements were defined by adding static VAr compensators (SVCs) on various transmission buses where low voltages occurred in the base case. A SVC is a device that automatically adjusts its VAr output to hold voltages at a pre-defined set point. The physical size and location of switched capacitor banks were determined from the output of the SVCs. The study was then re-performed with the SVC replaced with switched capacitor banks to verify that the voltage support requirements for each reinforcement plan were correct. The following table shows the switched capacitor bank requirements (in MVArs) for each of the seven reinforcement plans:

Location	1c	2e	3j	5a	5b	9b	10
T-Corners	160	150	45	30	40	90	30
Hume	50	20	20	20	40	40	10
Rocky Run	80	80	40	50	40	80	40
Spring Green	18	18	18	18	18	18	18
Eden	27	27	27	27	27	27	27
Kirkwood	18	18	18	18	18	18	18
Highway 8 Tap	---	---	250	160	250	---	---
Weston	---	---	20	---	---	---	---
Hillsboro	20	20	20	20	20	20	20
Arrowhead	---	---	120	---	---	---	---
Total	373	333	578	343	453	293	163

Table 2.5- 1

Table 2.5-1 shows that the capacitor bank requirements vary from 163 MVArs for Plan 10 (King - Eau Claire - Weston 345 kV) to 578 MVArs for Plan 3j (Arrowhead - Weston 345 kV). The capacitor bank requirements for Plans 3j, 5a, and 5b are driven by the fact that these options do not “stop” at an existing substation that already contains reactive support. For example, Plan 10 “stops” at the Eau Claire substation which already contains a substantial amount of capacitor banks (320 MVArs).

2.6 AC ANALYSIS – VERIFICATION OF TRANSFER CAPABILITY

Included in the Phase II analyses were full AC power flow solutions for the full set of contingencies. The full AC power flow solutions identified a number of line segments that would overload with an intact system or under a first contingency without any incremental transfers. In reviewing the output from these “base case” power flow solutions, many of the same “base case” problems were identified in each of the reinforcement plans. To assist in evaluating the impact of the “base case” problems, two tables were developed showing the loading on these lines.

The first table “ACCC Comparison-Intact System” included as Appendix A1, compares the performance of the each plan and to the base case without any transfers for an intact system. The results show small differences between the reinforcement plans. Of more importance, this table also shows the small increase in flow on these line segments as transfers are increased to 3000 MW (2000 MW West, 1000 MW South). This small increase in flow during transfers indicates that flow on these facilities is primarily caused by local area load serving requirements rather than by transfers. Also shown in this table is the impact of increased generator reactive power (VAr) output to support system voltages during transfers. Additionally, the increased power (MW) output of some of the area swing generators to supply the losses is illustrated.

The second table “ACCC Comparison-Selected Contingencies” included as Appendix A2, compares the performance of the options for selected contingencies. These include outages of several 345 kV lines into Wisconsin. The operating guides associated with these outages are also shown. In reviewing this table, the relative performance of the reinforcement plans is more pronounced than in the table for the intact system. For example, the two plans which terminate at Columbia (Plans 2e & 9b) substantially increase the flow on the Columbia - South Fond du Lac 345 kV line. Similarly, Plans 1c, 2e and 9b have a lesser impact on the Paddock - Wempleton 345 kV line than the other plan.

Chapter 3 GENERATOR RESPONSE TO SWITCHING (Delta-P)

3.1 Background

“Delta P” is defined as the sudden change in average power experienced by a generating unit at the instant following a transmission system switching operation (t=0+). The number is expressed in per unit (p.u.) calculated on the generator rated MVA base.

The Weston generating units, located in central Wisconsin and near the Arpin – Eau Claire interface, have experienced large power swings associated with the re-closure of the Arpin—Eau Claire 345 kV line. When this line is open, a phase angle difference between the western and eastern Wisconsin transmission systems is imposed; this is known as the Arpin phase angle problem. Past operating experience has indicated that in order to avoid damage to the generators at the Weston plant due to large power swings, the 345 kV breaker at Arpin should only be closed when the phase angle difference is 60 degrees or less. The Arpin phase angle limitation is a “proxy” limit for the maximum instantaneous power change on the Weston power plant generators before damage is sustained.

Analysis of the present day system calculated the Weston "delta P" corresponding to an Arpin 345 kV breaker re-close with a phase angle difference of 60 degrees. The calculations demonstrated that Weston Unit #3 would experience a “delta P” of 0.372 p.u. when the Eau Claire – Arpin 345 kV line is closed across a 60 degree phase angle.

For each reinforcement alternative, the study calculated the Weston Unit #3 “delta P” associated with a re-close of the Arpin 345 kV breaker assuming WUMS simultaneous import levels of 2000 MW from the west and 1000 MW from the south. If the resultant “delta P” is less than 0.372 p.u., the re-close was considered successful/permissible. Higher “delta P”s indicated a degradation when compared to the criteria used to operate today's system.

3.2 Delta-P Results

The following table presents the results of the Weston generator response to the switching of the Arpin – Eau Claire 345 kV line.

Impact of an Arpin - Eau Claire 345 kV Reclose on Weston Generator Unit #3

Reinforcement Option	Total WUMS Import (MW)	Weston #3 delta P (pu)		delta P Reduction at Max. Import
Base System	700 MW (550w/150s)	0.372	(1)	0.000
1c	3000 MW (2000w/1000s)	0.385		-0.013
2e	3000 MW (2000w/1000s)	0.357		0.015
3j	3000 MW (2000w/1000s)	0.336		0.036
5a	3000 MW (2000w/1000s)	0.206		0.166
5b	3000 MW (2000w/1000s)	0.308		0.064
9b	3000 MW (2000w/1000s)	0.363		0.009
10	3000 MW (2000w/1000s)	0.125		0.247

Notes:

(1) This is the existing sytem delta-P limit for Weston #3 with a 60 degree Arpin phase angle separation.

Table 3.2- 1

Table 3.2-1 demonstrates that each of the reinforcement plans except Plan 1c (Salem – Fitchburg 345 kV) result in a delta-P of less than the 0.372 per unit criterion at a simultaneous import of 3000 MW. At the 3000 MW level, Plan 1c exceeds the 0.372 per unit criterion by 0.013 per unit. Therefore, the transfer capability of Plan 1c is slightly less than 3000 MW due to the Weston #3 delta-P limit. This study did not attempt to determine the maximum western interface transfer capability (with the 1000 MW southern "bias") of Plan 1c at which the Weston delta-P limit is reached.

CHAPTER 4 DYNAMIC STABILITY

4.1 INTRODUCTION

Dynamic stability is the measure of the system's ability to react to a major system disturbance such as a short circuit on a transmission line, the opening of a line, the loss of a large generator, or the switching of a major load. Dynamic stability evaluates the ability of the system's generation units to remain synchronized and to "recover" from a system disturbance.

Dynamic stability analysis was performed as part of the WIRES Phase 2 study in order to assess the short term, dynamic performance of each reinforcement plan in response to major system disturbances. The response to known severe disturbances as well as disturbances involving the new transmission facilities were addressed.

The primary study objectives were to:

1. Evaluate the dynamic stability performance of each reinforcement plan at the WUMS 2000 West, 1000 South import condition.
2. Assess the ability of each plan to eliminate Eau Claire – Arpin cross tripping.
3. Assess the impact of each plan on the MAPP ¼ Hertz mode of oscillation.
4. Define the dynamic reactive power requirements needed to meet stability criterion for each plan.
5. Determine the potential increase in the Minnesota - WUMS stability limit achievable with each plan.

4.2 RESULTS

4.2.1 STUDY PROCEDURE

<u>Model Development</u>

This study was performed using the dynamic stability portion of the PSS/E power system analysis software. Due to the fast track nature of the study and the limited availability of WUMS area stability models, the study group chose to use a MAPP dynamics model which has had extensive use within MAPP for analysis of stability limited interfaces such as North Dakota, Manitoba – U.S., and Twin Cities 345 kV.

An updated WUMS representation including generator dynamics data was added to the model to provide an accurate representation within the WUMS area. Power flow model development is discussed further in section 4.2.2.

Study Criteria

This study adhered primarily to the study criteria defined in Appendix G of the MAPP Operating Studies Manual prepared by the MAPP Operating Review Subcommittee Working Groups as well as those defined in the MAPP System Design Standards. These criteria include transient bus voltage limitations, generator rotor angle oscillation damping and out of step relay margin limitations.

Since the WUMS area has not developed specific criteria for dynamic stability analysis, the MAPP standard values were used. For transient bus voltage limitations, a minimum of 0.7 p.u. and a maximum of 1.2 p.u. following fault clearing was used.

For generator rotor angle damping, a minimum damping ratio criterion of 0.05 p.u. was established. This ratio is obtained using Prony analysis which calculates eigenvalues for each major mode of oscillation. The current MAPP operating study criteria is a minimum damping ratio of 0.00816 for disturbances with faults and 0.0168 for line trips. The 0.05 p.u. criterion was selected to be consistent with the proposed MAPP planning standard.

Selection of Critical Disturbances

The disturbances studied included 15 MAPP, 25 WUMS, and all combinations of new facility fault/trip scenarios. The MAPP disturbances included North Dakota, Manitoba – U.S. 500 kV, and Twin Cities 345 kV normal and delayed clearing breaker failure faults. In the WUMS areas, normal and delayed clearing faults in both the Weston – Rocky Run and Columbia areas were studied. The new facility faults included normal clearing 3 phase faults at each line terminal of each line segment and a limited number of proxy breaker failure scenarios.

Description of Data Output

The primary output from dynamic stability analysis is time versus amplitude data for a specified set of monitored parameters or channels. A subset of these channels, usually the most critical quantities, are graphically plotted on paper for visual inspection. For this study, a standard set of channels typically used for northern MAPP stability analysis were monitored and analyzed. Additional channels were added to monitor critical busses and generators in the WUMS area such as Weston, Rocky Run and Columbia.

The MAPP stability analysis package also has automated routines that scan all output channels and stability runs in progress and will identify any study criteria violations. These routines, in addition, produce detailed reports that summarize all system conditions and criteria violations encountered for each simulation. Another routine generates summary tables that are compatible with Excel spreadsheets. These tables, referred to as "Stability Summary Tables", are included with this report and document every simulation performed during the course of the study.

Since this study involved a great deal of comparative analysis between plans, special overlay plots were produced that compare critical bus voltages and generator angles for key disturbances.

4.2.2 BASE CASE ASSUMPTIONS

A stability base case *(wb-sraa.uvj04Y4)* was developed from the MAPP 2002 summer off-peak model with high simultaneous export conditions of 1975 MW Manitoba (MHEX), 1950 MW North Dakota (NDEX), and 1350 MW Twin Cities 345 kV (TCEX). This model was based on the standard 1997 series MAPP models and was selected because the off-peak, high export condition has been determined to be the most stressed for dynamic stability.

Power flow cases for each of the seven WIREs plans studied were created from the stability base case using IDEVs developed for the WIREs AC analysis study path which were modified to match MAPP bus numbering conventions. Switched capacitors were added for each plan according to the levels determined by the AC analysis.

The WUMS 2000 MW west – 1000 MW south import condition was simulated by setting the WUMS region to 100% peak load, removing "fake" peaking generation, and reducing generation to approximately 85% of nominal. To cover the deficit WUMS generation, loads in Illinois (SIPC, EMO, IP, CILCO, CWLP, CIPS, and CI) were reduced proportionally. This biasing methodology yielded WUMS interface line loading flows that were comparable to those found in the base cases used by the other WIREs Phase 2 study paths.

Table 4.2.2-1, shown below, summarizes the power flow cases that were created for the various reinforcement plans.

Plan	Case Name	MHEX (MW)	NDEX (MW)	TCEX (MW)
Base	Wb-sraa.uvj04Y4	1975	1950	1350
1c	1c-sraa.uvj04Y4	1975	1950	1328*
2e	2e-sraa.uvg04Y4	1975	1950	1020*
3j	3j-sraa.uvg04Y4	1975	1950	1005*
5a	5a-sraa.uvf04Y4	1975	1950	910*
5b	5b-sraa.uvh04Y4	1975	1950	1117*
9b	9b-sraa.uvk04Y4	1975	1950	1395*
10	10-sraa.uvg04Y4	1975	1950	959*
* - TCEX flow following addition of new facilities				

Table 4.2.2- 1

Table 4.2.2-2 provides a summary of the WUMS interface flows for each of the plans. In this table, the flows from the stability power flow for Plan 3j are compared with those from the WIREs 3j AC analysis model.

Additional power flow documentation is included in Appendix B1.

	WIRES + 3j	MAPP 1c Bias	MAPP 2e Bias	MAPP 3j Bias	MAPP 5a Bias	MAPP 5b Bias	MAPP 9b Bias	MAPP 10 Bias
Minn – WUMS								
Eau Claire - Arpin 345 kV	753	908	857	773	704	831	860	742
Mauston 69 – Hilltop 69	23	27	26	24	22	25	24	22
T Corners 115 – Wien 115	66	86	77	52	36	60	71	44
Oakdale 69 – Council Crk 69	5	9	10	6	4	7	9	5
T TC 69 - Council Crk 69	48	59	57	55	49	55	49	50
Ned 161 - Ned 138	3	96	113	130	123	136	101	129
Bell Center 69 – Hillside 69	13	13	12	13	12	12	11	13
Sub-total	911	1198	1152	1053	950	1126	1125	1005
Arrowhead – Highway 8	471			495				
Prairie Island – Columbia			532					
Apple River – Hiway 8 Tap					679	353		
Eau Claire – Weston								576
Total Minn – WUMS	1382	1198	1684	1548	1629	1479	1125	1581
WUMS – South								
Wempleton – Paddock 345	889	727	776	866	837	878	743	848
Zion - Arcadian 345	296	256	261	252	235	268	256	245
Zion - Pleasant Prairie 345	184	109	119	110	77	137	107	95
Salem – Fitchburg		490						
Genoa – Columbia							554	
Total WUMS – South	1369	1582	1156	1228	1149	1283	1660	1188
Total WUMS	2751	2780	2840	2776	2778	2762	2785	2769
Manitoba Export (MHEX)	1940	1975	1975	1975	1977	1976	1976	1976
North Dakota Export (NDEX)	1100	1950	1940	1950	1942	1942	1942	1941
Twin Cities 345 Export (TCEX)	864	1322*	1007	1048*	910*	1117*	1395	959*
Northern MAPP East Bias		267	288	304	293	282	267	283

Table 4.2.2-2 – Summary of WIRES Stability Powerflow Cases

4.2.3 DYNAMIC STABILITY STUDY RESULTS

MAPP Disturbances

As discussed above, several of the worst known North Dakota, Twin Cities, and Manitoba – U.S. 500 kV MAPP disturbances were studied to test the dynamic robustness of each of the WIRES plans.

