Northern MAPP/Northwestern Ontario Disturbance
June 25, 1998

*** FINAL REPORT ***

Power System Disturbance Report

Compiled by:

Mid-Continent Area Power Pool (MAPP)

MAPP Committees:
Iowa Operating Review Working Group (IORWG)
Nebraska Operating Review Working Group (NORWG)
Northern MAPP Operating Review Working Group (NMORWG)

Ontario Hydro

Approved by:

MAPP Operating Review Subcommittee (ORS) on September 2, 1998

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Executive Summary

The cause of the disturbance on June 25, 1998, was a trip of the NSP King-Eau Claire 345kV line at 02:18 CDT along with the prior outage of the Prairie Island-Byron 345kV, which had tripped earlier at 01:34 CDT and could not be reclosed due to a high phase angle across the open breaker. The NSP Operators were focusing on closing the Prairie Island-Byron 345kV line at the time of the subsequent King-Eau Claire 345kV line trip.

The system was in an insecure state following the Prairie Island-Byron 345kV line trip, and not able to withstand the next contingency. The TCEX flow was 1004 MW, and had not been reduced by the NSP System Operators to achieve the safe Operating Guide stability limit of 700 MW prior to the subsequent King-Eau Claire 345kV line trip. Following the King-Eau Claire 345kV trip, the remaining underlying transmission lines out of the Twin Cities area were significantly overloaded and began tripping, and the cascading tripping continued until the entire northern MAPP region was separated from the Eastern Interconnection.

The impact of the disturbance was widespread, affecting the entire MAPP region and the Northwestern Ontario Hydro (OH) system. Northern MAPP separated from the Eastern Interconnection forming several islands, and resulting in the eventual blackout of the Northwestern OH system. In the MAPP region, more than 60 transmission lines tripped, over 4,000 MW of generation was lost, and more than 39,000 customers were affected by the loss of over 300 MW of load. In the Northwestern OH system, all of the tie lines tripped, about 270 MW of generation was lost, and more than 113,000 customers were affected by the loss of 650 MW of load.

No major damage to equipment was reported as a result of the disturbance. The system restoration was accomplished well by the System Operators, with the systems returning to normal within 19 hours after the disturbance began.

The MAPP Operating Standards were violated during this incident. The system was not re-adjusted immediately to a secure operating condition prior to the next contingency. NERC Operating Policies were also violated during the disturbance.

The primary recommendations of this report are:

1. The system must be operated within approved Operating Guide limits.
2. Following a contingency, the system must be returned to a reliable state within the readjustment period allowed in the MAPP Standards. Operating Guides must be reviewed to ensure procedures exist to restore system reliability in the allowable time periods.

3. Operating Guides should not rely on MAPP Line Loading Relief (LLR) procedure, in its current state, when the system is in an insecure state. Other readjustments must be used, and the local Operator must take responsibility to restore the system immediately.
4. Phase angle restrictions that can prevent reclosing of major interconnections during system emergencies should be reviewed and approved by the MAPP Operating Review Subcommittee (ORS). MAPP should seriously consider bypassing synchrocheck relays to permit direct closing of critical interconnections when it is necessary to maintain stability of the grid during an emergency.

List of Report Appendices and Figures

ABBREVIATIONS

AEP	American Electric Power
AGC	Automatic Generation Control
ALT	Alliant Utilities
BEPC	Basin Electric Power Cooperative
CBPC	Corn Belt Power Cooperative
CCS	Coal Creek Station
CP	Cooperative Power
CU DC	Cooperative Power/United Power Association DC line
DPC	Dairyland Power Cooperative
EM	MAPP Emergency Replacement Procedure
FERC	Federal Energy Regulatory Commission
GGS	Gerald Gentleman Station
IES	Alliant Utilities-IES Utilities, Inc.
IORWG	Iowa Operating Review Working Group
IPW	Alliant Utilities-Interstate Power Company
KCPL	Kansas City Power & Light
LES	Lincoln Electric System
LLR	Line Loading Relief Procedure
MAIN	Mid-American Interconnected Network
MAPP	Mid-Continent Area Power Pool
MCN	MAPP Communications Network
MDU	Montana-Dakota Utilities
MEC	MidAmerican Energy Company
MH	Manitoba Hydro
MHEX	Manitoba Hydro Export (See Appendix #4 for definition.)
MP	Minnesota Power
MPC	Minnkota Power Cooperative
MPW	Muscatine Power and Water
NDEX	North Dakota Export (See Appendix #4 for definition.)
NMORWG	Northern MAPP Operating Review Working Group
NORWG	Nebraska Operating Review Working Group
NPPD	Nebraska Public Power District
NSP	Northern States Power Company
NW OH	Northwestern Ontario Hydro System
NWPS	Northwestern Public Service Company
OASIS	Open Access Same Time Information System
OH	Ontario Hydro
OPPD	Omaha Public Power District
OTP	Otter Tail Power Company
RTU	Remote Terminal Unit
SPC	SaskPower
SPP	Southwest Power Pool
SQBT DC	Square Butte DC line
TCEX	Twin Cities Export (See Appendix #4 for definition.)
WAPA	Western Area Power Administration

1. INTRODUCTION

1.1 Description of the Disturbance:

In the early morning of June 25th the MAPP system was operating with heavy transfers east to MAIN and south to SPP. In particular, the sum of the loading on the three 345kV interconnections going east and south from the Twin Cities of Minneapolis and St. Paul, Minnesota were approximately 1578 MW which is near the established transfer limit for the Twin Cities Export (TCEX). At 01:34 CDT a thunderstorm initiated a single line to ground fault on the Prairie Island to Byron 345kV line, a segment of the interconnection from the Twin Cities south to Iowa. The line was carrying 636 MW at the time. While the fault was only temporary, a large standing phase angle across the open line breaker prevented the Northern States Power (NSP) System Operators from manually reclosing the line.

NSP System Operators called for small reductions in the Twin Cities export, but were unable to close the breaker and return the line to service. While this effort was in progress the King-Eau Claire 345kV line was tripped by a single line to ground fault at 02:18 CDT. This is a major interconnection from the Twin Cities to MAIN and is typically the most heavily loaded of the three Twin Cities interconnections. At the time of the trip it was loaded at about 1048 MW, and the TCEX flow was 1004 MW. Loss of this line with the Prairie Island-Byron 345kV line still open represented a subsequent contingency at the export level that existed, and was beyond the capability of the system at that time. 775

Soon after loss of the second 345kV interconnection critical underlying sub-transmission interconnections began to trip due to the overloads caused by the outages of the two 345kV Twin Cities export ties. At 02:21 CDT cascade tripping of the remaining ties between the northern MAPP region and the rest of the eastern interconnection occurred. The separated area consisted of large portions of Minnesota, North Dakota, South Dakota, Montana, and Wisconsin in the U.S. and the Canadian provinces of Manitoba and Saskatchewan. The separation event produced large voltage and frequency excursions, and a number of generating units tripped off line as a result.

The loss of the two 345kV Twin Cities export ties and underlying 115/161kV system, caused the flows on the two interconnections between MAPP and the northwestern Ontario Hydro system to increase substantially. Before the disturbance, both of these tie lines were supplying power to Ontario. These ties both tripped, and their loss initiated a disturbance that led to the tripping of the 230kV ties linking the northwestern Ontario Hydro system to the east. Cascade tripping led to the creation of a northwest Ontario island that was very deficient in generation. Shortly thereafter, most of the load (650 MW) was lost in the region other than a 20 MW island that formed around the Manitou Falls plant.

Frequency in the northern MAPP island increased to about 61 Hz due to the excess generation in the island. The western portion of the island in particular had a large unbalance in load and generation. At about 02:25 CDT, a major DC transmission line linking the western and eastern areas of the island tripped. This overloaded the parallel AC ties, and a cascade of line tripping separated the eastern and western portions of the island. The Manitoba and Saskatchewan systems remained connected to the eastern island, which consisted of most of Minnesota and a small portion of northwestern Wisconsin. The western island consisted of the North Dakota, northern South Dakota, and western Minnesota systems.

After this separation frequency in the eastern island (which included the Twin Cities) settled very close to 60 Hz, and automatic reclosing of a 115kV line in northwestern Wisconsin successfully reconnected the eastern island to the Eastern Interconnection about 3 minutes and 50 seconds after the initial island was formed. This reconnection occurred about 12 seconds after the eastern and western portions of the initial island separated.

Frequency of the western island increased above 63 Hz, and several units tripped on overfrequency. Frequency stabilized between 61 and 62 Hz. Operators reduced generation, and the island was reconnected to the Eastern Interconnection at 03:03 CDT, 41 minutes after the initial separation.

In the U.S., the loss of load was confined primarily to customers near the island boundaries that were tripped during the islanding sequence. Most of these outages were a direct result of the lines tripping or caused by the resulting voltage and frequency oscillations. Approximately 313 MW of load was lost. Service was restored to all customers by 06:45 CDT that morning, although some industrial customers did not achieve full load until the next day. In Ontario, about 650 MW of load was lost. System restoration there began at 03:12 CDT and was essentially complete by 06:45 CDT.

A total of approximately 4,171 MW of generation was lost during the event. This generation was returned to service at various times, but was all available within 12 hours of the event. No major equipment damage was reported.

1.2 Systems/Individuals Who Prepared Report:

This disturbance report was compiled by the Mid-Continent Area Power Pool (MAPP) staff, the following formal MAPP Committees, and representatives from Ontario Hydro (OH):

- Iowa Operating Review Working Group (IORWG)
- Nebraska Operating Review Working Group (NORWG)
- Northern MAPP Operating Review Working Group (NMORWG)

In addition to providing input to this report, Ontario Hydro will issue a separate report addressing their NW System collapse and restoration in more detail.

The complete list of people who contributed to the development of this report is included in Appendix #1.

1.3 Cause and Impact of Disturbance:

The cause of the disturbance was a trip of the NSP King-Eau Claire 345kV line at 02:18 CDT along with the prior outage of the Prairie Island-Byron 345kV line. The Twin Cities Export (TCEX) at the time of the King-Eau Claire 345kV line trip was approximately 1004 MW. The NSP Prairie Island-Byron 345kV line had tripped earlier at 01:34 CDT and could not be reclosed due to a high phase angle across the open breaker. The NSP Operators were focusing on closing the Prairie Island-Byron 345kV line at the time of the subsequent King-Eau Claire 345kV line trip.

The system was in an insecure state following the Prairie Island-Byron 345kV line trip, and not able to withstand the next contingency. The TCEX flow was not reduced by the NSP System Operators to achieve the safe Operating Guide stability limit of 700 MW prior to the subsequent King-Eau Claire 345kV line trip. Following the King-Eau Claire 345kV trip, the remaining underlying transmission lines out of the Twin Cities area were significantly overloaded and began tripping, and the cascading tripping continued until the entire northern MAPP region was separated from the Eastern Interconnection.

The impact of the disturbance was widespread, affecting the entire MAPP region and the Northwestern Ontario Hydro (OH) system. Northern MAPP separated from the Eastern Interconnection forming several islands, and resulting in the eventual blackout of the Northwestern OH system. The affected regions are shown in Figure #1. A significant amount of generation and load was lost during the disturbance. Significant voltage and frequency excursions, heavy transmission loading and power surges also occurred during the disturbance. No major damage to equipment was reported as a result of the disturbance.

1.3.1 Duration of Disturbance, Return to Normal:

The disturbance began on Thursday, June 25, 1998, at approximately 02:18 Central Daylight Time (CDT) following the trip of the NSP King-Eau Claire 345kV line.

The duration of the disturbance and subsequent system restoration until the system was returned to normal operation was approximately 4 hours 27 minutes in Northwestern Ontario, and approximately 19 hours in the MAPP region. All of the transmission, except those lines damaged by the storm, were returned to service by 05:49 CDT in the MAPP region and by 06:00 CDT in Northwestern Ontario. One Dairyland Power Cooperative (DPC) transmission line, damaged by the storm, was returned to service on 6/27/98.

The Ontario Hydro system was restored to normal at about 6:45 CDT with exception of some of the industrial loads. This system restoration started at 3:12 CDT.

The table below shows the times that each of the individual systems began losing transmission, generation, and load, and the subsequent times that each was returned to normal. All times shown are CDT on 06/25/98, unless otherwise noted.

Table 1-Outage Durations (Reported by Systems)

	TRANSMISSION		GENERATION		LOAD	
COMPANY	BEGIN	END	BEGIN	END	BEGIN	END
BEPC	02:22	04:13	02:26	10:01	N/A	N/A
CP	N/A	N/A	N/A	N/A	02:21	14:00
DPC	02:01	06/27/98[1]	N/A	N/A	02:18	03:43
IPW	02:19	03:53	02:22	04:38	02:19	03:44
MDU	02:22	03:08	02:26	13:54	02:22	03:33
MEC	02:22	04:14	02:22	08:41	N/A	N/A
MH	02:21	03:34	02:22	02:51	N/A	N/A
MP	02:21	05:17	N/A	03:03	02:22	06/26/98[2]
MPC	02:27	04:14	02:26	13:54	N/A	N/A
NPPD	N/A	N/A	N/A	N/A	02:22	05:20
NSP	02:18	04:22	02:21	11:15	02:18	03:00
OH	03:12	06:00	03:12	09:35	03:12	06:45
OTP	02:21	05:49	02:21	09:49	02:21	05:49
SPC	N/A	N/A	02:22	03:16	N/A	N/A
UPA	02:25	04:22	02:25	04:45	N/A	N/A
WAPA	02:21	03:35	02:22	03:57	N/A	N/A

("N/A" - Not applicable because no outages were reported)

During the disturbance, several MAPP Members and the MAPP Security Center suspended the Standards of Conduct under FERC Orders 888/889 due to the emergency conditions.

The table below shows the systems that suspended compliance with the FERC Orders 888/889 during the disturbance. The times that the MAPP Members notified the MAPP Security Center of changes or expected changes in the status of compliance with the FERC Orders are shown in [ ]'s.

[1] DPC Alma-Rock Elm 161kV line, which lost 5 structures due to storm, was restored on 6/27/98.
[2] MP's Lake Superior Paper customer was back to 100% load at about 05:00 on 6/26/98.

Table 2-FERC 888/889 Suspension Durations (Reported by Systems)

Company	Time Standards of Conduct Suspended (CDT) [MCN Broadcast]	Time Standards of Conduct Reinstated (CDT) [MCN Broadcast]
NSP	02:23 [02:23]	05:00 [04:32]
WAPA	02:21 [02:32]	04:36 [04:36]
MAPP	02:34 [02:34]	21:00 [21:00]
ALT	02:30 [Not Reported]	05:00 [04:56]
NSP	11:00 [10:18]	18:00 [17:20]

NSP suspended compliance with FERC Orders 888/889 twice during the disturbance. The first was for approximately 2-1/2 hours due to the emergency conditions during the system breakup. The second was later on 6/25/98 for approximately 7 hours due to emergency conditions in NSP's service territory due to loss of generation resulting from the event and a forecasted 1000 MW generation deficit.

WAPA (Upper Great Plains Region) suspended compliance with FERC Orders 888/889 for approximately 2 hours due to the emergency conditions during the system breakup.

Alliant suspended compliance with FERC Orders 888/889 during the disturbance for approximately 2-1/2 hours due to the emergency conditions during the system breakup.

The MAPP Security Center also suspended compliance with FERC Orders 888/889 for approximately 18-1/2 hours due to emergency conditions in the MAPP region during the system breakup and during the subsequent system restoration.

NSP, WAPA, and Alliant posted notice of the emergency suspensions of the Standards of Conduct on the OASIS within the required 24 hours after the emergency.

There is no specific time indication when the MAPP system returned to condition "green". The system condition in the MAPP Security Center remained "yellow" at 21:00 CDT, because the DPC Alma-Rock Elm 161kV line was still out of service with 5 structures down. Even in "yellow" condition, the MAPP Security Center Operator (SCO) on duty considered the MAPP system essentially back to normal at 21:00 CDT, 18 hours and 42 minutes after disturbance started. The Alma-Rock Elm 161kV line was restored to service 2 days later on 6/27/98. System condition "green" was not achieved following this disturbance due to subsequent storm related outages the following day on 6/26/98.

1.3.2 Magnitude of Load Lost, Number of Customers Affected:

In the MAPP region, the disturbance resulted in the loss of approximately 313 MW of load affecting approximately 39,000 customers.

The Northwestern OH system lost approximately 650 MW of load affecting 113,770 municipal and retail customers and 23 direct industrial customers.

The total load lost as a result of the disturbance was approximately 913 MW.

1.3.3 Transmission Losses, Islanding:

The sequence of events (Appendix #5) shows the major transmission lines tripped during the disturbance resulting in the formation of islands. Due to the cascading effect after the loss of Prairie Island-Byron 345kV line and King-Eau Claire 345kV line, numerous AC transmission lines tripped producing separations and islands throughout the MAPP and Ontario Hydro regions as shown in Figure #1.

Figure #2 shows the major transmission lines that tripped in the MAPP area and identifies the separations and islands formed in MAPP during the disturbance. In the figure, the black dots identify the lines that tripped during the initial separation between northern and southern MAPP, starting between Minnesota and Wisconsin, forming the Minnesota/Manitoba/North Dakota/Saskatchewan island. They also show the lines into MAPP that tripped separating the Northwestern Ontario Hydro system from MAPP. The red dots identify the lines that tripped during the subsequent separation between North Dakota and Minnesota forming the North Dakota island.

In the MAPP AC transmission system eight (8) 345kV lines, thirteen (13) 230kV lines, eight (8) 161kV lines, fourteen (14) 115kV lines, and at least nineteen (19) 69kV lines were lost. The Ontario Hydro Northwestern system was also severely affected by the disturbance. After losing the ties with MH and MP at 02:21 CDT, the NW Ontario Hydro system collapsed approximately 2 minutes later. The affected substations in NW OH are shown in the one-line diagram in Figure #3.

The disturbance also affected the DC lines in the MAPP region. Pole 1 of the CU DC line was manually tripped in an attempt to reduce the CU DC line power flow. This action increased the AC voltage at the Coal Creek Station and 28 seconds later CU pole 2 tripped on an overvoltage protection. Both poles were lost from 02:25 to 03:45 CDT. The Square Butte DC pole 2 also tripped from an over-frequency protection and was out from 02:25 to 03:48 CDT. The CU DC line tripping caused a separation between North Dakota and Minnesota forming the North Dakota island. Once North Dakota was separated from the larger island, the frequency in the Minnesota area quickly dropped to near 60 Hz (as shown in Figure #11) allowing a rapid automatic reconnection of the Minnesota/Manitoba/Saskatchewan island to the Eastern Interconnection

During the disturbance, the system separations formed the following islands: (See Figure #1).

- Separation between Minnesota and the Western Wisconsin system at 02:21:31 CDT.
- Separation of Northwestern Ontario Hydro from Manitoba and Minnesota at about 02:21:55 CDT and total collapse of the Northwestern OH system at 02:22:04 CDT when the East-West ties tripped.
- Formation of the Minnesota/Manitoba/North Dakota/Saskatchewan island at 02:22:09 CDT
- Formation of the North Dakota island at 02:25:47 CDT.

Minnesota, Manitoba, Saskatchewan and Western Wisconsin were tied back together at 02:25:59 CDT when the Ironwood-Park Falls 115kV line automatically reclosed about 12 seconds after the formation of the North Dakota island.

The North Dakota island was reconnected to the Eastern Interconnection at about 03:03:39 CDT when the Bismarck-Glenham 230kV line was manually closed.

The frequency in each of the islands that formed, compared to the frequency in the southern MAPP system that remained tied to the Eastern Interconnection, is shown in Figures #4 and #5.

1.3.4 Significant Frequency and/or Voltage Excursions:

Large frequency excursions took place when the initial Minnesota/Manitoba-Saskatchewan/North Dakota island was formed. The maximum frequency excursion, observed by the Dynamic System Monitor (DSM) at the Arrowhead 230kV bus, was 61.11 Hz and the minimum 59.48 Hz. MP also reported a maximum frequency of 61.2 Hz.

When this island formed, the southern MAPP system that remained tied to the Eastern Interconnection also experienced significant frequency excursions. Frequency reached values from 60.04 Hz down to 59.91 Hz in the DPC area. IPW reported similar values (minimum 59.925 Hz and maximum of 60.015 Hz).

In Nebraska, NPPD reported excursions from 59.5 Hz to 60.066 Hz. In Iowa, MEC recorded frequency excursions from 59.74 Hz to 60.04 Hz.

Following the separation of North Dakota from the initial island, the maximum frequency excursion recorded was 62.2 Hz. Following several generating unit trips, the North Dakota island frequency oscillated around approximately 61.3 Hz for about 30 minutes. An undetermined action occurred at about 02:53 CDT, and the North Dakota island frequency began to ramp down to 60.9 Hz over the next 6 minutes. Another change occurred at about 02:59 CDT, at which time the frequency began ramping down at a faster rate to 60.1 Hz at about 03:03 CDT, just prior to the reconnection of the North Dakota island to the Eastern Interconnection.

In the Northwestern Ontario Hydro system, the frequency went as low as 55 Hz. This initiated under-frequency load shedding protection schemes. However the system voltage continued to decay and the system collapsed.

Significant voltage excursions were recorded throughout the system during the disturbance.

Outside of the islands that formed, voltage excursions down to 0.87 p.u. were recorded at the Barron 161kV bus (northwestern Wisconsin). Alliant-IPW reported voltage excursions between 0.838 p.u. to 1.144 p.u.

The pre-disturbance operation values at Arrowhead 230kV bus (near Duluth Minnesota) were close to 138.8kV (phase to ground). During the disturbance, the voltage reached values as high as 142kV, and as low as 132kV. The voltage excursions at the King 345kV bus (just northeast of the Twin Cities) reached values from 335.45kV up to 377kV (the operational values pre-disturbance were about 350kV).

In the North Dakota island, voltage increased substantially after the separation from Minnesota. The Jamestown 115kV bus (central North Dakota) voltage was close to 118kV before the disturbance. Following the separation, the maximum voltage excursion was 128kV, and the minimum 113kV.

Significant voltage oscillations were recorded throughout the MAPP system during the approximately 5 minutes that the North Dakota system was asynchronous with Minnesota and still connected by one 115kV tie. The voltages at buses far from the tie line that the systems were slipping across can be seen in Figures #15 and #16 which show the King 345kV bus voltage in Minnesota and the Center 230kV bus voltage in central North Dakota. As seen in Figure #13, the voltages in North Dakota were oscillating by up to 8kV on central North Dakota 230kV buses.

2. CONCLUSIONS

2.1 Operating Conditions at time of Disturbance

2.1.1 MAPP/Northwestern OH Systems were within Operating Guide limits prior to initial outage

Prior to the initial outage of the Prairie Island-Byron 345kV line, the MAPP and Northwestern Ontario Hydro (OH) systems were operating within Operating Guide limits. However, the MAPP to MAIN interface was heavily loaded. The TCEX flow[3] was at its stability limit (with TCEX generation sensitivity adjustments applied) at 01:15 CDT. The Eau Claire-Arpin 345kV line flow was also at its allowable flow limit, and initial NERC TLR schedule collections had been requested earlier at 23:24 CDT on 6/24/98 to prepare for possible curtailments.

A severe thunderstorm was moving across the Twin Cities (Minnesota) area towards the east into Wisconsin prior to the disturbance.

2.1.2 Prairie Island-Byron 345kV line trip set up insecure operating condition prior to disturbance

The NSP Prairie Island-Byron 345kV line tripped at 01:34 CDT following a phase A to ground fault.

The high TCEX flow conditions during the early morning hours of 6/25/98 coupled with the trip of the Prairie Island-Byron 345kV line at 01:34 CDT, resulted in a violation of an Operating Guide limit or NERC Operating Security Limit[4] as defined by the latest NERC Operating Policy 2 (effective 7/1/98). Following the trip of the Prairie Island-Byron 345kV line, the system was operating in an insecure state because the TCEX flows were higher than the TCEX limit, and was not protected against the next contingency. There are no automatic readjustment[5] actions in place for any of the three 345kV lines comprising the TCEX interface.

2.1.3 NSP Operators focused on restoration of Prairie Island-Byron 345kV line

Following the trip of the Prairie Island-Byron 345kV line at 01:34 CDT, NSP Operators reported that they were focusing on restoring the line as quickly as possible. The actions taken by the NSP Operators in this timeframe are

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[3] Twin Cities Export (TCEX) is the sum of flows on the NSP lines out of the Minneapolis/St Paul (Twin Cities) area: Eau Claire-Arpin 345kV line, the Byron-Adams 345kV line, and the Wilmarth-Lakefield 345kV line. (See Appendix #4)

[4] NERC Operating Manual, Policy 2, Operating Security Limit Definition: "Operating Security Limits define the acceptable operating boundaries."

[5] MAPP Reliability Handbook, MAPP Operating Standards, Section 9.4.1 "Definitions".

outlined in the sequence of events. The line was energized successfully from one end, indicating that the line was okay. If the line could have been closed, the system would have been restored to a secure condition. However, the line could not be closed because there was an approximate 41-42 degree phase angle across the open line, and the protective lockout at Byron Substation prevented closing of the line for angles > 40 degrees. NSP Operators requested MAPP LLR schedule curtailments, in relatively small amounts, which were targeted at reducing the phase angle by 1-2 degrees. However, this small angle reduction was not achieved prior to the next major contingency of the King-Eau Claire 345kV line trip.

The NSP system load and generation during the 01:34 to 02:18 CDT timeframe, was relatively constant. Most of NSP's load that was lost as a result of the storm was lost before the Prairie Island-Byron 345kV line tripped. Sherco units #1, #2, and #3 were left on AGC during the attempts to lower Prairie Island generation and reclose the Prairie Island-Byron 345kV line. Sherco generation increased about 150 MW over the same time frame that Prairie Island generation was decreased by about 60 MW as a result of the AGC action.

NSP has since indicated that the phase angle limit for the manual re-close at Byron on the Prairie Island-Byron 345kV line can likely be increased to 50-55 degrees, from the existing limit of 40 degrees. If this change would have been in-place on June 25th the Prairie Island-Byron 345kV line could have been manually re-closed before the storm hit the Eau Claire area and the next major contingency occurred.

2.1.4 Twin Cities Export (TCEX) Prior Outage Operating Guides exceeded

Following the initial outage of the Prairie Island-Byron 345kV line, the TCEX flow was still approximately 1000 MW at 02:15 CDT (42 minutes after the line trip), which is above the Operating Guide limit. The MAPP approved Operating Guide for the Prairie Island-Byron 345kV outage limits the TCEX to 700 MW to protect system stability. The Operating Guide also shows that TCEX can be limited further by post-contingent steady state transmission loading and voltage limits, under some conditions. The post-contingent steady state transmission loading and voltage limits were monitored by the NSP Operators using on-line analysis and dynamic line ratings. Based on the operating conditions at the time, the NSP Operators determined that no excessive post-contingent overloads existed.

The TCEX flow was approximately 200 MW above the adjusted stability limit, even after the sensitivity adjustments to the TCEX limit based on Sherco generation levels and local Twin Cities metro area generation patterns were applied. This can be clearly seen in Figure #17, which shows the TCEX flows during the day on June 25th, and the TCEX limit as calculated by the NSP

Operators. The NSP Operator focus was on reducing the phase angle to allow reclosing of the Prairie Island-Byron 345kV line, which had been successfully energized from both ends, and not on reducing flows to reduce TCEX to the prior outage limit.

2.1.5 TCEX Sensitivity adjustment not demonstrated for Prior Outages

The sensitivity adjustment to the TCEX stability limit, based on Sherco generation levels and local Twin Cities metro area generation patterns, had not been demonstrated for prior outage conditions or approved by the appropriate MAPP Committees for use in the TCEX prior outage Operating Guides.

2.1.6 TCEX flow not reduced in time to sufficiently protect for next contingency

During high TCEX flow conditions, such as those that were present prior to the disturbance, the TCEX flows will be above Operating Guide limits immediately following a trip of one of the 345kV lines comprising the TCEX interface until the system can be readjusted to protect for the next contingency. The MAPP Design Standards and MAPP Operating Standards[6] require the control area operator to readjust the system immediately to restore the reliability of the system. The MAPP Design Standards allowable readjustment period is the 10 minutes immediately following the contingency[7]. The MAPP Operating Standards definition of the readjustment period is somewhat broader regarding the time periods allowed to restore the facility loadings[8] to acceptable levels. This MAPP requirement is more stringent than the requirement in the NERC Operating Standards[9], effective 7/1/98, which require the control area operator to readjust the system to within Operating Security Limits as soon as possible, but not longer than 30 minutes following the initial contingency.

In this case, no significant system readjustments to protect for the next major contingency had been implemented within 44 minutes after the initial 345kV line trip. The primary reason was the NSP Operator's expectation that the Prairie Island-Byron 345kV line could be returned to service once the phase angle could be reduced sufficiently. The King-Eau Claire 345kV line tripped approximately 44 minutes after the initial outage of the Prairie Island-Byron

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[6] MAPP Operating Standards & MAPP Design Standards (Section 9, MAPP Reliability Handbook): Readjustment – "Manual or conventional automatic action taken immediately following a disturbance to restore the Reliability of the system under conditions then existing. Permissible Readjustments for operating studies are listed in the Appendix."

[7] MAPP Design Standards (Section 9, MAPP Reliability Handbook), Appendix II, Permissible Readjustments: "The Readjustment period is the 10 minutes immediately following a contingency in which actions can be performed to address the contingency."

[8] MAPP Operating Standards (Section 9, MAPP Reliability Handbook), Appendix, Permissible Readjustments: "The Readjustment period is the time immediately following a contingency in which actions can be performed to keep facilities within emergency loading limits and emergency voltage limits. The length of the readjustment period will be 10 minutes to restore voltage levels to acceptable voltage levels. The readjustment period to keep loading within emergency limits is normally 10 minutes, however, this time period may be extended to the length of time the member has agreed the overloaded facility can exceed its normal rating when originally defining the emergency loading limits for the facility."

[9] NERC Operating Manual, Policy 2, Standard 2 (January 5, 1998)

345kV line, before the system conditions had been readjusted sufficiently to allow the system to survive this subsequent line trip. If the TCEX flow would have been reduced to the Operating Guide limit of 700 MW prior to the King-Eau Claire 345kV line trip, the disturbance may have been prevented.

2.1.7 MAPP Security Center Operator (SCO) not sufficiently aware of severity of system conditions prior to disturbance

The MAPP SCO was aware of the Prairie Island-Byron 345kV outage, and was working with the NSP Operator prior to the disturbance to attempt to reduce the TCEX to allow reclosure of the line.

NSP has indicated that the severity of the current system conditions, and the fact that the system conditions were beyond stability limits, was not communicated effectively to the MAPP SCO. The MAPP Security Center (SC) did not have the adjusted TCEX limit available, as calculated and used by the NSP Operators, and therefore could not determine precisely if the TCEX was above the Operating Guide limit, or when it was adjusted back within the Operating Guide limit.

However, the MAPP SCO should have been aware of the TCEX Operating Guide limit of 700 MW for the Prairie Island-Byron 345kV prior outage. Also, based on the high TCEX value at the time, the MAPP SCO should have been aware of the urgency of reducing TCEX for that condition because system instability was probable for a subsequent contingency.

2.2 Procedures utilized by NSP Operators for reducing Twin Cities Export (TCEX)

2.2.1 MAPP Line Loading Relief (LLR) Procedure requests by NSP Operators not large enough to reduce TCEX sufficiently to achieve Operating Guide limits or reduce phase angle sufficiently

With the Prairie Island-Byron 345kV line prior outage, the TCEX value was approximately 300 MW above the Operating Guide limit of 700 MW at 02:15 CDT (191 MW above the adjusted TCEX limit of 813 MW-which has not been demonstrated as outlined in section 2.1.5). The NSP Operators requested 50 MW of relief on the Eau Claire-Arpin 345kV line at 01:51 CDT in an attempt to reduce the standing phase angle on the open line. The 50 MW request is the standard increment typically requested by NSP for TCEX curtailments. Approximately 246 MW of schedule curtailments were subsequently requested by the MAPP SCO, and implemented by the Member systems. The NSP Operators later requested an additional 100 MW of relief on the Prairie Island-Byron 345kV line (which was still open) at 02:10 CDT. No schedule curtailments were requested by the MAPP SCO for the 100 MW LLR request prior to the subsequent trip of King-Eau Claire 345kV line at 02:18 CDT.

The total relief obtained on the TCEX interface through the MAPP LLR procedure prior to 02:18 CDT when the disturbance occurred was 50 MW, which was insufficient to reduce the phase angle on the open Prairie Island-Byron 345kV line to allow it to be reclosed or to reduce the TCEX flow to the prior outage Operating Guide limit of 700 MW.

2.2.2 MAPP Line Loading Relief (LLR) Procedure, in its current state, cannot be used effectively for emergency conditions where the system is in an insecure state

The MAPP LLR procedure cannot be relied upon to implement export reductions to achieve a secure operating condition within the readjustment period allowed in the MAPP Design or Operating Standards, or even within the maximum 30 minute readjustment period allowed in the NERC Operating Standards. The LLR process requires several manual steps, which are time consuming, and the execution time of the LLR program itself varies and can be lengthy. In addition, implementation of the procedure for schedule curtailment requests requires additional time, and a significant amount of communications between the MAPP SCO, MAPP Member Operators, Marketers slows down the implementation of the requested schedule curtailments. It can be difficult to achieve requested schedule curtailments quickly.

In the case of the first LLR request made by NSP for 50 MW at 01:51 CDT, the request was made approximately 16 minutes after the Prairie Island-Byron 345kV line tripped. The MAPP SCO responded to the request within 3 minutes, and requested the MAPP systems to implement schedule curtailments as soon as possible, or by 02:00 CDT at the latest. This introduced another 6 minutes of delay. Factoring in a minimum 5 minute schedule change ramp, the total time to implement the first 50 MW of relief was approximately 30 minutes. The MAPP SCO has indicated that the timing of this particular LLR request was ideal, and that other LLR requests may take significantly longer. The MAPP SCO has also indicated that MAPP Members routinely call and question the requested schedule curtailments, which may further delay implementation of the schedule curtailments.

The MAPP LLR procedure is an effective tool used by the MAPP Members to prevent overloading facilities before the system reaches an insecure state, and can be used in those "emergency" type situations where it can provide required relief within the allowable time constraints. Any Member of the MAPP Regional Transmission Committee (RTC) that owns transmission facilities in the RTC region may request MAPP to initiate the LLR procedure if it determines that one of its facilities is presently overloaded or may overload (i.e., exceed either its normal or emergency rating).

The goal of the MAPP LLR procedure is to unload transmission elements in a manner that does not jeopardize the reliability of the bulk transmission system and is fair to all transmission owners and transmission users. The LLR procedure
identifies transactions, on a priority basis, which are impacting a facility which is at or near its safe operating limit, and identifies schedule curtailments to achieve the requested relief to reduce the loading of the facility to normal levels.

2.2.3 Other Permissible Readjustments must be used to restore system reliability within the allowable time criteria

The MAPP LLR procedure cannot be used effectively to readjust the system back to a secure operating condition following contingencies, because it cannot be implemented quickly enough to restore the reliability of the system. Other system readjustments, as allowed for in the MAPP Operating Standards[10], should have been implemented following the trip of the Prairie Island-Byron 345kV line. These permissible readjustments include: generation rejection, generation reductions, reduction of economy exports to the extent possible within the readjustment period, adjustment of Load Tap Changing (LTC) transformers, phase shifters, or HVDC flows.

The NSP Operators implemented generation reduction at the NSP Prairie Island plant, but the reduction achieved was insufficient to reduce the TCEX within the Operating Guide limit prior to the next contingency (-63 MW from 01:13 to 02:17 CDT). This reduction was offset by generation increases in the control area due to AGC response.

2.2.4 MAPP Line Loading Relief (LLR) Procedure failed for request for relief on the open Prairie Island-Byron 345kV line

The second NSP LLR request for 100 MW of relief on the Prairie Island-Byron 345kV line (which was still open) was ineffective. The powerflow model used by the LLR process includes current outages in the MAPP system, and already had the Prairie Island-Byron 345kV line modeled out of service. The program, which determines the schedule curtailments, did not warn the MAPP SCO that the line (for which relief had been requested) was already out in the model, and therefore no schedules would have a power flow distribution factor (DF) across the line, and no schedules were identified for curtailment. The LLR schedule curtailment request, which was broadcast to the MAPP Member Operators, requested no schedule curtailments due to this shortcoming in the LLR program.

[10] MAPP Operating Standards, Permissible Readjustments.

However, even if the second LLR request had been processed properly, there would have been no time for MAPP Member Operators to implement any schedule curtailments prior to the time the next major contingency occurred.

2.2.5 Operating Guides not available for reduction of high phase angle across open Prairie Island-Byron 345kV line

The NSP Operators did not have formal procedures or Operating Guides available to identify specific actions to effectively reduce the phase angle on the open Prairie Island-Byron 345kV line. The NSP Operators were attempting to reduce the large phase angle with LLR requests and local generation reductions at Prairie Island (a 63 MW reduction between 01:13 CDT and 02:17 CDT). These actions were not effective in reducing the phase angle by the 1-2 degrees needed to allow the line to be reclosed.

The currently approved TCEX Operating Guide limits allow flows that exceed the post-contingent phase angle reclose limits on the Prairie Island-Byron 345kV line, and the King-Eau Claire-Arpin 345kV line. Therefore, whenever these lines trip at high TCEX conditions system readjustments will be required to allow reclosure.

2.3 Line tripping/Islanding which occurred during disturbance

2.3.1 The formation of the islands occurred as expected from historic studies, but islands did not have good load/generation balance, and the North Dakota island was not cleanly formed

The initial MAPP Minnesota/Manitoba/North Dakota/Saskatchewan island which formed during the disturbance occurred as expected. The transmission lines which tripped, were in the general vicinity of the region expected to open for an out-of-step condition between northern and southern MAPP. The Northwestern OH system islanding, due to the power surges from MAPP, would also be expected for this disturbance.

The subsequent separation of North Dakota from the eastern portion of the MAPP Minnesota/Manitoba/North Dakota/Saskatchewan island was initiated by loss of the CU HVDC line from a protection operation. The trip of the DC line resulted in a sudden increase in power on the AC system. The tripping of one Coal Creek Station unit immediately after the pole tripped was not enough to mitigate the DC line loss. The power surge caused tripping of the east-west ties between the North Dakota area and Minnesota, which separated the two systems.

The North Dakota island did not cleanly form, and the North Dakota system slipped against the Minnesota area at approximately 1.5 Hz, until the remaining

Grant County-Douglas County 115kV tie line between the two areas tripped due to a fault. The slipping occurred for approximately 5 minutes (from 02:26 CDT to 02:31 CDT) across this asynchronous connection, and was observable in the voltages throughout the MAPP system. This remaining tie line, and the other line sections further west and east of this line, did not trip due to out-of-step blocking on the distance relays. The Grant County-Douglas County 115kV line has been identified as the line which should be tripped during an out-of-step condition from historic studies, but was not enabled to trip for this condition.

There was no reported equipment damage to the terminals that tripped during any of the islanding. As noted in Section 5.2.3, there was damage to an out of service wave trap at the Douglas County substation, but the cause may not be related to this disturbance.

The islanding which occurred was due to normal distance protection tripping at the locus of the out-of-step condition between the regions. The islanding was not forced, and there was no coordinated out-of-step protective scheme in place to open the system at pre-determined locations. There is out-of-step blocking on a number of transmission lines between North and South Dakota to prevent multiple lines and lines with inadequately rated terminal facilities from tripping during an out-of-step swing.

Based on the lightly loaded early morning system conditions at the time of the disturbance, the northern MAPP area had a significant amount of excess generation on-line, which was being exported into southern MAPP and beyond MAPP. Therefore, when the disturbance occurred, the northern MAPP islands had a significant amount of excess generation on-line compared to the load in the islands, as evidenced by the extremely high frequency in those islands.

The Northwestern Ontario system, prior to the disturbance, was importing about 370 MW across the Manitoba, Minnesota, and eastern OH tie lines to support the area load. The NW Ontario island was generation deficient. As a result it suffered an excessive drop in the voltage and frequency prior to the total area collapse.

The generation unit tripping in the high frequency northern MAPP islands was primarily due to over-frequency protection, or due to governor action based on the exceedingly high frequency. Fortunately, the sequence of unit tripping, and apparent band of protective settings on the units in northern MAPP, prevented an excessive amount of generation from tripping and avoided a possible blackout in these islands. No formal studies have been performed to evaluate the coordination of the generation protection in the northern MAPP areas.

