November 13, 2009

NRC 2009-0114
10 CFR 50.90

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

Transmittal of Background Information to Support
License Amendment Request 261
Final Interconnection System Impact Study

References:
(1) FPL Energy Point Beach, LLC, Letter to NRC, dated April 7, 2009, License Amendment Request 261, Extended Power Uprate (ML091250564)
(2) FPL Energy Point Beach, LLC, Letter to NRC, dated April 8, 2009, Transmittal of Background Information to Support License Amendment Request 261, Interconnection System Impact Study (ML091000647)

To support NRC review of the Point Beach Nuclear Plant (PBNP) License Amendment Request 261 for an Extended Power Uprate (EPU), NextEra Energy Point Beach, LLC (NextEra) is providing the "Final G833/G834 with additional 6 MW per unit (J022/J023) Interconnection System Impact Study Report, 118 MW Nuclear Generation Increase (59 MW each at Point Beach Generators 1 and 2), Manitowoc County, Wisconsin," dated October 2, 2009.

The study was prepared by American Transmission Company (ATC), the transmission grid owner/operator for PBNP. The report provides the system impact study required by the Midwest Independent System Operator (MISO) for the PBNP EPU.

In order to address the thermal and stability limits of the transmission grid that will be associated with the implementation of the PBNP EPU, a combination of interim or final requirements including breaker protection improvements, installation of a switching station, line segment upgrades, and operating restrictions will be implemented. These requirements are being addressed to allow PBNP to operate either unit at EPU conditions. The Reference (1), Attachment 5, Licensing Report Section 2.3.2, contains a discussion of the Offsite Power System for the proposed EPU.

Summary of Regulatory Commitments

The final Interconnection System Impact Study transmitted via this letter fulfills Regulatory Commitment 2 of Reference (1).

Questions concerning the enclosure should be directed to Mr. Steve Hale, EPU Licensing Manager, at 561/691-2592.

Very truly yours,

NextEra Energy Point Beach, LLC

Larry Meyer
Site Vice President

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE 1

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

LICENSE AMENDMENT REQUEST 261
EXTENDED POWER UPRATE

FINAL
G833/G834 WITH ADDITIONAL 6 MW PER UNIT (J022/J023)
INTERCONNECTION SYSTEM IMPACT STUDY REPORT
118 MW NUCLEAR GENERATION INCREASE
(59 MW EACH AT POINT BEACH GENERATORS 1 AND 2)
MANITOWOC COUNTY, WISCONSIN
DATED OCTOBER 2, 2009

132 pages follow

AMERICAN TRANSMISSION COMPANY ®

FINAL

G833 /G834 with additional 6 MW per unit (J022/J023)
Interconnection System Impact Study Report

118 MW Nuclear Generation Increase
(59 MW each at Point Beach Generators 1 and 2)
Manitowoc County, Wisconsin

G833 - MISO Queue #39297-01
J022 - MISO Queue Date (1/16/2009)

G834 - MISO Queue #39297-02
J023 - MISO Queue Date (1/14/2009)

October 2, 2009
American Transmission Company, LLC

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Executive Summary

The Interconnection System Impact Study (ISIS) report for Midwest Independent System Operator (MISO) Generation Interconnection Requests identified as Projects G833, Queue #39297-01, and G834, Queue #39297-02, to the 345-kV transmission system in Manitowoc County, Wisconsin, was originally posted in July 2008 and the revision (#3) was posted on December 18, 2008. On January 14 and 16, 2009, the Interconnection Customer submitted additional requests of 6 MW per unit (MISO Generator Interconnection Requests J022 and J023) and the original dynamic models of the generators were modified. As a result, the requested additional generation is 59 MW for each of the Point Beach Nuclear generators with a total increase in plant output of 118 MW over the existing Interconnection Agreement. Each generator was studied with a net output, as measured at the low-side of the generator step-up transformer, of 619.56 MW net (642.96 MW gross per unit). The requested commercial operation date is May 31, 2010 for G834/J023 (Point Beach Unit 1) and May 31, 2011 for G833/J022 (Point Beach Unit 2).

