System Impact Study Report

Generator Interconnection Request G240
(MISO #37466-01)

55 MW Steam Turbine Facility

in Manitowoc County, Wisconsin

January 31, 2003

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Executive Summary

This report contains the System Impact Study (SIS) for Generation Interconnection Request (GIR) MISO project #G240, MISO Queue #37466-01. The purpose of this study is to evaluate the impact of the addition of 55 MW steam-turbine generation at the Lakefront 69kV substation located in Manitowoc, Wisconsin and jointly owned by the Manitowoc Public Utilities (MPU) and the American Transmission Company (ATC). The requested in-service date is December 2005. Presently connected to the Lakefront substation, there exist five steam-turbine units and two diesel units (total 89 MW). By 2005, two of the existing steam units (total 15 MW) will be retired. By the time the G240 unit is commissioned, the net increase of the total generation from the Lakefront substation will be 35 MW, counting the 5 MW auxiliary load for the new unit.

The new G240 generator will be connected to the Lakefront substation through a 13.8 kV / 69 kV step up transformer. Refer to Figure 1 for a one-line diagram of the system facilities at Lakefront and vicinity.

This study is to identify whether any stability, short circuit, or power flow limits may be violated by the addition of G240. If any stability, short circuit, or power flow problems are found, then possible solutions that might address these problems are suggested. Any problems identified in short circuit or stability analysis in the "Before" state (without the addition of G240) are to be resolved by ATC or the 3rd party involved prior to the commercial operation of G240 generation. Any additional problems identified in the short circuit or stability analysis in the "After" state (with the addition of G240) as compared to the "Before" state are to be attributed to the addition of G240 and resolved prior to the commercial operation of the facility.

The resolution of possible thermal loadability problems is not required for interconnection service, since thermal loadability impacts may be significantly affected by the specific power delivery requests from the facility. A customer can only identify whether any specific power delivery can be accomplished without causing thermal loadability problems or whether specific system modifications will be required via a valid Transmission Service Request (TSR) submitted on the MISO OASIS. Nevertheless, the thermal limit violations identified in this impact study, especially those local to the Lakefront 69 kV substation, can be a reasonable indication of some of the facilities that might need upgrading when power delivery service is requested.

ATC determined in its sole judgment that no GIRs with earlier queue positions may impact the G240 study results. The G240 unit is not in the electrical vicinity of any GIRs with earlier queue positions.

The results of this study may be subject to change. The results are based on data provided by the Generator and other ATC system information that was available at the time the study was performed. If there are any significant changes in the generator and controls data, in earlier queue GIRs, in related TSRs, or subsequent ATC transmission system development plans, then the results of this study may also change significantly. Therefore, this request may be subject to restudy. The Generator is responsible for communicating any significant generation facility data changes in a timely fashion to ATC prior to commercial operation.

System Impacts

Stability

There is no unacceptable stability impact due to the addition of G240. System stability performance is acceptable for all but one contingencies studied for before and after the addition of G240. It is considered a pre-existing condition.

The study indicates that the breaker-failure backup clearing time for the breaker at Revere (on line Revere – Lakefront 69kV) is not fast enough to maintain stability of the Lakefront units for a bolted 3-phase fault at Revere end of the line Revere-Northeast 69kV with the breaker at Revere (on line Revere – Northeast 69kV) failing.

Possible solutions include replacing existing breakers at Revere on line Revere – Lakefront 69kV and on line Revere – Northeast 69kV with faster breakers, developing communications between Revere and Northeast substations to enable faster far end clearing by the breaker at Northeast.

The breaker at Revere (on line Revere – Lakefront 69kV) is being replaced by ATC in 2003 for improved system reliability. The impact of this upgrade and other possible solutions for the stability problem will be evaluated in a facility study (if requested subsequently).

Presently in the existing system, the breakers at Lakefront substation on lines Lakefront – Revere 69kV and Lakefront – Dewey 69kV do not have breaker-failure backup clearing capability. This is not up to the standard of the breaker performance at majority of the ATC substations connected with generators. Breaker-failure backup clearing capability should be developed for the breakers at Lakefront substation and will be discussed further in the facility study.

Short Circuit

The increased short-circuit current due to the addition of G240 remains within the breakers' existing fault current interrupting capabilities in ATC system. No transmission level breaker upgrade is needed in this regard due to the addition of G240.

Power Flow

A Transmission Service Request (TSR) has not been submitted that would identify key power flow impacts that are based on specific, approved, power deliveries. Therefore, a power flow analysis was performed using generic G240 power dispatch scenarios – delivery to the outside ATC or to the increased ATC load. An extensive list of N-1 and selected N-2 contingencies in the vicinity of Lakefront were investigated. Power flow analysis found four branch overloads due to the addition of G240, as listed in the follows. Refer to Table 3.3.1 in section 3.3 for details regarding the thermal ratings and overloading levels of the above overloaded lines. The study found no voltage violations due to the addition of G240.

Thermal overloads due to the addition of G240:

Overloaded Elements	**Contingencies**
Revere - Lakefront 69kV	Dewey – Lakefront 69kV
Manrap - Custer 69kV	Lakefront - Revere 69kV & Custer - St.Nazianz 69kV
St.Nazianz – Custer 69 kV	Lakefront – Revere 69kV & Custer – Manrap 69kV
N.Holstein – St.Nazianz 69kV	Lakefront – Revere 69kV & Custer – Manrap 69kV

Possible solutions range from line terminal upgrades, increased line clearances, etc., to increase the ratings of the overloaded lines.

Further Study

The next step in the Generation Interconnection Request process is for the Generator to decide whether to proceed with a Facility Study. A Facility Study would investigate whether the selected System Upgrades will address all of the identified System Impact Study issues. The Facility Study will also include a budgetary cost estimate and schedule for any ATC system modifications that are required to resolve the identified impact problems.