The MAPP disturbances studied included:

AG1	4 cycle slgf @ Leland Olds 345 on Ft. Thompson line, Leland Olds breaker 2692 stuck. Clear @ 11 cycles by tripping faulted line.
EI2	Permanent bipole fault on the CUDC line. Both Coal Creek units tripped at 0.30 sec.
EJ2	Permanent bipole fault on the Square Butte dc line. No Young unit 2 tripping.
MQS	Single line to ground fault with breaker fail at Sherco with 8N28 stuck. Trip Sherco generator 3.
MSS	Single line to ground fault with breaker fail at Sherco with 8N32. Trip Sherco to Coon Creek 345 kV line.
MTS	Single line to ground fault with breaker fail at Monticello with 8N6 stuck. Trip Monticello to Elm Creek 345 kV.
NBS	Three-phase fault at Chisago on Chisago County-Forbes 500 kV line.
MAD	4 cycle 3 phase fault at Dorsey 500 kV. Clear the Dorsey - Forbes 500 kV line.
NAD	4 cycle 3 phase fault at Forbes 500 kV. Clear the Forbes - Dorsey 500 kV line.
MAT	Dorsey - Forbes line trip without a fault.
OAS	single line to ground fault with breaker fail at Dorsey with 602L stuck. Trip D602F.
PCS	Single line to ground fault with breaker fail at King with 8P6 stuck. Trip King - Eau Claire - Arpin 345 kV line and King to Chisago County 345 kV line.
PCT	Trip King - Eau Claire - Arpin 345 kV line and King to Chisago County 345 kV line without fault
PDS	Single line to ground fault with breaker fail at King with 8P6 stuck. Trip King - Eau Claire 345 kV line and King to Chisago County 345 kV line.
PDT	Trip King - Eau Claire 345 kV line without a fault
PET	Trip Eau Claire - Arpin 345 kV line without a fault
PYT	Trip of Prairie Island – Byron 345 kV without a fault
PYS	14 cycle SLG fault at Prairie Island 345 kV, trip Prairie Island-Byron 345 kV line.

In general, all plans met established transient voltage and rotor angle criteria.

The North Dakota disturbances tested, (AG1, EI2, EJ2), demonstrated that there was little impact from the WIREs facilities on critical North Dakota busses. The Groton 345 kV transient voltage was well above criterion and varied less than 1% between plans for these disturbances.

The Manitoba – U.S. 500 kV disturbances tested, (NBS, MAD, NAD, MAT, OAS), also met all criterion and did not indicate any degradation in Manitoba – U.S. transfer capability. Plan 3j does improve dynamic performance somewhat for the NBS disturbance by improving the transient voltage performance at the Whapeton 230 kV bus. The Arrowhead – Weston line provides an additional dynamic outlet from the MP system during the South 500 kV (Chisago – Forbes) to North 500 kV (Forbes – Dorsey) cross-tripping sequence.

The Twin Cities disturbances tested, (MQS, MSS, MTS, PCS, PCT, PYT, PYS), met criterion but demonstrated some differences in performance between the WIREs plans. The most pronounced differences were observed for disturbances involving a loss of either of the major Twin Cities 345 kV outlet facilities. For either a loss of the King – Eau Claire – Arpin (PCS) or the Prairie Island – Byron 345 kV (PYS) transmission lines, differences in transient voltage performance at MAPP and WUMS area busses and damping of the MAPP/MAIN ¼ Hertz mode of oscillation were observed. Damping of the ¼ Hertz mode is currently a stability limiting condition for Twin Cities 345 kV export and is discussed further below. Following the PCS disturbance, voltages in the Weston/Rocky Run area are more transiently depressed for plans 3j, 5a, 5b and 10. All of these plans terminate in the Weston area and subject it to dynamic post-contingency loading following the loss of the King – Eau Claire – Arpin line.

Appendix B2 contains stability summary tables for all cases run and overlay comparison plots for selected disturbances.

Eau Claire – Arpin Crosstrip Assessment

Three Twin Cities disturbances (PDS, PDT, PET) were run to assess the impact eliminating the cross tripping between the King – Eau Claire and the Eau Claire – Arpin 345 kV lines. All plans performed acceptably with the exception of 5b which had minor voltage violations in western Wisconsin for the PDS disturbance. It was assumed that these violations could be mitigated with additional reactive support.

¼ Hertz Mode Damping

The ¼ Hertz mode has been observed in MAPP system stability analysis for many years and can be characterized as an oscillation where MAPP and MAIN are swinging together at approximately 0.25 Hertz against the eastern equivalent. It has traditionally been well behaved and positively damped. In recent years, however, as transfer levels have increased, it has become a primary consideration for establishing the Twin Cities 345 kV export stability limits under system intact and prior outage conditions. Damping of this mode has been found to be critical following a loss of the

King – Eau Claire – Arpin (PCS) or the Prairie Island – Byron 345 kV (PYS) transmission lines.

To assess modal damping, simulations are run out to 15 seconds to capture several cycles of oscillation. Mathematical analysis using Prony techniques is then performed on generator rotor angles to determine effective damping ratios. As discussed earlier a minimum damping ratio criterion of 0.05 p.u. was established for this study.

All reinforcement plans met the study criterion at the 2000 – 1000 WUMS import level for both the PCS and PYS disturbances. Table 4.2.3-1 below summarizes the damping ratios calculated for each plan. For this analysis, damping ratios for the NSP Sherco 3 generator and MH Dorsey synchronous condensers were averaged to obtain a final value.

Plan	PCS (p.u.)	PYS (p.u.)
1c	0.087	0.055
2e	0.099	0.106
3j	0.088	0.100
5a	0.115	0.103
5b	0.093	0.077
9b	0.083	0.068
10	0.138	0.095

Table 4.2.3- 1

Incremental Transfer Capability Assessment

Since the damping of the ¼ Hertz oscillation mode is also dependent on transfer levels, additional stability analysis was performed to determine an incremental transfer capability (ITC) level for each plan. This was defined as the level of incremental transfer at which each plan satisfies the 0.05 p.u. damping ratio criterion following a loss of either the King or Prairie Island 345 kV lines.

Two increased transfer level cases, +300 MW and +600 MW, were created for each plan by reducing load in North Dakota and Minnesota and proportionally increasing load in the eastern equivalent. This had the effect of increasing MAPP export while maintaining the 2000 – 1000 WUMS import condition. Due to parallel path flow effects, a significant portion of this flow appears on and further stresses the MAPP – WUMS interface. Tables 4.2.3–2 and 4.2.3-3 below summarize the power flow cases utilized for this analysis.

+ 300 MW MAPP to East Transfer				
Plan	Case Name	MHEX (MW)	NDEX (MW)	TCEX (MW)
1c	1c-sraa.vvl04Y4	1975	1990	1457*
2e	2e-sraa.vvh04Y4	1975	1987	1211*
3j	3j-sraa.vvh04Y4	1975	1988	1112*
5a	5a-sraa.vvgf04Y4	1975	1988	999*
5b	5b-sraa.vvl04Y4	1975	1989	1244*
9b	9b-sraa.vvm04Y4	1975	1990	1171*
10	10-sraa.vvh04Y4	1975	1988	1076*
* - TCEX flow following addition of new facilities				

Table 4.2.3- 2

+ 600 MW MAPP to East Transfer				
Plan	Case Name	MHEX (MW)	NDEX (MW)	TCEX (MW)
1c	1c-sraa.wvn04Y4	1975	2037	1581*
2e	2e-sraa.wvi04Y4	1975	2034	1246*
3j	3j-sraa.wvi04Y4	1975	2034	1237*
5a	5a-sraa.wvif04Y4	1975	2035	1028*
5b	5b-sraa.wvk04Y4	1975	2035	1367*
9b	9b-sraa.wvo04Y4	1975	2036	1662*
10	10-sraa.wvi04Y4	1975	2034	1194*
* - TCEX flow following addition of new facilities				

Table 4.2.3- 3

Fifteen (15) second PCS and PYS simulations were run on each powerflow case and prony analysis was used to calculate damping ratios at each incremental power flow level. Linear interpolation was then used to find the ITC at the 0.05 p.u. criterion. During the investigation, it was discovered that the frequency damping control on the Square Butte HVDC transmission system, which terminates at the Arrowhead 230 kV substation, had a negative impact on the damping for Plan 3j. Therefore the damping ratios reported for 3j were obtained with the control disabled. It is assumed that the control would be re-tuned if Plan 3j were constructed. Table 4.2.3-4, shown below, summarizes the results.

		Damping Ratios		ITC at Criterion Linear
Plan	**0 MW**	**+300 MW**	**+600 MW**	**Interpolation**
PCS:				
1c	0.087	0.061	0.029	396 MW
2e	0.099	0.076	0.062	753
3j	0.088	0.075	0.032	448
5a	0.115	0.099	0.066	812
5b	0.093	0.068	0.030	431
9b	0.083	0.060	0.028	374
10	0.138	0.098	0.068	738

PYS:				
1c	0.055	0.010	-0.053	50 MW
2e	0.106	0.085	0.059	717
3j	0.100	0.080	0.048	596
5a	0.103	0.080	0.055	672
5b	0.077	0.042	0.001	222
9b	0.068	0.024	-0.027	121
10	0.095	0.068	0.038	477

Table 4.2.3- 4

The ITC for each reinforcement plan is assumed to be the lower of the two (PCS and PYS) interpolated values. The final ITC values rounded to the nearest 10 MW are summarized below.

Plan	1c	2e	3j	5a	5b	9b	10
MW Incremental Transfer	50	720	450	670	220	120	480

<u>WUMS area disturbances</u>

The WUMS stability analysis focused on known problematic locations, specifically, the Columbia and Weston areas.

The WUMS area disturbances studied included:

WAS 3 phase fault on Columbia – Rockdale 345 kV line

WBS 3 phase fault on Columbia – South Fond du Lac 345 kV line

WCS 3 phase fault on Columbia – North Madison 345 kV line

WDS 3 phase fault on Columbia 400 MVA 345/138 kV transformer

WES 3 phase fault on Columbia 2-200 MVA 345/138 kV transformer

WFS 3 phase fault on Columbia – South Fond du Lac 345 kV line, Columbia breaker stuck

WGS 3 phase fault on Columbia – Rockdale 345 kV line, Columbia breaker stuck

WHS 3 phase fault on Columbia – North Madison 345 kV line, Columbia breaker stuck

WIS 3 phase fault at North Appleton on Rocky Run – North Appleton 345 line

WJS 3 phase fault at North Appleton on Rocky Run – North Appleton 345 line, breaker failure at North Appleton

WKS 3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line

WLS 3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line, 6-1 breaker failure at Rocky Run (18 cycle clearing)

WLZ 3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line, 6-1 breaker failure at Rocky Run (14 cycle clearing)

WMS 3 phase fault at Arpin on Arpin – Rocky Run 345 line

WNS	3 phase fault at Arpin on Arpin – Rocky Run 345 line, 424-S breaker failure at Arpin
WOS	3 phase fault at Arpin on Arpin – Rocky Run 345 line, 627-S breaker failure at Arpin
WPS	3 phase fault at Rocky Run on Arpin – Rocky Run 345 line
WQS	3 phase fault at Rocky Run on Arpin – Rocky Run 345 line, 8-V breaker failure at Rocky Run (16 cycle clearing)
WQZ	3 phase fault at Rocky Run on Arpin – Rocky Run 345 line, 8-V breaker failure at Rocky Run (14 cycle clearing)
WRS	3 phase fault at Rocky Run on Rocky Run – Weston 345 line
WSS	3 phase fault at Rocky Run on Rocky Run – Weston 345 line, V-4 breaker failure at Rocky Run
WTS	3 phase fault at Weston on Rocky Run – Weston 345 line
WUS	3 phase fault at Weston on Rocky Run – Weston 345 line, breaker failure on Weston East 115 kV bus
WVS	3 phase fault at Weston on Rocky Run – Weston 345 line, breaker failure on Weston West 115 kV bus
WWS	3 phase fault at Weston on Rocky Run – Weston 345 line, breaker failure for future system with new 345 kV line into Weston

For the WUMS disturbances tested, all plans met established transient voltage and rotor angle criteria.

In the Weston area, the most severe disturbances were found to be the WLS and WNS cases which are 3 phase stuck breaker scenarios at Rocky Run and Arpin, respectively. Due to the severe nature of the fault, the voltage recovery at the Rocky Run, Weston and Arpin 345 kV busses is slow in comparison to other disturbances analyzed. This phenomenon was not negatively or positively impacted by any of the WIREs plans and is therefore considered to be a local area concern.

The Columbia area disturbances were found to be relatively moderate and were not negatively impacted by any of the WIREs plans.

Appendix B2 contains stability summary tables for all cases run and overlay comparison plots for selected disturbances.

Maximum Columbia & Weston Generation and Breaker Failure Performance

Since the 2000 -1000 WUMS import bias of the models used for dynamic stability analysis was achieved through an overall 80% generation reduction within WUMS, it was deemed necessary to perform additional sensitivity analysis with maximum generation levels represented at both Columbia and Weston. Of particular concern was the slow voltage recovery in the Weston area observed following delayed clearing 3 phase faults.

In the Columbia area, the WGS and WHS disturbances were re-run and found to be slightly impacted by increased generation. The post-fault voltage recovery was found to be slower at Columbia with maximum generation. Also, the immediate post-fault voltage was just below the 0.7 p.u. criterion for plans 2e, 3j, 5a and 5b, but was considered acceptable since it was recovering.