There was a significant decrease in MH HVDC power during the timeframe from the beginning of the disturbance, through initial island formation, until before the
split of the initial Minnesota/Manitoba/North Dakota/Saskatchewan island into two parts. This reduction was approximately 1200 MW, which certainly contributed to limiting the over-frequency in the initial island. The reduction in DC power included automatic DC reductions following the Kenora-Whiteshell 230kV #1 line (K21W) trip and from the Forbes DCAR relay, and further local DC reduction due to trip of Bipole 2 Valve groups 31 and 42 by over-frequency protection.

Immediately following the islanding of North Dakota, a large amplitude low frequency oscillation occurred in the North Dakota island. The dynamic system monitor at the Square Butte Center converter station (ND island) recorded an average value of 61.47 Hz with an oscillation frequency of 0.15 Hz for this event. The peak value of the oscillation reached 61.9 Hz. The oscillation was sustained and lasted for 30 seconds. At this time, both the cause and mitigating event are unknown. (See details in Figure #16)

2.3.2 The protective line tripping was correct during the disturbance; however, some of the line tripping/non-tripping was undesirable

The line tripping which occurred during the disturbance was correct. No relay mis-operations occurred.

However, some of the line tripping which occurred during the disturbance was undesirable. For example, the Raun-Ft Calhoun 345kV line in eastern Nebraska and the Raun-Lakefield 345kV line in northwestern Iowa tripped near the same time as the Wilmarth-Lakefield 345kV line tripped on the out-of-step condition. These two line trips in Iowa and Nebraska were undesirable, and appear to have tripped on the out-of-step swing along with the Wilmarth-Lakefield 345kV line. There is no out-of-step blocking on these southern 345kV lines. The Neal unit tripping (1012 MW total), which occurred in the southern MAPP system that remained connected to the Eastern Interconnection, may have been avoided if these additional 345kV line trips had not occurred.

Also, as described in 2.3.1 above, the non-tripping of the Grant County-Douglas County 115kV line for the out-of-step condition between North Dakota and Minnesota was undesirable, and resulted in approximately 5 minutes of slipping between the two asynchronous regions.

The operation of the Forbes DCAR relay, which initiated a 340 MW MH DC reduction, was "as designed but not as intended". The design did not anticipate operation of the relay for the unusual condition that occurred. Operation for similar local conditions at Forbes, but for different system circumstances, would likely be undesirable.

2.3.3 The tripping of the HVDC lines between North Dakota and Minnesota was undesirable

One or both poles of the two HVDC bipole lines between North Dakota and Minnesota were lost during the disturbance.

Both poles of the CU DC line were lost. CU DC Pole 1 was tripped manually by the UPA Operator at 02:25:14 CDT due to high loading and oscillations observed. The UPA Operator saw an increase in the bipole loading (due to the supplemental control response to the high island frequency), but did not fully understand why this occurred at the time. Continuing alarms associated with the disturbance at the Coal Creek RTU (at the rectifier end in North Dakota) also prevented any control actions there, so the supplemental damping controls could not be disabled. Prior loading of both Poles was 540 MW (where normal pole loading is 500 MW). CU DC Pole 2 then tripped properly on voltage stress protection at 02:25:42 CDT. The tripping of the bipole caused the separation of North Dakota from the Minnesota/Manitoba/Saskatchewan area due to the power surge on the parallel AC transmission lines between North Dakota and Minnesota. As seen in Figure #24, the tie lines between North Dakota and Minnesota were not significantly loaded prior to the trip of the CU DC line. Only one of the two Coal Creek Station units was tripped for the bipole trip, due to the unit tripping armed prior to the disturbance. The impact of the DC tripping on the Minnesota frequency is shown in Figure #11.

The Square Butte DC Pole 2 tripped on overfrequency protection at 02:25:44 CDT, when the North Dakota island frequency reached 62.2 Hz. This trip did not contribute to the North Dakota separation as it occurred after the islanding and was due to the overfrequency condition caused by the separation. The prior loading of the pole was 125 MW. Since the remaining pole ramped immediately to 250MW, which was the initial bipolar loading, the North Dakota island load-generation balance was not affected by the trip. There were no problems encountered with the Square Butte supplemental damping controls as they were disabled at the time of the disturbance.

2.3.4 Automatic Generation Controls (AGC) were disabled during islanding

The affected Control Area Operators correctly disabled AGC on a temporary basis during the islanding.

For the WAPA (Upper Great Plains Region) Control Area, which was split across the island boundaries, AGC was suspended at 02:10 CDT by automatic action based on the frequency deviation. WAPA Operators attempted to resume AGC at 02:23 CDT on Tie Line Bias, but this was unsuccessful. Control was switched to constant frequency at 02:59 CDT and back to Tie Line Bias at 03:06 CDT following the restoration of the North Dakota system to the

Eastern Interconnection. The Oahe plant was placed back on normal AGC control at 03:17 CDT.

The Otter Tail Power Company (OTP) Control Area was within the North Dakota island and lost all three units capable of AGC by 02:26 CDT. The regulation service dynamic schedule with Manitoba Hydro was turned off at 02:30:11 CDT because the OTP control area was separated from the MH control area at 02:25:42 CDT and remained off until 02:50:47 CDT. However, the tie line between the control areas was not returned to service until 03:25 CDT when the Letellier-Drayton 230kV line was energized. Thus, the OTP control area lost their AGC capability during the islanding. Also, the regulation service dynamic schedule was restored prior to the North Dakota island being resynchronized with the Eastern Interconnection.

For the United Power Association (UPA) Control Area, AGC tripped off-line at about 02:22 CDT due to sudden frequency deviation. AGC was returned to normal later in the morning when the system was restored.

For the Northern States Power Company (NSP) Control Area, Sherco units #1, #2, and #3 were on AGC prior to the disturbance. After Sherco #3 tripped at 02:25 CDT, the NSP Plant Operators switched Sherco units #1 and #2 into manual control mode, effectively disabling the AGC.

The Manitoba Hydro (MH) System Control Centre (SCC) tripped off AGC at 02:26 CDT due to the disturbance, and returned AGC to normal at 02:41 CDT.

2.3.5 The MAPP Security Center Operator (SCO) and MAPP Member Operators were not sufficiently aware of the system conditions or scope of the islanding

There was insufficient transmission line status and frequency metering available at the MAPP Security Center (SC) for the MAPP SCO to determine the status of the MAPP system during the disturbance. The single frequency meter available at the MAPP SC failed to indicate the proper local Twin Cities frequency during the disturbance. The MAPP SCO did not have adequate information to advise Member Operators regarding the system islanding. This lack of a full picture of the MAPP system conditions also prevented the MAPP SCO from being able to advise Members Operators regarding whether they should attempt to supply MAPP Emergency Energy Replacement (EM) schedules which were requested by Members that lost generation while the system was still separated. The WAPA MCN broadcast at 02:32 CDT appears to have been the first indication to many Member Operators that the system was islanded.

The Member Operators have indicated they were busy addressing issues in their local systems. There was very little communication between the MAPP

Member Operators, and few replies to requests for information by Member Operators, over the MAPP Communications Network (MCN) during the disturbance.

2.3.6 The MAPP MCN functioned well during disturbance, but was not utilized effectively

The MAPP Security Center Operator (SCO) and MAPP Member Operators have indicated that the MAPP Communications Network (MCN) functioned well during the disturbance, especially based on the large volume of data (primarily related to MAPP EM calls).

However, the MCN was not utilized by MAPP Member Operators as effectively as it could have been. Several MAPP Member Operators requested information from all the other Operators to help determine the conditions of the system, but did not receive replies. The large volume of information on the MCN (primarily EM Requests) may have made it difficult to review all the messages.

2.3.7 Response of Generating Units to High Island Frequency

Very little data is available on generating unit performance while operating islanded. Looking at the frequency chart in Figure #5 for the Minnesota/-Manitoba/North Dakota/Saskatchewan island that formed at 02:21 CDT, it can be seen that, after an initial overshoot, frequency went to about 60.75 Hz. At that point frequency started to increase and over the next 2 _ minutes there was a steady ramp to about 61 Hz. The trip of the Sherco 3 unit caused the frequency to stabilize at about 60.8 Hz.

After forming at 02:25 CDT, the North Dakota island operated for about 40 minutes before being resynchronized to the Eastern Interconnection. This island had a greater relative unbalance between generation and load, and stabilized at a frequency of about 61.3 Hz, higher than the initial island. Based on what data is available and the island frequency charts, it appears most generating plant turbine governors properly reduced output in response to the conditions that resulted when the island formed with excess generation. As shown in Figure #5, frequency was very stable in the North Dakota island for the thirty-minute period from initial formation until Operators began reducing frequency. This indicates that the units that survived the initial disturbances were quick to stabilize at an island frequency approximately two percent higher than normal. One unit that reported questionable performance was Young 2, which initially reduced but then rapidly returned to its pre-disturbance generating level.

The systems reported no specific Operator actions taken to reduce the extremely high frequency of about 61.3 Hz in the North Dakota island during the first 30 minutes after the island was formed. This sustained high frequency caused the units in the island to operate in an overspeed condition for an extended period of time. Operation in these conditions can result in damage or loss of life to steam unit turbines. No specific damage was reported by the systems. However, several systems are still evaluating the impacts of the high frequency operation and possible loss of life to their steam turbine units.

2.4 System Restoration

2.4.1 The system restoration was delayed due to lack of knowledge of system conditions, but overall was accomplished well by the Operators

MAPP Member Operators have indicated that they delayed restoration of certain tie lines and generation units based on a lack of sufficient information about the current MAPP system conditions. Improved communications between Operators in the islands would have facilitated quicker restoration of the system.

However, the overall system restoration both in the MAPP area and the NW Ontario area was accomplished with very few problems based on the severity of the disturbance and the number of transmission and generation facilities that tripped.

2.4.2 The automatic reclosing on the lines in Wisconsin/Minnesota assisted the restoration

The Ironwood-Park Falls 115kV line reclosed at 02:25:59 CDT, approximately 12 seconds after the North Dakota area separated from the Minnesota, Manitoba, and Saskatchewan area. This line had tripped approximately 4-1/2 minutes earlier and the automatic recloser closed the line once it was synchronized. This automatic line closure reconnected the Minnesota, Manitoba, and Saskatchewan island to the Eastern Interconnection. The remaining open lines between Minnesota and the Eastern Interconnection then quickly reclosed automatically. This automatic reclosing significantly shortened the duration of the Minnesota, Manitoba, and Saskatchewan island separation.

2.4.3 MAPP Security Center Operator (SCO) Request for Time Error Correction during disturbance

The MAPP SCO requested a Time Correction at 02:38 CDT to attempt to arrest the frequency decline observed on the system. The time error (TE) at the time was –4.65 seconds, so the request was acceptable in that respect. The time error was implemented in the Eastern Interconnection at 03:00 CDT, and terminated at 04:00 CDT. The frequency of the Eastern Interconnection improved after the time correction was implemented, and the North Dakota island was able to be restored at 03:03 CDT.

The MAPP SCO has indicated that he did check with NERC to verify there were no system problems outside of MAPP prior to calling for a Time Correction.

The frequency of the Eastern Interconnection was low (approximately 59.95 Hz) during the disturbance due to the loss of a significant amount of generation in MAPP and the separation of northern MAPP. The control areas that were deficit of generation due to unit tripping or loss of schedules from northern MAPP did not implement load shedding to restore the system frequency.

2.4.4 OH experienced high voltages during restoration of NW Ontario system

Ontario Hydro experienced high voltages on the NW Ontario transmission system as it was restoring the system from black out conditions. To control the voltage it was necessary to coordinate load and transmission restoration.

2.4.5 SCADA sync scope capability was effectively used to reconnect the North Dakota island

The North Dakota island was reconnected to the Eastern Interconnection at 03:03:39 CDT when WAPA closed the Bismarck-Glenham 230kV line using their automatic Synchro-Check System. This system automatically compares the voltage magnitude, voltage difference, phase angle, and phase angle rate of change across an open breaker prior to closing. If all of these values are within limits, breaker closure is accomplished. If the limits are exceeded, the WAPA Dispatcher is provided with a dynamic display of the incoming and running voltages and phase angle, via the SCADA system. Manual voltage and generation adjustments can then be performed until the values are within limits. This capability allowed the WAPA Dispatcher to restore the line remotely via SCADA.

2.5 SCADA/Metering/Communications operation during disturbance

2.5.1 Several MAPP Members and Ontario Hydro had SCADA, Metering, and/or RTU problems during the disturbance

Several MAPP Members experienced SCADA problems during and following the disturbance. Otter Tail Power Company (OTP) indicated that their system lost data such as alarms and messages. The United Power Association (UPA) System Operator experienced difficulty in completing control actions at a critical substation when the disturbance caused several points to continuously cycle in and out of alarm. Dairyland Power Cooperative (DPC) indicated that their Apple River RTU communications failed during the disturbance. Omaha Public Power District's (OPPD) EMS system, due to prioritization of tasks during the heavy alarm/event loading, failed to record frequency data from 02:22 to 02:23:30 CDT. MEC lost SCADA data due to the large number of alarms that occurred. Ontario Hydro also indicated that their system lost some data.

The disturbance caused a significant amount of data to be processed by the SCADA systems. WAPA indicated that their SCADA system recorded approximately 10,000 events, alarms, status changes, and telemetered limit excursions during the disturbance.

Due to the very high frequency in the islands (> 61 Hz), it was discovered that the OTP, UPA, and MAPP Security Center frequency meters/charts clipped and did not record the maximum frequency deviations. OTP's frequency meter clamped at 60.132 Hz due to a transducer limitation.

NSP reported that the Byron-Prairie Island 345kV line MW flow meter failed at the time of the Prairie Island-Byron 345kV line trip. As a result of this failure, the observed TCEX value was being manually determined from about 02:45 CDT on June 25th until June 27th at 19:17 CDT when the Byron-Adams 345kV line tripped due to storm damage to a number of structures. Once NSP Operators recognized the meter was not functioning properly at about 09:00 CDT on June 25th, the Operators manually entered the Byron-Adams 345 kV line flow as determined by the state estimator into the EMS system. The Operators also periodically checked the entered value with the state-estimated value. If the entered value was excessively off, the new state-estimated value was manually entered into the EMS system. The manually entered value was used to calculate TCEX.

The Byron RTU appears to have been operating properly. (Note: NSP has since reported that the meter has been subsequently repaired during the subsequent Byron-Adams 345kV line outage.)

2.5.2 Disturbance recorders performed adequately during disturbance, but several failed, and additional recorders are required

The disturbance recorders performed adequately during the disturbance, providing sufficient information to evaluate the system response. However, a number of units failed to record the disturbance, and there are areas in MAPP where additional monitoring would be useful.

NSP has four dynamic event recorders on the system positioned at the following substations: Coal Creek, Prairie, Forbes, and King. Of the four recorders only the King recorder contained usable data. The Coal Creek, Prairie, and Forbes units experienced communications problems and the data was unavailable for retrieval. The King recorder captured the Wilmarth-Lakefield 345kV line trip as well as the frequency deviations in the area.

Minnesota Power has dynamic disturbance recorders at the Arrowhead, Center and Littlefork substations which all triggered at various times during the disturbance. Most of the significant portions of the disturbance were recorded. Contiguous recording at each of these locations would have been beneficial for post-disturbance analysis.

Ontario Hydro has indicated that they plan to install additional disturbance recorders in their system to better monitor the system performance during similar system disturbances in future.

2.5.3 The SCADA and disturbance recorder data time stamping varies in accuracy and is difficult to correlate

The SCADA data available from the MAPP Member systems varied in time stamping from the nearest minute, to 4 second RTU scan rates, to GPS time synchronized. Substation equipment, including fault recorders, sequence of event recorders, and microprocessor relays, in MAPP often provide times to millisecond resolution. However, even if available, such data is not useful for system disturbance analysis unless the clocks in such equipment are synchronized to a time standard throughout the system so that events have a common time base. For the Sequence of Events compiled for this report, the timing of many events was based on less accurate sources such as SCADA logs. In cases when it was significant, reported times were adjusted so that events could be shown where they most likely occurred relative to other events.

The Minnesota Power dynamic system monitors which have accurate frequency transducers and GPS time synchronization were invaluable in analyzing this disturbance and identifying the correct sequence of events in many instances.

2.6 MAPP Emergency Energy Replacement Procedure (EM)

2.6.1 Requests for MAPP EM exceeded the reserves in MAPP

During the disturbance, there were eight concurrent requests for MAPP EM schedules due to the significant amount of generation lost. The total amount of energy replacement requested was 2215 MW, and exceeded the total required MAPP reserves of 1280 MW.

The volume of the EM requests, and the large number of schedule requests to the MAPP Member Operators was practically unmanageable. MAPP has indicated that it would have been beneficial if the MAPP SCO could have suspended the EM procedure when the magnitude of the EM requests became too large.

2.6.2 Requests for MAPP EM were made during the disturbance, and requested for units lost in the islands that had excessive generation on-line

As outlined in Section 5.10, four of the EM requests were from Members which lost generation within the North Dakota island, while it was still separated from the rest of MAPP and the Eastern Interconnection. Even with these generation losses the North Dakota island frequency at the time was greater than 61 Hz. The southern MAPP Members could not supply requested EM schedules across the separation until after 03:03 CDT.

The remaining four EM requests were from Members which lost generation in the southern/eastern MAPP areas that were still connected, or had been reconnected, to the Eastern Interconnection. Because of the separation, the MAPP Members within the North Dakota island could not deliver requested EM schedules until after 03:03 CDT.

The automatic MAPP EM procedure cannot be effectively implemented when the system is separated and the status of the system is unknown. However, the EM program was able to handle the large number of concurrent requests easily, and no problems occurred.

When the MAPP SCO determined for sure that the system separations in MAPP were restored, an MCN message was broadcast to all Members at 03:20 requesting them to respond to the EM requests in progress.

2.6.3 Several MAPP Members were not able to immediately supply EM schedules to requesting Members

Several Operators contacted the MAPP Security Center Operator (SCO) to request information on the islanding, which was still unclear at the time the EM requests were broadcast. The WAPA Operators, seeing excessive frequencies already in the area, notified MAPP that they would not be able to supply reserves immediately. The NSP Operators also notified MAPP that they would not be able to supply reserves.

The MAPP Members that did not comply with the requested EM schedules due to the high frequency were justified in doing so. Generation increases should not be implemented in a high frequency island.

Several additional MAPP Members did not supply EM requests immediately due to generation losses, uncertainty about the system conditions, etc.

All of the MAPP Members were supplying required reserves by 04:00 CDT. There were several additional EM requests later in the day, due to the generation lost during the disturbance. All MAPP Members responded to these later requests.

3. RECOMMENDATIONS

3.1 Operating Conditions at time of Disturbance

3.1.1 Readjusting system back within Operating Guide limits must be given priority

The system must be operated within the MAPP approved Operating Guide limits. Following a system contingency, the system exports must be reduced, or other necessary adjustments made immediately to return the system within the Operating Guide limits. These re-adjustments should be done as soon as possible, and must be completed within the readjustment period allowed in the MAPP Operating Standards.

Re-establishing the system conditions within the Operating Guide limits must be given priority once the system conditions stabilize and critical emergencies are addressed.

When the Operating Guide limits are re-established and the system can again securely withstand the next contingency, then other system restorations should be considered.

3.1.2 MAPP Security Center Operator (SCO) must assess security of transmission system

The MAPP Security Center Operator (SCO) must be aware of the presence of an Operating Security Limit Violation where the system conditions are outside of approved MAPP Operating Guides, and ensure actions are taken to return the system conditions within Operating Guide limits in the allowable time limits.

The MAPP Security Center (SC) must have applicable Operating Guides readily available for reference by the SCO, and have the necessary system information available to utilize the Operating Guides. An Operating Guide management system should be implemented. The MAPP SC should review the Operating Guides with the MAPP ORS, and appropriate ORS Working Groups, to ensure that the MAPP SC has up to date copies of all necessary Operating Guides, and that the Security Center Operators are familiar with these Guides.

The MAPP SC must obtain, or internally calculate, the adjusted TCEX limit, as calculated and used by the NSP Operators, so the SCO can determine precisely if the TCEX value is above Operating Guide limits at any time.

The MAPP Member Operators should notify MAPP immediately of an emergency condition where Operating Limits are exceeded, and apprise the MAPP SCO of the severity of the system conditions.

The MAPP SC should implement a dynamic security assessment tool to assess current system conditions and determine that adequate stability margins in northern MAPP and other applicable areas in MAPP exist at all times.

3.1.3 NSP must demonstrate the TCEX adjustment sensitivity for Prior Outage conditions

NSP must complete the necessary studies to demonstrate whether the TCEX limit can be increased during prior outage conditions based on Sherco generation levels, and the local Twin Cities metro area generation pattern. The prior outage Operating Guides should be updated to reflect this sensitivity.

The studies and updated Operating Guides must be submitted to the MAPP NMORWG and ORS for approval prior to their use.

3.1.4 The MAPP Operating Standards and Design Standards should be reviewed

The MAPP Operating Review Subcommittee (ORS) should review the Operating Standards definition for the Readjustment Period to ensure that it clearly specifies the allowable time period to restore the reliability of the system. The MAPP Design Standards allow permissible readjustments to restore the reliability of the system within 10 minutes.

The MAPP ORS and MAPP Design Review Subcommittee (DRS) should also jointly review the allowable time period to restore the reliability of the system against the new NERC Operating Policy 2 (Effective 7/1/98) which allows up to 30 minutes.[11]

3.1.5 The MAPP Operating Requirements should be reviewed

The appropriate MAPP Committees should review and update the MAPP Operating Requirements.

[11] NERC Operating Manual, Policy 2, Standard 2 (January 5, 1998): "Following a contingency or other event that results in an OPERATING SECURITY LIMIT violation, the CONTROL AREA shall return its transmission system to within OPERATING SECURITY LIMITS soon as possible, but no longer than 30 minutes." This NERC Standard requires that the system be able to again securely withstand the next first contingency within 30 minutes at the latest after a contingency occurs. The NERC definition of OPERATING SECURITY LIMITS is: "OPERATING SECURITY LIMITS define the acceptable operating boundaries."

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3.2 Procedures utilized to return to a secure state

3.2.1 NSP Operators should immediately reduce TCEX sufficiently to achieve Operating Guide limits

NSP should modify their internal Operating Guide implementation procedures (and associated Operating Guides) to indicate that the amount of TCEX reduction which should be requested (or implemented) is the larger of the typical 50 MW increment OR the absolute amount of negative "Net Export Margin". The "Net Export Margin" is defined as the TCEX limit less the Actual TCEX value.

Whenever the TCEX flow is above the Operating Guide limit, the export should be reduced as quickly as possible by the amount that the export is above the limit regardless of the procedures used.

3.2.2 MAPP Line Loading Relief (LLR) Procedure, in its current state, should not be relied upon for relief during emergency conditions where the system is in an insecure state

Operating Guides which must be implemented under emergency conditions (e.g. following a line trip) should be reviewed and updated as soon as possible to outline procedures to quickly reduce export or loading conditions without utilizing the current MAPP LLR procedure. The current MAPP LLR procedure should not be relied upon for relief during emergency conditions, as it cannot be implemented effectively and within the required timeframes in many cases.

Operating Guides that address emergency conditions, such as line trips, should identify permissible system readjustments, outlined in the MAPP Operating Standards, that can achieve the necessary system changes within the allowable readjustment period. These permissible readjustments include: generation rejection, generation reductions, reduction of economy exports to the extent possible within the readjustment period, adjustment of Load Tap Changing (LTC) transformers, phase shifters, or HVDC flows.

MAPP members should take whatever steps are necessary to return to a secure
operating state. Local action (reducing generation or cutting all allowable tariff schedules) should be taken immediately whenever Operating Guidelines are being violated. The violation of operating guidelines should be considered as an emergency state (stability limit exceeded) thus requiring local actions, including curtailing all contributing transmission service commitments as allowed by the MAPP Operating Standards. Calling for Line Loading Relief is not an appropriate response to the violation of Operating Guidelines, where the system is in an insecure state, and should be used only to prevent entering such a condition. Each control area must pre-determine the control action

required to coordinate its efforts with the MAPP Security Center to return to a secure operating state immediately.

The Operating Guides that rely on MAPP LLR as the primary procedure for reducing line loading or export levels, should identify other procedures to ensure the necessary relief can be achieved in the event that LLR cannot be effectively utilized.

The MAPP LLR Working Group (LLRWG) should review the current LLR procedure, and recommend/implement improvements to allow its use under emergency conditions, if the MAPP Members desire to utilize it in the future as a system readjustment procedure for emergency condition Operating Guides.

The MAPP Members should implement requested LLR schedule curtailments as soon as possible, and within the timeframe requested by the MAPP SCO. Members and other parties should not delay implementing schedule curtailments by contacting the MAPP SCO before making the schedule cuts, unless there are obvious errors in the requested schedule curtailments. The MAPP LLRWG should modify and clarify the LLR procedure implementation to allow the MAPP SCO to request immediate schedule curtailments for emergency conditions.

3.2.3 MAPP Line Loading Relief (LLR) Procedure software should be improved to prevent inadvertent schedule curtailment requests on an open transmission line/facility

The MAPP Center, in coordination with the MAPP LLRWG, should implement improvements in the LLR software to warn the SCO if the facility for which LLR is being evaluated is already open in the LLR powerflow model. The LLR software should not execute in this case and should not post requests for schedule curtailments, which identify no schedules to be curtailed. (Note: The MAPP Center staff has implemented this recommended software correction.)

MAPP Member Operators and other parties requesting MAPP LLR should not request LLR on a facility that is out of service (e.g. a transmission line that is open and cannot be reclosed due to large phase angle across the open line). If MAPP LLR is requested, a different facility (that will provide the required relief on the desired facility) should be utilized in the LLR request.

The MAPP LLRWG should review the appropriateness of utilizing LLR to reduce the phase angle on open transmission facilities.

3.2.4 Formal Operating Guides should be developed for reduction of high phase angle across open Prairie Island-Byron 345kV line, and other major transmission lines in MAPP

NSP and other MAPP Members with transmission lines that can develop high phase angles across the open line, preventing reclosure, should develop formal Operating Guides to identify effective and rapid procedures to reduce the phase angle.

In the case of the Twin Cities export lines, actions such as MH DC reductions and phase shifter adjustments in the area should be evaluated.

These phase angle reduction Guides and supporting studies should be submitted to the MAPP ORS and the appropriate ORS Working Group(s) for review and approval.

The MAPP Members should consider developing and observing "Storm Condition" Operating Limits during periods of severe storms. These limits could be based on the circuit automatic or manual permissible reclosure angles in the affected area.

3.2.5 Phase Angle Limit Calculations

In addition, NSP and other MAPP Members should review the phase angle limit settings on major transmission lines that can develop high phase angles across the open line, and ensure that the settings are not overly conservative. In the case where generating unit shaft torque is the limiting factor, detailed studies of the specific shaft system may be warranted. The MAPP systems should review the policies related to transient torque limits applied during critical system emergencies. Specifically, NSP should increase the manual re-close setting at the Byron Substation for the Prairie Island-Byron 345kV line, if possible. MAPP should seriously consider bypassing synchrocheck relays to permit direct closing of critical interconnections when it is necessary to maintain stability of the grid during an emergency.

3.3 <u>Line tripping/Islanding which occurred during disturbance</u>

3.3.1 The load/generation imbalance in the islands should be evaluated

The MAPP NMORWG should review the islanding which occurred in MAPP during the disturbance. Specifically, NMORWG should evaluate the locations that the islands formed, and the imbalance between the generation and load isolated within each island. NMORWG should identify further recommendations regarding the need for controlled islanding, or whether

Operating Guide changes are required to address the significant generation/load unbalance within the islands.

In addition, the NMORWG should review the coordination of generation over-frequency protection in the northern MAPP area.

3.3.2 The undesirable protective line tripping/non-tripping which occurred during the disturbance should be reviewed and corrected

MidAmerican Electric Company (MEC) and Alliant-IPW should review the protection settings, coordination, and out-of-step blocking philosophy on the Raun-Ft Calhoun 345kV line in eastern Nebraska and the Raun-Lakefield 345kV line in northwestern Iowa. The protection should be coordinated with the Wilmarth-Lakefield 345kV line to prevent unnecessary tripping during an out-of-step condition in the Twin Cities.

OTP and NSP should review the application of out-of-step blocking on the Grant County-Douglas County 115kV line, and the other lines in the immediate area, to determine the appropriate location to allow tripping for out-of-step conditions between North Dakota and Minnesota. This effort should be coordinated with the NMORWG overall review of the islanding (in Recommendation 3.3.1).

MH and MP should review the Forbes DCAR relay settings and revise as necessary to prevent undesired MH DC reductions for the conditions that occurred during this disturbance.

3.3.3 The MAPP Security Center Operator (SCO) must have a better overall picture of the MAPP system conditions and scope of islanding

The MAPP Security Center (SC) must have real time, or near-real time frequency metering from several geographic locations around the MAPP system, so the MAPP SCO can determine whether any island conditions exist, and the rough scope of the islanding. (Note: Additional frequency meters will be available in the new MAPP building fulfilling this recommendation in part. In the interim, the MAPP SC should replace the existing frequency meter, which is defective, as soon as possible.)

The MAPP SC also needs to incorporate an alarming function and clearly display the status changes of critical transmission facilities in the MAPP area, so the SCO can quickly determine the actual status of the overall MAPP system.

The MAPP SC staff should also internally review the adequacy of the information that is available to the SCO and determine whether it is sufficient. The MAPP SCO must be able to properly assess the MAPP transmission security at all times and effectively coordinate emergency operations in the MAPP region, as required in the NERC Operating Requirements.

The MAPP Member Operators must provide system status information to the MAPP SC, as required by the MAPP Operating Requirements. At a minimum, the Member Operators must provide indication over the MCN when their system is in an emergency condition, and when it is restored to a normal condition.

3.3.4 The tripping of the HVDC lines between North Dakota and Minnesota when North Dakota islands should be prevented during future disturbances

The over-frequency protection strategy at the Square Butte terminal of the Square Butte DC line should be reviewed to determine if new settings could be applied to prevent similar tripping during similar conditions.

UPA should develop an improved procedure and Operator training for operation of the CU DC line when the North Dakota AC system is islanded to prevent tripping of the CU DC line during similar conditions.

UPA should also review the coordination between the local North Dakota frequency contribution to the delta frequency (North Dakota/Minnesota) based damping control on the CU HVDC line.

3.3.5 Automatic Generation Controls (AGC) should be disabled during islanding

Once the MAPP Members recognize that the network has separated into islands, such that generators under AGC control are electrically separated from the area where the control area ACE is calculated, AGC should be temporarily turned off as outlined in the MAPP Operating Requirements (Section 19.A.5).

The control areas in each island should operate in the Flat Frequency mode, controlling only units within the island that contains the AGC frequency source, and make other adjustments, as required, to <u>immediately</u> restore the frequency to normal as required by the NERC Operating Policies and to minimize steam unit turbine loss of life during sustained operation in an overspeed condition.

Control areas involved in dynamic schedules for regulation service should turn off the dynamic schedule when the associated transmission is open. Control area operators should evaluate whether continued use of AGC could endanger system reliability when the frequency deviation exceeds 200 mHz. AGC may be suspended if reliability is endangered.

3.4 System Restoration

3.4.1 The MAPP Member Operators need critical information earlier from the MAPP Security Center and other Member Operators

The MAPP Member Operators need to be able to get critical information from the MAPP Security Center Operator (SCO) and other Member Operators earlier during a disturbance, to assist them in responding to the emergency.

The MAPP Security Center (SC) staff should further review the use of the MAPP Communications Network (MCN) during the disturbance, identify reasons that the MCN was not utilized as effectively as it could have been, and formulate additional recommendations to improve the use and benefits of the MCN for future disturbances or emergency conditions.

3.4.2 Automatic reclosing

The MAPP Members should assess the feasibility of operating critical interfaces within permissible "high speed" reclosure angle during the "high risk" conditions such as during Summer thunderstorms.

3.4.3 MAPP Security Center Operator (SCO) Request for Time Error Correction during disturbance

Time Error Correction should not be used as an emergency tool to correct regional frequency problems. Control area Operators should take other MAPP and NERC recommended actions to address low frequency conditions.

3.4.4 OH experienced high voltages during restoration of NW Ontario system

Ontario Hydro should review their system restoration plan for Northwestern Ontario to ensure acceptable system voltages during the restoration.

3.4.5 Phase Angle data should be available via SCADA

The MAPP Member systems should consider making phase angle data available to their Operators, via the SCADA systems, for critical transmission lines.

3.5 SCADA/Metering/Communications operation during disturbance

3.5.1 SCADA, Metering, and/or RTU problems observed during the disturbance should be corrected

The following MAPP Members should review the problems which occurred with their SCADA/EMS systems and report on actions taken to correct the problems: MidAmerican Energy Company (MEC), Omaha Public Power District (OPPD), Otter Tail Power Company (OTP), and United Power Association (UPA). Ontario Hydro should review the SCADA problems they experienced during the disturbance, and make necessary corrections.

The systems should review the capability of their SCADA/EMS to log critical analog data (e.g. generating unit MW, MVAR, and kV) during a system disturbance.

Otter Tail Power Company (OTP) should replace their defective frequency transducers, and add more frequency displays in their Control Center measuring the frequency in various locations in the OTP system to provide a means to recognize islanding in the OTP system.

United Power Association (UPA) should replace the defective frequency transducer in the UPA Control Center. UPA should also correct the problems with the Coal Creek RTU.

The MAPP Security Center should replace the defective frequency meter in the Security Center as also outlined in Recommendation 3.3.3 above.

NSP should review the Byron Substation RTU performance and correct any problems. DPC should review the Apple River RTU communications and correct any problems.

3.5.2 Disturbance Recorders

The systems that own disturbance recorders should review the performance of their equipment during the disturbance, and correct any operational problems that occurred. The systems should also review and adjust the triggering algorithms on these devices, if necessary, to assure complete recordings and reliable triggering for future events.

The MAPP Members should work together to identify additional locations for disturbance recorders, and install a more complete network of monitoring systems. The procedures for requesting triggering of the recorders throughout the MAPP system should be developed. The MAPP Security Center should have a procedure for triggering the MAPP Members' disturbance recorders when a significant disturbance occurs.

3.5.3 Need better time stamping for SCADA and Disturbance Recorder data

The systems should consider better time resolution for operation of critical breakers. This can be achieved through use of sequence of events recorders, fault recorders, or SCADA RTU's with sequence of events capability. Time synchronization using GPS receivers or similar hardware should be provided.

3.6 MAPP Emergency Energy Replacement Procedure (EM)

3.6.1 MAPP Security Center Operator (SCO) must have additional information and ability to manage EM calls during disturbances

As previously outlined in Recommendation 3.3.3, the MAPP SCO needs additional system information in order to manage coordinated procedures such as the EM procedure between the MAPP Members. The MAPP SCO must be able to provide feedback on the overall system conditions, and recommend to the Members how they should respond to automatic coordinated procedures during disturbances.

The MAPP SCO needs the ability to properly manage the EM procedure during disturbances. This should include authorization to suspend its automatic execution, if necessary, in the event that system conditions prevent it from being implemented properly, or if the EM schedule requests will negatively impact the system during emergency conditions. The MAPP Security Center, and appropriate MAPP Committees, should review this recommendation and the EM procedure performance during the June 25th disturbance, and formulate any additional recommendations. Specifically, this group should determine whether the automatic EM procedure should automatically be suspended if the amount of EM requested within a certain timeframe is too large (for example, greater than the MAPP Operating Reserve Requirement).

3.6.2 MAPP Member systems must comply with EM obligations, and review system conditions prior to submitting EM requests

MAPP Members must immediately respond to requests to provide reserves, unless the system conditions prevent the Member from responding to EM requests. In the event that a Member cannot immediately respond to an EM request, the Member should notify the MAPP Security Center Operator (SCO) as soon as possible.

The MAPP Member Operators should also review system conditions prior to requesting EM schedule requests for a unit loss. In the case where the system is separated, and islands are present, the Operators should determine whether the EM request will negatively impact the system conditions, and whether the other MAPP Members will even be able to supply the request. The MAPP Security Center, and appropriate MAPP Committees, should review the 2 minute initiation requirement of the MAPP EM procedure, specifically regarding whether this requirement allows the Operators to properly review the system conditions during an emergency prior to making the EM request for a generating unit loss.

3.7 NERC Operating Policy/MAPP Operating Standards Violations

3.7.1 Systems should review NERC Operating Policies violated during disturbance and take corrective action

Based upon the NERC Operating Policies that were violated during the disturbance, as outlined in this report, the MAPP Member systems should review these Policy violations and take corrective action. Specifically, NERC Operating Policies 1, 2, and 5 should be reviewed.

3.7.2 Systems should review MAPP Operating Standards and Operating Requirements violated during disturbance and take corrective action

The MAPP Member systems should review the MAPP Operating Standards and MAPP Operating Requirements to ensure compliance. Corrective actions should be taken to address the violations outlined in this report.

3.8 Other Recommendations

3.8.1 Otter Tail Power Company Control Center Backup Power

The OTP Control Center lost power during the disturbance. The UPS picked-up, but the back-up generator failed to pick-up the control center. It appears that system voltage oscillations caused the back-up generator control scheme to function incorrectly. OTP should review the back-up generator wiring and test the unit.

The OTP Control Center area was dimly lit when the emergency lighting was on. OTP should add additional emergency lighting fixtures in the Control Center to provide adequate lighting conditions.

3.8.2 MAPP Member systems should review generator response during high frequency islanding

The MAPP Member systems should review the response of all generators in the islands, especially in the extremely high frequency North Dakota island, and determine if the generator response was acceptable.

Based on the reported response of the Young 2 unit, its boiler and turbine controls should be reviewed to determine if they are properly set and coordinated.

4. PRIOR OUTAGE CONDITIONS

4.1 Generation Off-line and Out-of-Service:

None of the unit outages affected the reliability or transfer capabilities in MAPP or Northwestern Ontario systems. The total net generating capability off-line, in the islands that formed during the disturbance and in the MAPP systems that remained tied to the Eastern Interconnection, is shown below.

- Minnesota/Manitoba/Saskatchewan Island: 3,811 MW
- North Dakota Island: 281 MW
- NW Ontario Hydro Island: 980 MW
- Southern/Eastern MAPP: 2,024 MW

A summary of the individual generating units, which were off-line prior to the disturbance, is included in Appendix #3.

4.2 Generation On-line:

Generation in the MAPP region and the Northwestern Ontario area was normal prior to the Disturbance. The total net output (at about 02:17 CDT) of all the generating units, in the islands formed during the disturbance and in the MAPP systems that remained tied to the Eastern Interconnection, is shown below.

- Minnesota/Manitoba/Saskatchewan Island: 11,852 MW
- North Dakota Island: 2,810 MW
- NW Ontario Hydro Island: 270 MW
- Southern/Eastern MAPP: 7,641 MW

A summary of the individual on-line generating units net MW output prior to the disturbance is included in Appendix #3.

4.3 Transmission out of Service:

In the early morning of 6/25/98, no major transmission facilities were out of service for maintenance or other purposes that would impact reliability or regional transfer capabilities. The transmission facilities that were out of service were as follows:

Minnesota
Lake Marion-West Faribault 115kV
Carver County-Glendale-Scott County 115kV
Elm Creek-West Coon Rapids 115kV

North Dakota/South Dakota
Bristol-Summit 115kV
Brookings-White 115kV
Oahe-Eagle Butte 115kV

Nebraska
Tekamah-Raun 161kV
Stockville-Red Willow 115kV
Kearney-Lowell 115kV

Iowa
Avoca-Atlantic 161kV
Neal-Monona 161kV
Fox-Lake 161/69kV transformer #1
Fox Lake-Serburn 69kV
Marshalltown-Eldora 115kV
Wellsburg 115/69kV transformer

Manitoba/NW Ontario
Whiteshell-Kenora 230kV #2 (K22W)

However, just prior to the disturbance, one of the major 345kV lines out of the Twin Cities tripped, and a 161kV line was damaged, due to the severe storm going though the Twin Cities and western Wisconsin areas. These were as follows:

Prairie Island-Byron 345kV (Tripped @ 01:34 CDT)
Alma-Rock Elm 161kV (Tripped @ 02:01 CDT)

4.4 Interchange Summary, Significant Pre-disturbance Flows:

The export conditions and other significant flows at approximately 02:15 CDT, prior to the disturbance (but after the earlier trip of the Prairie Island-Byron 345kV line at 01:34 CDT), were as follows:

Northern MAPP
North Dakota Export (NDEX) = 1297 MW
Twin Cities Export (TCEX) = 1004 MW[12]
Manitoba Hydro Export (MHEX) = 1253 MW (From MH to USA)

CU DC Bipole Loading = 810 MW (From ND to MN)
(Coal Creek Station Generation = 840 MW, Amount on AC = 20 MW[13])

[12] Above Operating Guide Limit due to prior outage of Prairie Island-Byron 345kV line at 01:34 CDT.
[13] The 10MW difference is due to losses and DC auxiliary load.