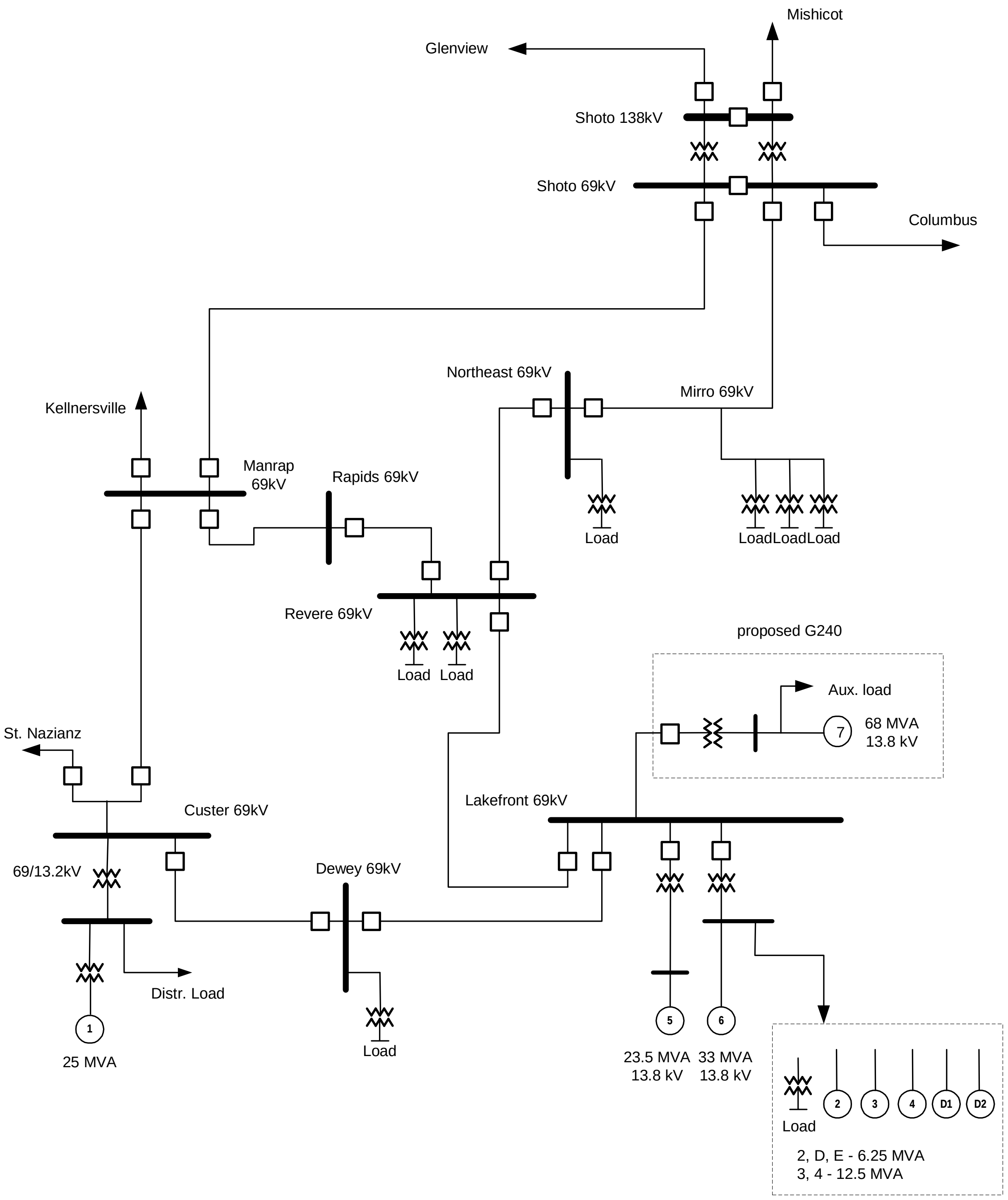


Figure 1: One-Line Diagram of the System at Lakefront 69kV Substation and Vicinity

1. Introduction and Project Description

This report contains the System Impact Study (SIS) for Generation Interconnection Request (GIR) MISO project #G240, MISO Queue #37466-01. The purpose of this study is to evaluate the impact of the addition of 55 MW steam-turbine generation at the Lakefront 69kV substation located in Manitowoc, Wisconsin and jointly owned by the Manitowoc Public Utilities (MPU) and the American Transmission Company (ATC). The requested in-service date is December 2005. Presently connected to the Lakefront substation, there exist five steam-turbine units and two diesel units (total 89 MW). By 2005, two of the existing steam units (total 15 MW) will be retired. By the time the G240 unit is commissioned, the net increase of the total generation from the Lakefront substation will be 35 MW, counting the 5 MW auxiliary load for the new unit. Refer to Figure 1 for a one-line diagram of the system facilities at Lakefront and vicinity.

This study is to identify whether any stability, short circuit, or power flow limits may be violated by the addition of G240. If any stability, short circuit, or power flow problems are found, then possible solutions that might address these problems are suggested.

The resolution of possible thermal loadability problems is not required for interconnection service, since thermal loadability impacts may be significantly affected by the specific power delivery requests from the facility. A customer can only identify whether any specific power delivery can be accomplished without causing thermal loadability problems or whether specific system modifications will be required via a valid Transmission Service Request (TSR) submitted on the MISO OASIS.

ATC determined in its sole judgment that no GIRs with earlier queue positions may impact the G240 study results. The G240 unit is not in the electrical vicinity of any GIRs with earlier queue positions.

Public information related to GIR queues can be found via the MISO web site at **http://oasis.midwestiso.org/documents/ATC/queue.html**

The results of this study may be subject to change. The results are based on data provided by the Generator and other ATC system information that was available at the time the study was performed. If there are any significant changes in the generator and controls data, in earlier queue GIRs, in related TSRs, or subsequent ATC transmission system development plans, then the results of this study may also change significantly. Therefore, this request may be subject to restudy. The Generator is responsible for communicating any significant generation facility data changes in a timely fashion to ATC prior to commercial operation.