Of the cases re-run in the Weston area, two were found to be unstable with maximum generation. For both the WLS (3 phase fault at Rocky Run on Rocky Run – North Appleton 345 line, 6-1 breaker failure at Rocky Run with 18 cycle clearing) and the WQS (3 phase fault at Rocky Run on Arpin – Rocky Run 345 line, 8-V breaker failure at Rocky Run with 16 cycle clearing) disturbances, the Weston units lost synchronism with the rest of the power system. A reduction in breaker failure clearing times to 14 cycles for both disturbances (WLZ and WQZ) was required to maintain Weston generator stability and meet criterion. The new clearing times were tested with all reinforcement plans and found to be acceptable.

<u>New Facility Disturbances</u>

A series of simulations were run to assess the dynamic performance of normal clearing 3 phase fault sequences on each line segment of the various reinforcement plans.

The following disturbances were studied for each respective plan:

<u>Plan 1c</u>
VA3 3 phase fault at Salem on Salem – Fitchburg 345 kV line
VA9 3 phase fault at Fitchburg on Salem – Fitchburg 345 kV line

<u>Plan 2e</u>
VE3 3 phase fault at Pr Islnd on Pr Islnd – LaCrosse 345 kV line
VE9 3 phase fault at LaCrosse on Pr Islnd – LaCrosse 345 kV line
VF3 3 phase fault at LaCrosse on Columbia – LaCrosse 345 kV line
VF9 3 phase fault at Columbia on Columbia – LaCrosse 345 kV line

<u>Plan 3j</u>
VI3 3 phase fault at Arrowhead on Arrowhead – Hiway 8 Tap 345 kV line
VJ3 3 phase fault at Hiway 8 Tap on Weston – Hiway 8 Tap 345 kV line
VJ9 3 phase fault at Weston on Weston – Hiway 8 Tap 345 kV line

<u>Plan 5a</u>
VM3 3 phase fault at Chisago on Chisago – Apple River 345 kV line
VM9 3 phase fault at Apple River on Chisago – Apple River 345 kV line
VN3 3 phase fault at Apple River on Hiway 8 Tap – Apple River 345 kV line
VN9 3 phase fault at Hiway 8 Tap on Hiway 8 Tap – Apple River 345 kV line
VO3 3 phase fault at Hiway 8 Tap on Weston – Hiway 8 Tap 345 kV line
VO9 3 phase fault at Weston on Weston – Hiway 8 Tap 345 kV line

<u>Plan 5b</u>
VQ3 3 phase fault at Chisago on Chisago – Apple River 230 kV line

VQ9 3 phase fault at Apple River on Chisago – Apple River 230 kV line
VR3 3 phase fault at Apple River on Hiway 8 Tap – Apple River 230 kV line
VR9 3 phase fault at Hiway 8 Tap on Hiway 8 Tap – Apple River 230 kV line
VS3 3 phase fault at Hiway 8 Tap on Weston – Hiway 8 Tap 230 kV line
VS9 3 phase fault at Weston on Weston – Hiway 8 Tap 230 kV line

Plan 9b
VU3 3 phase fault at Lakefield on Lakefield – Adams 345 kV line
VU9 3 phase fault at Adams on Lakefield – Adams 345 kV line
VV3 3 phase fault at Adams on Genoa – Adams 345 kV line
VV9 3 phase fault at Genoa on Genoa – Adams 345 kV line
VW3 3 phase fault at Genoa on Genoa – Columbia 345 kV line
VW9 3 phase fault at Columbia on Genoa – Columbia 345 kV line

Plan 10
VX3 3 phase fault at King on King – Eau Claire #2 345 kV line
VX9 3 phase fault at Eau Claire on King – Eau Claire #2 345 kV line
VY3 3 phase fault at Eau Claire on Weston – Eau Claire 345 kV line
VY9 3 phase fault at Weston on Weston – Eau Claire 345 kV line

The normal clearing 3 phase faults were all found to be relatively minor disturbances and did not produce any criteria violations.

Dynamic Reactive Support Requirements

Since all reinforcement plans met the established dynamic stability criteria for the cases studied, it can be assumed that no additional dynamic reactive support is required to meet the study objectives.

4.3 CONCLUSIONS

In general, all plans met established transient voltage and rotor angle criteria for the WUMS 2000 MW west – 1000 MW south import transfer condition. No additional reactive voltage support (VAr) requirements, over and above those identified through the power flow analyses, were identified.

The most pronounced difference between the reinforcement plans was observed for disturbances involving a loss of a major Twin Cities 345 kV outlet facility. For a loss of either the King – Eau Claire – Arpin 345 kV or the Prairie Island – Byron 345 kV transmission line, differences in transient voltage performance within MAPP and WUMS and damping of the MAPP/MAIN ¼ Hertz mode of oscillation were observed. Damping of the ¼ Hertz mode of oscillation is currently a stability limiting condition for the Twin Cities export (TCEX) limitation. The performance of ¼ Hz mode was also used to assess the incremental transfer capability (ITC) of each plan.

Some generator stability problems were identified in the Rocky Run area for delayed clearing breaker failure cases studied with maximum generation at Weston. These were found to be problems inherent in the base case and can be corrected with reduced failed breaker clearing times.

Chapter 5 VOLTAGE STABILITY

5.1 VOLTAGE STABILITY ANALYSIS, AND ITS IMPORTANCE

The topic of voltage stability deals with the challenge of ensuring the electric power transmission system has adequate reactive power supply capability to maintain all bus voltages at adequate levels, under both system intact and contingency conditions. Adequate operating margins or reactive supply reserve must be provided such that failure of any transmission system element (line, transformer, or bus section) or trip-out of any reactive power source (generator or capacitor bank) does not result in uncontrolled progressive decline of system voltages, which can result in system separation, under-voltage load shedding, or regional blackout.

Reactive power is the key to voltage control. Reactive power is measured in Volt-Amperes Reactive (VARs). Transmitting VARs an appreciable distance requires/causes a significant voltage difference, while another impediment to VAR transfer is that significant incremental VAR losses occur due to the series inductive reactance of the transmission lines and transformers. Since VARs "don't travel well", reactive supply is usually a highly-localized matter.

It is a characteristic of heavily-loaded transmission systems that reactive power consumption increases significantly following trip-out of a transmission interconnection. This is because the increased loading impressed upon the remaining parallel transmission circuits causes increased reactive losses. Since each circuit's reactive power consumption is proportional to the square of the line current ($Q = I^2X$) the post-contingent condition during high transfers often requires hundreds of MVAR additional reactive supply to maintain acceptable bus voltages. As explained previously, maintaining a satisfactory system voltage profile requires that these incremental reactive supply requirements be satisfied locally.

5.2 HOW THE PLANS' VOLTAGE STABILITY PERFORMANCE WAS STUDIED

Prior to activation of the WIRE Study Phase 2 technical analysis effort, the MAPP Transmission Reliability Assessment Working Group (TRAWG) had initiated a voltage stability study of the MAPP bulk power system. This study was for the purpose of analyzing--for the planned Year 2002 system configuration--the pre- and post-contingency power system performance for many source/sink transfer pairs, thereby enabling a determination of estimated power transfer limits as constrained by any voltage stability-imposed limitations which may be revealed. The TRAWG had contracted with Power Technologies, Inc. (PTI) to perform the power system simulations required and to provide a report summarizing the results observed and conclusions reached.

Consultations between the WIRE and TRAWG entities confirmed the desirability and feasibility of a coordinated voltage stability analysis effort. These consultations culminated in the decision to expand the scope of the PTI voltage stability analysis effort to include evaluation of the WIRE Study's seven Phase 2 transmission plans.

Because the TRAWG voltage stability effort was already under way, it was necessary to utilize the transfer source/sink definitions previously specified by the TRAWG. Of specific note is that the west-east power transfers (across the MAPP-WUMS interface) simulated in the TRAWG-initiated PTI analysis are structured in terms of MAPP-->MAIN source/sink pairs, and therefore represent a flow through WUMS to the postulated (MAIN) sink, whereas the WIRE study analyses were based on MAPP-->WUMS transfers, with a simultaneous MAIN-->WUMS transfer.

Consequently, the west-east power transfer capability MW limits identified in the TRAWG-initiated PTI analysis are not fully comparable with the other WIRE Study Phase 2 analysis efforts' results, due to the MAIN-WUMS interface not being held at a fixed loading. Notwithstanding this difference in analysis technique, it is possible to determine MAPP-WUMS interface loading at which the seven WIRE Study Phase 2 options exhibit voltage-related power transfer limitations.

5.3 Voltage Stability Results

As expected, the transmission options' voltage stability performance with respect to the MAPP-WUMS interface is determined by the degree to which the new transmission line reduces loading on the existing tie lines, and the degree to which the new line facilitates the delivery of reactive supplies to the Eau Claire/LaCrosse region where the voltage collapse phenomenon is first experienced.

Results of PTI's voltage stability analysis are summarized in the following table; PTI's full report, *Comparison of WIREs Reinforcement Alternatives* (PTI Report R21-99) is available as a separate reference document.

Plan	Description	Approximate W-->E Transfer Capability, MW
1c	Salem-Fitchburg 345 kV	2615
2e	Prairie Island-Columbia 345 kV	3245
3j	Arrowhead-Weston 345 kV	2615
5a	Chisago-Weston 345 kV	2865
5b	Apple River-Weston 230 kV	2865
9b	Lakefield-Columbia 345 kV	3105
10	King-Weston 345 kV	2865

Table 5.3- 1

Figure 5.3-1, shown below, graphically demonstrates the approximate Twin Cities export (TCEX) limits based on voltage stability limitations.

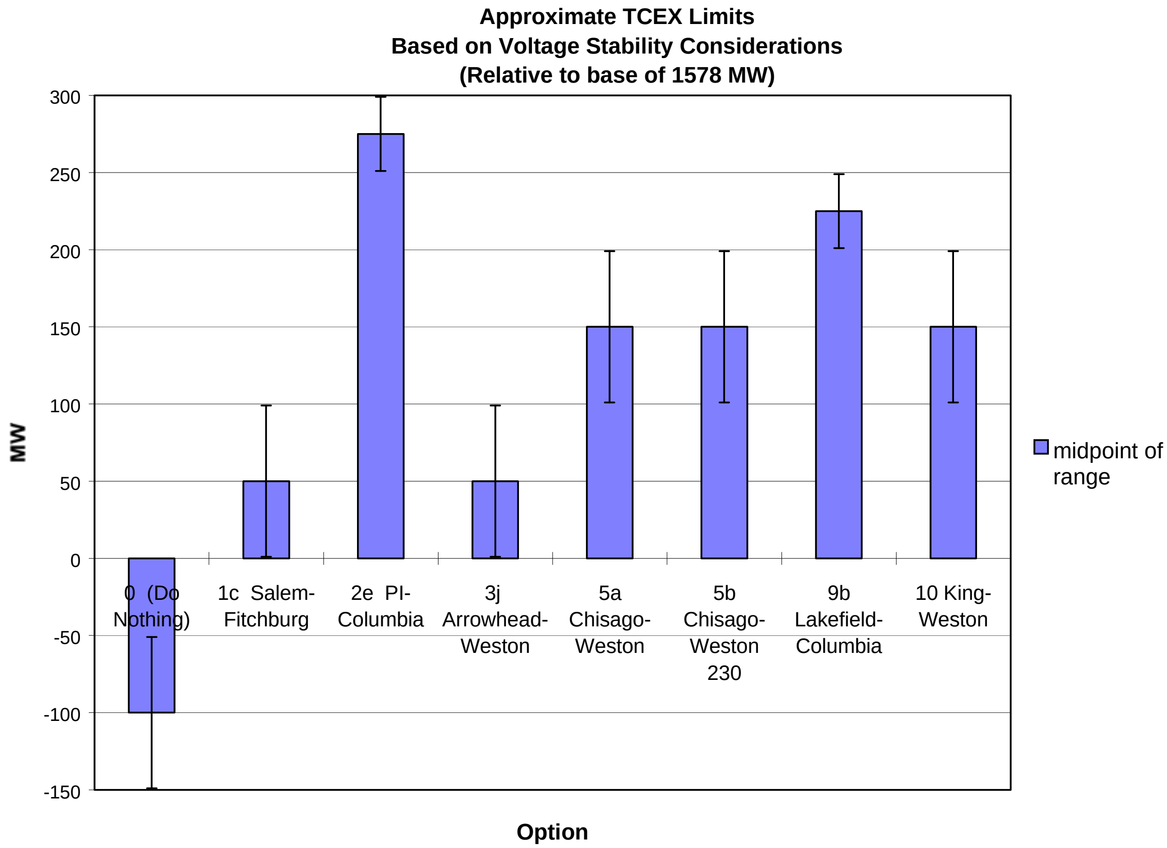

Figure 5.3- 1

5.4 Conclusions

All seven transmission reinforcement plans have adequate voltage stability performance with respect to the 2000 MW MAPP-->WUMS transfer capability criterion.

These voltage stability-constrained transfer limits are in all cases higher than the corresponding thermal or dynamic stability-imposed transfer limits associated with each transmission option. Consequently, although some transmission options appear to be more robust than others with respect to voltage stability performance, all options studied appear to be adequate to support a 2000 MW western interface transfer capability.

CHAPTER 6 MAPP FLOWGATE IMPACT

A flowgate is a set of one or more transmission lines common to a single interface. The MW flow on a flowgate allows a system operator to quickly determine the total flow across an interface. The total flow on a flowgate is the sum of the flow on each of the individual transmission lines that define the flowgate.

The WIREs study team evaluated the impact of each reinforcement plan on several flowgates defined for the MAPP region[2] by determining the flow on each flowgate with and without the reinforcement plan. Several other MAPP flowgates not significantly (>5% PTDF) impacted by imports into Wisconsin were not included in this analysis.

The change in flow on the flowgates were considered at the maximum simultaneous transfer level of 3000 MW (2000 MW western / 1000 MW southern). The results of the flowgate impact study are shown in the two tables below. The tables show the flow on each flowgate for the "base system" (without any reinforcements) and the flow with each reinforcement plan in service. The change in flow on each flowgate is expressed as a percent of the "base system" flow.