Square Butte DC Bipole Loading = 295 MW (From ND to MN)
(Young #2 Generation = 409 MW; Amount on AC = 115 MW[14])

Miles City DC Loading = 110 MW West-to-East (From WSCC to MAPP)

Tioga-Boundary Dam 230kV (B10T) Flow = 24 MW (From USA to SPC)

Byron-Adams 345kV Flow = 51 MW
Wilmarth-Lakefield 345kV Flow = 178 MW
Eau Claire-Arpin 345kV Flow = 775 MW
King-Eau Claire 345kV Flow = 1048 MW

Dorsey-Forbes 500kV (D602F) Flow = 909 MW (From MH to USA)
Letellier-Drayton 230kV (L20D) Flow = 171 MW (From MH to USA)
Richer-Moranville 230kV Flow = 173 MW (From MH to USA)

Saskatchewan:
Saskatchewan-Manitoba Import = 232 MW (From MH to SPC)
Saskatchewan-BEPC Import = 24 MW (From BEPC to SPC)
Saskatchewan-Alberta Import = 75 MW (From Alberta to SPC)

Northwestern Ontario
Whiteshell-Kenora 230kV (K21W) Flow = 120 MW (From MH to OH)
Wawa-Marathon 230kV #1 and #2 Flow = 157 MW (From East to NW System)
International Falls-Fort Frances 115kV (F3M) Flow = 96 MW (From MP to OH)

(NW Ontario System was importing approximately 370 MW.)

Southern MAPP
GGS East Flow[15] = 1510 MW (From west to east)
Cooper South Interface Flow[16] = 1073 MW (From MAPP to SPP)
Red Willow-Mingo 345kV Flow = 510 MW (From MAPP to SPP)

Sidney (Virginia Smith) DC Loading = 25 MW (From WSCC to MAPP)
Stegall DC Loading = 105 MW (From WSCC to MAPP)

The generation and significant line flows in the NSP control area prior to the Prairie Island-Byron 345kV line trip at 01:34 CDT, and prior to the King-Eau Claire 345kV line trip at 02:18 CDT are shown in Appendix #3 (Sections 3 and 4).

[14] The 1MW difference is due to losses and DC auxiliary load.

[15] GGS East Flow is sum of real power on the following lines: Gentleman-Sweetwater 345kV #1 and #2 lines, Gentleman-Red Willow 345kV line, and Gentleman-North Platte 230kV #1, #2, and #3 lines.

[16] Cooper South Interface flow is sum of real power on the Cooper-St Joe 345kV line and the Cooper-Fairport-St Joe 345kV line.

4.5 Voltages at Key Substations:

Before the trip of Prairie Island-Byron 345kV line at 01:34 CDT, system voltages were within normal operating limits in both the MAPP system and the Northwestern Ontario Hydro system. The table below shows normal voltage values in southern Minnesota at 01:00 CDT.

Table 3 – Voltages (kV) in southern Minnesota at 01:00 CDT

Time (CDT)	Byron 345kV bus	Byron 161kV bus	Maple Leaf 161kV bus	Rochester 161kV bus	Rochester 161kV bus
01:00	345.3	162	163.1	162.6	161.6

Voltages in the NSP control area were normal prior to the King-Eau Claire 345kV line trip at 02:18 CDT, and were restored to normal levels immediately after the disturbance. The table below shows the voltages at several critical NSP buses, prior to and during the disturbance. As can be seen from the table, the voltages on the stressed east interconnections from the Twin Cities area towards MAIN were still acceptable at 02:00 CDT following the trip of the Prairie Island-Byron 345kV line at 01:34 CDT.

Table 4 – NSP Control Area Voltages (kV) Prior To and After Disturbance

Time (CDT)	King 345kV	Eau Claire 345kV	Eau Claire 161kV	Prairie Island 345kV	Byron 345kV	Wilmarth 345kV
01:00	349	341	164	353	350	350
02:00	350	334	165	355	341	343
03:00	357	364	165	355	359	354
04:00	355	360	164	352	358	355

The voltages in the Alliant-IPW system, south of the Twin Cities, were also normal after the initial trip of the Prairie Island-Byron 345kV line, as shown in the table below:

Table 5 – Alliant-IPW Voltages (kV) After Prairie Island-Byron 345kV trip

Time (CDT)	Lakefield 345kV	Fox Lake 161kV	Heron Lake 161kV	Winnebago 161kV	Adams 161kV	Rock Creek 161kV
01:38	346	160	165	158	164	162

DPC's voltages on the 161kV system were normal after the initial trip of the Prairie Island-Byron 345 kV line, as follows:

Table 6 – DPC Area Voltages (kV) After Prairie Island-Byron 345kV trip

Time (CDT)	Alma 161 Bus A (kV)	Genoa 161 North Bus (kV)
01:35	161.22	163.1

Figure #12 shows the voltage at the King 345kV bus (just north east of the Twin Cities), coincident with the trip of the Prairie Island-Byron 345kV line at 01:34 CDT. As can be seen, the King voltage prior to the line trip was around 355kV. When the line tripped, the voltage spiked down to approximately 338kV (98% of nominal). However, the voltage stabilized after that at around 352kV (102% of nominal), which is the normal operating voltage, and remained at this level until several minutes later when the King-Eau Claire 345kV line tripped.

4.6 Abnormal System Conditions:

The Twin Cities Export (TCEX) was above Operating Guide limits with the Prairie Island-Byron 345kV line out of service prior to the second contingency, trip of the King-Eau Claire 345kV line.

No abnormal system conditions were present which adversely impacted system restoration.

5. DESCRIPTION OF THE DISTURBANCE

5.1 Initiating Disturbance - Description and Cause

In the morning of June 25th, a severe thunderstorm, heading east, crossed the Twin Cities area (Minnesota). Due to this thunderstorm, at 01:34 CDT, a fault was detected by the relays on the Prairie Island-Byron 345kV line, causing the line to trip. A large phase angle existed across the open line. The NSP Operators attempted to reduce the phase angle difference in order to restore the line.

At 01:51 CDT, the NSP Operators contacted the MAPP Security Center Operator (SCO), and requested 50 MW of relief on the King-Eau Claire 345kV line using the MAPP Line Loading Relief (LLR) procedure. The MAPP SCO processed the LLR and requested curtailments across 02:00 CDT or ASAP.

The phase angle did not sufficiently decrease. At 02:11 CDT, NSP requested 100 MW of relief on the Prairie Island-Byron 345kV line, already open, in an attempt to further reduce the phase angle difference. The MAPP SCO issued this second LLR to be effective across 02:30 CDT.

Before the second LLR was posted on the MAPP Communication Network (MCN), at 02:18 CDT, the relays on NSP's King-Eau Claire 345kV line detected a phase to ground fault and tripped the line.

Just prior to the King-Eau Claire 345kV trip, at 02:15 CDT, the Twin Cities Export (TCEX) was 1004 MW, the North Dakota Export (NDEX) was 1297 MW, and the Manitoba Hydro Export (MHEX) was 1253 MW. The approved Operating Guides define a maximum value of 700 MW for TCEX during the outage of the Prairie Island-Byron 345kV line considering the flow conditions in the Northern MAPP region.

Following the tripping of King-Eau Claire 345kV line, the Eau Claire-Arpin 345kV cross-tripped. The western Wisconsin 115kV and underlying system overloaded. At 02:21:31 CDT, after the Ironwood-Park Falls 115kV line tripped, the Twin Cities system was separated from western Wisconsin.

The separation took 3 minutes and 10 seconds. In this period the tie-line flows between OH-MH and OH-MP increased beyond scheduled values. OH Operators made an attempt to ramp the schedules back to the original values, but were unsuccessful. Voltage oscillations in the area of OH-MAPP ties along with heavy local load stressed these interfaces. At 02:21:55 CDT, OH separated from the MAPP system after the tripping of the Manitoba-Ontario tie (Kenora-Whiteshell 230kV line) by overcurrent protection followed by the tripping of the Minnesota - Ontario tie (Fort Frances-International Falls 115kV line) by out-of-step protection. Within 1/10 of a second after Ontario Hydro separated from MAPP, the OH East-West ties (Marathon-Wawa 230kV lines) tripped separating the NW OH System from the Eastern OH System. Following the loss of all import ties, and because there was insufficient local generation on-line, the NW OH System collapsed and was blacked out.

At 02:21:56 CDT, the Wilmarth-Lakefield 345kV tripped due to distance relay action due to out-of-step conditions, opening the last of the TCEX interface 345kV lines.

The cascading line tripping continued until the entire northern MAPP region was separated from the southern MAPP region. The initial MAPP island formed at 02:22:09 CDT consisted of the Minnesota, Manitoba, North Dakota, and Saskatchewan areas. The frequency in the island ramped to 61.1 Hz and stabilized for about 2 _ minutes, dropping to 60.8 Hz when Sherco #3 tripped.

At 02:25:14 CDT, the UPA Operator manually tripped the CU DC Pole 1. About 28 seconds later CU DC Pole 2 tripped, starting the formation of the North Dakota island. The Letellier-Drayton 230kV and Boundary Dam-Tioga 230kV lines tripped at this time by out-of-step protection separating North Dakota from Canada. The remaining lines between North Dakota and Minnesota tripped quickly at about 02:25:47 CDT, except for the Grant County-Douglas County 115kV line which remained closed for about 5 minutes after the North Dakota and Minnesota areas lost synchronism. The Minnesota, Manitoba, and Saskatchewan areas remained connected as an island.

The restoration process in the Minnesota, Manitoba, and Saskatchewan area started at 02:25:59 CDT when the Ironwood-Park Falls 115kV line automatically reclosed. The Minnesota-Manitoba-Saskatchewan island was then tied back with the Eastern Interconnection. The remaining lines that tripped in Minnesota and Wisconsin were quickly closed.

The North Dakota island was not reconnected to the Eastern Interconnection until 03:03:39 CDT when Bismarck-Glenham 230kV line was manually closed via SCADA. The remaining lines which tripped forming the North Dakota island were then quickly restored by System Operators.

5.2 <u>Transmission Outages-Reasons:</u>

During the disturbance more than 60 lines tripped due to overloading and out-of-step conditions. The complete list of lines that tripped during the disturbance appears in Appendix #2.

The key line trips that triggered the cascading effects were:

- Prairie Island - Byron 345kV: A fault was recorded and tripping was proper. Restoration was delayed due to a greater than 40 degree voltage angle across the open line.
- King - Eau Claire 345kV: A phase to ground fault was recorded and no improper relay operations have been detected.
- Wilmarth-Lakefield Jct. 345kV: The line tripped at Wilmarth via zone two primary and secondary phase distance relays. IPW reported out-of-step targets and timers. This combination of targets is consistent with a trip for an out-of-step condition.

All transmission line protective relay actions operated correctly in Ontario Hydro.

5.2.1 CU DC Tripping During the Disturbance

At 02:21 CDT, UPA System Operators saw oscillating line flows and voltages in the North Dakota coal fields. They also saw that power on the CU DC line was higher than ordered and appeared to be oscillating. The high DC line power was contributing to a large unbalance between Coal Creek Station (CCS) plant output, which had dropped, and the DC line. This was producing a large unscheduled flow into Coal Creek on the AC ties. Operators attempted to reduce this unscheduled flow by manually reducing the DC power using SCADA. This could not be accomplished as there were intermittent DC high power alarms that prevented any control actions by the Coal Creek RTU.

At 02:15 CDT, the Coal Creek Station net generation was 840 MW (520 MW on CCS 1 and 320 MW on CCS 2) with the CU DC schedule set at 810 MW. There was 20 MW[17] flowing into the AC system at Coal Creek. At 02:25 CDT, 7 minutes after the disturbance started, CCS generation was 540 MW net (385/155 MW) and the CU DC loading was 1090 MW. There was a flow of about 530 MW into the Coal Creek bus from the North Dakota AC system. Since monopole operation would provide adequate power transmission for the Coal Creek Station generation at this time, the operator decided to trip one pole to force a reduction in the DC power schedule. This control action could be done using the SCADA RTU at the inverter terminal. At 2:25:14 CDT, pole 1 of the CU DC line was manually tripped.

The trip of pole 1 better balanced the plant and HVDC line power, reducing the unscheduled flow into the Coal Creek DC terminal from the AC system from 530 MW to 90 MW. This produced a sudden increase in the parallel AC system loading as shown, for example, in Figure #24. However, it appears there was an increase in the AC voltage at the Coal Creek bus. This was in part due to

[17] The 10MW difference is due to losses and DC auxiliary load

the reduction in reactive power requirements of the DC. There were also continuing voltage oscillations at Coal Creek on the 230kV AC bus after the pole tripped. The high voltage at Coal Creek resulted in a protection operation on pole 2, the remaining pole, and it tripped at 02:25:42 CDT. The pole tripped on voltage stress protection.

The loss of both poles initiated a trip of Coal Creek Station Unit 2, which was armed to trip for loss of the bipole. The unit tripped about 7 _ cycles after the pole 2 trip. A runback signal was also sent to CCS Unit 1, which would have runback from 370 MW to about 300 MW in one minute. The decision to arm one unit for loss of the bipole was based on the pre-disturbance conditions of CCS generation at 840 MW and NDEX export at about 1300 MW. Since CCS generation actually decreased as a result of the islanding, the Operator continued the arming of only one unit during this period.

The reason the DC line power had increased during this event was that the CU DC line has a frequency controller that is active when the frequency deviation at Coal Creek exceeds 0.1 Hz. The purpose of this controller is to stabilize Coal Creek bus frequency when the DC line and the Coal Creek units are operating radially (i.e isolated from the North Dakota AC system). For the bus frequency above 60 Hz, this control is allowed to increase DC power up to 400 MW above the power order. The controller has a gain of 300 MW/Hz. For the increase in rectifier-end frequency to about 61 Hz, the frequency control increased the DC power to about 1090 MW at 02:25 CDT. The CU frequency differential damping control was also active, but this control is sensitive to changes in frequency, and it would not react to the steady-state increase in frequency that occurred.

5.2.2 Square Butte DC Tripping During the Disturbance

The Square Butte DC Pole 2 tripped on overfrequency protection at 02:25:44 CDT, when the North Dakota island frequency reached 62.2 Hz. This protection was designed to trip the HVDC system on overfrequency in the event that the Center converter station (rectifier) and the Young 2 generator would become isolated from the local ac system. This was an appropriate protection response.

Although the HVDC system should continue to operate reliably during off-nominal frequency conditions, there are concerns regarding the performance of the harmonic filters tuned to 60 Hz based harmonic frequencies. Inadequate filtering could lead to voltage distortion, which could cause operational problems.

5.2.3 North Dakota Island, Post-Separation Oscillation, Slipping

Immediately following the islanding of North Dakota, a large amplitude low frequency oscillation occurred in the North Dakota island. The dynamic system monitor at the Square Butte Center converter station (ND island) recorded an average value of 61.47 Hz and a frequency of 0.15 Hz for this event. The peak value of the oscillation reached 61.9 Hz. The oscillation was sustained and lasted for 30 seconds. At this time, both the cause and the mitigating event are unknown. (See details in Figure #16)

The North Dakota island did not cleanly separate from Minnesota because one 115kV line remained connected between the two asynchronous systems. The slipping between the two areas (at approximately 1.5 Hz) was observable in the voltages throughout the MAPP system from about 02:26 CDT until 02:31 CDT. These voltage oscillations can be most clearly seen in Figure #16, which shows the line-to-neutral voltage at the Center 230kV bus in central North Dakota. The voltage oscillation can also be clearly seen at the King 345kV bus on the eastside of the Twin Cities in Figure #15. Oscillations can be seen as far north as Saskatchewan in Figures #21 and #22. Figure #13 shows the same voltage excursions (at a reduced resolution) at the Bismarck 230kV bus in central North Dakota.

The Douglas County-Grant County 115 kV line (Figure #2) in western Minnesota was the last tie line to trip in the formation of the North Dakota island, but did not trip for the out-of-step condition. This line has zone 2 out-of-step blocking at the Grant County end. The Douglas County end relaying has zone 1 and zone 2 out-of-step blocking. The line sections further to the west and east of this line, also have out-of-step blocking, so no line protection in the area was able to open this last interconnection.

The Douglas County -Grant County 115kV line did finally trip approximately 5 minutes after the initial formation of the North Dakota Island due to a fault at the Douglas County end. When crews arrived at the Douglas County substation they found a damaged out of service wave trap and observed the wave trap leads were flapping in the wind. Apparently the flapping leads of the wave trap at Douglas County caused a fault which opened the line, or what ever damaged the wave trap also caused the fault. The exact cause is unknown.

5.3 <u>Loss of Generation-Description and Reasons</u>

During the disturbance, a total of 4,171 MW of generation was disconnected in the MAPP and Northwestern OH systems. Almost all of this generation was tripped in a period of approximately 4 minutes.

The generation that tripped off-line during the disturbance, in chronological order, is shown below. Additional information on the generation trips can be found in the sequence of events.

Table 7 – Generation that tripped during the Disturbance

Units Tripped	Net MW Tripped	Time Tripped (CDT)	Time Back On-line (CDT)	Reason for Trip
Jenpeg #3-4	60	02:21:50	02:51	Over-frequency
Ft Randall Units #1-6 & 8	42	02:21:57	03:57	Over-excitation
Winton #2	2.0	02:21:58	03:03	Over-speed
Neal #4	490	02:21:58	08:41	Generator Distance Relay
Cedar Falls Streeter unit #7	8	02:22:01	09:27	Loss of field protection
Knife Falls #1,2 and 3	1.9	02:22.02	03:01	Over-speed
Hoot Lake #3	18	02:22:10	04:45	Low load
Fox Lake #3	18	02:22:13	04:38	Over-excitation
Poplar River #2	291	02:22:13	03:15	Over-frequency
Riverside #7	66	02:22:35	06:28	Unknown
Neal #3	430	02:22:35	04:37	High Volt/Hz
Neal #2	92	02:23:02	06:56	High Volt/Hz
Bayfront #4,#5 and #6	31	02:24:21	03:30	Over-frequency
Sherco #3	738	02:24:58	11:35	Low drum level
Bigstone	342	02:25	11:30	Boiler problem
Coal Creek #2	320	02:25:12	04:45	Loss of bipole
Blanchard #1,2 and 3	17.7	02:25:50	03:11	Over-speed
Antelope Valley Station #2	370	02:25:55	10:01	Over-frequency
Coyote	367	02:26:17	13:54	Boiler Load Rejection
Hoot Lake #2	32	02:26:20	04:36	Fuel Problem
Highbridge #6	149	02:26:51	04:37	Manual trip (Overfire Condition)
Grand Island Cherry #3	15	02:37	09:55	Fuel trip in boiler
Total MAPP	**3900.6**			
Thunder Bay #3	153	02:22:04	09:35	System Collapse
Other OH Hydro	113	02:22:04	09:35	System Collapse
Total NW OH	**270**			
Total	**4170.6**			

The Manitoba Hydro (MH) DC reductions and other protective actions on the MH bipoles reduced the bipole line flows by approximately 1200 MW during the disturbance. The 1200 MW decrease in DC power included a 265 MW DC reduction for trip of Manitoba - Ontario tie (Whiteshell-Kenora 230kV #1, K21W), a 340 MW DC reduction for operation of Forbes DCAR relay, a 250 MW decrease due to over-frequency tripping of bipole 2 valve groups 31 and 42, and a 300 MW decrease due to operation of the DC damping control. These DC reductions removed another 1080 MW[18] of generation resource from the MAPP system in addition to the generation losses shown above. During the separations and islanding, this reduction was beneficial as it preserved the ties between MH and Minnesota and reduced the overfrequency in the island.

Except for over-frequency tripping of HVDC valve groups, the MH DC power decreases were the result of control actions and resulted in a very brief loss of generation capability to MAPP. The four DC valve groups were returned to service by 02:41 CDT. Export schedules were restored to the U.S. utilities in Minnesota and North Dakota by 03:22 CDT. Export schedules to Wisconsin were further delayed by transmission outages outside the Manitoba System.

The majority of the generation losses during the disturbance were due to the overfrequency conditions in the northern MAPP islands. The generation tripping in southern MAPP was primarily due to over-excitation caused by these units significantly increasing reactive power output as the northern MAPP system was separating from southern MAPP and a significant amount of power surged through the area. The MEC's Neal units in western Iowa clearly show the impact of the power surges as seen in Figure #18. The generation losses in Ontario were due to the complete collapse of the system.

A significant amount of additional generation in the MAPP region was almost lost during the disturbance.

Large power swings at the Gerald Gentleman Station (1107 MW net) in central Nebraska were observed by the NPPD Generation Control Operator. The Generation Control Operator instructed the unit operators to take the units "in hand" to keep them from tripping. NPPD's Cooper Nuclear Station personnel reported being within 0.2 volts of tripping the unit (761 MW net) due to loss of auxiliary equipment.

5.3.1 Generation Unit Response in North Dakota island

The North Dakota island formed about 02:25:47 CDT. The ND island frequency increased to over 62 Hz, and then stabilized during the duration of the island at about 61.3 Hz.

The affected Control Area Operators correctly disabled AGC on a temporary basis during the islanding, due to the high frequency, and the uncertainty concerning the system separations.

[18] The 265MW DC reduction for the Kenora-Whiteshell 230kV line trip only represents a loss of generation to the MAPP system of about 145MW because the pre-disturbance flow on the tie line was 120MW from MH to Ontario. The actual reduction exceeded the initial tie line loading because of the large inadvertent flow on the line following the loss of the two Twin Cities 345kV lines.

For the WAPA (Upper Great Plains Region) Control Area, which was split across the island boundaries, AGC was suspended at 02:10 CDT by automatic action based on the frequency deviation. WAPA Operators attempted to resume AGC at 02:23 CDT on Tie Line Bias, but this was unsuccessful. Control was switched to constant frequency at 02:59 CDT and back to Tie Line Bias at 03:06 CDT (following the restoration of the North Dakota system to the Eastern Interconnection). The Oahe plant was placed back on normal AGC control at 03:17 CDT.

The Otter Tail Power Company (OTP) Control Area was within the North Dakota island and lost all three units capable of AGC by 02:26 CDT. The regulation service dynamic schedule with Manitoba Hydro was turned off at 02:30:11 CDT because the OTP control area was separated from the MH control area at 02:25:42 CDT and remained off until 02:50:47 CDT. However, the tie line between the control areas was not returned to service until 03:25 CDT when the Letellier-Drayton 230kV line was energized. Thus, the OTP control area lost their AGC capability during the disturbance and subsequent islanding. Also, the regulation service dynamic schedule was restored prior to the North Dakota being resynchronized with the Eastern Interconnection.

For the United Power Association (UPA) Control Area, AGC tripped off-line at about 02:22 CDT due to sudden frequency deviation. AGC was returned to normal later in the morning when the system was restored.

For the Northern States Power Company (NSP) Control Area, Sherco units #1, #2, and #3 were on AGC prior to the disturbance. After Sherco #3 tripped at 02:25 CDT, the NSP Plant Operators switched Sherco units #1 and #2 into manual control mode, effectively disabling the AGC.

The Manitoba Hydro (MH) System Control Centre (SCC) tripped off AGC at 02:26 CDT due to the disturbance, and returned AGC to normal at 02:41 CDT.

Reductions and significant fluctuations in the net output of generating units were experienced in the North Dakota island. The following unit responses were reported.

- At the Coal Creek Station (CCS), at 02:15 CDT, CCS 1 was at 520 MW net output and 320 MW net on CCS 2. At about 02:25 CDT, a reduction in generation followed the frequency increase to 61 Hz: CCS 1 was at 385 MW net and CCS 2 at 155 MW net.
- Young 1 remained constant at 210 MW, with rapid 10 to 50 MW fluctuations due to governor actions.
- Young 2 began to governor-induced ramp down from 415 MW net at 02:23 CDT to 335 MW at 02:30 CDT. Once the governor was satisfied, the turbine

began ramping back up to 410 MW net at 03:03 CDT. After that, per dispatch request, the unit began to ramp down to 270 MW at 03:45 CDT.

5.4 Voltage and/or Frequency excursions

The system voltages and frequency recovered well after the Prairie-Byron 345kV line tripped. A spike in the frequency, reaching 60.2 Hz, was observed at the Arrowhead bus, however the frequency returned to normal rapidly. The frequency stabilized at near normal values after the subsequent trip of King-Eau Claire 345kV line. Figure #6 shows the system frequency after the Prairie Island-Byron 345kV line trip. Figure #7 shows the system frequency after the subsequent King-Eau Claire 345kV line trip.

Significant frequency excursions began to take place during the ensuing system separation and in the islands that formed. The following are some observations about the frequency excursions and oscillations in the Northern MAPP area:

- When the second contingency (King-Eau Claire 345kV line trip) occurred a frequency spike to 60.17 Hz at Arrowhead (see Figure #7) but was damped rapidly and stabilized to 60 Hz.
- During the Twin cities-Northwest Wisconsin separation, oscillations, with average value of 60 Hz and maximum amplitude of 0.16 Hz, were observed at Arrowhead (see Figure #8).
- The frequency in the Minnesota/Manitoba/North Dakota/Saskatchewan island increased up to 61.11 Hz (see Figure #9). After that it stabilized, with some minor oscillations, at a value close to 60.8 Hz.
- When North Dakota separated from the northern MAPP island, the frequency in the Minnesota/Manitoba/Saskatchewan island dropped to 59.95 Hz and finally recovered when the island was reconnected to the Eastern Interconnection.
- The frequency in the North Dakota island increased to 62.2 Hz (See Figure #5) and then settled at an average value of about 61.3 Hz for approximately 30 minutes.

In the southern and eastern MAPP regions frequency dropped after Minnesota/Manitoba/North Dakota/Saskatchewan island formed. In the east, DPC reported frequency excursions from 59.91 Hz up to 60.04 Hz. In the south, NPPD reported excursions from 59.50 Hz to 60.066 Hz and MEC reported excursions from 59.4 Hz to 60.04 Hz. IPW reported excursions from of 59.925 Hz to 60.015 Hz

Prior to 02:18 CDT, the voltages in the MAPP region were normal and within operational limits. Once the cascade line tripping and system separations began, significant voltage changes and swings were observed throughout the MAPP system.

In the DPC system, severe transient voltage oscillations occurred. At Adams 161kV bus 2, voltage ranged from 150.1kV at 02:21 CDT to 170.6kV at 02:25 CDT. Figure #23 shows the voltage swings at Alma 161kV bus A. The Barron 161kV bus voltage varied from 140.9kV (87%) at 02:21 CDT to 165.2kV at 02:25 CDT. The Winnco 69kV bus voltage varied from 62.6kV (91%) at 02:21 CDT to 75.8kV (110%) at 02:22 CDT. The Winnco 161kV bus voltage reached 191kV (119%).

The WAPA area also experienced voltage oscillations. Prior to the tripping of King-Eau Claire 345kV, the Bismarck 230kV bus was about 240kV. After the trip of King-Eau Claire 345kV line, the Bismarck 230kV bus voltage dropped to about 232kV. The Bismarck voltage then jumped to about 247kV during the Minnesota/Manitoba/North Dakota/Saskatchewan island formation, and then dropped quickly to about 237kV. When the North Dakota island formed, the Bismarck 230kV bus voltage jumped to about 252kV. During approximately 5 minutes when North Dakota slipped against Minnesota, the voltage began oscillating between 241kV and 251kV. Figure #13 shows the voltage fluctuations on the Bismarck 230kV bus. Most of the WAPA North Dakota system experienced a similar pattern of voltage fluctuations during this timeframe.

Similar voltage oscillations were experienced on the Tioga side of Boundary Dam phase shifter (SPC, Canada). Before the King-Eau Claire 345kV line trip, voltages were within operational limits at 230kV. During the system separation coinciding with the formation of the Minnesota/Manitoba/Saskatchewan/North Dakota island, the Boundary Dam bus voltage dropped to around 200kV. Following the trip of the Tioga-Boundary Dam 230kV line in the subsequent formation of the North Dakota island, the Boundary Dam 230kV bus voltage increased up to 274kV and the 5-minute oscillation during the system slipping can also be seen in Figures #21 and #22.

Voltage swings at the King 345kV bus following the Wilmarth-Lakefield 345kV line trip are shown in Figure #14. The King 345kV voltage jumped from 350kV to 375kV in milliseconds. The voltage oscillations during the system slipping can also be seen at the King 345kV bus. Figure #15 shows the voltage oscillation with an amplitude of about 4.5kV with an average value of approximately 363kV.

The response of the Watertown Static Var System (SVS) in eastern South Dakota during the North Dakota/Minnesota slipping can be see in Figure #19. The SVS reduced the voltage oscillations in the area.

The voltage at the Gentleman 345kV Bus (in central Nebraska) changed significantly from 343kV to 374kV during the disturbance.

Significant real and reactive power swings were observed throughout southern MAPP. The reactive output at the Cooper Nuclear Station in southeastern Nebraska changed from supplying 142Mvar to supplying 369Mvar, and then back to absorbing 39Mvar within a period of 20 seconds. The Cooper real power output changed from 761 MW to 866 MW and down again to 666 MW during the disturbance. Swings of 200 to 300Mvar were seen at the Gentleman plant in central Nebraska. The Cooper South interface flows (sum of the Cooper-Fairport and Cooper-St. Joe 345kV lines) changed from 1073 MW up to 1370 MW, and then down to 297 MW during the disturbance.

5.5 Load Losses-Magnitude/Duration and Reasons:

The following tables show the amount of load lost and the number of customers affected during the disturbance in the MAPP region and in the OH system.

Table 8 - MAPP Member Load Losses

Company	Load Lost (MW)	Total MW-Minutes	# Customers Affected
CP	18	9,709 MW-min	N/A
DPC	12	504 MW-min	2,370
IPW	20	1,597 MW-min	6,270
MDU	10	845 MW-min	7,300
MP	120	23,040 MW-min *	6
NPPD	65	4,010 MW-min *	3
NSP	31.2	1,228 MW-min	16,000
OTP	36.6	4,006 MW-min	7,154
Total MAPP	**312.8**	**44,939 MW-min**	**39,103**

* Industrial Customers

Table 9 - Ontario Hydro Load Losses

Company	Load Lost (MW)	Total MW-Minutes	# Customers Affected
OH	650	90,400 MW-min	113,770 retail & 23 industrial

The main reason for the loss of load was under-voltage load shedding. However, in some cases, the tripping of the transmission lines feeding the load caused the loss. The duration of the loss of load, due to the disturbance, in the MAPP region, varied between 1 minute and 3 hours.

In the Ontario Hydro system, the loss of load was due to a total collapse of their Northwestern system. The duration of the load lost varied from 1 to 4.5 hours.

5.6 Underfrequency load shedding performance:

No automatic underfrequency load shedding occurred during the disturbance in the MAPP region.

Based on minimum frequency excursion of approximately 59.4 Hz in the southern MAPP system, which remained connected to the Eastern Interconnection, no automatic underfrequency load shedding was expected. The MAPP underfrequency load shedding program[19] correctly did not operate, as it requires the first stage of automatic load shedding at 59.3 Hz. The islands that formed had a significant amount of surplus generation, with the frequency well above 60 Hz, and therefore no load was shed in the islands on underfrequency.

After the frequency decline in the southern MAPP was arrested, no manual load shedding was implemented.

Ontario Hydro underfrequency load shedding operated, but the undergenerated NW OH island collapsed much faster than the load shedding could take place.

5.7 Special Protection Scheme performance:

The Special Protection Schemes (SPS) associated with the Manitoba Hydro DC reductions that occurred during the disturbance all operated properly. The two MH DC reductions during the disturbance were as follows:

- Following the Kenora-Whiteshell 230kV line (K21W) trip, a 265 MW MH DC reduction was correctly initiated at 02:21:54:880 CDT.

- In response to system swings, the Forbes DCAR (Delta Current Admittance Relay) operated, and a 340 MW MH DC reduction was correctly initiated at 02:21:57.486 CDT. The 340 MW of DC reduction was beneficial for the over generating islanding condition. However, the operation of the Forbes DCAR relay was "as designed but not as intended". The design did not anticipate operation of the relay for the unusual conditions which occurred. Operation for similar local conditions at Forbes, but for different system circumstances, would likely be undesirable.

[19] MAPP Operating Handbook, Section IV

The operations of the SPS were adequate and as expected. However, the SPS operation was not expected for the DC reduction initiated by the Forbes DCAR relay.

5.8 Communications/SCADA system performance:

Several MAPP Members had SCADA problems during the disturbance. Otter Tail Power Company (OTP) indicated that their system lost data such as alarms and messages. The United Power Association (UPA) System Operator experienced difficulty in completing control actions at a critical substation when the disturbance caused several points to continuously cycle in and out of alarm. Dairyland Power Cooperative (DPC) indicated that their Apple River RTU communications failed during the disturbance. Omaha Public Power District's (OPPD) EMS system, due to prioritization of tasks during the heavy alarm/event loading, failed to record frequency data from 02:22 to 02:23:30 CDT. MEC lost SCADA data due to the large number of alarms that occurred. Ontario Hydro also indicated that their system lost some data.

The MAPP Communications Network (MCN) operated properly during the disturbance.

5.9 System Restoration-Description/Significant Issues:

Given the magnitude of the disturbance, the restoration process in the transmission system was achieved quickly. In the MAPP region, the restoration process started at about 02:26 CDT, with the reconnection of the Minnesota/Manitoba/Saskatchewan island to the Eastern Interconnection. The process finished at 04:47 CDT (2 hours and 29 minutes after the King-Eau Claire 345kV line trip) when the ties between Minnesota Power and the NW OH system were closed. The Alma-Rock Elm 161kV line was not restored until June 27th due to damage to 5 structures caused by the severe thunderstorm.

Restoration in NW OH system started with OH closing its ties to the eastern OH system at 03:12 CDT. At 05:46 CDT, the 230kV system was restored and at 06:00 CDT potential was restored to all customer loads.

The automatic re-closure of the Ironwood-Park Falls 115kV line (Western Wisconsin), which occurred at 02:25:59 CDT, initiated the restoration process in the eastern portion of the MAPP region. The automatic re-closure of this line tied back the Minnesota/Manitoba/Saskatchewan island to the Eastern Interconnection. This happened while the North Dakota island was already slipping against the Eastern Interconnection.

Restoration of the NSP transmission system started with lines that connect the Twin Cities with eastern Wisconsin. At 02:26:22 CDT, the King–Eau Claire

345kV line was back in service and seven minutes later the Prairie-Island 345kV line was restored. However, the 345kV tie with MAIN was not restored until 03:03 CDT, when the Eau Claire-Arpin 345kV line was returned to service. The last TCEX interface line, the Wilmarth-Lakefield 345kV line, was restored at 03:19 CDT. The NSP transmission system was back to normal (almost 1 hour after the King-Eau Claire 345kV line trip).

The reconnection between the North Dakota island and the Eastern Interconnection began with the manual restoration of the Bismarck-Glenham 230kV line. The remaining ties were quickly closed.

The CU HVDC was out of service from 02:25 CDT until 03:45 CDT when the Pole 1 was de-blocked. Nine minutes later, Pole 2 was de-blocked. The SQBT DC Pole 2 was restarted at 03:48 CDT, after being out of service since 02:25:44 CDT.

No major problems occurred in the restoration process for the transmission system.

All of the MAPP systems reported normal operations by 21:00 CDT. The Northwestern Ontario system was restored to normal conditions by 06:45 CDT.

5.9.1 Generation Restoration:

The majority of the generating units that tripped were restored with no problems.

MAPP Members reported problems bringing three units back on-line after the disturbance:

- Big Stone plant (425 MW net capability) tripped off line at 02:25 CDT. The unit was brought on-line at 09:06. The plant tripped off-line at 09:18 due to a boiler problem unrelated to the disturbance. The Big Stone plant was back on-line at 09:49 and remained on-line.

- Coyote plant (400 MW net capability) tripped off-line at 02:26 CDT. The unit was brought on line at 05:11. MDU held Coyote off-line until they were sure there was sufficient power on the network to start Coyote up. The plant tripped off-line at 06:48 due to a problem with fans. The unit was on and off-line several times due to problems associated with turbine controls, which were unrelated to the disturbance. The Coyote plant was back on-line at 13:54 and remained on-line.

- Sherco #3 unit (871 MW capability) tripped off-line at 02:24:51 due to a low drum level. The unit was brought on line at 11:35. Sherco #3 had a boiler relief valve that stuck open. The valve had to be replaced before the unit could be brought back on-line.

Due to the delay in the restoration of the Sherco #3 unit (871 MW) and the continuing maintenance outage of the King unit (567 MW), NSP declared an "energy alert" for later in the day on June 25th. NSP was forecasting a 1000 MW generation deficit due to the expected hot weather and these unit outages. NSP made a public appeal to their retail, commercial, and industrial customers to reduce power usage. This public appeal was expected to last until 20:00 CDT on June 25th. With the return of the Sherco #3 unit sooner than expected, the power reductions realized from "interruptible" customers, and NSP's ability to obtain larger energy purchases that expected, NSP was able to lift the "energy alert" and cancel the public appeal at 16:30 CDT. The public appeal was successful.

5.10 MAPP Emergency Replacement Procedure (EM) Calls

During the disturbance, several MAPP Members invoked the MAPP Emergency Replacement Procedure (EM)[20], due to the loss of generating units. The EM program is the mechanism that MAPP Members have to establish the individual amount of reserve contributions after the loss of a specific generator.

During the disturbance, eight EM calls were made in a period of 11 minutes as shown in the following table. Specific details of the EM requests are included in the Sequence of Events.

Table 10 – Summary Of MAPP Emergency Replacement Requests

EM Call	Time (CDT)	Company	Generation Unit Lost	Requested MW
1	02:28	MEC-ALT	Neal 3	450
2	02:31	SMP	Sherco 3	230
3	02:32	OTP	Big Stone *	219
4	02:34	OTP	Coyote *	140
5	02:34	UPA-GSE	Coal Creek 2 *	630
6	02:36	NWPS	Big Stone *	95
7	02:37	NWPS	Coyote *	40
8	02:39	MEC-NWPS	Neal 4	411
TOTAL				**2215 MW**

* Units isolated in North Dakota island at time of EM Request

The total amount of generation requested at 02:39 CDT was 2215 MW. At that time, the assigned generation reserve for the entire MAPP region was 1280 MW. Due to the transmission system islands during that period (from 02:25:47

[20] MAPP Operating Handbook, Section IV

to 03:03:39 CDT), the North Dakota island had a significant amount of excess generation on-line even after the units above tripped. The frequency settled at close to 61.3 Hz. The Members in the island requested EM schedules to cover their generation losses, even though the frequency at the time was very high. Due to the separation, the MAPP Members in the North Dakota island were unable to deliver EM schedules to the Members outside the island, and vice versa.

Due the uncertainty concerning the system conditions, several MAPP Members did not immediately comply with the requests for EM schedules. The EM schedule requests were being broadcast right in the middle of the disturbance, which made it difficult to respond to them, as the system Operators were focusing on responding to the emergency conditions.

The WAPA and NSP Operators notified the MAPP Security Center Operator (SCO) during phone conversations during the disturbance, that they were not immediately responding to the EM schedule requests. The WAPA Operators indicated that they were in an island situation and were unsure at that time of the location and extent of the islanding. Based on the extremely high frequency in the control area, and not being able to determine for sure if schedules could actually be delivered to the requesting parties, the WAPA Operators delayed responding to the all EM requests until 03:23 CDT. The NSP Operators were also unsure of the overall system condition, and were concerned that increasing generation, and thus increasing transfers, could cause additional lines to trip. The NSP Operators delayed responding to the EM requests, because of concern about making the system conditions worse, until 04:00 CDT.