This ISIS report identifies the Interconnection Facilities and Network Upgrades needed to facilitate the requested interconnection for either Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS). For interconnection, the good faith estimate of cost for the Network Upgrades identified in this report is approximately between \$131 million and \$246 million. The cost range of the proposed project has been updated from the draft report to a range of costs due to the uncertain condition of the existing 345/138 kV double circuit structures reported from ATC Asset Management in their recent review of the draft system impact study. The condition of the existing 345/138 kV structures will be evaluated as part of the detailed engineering study during the Facilities Study. The preliminary, good faith estimate of schedule indicates that all of the Network Upgrades can be in-service within 8-10 years of an executed Generator Interconnection Agreement.

Although there are no required Interconnection Facilities for this project, ATC recommends installing 345 kV circuit breakers on the high side of each of the two 345/13.2 kV auxiliary transformers to prevent a breaker failure event during auxiliary transformer faults from tripping Point Beach generation. Although a fault on these transformers does not cause the local generators such as Point Beach and Kewaunee to lose synchronism with the required Network Upgrades assumed in-service, ATC still recommends that the Interconnection Customer reduce the primary fault clearing time for the Point Beach auxiliary transformer from 5.1 cycles to 4.0 cycles to prevent these faults from causing the instability of the local generators until the proposed solution is in service. Section 1.3 describes the reliability benefits of these recommendations.

This study was performed with the proposed Power System Stabilizers at Point Beach in-service. The Interconnection Customer must commission a tuning study for the new Point Beach Power System Stabilizers (PSSs) as described in Section 1.3 of this report.

The Interconnection Customer will have to submit the Definitive Planning Continuation milestones (M3) prior to entering the Facilities Study for this project. An Interconnection

Facilities Study will specify in more detail the time and cost of the equipment, engineering, procurement and construction of the system upgrades identified in the ISIS report.