	COOPER_S		FT CAL_S		FT CAL_3459	
Reinforcement Plan	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)
Base System	378.9	0.0%	542.7	0.0%	470.2	0.0%
1c	348.8	-7.9%	534.8	-1.5%	466.2	-0.9%
2e	310.4	-18.1%	491.1	-9.5%	427.3	-9.1%
3j	323.2	-14.7%	500.5	-7.8%	432.9	-7.9%
5a	317.8	-16.1%	495.8	-8.6%	430.1	-8.5%
5b	334.8	-11.6%	512.4	-5.6%	445.3	-5.3%
9b	294.3	-22.3%	471.4	-13.1%	415.0	-11.7%
10	320.4	-15.4%	499.0	-8.1%	433.8	-7.7%

Table 6- 1

[2] Although MAIN defines a limited set of flowgates for coordination of ATCs with the MAPP and ECAR regions, the MAIN transmission system is typically thermally limited by single transmission elements.

	ECL-ARP		PRI-BYN		MN EX	
Reinforcement Plan	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)	Flow (MW)	Change From Base (%)
Base System	929.6	0.0%	777.7	0.0%	2349.8	0.0%
1c	921.9	-0.8%	788.1	1.3%	2356.7	0.3%
2e	870.8	-6.3%	575.1	-26.1%	1935.8	-17.6%
3j	746.7	-19.7%	657.1	-15.5%	1951.5	-17.0%
5a	704.0	-24.3%	635.1	-18.3%	1865.2	-20.6%
5b	831.0	-10.6%	707.7	-9.0%	2191.9	-6.7%
9b	859.6	-7.5%	832.4	7.0%	2539.0	8.1%
10	742.0	-20.2%	649.2	-16.5%	1874.1	-20.2%

Table 6- 2

These tables show, that with few exceptions, the addition of a reinforcement plan to the system does not increase loading on the MAPP flowgates. Those flowgates which exhibit an increased flow due to the addition of a reinforcement plan are flowgates near the Twin Cities area whose definition would likely change if a new western interface transmission line is constructed. Therefore, these flowgates are not necessarily defined appropriately in a post-reinforcement scenario but are included here for demonstration purposes.

Chapter 7 Loss Evaluation

7.1 Impact of Losses

Each alternative reinforcement plan considered in this analysis would introduce unique loss features into the transmission system. An analysis was done to quantify the relative cost of losses among the plans. The costs are summarized in the form of an equivalent capital investment adjustment to the initial capital construction cost for each alternative.

The process computes the lifetime costs for the installed generating capacity and associated energy to serve the losses that would prevail for each alternative. Transmission losses are included for the MAPP, MAIN, and SPP Regions. The total costs for each plan are illustrated, as well as a more meaningful cost adder. The cost adder is based on subtracting the life time costs of the lowest cost alternative, from the cost of all alternatives.

Three components of adjusted capital cost were computed. These are due to generation capacity to supply the losses, annual energy losses to serve load, and annual energy losses due to point-to-point transactions.

- **Capacity Cost** - Each plan causes the greatest demand for losses at some planned transfer level condition. In the cost evaluation, the maximum amount of loss caused by a plan is assigned a cost of 400 $/kW. The resulting cost represents the cost for installed generating capacity that would be required to serve the losses.

- **Energy Loss for Load** - Each plan has energy losses associated with the annual hourly loss that occurs as the load pattern is served. The annual energy lost as a consequence of serving load is priced out at 15 $/MWh. The resulting annual energy cost is equated to a levelized annual carrying charge. The annual carrying charge dollars are then converted to an equivalent capital investment, by dividing by 15 %.

- **Energy Loss for Transactions** - Each plan has energy losses that are required to support the various point-to-point transactions that are planned. After determining the annual energy associated with the point-to-point transactions, a capital investment is computed by dividing by 15 %.

7.2 Simulation of Point-to-Point Transaction Levels Modeled in Power Flow Cases

The loss analysis was accomplished by constructing AC power flow cases to represent various combinations of transactions. In all, eleven sets of various import and export combinations were developed to quantify the losses. From these cases, the incremental loss difference between plans is determined and economic loss values are applied to summarize the loss performance of each plan.

Base cases from each of the proposed WIRES study plans were used as a starting point. The imbedded transfers from the west (375 MW) and south (150 MW) were removed by adjusting generation in western MAPP, Illinois, ECAR and Wisconsin, so that the Wisconsin was zero. All known WIREs base case updates were included in the cases used to produce the loss information. This established the losses for each plan at the zero transfer level. This established one of the eleven sets of power flow base cases (also shown in Table 7.3-3).

The remaining Ten transfer cases for each plan were developed by utilizing generation changes to simulate power transfers relative to the zero transfer level. To avoid unrealistic flow patterns, generators were not increased beyond their maximum output levels. The assumption of 700 MW of new generation in the western MAPP region was carried forward from the earlier WIREs transfer simulations and used in the instances where 2000 MW of transfer was required from the western MAPP region. The only exception to utilizing generation to simulate transfers occurred when 1000 MW or 2000 MW was required from the west. In those instances there was not enough generation available so load was scaled down in MAPP to provide some of the transfer. For 1000 MW of transfer, 625 MW of load was scaled in Western MAPP. For 2000 MW transfer, 925 MW of load was scaled.

7.3 Loss Evaluation - Results

Table 7.3-1 illustrates the total up front costs to pay for the entire loss obligation of each plan over its useful life. Table 7.3-1 demonstrates the capital cost required to supply the capacity for "on-peak" losses, the annual energy loss to serve local area load, and the annual energy loss due to point-to-point transactions. The equivalent capital cost adders for each of the three loss components is shown in millions of dollars.

	Loss Profile		**Equivalent Capital Cost Due to Losses [millions of $]**			
Plan Description	Peak Losses At Zero Transfer [MW]	Relative to Lowest Loss Plan (MW)	Capacity Cost	Energy Loss For Load	Energy Loss For Xacts	**Total (M$)**
Plan 1c Salem – Fitchberg 345 kV	3,975	24	$ 1,867	$ 1,045	$ 136	$ 3,047
Plan 2e Prairie Is – Columbia 345 kV	3,973	22	$ 1,852	$ 1,044	$ 128	$ 3,024
Plan 3j Arrowhead – Weston 345 kV	3,951	0	$ 1,836	$ 1,038	$ 123	$ 2,997
Plan 5a Chisago – Weston 345 kV	3,956	5	$ 1,836	$ 1,040	$ 122	$ 2,998
Plan 5b Apple River - Weston 230 kV	3,970	19	$ 1,860	$ 1,043	$ 132	$ 3,035
Plan 9b Lakefield – Columbia 345 kV	3,980	28	$ 1,851	$ 1,046	$ 128	$ 3,026
Plan 10 King – Weston 345 kV	3,968	17	$ 1,849	$ 1,043	$ 126	$ 3,017
Pre-plan System	4,002	50	$ 1,892	$ 1,052	$ 147	$ 3,091

Table 7.3- 1

Table 7.3-2 illustrates the differences among plans relative to the lowest cost plan for each of the three individual loss components. The net composite capital cost adder shown in the last column is the difference between the total capital cost of the least loss expense plan and the remaining plans. These results demonstrate that Plan 3j (Arrowhead – Weston 345 kV) creates the smallest economic burden from a loss perspective.

	Equivalent Capital Cost Adder Due to Losses [millions of $]				
Plan Description	Capacity Cost	Energy Loss For Load	Energy Loss For Xacts	Sum Of Difference	**Composite Net Adder (M$)**
Plan 1c Salem - Fitchberg 345 kV	$31.0	$6.3	$13.8	$51.1	$50.2
Plan 2e Prairie Is – Columbia 345 kV	$16.4	$5.7	$6.0	$28.1	$27.2
Plan 3j Arrowhead - Weston 345 kV	$0.0	$0.0	$0.9	$0.9	$0.0
Plan 5a Chisago - Weston 345 kV	$0.9	$1.3	$0.0	$2.3	$1.4
Plan 5b Apple River - Weston 230 kV	$24.1	$5.0	$10.5	$39.6	$38.7
Plan 9b Lakefield - Columbia 345 kV	$15.9	$7.5	$6.5	$29.9	$29.0
Plan 10 King – Weston 345 kV	$13.4	$4.4	$3.8	$21.7	$20.8
Pre-plan System	$56.7	$13.2	$25.2	$95.2	$94.3

Table 7.3- 2

The capital adjustment for point-to-point transactions in Table 7.3-1 depends on the load factor of the transactions. In other words, the energy to supply the losses depends on how long the transfers are sustained at various operating levels on an annual basis. Due to the varying degrees of point-to point transmission usage that can occur, the annual energy losses for transactions were computed for each plan over a range of potential operating conditions. Both Tables 7.3-1 and 7.3-2 use the weighting of point-to-point transactions as illustrated in Table 7.3-3. For example, 5% of the time a 2000 MW import into WUMS from the West and a 1000 MW import from the South is one operating point along with, 40% of the time at a 1000 MW West import and 0 South import, etc.

Scenario For P-to-P Loss Calculation
[% of Time at Transfer Condition]

		West Import Schedule		
		0	1000	2000
South Import Schedule	2000	0%	5%	N/A
	1000	0%	10%	5%
	0	35%	40%	5%
	-1000	N/A	0%	0%
	-2000	N/A	N/A	0%

SUM = 100 %

Table 7.3- 3

Similarly, the energy loss for load depends on how long the load is sustained at various operating levels. However, an annual load pattern is sufficiently predictable, so that the resulting cost for energy loss for load is a constant for each plan. The annual energy to serve load in each plan has been set at 30% of the energy that would be lost if the peak load occurred all hours in the year. Since the load is the same for all plans, it follows that the unique electrical characteristic for each transmission plan is the only factor affecting the energy lost to serve load.

Table 7.3-4 shows the effect of the capital cost loss adders for each region separately relative to the plan with the smallest equivalent capital cost adder for losses. Loss adders were calculated for each region separately (while ignoring the other two regions). Then the three regions (MAPP, MAIN, and SPP) are recombined in Table 7.3-4 to create the percent shares shown in the three right columns. The base combined dollar adder column in Table 7.3-4 (to which the percents apply) is identical to the right hand column in Table 7.3-2. A negative share indicates that losses are actually reduced in that region.

	Equivalent Capital Cost Adder Due to Losses [millions of $]			
Plan Description	Composite Net Adder (M$)	MAPP Share	MAIN Share	SPP Share
Plan 1c Salem - Fitchberg 345 kV	$50.2	125%	-28%	3%
Plan 2e Prairie Is – Columbia 345 kV	$27.2	105%	-6%	2%
Plan 3j Arrowhead - Weston 345 kV	$0.0	0%	0%	0%
Plan 5a Chisago - Weston 345 kV	$1.4	-732%	832%	0%
Plan 5b Apple River - Weston 230 kV	$38.7	70%	29%	1%
Plan 9b Lakefield - Columbia 345 kV	$29.0	114%	-16%	2%
Plan 10 King - Weston 345 kV	$20.8	53%	47%	0%

Table 7.3- 4

Chapter 8 Construction Cost Estimates

8.1 WIREs Cost Estimate Development Process

The cost estimates for the WIREs transmission project plans are made up of three parts, as shown in the WIREs Cost Estimate Summary sheets (***Appendix C1***). These three parts are Cost of New Transmission Lines, Cost of Substation Terminal Improvements, and Cost of Associated Projects and Upgrades. There is one summary sheet for each plan, with total costs listed at the bottom of each sheet.

There is one item to be noted regarding the summary sheet for Plan 5b. On the summary sheet plan 5b is titled “Apple River-Weston 230 kV” rather than “Chisago-Weston 230kV”, and has been cost estimated with new 230 kV line construction beginning at Apple River rather than Chisago. This has been done to accurately reflect the inclusion of the Chisago-Apple River 230 kV line project in the base case used for the WIREs analysis.

Cost of New Transmission Lines

The cost estimates for the new transmission lines were developed by Black & Veatch (B&V), a transmission consultant retained by WRAO for this purpose. The assumptions, clarifications, and methods used by B&V to develop the cost estimates are listed in ***Appendix C2***. B&V’s full report, titled *Wisconsin Interface Reliability Enhancement Study Cost Estimates,* is available upon request.

The transmission line cost estimates were developed based on the study areas defined for each plan by an environmental consultant, Resource Strategies Inc. (RSI), working with WRAO and the WIREs group on the study. RSI used desired line endpoint and midpoint information provided by the WIREs group to determine the most feasible high level study corridors, from an environmental perspective, for the new lines. For all plans except plan 9b, two distinct alternate study areas were identified for each plan.

Two estimates for each alternate study area were developed – one for single circuit construction and one for double circuit construction. The single circuit estimate assumed construction of a completely new line through the study area, utilizing corridor sharing with existing transmission or transportation corridors where feasible. The double circuit estimate assumed construction of new shared structures with existing transmission lines in the study area where feasible. B&V used cost per mile figures determined for the first alternate study area to calculate the costs for the second alternate study area for each plan. The calculation methodology is explained in ***Appendix C2***. An additional worksheet is included which illustrates more directly which figures were used to calculate the ultimate cost estimates for each transmission line plan (***Appendix C2a***). A detailed component cost breakdown of each estimate is also included (***Appendix C2b***).

Additionally, for plans 3j, 5a, and 5b the Alternate 1 study area enabled the inclusion of facilities (listed as Highway 8 Tap -- Highway 8 115 kV transmission line) to address local load serving needs. The cost estimate for this local load serving line addition was supplied by Wisconsin Public Service and is included in the total cost estimate for the Alternate 1 study area for those plans.

Cost of Substation Terminal Improvements

The cost estimates for the substation terminal additions and enhancements required for each WIRES plan were developed by the utilities whose service territories include the affected substations. B&V supplied standard substation component costs and assumptions (***Appendix C3***) which were used by each utility to determine the estimated cost for these improvements.

For plans 3j, 5a, and 5b, the additional substation facilities required to support the local load serving project as noted above are included in the total cost estimate for the Alternate 1 study area.