2. Criteria, Methodology and Assumptions

2.1 Study Criteria

All of the MISO-adopted NERC Reliability Criteria and the ATC contingency criteria are to be met for both the stability analysis, as well as the power flow (thermal loadability and voltage) analysis. Details of the thermal overloading criteria, voltage violation criteria, stability criteria and how contingencies and monitored elements were determined for this study can be found in Appendix D.

2.2 Study Methodology

2.2.1 Before and After Comparison

To identify what impacts should be attributed to the G240, two system conditions were examined, "Before" and "After" the addition of the proposed generation. The "Before" state is to identify the expected system without the addition of G240. The "After" state is to represent the expected system with G240 in service. Any additional problems identified in the "After" state as compared to the "Before" state are to be attributed to the addition of G240.

2.2.2 Base Case Development

A. General

The Summer 2004 Peak base case from the Multi-Regional Modeling Working Group (MMWG) 1999 series was used as the starting point for the development of the various power flow analysis and stability analysis base cases. The 1999 series was used because the 2000 series posed a number of stability simulation problems.

The power flow analysis was performed using the full 100% peak load base case because this should yield the most conservative results.

The stability analysis was performed using the above base case, which was then modified to represent a light load (50% of peak load) condition. Simulations were performed at the light-load (50%) system load level. The stability performance in this area during light-load conditions is worse than at higher load levels. This is expected due to the different system conditions the generators see at light load, specifically the longer electrical path from source to load. Therefore, the light-load studies were performed to identify the more conservative stability performance in this area, and to identify required upgrades that will protect the transmission system and generation in this area for year round conditions.

B. Refer to Appendix D for more details

More details regarding the development of the load flow and dynamic cases for this study can be found in Appendix D.

2.3 Assumptions

2.3.1 Generation Facility Model Data

The latest power flow and dynamic model information for the G240 generator and exciter, as provided by the Generator, was used in the study. The information was incorporated into the dynamic study database. Response of the modeled excitation system was tested to ensure reasonable performance.

For the existing steam turbine generator units 2, 3, 4, 5 and 6 at Lakefront and the gas turbine generator at Custer, generic data and generic model were used to represent their excitation systems. The selected data and model provide reasonable voltage regulation performance. The Generator did not provide information in this regard.

The MAIN dynamic database of 1999 series lacks governor models for the existing units at Lakefront. Steam turbine governors typically respond slowly and have relatively less effect on transient stability. Therefore, no assumptions were made and no governor models were included for the existing and new units at Lakefront. The gas turbine governor for the Custer generator is modeled in the MAIN dynamic database.

Other G240 generator and facility information provided by the Generator and used in the simulation database includes:

68 MVA, 0.85 pf, 13.8 kV, auxiliary load 5 MW and 4.6 MVAR

For the G240 generator GSU:
Two winding, grounded Y / Δ, 69 kV/ 13.8 kV, 7% impedance on 46 MVA

3. Analysis Results

3.1 Stability Analysis Results

The stability analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-26 (PSS/E, Version 26) program from Power Technologies, Inc (PTI). This program is accepted industry-wide for dynamic stability analysis.

Twenty-three contingencies were studied in the “Before” and “After” states to evaluate stability impact of the addition of G240. Table A.1 in Appendix A tabulates the simulation results. It shows that the system stability performance is satisfactory for the primary contingencies and the prior outage contingencies studied in both “Before” and “After” states, even though the stability margins were reduced somewhat in the “After” state for most of these contingencies. In general, stability performance is determined satisfactory for a contingency if the Maximum Expected Clearing Time (MECT) is smaller than the computed Critical Clearing Time (CCT) for the contingency. MECT is dictated by the existing system facilities. Stability margin relevant to a contingency is the difference between the CCT and the MECT associated with the contingency.

The study found that the stability performance is not acceptable for one contingency for before and after the addition of G240. This contingency involves a breaker failure scenario. The description of this contingency is listed in Table 3.1.1. It is found that the breaker-failure backup clearing time for the breaker at Revere (on line Revere-Lakefront 69kV) is not fast enough to maintain stability of the Lakefront units for a bolted 3-phase fault at the Revere end of the line Revere-Northeast 69kV with the breaker at Revere failing.

Figures 3.1.1 and 3.1.2 show plots of generator angles and terminal voltages from simulations of the contingency as described in Table 3.1.1, for both with and without the addition of G240. These plots show instability of the Lakefront units due to slow backup clearing by the breaker at Revere (on line Revere – Lakefront 69kV).

Possible solutions include replacing existing breakers at Revere on line Revere – Lakefront 69kV and on line Revere – Northeast 69kV with faster breakers, developing communications between Revere and Northeast substations to enable faster far end clearing by the breaker at Northeast.

The breaker at Revere (on line Revere – Lakefront 69kV) is being replaced by ATC in 2003 for improved system reliability. The impact of this upgrade and other possible solutions for the stability problem will be evaluated in a facility study (if requested subsequently).