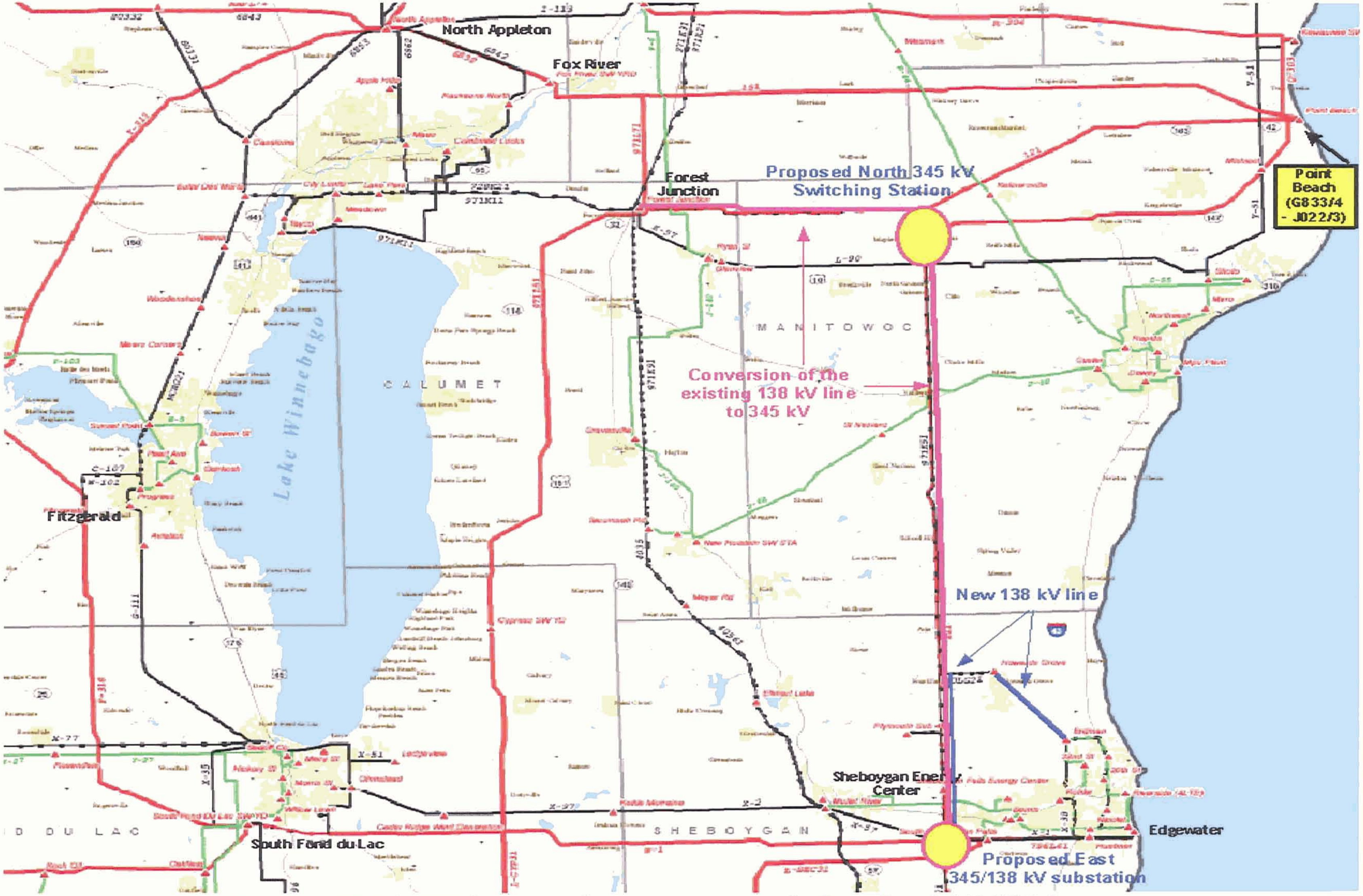


Figure 1 – G833/4-J022/3 Proposed Interconnection at the Point Beach 345 kV Substation and Surrounding System with Proposed Solution

1. Summary

This study evaluates the impact of the proposed 118 MW increase in generation at the Point Beach nuclear plant which is connected to the 345 kV transmission system in Manitowoc County, Wisconsin. This is the re-study of the Interconnection System Impact Study (ISIS) for Generator Interconnection Requests G833 and G834 (53 MW per unit, Queue #39297-01 and #39297-02) and the ISIS for requests J022 and J023 (6 MW per unit, Queue dates: January 14 and 16, 2009). This study incorporates the updated dynamic models of the generator provided by the Interconnection Customer. The customer has requested the following dates for the various stages of interconnection:

- Interconnection Facilities In-Service (Backfeed) Date: Existing facility, not applicable.
- Initial Synchronization Date: Not supplied
- Commercial Operation Date: May 31, 2010 for G834/J023 and May 31, 2011 for G833/J022.

Due to the proposed commercial operation dates of the Interconnection Requests (i.e. May 2010 for Unit #1 at Point Beach and May 2011 for Unit #2 at Point Beach), a study report is posted describing the "interim" system improvements that can form the basis for a Temporary Interconnection Agreement until the Network Upgrades described in this ISIS report can be completed. The "Interim Operation" Re-study Report can be found at:

http://oasis.midwestiso.org/documents/ATC/Cluster_8_Queue.html.