Cost of Associated Projects and Upgrades

The associated projects and upgrades are various system improvements necessary for the plan under consideration to achieve the required power transfer and performance goals. These projects and upgrades are in addition to the new transmission line(s) and must be constructed along with the line(s) to achieve the required performance levels. These projects and upgrades are not already included in the planning models as base case facilities; they are additions to the base case facilities and thus are specifically listed and estimated for each plan. The cost estimates for these projects were developed by the utilities whose service territories include the affected facilities.

Some associated projects and upgrades are common requirements for multiple plans, and some are unique to a single plan (***Appendix C4***). Two projects which are common to all plans, “Plano-Plano Tap 345 kV line (ComEd)” and “Convert Oak Creek-Arcadian to 345 kV operation (WE)”, were listed in the summary sheets but their costs were not included in the total cost estimates for each plan. The two projects are excluded from the construction cost estimates because the regulatory approval process is underway for each.

Chapter 9 EVALUATED COST PROXY

The reinforcements plans presented in this report are intended to ensure the adequacy and security of the regional transmission system. An ancillary benefit of a major transmission expansion plan is the ability to address local load serving needs as customer load continues to grow. Several of the reinforcement plans presented in this report have the ability to address local load serving requirements.

Reinforcement Plans 2e (Prairie Island – Columbia 345 kV), 3j (Arrowhead – Weston 345 kV), 5a (Chisago – Weston 345 kV), and 5b (Chisago – Weston 230 kV) all have the ability to address certain local area load serving needs. To account for this benefit, the avoided cost of the local area load serving facilities was determined. The following table demonstrates the local load serving benefits associated with each project based on the "study areas" identified by the environmental analysis team. The study areas are referred to as "Study Area 1" and "Study Area 2". Notice that the study area dictates a plan's ability to defer or eliminate a local area load serving project.

	Avoided Local Load Serving Projects (base case facilities) ($ M)					
Plan	Study Area 1			Study Area 2		
	Facility	Cost	Year	Facility	Cost	Year
1c	none			none		
2e	LaCrosse Area Reinf	$1.8	2002	LaCrosse Area Reinf	$1.8	2002
3j	Upperwest Area Reinf	$10.5	2002	none		
5a	Upperwest Area Reinf	$10.5	2002			
	Chisago Co.-Apple R	$47.0	2002	Chisago Co.-Apple R	$47.0	2002
5b	Upperwest Area Reinf	$10.5	2002	none		
9b	none			none		
10	none			none		

Table 9- 1

An indicative "evaluated cost proxy" was determined for each reinforcement plan by considering the net impact of the construction cost, the equivalent capital cost adder for system losses, and the savings from avoided local load serving projects. The arithmetic sum of these three factors is a "proxy" for a more detailed economic analysis that considers the time value of money, inflation, etc.

The evaluated cost proxy, shown below, is shown as a range of values to account for the multiple study areas for each reinforcement plan. The range of costs is indicative of the magnitude of uncertainty associated with the study areas.

Evaluated Cost Proxy

	Single Circuit Construction ($M)		*Potential Double Circuit Construction ($M)*	
Plan	Study Area 1	Study Area 2	Study Area 1	Study Area 2
1c	$166.0	$195.0	$208.0	$277.0
2e	$194.8	$201.8	$268.8	$290.8
3j	$199.0	$176.8	$299.0	$265.8
5a	$148.5	$126.4	$227.5	$194.4
5b	$172.5	$156.6	$236.5	$209.6
9b	$255.5	-	$423.5	-
10	$156.8	$159.8	$230.8	$282.8

Notes:
- Evaluated Cost Proxy = Construction Cost - Avoided Local Load Serving Facilities + Capital Cost Adder for Losses
- Evaluated cost proxy not a full economic evaluation.

Table 9- 2

Appendix A1

ACCC Comparison – Intact System

COMMENTS		Rate	Base	1c	2e	3j	5a	5b	9b	10
These lines tie the 161 kV @ Monroe County with the 138 kV @ Council Creek and participate in the transfers. They are overloaded in the transfer case without any contingencies. Under high transfers the Council Creek bus tie would open.	872 COC 69.0 - 67600*T TC 69.0	50.0	28.9	60.4	57.7	53.8	51.8	58.9	53.1	53.8
	67600 T TC 69.0 - 67602*TOMAH 69.0	47.0	34.2	65.0	62.3	58.5	56.4	63.4	57.7	58.4
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	47.0	35.8	66.6	63.9	60.0	58.0	64.9	59.3	59.9
	67603 SPARTA 69.0 - 69121*MONROCO869.0	47.0	37.9	70.0	67.1	62.8	60.7	68.1	62.1	62.7
These lines participate in the transfers. They have a very small participation factor (<30MW). However, they show up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	62329 NEAL 4 5 161 - 62351*MONONA 5 161	134.0	116.9	142.9	136.6	136.9	136.3	138.8	135.1	136.9
	62351*MONONA 5 161 - 62355 CARROLL5 161	113.0	94.3	120.2	114.3	114.6	114.2	116.5	113.0	114.7
This line goes from NW Ill. To SW Wis. and participates in the transfers. It has a very small participation factor(<15MW). However, it shows up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	67547*PILOT NB69.0 - 67811 GALENA8 69.0	48.0	39.5	45.2	50.9	53.1	52.9	54.3	50.6	53.3
This transformer feeds the 69 kV which forms a parallel path from Riverton to Millaca 230 kV. It has a very small participation factor (<10MW). However, it shows up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	61353*RIVERTN7 115 0- 66093 RIVTON 869.0	19.9	32.7	37.8	38.6	37.3	38.4	38.3	37.9	38.5
	66093*RIVTON 869.0 - 66096 OAKLWNTP69.0	24.0	21.6	26.2	26.9	23.7	26.0	26.5	26.3	26.8

These 69 kv lines are part of a parallel path to the Willmar to Crow River/Big Swan 115 kV. They have a very small participation factor (<10MW). However, they show up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	61519*WILLMAR869.0 - 66147 SVEATAP869.0	23.9	24.5	32.9	34.7	34.0	34.2	33.6	33.3	34.3
	66147*SVEATAP869.0 - 66199 LITCHTP869.0	20.0	21.6	29.9	31.8	31.0	31.3	30.6	30.3	31.4
This 69 kV line ties the 230 kV @ Millaca to Rush City. It has a very small participation factor (<5MW). However, it shows up as overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	66115*LONGSDG869.0 - 66118 MILACA 869.0	24.0	22.9	25.9	26.1	25.7	25.6	26.4	25.9	26.0
These 69 kV lines are part of a parallel path to the Elk River to Bunker 230 kV. They have a negligible participation factor. However, they show up as overloaded in the transfer case without any contingencies. The negligible participation factor indicates this is more of a local load problem.	61509 ELK RIV869.0 - 66053*RDFTAP 869.0	29.0	30.8	32.4	32.5	32.4	32.4	32.6	32.3	32.5
	61509*ELK RIV869.0 - 66188 TRLHVN 869.0	24.0	27.9	28.3	28.7	26.7	27.6	27.6	28.5	27.9
These 69 kV lines tie the Cedar Ck 230 kV to Rush City. They have a negligible participation factor. However, they show up as overloaded in the transfer case without any contingencies. The negligible participation factor indicates this is more of a local load problem.	66045*COOPER 869.0 - 66079 SDRVL SW69.0	24.0	25.7	25.4	25.1	27.8	25.3	26.2	25.4	24.8
	66079*SDRVL SW69.0 - 66082 CEDARCK869.0	24.0	31.0	32.2	32.2	33.8	31.9	33.0	32.2	32.0
This transformer feeds the 34.5 kV which is part of a parallel path to the 161 kV from Apple River to Barron. It has a negligible participation factor. However, it shows up as overloaded in the transfer case without any contingencies. The negligible participation factor indicates this is more of a local load problem.	67719 BALSM L869.0 - 67727*BLSM LK934.5	12.0	16.4	18.3	17.6	17.2	17.1	18.1	17.8	17.5

This line participates in the transfers. It exceeds it's 220 MVA RATEA rating and it shows up for many of the ComEd contingencies. The flow on this line is controlled by a phase-shifter which would eliminate these overloads	36648*CROSB; B 138 - 36866 JEFFE; B 138	220.0	177.5	233.5	233.6	234.1	233.7	238.1	233.1	234.4
This 69kV line is part of a parallel path to the 161kV around Ottumwa. It does not participate in the transfers. However, it shows up as overloaded in the transfer case without any contingencies. The none participation indicates this is local load problem.	62639 EICTAP 869.0 - 62641*EIC 869.0	41.0	48.8	46.2	46.7	46.7	46.7	46.5	46.8	46.6
This 161 kV line is south of St. Louis. It does not participate in the transfers. However, it shows up as overloaded in the transfer case without any contingencies. The none participation indicates this is local load problem.	31325 FRED TAP 161 - 58756*FREDTN 5 161	45.0	63.9	62.5	62.8	62.7	62.7	62.6	62.8	62.7
This transformer participates in the transfers. It has a very small participation factor (<25MW). However, it shows up as close to being overloaded in the transfer case without any contingencies. The small participation factor indicates this is more of a local load problem.	918*SGL 138 138 - 919 SGL 69 69.0	46.7	19.8	43.3	42.2	40.8	41.4	41.6	42.9	40.3
Radial	65813*LITCHFLD69.0 - 66199 LITCHTP869.0	18.0	21.6	21.6	21.6	21.6	21.6	21.6	21.6	21.6
	66201*HUTCH PT69.0 - 66203 HUTCHMUN69.0	30.0	39.5	39.4	39.5	39.5	39.5	39.5	39.5	39.5
	62542*WILMSBG7 115 - 62614 WILMSBG934.5	13.0	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
Increased VAR output to support the voltage	31125 CALAWY 1 345 - 31124*CAL G125.0	1245.0	1159.8	1160.2	1159.7	1159.6	1159.7	1159.5	1159.8	1159.7
	31598 MER 2&3 138 - 31596*MER 216.5	150.0	137.7	137.7	137.6	137.6	137.6	137.7	139.2	137.7
	60816 COYOTE 3 345 - 60815*COYOTE1G24.0	428.0	405.3	409.4	409.7	409.7	409.9	409.6	409.5	409.8
	62012 FOX LK 5 161 - 62016*FOXLK53G13.8	85.0	82.2	82.1	82.1	82.1	82.1	82.1	82.1	82.1
	62143 ALMA 5 161 - 62140*ALMA5 5G14.4	90.0	89.2	91.3	87.5	90.4	88.2	89.3	91.3	87.8
	62328 NEAL N 5 161 - 62341*NEAL 1G18.0	150.0	142.3	147.8	146.6	146.2	145.8	146.3	146.9	146.0

Area swing for OPPD it is overgenerating to cover losses PMAX=648	60285 NEBRCTY3 345 - 60284*NEBRC31G18.0	672.0	587.7	722.2	719.6	718.8	719.1	721.3	721.6	720.7
Area swing for NSP it is overgenerating to cover losses PMAX=735	61662 SHERCO 3 345 - 61682*SHERC32G24.0	800.0	710.7	830.3	819.4	757.8	775.3	811.1	821.6	793.3
Area swing for MEC it is overgenerating to cover losses PMAX=539.8	62330 RAUN 3 345 - 62343*NEAL 3G22.0	560.0	493.8	556.5	546.8	544.9	544.3	547.0	547.3	545.0

APPENDIX A2

ACCC Comparison – Selected Contingencies

CONTINGENCY		Rate	Base	1c	2e	3j	5a	5b	9b	10
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	441.4	782.3	820.3	923.6	909.6	968.4	814.5	907.0
	872 COC 69 69.0 - 67600*T TC 69.0	50.0	34.6	65.3	64.6	57.6	54.4	62.9	58.2	57.3
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	39.7	70.0	69.4	62.4	59.1	67.6	63.0	61.9
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	41.3	71.6	71.0	63.9	60.6	69.2	64.6	63.4
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	43.6	75.7	75.1	67.3	63.6	73.1	68.1	66.4
	61854 EAU CLA5 161 - 61870*WHEATON5 161	294.0	369.8	342.5	319.9	287.1	272.0	301.2	332.7	177.9
	538*COL 345 345 - 628 SFL 345 345	676.0	265.4	489.3	567.9	300.8	285.8	323.6	571.8	274.4
	750*GSS 138 138 - 753 RDR 138 138	72.0	31.6	46.4	50.1	16.1	12.7	23.9	50.3	8.5
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	46.8	73.4	115.9	128.3	126.2	137.0	123.1	119.3
	62103 CASVILL5 161 - 7 *NED 161	221.0	38.3	71.5	108.6	122.1	120.1	131.5	114.9	113.2
	7 *NED 161 - 62108 GRANGRAE	221.0	25.8	35.3	19.2	16.1	18.9	16.7	27.1	17.5
	7 NED 161 - 9 *NED 138	280.0	44.8	100.7	108.2	121.8	117.2	128.7	103.8	118.0
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	494.8	841.2	851.9	980.3	953.7	1033.9	851.1	950.5
61853 EAU CL 3345.00 - 930 ARP 345 345.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	56.5	91.7	83.6	79.2	72.5	85.4	81.6	71.4
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	61.1	96.3	88.7	84.0	77.4	90.2	86.5	76.3
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	62.6	98.4	90.8	85.8	79.2	92.2	88.4	78.1
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	65.7	109.5	99.6	92.5	84.8	100.8	96.3	83.4
	61854 EAU CLA5 161 - 61870*WHEATON5 161	294.0	276.9	199.3	162.2	161.6	156.8	188.2	199.8	134.3
	538*COL 345 345 - 628 SFL 345 345 {A}	676.0	318.2	633.1	728.3	371.3	352.0	419.7	729.6	341.2
	750*GSS 138 138 - 753 RDR 138 138	72.0	49.0	85.5	87.9	38.7	32.8	54.9	88.2	30.1
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	47.8	59.9	113.7	122.9	123.2	131.8	120.5	122.1
	62103 CASVILL5 161 - 7 *NED 161	221.0	41.0	57.3	106.8	118.0	118.0	127.2	112.4	116.3
	7 *NED 161 - 62108 GRANGRAE	221.0	26.8	71.1	31.7	31.7	25.0	34.6	32.6	24.4
	7 NED 161 - 9 *NED 138	280.0	61.9	118.6	119.8	138.8	132.0	147.2	115.7	130.7
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	503.2	849.6	855.4	990.1	962.1	1045.8	855.0	957.8
61853 EAU CL 3345.00 - 930 ARP 345 345.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	20.2	33.8	27.2	28.8	26.4	30.6	27.7	26.1
870 COC 69.000 - 872 COC 69 69.000	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	25.5	39.8	33.0	34.5	31.9	36.6	33.4	31.5
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	27.1	41.6	34.7	36.2	33.6	38.4	35.1	33.2
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	28.9	44.6	37.1	38.6	35.7	41.1	37.4	35.3
	61854 EAU CLA5 161 - 61870*WHEATON5 161	294.0	276.7	199.1	161.0	159.5	155.0	187.4	199.2	135.8
	538*COL 345 345 - 628 SFL 345 345 {A}	676.0	322.8	644.0	744.4	377.4	357.3	427.4	744.5	345.4
	750*GSS 138 138 - 753 RDR 138 138	72.0	54.4	95.1	97.9	45.6	38.9	63.5	97.8	36.0
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	42.9	50.1	107.8	116.0	116.9	124.2	114.9	116.0
	62103 CASVILL5 161 - 7 *NED 161	221.0	37.1	48.5	101.8	112.1	112.6	121.0	107.8	111.2
	7 *NED 161 - 62108 GRANGRAE	221.0	31	83.3	34.7	39.8	31.2	42.8	31.6	30.4
	7 NED 161 - 9 *NED 138	280.0	65.3	125.1	124.2	144.7	137.2	154.4	119.6	135.6
61695 AS KING3345.00 - 61853 EAU CL 3345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	506.5	850.5	855.8	992.7	964.3	1048.8	855.2	960.1
61853 EAU CL 3345.00 - 930 ARP 345 345.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	17.1	28.2	21.5	24.1	22.1	25.2	22.7	21.8
870 COC 69.000 - 872 COC 69 69.000	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	22.3	34.0	27.1	29.6	27.5	31.0	28.2	27.2
859 HLT 69 69.000 - 67591 MAUSTON 69.000	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	23.9	35.8	28.8	31.3	29.1	32.7	29.8	28.8