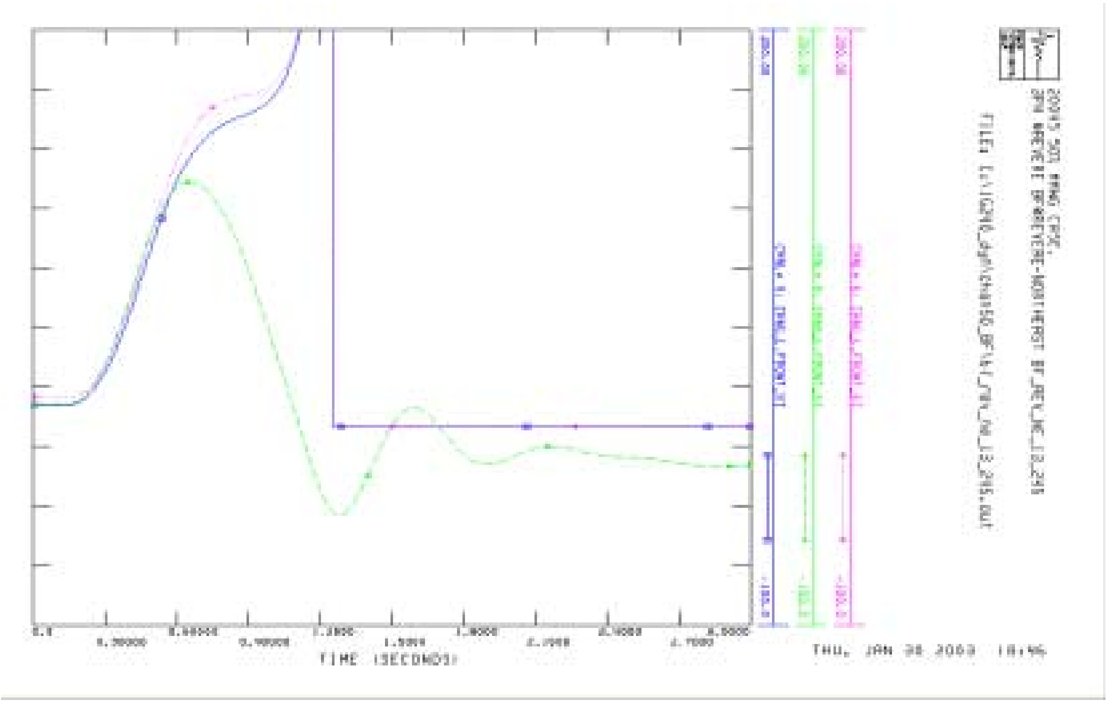
The stability problem associated with the slow breaker-failure backup clearing as discussed above is a pre-existing condition and should be resolved by ATC.

There is another pre-existing condition worth noting. Presently, the breakers at Lakefront substation on lines Lakefront – Revere 69kV and Lakefront – Dewey 69kV do not have breaker-failure backup clearing capability. This is not up to the standard of the breaker performance at majority of the ATC substations connected with generators. Breaker-failure backup clearing capability should be developed for the breakers at Lakefront substation and will be discussed further in the facility study.

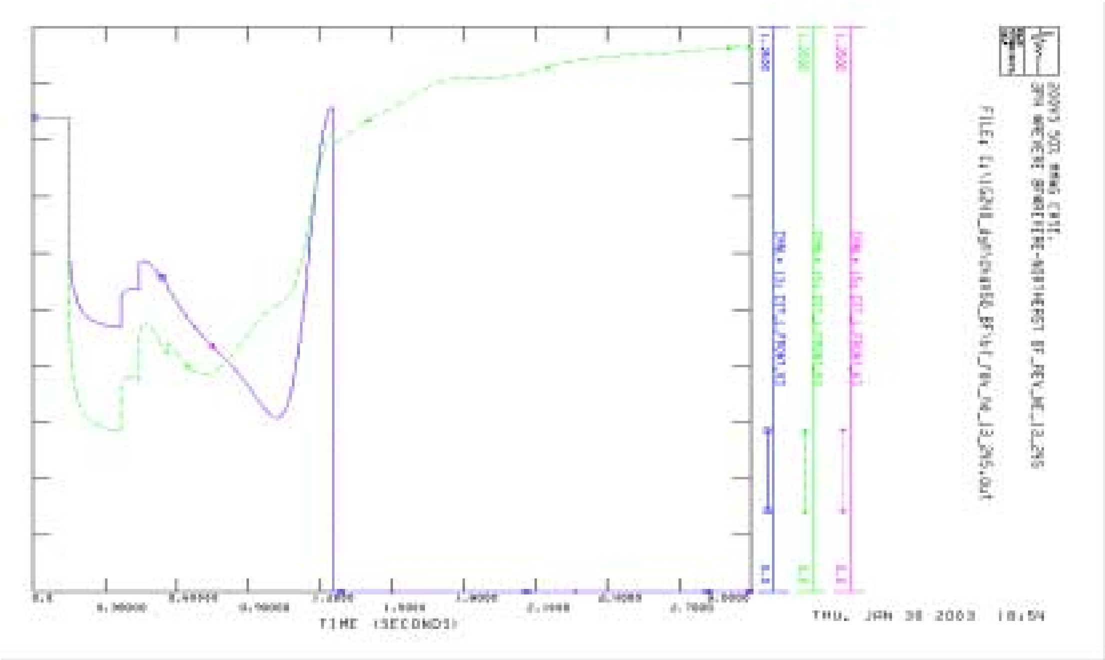
Table 3.1.1 – Contingencies Expected to Cause System Instability in 2005 With and Without the Addition of G240

MECT – Maximum expected clearing time, determined by existing transmission facilities
CCT - Critical clearing time, computed from dynamic simulation

ID	**3-Phase Fault**	**Conditions**	**MECT**	**CCT**	**Unstable units**	**CCT**	**Unstable units**
				With G240 unit (ID #7)		**Without G240 unit (ID #7)**	
F.22	At Revere end on Revere – Northeast 69kV	Breaker failure at: Revere 69 kV Far end clearing & time: Northeast 24.5cy Near end backup clearing & time: Revere – Rapids 17.5cy Revere - Lakefront →	19.5	19.0	Lakefront units 4,6,D,E became unstable at 20 cycles.	12.0	Lakefront units 2,3,4,6,D,E became unstable at 13 cycles.