UPA also did not respond to the early EM calls because of the disturbance and the loss of Coal Creek Station 2, but began delivering EM schedules starting at 03:48 CDT.

Once the transmission system was restored sufficiently, and the islanded areas reconnected, all of the MAPP Members were compliant with delivering their required EM schedules.

5.11 MAPP SCO Request for Time Error Correction

During the disturbance, a Time Error Correction was requested by the MAPP SCO. At 02:30 CDT, the operators from KCPL reported to the MAPP SCO a frequency value of 59.95 Hz. The KCPL operator suggested that a Time Error Correction could help boost the frequency.

Four minutes later at 02:34 CDT, the MAPP SCO operator called the NERC Hot Line to report the emergency situation in the MAPP region, and informed them about the possibility of MAPP requesting a Time Error Correction.

At 02:40 CDT, the MAPP SCO sent a Time Error Correction request to American Electric Power (AEP). Five minutes later at 02:45 CDT, the AEP operator informed the MAPP Center that the time error was -4.65 seconds and the target frequency across 03:00 CDT would be 60:02 Hz (Time Error Correction Identification "H").

At 02:49 CDT, the MAPP SCO sent a MCN message to all MAPP Members instituting the Time Error Correction. The North Dakota system was still separated with the frequency in the island at approximately 61.3 Hz at the time the time error was requested.

Several MAPP Member control areas did not implement the requested Time Error Correction (TEC), due to the disturbance. WAPA, whose control area was separated at the time of the request, indicated that they did not respond to the TEC. When the TEC was requested, the WAPA control area was off AGC. UPA has indicated that at the time of the TEC request that they were still recovering from the disturbance and the loss of the CU DC line and Coal Creek Station #2, and therefore did not participate.

The times at which Members in the MAPP region initiated the Time Error Correction varied. For example, NPPD initiated the Time Error Correction at 02:49 CDT and removed it at 03:41 CDT. OTP responded to the request, initiating the correction at 03:01 CDT and removing it at 04:10 CDT.

Around 03:00 CDT, the low frequency in the MAPP system tied to the Eastern Interconnection began to immediately increase as shown in Figure #20, and was soon at the targeted value of 60.02 Hz. At 03:03:39 CDT, the North Dakota island was reconnected to the Eastern Interconnection restoring significant generation to the MAPP region.

Minutes later at about 03:13 CDT, the frequency of the interconnected system reached approximately 60.035 Hz. At 03:41 CDT, the MAPP SCO called AEP to request that the Time Error Correction be terminated. AEP issued the Time Error Correction termination for across 04:00 CDT. The MAPP SCO broadcast an MCN message to all MAPP Members requesting that the Time Error Correction be terminated at 04:00 CDT.

6. SEQUENCE OF EVENTS

A chronological listing of all of the relevant transmission and generation outages, and islanding which occurred during the disturbance is included as Appendix #5. The sequence of events also lists the export conditions, relevant communications between the MAPP member system and the MAPP Security Center Operator, MAPP EM Procedure calls, and other relevant events that occurred during the disturbance.

Appendix #1

List of parties contributing to the Disturbance Report

<u>MAPP Staff</u>
Mike Brytowsky
LaWayne Buelow
Johan Galleberg
Carlos Gonzalez-Perez
Tim Liffrig
Barry McMahon
Ben Porath
Zachary Gerbozy

<u>IORWG Members and contributors:</u>
Ken Goldsmith, Alliant Utilities-IES (IES)
Jarred Miland, Alliant Utilities-Interstate Power (IPW)
Dick Pursley, Alliant Utilities-Interstate Power (IPW)
Richard Hegna, Corn Belt Power Cooperative (CBPC)
Miodrag Djukanovic, MidAmerican Energy (MEC)
Ken Moss, MidAmerican Energy (MEC)
Larry VanWyhe, MidAmerican Energy (MEC)
Richard Huebner, Muscatine Power and Water (MPW)

<u>NORWG Members and contributors:</u>
Barry Francis, Basin Electric Power Cooperative (BEPC)
Al Meyer, Hastings Utilities (HU)
Laurie Gregg, Lincoln Electric System (LES)
Duane Breithault, Municipal Energy Agency of Nebraska (MEAN)
Ron Gunderson, Nebraska Public Power District (NPPD)
Brian Brownlow, Nebraska Public Power District (NPPD)
John Mayhan, Omaha Public Power District (OPPD)
David Kulisek, Omaha Public Power District (OPPD)
Gayle Nansel, Western Area Power Administration (WAPA)

<u>NMORWG Members and contributors:</u>
Mike Risan, Basin Electric Power Cooperative (BEPC)
Mike Steckelberg, Cooperative Power (CP)
Terry Torgerson, Dairyland Power Cooperative (DPC)
Bob Roddy, Dairyland Power Cooperative (DPC)
Wayne Haidle, Montana-Dakota Utilities (MDU)
Robert Coish, Manitoba Hydro (MH)
Allan Silk, Manitoba Hydro (MH)
George Sweezy, Minnesota Power (MP)

Appendix #1 (Continued)

List of parties contributing to the Disturbance Report

NMORWG Members and contributors (continued):
Dudley Maki, Minnesota Power (MP)
Dennis Swanson, Minnkota Power Cooperative, Inc. (MPC)
Tim Bartel, Minnkota Power Cooperative, Inc. (MPC)
Dean Schiro, Northern States Power Co. (NSP)
Darwin Porter, Northern States Power Co. (NSP)
Greg Pieper, Northern States Power Co. (NSP)
Mike McMullen, Northern States Power Co. (NSP)
Terry Volkmann, Northern States Power Co. (NSP)
Dale Jepsen, Northwestern Public Service Company (NWPS)
Larry Larson, Otter Tail Power Company (OTP)
Barry Peterson, Otter Tail Power Company (OTP)
Walter Omoth, SaskPower (SPC)
Karl Mortensen, United Power Association (UPA)
Earl Cass, Western Area Power Administration (WAPA)
Bob Chapman, Western Area Power Administration (WAPA)
Darrell Crocker, Western Area Power Administration (WAPA)
Steve Sanders, Western Area Power Administration (WAPA)
David Schilder, Western Area Power Administration (WAPA)
Edward Weber, Western Area Power Administration (WAPA)

Other MAPP:
Jeff Ihrke, Southern Minnesota Municipal Power Agency (SMMPA)

Ontario Hydro
Mike Radan
Kenneth Chan
Chak M. Louie

Appendix #2

Transmission facilities (69kV and above) that tripped during Disturbance

DPC:
Alma-Rock Elm 161kV (5 structures down due to storm damage)
Apple River-Crystal Cave/Pine Lake (Open-ended at Apple River)
Twin Lakes-Winnco 69kV (Open-ended at Twin Lakes)
Apple River 69kV Bus and associated 69kV lines
Barron-Pine Lake 69kV (Open-ended at Barron)

Alliant-IPW:
Lakefield-Fox Lake-Winnebago-Hayward 161kV
Lakefield 345/161 transformer
Rutland-Fox Lake 69kV
Albert Lea Westside-Walters 69kV
Fox Lake-Dunnel 69kV (radial)
Winnco-Thompson 69kV
Fox Lake-Sherburn 69kV
Winnco-Forest City 69kV
Montgomery-New Prague 69kV

MDU:
Tioga 230/115kV transformer (Open-ended on 230kV side)

MEC:
Lakefield-Raun 345kV

MH:
Kenora-Whiteshell 230kV (K21W)
Letelier-Drayton 230kV

MP:
Stinson-Minong 161kV (Open-ended at Stinson)
International Falls-Fort Francis Phase Shifter (F3M) 115kV
Audubon-Hubbard 230kV
Rush Lake Tap-Wing River 230kV
Square Butte HVDC Pole #2

Appendix #2 (Continued)

Transmission facilities (69kV and above) that tripped during Disturbance

<u>NSP:</u>
Prairie Island-Byron 345kV
King-Eau Claire 345kV
Eau Claire-Arpin 345kV
Wilmarth-Lakefield Jct. 345kV
Afton-Red Rock 115kV
Red Rock-Crystal Cave 115kV
Pine Lake-Wissota 115kV
Pine Lake-Apple River/Crystal Cave 161kV
South Faribault-West Owatonna 161kV
Ironwood-Park Falls 115kV
Wilmarth-Winnebago 161kV
Pathfinder-Split Rock 115kV
Panther-Granite Falls 230kV
Minnesota Valley-Franklin 115kV
Willmar-Kerkhoven/Minnesota Valley Jct. 115kV
T-Corners - Wien 115kV
Cannon Falls - Northfield 69kV
Cannon Falls - Zumbrota 69kV
Cannon Falls - Spring Creek 69kV
Pine Lake - Rock Elm 69kV
Red Wing - Alma 69kV
Stone Lake - Bayfront 69kV
MN Valley - Bird Island 69kV
Willmar - Granite Falls 69kV
Douglas County - Westport 69kV
Douglas County - Osakis 69kV

<u>NWPS:</u>
Huron-Redfield 115kV
Huron West Park-Mitchell 115kV

<u>OH:</u>
All 230kV, 115kV and below in the NW OH system (west of Wawa)

<u>OPPD:</u>
Raun-Fort Calhoun 345kV

Appendix #2 (Continued)

Transmission facilities (69kV and above) that tripped during Disturbance

OTP:
Grant-Douglas County-Alexandria 115kV
Toronto-Burr 115kV (Open at Toronto)

UPA:
Prairie-Ramsey 230kV
McHenry-Ramsey 230kV
Granite Falls-Willmar 230kV
CU HVDC Pole #1 and CU HVDC Pole #2

WAPA:
Bismarck-Glenham-Sully Buttes 230kV line
Fort Thompson terminal of the Leland Olds 345kV line
White-Split Rock 345kV line
Fort Thompson-Huron No.1 230kV line
Fort Thompson-Huron No.2 230kV line
Huron terminal of the Storla 115kV line
Brookings terminal of the Flandreau 115kV line
Hettinger-Maurine 230kV line
Tioga-Boundary Dam 230kV line

Appendix #3

Conditions Prior to the Disturbance

1. Generation off-line/out of service:

1.1 Minnesota/Manitoba/Saskatchewan Island Area

Company	Generation Units Off-line/Out of Service	Capability (MW)
MH	Brandon	93.6
MH	Grand Rapids	236
MP	Hibbard 3	36.8
MP	Hibbard 4	15
NSP	Angus Anson 2	116
NSP	Angus Anson 3	116
NSP	Big Falls 2 - 3	5.1
NSP	Black Dog 1	75
NSP	Black Dog 3	109
NSP	Blue Lake 1 - 4	203
NSP	Chippewa Falls 2 - 6	16.8
NSP	Cornell 2 - 4	19.5
NSP	Dells 1 – 7	8.5
NSP	French Island 1 - 4	171
NSP	Granite City 1 - 4	61
NSP	Holcombe 1 - 3	35.5
NSP	Inver Hills 1 - 6	343
NSP	Jim Falls 1, 2, & 4	57.4
NSP	Key City 1 - 4	65
NSP	King 1	567
NSP	Menomonie 1 - 2	5.3
NSP	Minnesota Valley 3	47
NSP	Pathfinder 1	61
NSP	St Croix Falls 6 - 8	9
NSP	West Faribault 2 - 3	32
NSP	Wheaton 1 - 6	342
NSP	Wilmarth 1 - 2	22
NSP	Wissota 2 - 6	31.2
SPC	Total Generation Off-Line	836
UPA	Cambridge CT	25
UPA	Maple Lake CT	25
UPA	Rock Lake CT	25
TOTAL		**3810.7**

Appendix #3 (Continued)

Conditions Prior to the Disturbance

1. **Generation off-line/out of service: (Continued)**

1.2 North Dakota Island Area

Company	Generation Units Off-line/Out of Service	Capability (MW)
BEPC	Leland Olds 1 (Unavailable)	210
OTP	Hoot Lake 1	7.6
OTP	Jamestown 1 – 2	41.9
OTP	Lake Preston	21.8
TOTAL		**281.3**

1.3 In Northwestern Ontario Area

Company	Generation Units Off-line/Out of Service	Capability (MW)
OH	Atikokan	230
OH	Hydraulic (Total)	505
OH	Thunder Bay 2	155
OH	West Coast (NUG)	90
TOTAL		**980**

1.4 Southern/Eastern MAPP Area (Nebraska/Iowa/Wisconsin)

Company	Generation Units Off-line/Out of Service	Capability (MW)
DPC	Flambeau 1 – 2	14.3
IPW	Fox Lake 1, 2, & 4	45.3
IPW	Kapp 1	18
IPW	Lansing 1 – 2	26.2
IPW	Lime Creek 1 – 2	70
LES	8th & J	32
LES	Rokeby 1 – 2	136
MEC	Louisa	700
NPPD	Columbus 1	40
NPPD	Kingsley 1	38
NPPD	Sheldon 2	120
WAPA	Big Bend 1, 3, 5, 6, & 8	335
WAPA	Oahe 3, 5, 6, & 7	449
TOTAL		**2023.8**

Appendix #3 (Continued)

Conditions Prior to the Disturbance

2. Generation on-line (At approximately 02:17 CDT):

2.1 Minnesota/Manitoba/Saskatchewan Island Area

Company	Generation Units On-Line	Net Output (MW)
MH	Sum of Northern Collector	3030
MH	Southern Generation	1094
MP	Total generation in Island	943
MP	Young 2 (On SQBT DC)	250
NSP	Bay Front 4 – 6	31
NSP	Big Falls 1	2
NSP	Black Dog 2	76
NSP	Black Dog 4	144
NSP	Cedar Falls 1 – 3	6
NSP	Chippewa Falls 1	3
NSP	Cornell 1	1
NSP	Flambeau 1	1.5
NSP	Hennepin Island 1 – 5	12
NSP	High Bridge 5	78
NSP	High Bridge 6	149
NSP	Monticello 1	546
NSP	Prairie Island 1	502
NSP	Prairie Island 2	459
NSP	Red Wing 1 – 2	16
NSP	Riverside 7	66
NSP	Riverside 8	222
NSP	Sherco 1	547
NSP	Sherco 2	552
NSP	Sherco 3	738
NSP	St Croix Falls 1 – 5	12
NSP	Wissota 1	4
SPC	Total generation in Island	1524
UPA	Coal Creek (On CU DC)	810
UPA	Elk River	33
TOTAL		**11851.5**

Appendix #3 (Continued)

Conditions Prior to the Disturbance

2. **Generation on-line (At approximately 02:17 CDT): (Continued)**

2.2 North Dakota Island Area

Company	Generation Units On-Line	Net Output (MW)
BEPC	Antelope Valley 1	423
BEPC	Antelope Valley 2	430
BEPC	Leland Olds 2	272
MDU	Heskett 1	7
MDU	Heskett 2	35
MP	Young 1	214
MP	Young 2 (Into AC)	150
OTP	Big Stone	408
OTP	Coyote	375
OTP	Hoot Lake 2	28
OTP	Hoot Lake 3	18
UPA	Coal Creek (Into AC)	30
UPA	Stanton	147
WAPA	Ft. Peck 4 (3&5 Cond)	45
WAPA	Garrison 1-5 (2&4 Cond)	228
TOTAL		**2810**

2.3 Northwestern Ontario Island Area

Company	Generation Units On-line	Net Output (MW)
OH	Alexander	18
OH	Augusabon	0
OH	Cameron	16
OH	Manitou	13
OH	Silver Falls	0
OH	Thunder Bay #3	153
OH	White Dog	0
OH	Kakabeka	0
OH	Ear Falls	7
NUG	Total NUGs	63
TOTAL		**270**

Appendix #3 (Continued)

Conditions Prior to the Disturbance

2. **Generation on-line (At approximately 02:17 CDT): (Continued)**

2.4 In Southern/Eastern MAPP Area (Nebraska/Iowa/Wisconsin)

Company	Generation Units On-Line	Net Output (MW)
BEPC	Laramie River 1	549
DPC	Alma 1 – 5	79.7
DPC	Flambeau 3	1.5
DPC	Genoa 3	248.0
DPC	JPM	238.3
IES	Burlington	96
IES	DAEC	507
IES	Fair Station 2	38
IES	Ottumwa	615
IES	Prairie Creek 3 – 4	121
IES	Red Cedar	20
IES	Sutherland 1 – 3	115
IPW	Dubuque 3 – 4	36
IPW	Fox Lake 3	18
IPW	Kapp 2	183
IPW	Lansing 3 – 4	211
MEC	Council Bluffs 1 – 3	651
MEC	Neal 1	105.4
MEC	Neal 2	91.7
MEC	Neal 3	430
MEC	Neal 4	490
MEC	Riverside 3, 5	39.3
MEC	Waste Mng. 1 & 2	5
NPPD	Canaday	81
NPPD	Columbus 2 – 3	21
NPPD	Cooper	761
NPPD	Gentleman 1 – 2	1107
NPPD	Jeffrey	16
NPPD	Johnson 1	8
NPPD	Johnson 2	14
NPPD	North Platte 1 – 2	23
NPPD	Sheldon 1	72
OPPD	Ft. Calhoun	475
WAPA	Big Bend 2, 4, 7 (Cond)	0
WAPA	Ft Randall 2, 7 (1,3-6,8 Cond)	84
WAPA	Gavins Point 1-3	90
WAPA	Oahe 1,2, 4 (Cond)	0
TOTAL		**7640.9**

Appendix #3 (Continued)

Conditions Prior to the Disturbance

3. **Comparison of NSP Unit Generation prior to Prairie-Island Byron 345kV line trip (at 01:34 CDT) and King-Eau Claire 345kV line trip (at 02:18 CDT).**

Generation Units On-line	Net MW at 01:13 CDT	Net MW At 02:17 CDT	Generation Units On-line	Net MW at 01:13 CDT	Net MW at 02:17 CDT
L. S. Power	156.4	Off-line	Black Dog 4	144.3	144.1
Cedar Falls 1	2.2	2.2	High Bridge 6	148.9	148.6
Cedar Falls 2	2.3	2.3	Riverside 8	224.0	224.0
Cedar Falls 3	2.4	2.4	Prairie Island 2	522.0	459.3
Bay Front 4	9.4	8.9	Prairie Island 1	502.0	502.0
Bay Front 6	10.5	10.1	Monticello	543.1	546.0
Bay Front 5	14.2	12.5	Sherco 1	618.2	546.9
Riverside 7	94.0	66.0	Sherco 2	609.8	552.2
Black Dog 3	75.8	75.6	Sherco 3	841.0	738.0
High Bridge 5	78.1	77.7	**Totals:**	**4598.6**	**4118.8**

4. **Significant NSP flows prior to Prairie-Island Byron 345kV line trip (at 01:34 CDT) and King-Eau Claire 345kV line trip (at 02:18 CDT).**

NSP Lines/Export	Flow (MW/MVAR) at 01:30 CDT	Flow (MW/MVAR) at 02:17 CDT
TCEX	1540.9	1004
Eau Claire-Arpin 345kV	803.0 / 32.6	778.9 / 23.9
Byron-Adams 345kV	636.1 / -45.7	49.3 / -75.2
Wilmarth-Lakefield Jct. 345kV	101.8 / -42.6	175.8 / -70.5
Prairie Island-Byron 345kV	873.9 / 69.8	Out of Service
Alma-Rock Elm 161kV	11.8 / 6.1	Out of Service
King-Eau Claire 345kV	946.8 / 131.6	1048.4 / 143.8
Red Rock-Crystal Cave 115kV	143.5 / 6.9	175.6 / 11.5
Pine Lake-Wissota 115kV	50.3 / -28.9	56.7 / -34.4
Pine Lake-Apple R/Crystal Cave 161kV	32.8 / -16.0	44.8 / -18.1
South Faribault-West Owatonna 161kV	38.3 / -11.6	113.9 / -52.1
Ironwood-Park Falls 115kV	29.8 / -7.0	25.0 / -6.7
Split Rock-White 345kV	-346.8 / 25.5	-332.3 / 21.1
Pathfinder-Split Rock 115kV	1.3 / 7.0	8.9 / 0.7
Wilmarth-Winnebago 161kV	90.6 / -10.0	128.9 / -12.9

Appendix #4

TCEX, NDEX, and MHEX Definitions

Twin Cities 345kV Export Ties (TCEX)

```
Terminal A                               Terminal B
Eau Claire       |---->-------------|    Arpin            345kV
Byron            |---->-------------|    Adams            345kV
Wilmarth         |---->-------------|    Lakefield        345kV
```

North Dakota Export Ties (NDEX)

```
Terminal A                               Terminal B
Leland Olds      |--------------->--|    Ft. Thompson     345kV
Leland Olds      |--------------->--|    Groton           345kV
Antelope Valley  |--------------->--|    Huron            345kV
Sully Butte      |--------------->--|    Oahe             230kV
Bison            |--------------->--|    Maurine          230kV
Big Stone        |--------------->--|    Blair            230kV
Morris           |--------------->--|    Granite Falls    230kV
Sheyenne         |---|-->-----------|    Hubbard          230kV
                    Audubon

Inman            |---->-------------|    Wing River       230kV
Ellendale        |---->-------------|    Aberdeen Jct.    115kV
Edgeley          |---->-------------|    Ordway           115kV
Forman           |---->-------------|    Summit           115kV
Canby            |--------------->--|    Granite Falls    115kV
Alexandria       |--------------->--|    Douglas Co.      115kV
Laporte          |--------------->--|    Badoura          115kV
Kerkhoven        |---->-------------|    Kerkhoven Tap    115kV
Drayton          |--------------->--|    Letellier        230kV
```

Manitoba Hydro Export (MHEX)

```
Terminal A                               Terminal B
Dorsey           |---->----|--------|    Forbes           500kV
                        Roseau
Letellier        |---->-------------|    Drayton          230kV
Richer           |---->-------------|    Roseau           230kV
```

NOTE: Positive flow from terminal A to terminal B means power is leaving an area on a given line. The arrow symbol indicates the location that the flow is measured. A positive measurement is obtained if the real power is flowing in the direction of the arrow symbol.

Appendix #5

Sequence of Events

Northern MAPP/Northwestern Ontario Disturbance - June 25, 1998 @ 02:18CDT

Time (CDT)	Reporting Company	Event
06/24/98 23:24	MAPP (MCN)	ALT / Requested NERC TLR on the Eau Claire-Arpin 345kV line. The line loading is 786 MW and the alarm limit is 725 MW (based on the operating guides). Note: The 725 MW alarm is the recommended off-peak flow limit identified in the "Minnesota-Eastern Wisconsin Phase Angle Reduction Guide (August 15, 1997)". This pre-contingent operating limit is intended to protect eastern Wisconsin area by preventing an excessive post-contingent phase angle for reclosing the Eau Claire-Arpin 345kV line. No requests for curtailments were made, as only a schedule collection took place.
06/25/98 prior to event	NSP	King Generating Unit - Off-Line **(Prior outage)**
06/25/98 prior to event	NSP	Lake Marion - West Faribault 115kV Line Carver County – Glendale - Scott County 115kV Line Elm Creek - West Coon Rapids 115kV Line **(Prior outages) Maintenance.**
01:13	NSP	Prairie Island unit #2 at 522 MW
01:14	MP	Badoura 40L,48L,725L (Note: 725L line is the Badoura-Bemidji 115kV line),64L and 2TM OPEN by relay. Failed CCPD on 725 line
01:14:54	OTP	Bemidji CB 1245 tripped and reclosed auto. Cass Lake load off until restored by dispatcher at 01:15 and 01:18
01:15	**Exports**	**NDEX=1501 MW, MHEX=1681 MW, TCEX=1578 MW (Byron-Adams=650 MW, Wilmarth-Lakefield=106 MW, Eau Claire-Arpin 345kV=822 MW)**
01:19:12	NSP	Open - Lafayette - Schilling 69kV
01:34:19.616	NSP	**Prairie Island - Byron 345kV line trips** (NSP shows at 1:34:23, DPC shows at 01:34:30, MP shows at 01:34:19.616) Phase A to ground fault recorded and tripping was proper. There is no instantaneous reclose on this line. Line could not be reclosed manually due to greater than 40 degree phase angle across the open line.
01:34:19:618	UPA	Dickinson 345 CU HVDC pole 2 commutation failure
01:34:35.348	NSP	Prairie Island-Byron 345kV line auto recloses properly (Prairie Island breaker 8H9 reclosed on hot bus/dead line) at Prairie Island. The line was open at the Byron end. About 8 cycles later, a Phase A to ground fault was detected, and the line tripped back out 2-1/2 cycles later. (NSP shows at 01:34:39)
01:35 (approx.)	NSP	Byron breaker 8S14 recloses properly (hot bus/dead line) energizing the open-ended Prairie Island-Byron 345kV line, and remains closed. The line was open at the Prairie Island end.
01:36:00	NSP	Open - Cannon Falls - Spring Creek 69kV,

Time (CDT)	Reporting Company	Event
		Cannon Falls - Northfield 69kV, and Cannon Falls - Zumbrota 69kV lines.
01:36:10	UPA	Rush City 69 9NB2 Trip Rush City-Blaine 69kV Tripped and Reclosed auto at 1:36:13
01:36:10	UPA	Blaine 69 23NB4 Rush City-Blaine 69kV Tripped and reclosed auto at 1:36:16
01:37:51	NSP	Operator attempts to manually close Prairie Island-Byron 345kV line at Prairie Island (8H9). Unsuccessful due to high phase angle.
01:38:36	NSP	Operator manually opens breaker at Byron (8S14) on Prairie Island-Byron 345kV line, de-energizing the open-ended line.
01:39	MAPP (MCN)	NSP / PRI-BYN 345KV TRIPPED @ 0134. REMAINS OPEN.
01:39:23	NSP	Operator manually closes breaker at Prairie Island (8H9) on Prairie Island-Byron 345kV line. Prairie Island breaker (8H8) also manually closed at 01:39:27. The line is energized, but open-ended at the Byron end.
01:41	MAPP (MCN)	SMP / BYN-ADM 345KV TRIPPED @ 0133 & RECLOSED AUTO. (Note: Alliant-IPW later indicated that Adams CB 8S2 did not actually trip on or around 01:33.)
01:41:28	NSP	Operator attempts to manually close Prairie Island-Byron 345kV line at Byron (8S15). Unsuccessful due to high phase angle. Approximately 7 minutes have elapsed since the line tripped at 01:34.
01:45	**Exports**	**NDEX=1448 MW, MHEX=1578 MW, TCEX=1062 MW (Byron-Adams=64 MW, Wilmarth-Lakefield=180 MW, Eau Claire-Arpin 345kV=818 MW)**
01:51	MAPP (MCN) **(LLR)**	NSP / REQUESTING 50 MWS LLR ON ECL-ARP 345KV DUE TO PRI-BYN 345KV OUT. REDUCED 246 MWS PRI '1' SCHEDS FOR RELIEF. POSTED. LOCKED. MASTER RUN #12552. Note: NSP calls LLR in the line Eau Claire-Arpin 345kV. They request curtailments of 50 MW. Conditions on that line reported by NSP are: Load Level: 830 MW, Load limit : 800 MW
01:54	MAPP **(LLR)**	Note: The message for the 50 MW relief on the Eau Claire-Arpin 345kV line is broadcast on the MCN. The curtailments will take place ASAP or across 02:00. (MAPP shows that the requested curtailments took place on time or before the tripping of King-Eau Claire 345kV line)
01:59:10	UPA	Crow River 69 4M62 Mpl Lk-Crw Rvr-Hutch 69kV Tripped and reclosed auto at 1:59:18
01:59:10	UPA	Hutchinson 69 C3NB2 Mpl Lk-Crw Rvr-Hutch 69kV Tripped and reclosed auto at 1:59:14
01:59:10	UPA	Maple Lake 69 1NB2 Mpl Lk-Crw Rvr-Hutch 69kV Tripped and reclosed auto at 1:59:17
02:00:10	DPC	Alma-Rock Elm 69kV relayed to lockout
02:01:40	DPC	Alma - Rock Elm 161kV Open (Storm damage, 5 structures down) Relayed to Lockout. (NSP shows at 02:01:33) Line returned to service on 6/27/98 at 14:54.
02:02:31:282	UPA	Coal Creek 230 CU HVDC P1 and P2 Line Protection and restart
02:08:07	DPC	Alma-Rock Elm 69kV line restored.

Time (CDT)	Reporting Company	Event
02:10	MAPP (MCN) **(LLR)**	NSP(R) / CAN'T CLOSE PRI-BYN DUE TO PHASE ANGLE. WOULD LIKE 100 MWS LLR ON PRI-BYN TO REDUCE PHASE ANGLE. POSTED. LOCKED. MASTER RUN # 12558.
02:11	MAPP **(LLR)**	Note: NSP calls 100 MW LLR in the interface Prairie Island-Byron. The line is open at this time. The start time for the curtailments is 02:30
02:15	**Exports**	**NDEX=1297 MW, MHEX=1253 MW, TCEX=1004 MW (Byron-Adams=51 MW, Wilmarth-Lakefield=178 MW, Eau Claire-Arpin 345kV=775 MW)**
02:17	NSP	Prairie Island unit #2 at 459 MW (63 MW reduction since 01:13) NSP lowering generator output to attempt to reduce Prairie Island-Byron 345kV phase angle.
02:18:18.093	NSP	**King - Eau Claire 345kV line trips.** Phase A, SLG fault, relay operation appears proper. **THIS EVENT BEGINS THE CASCADE THAT EVENTUALLY SEPARATES NORTHERN MAPP AND RESULTS IN THE FORMATION OF SEVERAL ISLANDS.** **With two major Twin Cities 345kV outlets out of service, the remaining tie (Blue Lake – Wilmarth 345kV) and the underlying system on the Minnesota – Wisconsin interface are heavily stressed. The frequency oscillations after the line trip were positively damped and decayed quickly. (NSP shows at 02:18:18, DPC shows at 02:18:44, MP shows at 02:18:18.093)** **Beginning at this time and lasting approximately 20minutes, the Alma 161kV bus voltage was unstable and varying between 156kV to 168kV, and the JPM unit reactive output was varying between 160Mvar to –55Mvar.** Between 2:18 and 2:25 AM, a total of 14 NSP distribution feeders at Menomonie, Bayfront, Ironwood, Rice Lake, T-Corners, and Cumberland in western Wisconsin tripped on undervoltage.
02:18	MH	Unusual "circulating flow" observed on MH-US ties: Dorsey-Forbes 500kV (D602F) south flow <u>decreases</u> from 922 MW to 793 MW, Lettelier-Drayton 230kV (L20D) south flow <u>increases</u> from 171 MW to 229 MW, Richer-Moranville 230kV (R50M) no significant change. MH-OH tie Kenora-Whiteshell 230kV (K21W) east flow increases from 114 MW to 169 MW
02:18:00 to 02:18:18	OH	Whiteshell Phase Shifter had maintained 120 MW schedule from MH to OH and International Falls PSTs with 90 MW schedule from MP to OH. Flows into Northwestern (NW) Ontario were within operating limits.
02:18:20	IPW	Trip CB 657 Montgomery - New Prague 69KV zone 3ϕ
02:18:22	NSP	**Eau Claire - Arpin 345kV Open (Cross-Trip from King-Eau Claire 345kV)**
02:18:22	NSP	Afton - Red Rock 115kV Open
02:18:22	NSP	Red Rock - Crystal Cave 115kV Open (Phase distance, zone 2 trip) Note: The frequency oscillations after the line trip were positively damped and decayed quickly.
02:18:34	MP	LSPI 10K Capacitor Bank CLOSED

Time (CDT)	Reporting Company	Event
02:19:00	OH	Kenora-Whiteshell 230kV (K21W) and International Falls-Fort Frances Phase Shifter (F3M) loading increased and off the schedule. OH requested MP to return F3M flow north back to 90 MW schedule. MP reported they were having some problems on their system but would ramp back to 90 MW ASAP.
02:19:28	DPC	NSP Bayfront and Ironwood 34.5kV feeders tripped shedding the Bayfield, Barsdale, Highbridge, Kimball, Ironbelt, and Morse DPC substations. 58 minute customer outage on Bayfield, 40 minute customer outage on the remaining substations.
02:19:59	MAPP **(LLR)**	Note: The message for the 100 MW relief in the Prairie Island-Byron interface is sent out through the MCN. The curtailments should take place ASAP, not later than 02:30. NO schedules are specifically identified for reduction. No schedule cuts are made.
02:20:01	NSP	Pine Lake - Wissota 115kV Open (Timed Overcurrent)
02:20:08	DPC	Crystal Cave-Apple River 161kV line tripped and the Apple River 69kV bus cleared. (NSP shows at 02:25:42 when Apple River RTU communications were restored.)
02:20:46	NSP	Pine Lake - Apple River/Crystal Cave 161kV Open (Timed Overcurrent)
02:20:52	DPC	Alma 4NB11 (69kV to Red Wing) tripped and did not reclose
02:21:22	MAPP (MCN)	NSP / ASK-ECL-ARP TRIPPED. NSP IS SUSPENDING FERC 888/889 DUE TO LOSS OF 345KV INTERCONNECTIONS. (MCN message from NSPM to BC)
02:21:24:280	MP	**Stinson – Minong 161kV line trips** (Stinson CB 6T opened by time overcurrent relay). This line trip continues the cascade tripping of the Minnesota - Wisconsin ties which separates Minnesota from Northwest Wisconsin. **The Stinson-Ironwood-Park Falls 115kV line is the only tie to Northwest Wisconsin remaining at this point.** (NSP shows 2:21:26) The remaining ties from the Twin Cities to the south, and those to Northwest Ontario are further stressed.
02:21:24	MH	Another change in tie flows accompanied by oscillations.: D602F decreases further to approx. 647 MW, L20D increases to approx., 330 MW, K21W increases to approx. 250 MW. Note: only one MH-OH tie was in-service.
02:21:26	DPC	Barron 16NB4 (69kV to Pine Lake) tripped and did not reclose
02:21:27	NSP	South Faribault - West Owatonna 161kV Open
02:21.28	MP	Little Fork 20K and 21K CLOSED
02:21:28	OH	Kenora bus voltage dropped from 234 to 218kV and Fort Frances from 119 to 110kV.
02:21:28.464	WAPA	Spencer PCB 1242 trips (phase distance, zone 3) – opening 161/69kV interconnection
02:21:29	NSP	Cedar Falls generation (6.9 MW) trips (restored at 02:26:25).
02:21:30	IPW	Trip CB 660 Hayward to Winnebago 161kV zone 3ϕ
02:21:31	IPW	Trip CB 775 Fox Lake to Winnebago 161kV zone 2ϕ **All ties south between NSP system and Iowa are now tripped except for Wilmarth-Lakefield 345kV line and the Wilmarth-Winnebago 161kV line which is only interconnected through the Winnco 69kV underlying system.**
02:21:31	NSP	**Ironwood – Park Falls 115kV Trips (Overload)**

Time (CDT)	Reporting Company	Event
		Minnesota separated from Northwest Wisconsin (all Twin Cities east ties tripped).
02:21:32	IPW	Trip CB 620 Albert Lea Westside to Walters 69kV zone 2ϕ
02:21.46	MP	Stinson 10K Capacitor Bank OPEN
02:21:52	OH	Largest power surge recorded on Kenora-Whiteshell 230kV line (K21W) (244 MW) @t=02:21:52. Largest surge on International Falls-Ft Francis Phase Shifter (F3M) (174 MW) was recorded @t=02:21:38. Both MH>OH and MP>OH tie flows exceeded operating limits.
02:21:54:880	MP	**Manitoba – Ontario 230kV (K21W) tie trips** by overcurrent protection. This line trip correctly initiated a MH DC reduction (265 MW). ***(SPS OPERATION)***
02:21:55.147	MP	**International Falls-Ft Francis Phase Shifter (F3M) tie between Minnesota Power and Ontario trips** by out-of-step protection in response to the Kenora-Whiteshell 230kV line (K21W) trip. The NW Ontario East-West Ties (Wawa-Marathon 230kV Line #1 and #2) trip in response to K21W and F3M trips. (See OH 02:22:04 event) **NW Ontario separated from Manitoba and Minnesota.**
02:21:55	MP	Little Fork 22K Capacitor Bank CLOSED
02:21:56	MH	Frequency starts to increase and Dorsey frequency damping controller reacts by gradually decreasing MH DC power. (Approximately a 300 MW reduction over a 1 second timeframe)
02:21.56	MP	Little Fork 20K,21K,22K and 25K Capacitor Banks OPEN
02:21:56.922	NSP	**Wilmarth – Lakefield 345kV line trips** (Tripped on zone 2 primary and secondary phase distance relays. IPW reported "out of step" targets and timers. This combination of targets is consistent with a trip for an out of step condition.) The cascade tripping of the remaining Minnesota and North Dakota ties to the south commences. Minnesota, Manitoba, and North Dakota are ultimately islanded together. (NSP shows 02:21:57, MP shows at 02:21:56.922)
02:21:56.948	WAPA	Ft Thompson terminal of Leland Olds-Ft Thompson 345kV line opens, open ending the line, no automatic reclose. PCB's 2992 and 2996 tripped (phase distance, zone 1)
02:21:57.160	WAPA	White terminal of White-Split Rock 345kV line opens. PCB's 396 and 492 tripped (phase distance, zone 1)
02:21:57.177	WAPA	Split Rock terminal of White-Split Rock 345kV line also opens, de-energizing line, no automatic reclose. PCB's 196 and 192 tripped (target unknown) (NSP shows 02:21:59)
02:21:57.186	WAPA	Bismarck terminal of Bismarck-Glenham 230kV line opens, open ending the line. PCB 582 tripped (phase distance, zone 1 and 2). Glenham PCB 382 tripped at 02:21:57:375 at which time the line was already de-energized. (MDU shows 02:21:57:383 for PCB 382 trip). Glenham PCB 382 was closed at 02:21:58:069 at which time the line was still de-energized from both ends. (MDU shows 02:21:58:081 for PCB 382 close).
02:21:57.246	WAPA	Ft Randall units 1-6 and 8 tripped. Units 1 and 7 were loaded at 42 MW each prior to disturbance. Remaining units were condensing. Unit 1 tripped during disturbance resulted in 42 MW loss. Unit #1 back on-line approx. 03:57.