	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	25.6	38.2	30.7	33.3	31.0	35.0	31.8	30.7
	61854 EAU CLA5 161 - 61870*WHEATON5 161{A}	294.0	276.6	199.1	160.6	159.2	154.2	186.9	199.1	136.1
	538*COL 345 345 - 628 SFL 345 345 {A}	676.0	326.1	653.1	754.5	383.1	362.8	434.8	754.2	350.2
	750*GSS 138 138 - 753 RDR 138 138	72.0	58.5	102.4	104.8	51.1	43.9	69.8	104.6	40.8
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	38.9	42.1	101.3	110.0	111.4	117.7	109.1	110.8
	62103 CASVILL5 161 - 7 *NED 161	221.0	34.1	41.6	96.3	107.0	107.9	115.4	102.7	106.7
	7 *NED 161 - 62108 GRANGRAE	221.0	33.7	90.8	37.7	45.5	36.7	48.7	31.4	35.5
	7 NED 161 - 9 *NED 138	280.0	66.7	128.4	127.1	147.9	139.7	157.7	121.7	138.1
930 ARP 345 345.00 - 2921 ROCKY RN345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	424.3	764.8	801.7	908.0	895.3	944.9	795.0	896.6
	67588*T HLB 69.0 - 67589 T UC 69.0	94.6	50.9	79.7	72.6	77.9	74.8	82.6	68.6	74.6
	872 COC 69 69.0 - 67600*T TC 69.0	50.0	34.9	68.5	62.1	58.5	54.9	63.9	59.0	55.3
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	40.0	73.6	67.0	63.4	59.7	68.8	63.9	60.0
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	41.5	75.5	68.7	65.1	61.3	70.5	65.6	61.5
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	43.8	81.0	72.7	68.7	64.4	74.7	69.4	64.6
	61861*MONROCO5 161 - 69121 MONROCO869.0	91.0	60.3	85.9	78.5	76.0	72.9	80.2	76.2	72.7
	904 SAR 138 138 - 911*POE 138 138	143.0	104.2	205.1	185.7	147.3	133.5	166.8	194.1	119.4
	907 RUT 69 69.0 - 919*SGL 69 69.0	48.0	17.7	56.3	53.4	46.5	42.6	51.0	54.4	39.0
	911*POE 138 138 - 912 POE 69 69.0	46.7	14.5	45.7	47.1	41.1	37.0	43.2	46.8	34.7
	911 POE 138 138 - 928*LPV 138 138	287.0	201.5	324.5	293.3	287.0	271.4	305.7	303.3	251.7
	918*SGL 138 138 - 919 SGL 69 69.0	46.7	39.1	81.6	77.1	70.2	65.4	75.3	79.1	61.2
	918*SGL 138 138 - 928 LPV 138 138	286.0	209.3	333.1	304.7	297.7	280.9	317.3	313.8	260.6
	918*SGL 138 138 - 931 ARP 138 138	287.0	247.1	411.6	380.5	366.3	344.9	390.9	390.7	320.8
	930*ARP 345 345 - 931 ARP 138 138	395.0	330.9	538.6	497.2	450.6	418.3	490.5	509.9	388.8
	2988 BAKER 115 - 2990*SARATOGA 115	138.0	77.7	227.9	206.6	142.6	126.3	170.3	211.2	113.6
	2988*BAKER 115 - 2992 COYNE 115	239.0	67.7	210.9	188.8	129.9	117.4	154.6	193.9	107.5
930 ARP 345 345.00 - 2921 ROCKY RN345.00	192*PAD 345 345 - 36406 WEMPL; B 345	1097.0	472.2	823.0	835.5	965.2	942.5	1011.7	833.3	929.0
911 POE 138 138.00 - 802 SAL 138 138.00	67588*T HLB 69.0 - 67589 T UC 69.0	94.6	61.4	91.0	82.2	89.6	85.3	94.4	78.3	82.1
911 POE 138 138.00 - 904 SAR 138 138.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	54.4	92.8	84.0	80.1	74.0	86.5	82.9	69.3
4002 WWR 25 46.000 - 3460 WATER QU46.000	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	59.0	97.1	89.0	84.9	78.8	91.2	87.5	74.1
932 ARP 115 115.00 - 2752 HUME 115.00	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	60.5	99.1	90.9	86.7	80.6	93.1	89.3	75.8
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	63.3	110.0	99.1	93.4	86.3	101.7	96.7	80.6
	61861*MONROCO5 161 - 69121 MONROCO869.0	91.0	71.3	101.7	95.5	92.2	88.3	96.9	92.7	83.8
192 PAD 345 345.00 - 36406 WEMPL; B345.00	387 SPG 69 69.0 - 393*ARE 69 69.0	36.0	25.0	22.9	36.7	42.2	41.8	43.6	37.1	42.3
1883 WHITWATR138.00 - 1445 LKHD TP 138.00	872 COC 69 69.0 - 67600*T TC 69.0	50.0	34.5	66.2	60.7	64.9	62.4	69.3	57.6	64.0
	67600 T TC 69.0 - 67602*TOMAH 69.0	51.7	39.6	70.9	65.5	69.9	67.2	74.3	62.4	68.8
	67602 TOMAH 69.0 - 67603*SPARTA 69.0	51.7	41.2	72.6	67.1	71.6	68.8	76.1	64.0	70.5
	67603 SPARTA 69.0 - 69121*MONROCO869.0	51.7	43.4	76.8	70.8	76.1	72.8	81.2	67.4	74.7
	62077 TRK RIV5 161- 62103 *CASVILL5 161	222.0	75.2	90.4	176.5	194.3	192.8	201.3	178.6	193.6
	62103 CASVILL5 161 - 7 *NED 161	221.0	66.2	90.3	169.6	190.5	188.5	198.6	170.4	189.5
	7 *NED 161 - 62108 GRANGRAE	221.0	24.1	38.1	14.9	9.5	6.0	8.8	25.9	6.5
	7 NED 161 - 9 *NED 138	280.0	68.7	126.9	156.7	191.6	186.4	199.7	148.3	189.1
	67547*PILOT NB69.0 - 67811 GALENA8 69.0	52.8	46.8	53.2	65.2	71.8	70.9	73.4	64.3	71.2
9 NED 138 138.00 - 33 POT 138 138.00	67547*PILOT NB69.0 67811 - GALENA8 69.0	52.8	50.2	58.9	65.9	68.9	68.5	70.5	65.0	69.0

2950 WHITNG A115.00 - 2970 HOOVER 115.00	941*WHB 69 - 69.0 943 RTP 69	36.0	35.1	35.8	33.8	47.4	48.3	45.3	34.2	46.2
61325 BLCKBRY4 230 - 61326 BOSWELL4 230 1	61325 BLCKBRY4 230 - 61326*BOSWELL4 230 2	503.0	607.0	596.1	595.6	630.1	589.7	595.4	597.0	593.9
62330 RAUN 3345.00 - 62367 LEHIGH 3345.00	62329 NEAL 4 5 161 - 62351*MONONA 5 161	131.0	138.0	172.6	164.2	164.7	163.8	167.2	161.5	164.6
	62351*MONONA 5 161 - 62355 CARROLL5 161	113.0	112.4	144.8	137.4	137.9	137.2	140.1	135.2	137.9
NOTES: {A} Presently this line is limited by CT's.										

APPENDIX B

The full text for Appendix B is contained in a separate document.

Reference File: WIREs_Appen_B.PDF

Appendix

C1

Plan 1c (Salem-Fitchburg 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Alternate 1: Salem-Fitchburg 1-N Madison-Rockdale	$ 88,000	$ 130,000
Alternate 2: Salem-Fitchburg 2-N Madison-Rockdale	$ 117,000	$ 199,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
Salem SS	ALTE	$ 1,569
Fitchburg SS	MGE	$ 6,331
N. Madison SS	MGE	$ 2,251
Rockdale SS	MGE	$ 1,846
TOTAL		**$ 11,997**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Wheaton 161 kV busses tied together	NSP	$ 4,000
Relocate Des Plaines transformer on new bus	COMED	$ 50
Reconductor Wheaton-Elk Mound	NSP	$ 324
Uprate Elk Mound-Barron to 212F operating temp	NSP	$ 759
Reconductor Wien-T-Corners with SSAC	WPS	$ 1,200
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction- Highway V 138 kV line to 275 deg	WE	$ 215
Upgrade Quad Cities-Rock Creek terminal equipmnt CT	ALTW	$ 75
Install 373 Mvars Capacitors	WIRES	$ 5,595
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 15,823**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	**DOUBLE CKT**
TOTAL OPTION 1C ALTERNATE 1 COST (000)	**$ 115,820**	**$ 157,820**
TOTAL OPTION 1C ALTERNATE 2 COST (000)	**$ 144,820**	**$ 226,820**

Plan 2e (Prairie Island – Columbia 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Alternate 1: Prairie Island-LaCrosse 1-Columbia	$ 146,000	$ 220,000
Alternate 2: Prairie Island-LaCrosse 2-Columbia	$ 153,000	$ 242,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
Prairie Island SS	NSP	$ 1,500
LaCrosse SS	NSP	$ 6,688
Columbia SS	ALTE	$ 1,493
TOTAL		**$ 9,681**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Reconductor Wheaton-Elk Mound	NSP	$ 324
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Upgrade Blackhawk-Colley Rd terminal equipment	WPL	$ 200
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Replace ss limiters on Columbia-S FDL 345 kV line	WPL	$ 300
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Rockdale Transformer	ALTE	$ 4,000
Upgrade Green Lake-Roeder terminal equipment	ALTE	$ 25
Install 333 Mvars Capacitors	WIRES	$ 4,995
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 13,764**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 2E ALTERNATE 1 COST (000)	**$ 169,445**	**$ 243,445**
TOTAL OPTION 2E ALTERNATE 2 COST (000)	**$ 176,445**	**$ 265,445**

Plan 3j (Arrowhead – Weston 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
*Alternate 1: Arrowhead-Ladysmith-Weston 1	$ 161,000	$ 261,000
Highway 8 Tap-Highway 8 115 kV	$ 6,000	$ 6,000
**Alternate 2: Arrowhead-Ladysmith-Weston 2	$ 142,000	$ 231,000

SUBSTATION TERMINAL IMPROVEMENTS			
SUBSTATION	**UTILITY**	**COST (000)**	
		Alternate 1	**Alternate 2**
Arrowhead SS	MP	$ 6,100	$ 6,100
Highway 8 Tap-New SS	WPS	$ 7,403	
Highway 8 SS	WPS	$ 220	
Weston 345 kV SS	WPS	$ 3,084	$ 3,084
TOTAL		**$ 16,807**	**$ 9,184**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$ 300
Upgrade Weston 345/115 to 500 MVA	WPS	$ 2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$ 4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$ 50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$ 10
Rockdale transformer	ALTE	$ 4,000
Weston-Northpoint	WPS	$ 2,400
Reconductor Rocky Run-Whiting Ave with SSAC	WPS	$ 200
Install 578 Mvars Capacitors	WIRES	$ 8,670
Convert Oak Creek-Arcadian to 345 kV operation ***	WE	
Plano-Plano Tap 345 kV line***	COMED	
TOTAL		**$ 25,650**

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 3J ALTERNATE 1 COST (000)	**$ 209,457**	**$ 309,457**
TOTAL OPTION 3J ALTERNATE 2 COST (000)	**$ 176,834**	**$ 265,834**

**Alternate 1-Study area enables local load serving project.*
***Alternate 2 -Study area without local load serving project.*

***Projects required to achieve transfer amounts, costs not included here.

Plan 5a (Chisago – Weston 345 kV)