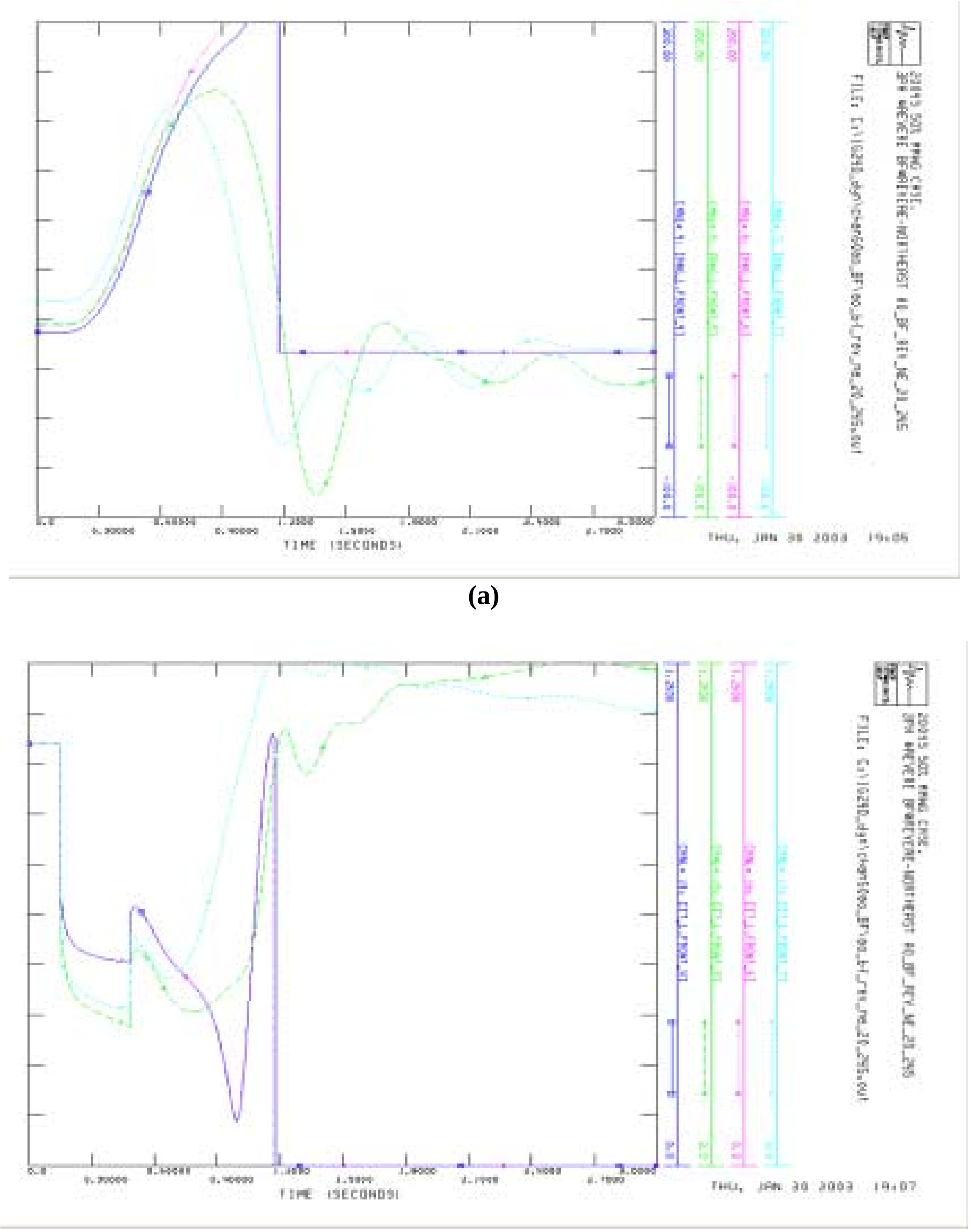


(a)



(b)

Figure 3.1.1 – Angle and Terminal Voltages of the Lakefront Units 4, 5 and 6, Unstable Behavior
Without G240; Backup Clearing in 13 Cycles at Revere on Line Revere - Lakefront



(a)

(b)

Figure 3.1.2 – Angle and Terminal Voltages of the Lakefront Units 4, 5, 6 and 7, Unstable Behavior
With G240; Backup Clearing in 20 Cycles at Revere on Line Revere - Lakefront

3.2 Short-Circuit Analysis Results

The short circuit analysis was performed using the Computer Assisted Protection Engineering (CAPE) program (Build Date May 6, 2002). This program is accepted industry-wide for short circuit analysis.

The purpose of the short-circuit analysis is to identify ATC circuit breakers that likely need to be replaced due to inadequate fault interrupting capabilities caused by the addition of G240. In this study, short-circuit current of the breakers which satisfy either of the following two conditions were investigated:

1) breakers that are within 3 substations from the Lakefront substation and short-circuit current increased by at lease 1% in the “After” state;
2) any breaker whose short-circuit current was increased by at least 500 Amps in the “After” state.

The adjusted short-circuit current for the relevant breakers and their existing current interrupting capabilities are tabulated in Table B.1 for single-line to ground fault and Table B.2 for three-phase fault in Appendix B.

In summary, the addition of G240 increases short-circuit current for multiple breakers. However, adjusted short-circuit current did not exceed fault current interrupting capability for any evaluated breaker at transmission level in ATC system.

Thevenin equivalent impedances at three substations near Lakefront were computed, as shown in Table B.3 in Appendix B. This information may be useful to the Distribution (the MPU in the context of this study) to configure whether there are any current interrupting devices at distribution levels that might be over duty due to the addition of G240.

3.3 Power Flow Analysis Results

A Transmission Service Request (TSR) has not been submitted that would identify key power flow impacts that are based on a specific, approved G240 power delivery. Therefore, power flow analysis was performed using generic power dispatch scenarios. Two generic dispatches were considered – 1) deliver 25% of the G240 generation east to the Northern Sate Power company load and 75% of the generation south to the Common Wealth Edison company load; 2) deliver G240 generation to all ATC load. An extensive list of N-1 contingencies and a number of selected N-2 contingencies near Lakefront substation were investigated. PTI MUST AC Contingency Analysis module was used for power flow analysis.

The purpose of the power flow analysis was to identify the impact of the G240 addition on branch thermal loadings and system voltages. The approach was to compare branch thermal loadings (MVA flows) and bus voltages in the “Before” and “After” states. Note that the focus was not on identifying all violations in either “Before” or “After” state. Instead, the focus was to identify the impact due to the addition of G240 generation.