Time (CDT)	Reporting Company	Event
02:21:57.249	WAPA	Ft Thompson terminal of Ft Thompson-Huron #2 230kV line opens, open ending the line. PCB 786 tripped (phase distance, zone 1)
02:21:57.250	WAPA	Glenham terminal of Glenham-Sully Buttes 230kV line opens, open ending the line, de-energizing Glenham substation and associated customer loads. PCB 282 tripped (phase distance, zone 1) (MDU shows 02:21:57:256)
02:21:57.255	WAPA	Ft Thompson terminal of Ft Thompson-Huron #1 230kV line opens, open ending the line. PCB's 586 and 582 tripped (phase distance, zone 1)
02:21:57.264	WAPA	Huron terminal of Ft Thompson-Huron #2 230kV line opens, de-energizing line, no automatic reclose. PCB's 786 and 782 tripped (phase distance, zone 1).
02:21:57.266	WAPA	Huron terminal of Huron-Storla 115kV line opens, open ending the line. PCB 1362 tripped (phase distance, zone 1)
02:21:57.266	WAPA	Huron terminal of Ft Thompson-Huron #1 230kV line opens, de-energizing line, no automatic reclose. PCB's 582 and 586 tripped (phase distance, zone 1)
02:21:57.282	WAPA	Brookings terminal of Brookings-Flandreau 115kV line opens, open ending the line, no automatic reclose. PCB 1862 tripped (phase distance, zone 1)
02:21:57.293	WAPA	Maurine terminal of Maurine-Hettinger 230kV line opens, open ending the line, no automatic reclose. PCB's 282 and 582 tripped (phase distance, zone 1)
02:21:57.331	WAPA	Hettinger terminal of Maurine-Hettinger 230kV line also opens, de-energizing line, momentarily de-energizing Bison substation and associated customer load, automatic reclose. PCB's 282 and 186 tripped (phase distance, zone 1) (MDU shows 02:21:57:332 and 02:21:57:334 respectively)
02:21:57:486	MH	D602F MH DC reduction (40% = 340 MW) received at Dorsey from Forbes. Forbes DCAR relay operated in response to system swings. ***(SPS OPERATION)***
02:21:57.839	WAPA	Hettinger terminal of Hettinger-Maurine 230kV line re-closes, re-energizing open ended Hettinger-Bison-Maurine 230kV line, restoring service to Bison substation. PCB 282 reclosed. (MDU shows 02:21:57:845)
02:21 (approx.)	OTP	Wahpeton CB 215 tripped on under-voltage. Load restored at 03:15
02:21 (approx.)	OTP	Toronto CB 515 tripped on under-voltage. Load restored at 03:17
02:21 (approx.)	OTP	Big Stone Hwy 12 CS 1211 opened on under voltage. Load restored at 03:14.
02:21 (approx.)	OTP	Marsh Lake CB 475 tripped. Loads restored at 03:18
02:21:57	NSP	Buffalo Ridge - Pipestone 115kV Open
02:21:58	MEC	Neal unit #4 tripped (Load level=490 MW) (Generator distance protection). Back on-line at 08:41 and at full load at 15:00.
02:21:58	DPC	Twin Lakes-Winnco 69kV tripped and remained open-ended at Winnco (34NB9) for 5-1/2 minutes.
02:21:58	MH	Frequency reaches 60.8 Hz blocking Bipole 2 valve groups 31 and 42 by overfrequency protection , resulting in 250 MW dc power decrease
02:21:58	MH	Frequency stabilizes at 61.0 Hz and Bipole 1 valve groups 12 and 23 block by overfrequency protection. No significant power change on Bipole 1 as remaining valve groups compensate
02:21.58	MP	Winton Generator 2U OPEN by relay

Time (CDT)	Reporting Company	Event
02:22:00	IPW	Trip CB 862 Dotson to Rutland 69kV zone 1ϕ Trip CB 711 Rutland to Dotson 69kV zone 1ϕ
02:22:01	IPW	Trip CB 007 Emery to Franklin 161kV (zone 2 carrier) (unrelated to disturbance) Trip CB 773 Fox Lake to Lakefield 161kV (zone 2ϕ) Trip CB 737 Fox Lake 161/69 Transformer (time overcurrent) Open Lakefield-Wilmarth 345kV (out of step) Open Lakefield-Raun 345kV (out of step) Open Lakefield 345/161kV transformer (out of step) The Raun-Ft Calhoun 345kV line opens 75msec after Lakefield-Raun 345kV line (out of step) Lakefield-Triboji (Wisdom) 161kV line flows: 123 MW @02:16, 196 MW @02:21, 240 MW @02:22, and -25 MW @02:22:30 after Wilmarth-Lakefield-Raun 345kV line trips. Cedar Falls Streeter unit #7 tripped (Loss of field protection)
02:22 (approx.)	NPPD	Disturbance in Northern MAPP area which resulted in loss of load and voltage and frequency oscillations on NPPD's system
02:22:01	NSP	Buffalo Ridge - Pipestone 115kV automatically reclosed
02:22:01	NWPS	Mitchell PCB 2731 to Huron 115kV opened, did not Reclose.
02:22:01	NWPS	Redfield PCB 4704 to Huron 115kV opened and reclosed.
02:22:01.799	MDU	HETTINGER 230KV JCT. SUB. 230KV PCB #186 RING BUS CLOSED -- Restore ring bus (Hettinger-Maurine already energized)
02:22:02.406	MDU	ELLENDALE 230KV JCT. SUB. 14KV PCB #5137 REACTOR OPEN
02:22.02	MP	Knife Falls Generators 1U, 2U 3U OPEN by relay
02:22:03	NSP	Pathfinder - Split Rock 115kV Open
02:22:04	OH	East-West ties (Wawa-Marathon 230kV Line #1 and #2, designated as W21M and W22M) tripped. Prior to the trips, the East-West ties were left supplying the NW system, which was deficient by about 360 MW. Due to large power surge on W21W+W22M into the NW Ontario following the loss of K21W + F3M, Marathon voltage was brought down to 17% (i.e. from 175kV to 40kV in _ second) and the current on W22M to about 940 amps. W22M was tripped by line protection, then W21M tripped 4.5 cycles later. Thunder Bay G3 (thermal unit) tripped on under-frequency protection. FTR load shedding triggered. At this time, the NW system collapsed and was shut down with the exception of a 20 MW island containing Ear Fall GS, Manitou GS, Red Lake TS and Ear Falls DS. **NW Ontario ISLAND (blacked out) formed. Approximately 650 MW of load lost.**
02:22:06	IPW	Close CB 862 Dotson to Rutland 69kV Close CB 711 Rultand to Dotson 69kV (Auto reclose) Trip CB 710 Rutland 161/69 Transformer (Reason unknown) Trip CB 712 Rutland to Fairmont 69kV zone 1ϕ
02:22:09.434	MDU	ELLENDALE 230KV JCT. SUB. 14KV PCB #5137 REACTOR CLOSE
02:22:09	NSP	**Open - Wilmarth – Winnebago 161kV Line** **Minnesota/Manitoba/North Dakota/Saskatchewan (MN-MH-ND-**

Time (CDT)	Reporting Company	Event
		SASK) ISLAND is formed. **The frequency of the island increases almost immediately to 60.9 Hz, then drops to 60.7 Hz over the next 13 seconds (appears due primarily to Poplar River #2 unit trip), and then ramps to 61.1 Hz over the next approx. 2-1/2 minutes.**
02:22.10	MP	International Falls 726L OPEN by out of step relay, (MP-Ontario Tie)
02:22:10	OTP	Hoot Lake #3 tripped on low load while following frequency excursions. Output was 18 MW before trip. Unit returned at 04:45
02:22:11	NSP	Open Pine Lake - Rock Elm 69kV
02:22:12	NSP	Open T-Corners - Wien 115kV (Over-current trip)
02:22.12	MP	International Falls 11K Capacitor Bank OPEN LSPI 10K Capacitor Bank OPEN
02:22:13	IPW	Fox Lake G3 (88MVA rating) tripped at 2:22 with 18 MW of output on over-excitation. The reactive output went from 7MVAR at 2:18:00 to 58MVAR at 2:18:30. Lansing G4 (274MVA rating) increased reactive output from 9MVAR at 2:17:00 to 44MVAR at 2:21:30 with a real power output of 185 MW.
02:22:13 (approx.)	SPC	The SaskPower frequency increased rapidly to 60.85 Hz. This caused intercept valves to operate on the 300 MW Poplar River #2 thermal unit. The unit tripped off line due to cold reheat steam pressure. SaskPower frequency continued to increase subsequent to the unit trip. The maximum frequency observed was 61.05 Hz. at approx. 02:24:57.
02:22:32	NSP	Open Red Wing - Alma 69kV (out due to storm damage) Open Pine Lake - Barron 69kV restoration at 2:34:55
02:22:35	MEC	Neal unit #3 tripped (430 MW) on Volt/Hz protection. Unit back on-line at 04:37, reached full load at 10:00.
02:22:35	NSP	Riverside unit #7 tripped (66 MW)
02:22:40	NSP	Open Stone Lake – Bayfront 69kV
02:22:42	IPW	Open Mt Lake 69kV, 5.4MVAR Capacitor Bank (Overvoltage trip)
02:22.48	MP	Forbes 20K OPEN (90 I initiate) Capacitor Bank
02:22:51.496	WAPA	Tioga 230/115kV transformer 230kV terminal opens, open ending transformer. PCB's 782 and 882 tripped (Reverse Power Flow)
02:22:53	UPA	Dickinson 345 62JSM3 Dickinson 114 MVAR shunt bank Manually tripped for voltage control
02:22.58	MP	Brainerd 2K OPEN
02:23:02	MEC	Neal unit #2 tripped (92 MW) on Volt/Hz protection. Unit back on-line at 06:56, reached full load at 11:00.
02:23:35	MAPP (MCN)	**NSP IS SUSPENDING FERC 888/889 DUE TO LOSS OF 345KV INTERCONNECTIONS. (MCN message from NSPM to BC)**
02:24:17	UPA	Grasston 69 15NB1 Grasston-Cambridge 69kV Tripped and reclosed auto at 2:24:23
02:24:17	UPA	Cambridge 69 2NB4 Grasston-Cambridge 69kV Tripped and reclosed auto at 2:24:25
02:24:31	MP	Unknown event causes significant frequency excursions.
02:24:51.041	NSP	Sherco Unit 3 trips (738 MW) (NSP shows at 02:24:58, MP shows at 02:24:51.041) **MN-MH-ND-SASK ISLAND frequency drops quickly from 61.1 Hz due to unit trip and stabilizes at 60.8 Hz.**
02:25	MH	Flow on D602F steps from 150 MW north to 30 MW north then to 100 MW south. L20D steps from 30 MW north to 120 MW north .

Time (CDT)	Reporting Company	Event
02:25:14.204	UPA	**CU HVDC Pole 1 manually tripped** Dickinson 345 62JB1,62JB2 CU HVDC Pole 1 manually tripped (MP shows at 02:25:14.360) Coal Creek 230 61RB1,61RB2 CU HVDC Pole 1 manually tripped at 02:25:14.282 **MN-MH-ND-SASK ISLAND frequency drops slightly.**
02:25:42.042	UPA	**CU HVDC Pole 2 trips** Coal Creek 230 61RB5,61RB6 CU HVDC Pole 2 trip on voltage stress protection at Coal Creek at 02:25:42.042 Dickinson 345 62JB5,62JB6 CU HVDC Pole 2 trip on voltage stress protection at Coal Creek at 02:25:42.111 (MP shows at 02:25:42.036) **At this point the Minnesota/Manitoba/Saskatchewan and North Dakota frequencies start to diverge and the separation of North Dakota from Minnesota/Manitoba/Saskatchewan commences.** **Following the separation of ND from MN/MH/SASK there was a 0.15 Hz oscillation of the frequency in the ND system. This was a poorly damped oscillation with an amplitude of +/- 0.5 Hz which lasted for 31.5 seconds until 02:26:16.**
02:25:42.161	UPA	Coal Creek 230 61RB3 CCS Unit 2 Unit 2 trip for loss of HVDC Note: CCS Unit 1 remained on-line on the AC system (370 MW net)
02:25:42	MH	L20D steps from 120 north to 300 north and Letellier voltage declines to 0.75 pu. **Lettelier-Drayton 230kV (L20D) trips** (Out of step protection). No MH DC reduction as flow north (correct response).
02:25:42.33	UPA	Ramsey 230 33RB3 Cap Bank 1 Automatically closed
02:25:42.50	UPA	Ramsey 230 33RB4 Cap Bank 2 Automatically closed
02:25:42.684	UPA	Coal Creek 230 61RSM2 CC High Pass Filter 1 Auto trip for loss of HVDC
02:25:42.684	UPA	Coal Creek 230 61RSM4 CC High Pass Filter 2 Auto trip for loss of HVDC
02:25:42.951	WAPA	**Tioga 230kV breaker opens, open ending the Tioga-Boundary Dam 230kV (B10T) line,** and the Tioga-Logan 230kV line). PCB 786 tripped (out of step protection).
02:25:43.037	SPC	Boundary Dam-Tioga (B10T) line tripped at Boundary Dam by direct transfer trip signal from Tioga. Suspected operation of the out of step relaying at Tioga. Impedance relaying at Boundary Dam end of B10T started but did not issue a trip signal. The SaskPower frequency dropped to 59.65 Hz immediately after the B10T trip occurred. Frequency returned to 60 Hz by approx. 02:26:05.
02:25:43.233	WAPA	Open-Ended Tioga-Boundary Dam 230kV (B10T) line energized from the Tioga end. PCB 882 closed manually via SCADA.

Time (CDT)	Reporting Company	Event
02:25:43.299	WAPA	Huron terminal of Huron-Storla 115kV line recloses. PCB 1362 reclosed. Systems are asynchronous across this line, resulting in the subsequent immediate trip at 02:25:43.625.
02:25:43.47	UPA	Ramsey 230 33RB3 Cap Bank 1 Automatically tripped
02:25:43.47	UPA	Ramsey 230 33RB4 Cap Bank 2 Automatically tripped
02:25:43.580	OTP/MP	Audubon CB 2125 tripped on instantaneous over current due to large current flow on Hubbard 230kV line. Closed at 03:23 by dispatcher.
02:25:43.625	WAPA	Huron terminal of Huron-Storla 115kV line opens, open ending the line. PCB 1362 tripped (phase distance, zone 1)
02:25:43.689	WAPA	Storla terminal of Huron-Storla 115kV line opens, momentarily de-energizing the Woonsocket substation and associated customer load, automatic reclose. PCB's 2266 and 2162 tripped (phase distance, zone 1)
02:25:43.750	WAPA	Granite Falls terminal of Granite Falls-Panther 230kV line opens, open ending the line to NSP's substation. PCB 682 tripped (phase distance) (NSP shows 02:25)
02:25.43.751	MP	Wing River 915L OPEN by Zone 1 distance relay (Opens Wing River-Inman 230kV line)
02:25:43.795	WAPA	Granite Falls terminal of 69kV interconnection with UPA opens, automatic reclose. PCB 4352 tripped (phase distance, zone 1, phase B)
02:25 (approx.)	OTP	Big Stone Plant tripped off line during voltage excursions, could not follow. Output was 342 MW before trip. On line at 09:06, off at 09:18, on line at 09:49 and released for 400 MW at 11:30.
02:25 (approx.)	OTP	Fergus Falls CB 2265 trips and recloses successfully. Zone 1 distance due to depressed voltage and large current flow on 230 line
02:25:44.231	UPA	Coal Creek 230 61RB8,61RB9 CC Filter Bank 3 Overvoltage trip
02:25:44.266	UPA	Coal Creek 230 61RB10,61RB11 CC Filter Bank 2 Overvoltage trip
02:25:44.437	MP	**Square Butte HVDC Pole 2 trips** on over-frequency at 62.2 Hz. Pre-trip loading of both poles is 250 MW. Square Butte breakers 18 & 19 OPEN by Square Butte Pole #2 frequency Protection. Pole #1 picked up Pole #2's share of the flow. At 02:25:44.453, Pole 1 starts ramp (500 to 1000 amps). At 02:25:44.614 (177mSec after Pole #2 tripped) Pole 1 finishes ramp (at 1000 amps). After that time, no additional energy was transferred into the North Dakota AC system.
02:25:44.792	WAPA	Storla terminal of Huron-Storla 115kV line re-closes, restoring service to Woonsocket substation. PCB 2266 reclosed.
02:25:46	NSP	Open MN Valley - Bird Island 69kV
02:25:46	UPA	Willmar 69 13WB1 Willmar-MN Valley 115kV Tripped by Protections
02:25:46	UPA	Willmar 69 13NB2 Willmar-Granite Falls 69kV Tripped by Protections (NSP shows 02:25:47)
02:25:46	UPA	Willmar 69 13NB3 Willmar-Hutchinson 69kV Tripped by Protections
02:25:46	UPA	Willmar 69 13NB6 Willmar-Granite Falls 230kV Tripped by protections
02:25:46.211	WAPA	Granite Falls terminal of 69kV interconnection with UPA recloses. PCB 4352 closed.
02:25:47	NSP	Minnesota Valley - Franklin 115kV Open

Time (CDT)	Reporting Company	Event
02:25:47	NSP	Open Douglas Cty - Osakis 69kV
02:25:47	NSP	**Willmar - Kerkhoven/MN Val. Jct 115kV Open** **The initial MN/MH/ND/SASK ISLAND has essentially completed a separation into two smaller ISLANDS, resulting in a North Dakota ISLAND and a Minnesota/Manitoba/Saskatchewan ISLAND being formed. However, one 115kV tie line remains energized between the two smaller ISLANDS (the Grant County-Douglas County 115kV line, which trips approximately 5minutes later at 02:30:59). During the time this line remains in-service, the North Dakota system is slipping against the Minnesota system, resulting in significant voltage oscillations.** **The frequency of the ND ISLAND immediately increases to approximately 62 Hz.**
02:25.48	MP	Blanchard Generator 3U OPEN by relay
02:25.49	MP	Square Butte 89FHP2 and 89F11-13P2 OPEN (Pole 2 Filters)
02:25.50	MP	Blanchard Generators 1U & 2U OPEN by relay
02:25:50	NSP	Open Douglas Cty – Westport 69kV
02:25:55.243	WAPA	Antelope Valley Unit #2 tripped by over frequency (64 Hz max recorded), prior loading was 430 MW, loading at time of trip was 370 MW. PCB U2 tripped. **The frequency of the ND ISLAND decreases to approx. 61 Hz over the next 20 seconds due to AVS2 trip, and then increases to approximately 61.8 Hz over the next 10 seconds until it appears that the Coyote unit tripped.**
02:25.56	MP	Square Butte 89TP2 OPEN (Pole 2 Line Disconnect)
02:25:58	NSP	Close Stone Lake – Bayfront 69kV
02:25:59	NSP	**Ironwood – Park Falls 115kV Closed** **This line closure reconnected Minnesota/Manitoba/Saskatchewan ISLAND to Eastern Interconnection approx. 12 seconds after it was formed when North Dakota separated from the Minnesota/Manitoba/North Dakota/Saskatchewan ISLAND. The North Dakota ISLAND is still slipping against the Eastern Interconnection at this point through the Douglas County-Grant County 115kV line which is still energized.** **The frequency of the NSP/MH/SASK systems immediatély decreases to approximately 59.95 Hz to match the frequency measured in the NPPD and DPC systems at the time.**
02:26	MAPP (MCN)	MAPP SCO REQUESTED VOLUNTARY ECONOMY SCHEDULE REDUCTIONS TO ASSIST IN UNLOADING NSP'S 345KV LINES TO REDUCE THE PHASE ANGLE TO RECLOSE PRI-BYN.
02:26	NSP	Afton - Red Rock 115kV Closed (by SCADA)
02:26 to 03:11 (approx.)	OH	In preparation for the system restoration, opened all 230, 115 and 24kV breakers that were still closed and off potential.
02:26 (approx.)	OTP	Hoot Lake 2 tripped off line due to fuel trip, probably voltage related. Output was 32 MW before trip. On line at 04:36
02:26:01.462	WAPA	Tioga PCB 782 closed, restoring Tioga 230/115kV interconnection and the Tioga-Logan 230kV line.
02:26:16	MP	**Poorly damped 0.15 Hz oscillation in ND suddenly stops**
02:26:17.162	MDU	COYOTE 345KV JCT. SUB.

Time (CDT)	Reporting Company	Event
		TT-94TTP FROM PLANT OPERATED -- Trip command issued from plant
02:26:17.200	MDU	COYOTE 345KV JCT. SUB. 345KV PCB #5712 RING BUS OPEN -- Ring bus opened
02:26:17.207	MDU	COYOTE 345KV JCT. SUB. 345KV PCB #5715 RING BUS OPEN -- Coyote plant tripped off-line. Output was 375 MW prior to disturbance, approx 0 MW just prior to trip. Unit was on and off-line several times until 13:54 when it remained on-line. **The frequency of the ND ISLAND begins to decrease over the next approx. 2 minutes to settle between 61.3-61.4 Hz.**
02:26:19	NSP	Red Rock - Crystal Cave 115kV Closed
02:26:19	NSP	South Faribault - West Owatonna 161kV Closed
02:26:21	NSP	Pine Lake - Rock Elm 69kV Closed
02:26:22	NSP	King - Eau Claire 345kV Closed
02:26:22	NSP	Pine Lake - Wissota 115kV Closed
02:26:25.344	WAPA	Groton 345/115kV transformer KU2A tripped by Overvoltage protection. PCB's 8492, 8392, and 762 tripped (Instantaneous and timed overvoltage, transformer de-energized and locked out).
02:26.50	MP	Square Butte 89PSS2 CLOSED (Pole Shorting Switch)
02:26:51	NSP	Highbridge #6 149 MW tripped
02:26.55	MP	Arrowhead 89PSS2 CLOSED (Pole Shorting Switch)
02:27	MAPP	MEC / NEAL #2 & #3 TRIPPED.
02:27:03	NWPS	Aberdeen PCB 5701 to Redfield closed by operator.
02:27:04.066	UPA	Dickinson 345 62JSM8 Dkn Band Pass Filter 2 Manually tripped for voltage control
02:27:11.635	UPA	Dickinson 345 62JSM2 Dkn Band Pass Filter 1 Manually tripped for voltage control
02:27.22	MP	Verndale 2K Capacitor Bank CLOSED
02:27:36	DPC	Twin Lakes-Winnco 69kV looped (34NB9 Closed)
02:27:57.10	UPA	Ramsey 230 33RB2 Ramsey-Prairie 230kV Tripped by protections
02:28	MAPP (MCN-EM)	MEC / NEAL-3 FOR 450 MWS X 0230 (JOINT). CANCELLED X 0330. TOTAL DELIVERED = 324 MWS-MEC & 126 MWS -ALT. OASIS #95205-MEC. OASIS #95214-ALT. TC E-MAILED.
02:28:00.052	UPA	Dickinson 345 62JSM1 Dkn High Pass Filter 1 Manually tripped for voltage control
02:28:20.119	UPA	Dickinson 345 62JSM9 Dkn High Pass Filter 2 Manually tripped for voltage control
02:29:34.98	UPA	Ramsey 230 33RB1 Ramsey-McHenry 230kV Tripped on Overvoltage
02:29:35.03	UPA	Ramsey 115 33WB1 Ramsey 230/115kV Transformer Tripped on Overvoltage
02:30.16	MP	Wing River 915L ATTEMPTED TO CLOSE VIA SCADA "FAILED TO CLOSE"
02:30:59	NSP	**Douglas County – Grant County 115kV line trips (Douglas County CB 5N606 trips due to a fault)** **This line trip finally completes the electrical separation of the North Dakota ISLAND from the Eastern Interconnection, and**

Time (CDT)	Reporting Company	Event
		ends the severe voltage oscillations, which had been occurring for approximately the last 5 minutes due to the slipping between the two areas. The Grant County end breaker (OCB 1345) opens at 02:31:18. Alexandria CB 250 opened, MRES load lost. Restored at 05:36. Brandon 115 Sub loads lost, restored to normal at 05:24. Some loads on at 04:50
02:30:59	NSP	Elbow Lake CB 1314 opened. Loads restored at 04:19 and 04:46. This is part of Grant County-Douglas County line.
02:31	MAPP **(MCN-EM)**	SMP / SHERCO-3 FOR 230 MWS X 0233 (SOLE). LOWERED TO 100 MWS X 0335. CANCELLED X 0405. TOTAL DELIVERED = 288 MWS. OASIS #95207. TC E-MAILED.
02:31:44.012	WAPA	Bismarck terminal of Bismarck-Glenham 230kV line closed, restoring service to Glenham substation - 9min,45sec outage. PCB 582 closed.
02:31.50	MP	Verndale 1-2KM and 2K OPEN
02:32	MAPP (MCN)	WAPA / ISLANDED FROM THE SYSTEM. F = 61.363 Hz. REQUESTING FREQ. INFO FROM OTHERS.
02:32	MAPP **(MCN-EM)**	OTP / BIGSTONE FOR 219 MWS X 0234 (SOLE). LOWERED TO 100 MWS X 0600. CANCELLED X 0800. OASIS #95236. TC E-MAILED. TOTAL DELIVERED = 1006 MWS.
02:32:51	UPA	Coal Creek 230 61RSM1 CC Band Pass Filter 1 Manually tripped for voltage control
02:33:17	NSP	Prairie Island - Byron 345kV Closed (DPC shows at 02:33:49)
02:34 (approx.)	MAPP (Phone Call)	*****NERC HOTLINE***** INITIATED BY MAPP - INFORMED ALL REGIONS OF MAPP STATUS, **SUSPENDED FERC 888/889 AS A REGION**, ASKED FOR ASSISTANCE WITH GENERATION RESERVES.
02:34	MAPP **(MCN-EM)**	OTP / COYOTE FOR 140 MWS X 0234 (SOLE). LOWERED TO 50 MWS X 0515. INCREASED TO 125 MWS X 0652. INCREASED TO 125 MWS X 0652. INCREASED TO 175 MWS X 0655. CANCELLED X 0800. OASIS #95235. TC E-MAILED. TOTAL DELIVERED = 594 MWS.
02:34	MAPP **(MCN-EM)**	UPA / COAL CREEK #2 FOR 630 MWS X 0236 (JOINT). LOWERED TO 280 MWS X 0330. CANCELLED X 0400. TOTAL DELIVERED = 417 MWS-GSE & 290 MWS-UPA. OASIS #95208-UPA. OASIS #95215-GSE. TC E-MAILED.
02:34:09	IPW	Open Montgomery (MN) 69kV, 6.0MVAR Cap Overvoltage
02:34:16	UPA	Coal Creek 230 61RSM3 CC Band Pass Filter 2 Manually tripped for voltage control
02:34:51	DPC	Close Pine Lake - Barron 69kV (CB 16NB4 Closed) (NSP shows at 02:34:55)
02:36	MAPP **(MCN-EM)**	NWPS / BIGSTONE FOR 95 MWS X 0240 (SOLE). CANCELLED X 0330. TOTAL DELIVERED = 80 MWS. OASIS #95209. TC E-MAILED.
02:36:06.949	WAPA	Open-Ended Tioga-Boundary Dam 230kV (B10T) line de-energized from the Tioga end. PCB 882 opened manually via SCADA.
02:36:17	UPA	McHenry 230 32RB3 McHenry-Ramsey 230kV Transfer trip

Time (CDT)	Reporting Company	Event
		from Ramsey
02:36:17	UPA	McHenry 115 32WB1 McHenry-Ramsey 230kV Transfer trip from Ramsey
02:36:34	MAPP (MCN)	WAPA / SUSPENDING FERC 888/889 DUE TO DISTURBANCE
02:36:40.045	SPC	Boundary Dam-Tioga 230kV (B10T) line energized from Boundary Dam end. Still open at the Tioga end until 03:09:03.904.
02:37	MAPP **(MCN-EM)**	NWPS / COYOTE FOR 40 MWS X 0240 (SOLE). CANCELLED X 0330. TOTAL DELIVERED = 33 MWS. OASIS #95210. TC E-MAILED
02:38 (approx.)	MAPP (Phone Call)	MAPP SECURITY CENTER OPERATOR CALLED AEP TO REQUEST A TIME CORRECTION TO STOP THE FREQ. DECLINE. START TC 'H' @ 0300 @ F = 60.02 Hz. TE = -4.65 SEC.
02:38:34	IPW	Open Highway 106 69kV, 6.1MVAR Cap Overvoltage
02:38:55.231	WAPA	Bismarck terminal of Bismarck-Glenham 230kV line manually opened for voltage control, de-energizing the Glenham substation and associated customer load. PCB 582 tripped (by SCADA).
02:39	MAPP **(MCN-EM)**	MEC / NEAL-4 FOR 411 MWS X 0241 (JOINT). CANCELLED X 0330. TOTAL DELIVERED = 248 MWS-MEC & 88 MWS-NWPS & 0 MWS ALT. OASIS #95206-MEC. OASIS #95213-ALT(INVALID-NO ALT EM). OASIS #95226-NWPS. TC E-MAILED.
02:39:10	IPW	Open Lime Creek 69kV, 6.0MVR Cap Overvoltage
02:39.13	MP	Badoura 5R CLOSED by control
02:43	MAPP (MCN)	UPA / COAL CREEK FREQUENCY = 60.4 Hz.
02:45	**Exports**	**NDEX=247 MW, MHEX=1161 MW, TCEX=43 MW**
02:47:13	UPA	Hutchinson 69 C3NB3 Hutchinson Generators Tripped and reclosed at 2:51:19
02:50:15	IPW	Trip CB 34NB9 Winnco to Thompson 69kV zone 1ϕ
02:50:51	IPW	Close CB 34NB9 Winnco to Thompson 69kV
02:51:13	IPW	Trip CB 735 Fox Lake to CP Dunnel 69kV
02:51:19	IPW	Trip CB 734 Fox Lake to Fairmont 69kV
02:51:25	IPW	Trip CB 736 Fox Lake to St James 69kV the Fox Lake 69kV bus was opened manually by Fox Lake Plant operators according to 'black start' contingency plan
02:51.34	MP	Wing River 915L (Wing River-Fergus Falls 230kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"
02:52.06	MP	Wing River 915L (Wing River-Fergus Falls 230kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"
02:52.54	MP	Badoura 64L (Badoura 230/115kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"
02:52:57.635	WAPA	Huron terminal of Ft Thompson-Huron #1 230kV line closed, closing the line, line stayed in approx 1/2 sec before tripping. PCB 582 closed manually via SCADA.
02:52:58.192	WAPA	Huron terminal of Ft Thompson-Huron #1 230kV line opens, open ended the line. PCB 582 tripped (target to be determined).
02:52:58.199	WAPA	Ft Thompson terminal of Ft Thompson-Huron #1 230kV line opens, de-energizing already open line. PCB 582 tripped (target to be determined).
02:53	MAPP (MCN)	MAPP / MAPP AS A REGION SUSPENDED FERC 888/889 DUE TO SEVERAL OUTAGES AND SUBSEQUENT GENERATION

Time (CDT)	Reporting Company	Event
		TRIPPING:
02:53	MP	Ontario Hydro Fort Frances 22EH, 22EL3, 22HL1, 22JL1, 22JL6 & 22L3L6 OPEN
02:54	MAPP	MAIN & PJM POSTED MAPP CONDITION TO ITS MEMBERS.
02:54:22	NSP	Closed - Cannon Falls - Zumbrota 69kV
02:55	MAPP (MCN)	NSP / PRI-BYN BACK, ASK-ECL BACK. ECL-ARP STILL OUT.
02:55:02.308	WAPA	Glenham terminal of Glenham-Sully Buttes 230kV line closed, restoring service to Glenham substation – 16min,7sec outage. PCB 282 closed manually via SCADA.
02:55:10	NSP	Closed - Cannon Falls - Northfield 69kV
02:56:34	NSP	Closed - Cannon Falls - Spring Creek 69kV
02:57	MAPP (MCN)	WAPA / THINKS THEIR NORTH-SOUTH SYSTEMS ARE SEPARATED. APPEARS TO BE INTERCONNECTED AGAIN @ 0308 W/ STABLE FREQ.
02:58.44	MP	Badoura 64L (Badoura 230/115kV) ATTEMPTED TO CLOSE VIA SCADA"FAILED TO CLOSE"
02:59:46	NWPS	Mitchell PCB 2731 to Huron 115kV closed by operator, energizing line. Huron end breaker still open.
02:59:51	NSP	(Eau Claire end only) Eau Claire – Arpin 345kV Closed
03:00.02	MP	Blanchard Generator 1U CLOSED
03:01.08	MP	Knife Falls Generator 1U CLOSED
03:01:27	DPC	Trip CB 34NB40 Winnco to Grant 69kV (manually by DPC) (IPW shows at 03:01:28) Opened Winnco 34NB40 by EMS to shed Grant, Linden, and Forest City. This was due to the overload of the Hayward-Twin Lakes-Winnco 69kV circuit and low voltage in the Winnco area. Voltage on the Winnco 161kV bus reached 191kV. 33 minute customer outage.
03:02.48	MP	Knife Falls Generator 2U CLOSED
03:03	NSP	Closed - King - Eau Claire - Arpin 345kV (Line restored)
03:03	NSP	Closed - Panther – Granite Falls 230kV (Line restored later at 03:18:59.032 when WAPA closed Granite Falls end breaker.)
03:03.12	MP	Winton Generator 2U CLOSED
03:03.16	MP	Badoura 64L (Badoura 230/115kV) CLOSED by control.
03:03:39.137	WAPA	**Bismarck terminal of Bismarck-Glenham 230kV line closed, restoring line to service.** PCB 582 closed manually via SCADA. **Reconnected North Dakota ISLAND to Eastern Interconnection approx. 38 minutes after it was formed. North Dakota had been islanded from Eastern Interconnection for approx. 41-1/2 minutes.**
03:03.40	MP	Badoura 48L CLOSED by control
03:03:43	NSP	Close MN Valley - Bird Island 69kV
03:03:44	NSP	Pathfinder - Split Rock 115kV Closed
03:03:44.182	WAPA	Huron terminal of Huron-Storla 115kV line closed, restoring line to service. PCB 1362 closed manually via SCADA.
03:03.50	MP	Blanchard Generator 2U CLOSED
03:03:50	WAPA	**WAPA Frequency (measured at Watertown bus) is 60.03 Hz.**
03:03.54	MP	Badoura 40L (Black Dog-Badoura 115kV) closed by control
03:04.26	MP	Badoura 2K Capacitor Bank OPEN
03:05:17.139	WAPA	Ft Thompson terminal of Ft Thompson-Leland Olds 345kV line closed, restoring line to service. PCB 2992 closed manually via SCADA.

Time (CDT)	Reporting Company	Event
03:05:43	UPA	Willmar 69 13NB3 Willmar-Hutchinson 69kV Manually reclosed at 3:05:43
03:06	MAPP (MCN)	NSP / ECL-ARP BACK @ 0305
03:07:55.819	WAPA	Maurine terminal of Maurine-Hettinger 230kV line closed, restoring line to service. PCB 582 closed manually via SCADA.
03:08:58	NSP	Pine Lake - Apple River/Crystal Cave 161kV Closed
03:09	MAPP (MCN)	IPW / XMS CURRENTLY OUT / LAKEFIELD-FOX LAKE 161KV, FOX LAKE-RUTLAND 161KV, WINNEBAGO JCT-WILMARTH 161KV, EMERY-FRANKLIN 161KV, HAYWARD-WINNEBAGO JCT 161KV, PLUS SEVERAL 69KV LINES.
03:09:03.904	WAPA	Tioga terminal of Tioga-Boundary Dam 230kV (B10T) line closed, restoring line to service. PCB 786 closed manually via SCADA. Tioga ring PCB 882 closed manually via SCADA at 03:09:34.212. **Tie line between Saskatchewan and North Dakota restored.**
03:09:11.854	WAPA	Huron terminal of Huron-Ft Thompson #1 230kV line closed, restoring line to servicej. PCB 582 closed manually via SCADA.
03:09:36	DPC	Apple River-Crystal Cave 161kV restored
03:11.30	MP	Blanchard Generator 3U CLOSED
03:12	OH	**OH Northwestern system restoration began from the OH eastern system.** Wawa-Marathon 230kV #1 (W21M) energized from Wawa.
03:13:08.208	WAPA	Split Rock terminal of Split Rock-White 345kV line closed, restoring line to service. PCB 196 closed manually via SCADA. (NSP shows at 03:13:11)
03:15	**Exports**	**NDEX=305 MW, MHEX=1194 MW, TCEX=184 MW**
03:15:52	SPC	Poplar River #2 unit resynched to the system.
03:16:42	NSP	Wilmarth - Lakefield Jct. 345kV energized from NSP end.
03:18:59.032	WAPA	Granite Falls terminal of Granite Falls-Panther 230kV line closed, restoring the line to service. PCB 682 closed manually via SCADA.
03:19:28	NSP	Close T-Corners – Wien 115kV
03:19:32	IPW	Close Wilmarth CB 885. Wilmarth-Lakefield 345kV line restored to service. **NSP transmission system essentially back to NORMAL.**
03:20	MAPP (MCN)	NSP / WILMARTH-LAKEFIELD 345KV BACK
03:20	MAPP (MCN-EM)	REQUESTED ALL COMPANIES TO RESPOND TO EM'S IN PROGRESS WITH THE ASSIGNED MWS.
03:20:23.155	WAPA	Brookings terminal of Brookings-Flandreau 115kV line closed, restoring line to service. PCB 1862 closed manually via SCADA.
03:21	OH	All Kenora breakers reported open by traveler operators.
03:23	MP	OTP reports 2125 Breaker at Audobon CLOSED (909 line is service)
03:23:08	IPW	Close CB 881 Lakefield to Raun 345kV
03:23.32	MP	Scanlon Generator 2U CLOSED
03:25	MH	Lettelier-Drayton 230kV (L20D) line restored to service
03:25:02	IPW	Close CB 884 Lakefield 345/161 Transformer
03:26.08	MP	Square Butte 89TP2 (Pole 2 Line Disconnect) CLOSED
03:26.08	MP	Scanlon Generator 1U CLOSED

Time (CDT)	Reporting Company	Event
03:27	MAPP (MCN)	MH / L20D IN SERVICE @ 0325. WENT OUT @ 0225.
03:28	MAPP (MCN)	MP / WING RIVER-FERGUS FALLS 230KV. SQ BT HVDC POLE #2 OUT. INTERNATIONAL FALLS-FORT FRANCIS OUT. NO GENERATION OUTAGES.
03:28.28	MP	Sandstone 4TM Transformer CLOSED auto
03:29	MAPP (MCN)	OPPD / ALL GEN OK
03:29:14	UPA	Pine City 69 4NB2 Pine City-Hinckley 69kV Reclosed at 3:29:20
03:29.18	MP	Sandstone 4TM Transformer OPENED by relay Hinckley 1T/1H1 Transformer OPENED by relay, remained open for transformer inspection
03:31	OH	Restoration of OH's NW system started from Manitoba by having Kenora-Whiteshell 230kV #1 (K21W) energized from Manitoba.
03:31:41	IPW	Close CB 007 Emery to Franklin 161kV
03:32:10	DPC	Apple River 69kV Bus back in service
03:33.47	MP	Wing River 915L (Wing River-Fergus Falls 230kV) CLOSED by control
03:34	MAPP (MCN)	CBPC / CBPC 161KV SYSTEM BACK IN SERVICE. PUT TWO TURBINES ON-LINE & RAISED WINDOM TO MAX OUTPUT.
03:34	MH	**Whiteshell-Kenora 230kV (K21W) restored to service** **Manitoba reconnected with Ontario.**
03:34	OH	Kenora L21L24 closed. K24F and Fort Frances T1 on potential via K21W.
03:34:57	IPW	Close CB 773 Fox Lake to Lakefield 161kV
03:35:31.091	WAPA	Spencer 161/69kV interconnection closed. PCB 1242 closed manually via SCADA.
03:35:55	UPA	Crowell 115 18WB4 MP Cromwell-Riverton 115kV Reclosed by MP at 3:44:42
03:35.56	MP	Riverton 13L OPEN by relay, closed auto Cromwell 13L OPEN by relay, closed auto
03:36	MAPP (MCN)	IESC / SYSTEM CONDITION 'GREEN'
03:36.03	MP	Scanlon Generator 3U CLOSED
03:38:17	IPW	Close CB 737 Fox Lake 161/69kV Transformer
03:38:40	NSP	Close Douglas County - Westport 69kV
03:38.50	MP	Square Butte breaker 18 & 19 (Pole 2 AC breakers) CLOSED
03:38:56	NSP	Close Douglas County - Osakis 69kV
03:39	MAPP (MCN)	NWPS / HURON-MITCHELL 115KV OPEN. ALL OTHER XMS IS NORMAL.
03:39:23	IPW	Close CB 734 Fox Lake to Fairmont 69kV
03:40:00	NSP	Douglas County CB 5N606 closed energizing the Douglas County-Grant 115kV line. Additional switching of the breaker occurred during the day for maintenance reasons. The line was fully restored at 22:02.
03:40:53	IPW	Close CB 736 Fox Lake to St James 69kV
03:41	MAPP	SECURITY CENTER OPERATOR CALLED AEP TO END TC 'H' DUE TO MAPP SYSTEM FREQ > 60.02 Hz. @ 0400 END TC. SET F = 60 Hz.
03:42	MAPP (MCN)	OPPD / 161KV XMS SYSTEM INTACT. RAUN-FT CALHOUN 345KV W/ MEC BRKR'S OPEN.