NEW TRANSMISSION LINE(S)				
LINES	**COST (000)**			
	SINGLE CKT		**DOUBLE CKT**	
*Alternate 1: Chisago-Apple River-Ladysmith-Weston 1	$	148,000	$	227,000
Highway 8 Tap-Highway 8 115 kV	$	6,000	$	6,000
**Alternate 2: Chisago-Apple River-Ladysmith-Weston 2	$	129,000	$	197,000

SUBSTATION TERMINAL IMPROVEMENTS					
SUBSTATION	**UTILITY**	**COST (000)**			
		Alternate 1		**Alternate 2**	
Chisago SS	NSP	$	1,500	$	1,500
Apple River SS	NSP	$	9,773	$	9,773
Lawrence Creek- New SS	NSP	$	6,482	$	6,482
Highway 8 Tap- New SS	WPS	$	7,403		
Weston 345 kV SS	WPS	$	3,084	$	3,084
Highway 8 SS	WPS	$	220		
TOTAL		**$**	**28,462**	**$**	**20,839**

ASSOCIATED PROJECTS AND UPGRADES			
ITEM	**UTILITY**	**COST (000)**	
Reconductor Eau Claire-Weaton	NSP	$	387
Upgrade Barron-Apple River terminal equipment	NSP	$	10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$	10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$	1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$	1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$	1,000
Reconductor Wheaton-Wheaton Tap	NSP	$	198
Relocate Des Plaines transformer on new bus	COMED	$	50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$	300
Upgrade Weston 345/115 to 500 MVA	WPS	$	2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$	4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$	-
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$	215
Improve Goodings-Lockport Red/Blue line sag	COMED	$	50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$	50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$	10
Rockdale transformer	ALTE	$	4,000
Weston-Northpoint	WPS	$	2,400
Reconductor Rocky Run-Whiting Ave with SSAC	WPS	$	200
Install 343 Mvars Capacitors	WIRES	$	5,145
Convert Oak Creek-Arcadian to 345 kV operation ***	WE		
Plano-Plano Tap 345 kV line***	COMED		
TOTAL		**$**	**22,125**

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 5A ALTERNATE 1 COST (000)	**$ 204,587**	**$ 283,587**
TOTAL OPTION 5A ALTERNATE 2 COST (000)	**$ 171,964**	**$ 239,964**

**Alternate 1-Study area enables local load serving project.*
***Alternate 2-Study area without local load serving project.*

***Projects required to achieve transfer amounts, costs not included here.

Plan 5b (Apple River – Weston 230 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
*Alternate 1: Apple River-Ladysmith-Weston 1	$ 94,000	$ 158,000
Highway 8 Tap-Highway 8 115 kV	$ 6,000	$ 6,000
**Alternate 2: Apple River-Ladysmith-Weston 2	$ 80,000	$ 133,000

SUBSTATION TERMINAL IMPROVEMENTS			
SUBSTATION	**UTILITY**	**COST (000)**	
		Alternate 1	**Alternate 2**
Apple River SS	NSP	$ 1,161	$ 1,161
Highway 8 Tap- New SS	WPS	$ 6,241	
Weston 230/345 kV SS	WPS	$ 13,128	$ 13,128
Highway 8 SS	WPS	$ 220	
TOTAL		**$ 20,750**	**$ 14,289**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$ 300
Upgrade Weston 345/115 to 500 MVA	WPS	$ 2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$ 4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$ 50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$ 10
Rockdale transformer	ALTE	$ 4,000
Weston-Northpoint	WPS	$ 2,400
Install 453 Mvars Capacitors	WIRES	$ 6,795
Convert Oak Creek-Arcadian to 345 kV operation ***	WE	
Plano-Plano Tap 345 kV line***	COMED	
TOTAL		**$ 23,575**

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 5B ALTERNATE 1 COST (000)	**$ 144,325**	**$ 208,325**
TOTAL OPTION 5B ALTERNATE 2 COST (000)	**$ 117,864**	**$ 170,864**

**Alternate 1-Study area enables local load serving project.*
***Alternate 2-Study area without local load serving project.*

***Projects required to achieve transfer amounts, costs not included here.

Plan 9b (Lakefield – Columbia 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Lakefield-Adams-Genoa-Columbia	$ 197,000	$ 365,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
Lakefield SS	NSP	$ 801
Adams SS	NSP	$ 2,301
Genoa SS	DPC	$ 6,085
Columbia SS	ALTE	$ 1,493
TOTAL		**$ 10,680**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Wheaton 161 kV busses tied together	NSP	$ 4,000
Relocate Des Plaines transformer on new bus	COMED	$ 50
Reconductor Wheaton-Elk Mound	NSP	$ 324
Uprate Elk Mound-Barron to 212 F operating temp	NSP	$ 759
Reconductor Wien-T-Corners with SSAC	WPS	$ 1,200
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Upgrade Blackhawk-Colley Rd terminal equipment	WPL	$ 200
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Rockdale Transformer	ALTE	$ 4,000
Upgrade Green Lake-Roeder terminal equipment	ALTE	$ 25
Install 293 Mvars Capacitors	WIRES	$ 4,395
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 18,823**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	DOUBLE CKT
TOTAL OPTION 9B COST (000)	**$ 226,503**	**$ 394,503**

Plan 10 (King – Weston 345 kV)

NEW TRANSMISSION LINE(S)		
LINES	**COST (000)**	
	SINGLE CKT	**DOUBLE CKT**
Alternate 1: King-Eau Claire 1-Weston	$ 109,000	$ 183,000
Alternate 2: King-Eau Claire 2-Weston	$ 112,000	$ 235,000

SUBSTATION TERMINAL IMPROVEMENTS		
SUBSTATION	**UTILITY**	**COST (000)**
King SS	NSP	$ 2,198
Eau Claire SS	NSP	$ 2,301
Weston SS	WSP	$ 3,084
TOTAL		**$ 7,583**

ASSOCIATED PROJECTS AND UPGRADES		
ITEM	**UTILITY**	**COST (000)**
Reconductor Eau Claire-Weaton	NSP	$ 387
Upgrade Barron-Apple River terminal equipment	NSP	$ 10
Reconductor portion of Itasca-Lombard R (0.1 mi)	COMED	$ 10
Upgrade Itasaca-Lombard B 345 kV breaker	COMED	$ 1,000
Upgrade Itasaca-Lombard R 345 kV breaker	COMED	$ 1,000
Schaumburg Breaker's/Swap red & blue terminations	COMED	$ 1,000
Reconductor Wheaton-Wheaton Tap	NSP	$ 198
Relocate Des Plaines transformer on new bus	COMED	$ 50
Upgrade Weston-Rocky Run 345 kV terminal eq	WPS	$ 300
Upgrade Weston 345/115 to 500 MVA	WPS	$ 2,000
Rebuild Kelly-Whitcomb (24 mi) 115 kV line	WPS	$ 4,100
Upgrade Goodings Grove 345 kV bus tie	COMED	$ -
Inc Forest Junction-Highway V 138 kV line to 275 deg	WE	$ 215
Improve Goodings-Lockport Red/Blue line sag	COMED	$ 50
Upgrade Sand Lake-Port Edwards terminal eq	WPL	$ 50
Upgrade Pulliam 138/115 kV terminal eq	WPS	$ 10
Rockdale Transformer	ALTE	$ 4,000
Weston-Northpoint	WPS	$ 2,400
Reconductor Rocky Run-Whiting Ave with SSAC	WPS	$ 200
Install 163 Mvars Capacitors	WIRES	$ 2,445
Convert Oak Creek-Arcadian to 345 kV operation *	WE	
Plano-Plano Tap 345 kV line*	COMED	
TOTAL		**$ 19,425**

*Projects required to achieve transfer amounts, costs not included here.

	SINGLE CKT	**DOUBLE CKT**
TOTAL OPTION 10 ALTERNATE 1 COST (000)	**$ 136,008**	**$ 210,008**
TOTAL OPTION 10 ALTERNATE 2 COST (000)	**$ 139,008**	**$ 262,008**

Appendix

C2

WISCONSIN INTERFACE RELIABILITY ENHANCEMENT STUDY CONCEPTUAL COST ESTIMATE SUMMARY

The Wisconsin Reliability Assessment Organization (WRAO) is performing a Wisconsin Interface Reliability Enhancement Study (WIREs) to identify possible regional transmission improvements that could increase the transfer capability between eastern Wisconsin and adjoining regions. This document contains conceptual cost estimates of line route options for this study. This section includes the following information.

- Summary table of costs for each line route option
- A description of the line routes
- Costs for the segments within line routes 3j, 5a and 5b
- Assumptions and clarifications for the estimates
- Sketches of the structure configurations

Included in section 2.0 are the detailed conceptual cost estimates for the new 345 kV single circuit transmission line routes (1 route is also estimated as 230 kV).

Included in section 3.0 are the detailed conceptual cost estimates for 345 kV double circuit transmission lines (1 is also estimated as 230 kV) for the same routes as sections 2.0. These estimates assume the new double circuit line erected in the existing right-of-way will replace an existing single circuit transmission line. The actual single circuit/double circuit cost estimates in the summary table contain portions of the line as double circuit and the rest as single circuit based on an estimated length of sharing right-of-way of existing lines in the individual corridors. The estimates in sections 3.0 were used to obtain the costs for the double circuit options as shown in the following example.

Route 1c
(Single circuit miles Route 1c) x (SC cost/mile Route 1c) + (double circuit miles Route 1c) x (DC cost/mile Route 1c) = cost of SC/DC cost Route 1c

(69 miles SC) x ($715,000/mile) + (54 miles DC) x ($1,496,000/mile) = $130,000,000 (rounded)

A second alternate route was identified for each option and was estimated as a single circuit and double circuit. These estimates were done using the cost/mile from the first alternate route as shown in the following example.

Route 1c
(Single circuit miles for Route 1c, alternate 2) x (single circuit cost/mile for Route 1c, alternate 1) = cost for Route 1c, alternate 2

(164 miles) x ($715,000/mile) = $117,000,000 (rounded)

Similarly the segment costs for line routes 3j, 5a and 5b were done using the cost/mile values for those line routes.

These cost estimates were completed without performing structure studies, conductor studies and specific line route studies. Structures, foundations, conductors and other items were estimated based on an acceptable, economical type for construction of a 345 kV or 230 kV line. Studies should be completed for the final selected route to determine the best economical choice for that line route.

ASSUMPTIONS AND CLARIFICATIONS

1. The quantities of materials and labor shown are those estimated to be actually required for the design and construction of the line. Costs for bonds have not been included.

2. Although these transmission line options will not be constructed entirely in the State of Wisconsin, the vast majority will be. For simplicity of estimating, Wisconsin state sales and use tax has been included in all estimates. The tax rate is 5.6 percent, and is applied to material and labor, excluding labor associated with foundation installation.

3. The assumed design loading conditions are the following.

   - NESC Heavy
   - Extreme Wind: 21 psf high wind
   - Extreme Ice: 1.5 inches of ice with 4 psf wind, 0ºF
   - -20ºF
   - 200ºF

   The overload factors used are in accordance with the NESC for the NESC load case, 1.25 for the extreme wind load case and 1.0 for the extreme ice load case. Clearance requirements are in accordance with the NESC, and Wisconsin code.

4. These 345 kV lines are designed for bundled 2-795 kcmil, 26/7 ACSR “Drake” conductor with two 134.6 kcmil 12/7 ACSR “Leghorn” shield wires. The 230 kV lines are designed for 1033.5 kcmil 54/7 ACSR “Curlew” conductor and two 134.6 kcmil 12/7 ACSR “Leghorn” shield wires. All wire quantities are the exact line footage.

5. No restrictions were used on placement of structures in swamps and wetlands.

6. All single circuit tangent structures are steel H-frames. All single circuit angle structures are steel H-frames and are similar to the tangent structures. All single circuit deadend structures are steel lattice towers. For double circuit structures, all

tangents are single poles, all angle and deadend structures are lattice towers.

7. The 345kV suspension structures have 18-20 kip insulators per string and the deadends have 2 strings of 18-30 kip insulators per string. The 230 kV suspension structures have 14-20 kip insulators per string and the deadends have s strings of 16-30 kip insulators per string.

8. The average 345 kV single circuit structure height is 85' with an average span of 950'. The average 345 kV double circuit structure height is 125' with an average span of 850'. The average 230 kV single circuit structure height is 80' with an average span of 950'. The average 230 kV double circuit structure height is 120' with an average span of 850'. Ground clearance used for 345 kV is 27' and for 230 kV is 25'.

9. Structure types were based on the following distribution.

Line Route	% Tangents	% Angles	% Deadends
1c	80	16	4
2e	70	24	6
3j	80	16	4
5a/5b	80	17	3
9b	80	17	3
10	80	17	3

10. A rock adder has been included to account for increases in foundation cost due to rock coring. A percentage of structures were given this adder based on general geographic characteristics of the State of Wisconsin extrapolated from USGS map "Depth to Bedrock in Wisconsin" 1973. The estimates include a percentage of the line requiring the bottom 5 feet of the foundations in rock. The percentages per segment used are as follows.

Line Route	Percentage of Line Considered in Rock
1c	50%
2e	25%
3j	5%
5a/5b	15%
9b	25%
10	30%

11. Wetland matting is assumed to be required for 10 percent of the wetland areas listed in the report for the line routes.

12. The soil type assumed for the foundation design is good soil (sand, gravel, or stiff clay).

    Foundations are assumed to be drilled piers for all structure types except the single circuit H-frame structures. The single circuit H-frame structures are assumed to be direct embedded 10 percent of the pole length plus four feet.

13. Construction will be performed during the time of year when the line route is driveable. Minimal access roads to the right-of-way are included in the right-of-way clearing expense.

14. The clearing of land is split into three categories based on the report. These categories are average, forested or wetlands. Average clearing costs are used for all areas not specifically designated forested and wetlands in the report.

15. For the estimate, we have assumed one soil boring at every angle and deadend and one additional boring per mile.

16. No mitigation costs are included for the wetland areas, wildlife or scenic areas or Indian reservations. No mitigation costs are included for induced voltages on railroad tracks, pipelines or adjacent communication or signal wires. It is assumed the 10% contingency will cover these potential costs.

17. The ground survey work is assumed to be performed by the same surveyor who will do the aerial survey for the line route. The surveyor will provide digitized plan and profile sheets for the cost included for the design survey work. The survey work is split into two costs, one for forested areas and one for the rest of the line.