Thermal loadability

The study found that the G240 addition causes thermal overloads on four branches under contingency conditions. Table 3.3.1 summarizes the worst overloads on these branches, contingencies under which the worst overloads occurred and the studied dispatches under which the branches were overloaded.

Possible solutions range from line terminal upgrades, increased line clearances, etc., to increase the ratings of the overloaded lines.

Voltage violation

The analysis found no voltage violations due to the addition of the G240 unit for the studied contingencies and dispatches.

4. Further Study

The next step in the Generation Interconnection Request process is for the Generator to decide whether to proceed with a Facility Study. A Facility Study would investigate whether the selected System Upgrades will address all of the identified System Impact Study issues. The Facility Study will also include a budgetary cost estimate and schedule for any ATC system modifications that are required to resolve the identified impact problems.

Table 3.3.1 – Overloaded Elements due to the Addition of G240 Generation

Overload Elements	MVA Rating[1]	With G240 MVA Flow	Without G240 MVA Flow	Contingencies	Dispatches[2]
Revere - Lakefront 69kV	82.0	96.6	58.2	Dewey – Lakefront 69kV	1 & 2
Manrap – Custer 69kV	56.0	90.1	53.2	Lakefront - Revere 69kV & Custer - St.Nazianz 69kV	1 & 2
St.Nazianz – Custer 69 kV	36.0	90.6	56.6	Lakefront – Revere 69kV & Custer – Manrap 69kV	1 & 2
N.Holstein – St.Nazianz 69kV	36.0	81.5	48.3	Lakefront – Revere 69kV & Custer – Manrap 69kV	1 & 2

[1] For the above listed contingency cases, emergency rating (rate B) was used.

[2] Dispatch pattern 1 – deliver 25% of the G240 generation east to NSP and 75% of the generation south to CE;
pattern 2 – deliver G240 generation to all ATC load.

Appendix A

Stability Analysis Results

Table A.1 – Stability Impacts for the Expected System in 2005 With and Without the Addition of G240

MECT – Maximum expected clearing time, determined by existing transmission facilities
CCT - Critical clearing time, computed from dynamic simulation

ID	**3-Phase Fault**	**Conditions**	**MECT**	**CCT**	**Unstable units**	**CCT**	**Unstable units**
				With G240 unit (ID #7)		**Without G240 unit (ID #7)**	
Faults Involving Prior Outages							
F.1	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Custer - Manrap 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E and Custer unit became unstable at 15 cycles.	13.0	Lakefront units 2,3,4,5,6,D,E and Custer unit became unstable at 14 cycles.
F.2	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Custer - St. Nazianz 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	14.0	Lakefront units 2,3,4,5,6,D,E became unstable at 15 cycles.
F.3	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Manrap - Kellnersville 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable.
F.4	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Manrap - Shoto 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable.
F.5	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Revere - Northeast 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable.
F.6	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Revere - Rapids 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable.

Table A.1 (cont.) – Stability Impacts for the Expected System in 2005 With and Without the Addition of G240

MECT – Maximum expected clearing time, determined by existing transmission facilities
CCT - Critical clearing time, computed from dynamic simulation

F.7	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Shoto - Glenville 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable
F.8	At Lakefront end on Lakefront – Revere 69 kV	Prior outage Shoto - Mishicot 69kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.9	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Custer - Manrap 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.10	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Custer - St. Nazianz 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.11	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Dewey - Custer 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.12	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Manrap - Kellnersville 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.13	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Manrap - Shoto 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.

Table A.1 (cont.) – Stability Impacts for the Expected System in 2005 With and Without the Addition of G240

MECT – Maximum expected clearing time, determined by existing transmission facilities
CCT - Critical clearing time, computed from dynamic simulation

F.14	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Revere - Northeast 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.15	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Revere - Rapids 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles
F.16	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Shoto - Glenville 69kV	7.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.17	At Lakefront end on Lakefront – Dewey 69 kV	Prior outage Shoto - Mishicot 69kV	7.0	14.0	Lakefront units 4,6,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
Faults Involving Breaker Failures							
F.18	At Custer end on Custer - Manrap 69 kV	Breaker failure at: Custer 69 kV Far end clearing & time: Manrap 7cy Near end backup clearing & time: Custer - N.Holstein 19cy Custer - Dewey →	17.0	>20.0	Custer unit became unstable at 20 cycles. But the rest of the system remains stable.	>20.0	Custer unit became unstable at 20 cycles. But the rest of the system remains stable.

Table A.1 (cont.) – Stability Impacts for the Expected System in 2005 With and Without the Addition of G240

MECT – Maximum expected clearing time, determined by existing transmission facilities
CCT - Critical clearing time, computed from dynamic simulation

F.19	At Dewey end on Dewey – Custer 69 kV	Breaker failure at: Dewey 69 kV Far end clearing & time: Custer 5cy Near end backup clearing & time: Dewey - Lakefront →	13.0	>18.0	None of the Lakefront units and Custer unit became unstable at 18 cycles.	>18.0	None of the Lakefront units and Custer unit became unstable at 18 cycles.
F.20	At Revere end on Revere – Rapids 69kV	Breaker failure at: Revere 69 kV Far end clearing & time: Rapids 7cy Near end backup clearing & time: Revere – Northeast 16.5cy Revere - Lakefront →	16.5	>20.0	None of the Lakefront units and Custer unit became unstable at 20 cycles.	>19.0	None of the Lakefront units and Custer unit became unstable at 19 cycles.
F.21	At Revere end on Revere – Northeast 69kV	Breaker failure at: Revere 69 kV Far end clearing & time: Northeast 24.5cy Near end backup clearing & time: Revere – Rapids 17.5cy Revere - Lakefront →	19.5	19.0	Lakefront units 4,6,D,E became unstable at 20 cycles.	12.0	Lakefront units 2,3,4,6,D,E became unstable at 13 cycles.
Faults Cleared in Primary Clearing Time							
F.22	At Lakefront end on Lakefront – Revere 69 kV	Primary clearing: Lakefront – Revere 69 kV	8.0	14.0	Lakefront units 4,5,6,7,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.
F.23	At Lakefront end on Lakefront – Dewey 69 kV	Primary clearing: Lakefront – Dewey 69 kV	7.0	14.0	Lakefront units 4,6,D,E became unstable at 15 cycles.	>15.0	None of the units at Lakefront and Custer became unstable at 15 cycles.