Time (CDT)	Reporting Company	Event
03:42	MAPP (MCN)	MDU / COYOTE EXPECTED BACK IN AN HOUR.
03:42:17	IPW	Close CB 775 Fox Lake to Winnebago 161kV
03:43:07	IPW	Close CB 735 Fox Lake to CP Dunnel 69kV
03:43:52	DPC	Close CB 34NB40 Winnco to Grant 69kV (IPW shows at 03:43:54)
03:45	**Exports**	**NDEX=400 MW, MHEX=1312 MW, TCEX=481 MW**
03:45:31	UPA	Coal Ck, Dickinson CU HVDC Pole 1 de-blocked
03:46	MAPP (MCN)	UPA / CU HVDC POLE #1 DE-BLOCKED @ 0345.
03:48	MP	Square Butte DC Pole #2 restarted (75 MW per pole)
03:48	MAPP (MCN)	SJLP / GEN & XMS SYSTEM INTACT.
03:48	MAPP **(MCN-EM)**	MDU / COYOTE FOR 40 MWS X 0349 (JOINT). THEY WANTED A SOLE EM. SKI CANCELLED EM X 0356. TOTAL DELIVERED = 1 MW-MDU, 2 MWS-OTP, 1 MW-MPC, 1 MW-NWPS. OASIS #95211-MDU, #95227-NWPS, #95228-OTP, #95229-MPC. TC E-MAILED.
03:48:48	OTP	Jamestown Turbine #2 on line.
03:49:04	IPW	Close CB 660 Hayward to Winnebago 161kV. Lakefield-Haywood 161kV is then restored (Winnebago-Wilmarth 161kV still out)
03:50	MAPP (MCN)	MP / WING RIVER-FERGUS FALLS 230KV INSERVICE @ 0333. POLE #2 OF SQ BT HVDC IN SERVICE @ 0348.
03:50:13	IPW	Close CB 712 Rutland to Fairmont 69kV
03:51	OH	Ontario East and West system tied at Lakehead TS. Ontario Hydro in synchronism with Manitoba Hydro.
03:53	MAPP (MCN)	MPC / RAMSEY-PRAIRIE TRIPPED @ 0227. SBBT HVDC POLE 2 TRIPPED @ 0225 BACK @ 0348. L20D TRIPPED @ 0222 BACK @ 0325. YOUNG #2 ARMED @ 0355
03:53:07	IPW	Close CB 710 Rutland 161/69kV Transformer
03:53:54	UPA	Coal Ck, Dickinson CU HVDC Pole 2 de-blocked
03:55	MP	Stinson 6T CLOSED by control restoring Stinson-Minong 115kV line (762 Line in service) (NSP shows at 03:55)
03:56	MAPP (MCN)	UPA / CU HVDC IN BIPOLE OPERATION. WILMAR-GRANITE FALLS 230KV LINE BACK @ 0402.
03:56	MAPP **(MCN-EM)**	MDU / COYOTE FOR 40 MWS X 0358 (SOLE). CANCELLED X 0438. TOTAL DELIVERED = 26 MWS. OASIS #95212. TC E-MAILED.
03:59	MAPP (MCN)	LES / NO XMS & GEN OUT.
03:59	MP	Fond Du Lac 15L OPEN by control Hibbard 15L OPEN by control, NORMAL OPERATING CONDITION FOR STORMS
04:00	OH	Station service restored to Thunder Bay Generating Station
04:00:50	UPA	Willmar 69 13NB6 Willmar-Granite Falls 230kV Manually closed
04:01	MAPP **(MCN-EM)**	REQUESTED ALL COMPANIES TO CONTRIBUTE TO THE EM'S IN PROGRESS WITH THE ASSIGNED MWS. ALSO, REQUESTED THAT ANYONE NOT CONTRIBUTING INFORM THE MAPP CC AS TO THE REASON.
04:01:08	UPA	Willmar 69 13NB2 Willmar-Granite Falls 69kV Manually

Time (CDT)	Reporting Company	Event
		closed (NSP shows at 04:01:13)
04:02:11	OTP	Lake Preston Turbine on line.
04:03	MAPP (MCN)	MP / @ 0355 6T @ STINSON AVE CLOSED AND RAMPING UP PHASE SHIFTER TO NORMAL INTO WI.
04:03:36	UPA	McHenry 230 32RB3 Energize McH 230/115 Xfmr from Stanton-Coal Creek 230kV line
04:03:52	UPA	McHenry 115 32WB1 115kV breaker for McH 230/115 xfmr Manually closed
04:05	MAPP (MCN)	UPA / 32WB1 & 32RB3 CLOSED @ MCHENRY STATION @ 0403.
04:07	MAPP (MCN)	MPC / OTP REPORTS FERGUS FALLS-GRANT CO. 115KC OUT.
04:10	MEC	Lakefield-Raun 345kV line restored to service.
04:11	MAPP (MCN)	MP / THE BADOURA END OF BADOURA-BEMIDJI 115KV OUT.
04:11	MAPP (MCN) **(LLR)**	NSP / CANCEL LLR ON ECL-ARP & PRI-BYN IMMEDIATELY. (WAS DONE)
04:11:03	IPW	Albert LeaWestside-Walters 69kV restored
04:13:02.220	WAPA	Groton 345/115kV transformer KU2A restored to service. PCB's 8492 and 762 closed manually via SCADA (PCB 8392 subsequently closed)
04:14	MEC	Raun-Ft Calhoun 345kV line restored to service.
04:14	MP	MPC reports 5412 breaker at Laporte CLOSED (725 line)
04:14:45	MPC	Prairie - Ramsey 230kV line closed
04:15	**Exports**	**NDEX=567 MW, MHEX=1470 MW, TCEX=624 MW**
04:17:17	UPA	Ramsey 230 33RB2 Ramsey-Prairie 230kV Manually closed
04:17:25	UPA	Ramsey 115 33WB1 Ramsey 230/115kV Xfmr Manually closed
04:20	MAPP (MCN)	MPC / MCHENRY-RAMSEY-PRAIRIE 230KV BACK @ 0418.
04:22:11	OTP	Jamestown Turbine #1 on line
04:22:20	UPA	Willmar 69 13WB1 Willmar-MN Valley 115kV Manually closed
04:22:26	NSP	Willmar - Kerkhoven/MN Val. Jct 115kV Closed
04:31	MAPP (MCN)	IPW / SYSTEM BACK TO NORMAL **IPW system back to NORMAL.**
04:32	MAPP (MCN)	**NSP / @ 0500 NSP IS COMPLYING WITH FERC 888/889 REQUIREMENTS.**
04:32:41	NWPS	Huron-Mitchell 115kV line restored (Huron breaker closed)
04:34	MAPP (MCN)	NWPS / HURON-MITCHELL CLOSED @ 0433.
04:36	MAPP (MCN)	**WAPA / @ 0430 WAPA IS COMPLYING WITH FERC 888/889 REQUIREMENTS.**
04:37	NSP	High Bridge unit #6 back on-line
04:38	MAPP (MCN)	MEC / SYSTEM CONDITION 'GREEN'
04:41	MAPP	MP / @ 0114 BADOURA 115KV BUS RELAYED – DUE TO B/O

Time (CDT)	Reporting Company	Event
	(MCN)	CCPD AND WAVE TRAP ON BADOURA. BEMIDJI 115KV LINE BUS BACK IN @ 0303. BADOURA-BEMIDJI STILL OUT. @ 0222 SQ BT HVDC POLE 2 STOPPED & CENTER 230KC AC BUSES OUT. ALL BACK @ 0348 @ 0225 WING RIVER-FERGUS 230KV OUT. BCAK @ 0333 @ 0222 I'NAT FALLS-FT FRANCIS OUT. COMING BACK SHORTLY.
04:44	MP	Ontario Hydro CLOSED breaker 22EL3 and energized 726 line to the US.
04:45	**Exports**	**NDEX=493 MW, MHEX=1531 MW, TCEX=830 MW**
04:45:09	UPA	Coal Creek 230 61RB2 Coal Creek Station Unit 2 Back on line **UPA system back to NORMAL.**
04:47	MAPP (MCN)	UPA / COAL CREEK STATION #2 ON-LINE @ 0446.
04:48	MAPP (MCN)	MEC / NEAL #3 ON-LINE @ 0437. WILL GO TO 150 MWS, THEN RELEASE TO F/L. NEAL #4 CAN'T GET IGNITERS TO FIRE BOILER. NOT EXPECTED BACK BEFORE 0800.
04:56	MAPP (MCN)	ALT / @ 0500 WILL BE BACK IN COMPLIANCE WITH FERC 888/889 ORDERS.
04:57	MP	**International Falls 726L CLOSED by control, MP-OH (F3M) interconnection restored.** (OH shows at 04:57) **Minnesota Power-Ontario interconnection restored.** **MP System back to NORMAL.**
05:06	MAPP (MCN)	MAPP SYSTEM QUICK SYSTEM SUMMARY SENT.
05:08:46	NSP	Grant County OCB 1345 closed, beginning the restoration of the load at Elbow Lake, Alexandria, and Brandon.
05:10	MAPP (MCN)	DPC / ROCK ELM-ALMA 161KV OUT @ 0201. WILL FLY LINE IN MORNING.
05:11	MAPP (MCN)	MP / @ 0457 I'NAT-FT FRANCIS LINE & PHASE SHIFTING XFMR BACK & @ ZERO FLOW.
05:15	MAPP (MCN)	IPW / FOX LAKE TRIPPED @ 0222. BACK @ 0438. ONLY HAVE BLUE LAKE-WINNEBAGO 161KV OUT.
05:15	**Exports**	**NDEX=625 MW, MHEX=1671 MW, TCEX=1005 MW**
05:17	MP	Ontario Hydro CLOSED 22EH,22HL1,22JL1,22JL6,22L3L6 at Fort Frances.
05:20	NPPD	All customers lost during disturbance restored. **NPPD system back to NORMAL.**
05:22	MAPP (MCN)	CBPC / EMERY-FRANKLIN-HAMPTON 161KV OPEN @ 0221. FRANKLIN END CLOSED @ 0258, HAMPTON END CLOSED @ 0259, EMERY END CLOSED @ 0331.
05:33	MAPP (MCN)	WAPA / GROTON XFMR BACK @ 0413.
05:43	MAPP (MCN)	IPW / LAKEFIELD-FOX LAKE 161KV BACK @ 0342, FOX LAKE-RUTLAND 161KV BACK @ 0406, WINNEBAGO JCT-WILMARTH 161KV STILL OUT, HAYWARD-WINNEBAGO JCT 161KV BACK @ 0406.

Time (CDT)	Reporting Company	Event
05:45	**Exports**	**NDEX=633 MW, MHEX=1723 MW, TCEX=1107 MW**
05:46	OH	Northwestern Ontario 230kV system restored.
06:00	OH	Potential restored to all customer loads, 400 MW of load restored and 250 MW of heavy industrial load remained off.
06:15	**Exports**	**NDEX=988 MW, MHEX=1687 MW, TCEX=1230 MW**
06:28	NSP	Riverside unit #7 back on-line
06:45	**Exports**	**NDEX=935 MW, MHEX=1690 MW, TCEX=1167 MW**
06:48	OTP	Coyote was brought back on line and tripped off at 06:48 AM due to a fan problem. There were a few other start-ups and trips of the unit before it was finally returned at 13:54.
06:56	MEC	Neal unit #2 back on-line, reached full load at 11:00
07:15	**Exports**	**NDEX=706 MW, MHEX=1810 MW, TCEX=1046 MW**
07:42	MAPP (MCN-EM)	OTP / BIGSTONE-COYOTE COMBINED EM X 0800 FOR 305 MWS (SOLE).
08:41	MEC	Neal unit #4 back on-line, reached full load at 15:00.
09:06	OTP	An attempt was made to get the Big Stone unit back on line and it Tripped back off at 09:18. Another attempt was made to bring it on line at 09:49, which was successful. Big Stone was released for 400 MW at 11:30.
09:35	OH	Thunder Bay G3 unit back on-line
10:11	WAPA	Antelope Valley Station (AVS) unit #2 back on-line **WAPA/BEPC system is back to NORMAL.**
10:15	**Exports**	**NDEX=615 MW, MHEX=1692 MW, TCEX=639 MW**
10:17:46	MAPP (MCN)	NSP / NSP SUSPENDED FERC 888/889 DUE TO LOSS OF GENERATION (MCN message from NSPM to BC)
11:30:57	NSP	Wilmarth-Winnebago 161kV line restored to service
11:35	NSP	Sherco unit #3 back on-line
12:43	NSP	Closed – Minnesota Valley - Franklin 115kV
13:54	MPC	Coyote unit back on-line (Breaker #5712 closed)
15:00 (approx.)	MEC	**MEC system is back to NORMAL.**
17:15	**Exports**	**NDEX=1392 MW, MHEX=1694 MW, TCEX=1151 MW**
17:20:01	MAPP (MCN)	NSP / NSP WILL BE OUT OF SYSTEM EMERGENCY AT 18:00 AND WILL BE COMPLYING WITH FERC 888/889. (MCN Message from NSPM to BC)
18:00	NSP	**NSP system is back to NORMAL**
20:52	NSP	Closed – Lafayette – Schilling 69kV
22:02	OTP	Douglas County-Grant County 115kV line was returned to service. Both ends of the line were closed at the times stated in the sequence of events at 03:40 and 05:08:46, but what was not listed was additional switching along this line (Elbow Lake, Brandon, and Alexandria) and several opening and closing operations of the breaker at Douglas County. The entire Douglas County-Alexandria 115kV line was closed through at 22:02.
21:00 (approx.)	MAPP (MCN)	MAPP AS A REGION COMPLYING WITH FERC 888/889.

Notes:

1. Broadcasts on the MAPP Communications Network are noted with "MAPP (MCN)". Broadcasts related to MAPP Emergency Energy Replacement Procedure (EM) are noted with "MAPP (MCN-EM)".
2. Exports are from 30 minute interval exports posted on MAPP Web Page. Times on these entries are approximate. Systems submit data at 15minutes after and 15 minutes before the hour. The data on the MAPP Web page is shown as 24 minutes after and 6 minutes before the hour due to processing delay at MAPP.
3. Times that are uncertain, are shown marked "(approx.)". They are ordered in the sequence of events where it appears they most likely occurred.

Disturbance Report Figures

dist0625.doc
09/10/98, SCS/CGP

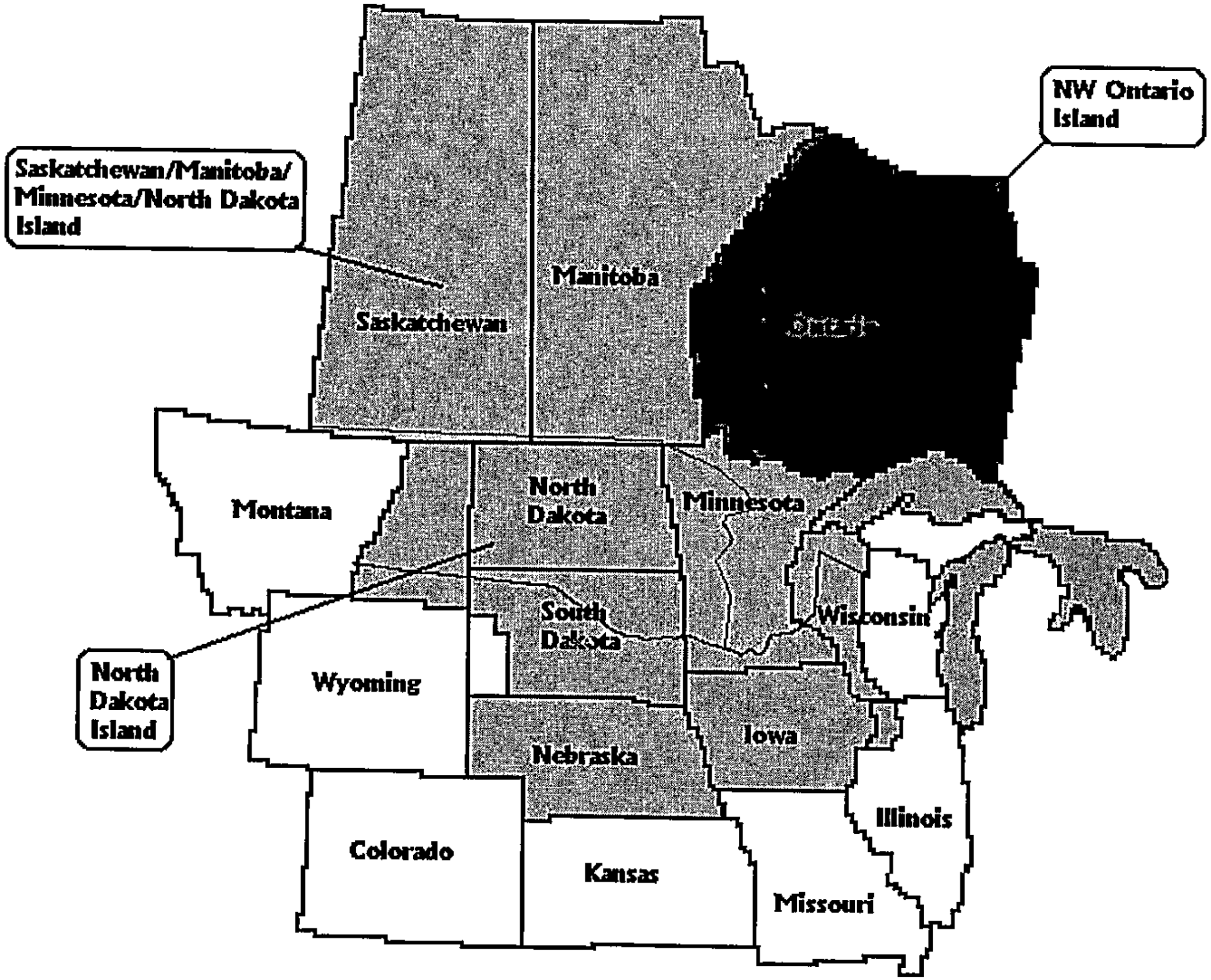
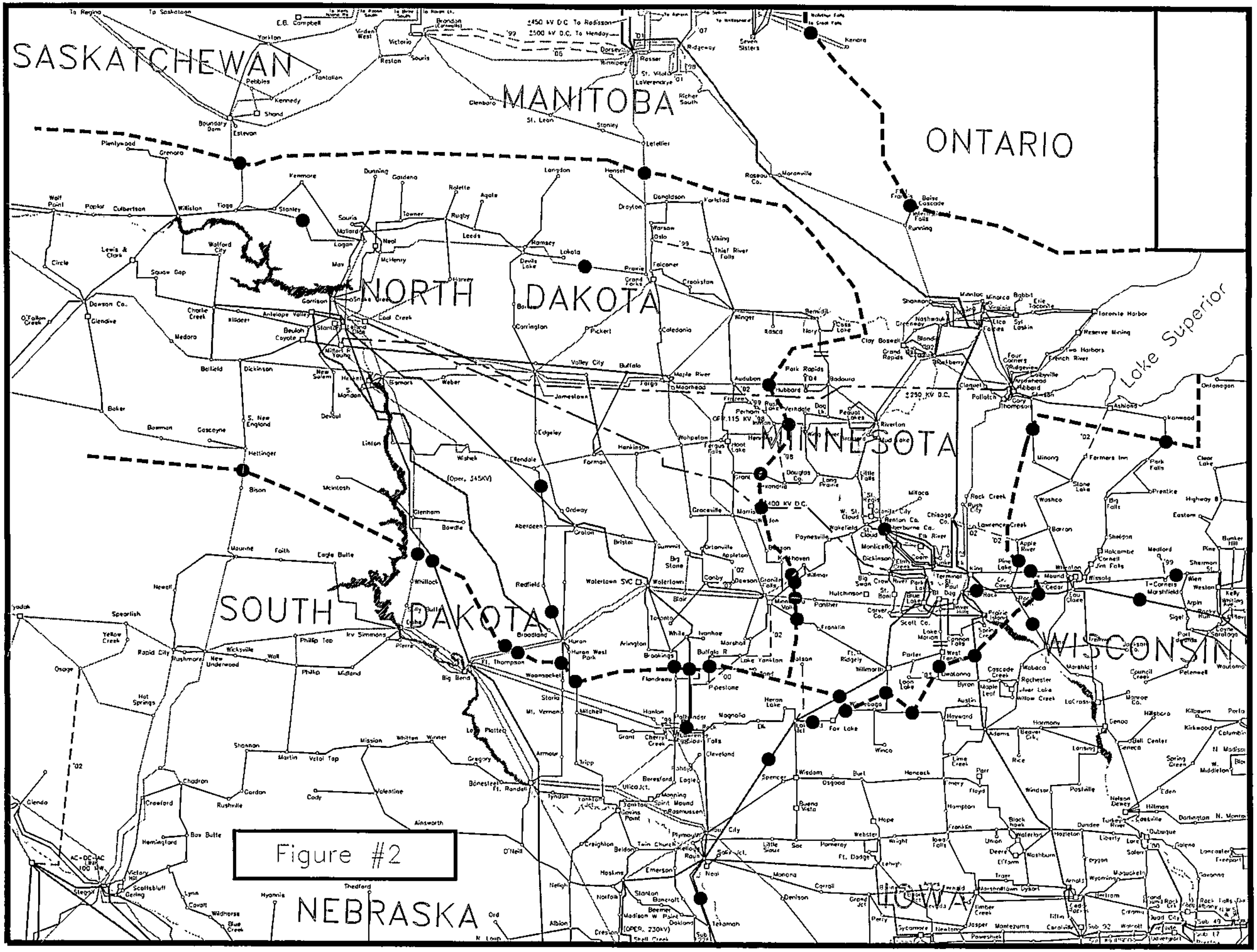

Saskatchewan/Manitoba/
Minnesota/North Dakota
Island
NW Ontario
Island
Saskatchewan
Manitoba
Montana
North
Dakota
Minnesota
Wisconsin
South
Dakota
North
Dakota
Island
Wyoming
Nebraska
Iowa
Illinois
Colorado
Kansas
Missouri

FIGURE #1



SASKATCHEWAN
MANITOBA
ONTARIO
NORTH DAKOTA
SOUTH DAKOTA
MINNESOTA
WISCONSIN
IOWA
NEBRASKA
Lake Superior

Figure #2

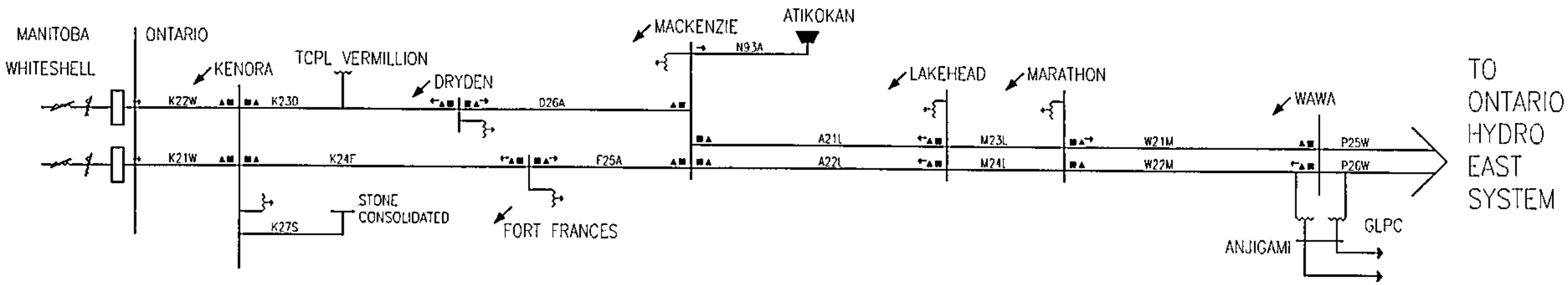
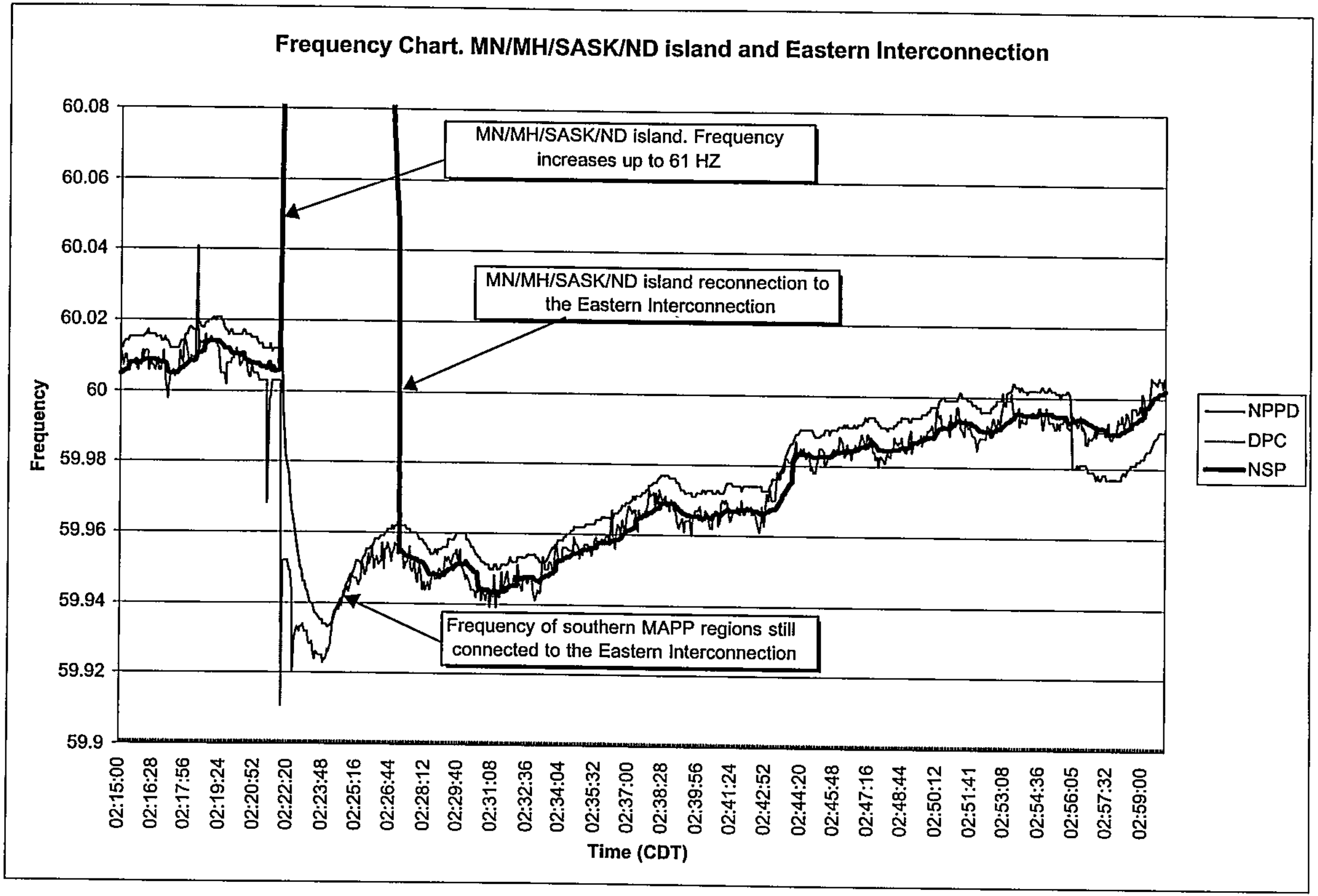
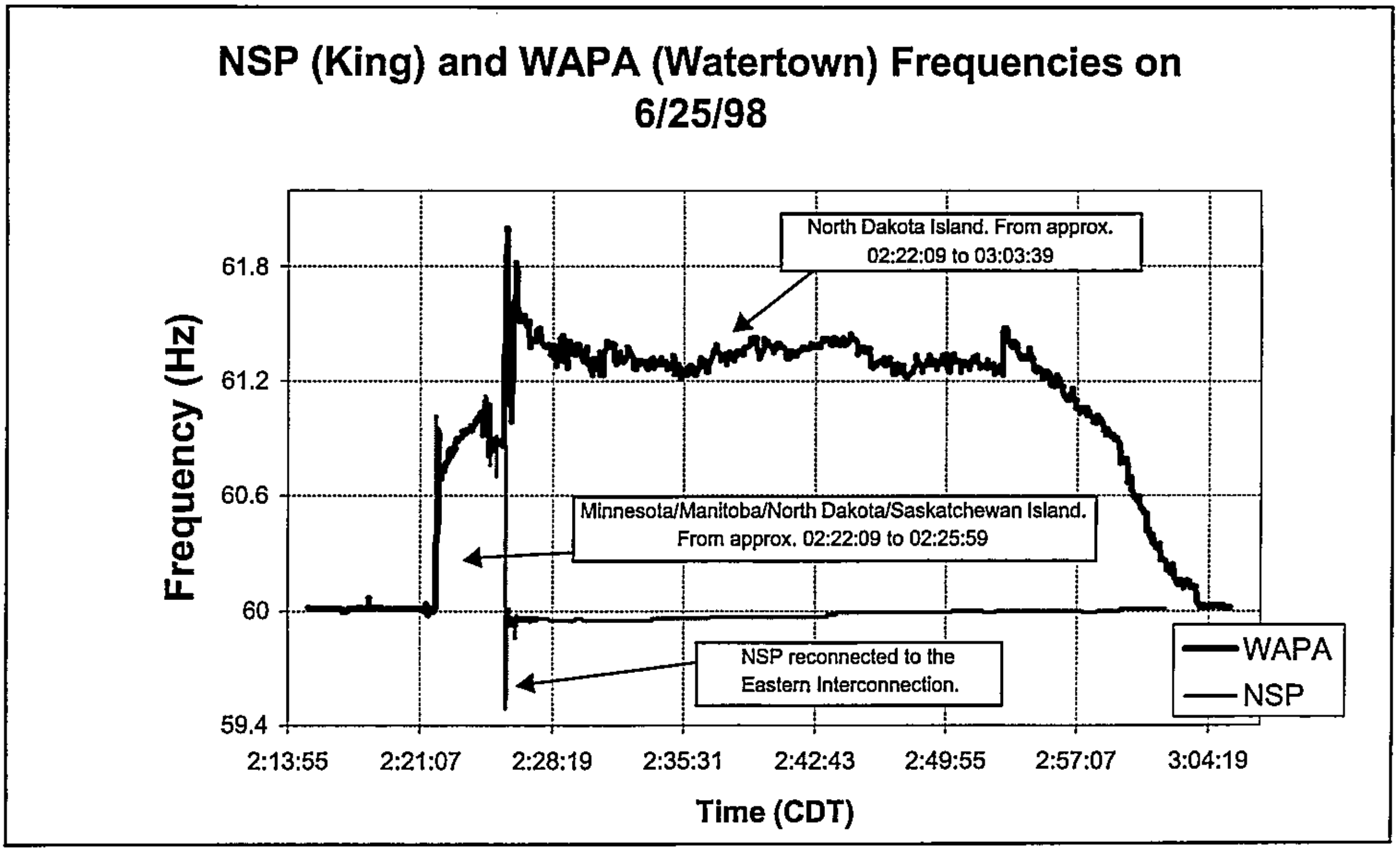


FIGURE #3	NW ONTARIO HYDRO SYSTEM



Frequency Chart. MN/MH/SASK/ND island and Eastern Interconnection
60.08
60.06
60.04
60.02
60
59.98
59.96
59.94
59.92
59.9
Frequency
MN/MH/SASK/ND island. Frequency increases up to 61 HZ
MN/MH/SASK/ND island reconnection to the Eastern Interconnection
Frequency of southern MAPP regions still connected to the Eastern Interconnection
NPPD
DPC
NSP
02:15:00
02:16:28
02:17:56
02:19:24
02:20:52
02:22:20
02:23:48
02:25:16
02:26:44
02:28:12
02:29:40
02:31:08
02:32:36
02:34:04
02:35:32
02:37:00
02:38:28
02:39:56
02:41:24
02:42:52
02:44:20
02:45:48
02:47:16
02:48:44
02:50:12
02:51:41
02:53:08
02:54:36
02:56:05
02:57:32
02:59:00
Time (CDT)

FIGURE #4


NSP (King) and WAPA (Watertown) Frequencies on 6/25/98
North Dakota Island. From approx. 02:22:09 to 03:03:39
Minnesota/Manitoba/North Dakota/Saskatchewan Island. From approx. 02:22:09 to 02:25:59
NSP reconnected to the Eastern Interconnection.
WAPA
NSP
Frequency (Hz)
61.8
61.2
60.6
60
59.4
2:13:55
2:21:07
2:28:19
2:35:31
2:42:43
2:49:55
2:57:07
3:04:19
Time (CDT)

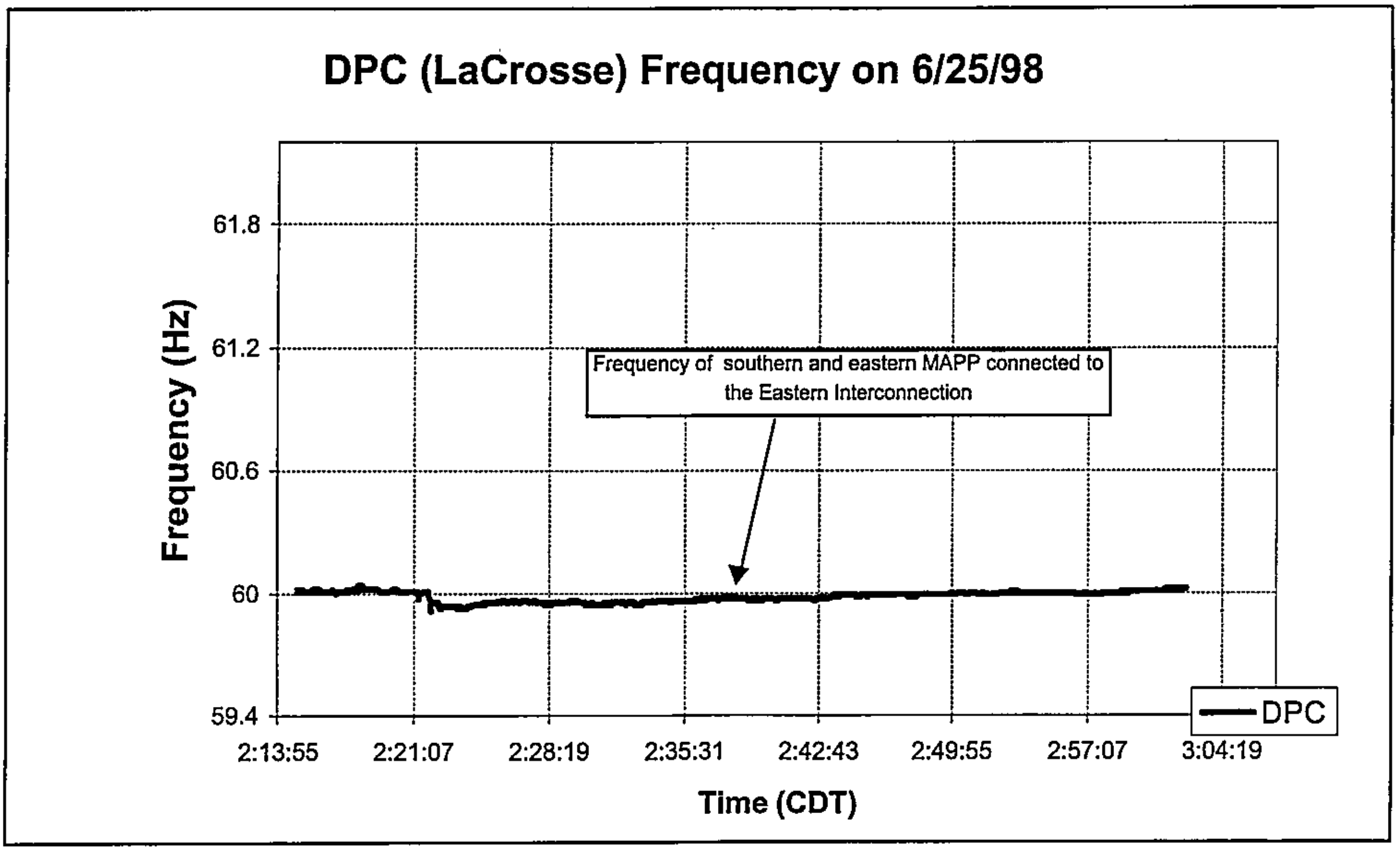

DPC (LaCrosse) Frequency on 6/25/98
Frequency of southern and eastern MAPP connected to the Eastern Interconnection
DPC
Frequency (Hz)
61.8
61.2
60.6
60
59.4
2:13:55
2:21:07
2:28:19
2:35:31
2:42:43
2:49:55
2:57:07
3:04:19
Time (CDT)