18. Deadends are included in the estimate at a minimum of one every ten miles.

19. All costs are in 1999 dollars, then escalated by adding 3 percent per year for the assumed in-service date of 2002.

20. The engineering and construction management costs per segment have been estimated at 7 and 3 percent of the material and labor cost respectively.

21. The right-of-way is assumed to be 150' for new 345 kV single circuit lines and 100' for new 230 kV single circuit lines. The right-of-way is assumed to be an additional 50' for new 345kV double circuit lines and 25' for 230kV double circuit lines.

22. For line segments along an existing transmission line, the double circuit cost estimates assume the existing line is the same voltage as the new line. An additional cost of $200,000 is assumed, $150,000 for removal of the existing line and $50,000 for working with and near an energized line. No salvage value is assumed during removal of the existing line.

23. No costs for the design or construction of substations are included in this estimate.

Appendix C2a

Option		Length (miles)	Cost/Mile ($M)	S-C Cost ($M)	Length (miles)	Cost/Mile ($M)	Cost ($M)	S-C/D-C Cost ($M)
1c Alternate 1: 123 miles								
Single Circuit	SC	123	0.715102	**$88**	69	0.715102	49.3	
Double Circuit	DC				54	1.496119	80.8	**$130**
1c Alternate 2: 164 miles								
	SC	164	0.715102	**$117**	59	0.715102	42.2	
	DC				105	1.496119	157.1	**$199**
2e Alternate 1: 195 miles								
	SC	195	0.747197	**$146**	109	0.747197	81.4	
	DC				86	1.605531	138.1	**$220**
2e Alternate 2: 205 miles								
	SC	205	0.747197	**$153**	102	0.747197	76.2	
	DC				103	1.605531	165.4	**$242**
3j Alternate 1: 228 miles								
	SC	228	0.703695	**$160**	103	0.703695	72.5	
	DC				125	1.509201	188.7	**$261**
3j Alternate 2: 201 miles								
	SC	201	0.703695	**$141**	90	0.703695	63.3	
	DC				111	1.509201	167.5	**$231**
5a Alternate 1: 214 miles								
	SC	214	0.689653	**$148**	116	0.689653	80.0	
	DC				98	1.501430	147.1	**$227**
5a Alternate 2: 187 miles								
	SC	187	0.689653	**$129**	103	0.689653	71.0	
	DC				84	1.501430	126.1	**$197**
5b Alternate 1: 214 miles								
	SC	214	0.528274	**$113**	116	0.528274	61.3	
	DC				98	1.290428	126.5	**$188**
5b Alternate 2: 187 miles								
	SC	187	0.528274	**$99**	103	0.528274	54.4	
	DC				84	1.290428	108.4	**$163**
9b: 292 miles								
	SC	292	0.673196	**$197**	87	0.673196	58.6	
	DC				205	1.495523	306.6	**$365**
10 Alternate 1: 156 miles								
	SC	156	0.69742	**$109**	63	0.697420	43.9	
	DC				93	1.492920	138.8	**$183**
10 Alternate 2: 160 miles								
	SC	160	0.69742	**$112**	5	0.697420	3.5	
	DC				155	1.492920	231.4	**$235**

Appendix C2b

	OPTION 1C	OPTION 2E	OPTION 3J	OPTION 5A	OPTION 5B	OPTION 9B	OPTION 10
LAND AND LAND RIGHTS	$16,308,057	$25,444,960	$25,846,080	$24,416,000	$20,380,548	$34,736,120	$20,008,040
TOWERS AND FIXTURES							
Land and Crop Damage	$87,146	$138,158	$161,538	$151,619	$151,619	$206,882	$110,526
Structures - Materials	$12,131,700	$20,170,450	$22,116,100	$20,542,140	$15,897,650	$27,838,600	$15,115,030
Structures - Labor	$5,791,992	$10,111,579	$11,069,114	$9,856,164	$8,058,394	$12,831,617	$7,051,264
Install Tower Footings							
Materials	$1,630,640	$2,841,630	$2,941,910	$2,663,960	$2,146,755	$3,619,890	$1,963,962
Installation	$10,197,244	$16,670,053	$16,108,236	$15,010,748	$12,261,190	$20,696,721	$11,537,706
Engineering	$2,082,610	$3,485,560	$3,656,475	$3,365,111	$2,685,479	$4,549,078	$2,496,757
Soil Borings	$573,340	$1,133,600	$1,052,940	$981,000	$981,000	$1,345,060	$721,580
Construction Management	$892,547	$1,493,811	$1,567,061	$1,442,190	$1,150,920	$1,949,605	$1,070,039
Sundries 5% of Labor	$976,887	$1,644,730	$1,672,691	$1,532,761	$1,256,849	$2,068,604	$1,143,867
State Tax (5.6% M&L) Excluding Fnd Labor)	$1,348,464	$2,289,356	$2,468,272	$2,261,466	$1,801,915	$3,035,337	$1,655,500
OVERHEAD CONDUCTORS AND DEVICES							
Land and Crop Damage	$87,146	$138,158	$161,538	$151,619	$151,619	$206,882	$110,526
Line Survey	$1,039,154	$1,865,699	$2,389,553	$2,105,499	$2,105,499	$2,454,299	$1,377,324
Clearing	$5,690,131	$10,936,664	$14,620,269	$12,511,416	$8,340,944	$13,402,045	$7,739,396
Conductors and Accessories							
Material	$6,380,072	$10,113,536	$11,824,564	$11,098,995	$7,293,312	$15,142,366	$8,091,782
Installation	$7,274,345	$11,528,675	$13,478,130	$12,652,103	$7,639,070	$17,257,133	$9,225,946
Insulators							
Material	$1,667,700	$2,719,550	$3,030,200	$2,792,580	$2,532,942	$3,782,300	$2,054,650
Installation	$1,133,817	$1,840,485	$2,062,509	$1,906,071	$1,906,071	$2,580,950	$1,402,128
Engineering	$1,622,965	$2,730,323	$3,318,366	$3,014,667	$2,087,249	$3,823,337	$2,092,386
Construction Management	$695,557	$1,170,138	$1,422,157	$1,292,000	$894,535	$1,638,573	$896,737
Sundries (5% of Labor)	$872,798	$1,503,599	$1,864,549	$1,674,088	$1,148,668	$2,057,817	$1,136,696
State Tax (5.6% M&L)	$1,477,086	$2,486,885	$3,024,577	$2,746,655	$1,901,104	$3,479,774	$1,904,955
10% CONTINGENCY	7,996,139	13,245,759	14,585,682	13,416,885	10,277,333	17,870,298	9,890,679
TOTAL	**87,957,538**	**145,703,357**	**160,442,512**	**147,585,738**	**113,050,664**	**196,573,288**	**108,797,477**
per mile	715,101	747,196	703,695	689,652	528,274	673,196	697,419

APPENDIX

C3

SUBSTATION TERMINAL COMPONENT COSTS
(information supplied by Black & Veatch)

Clarifications and Assumptions	
1	1999 Dollars.
2	No contingency has been included. Recommend 15% be used.
3	No taxes have been included.
4	It is assumed the existing control room and station service is adequate for addition of the equipment. If a control building addition is needed, use $150/square foot for prefab building, foundation, lights, raceway and HVAC.
5	Foundation are assumed to be drilled pier in firm soil. No rock encountered.
6	No real estate costs are included.
7	No cost for permitting or environmental considerations have been included.

345 kV "Component Costs" for the addition of a typical 345kV line position at an existing substation.:

345kV		
COMPONENT	MATERIAL COST	LABOR COST
345Kv Breaker, 2000A, 40ka, dead tank, 3-ph	$220,000	$15,000
345kV Breaker foundation	$8,000	$12,000
345kV Dead-end Structure	$40,000	$8,000
345kV DE Structure foundation	$10,000	$20,000
345kV Disconnect Switch and structural support	$25,000	$6,000
345kV Disconnect Switch foundation	$2,000	$2,000
345kV line relaying panel	$45,000	$1,000
345kV breaker control panel	$25,000	$1,000
345kV CCVT and support, 1-ph	$8,000	$1,000
345kV PT and support, 1-ph	$18,000	$1,000
Control and Power Cable per Breaker	$6,000	$6,000
345kV low profile bus, insulators, fittings and structures (Line position tapping into a ring bus)	$50,000	$30,000
345kV bus support foundations	$6,000	$10,000
Minor Site Grading, grounding, raceway and fencing	$10,000	$20,000
345/138kV, 300/400/500 MVA Transformer	$2,200,000	$60,000
345/138kV, 300/400/500 MVA Transformer w/LTC	$2,900,000	$65,000
345/138kV,300/400/500 MVA Transformer & misc Transformer relay panel	$15,000 $25,000	$20,000 $1,000
Engineering and construction management-use 15% of total material and labor		

230 kV "Component Costs" for the addition of a typical 230kV line position at an existing substation.:

230kV		
COMPONENT	**MATERIAL COST**	**LABOR COST**
230kV Breaker, 2000A, 40ka, dead-tank, 3-ph	$100,000	$7,000
230kV Breaker foundation	$4,000	$6,000
230kV Dead-end Structure	$32,000	$6,000
230kV DE Structure foundation	$9,000	$14,000
230kV Disconnect Switch and Structural support	$14,000	$5,000
230kV Disconnect Switch foundation	$1,500	$1,500
230kV line relaying panel	$40,000	$1,000
230kV breaker control panel	$25,000	$1,000
230kV CCVT and support, 1-ph	$6,000	$1,000
230kV PT and support, 1-ph	$14,000	$1,000
Control and Power Cable per Breaker	$5,000	$5,000
230kV low profile bus, insulators, fittings and structures (Line position tapping into a ring bus)	$40,000	$24,000
230kV bus support foundations	$5,000	$7,000
Minor Site Grading, grounding, raceway, and fencing	$8,000	$18,000
230/138kV, 300/400/500 MVA Transformer	$2,000,000	$55,000
230/138kV, 300/400/500 MVA Transformer w/LTC	$2,700,000	$60,000
230/138kV, 300/400/500 MVA & misc Transformer relay panel	$12,000 $25,000	$16,000 $1,000
Engineering and construction management-use 15% of total material and labor		

161 kV "Component Costs" for the addition of a typical 161kV line position at an existing substation.:

161kV		
COMPONENT	**MATERIAL COST**	**LABOR COST**
161kV circuit switcher with support	$55,000	$5,000
161kV circuit switcher foundation	$2,000	$2,000
345/161kV 300/400/500 MVA Transformer	$2,300,000	$60,000
345/161kV 300/400/500 MVA Transformer w/LTC	$3,000,000	$65,000
345/161kV 300/400/500 MVA Transformer Foundation w/ Oil Cont	$15,000	$20,000

APPENDIX C4

Item	Project	1c	2e	3j	5a	5b	9b	10	Cost
1	Reconductor Eau Claire - Wheaton	1	1	1	1	1	1	1	NSP $387
2	Upgrade Barron - Apple River terminal	1	1	1	1	1	1	1	NSP $10
3	Reconductor portion of Itasca - Lombard R	1	1	1	1	1	1	1	COMED $10
4	Upgrade Itasca - Lombard B 345 kV breaker	1	1	1	1	1	1	1	COMED $1,000
5	Upgrade Itasca - Lombard R 345 kV breaker	1	1	1	1	1	1	1	COMED $1,000
6	Schaumburg Breaker's/Swap red & blue	1	1	1	1	1	1	1	COMED $1,000
7	Reconductor Wheaton - Wheaton Tap	1	1	1	1	1	1	1	NSP $198
	Convert Oak Creek-Arcadian to 345 kV	1	1	1	1	1	1	1	WE $12,127
	Plano-Plano Tap 345 kV line	1	1	1	1	1	1	1	COMED $35,000
8	Wheaton 161 kV busses tied together	1					1		NSP $4,000
9	Relocate Des Plaines transformer on new bus	1	1	1	1	1	1	1	COMED $50
10	Upgrade Weston - Rocky Run 345 kV			1	1	1		1	WPS $300
11	Reconductor Wheaton - Elk Mound	1	1				1		NSP $324
12	Upgrade Weston 345/115 to 500 MVA			1	1	1		1	WPS $2,000
13	Rebuild Kelly-Whitcomb (24 mi) 115 kV line			1	1	1		1	WPS $4,100
14	Uprate Elk Mound - Barron to 212 F operating	1					1		NSP $759
15	Reconductor Wien - T-Corners with SSAC	1					1		WPS $1,200
16	Upgrade Goodings Grove 345 kV bus tie	1	1	1	1	1	1	1	COMED $0
17	Upgrade Blackhawk - Colley Rd terminal		1				1		WPL $200
18	Inc Forest Junction-Highway V 138kV to 275	1	1	1	1	1	1	1	WE $215
19	Replace ss limiters on Columbia-S FDL 345		1						WPL $300
20	Improve Goodings-Lockport Red/Blue line		1	1	1	1	1	1	COMED $50
21	Upgrade Sand Lake-Port Edwards terminal			1	1	1		1	WPL $50
22	Upgrade Pulliam 138/115 kV terminal eq.			1	1	1		1	WPS $10
23	Rockdale transformer		1	1	1	1	1	1	ALTE $4,000
24	Weston-Northpoint			1	1	1		1	WPS - $2,400
25	Reconductor Rocky Run-Whiting Ave SSAC			1	1			1	WPS - $200
26	Upgrade Green Lake-Roeder term equip		1				1		ALLIANT $25
27	Upgrade Quad Cities-Rock Ck term equip CT	1							ALTW $75
28	Install 373 Mvars	1							WIREs $15/KVAR $5,595
29	Install 333 Mvars		1						WIREs $15/KVAR $4,995
30	Install 578 Mvars			1					WIREs $15/KVAR $8,670
31	Install 343 Mvars				1				WIREs $15/KVAR $5,145
32	Install 453 Mvars					1			WIREs $15/KVAR $6,795
33	Install 293 Mvars						1		WIREs $15/KVAR $4,395
34	Install 163 Mvars							1	WIREs $15/KVAR $2,445