Appendix B

Short Circuit Analysis

Table B.1 – Short-Circuit Results for the Expected System in 2005 With the Addition of G240

Single-line to ground fault
Breakers evaluated are at "From" end of the lines listed below

From bus	To bus	Ckt	Base kV	INTR rating Amps	Adj. Duty Amps	Increase[1] Amps
CUSTER	DEWEY	1	69.0	31500	5462	418
CUSTER	MANRAP	1	69.0	19909	5070	788
CUSTER	S.NAZIAN	1	69.0	19909	6871	1291
DEWEY	CUSTER	1	69.0	40000	6558	1654
DEWEY	LAKEFRONT	1	69.0	40000	3683	196
LAKEFRONT	DEWEY	1	69.0	31500	10496	3606
LAKEFRONT	GND_XFMR	1	69.0	31500	11429	3853
LAKEFRONT	PLANT GSU_B2	1	69.0	31500	10005	3719
LAKEFRONT	PLANT GSU_B3	1	69.0	31500	10435	3517
LAKEFRONT	REVERE	1	69.0	27000	9704	3670
MANRAP	CUSTER	1	69.0	19909	7669	955
MANRAP	KELNRSVL	1	69.0	19909	8158	1461
MANRAP	RAPIDS	1	69.0	19909	6416	601
MANRAP	SHOTO	1	69.0	19909	7487	1454
NORTHEAST	MIRRO	1	69.0	27000	4657	781
NORTHEAST	REVERE	1	69.0	27000	4627	65
RAPIDS	REVERE	1	69.0	31500	6411	600
REVERE	LAKEFRONT	1	69.0	21000	6740	425
REVERE	NORTHEAST	1	69.0	21000	7739	1942
REVERE	RAPIDS	1	69.0	12600	7875	1578
SHOTO	COLUM ST	1	69.0	19909	12520	790
SHOTO	MANRAP	1	69.0	19909	11646	513
SHOTO	MIRRO	1	69.0	19909	11318	384

[1] Increase in adjusted short circuit duty from "Before" (without G240)

Table B.2 – Short-Circuit Results for the Expected system in 2005 With the Addition of G240

Three-phase fault
Breakers evaluated are at "From" end of the lines listed below

From bus	To bus	Ckt	Base kV	INTR Amps	Adj. Duty Amps	Increase[1] Amps
CUSTER	DEWEY	1	69.0	31500	9583	688
CUSTER	MANRAP	1	69.0	19909	8142	798
CUSTER	S.NAZIAN	1	69.0	19909	10345	1350
DEWEY	CUSTER	1	69.0	40000	7361	1162
DEWEY	LAKEFRONT	1	69.0	40000	5294	269
LAKEFRONT	DEWEY	1	69.0	31500	10034	2042
LAKEFRONT	GND_XFMR	1	69.0	31500	10790	2043
LAKEFRONT	PLANT GSU_B2	1	69.0	31500	9786	2036
LAKEFRONT	PLANT GSU_B3	1	69.0	31500	9459	2205
LAKEFRONT	REVERE	1	69.0	27000	8424	2051
MANRAP	CUSTER	1	69.0	19909	9669	1006
MANRAP	KELNRSVL	1	69.0	19909	9600	1308
MANRAP	RAPIDS	1	69.0	19909	8582	678
MANRAP	SHOTO	1	69.0	19909	9200	1228
NORTHEAST	MIRRO	1	69.0	27000	6376	793
NORTHEAST	REVERE	1	69.0	27000	6171	150
RAPIDS	REVERE	1	69.0	31500	8573	677
REVERE	LAKEFRONT	1	69.0	21000	8773	541
REVERE	NORTHEAST	1	69.0	21000	9078	1521
REVERE	RAPIDS	1	69.0	12600	9328	1361
SHOTO	COLUM ST	1	69.0	19909	12258	885
SHOTO	MANRAP	1	69.0	19909	11328	603
SHOTO	MIRRO	1	69.0	19909	10992	467

[1] Increase in adjusted short circuit duty from "Before" (without G240)

Table B.3 - Thevenin Equivalent Impedances in Ohms at Three Substations near Lakefront

	Without G240			With G240		
	Pos Seq.	Neg. Seq.	Zero Seq.	Pos Seq.	Neg. Seq.	Zero Seq.
Revere 69kV	0.90971+ j 4.1341	0.89393+ j 4.0802	1.44216+ j 7.0800	0.72536+ j 3.5624	0.74200+ j 3.5382	1.06402+ j 5.1560
Dewey 69kV	1.08537+ j 4.9643	1.05982+ j 4.8995	1.70246+ j 8.8219	0.81884+ j 4.2618	0.83603+ j 4.2317	1.07870+ j 5.8710
N. East 69kV	0.98946+ j 4.3878	0.97915+ j 4.3421	1.77287+ j 7.6986	0.87628+ j 3.9571	0.88892+ j 3.9354	1.60714+ j 6.7241

Appendix C

Power Flow Analysis

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Appendix D

Study Criteria and Methodology

D.1 Study Criteria

All of the MISO-adopted NERC Reliability Criteria and the ATC contingency criteria are to be met for both the stability analysis, as well as the power flow (thermal loadability and voltage) analysis.