FIGURE #5

Prairie Island-Byron 345kV LineTrip
Arrowhead Frequency

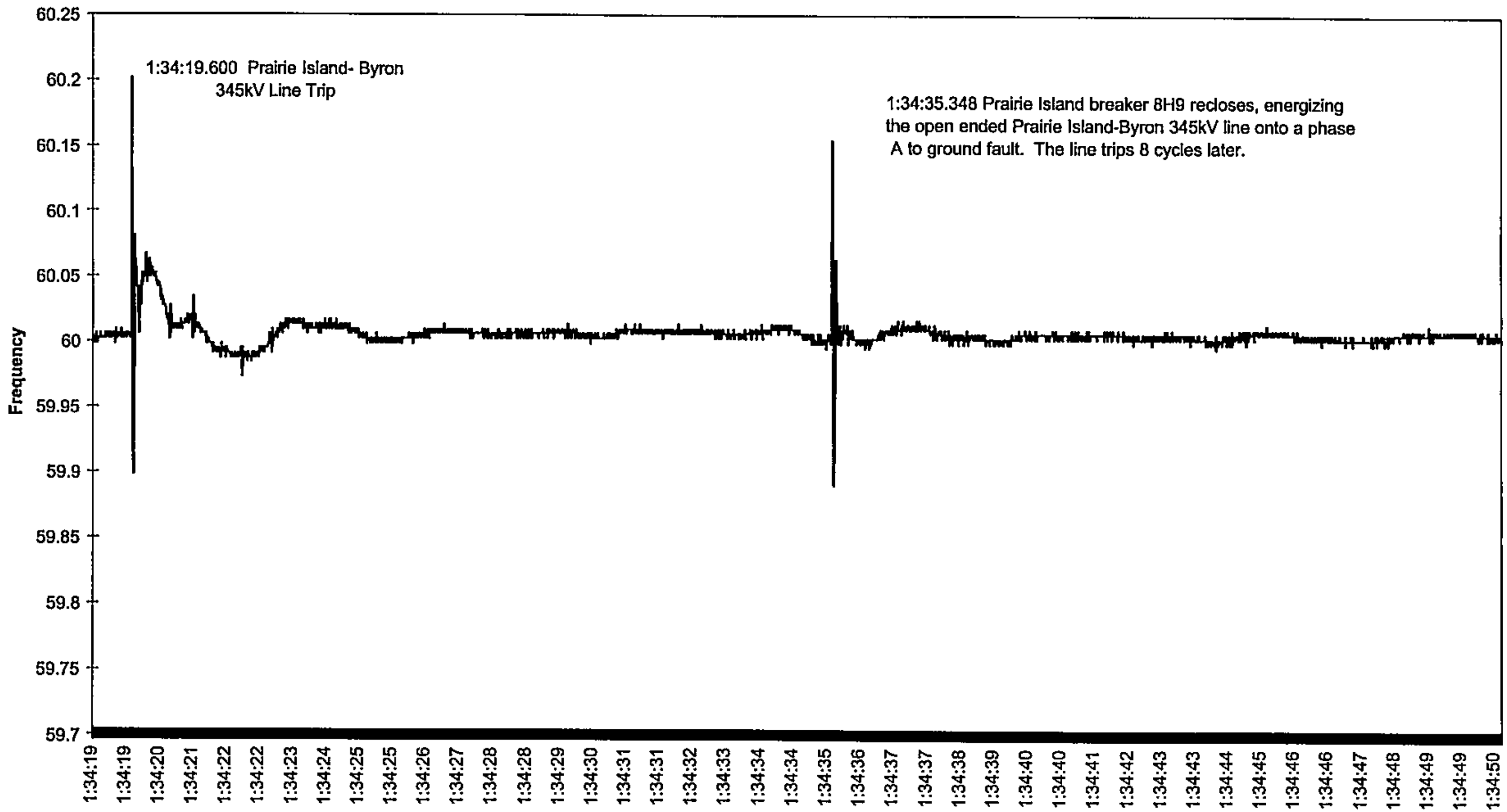


FIGURE #6

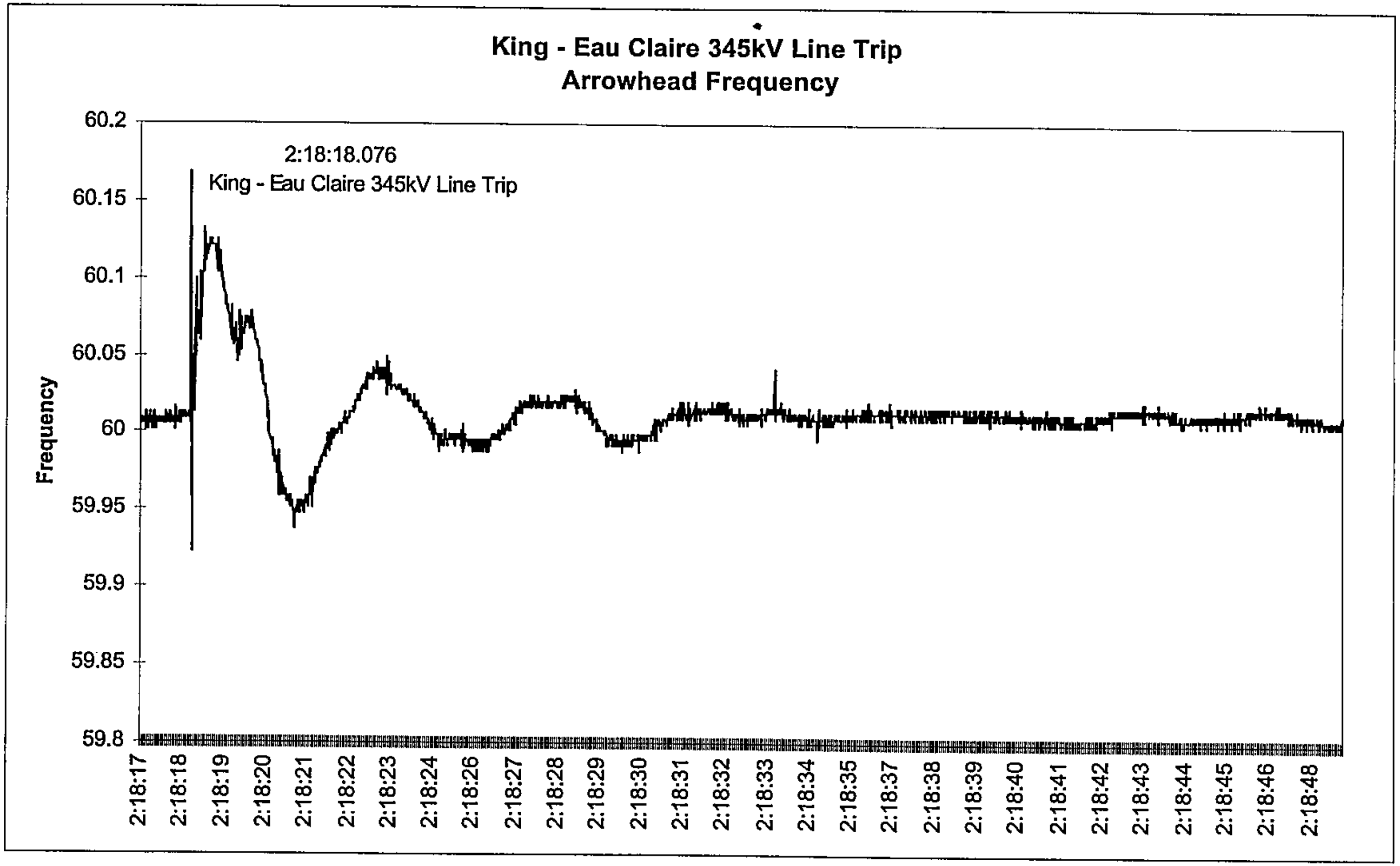
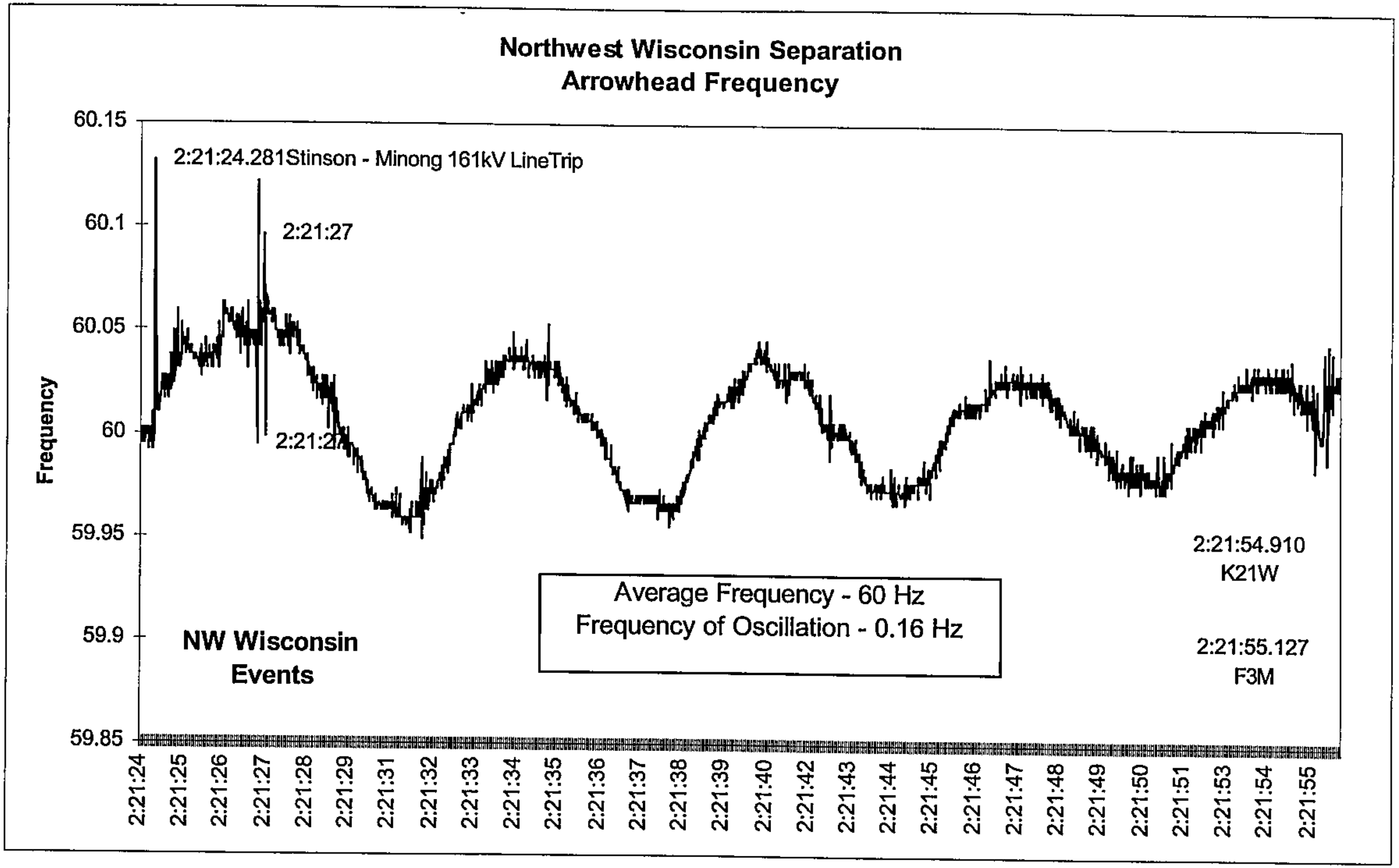

King - Eau Claire 345kV Line Trip
Arrowhead Frequency
2:18:18.076
King - Eau Claire 345kV Line Trip
Frequency
60.2
60.15
60.1
60.05
60
59.95
59.9
59.85
59.8
2:18:17
2:18:18
2:18:19
2:18:20
2:18:21
2:18:22
2:18:23
2:18:24
2:18:26
2:18:27
2:18:28
2:18:29
2:18:30
2:18:31
2:18:32
2:18:33
2:18:34
2:18:35
2:18:37
2:18:38
2:18:39
2:18:40
2:18:41
2:18:42
2:18:43
2:18:44
2:18:45
2:18:46
2:18:48

FIGURE #7



Northwest Wisconsin Separation
Arrowhead Frequency
Frequency
60.15
60.1
60.05
60
59.95
59.9
59.85
2:21:24.281Stinson - Minong 161kV LineTrip
2:21:27
NW Wisconsin
Events
Average Frequency - 60 Hz
Frequency of Oscillation - 0.16 Hz
2:21:54.910
K21W
2:21:55.127
F3M
2:21:24
2:21:25
2:21:26
2:21:27
2:21:28
2:21:29
2:21:31
2:21:32
2:21:33
2:21:34
2:21:35
2:21:36
2:21:37
2:21:38
2:21:39
2:21:40
2:21:42
2:21:43
2:21:44
2:21:45
2:21:46
2:21:47
2:21:48
2:21:49
2:21:50
2:21:51
2:21:53
2:21:54
2:21:55

FIGURE #8

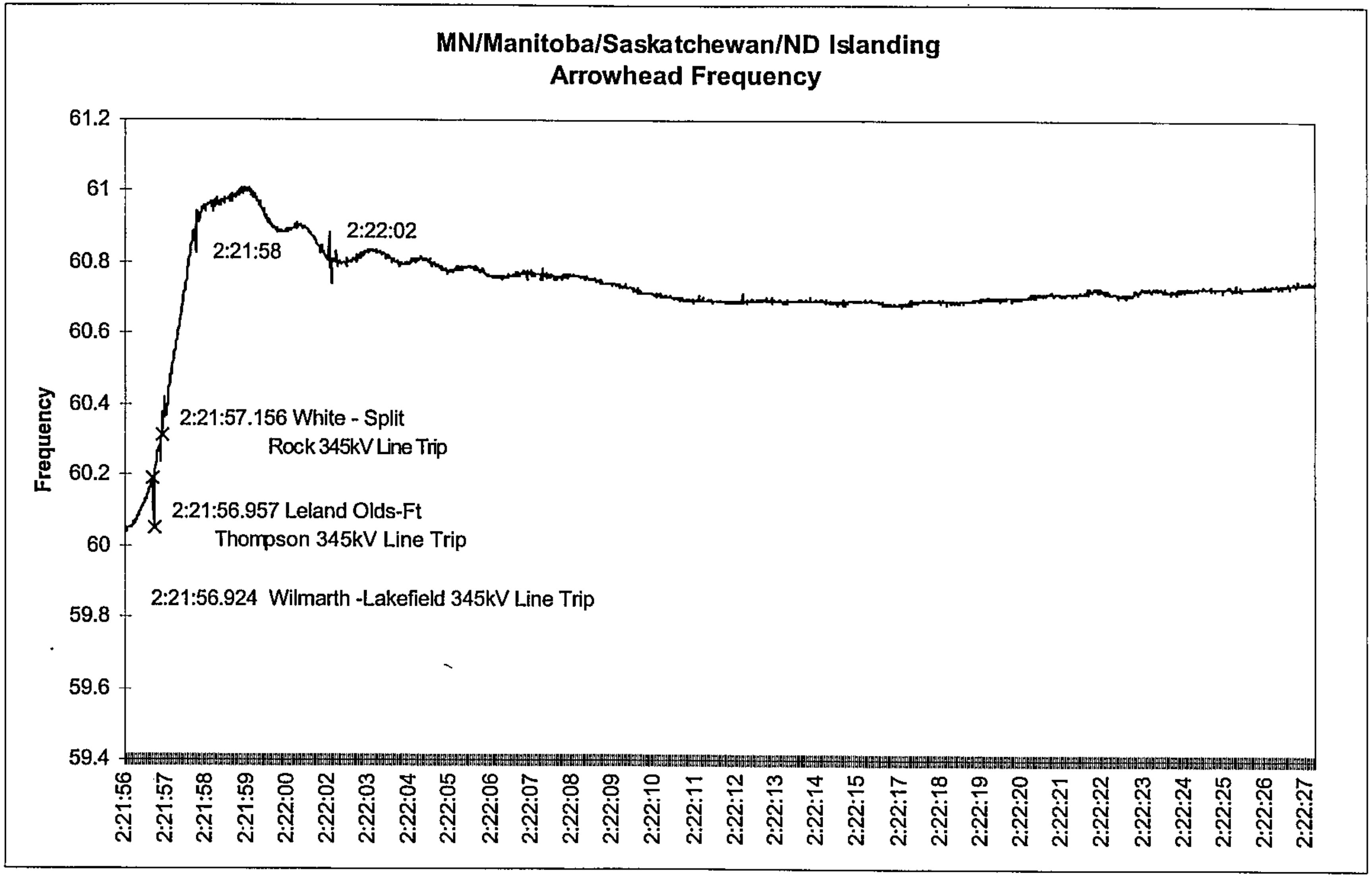

MN/Manitoba/Saskatchewan/ND Islanding
Arrowhead Frequency
Frequency
61.2
61
60.8
60.6
60.4
60.2
60
59.8
59.6
59.4
2:21:58
2:22:02
2:21:57.156 White - Split
Rock 345kV Line Trip
2:21:56.957 Leland Olds-Ft
Thompson 345kV Line Trip
2:21:56.924 Wilmarth -Lakefield 345kV Line Trip
2:21:56
2:21:57
2:21:58
2:21:59
2:22:00
2:22:02
2:22:03
2:22:04
2:22:05
2:22:06
2:22:07
2:22:08
2:22:09
2:22:10
2:22:11
2:22:12
2:22:13
2:22:14
2:22:15
2:22:17
2:22:18
2:22:19
2:22:20
2:22:21
2:22:22
2:22:23
2:22:24
2:22:25
2:22:26
2:22:27

FIGURE #9

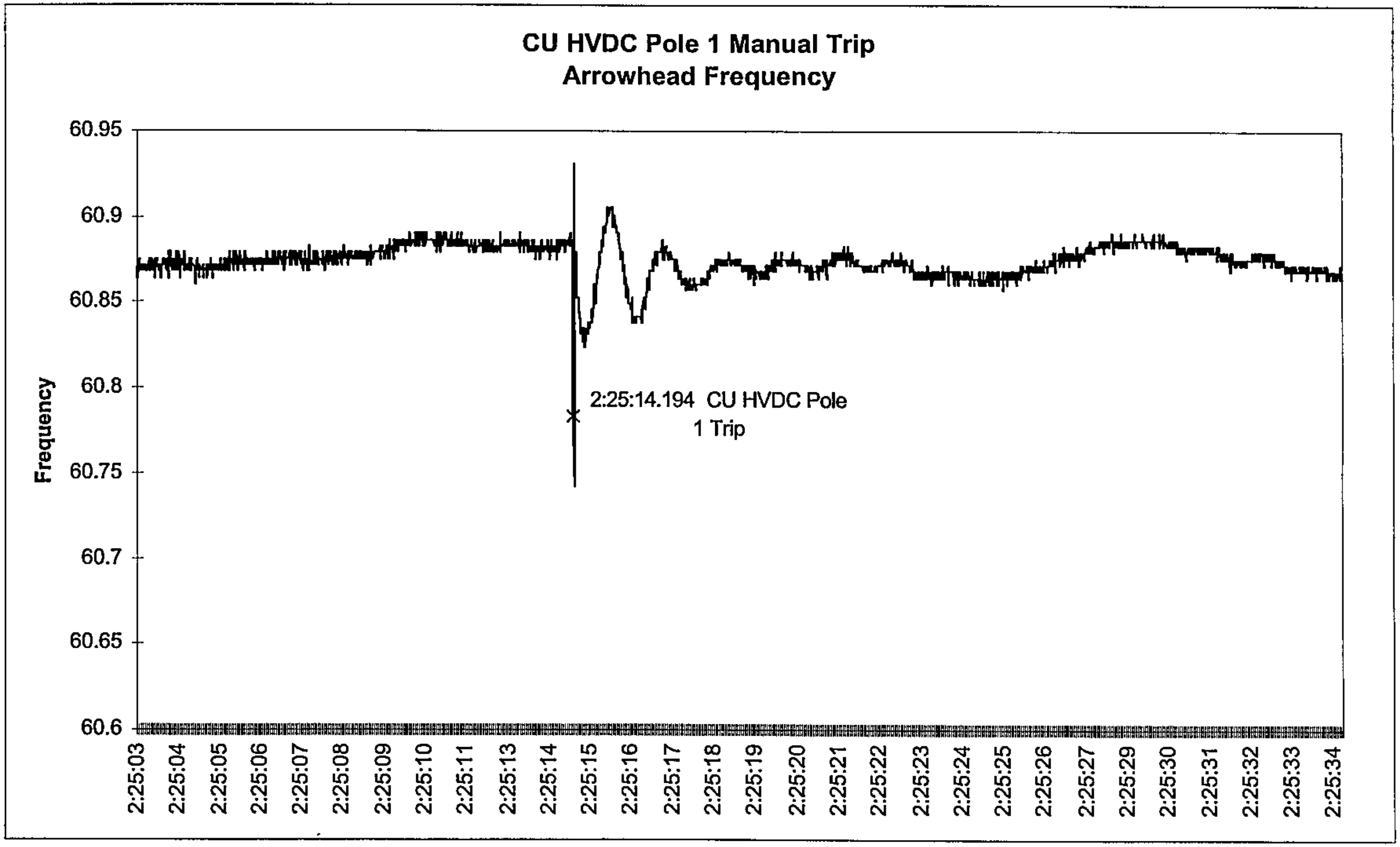
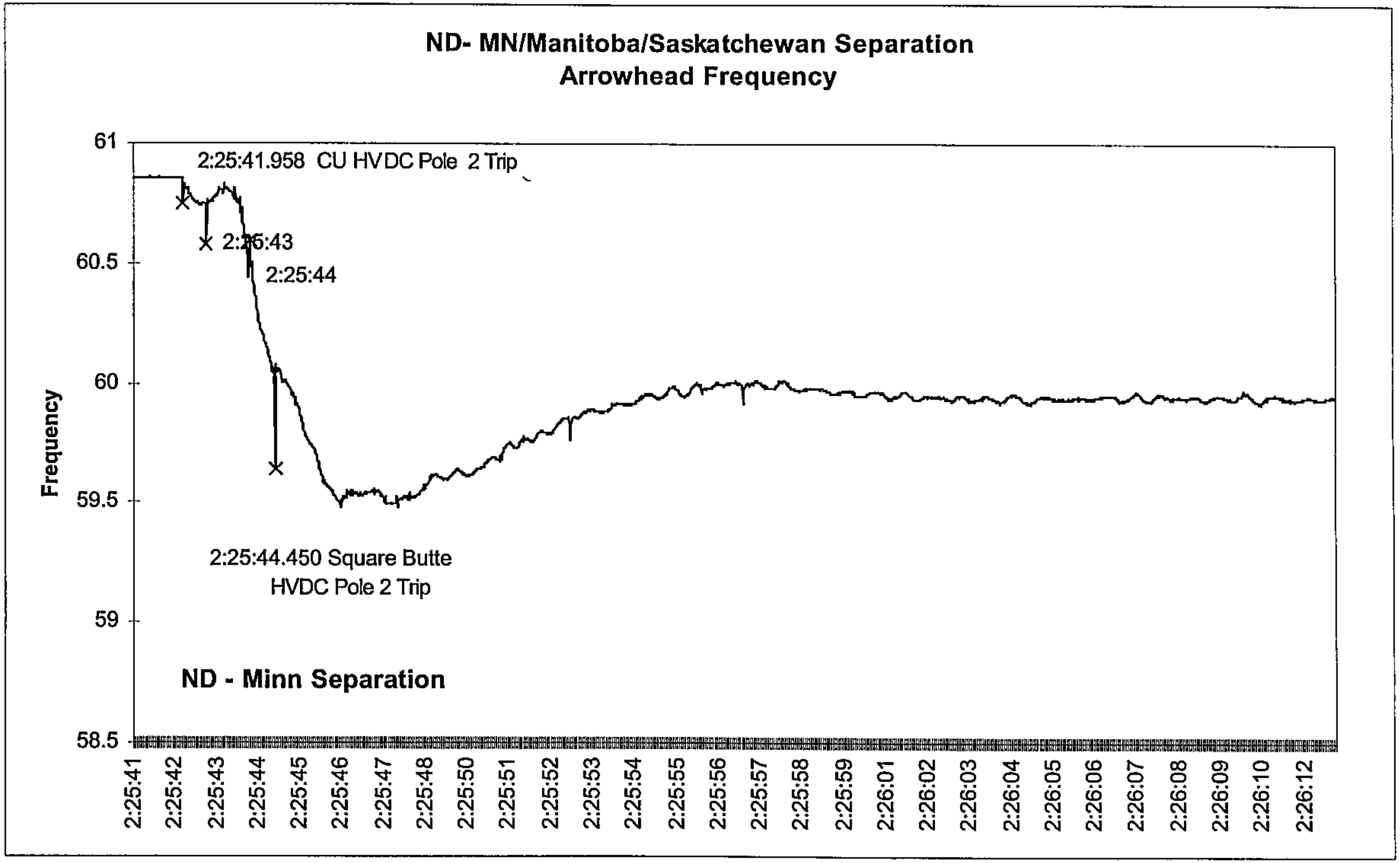

CU HVDC Pole 1 Manual Trip
Arrowhead Frequency
Frequency
60.95
60.9
60.85
60.8
60.75
60.7
60.65
60.6
2:25:14.194 CU HVDC Pole 1 Trip
2:25:03
2:25:04
2:25:05
2:25:06
2:25:07
2:25:08
2:25:09
2:25:10
2:25:11
2:25:13
2:25:14
2:25:15
2:25:16
2:25:17
2:25:18
2:25:19
2:25:20
2:25:21
2:25:22
2:25:23
2:25:24
2:25:25
2:25:26
2:25:27
2:25:29
2:25:30
2:25:31
2:25:32
2:25:33
2:25:34

FIGURE #10



ND- MN/Manitoba/Saskatchewan Separation
Arrowhead Frequency
2:25:41.958 CU HVDC Pole 2 Trip
2:25:43
2:25:44
2:25:44.450 Square Butte
HVDC Pole 2 Trip
ND - Minn Separation
Frequency
61
60.5
60
59.5
59
58.5
2:25:41
2:25:42
2:25:43
2:25:44
2:25:45
2:25:46
2:25:47
2:25:48
2:25:50
2:25:51
2:25:52
2:25:53
2:25:54
2:25:55
2:25:56
2:25:57
2:25:58
2:25:59
2:26:01
2:26:02
2:26:03
2:26:04
2:26:05
2:26:06
2:26:07
2:26:08
2:26:09
2:26:10
2:26:12

FIGURE #11

June 25, 1998 King 345 kV bus Voltage

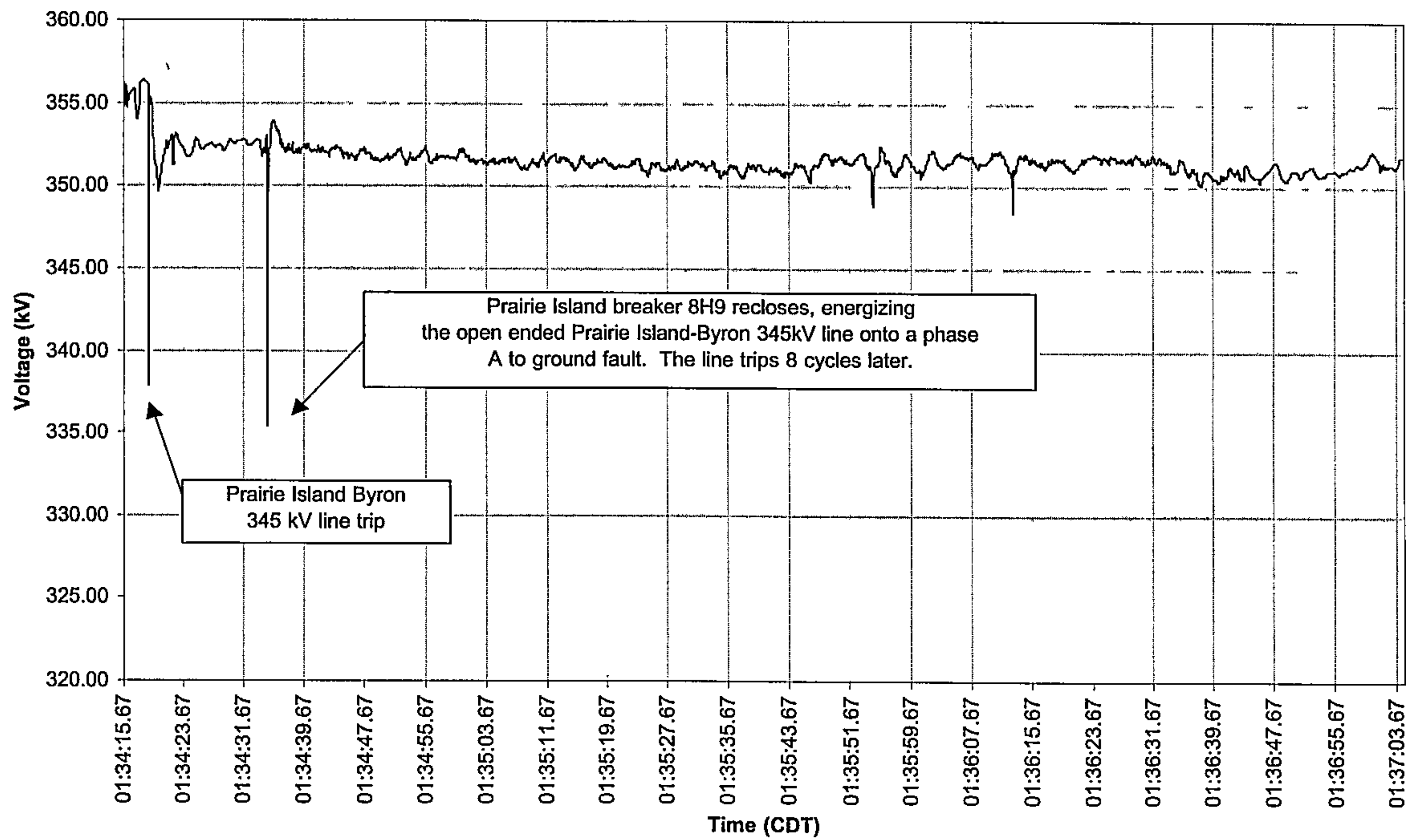


FIGURE #12

BISMARCK 230 kV WEST BUS VOLTAGE

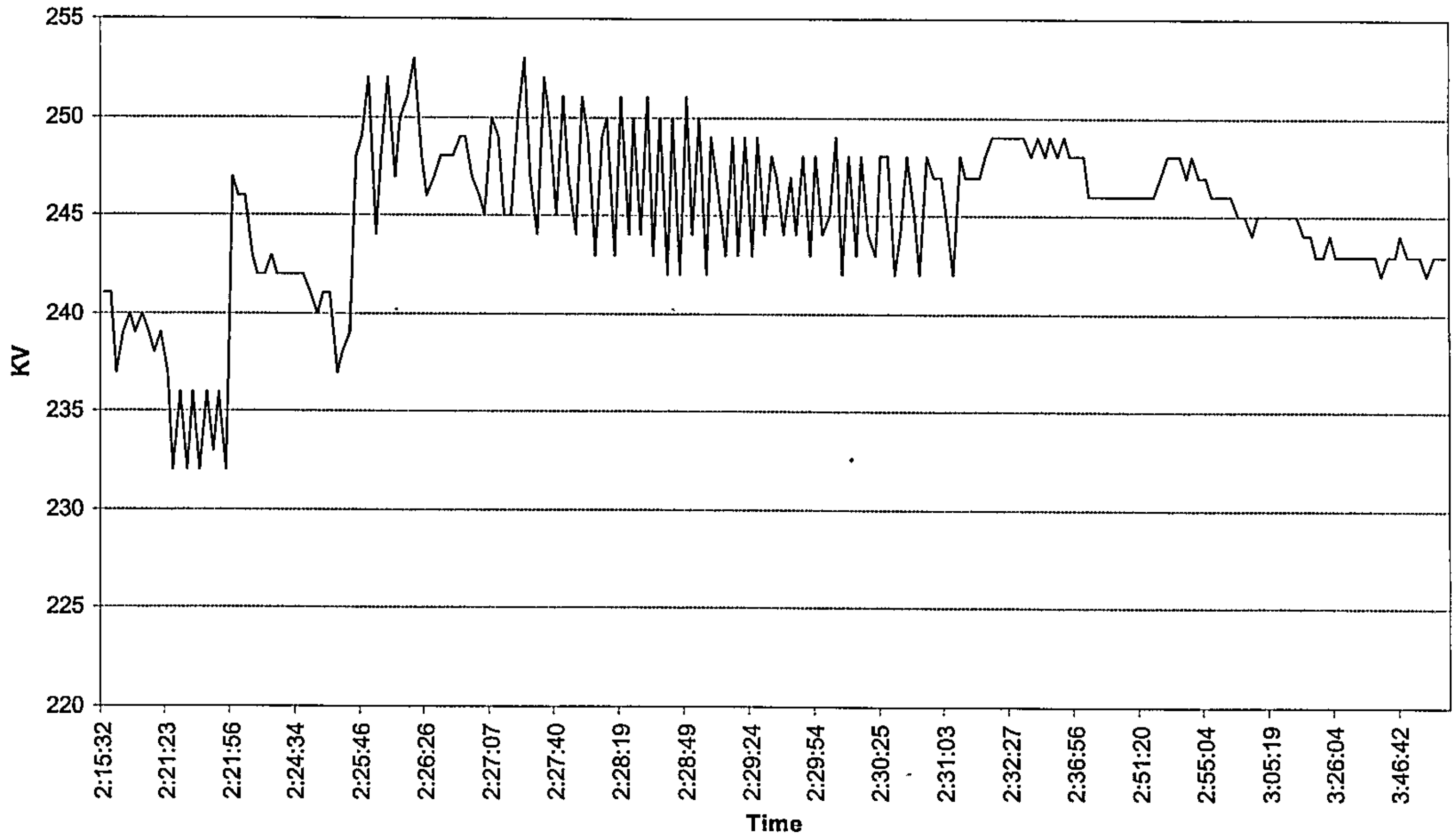


FIGURE #13

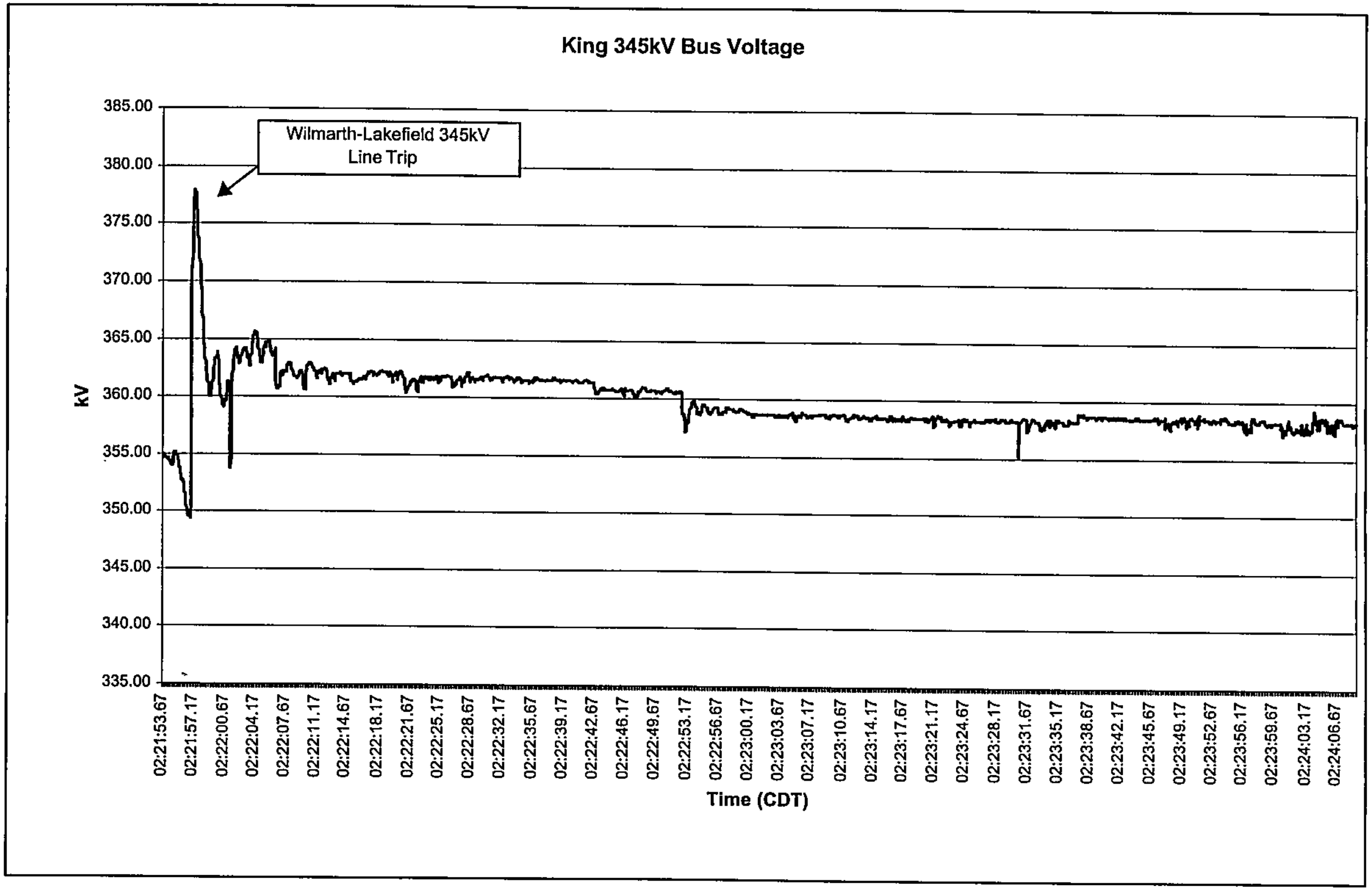

King 345kV Bus Voltage
Wilmarth-Lakefield 345kV
Line Trip
385.00
380.00
375.00
370.00
365.00
360.00
355.00
350.00
345.00
340.00
335.00
kV
02:21:53.67
02:21:57.17
02:22:00.67
02:22:04.17
02:22:07.67
02:22:11.17
02:22:14.67
02:22:18.17
02:22:21.67
02:22:25.17
02:22:28.67
02:22:32.17
02:22:35.67
02:22:39.17
02:22:42.67
02:22:46.17
02:22:49.67
02:22:53.17
02:22:56.67
02:23:00.17
02:23:03.67
02:23:07.17
02:23:10.67
02:23:14.17
02:23:17.67
02:23:21.17
02:23:24.67
02:23:28.17
02:23:31.67
02:23:35.17
02:23:38.67
02:23:42.17
02:23:45.67
02:23:49.17
02:23:52.67
02:23:56.17
02:23:59.67
02:24:03.17
02:24:06.67
Time (CDT)

FIGURE #14

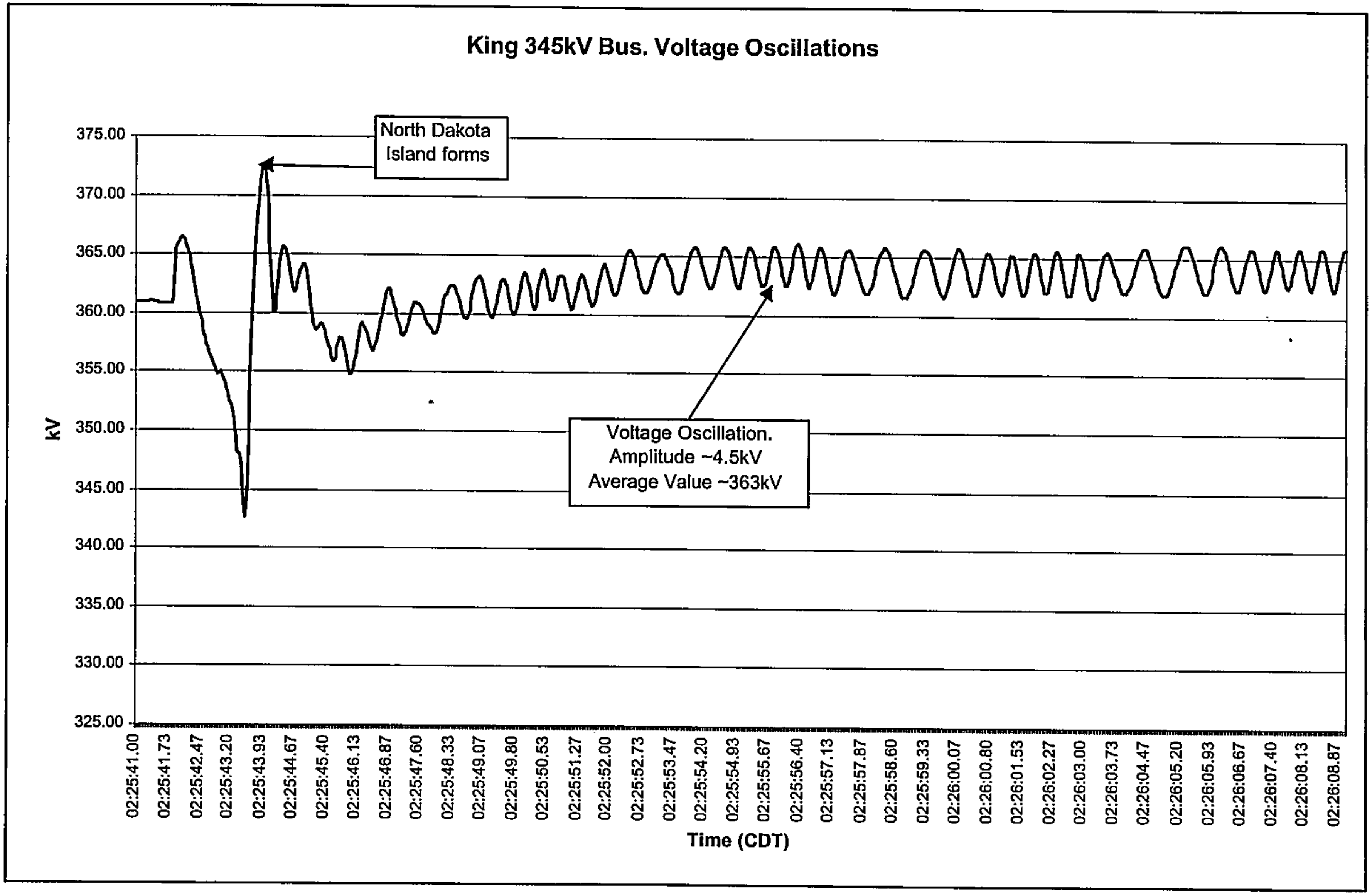
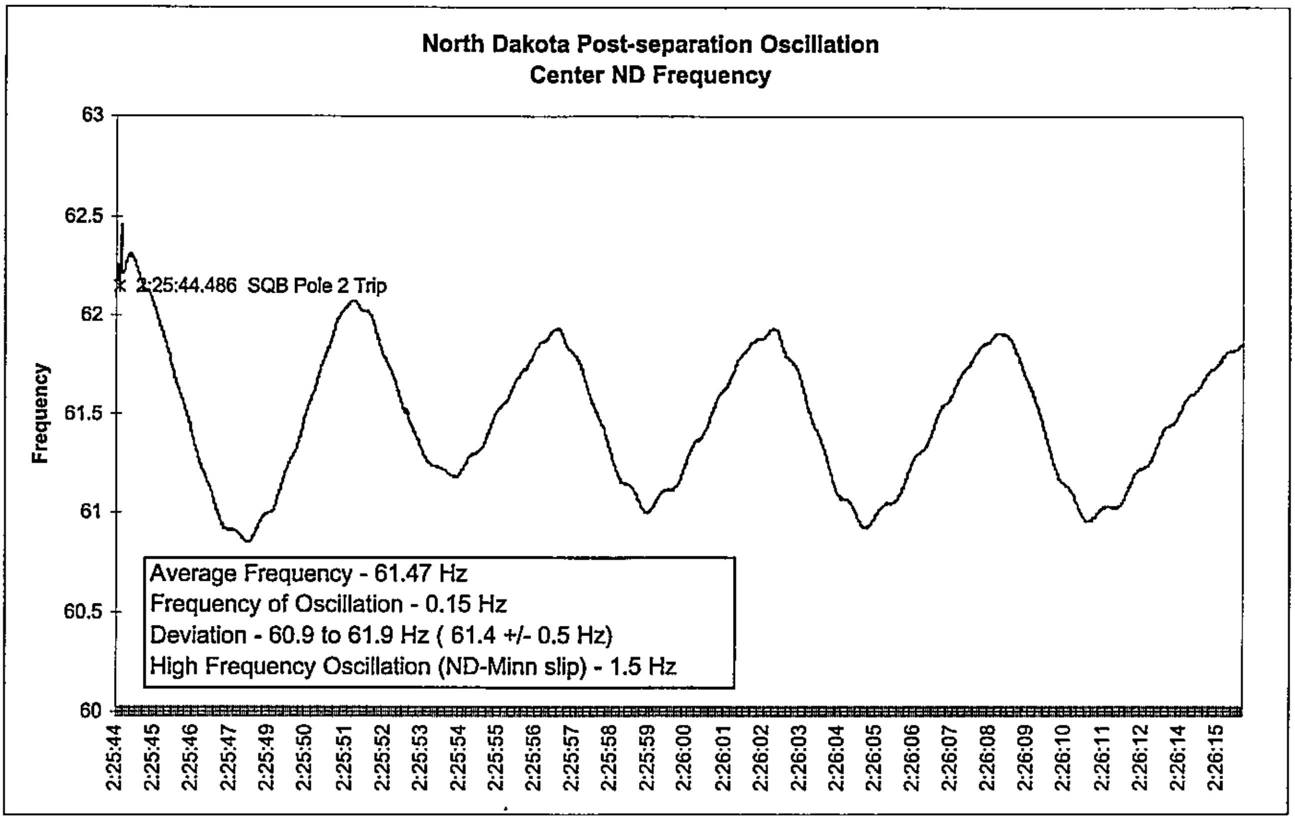