D.1.1 Contingencies

For stability analysis, a set of branches in the vicinity of the generator/power plant of concern is selected as contingencies, based on engineering judgment. Fault analysis is performed for the following three categories of contingency conditions:

1. Fault cleared in primary time with an otherwise intact system.
2. Fault cleared in delayed clearing time (i.e. breaker failure conditions) with an otherwise intact system.
3. Fault cleared in primary clearing time with a pre-existing outage of any other transmission element.

For the power flow analysis, the contingencies include the normal (intact) system configuration, standard N-1 contingencies and a set of N-2 contingencies that ATC has determined to be significant.

D.1.2 Monitored Elements

For power flow analysis, load carrying elements of voltage level above 69 kV in the ATC areas - Wisconsin Public Service Corp Control Area, Wisconsin Electric Power Co. Control area and Alliant East Control Area were monitored.

D.1.3 Thermal Loadability Criteria

For the normal (intact) system conditions, the loading of all transmission system elements significantly affected by G240 must not exceed 100% of the summer normal loadability rating (Rate A). For contingency system conditions (selected N-1 and N-2 contingencies), the loading of all transmission system elements significantly affected by G240 must not exceed 100% of the summer emergency loadability rating (Rate B).

D.1.4 Voltage Level Criteria

For normal (intact) system conditions, the voltage level of all buses significantly affected by G240 must be in the range of 95% to 105% of the nominal system voltage. For contingency system conditions (selected N-1 and N-2 contingencies), the voltage level of all buses significantly affected by G240 must be in the range of 90% to 110% of the nominal system voltage.

D.1.5 Stability Criteria

Transient stability simulations were performed to determine Critical Clearing Times (CCT) for all pertinent criteria contingencies. CCT is a period relative to the start of a fault, within which all generators in the system remain stable (synchronized). The computed CCTs are then compared to the Maximum Expected Clearing Times (MECTs) which are dictated by the parting times of the existing breakers and the action times of the associated relays. In any contingency, if the computed CCT is less than the MECT, it is considered an unstable situation and is unacceptable. The computed CCT values are measured to the nearest 1 cycle in this impact study.

D.2 Study Methodology

D.2.1 Before and After Comparison

To identify what impacts should be attributed to the G240, two system conditions were examined, “Before” and “After” the addition of the proposed generation. The “Before” base case is to identify the expected system without the addition of G240. The “After” base case is to represent the expected system with G240 in service. Any additional problems identified in the “After” state as compared to the “Before” state are to be attributed to the addition of G240 and resolved prior to commercial operation of the facility.

D.2.2 Base Case Development

1) General

The Summer 2004 Peak base case from the Multi-Regional Modeling Working Group (MMWG) 1999 series was used as the starting point for the development of the various power flow analysis and stability analysis base cases. The 1999 series was used because the 2000 series posed a number of stability simulation problems.

The power flow analysis was performed using the full 100% peak load base case because this should yield the most conservative results.

The stability analysis was performed using the above base case, which was then modified to represent a light load (50% of peak load) condition. Simulations were performed at the light-load (50%) system load level. The stability performance in this area during light-load conditions is worse than at higher load levels. This is expected due to the different system conditions the generators see at light load, specifically the longer electrical path from source to load. Therefore, the light-load studies were performed to identify the more conservative stability performance in this area, and to identify required upgrades that will protect the transmission system and generation in this area for year round conditions.

The 2004 MMWG stability base case contains dynamic model information for generators throughout MAIN, as well as a significant portion of the continental United States. The original case and model database were *not* modified to include other proposed generation interconnection customers.

2) Generation Dispatch

By 2005 when the 55 MW G240 generation is committed, two of the existing steam units connected to the Lakefront substation will be retired. Therefore, the net increase in power generation from the substation will be 35 MW, counting the 5 MW auxiliary load of the new unit. This net increase of generation will be delivered to loads according to different dispatches.

For power flow analysis, two dispatches were considered in this impact study. First, 75% of the net generation increase was delivered south to the Commonwealth Edison company load and 25% west to the Northern States Power company load. Second, the net generation increase was delivered to all ATC load (all ATC loads were scaled up).

For stability analysis, 75% of the net generation increase was delivered south to the Commonwealth Edison network load and 25% west to the Northern States Power network load.

3) Scheduled Voltage

The scheduled voltage levels at all buses in the MAIN base case were unchanged. For the power flow analysis (100% of peak load condition), the scheduled voltage at the Lakefront 69 kV bus was selected to cause the new and existing generators to operate at 0.98 lagging power factor for the normal (intact) system configuration. For the stability analysis (50% of peak load condition), the scheduled voltage at Lakefront 69 kV bus was selected to cause the generators to operate at 1.00 (unity) power factor. In the unit power fact or close to unit power factor conditions, MW generation should be close to maximum for generators. The unity power factor condition produces conservative analysis results.

4) Interface Exchange Considerations

The power flow analysis and stability analysis were performed at one interface exchange pattern. This interface exchange is used by ATC to produce relatively conservative results.

D.2.3 Software Analysis Tools

The stability analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-26 (PSS/E, Version 26) program from Power Technologies, Inc (PTI). This program is accepted industry-wide for dynamic stability analysis.

The short circuit analysis was performed using the Computer Assisted Protection Engineering (CAPE) program (Build Date May 6, 2002). This program is accepted industry-wide for short circuit analysis.

The system power flow analysis was performed using the PTI Managing and Utilizing System Transmission (MUST) software package (Version 4.0). This program is accepted industry-wide for power flow and power transfer analysis. The AC Contingency Analysis module in MUST was utilized in this impact study to evaluate power flow thermal overloads and voltage violations.

D.2.4 Obtain Critical Clearing Time

Three-phase faults were applied at the faulted bus and cleared in progressively longer times to determine the critical clearing time (CCT) to avoid any generating unit becoming unstable after clearing the fault. For example, a CCT of 10 cycles means that one or more generating units became unstable at 11 cycles, while all units remained stable at 10 cycles. CCT is the longest time that fault conditions can be applied at the described location before being removed by protective equipment for which the units on the system will remain stable.