King 345kV Bus. Voltage Oscillations
North Dakota
Island forms
Voltage Oscillation.
Amplitude ~4.5kV
Average Value ~363kV
kV
375.00
370.00
365.00
360.00
355.00
350.00
345.00
340.00
335.00
330.00
325.00
02:25:41.00
02:25:41.73
02:25:42.47
02:25:43.20
02:25:43.93
02:25:44.67
02:25:45.40
02:25:46.13
02:25:46.87
02:25:47.60
02:25:48.33
02:25:49.07
02:25:49.80
02:25:50.53
02:25:51.27
02:25:52.00
02:25:52.73
02:25:53.47
02:25:54.20
02:25:54.93
02:25:55.67
02:25:56.40
02:25:57.13
02:25:57.87
02:25:58.60
02:25:59.33
02:26:00.07
02:26:00.80
02:26:01.53
02:26:02.27
02:26:03.00
02:26:03.73
02:26:04.47
02:26:05.20
02:26:05.93
02:26:06.67
02:26:07.40
02:26:08.13
02:26:08.87
Time (CDT)

FIGURE #15


North Dakota Post-separation Oscillation
Center ND Frequency
Frequency
63
62.5
62
61.5
61
60.5
60
2:25:44.486 SQB Pole 2 Trip
Average Frequency - 61.47 Hz
Frequency of Oscillation - 0.15 Hz
Deviation - 60.9 to 61.9 Hz (61.4 +/- 0.5 Hz)
High Frequency Oscillation (ND-Minn slip) - 1.5 Hz
2:25:44
2:25:45
2:25:46
2:25:47
2:25:49
2:25:50
2:25:51
2:25:52
2:25:53
2:25:54
2:25:55
2:25:56
2:25:57
2:25:58
2:25:59
2:26:00
2:26:01
2:26:02
2:26:03
2:26:04
2:26:05
2:26:06
2:26:07
2:26:08
2:26:09
2:26:10
2:26:11
2:26:12
2:26:14
2:26:15

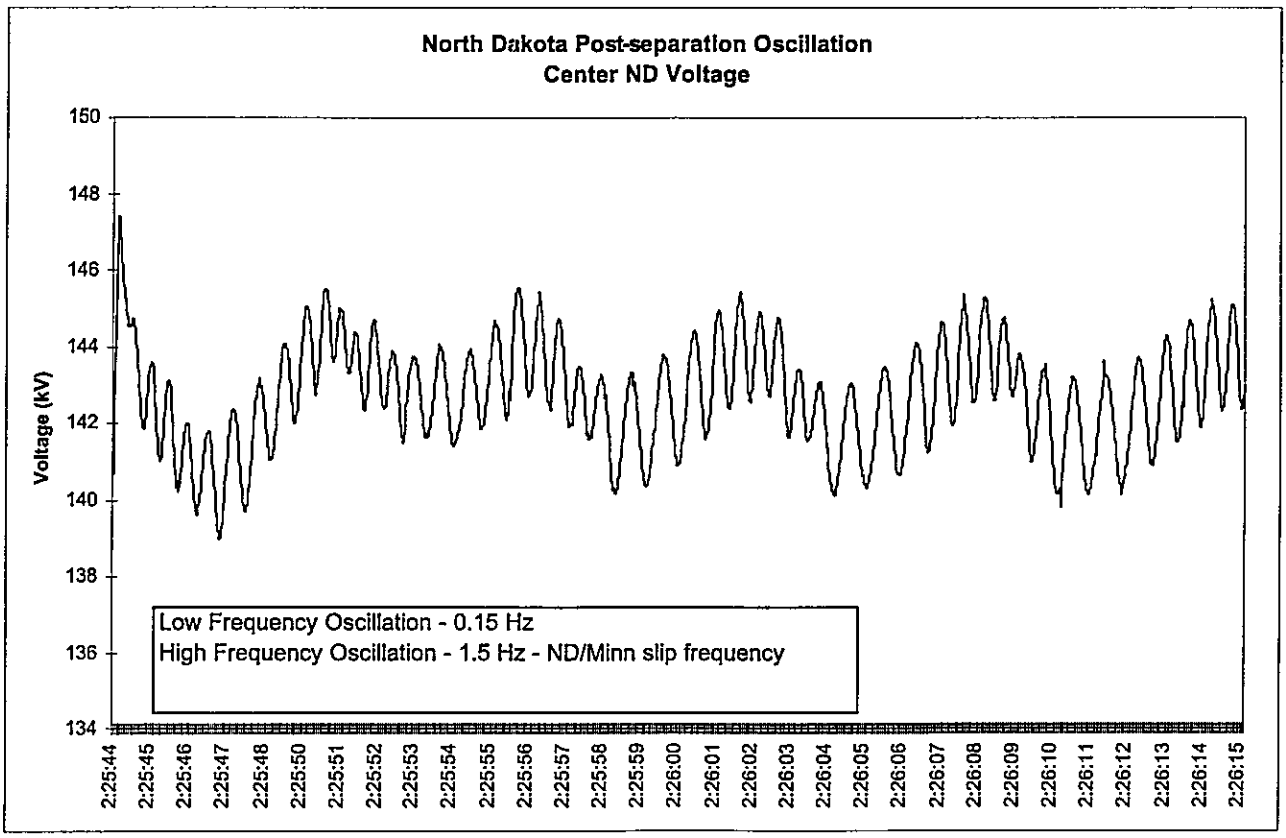

North Dakota Post-separation Oscillation
Center ND Voltage
Voltage (kV)
150
148
146
144
142
140
138
136
134
Low Frequency Oscillation - 0.15 Hz
High Frequency Oscillation - 1.5 Hz - ND/Minn slip frequency
2:25:44
2:25:45
2:25:46
2:25:47
2:25:48
2:25:50
2:25:51
2:25:52
2:25:53
2:25:54
2:25:55
2:25:56
2:25:57
2:25:58
2:25:59
2:26:00
2:26:01
2:26:02
2:26:03
2:26:04
2:26:05
2:26:06
2:26:07
2:26:08
2:26:09
2:26:10
2:26:11
2:26:12
2:26:13
2:26:14
2:26:15

FIGURE #16

June 25, 1998 TCEX Values

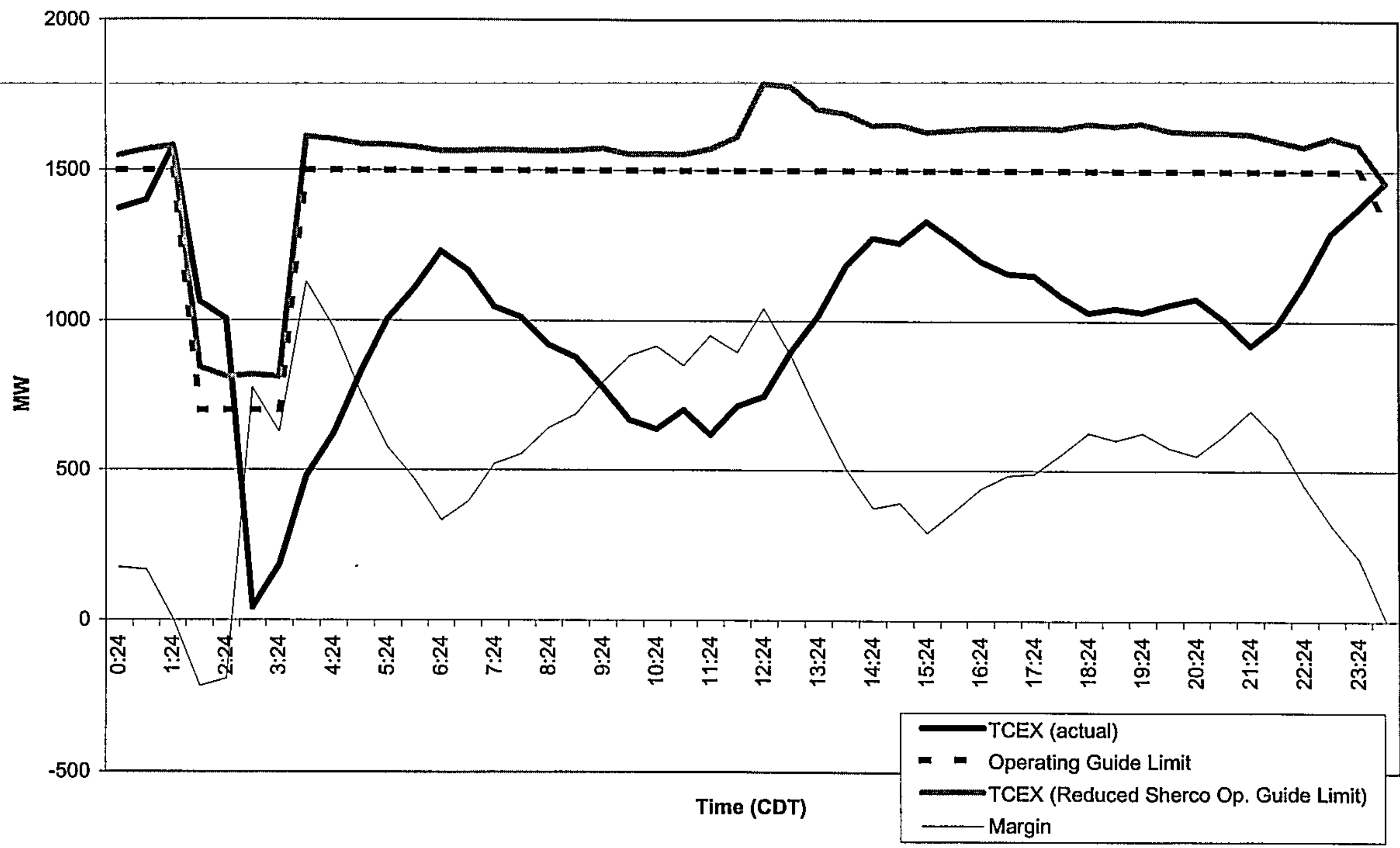
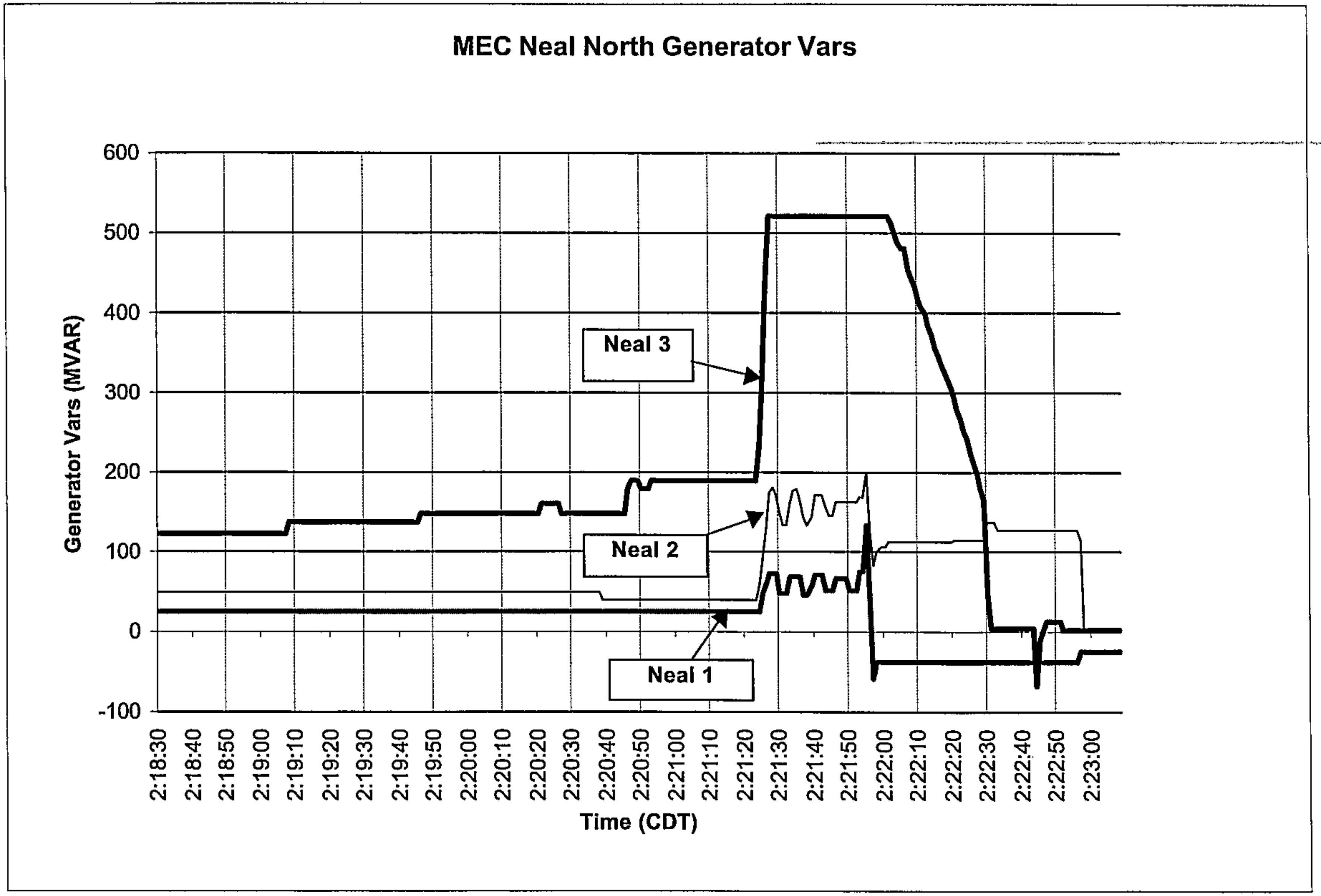


FIGURE #17



MEC Neal North Generator Vars
Generator Vars (MVAR)
600
500
400
300
200
100
0
-100
Neal 3
Neal 2
Neal 1
2:18:30
2:18:40
2:18:50
2:19:00
2:19:10
2:19:20
2:19:30
2:19:40
2:19:50
2:20:00
2:20:10
2:20:20
2:20:30
2:20:40
2:20:50
2:21:00
2:21:10
2:21:20
2:21:30
2:21:40
2:21:50
2:22:00
2:22:10
2:22:20
2:22:30
2:22:40
2:22:50
2:23:00
Time (CDT)

FIGURE #18

Watertown SVS MVAR

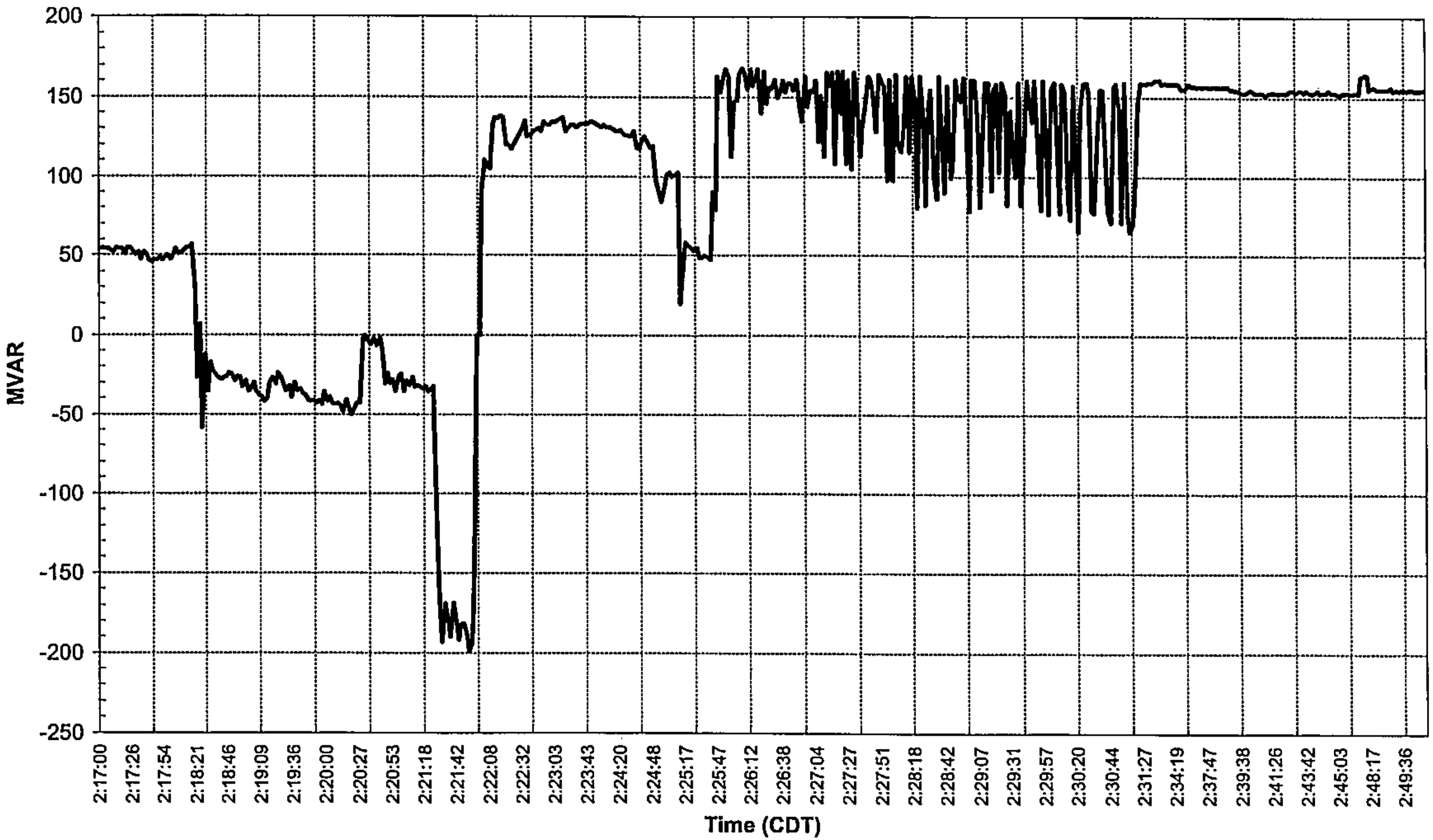
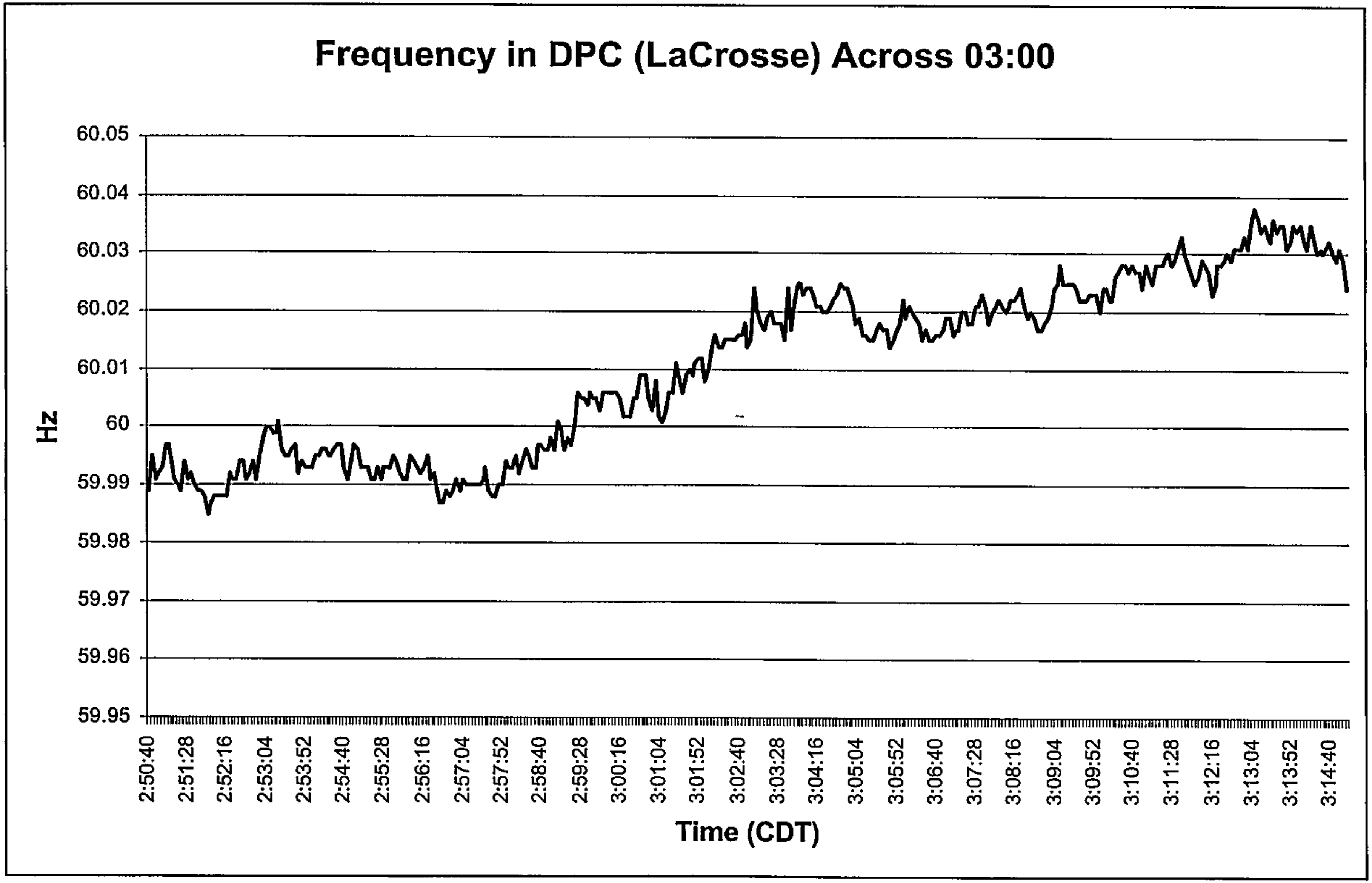


FIGURE #19



Frequency in DPC (LaCrosse) Across 03:00
Hz
60.05
60.04
60.03
60.02
60.01
60
59.99
59.98
59.97
59.96
59.95
2:50:40
2:51:28
2:52:16
2:53:04
2:53:52
2:54:40
2:55:28
2:56:16
2:57:04
2:57:52
2:58:40
2:59:28
3:00:16
3:01:04
3:01:52
3:02:40
3:03:28
3:04:16
3:05:04
3:05:52
3:06:40
3:07:28
3:08:16
3:09:04
3:09:52
3:10:40
3:11:28
3:12:16
3:13:04
3:13:52
3:14:40
Time (CDT)

FIGURE #20

Tioga-Boundary Dam 230 KV line Flow. Voltage At Boundary Dam Station

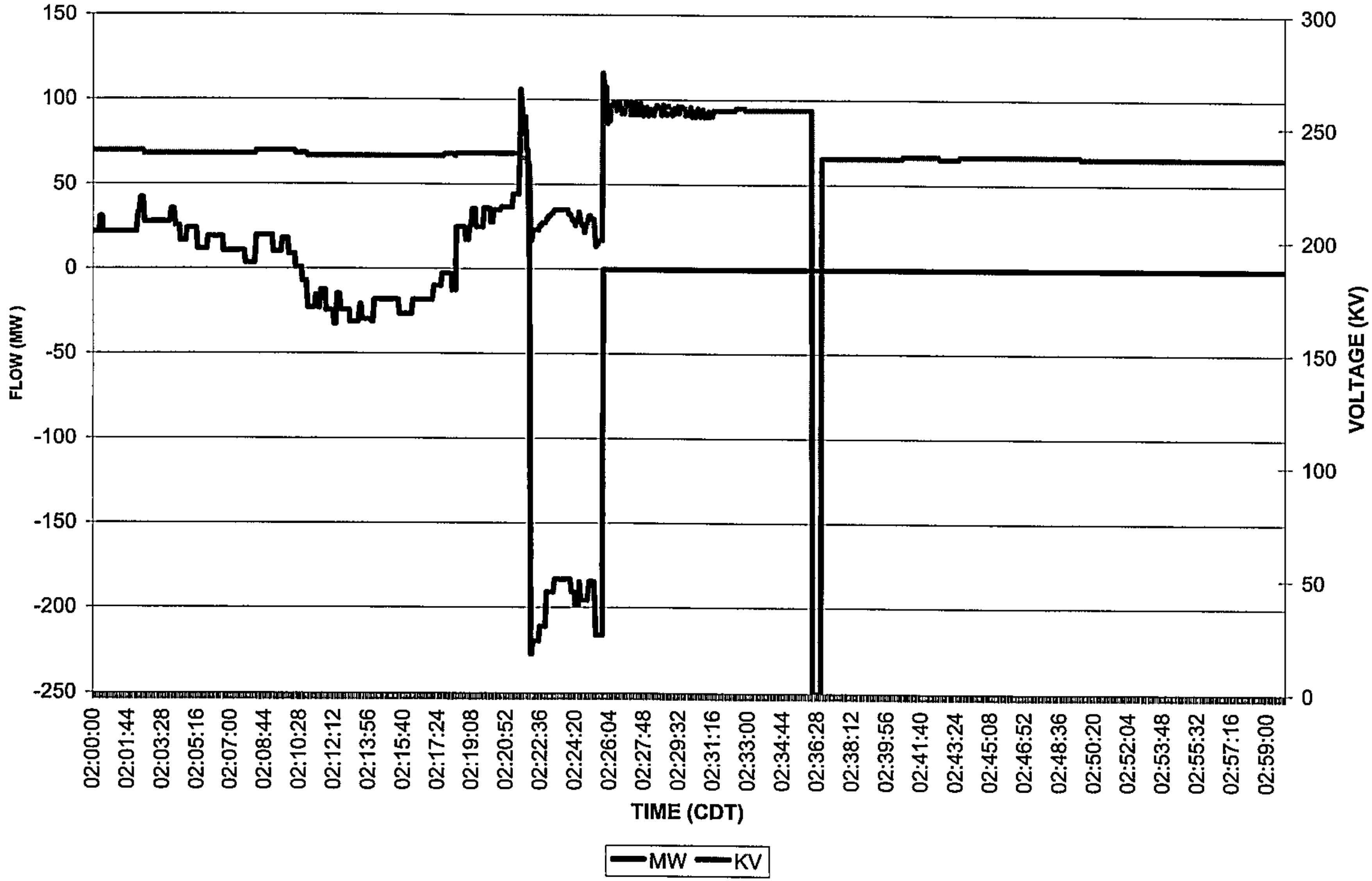
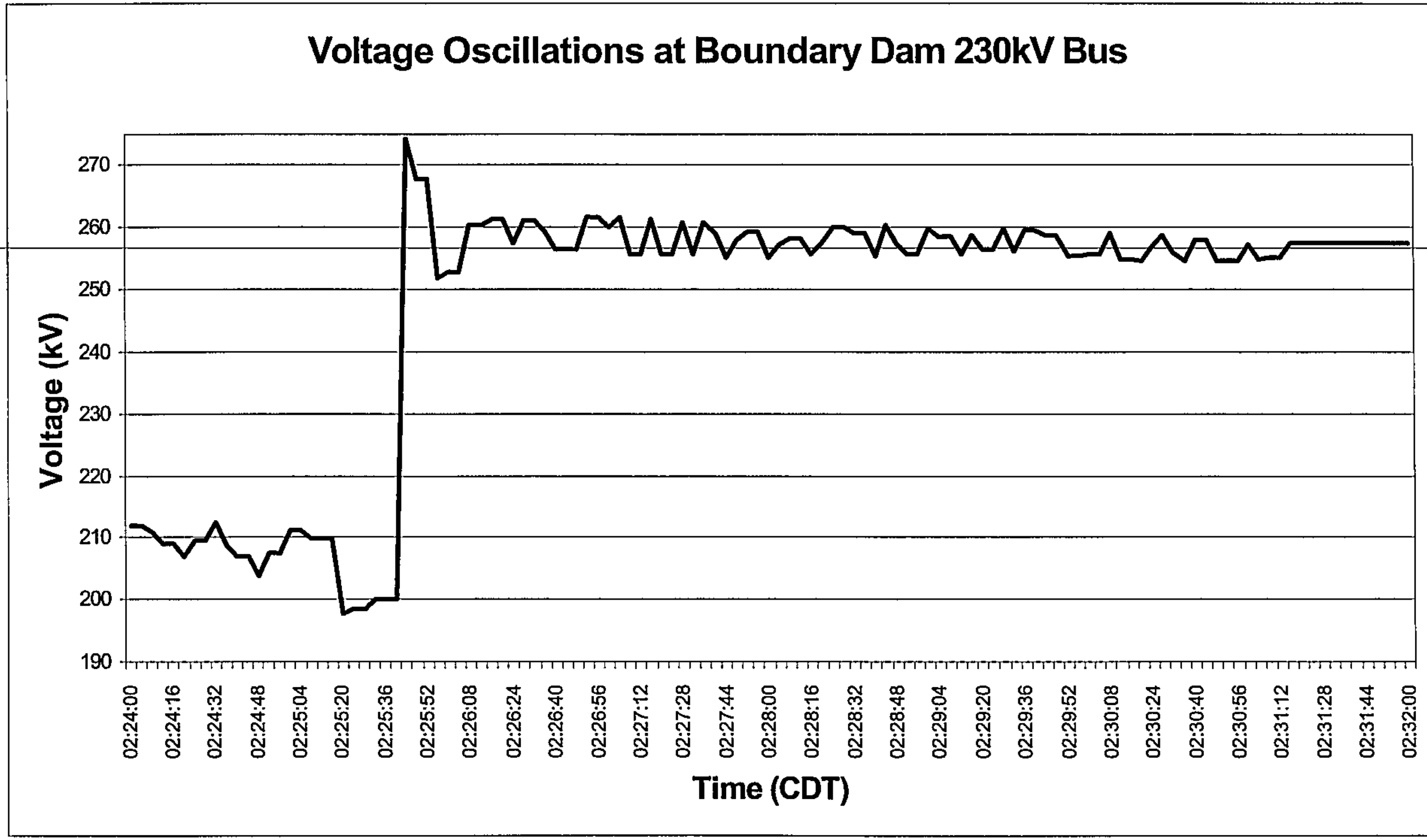


FIGURE #21



Voltage Oscillations at Boundary Dam 230kV Bus
Voltage (kV)
270
260
250
240
230
220
210
200
190
02:24:00
02:24:16
02:24:32
02:24:48
02:25:04
02:25:20
02:25:36
02:25:52
02:26:08
02:26:24
02:26:40
02:26:56
02:27:12
02:27:28
02:27:44
02:28:00
02:28:16
02:28:32
02:28:48
02:29:04
02:29:20
02:29:36
02:29:52
02:30:08
02:30:24
02:30:40
02:30:56
02:31:12
02:31:28
02:31:44
02:32:00
Time (CDT)

FIGURE #22

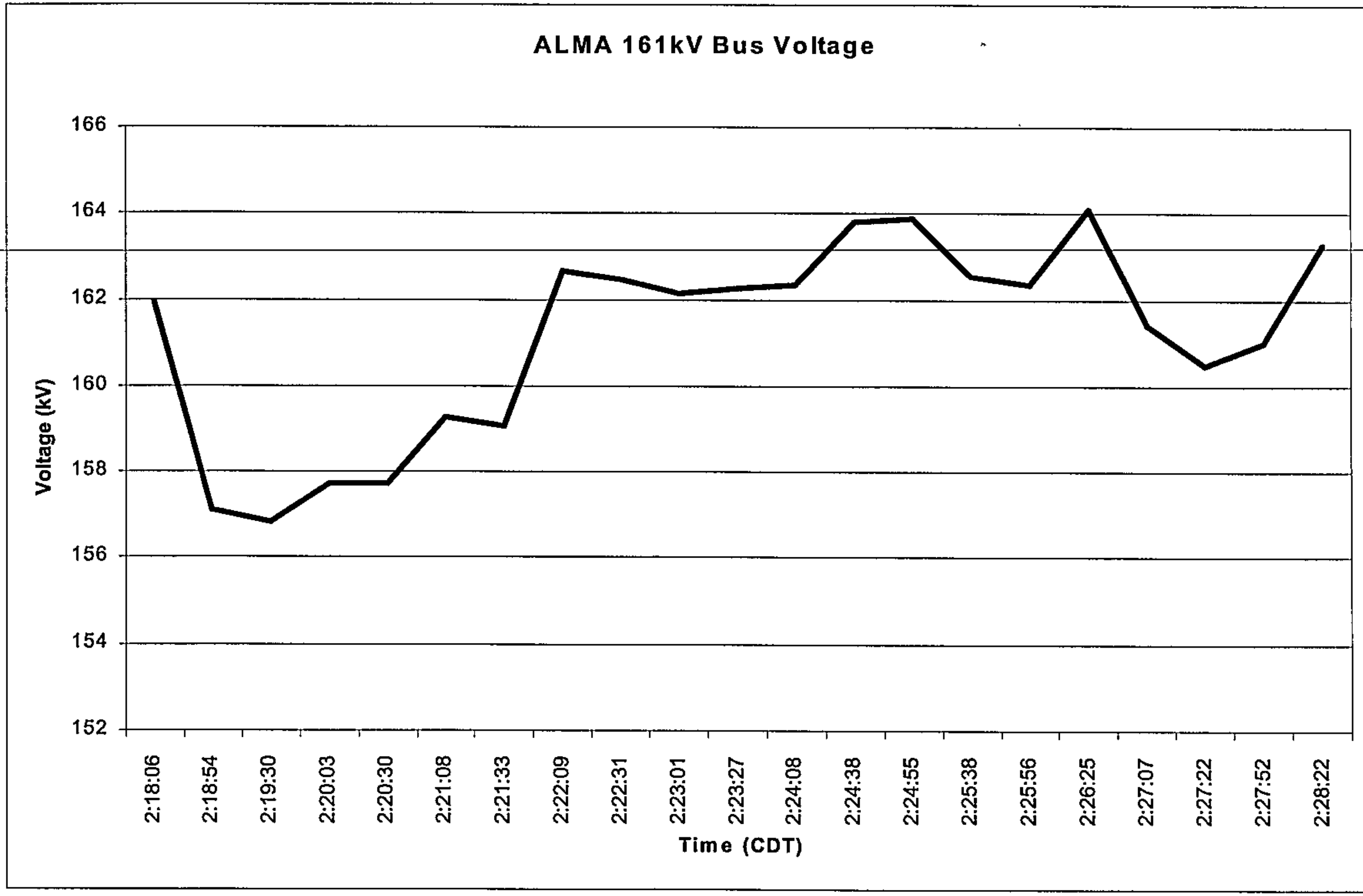

ALMA 161kV Bus Voltage
166
164
162
160
158
156
154
152
Voltage (kV)
2:18:06
2:18:54
2:19:30
2:20:03
2:20:30
2:21:08
2:21:33
2:22:09
2:22:31
2:23:01
2:23:27
2:24:08
2:24:38
2:24:55
2:25:38
2:25:56
2:26:25
2:27:07
2:27:22
2:27:52
2:28:22
Time (CDT)

FIGURE #23

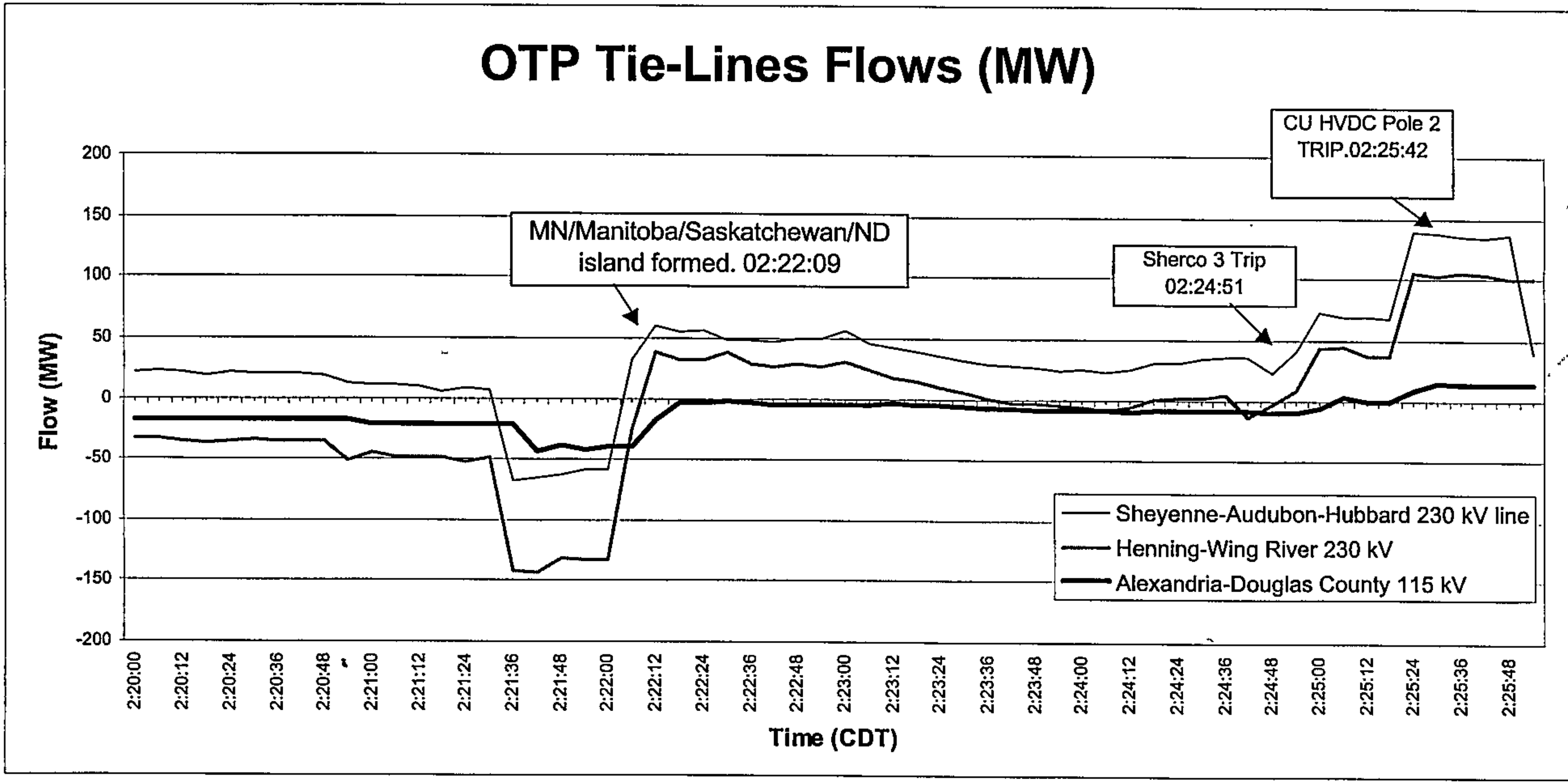

OTP Tie-Lines Flows (MW)
CU HVDC Pole 2
TRIP.02:25:42
MN/Manitoba/Saskatchewan/ND
island formed. 02:22:09
Sherco 3 Trip
02:24:51
Flow (MW)
200
150
100
50
0
-50
-100
-150
-200
Sheyenne-Audubon-Hubbard 230 kV line
Henning-Wing River 230 kV
Alexandria-Douglas County 115 kV
2:20:00
2:20:12
2:20:24
2:20:36
2:20:48
2:21:00
2:21:12
2:21:24
2:21:36
2:21:48
2:22:00
2:22:12
2:22:24
2:22:36
2:22:48
2:23:00
2:23:12
2:23:24
2:23:36
2:23:48
2:24:00
2:24:12
2:24:24
2:24:36
2:24:48
2:25:00
2:25:12
2:25:24
2:25:36
2:25:48
Time (CDT)

FIGURE #24