The Interim Operation Re-study Report examines the period between the expected commercial operation date and the expected completion date of a long term solution to identify the possible unit restrictions and/or interim system improvement needed during the interim periods. After implementation of the upgrades needed for "interim" operation, there are several issues that must be addressed to ensure that the Point Beach generation increase is reliable beyond temporary operation. The issues are:

(1) Generator instability due to the isolation of Point Beach Generator 1 on L111 (Point Beach-Sheboygan) which occurs when Point Beach 345 kV breaker 2-3 is out of service and L121 (Point Beach-Forest Junction 345 kV) trips,

(2) Generator instability due to the outage of 6832 (Fox River-North Appleton) followed by a fault on R-304 (Kewaunee-North Appleton),

(3) Most significantly, limitations on Point Beach and Kewaunee generating unit reactive power output at all hours. Generator instability was identified for fault conditions when Point Beach and Kewaunee units produce relatively small reactive power output (over-excitation) or absorbs reactive power from transmission system (under-excitation). Reactive power output from a synchronous machine has an impact on the transient stability of the unit. Typically, the lower the excitation on a generating unit, the less stable the unit tends to be under a fault condition. The results of the interim operation study indicate that a certain level of reactive power output (over-excitation) needs to be maintained to ensure generation stability in anticipation of critical fault conditions. The units may not be allowed to reduce their MVAR outputs, reducing their effectiveness in controlling system voltage.

The interim operation study identified that, for temporary operation, Issue (1) and (2) should be mitigated by reducing generation at Point Beach to 580 MW (G1 gross) and 600 MW (G2 gross) respectively, and Issue (3) should be mitigated by maintaining MVAR output from Point Beach and Kewaunee to a certain level through the use of Minimum Excitation Limiter settings. Issue (1) may be addressed by a long term solution such as reconfiguring the existing Point Beach substation such that Point Beach Unit #1 cannot be isolated on 345-kV line L111. However, a more robust long term solution such as a new 345 kV line and/or substation will be needed to address Issue (2) and Issue (3). Issues (2) and (3) can not be solved by reconfiguring Point Beach because the issues are primarily due to the limited number of 345-kV outlets out of Fox Valley area for the amount of generation located in this area.

This System Impact Study is performed to identify a long-term solution that addresses the following needs and/or provides benefits:

- Addresses the generation instability issues under prior outage conditions,
- Ensures a wider operating envelope for the local transmission system and the interconnected generators by permitting generating unit operation at unity or under-excited conditions,
- Provides better maintenance and operations flexibility during planned or unplanned transmission outage conditions by tying together critical transmission elements in strategic locations and, possibly, providing an additional transmission outlet, and
- Relieves loadings under intact and contingency conditions on the existing 138 kV and 345 kV lines running from Fox Valley area to the south by providing an additional transmission outlet.

This study also identifies steady state system thermal and voltage impacts, system angular stability impact and the circuit breaker fault duty impacts associated with the interconnection of G833/J022 and G834/J023. These interconnection system impacts are based on AC power flow analyses, transient stability analysis and short circuit analysis. This study also identifies the Network Upgrades and Interconnection Facilities required to eliminate any unacceptable system impacts and to allow the generator to interconnect to the system. Preliminary, good faith estimates of cost and schedule will be provided for the identified Network Upgrades.

The Generator Interconnection Procedures permit the Interconnection Customer to request specific Backfeed, Initial Synchronization and Commercial Operation Dates. G833/J022 and G834/J023 involve increasing output from existing generators and the required Interconnection Facilities already exist. The Interconnection Facilities Study process will include a high-level evaluation of any known scheduled outage requirements. The scheduled outage requirements and associated evaluations will continue to be refined as project implementation details progress.

The proposed increase in Point Beach generation will be obtained by increasing the thermal power of the reactor. This will require the rewinding of the stator and rotor of the existing Point Beach generators. No changes to the Point Beach substation layout are required to "interconnect" the increased generation since the units are already connected to the transmission grid. Figure 1.1 shows the expected 345 kV transmission system topology near the Point Beach substation for the 2011 time frame, including the required Network Upgrades that eliminates the stability issues found with the increased Point Beach generation.

Note that Figure 1.1 shows the existing substation layout for the existing Generating Facilities. Figure 1.1 provides a conceptual, equivalent depiction of the Interconnection Customer's Generating Facilities. The Interconnection Customer will need to supply Generating Facility diagrams for the Generator Interconnection Agreement.

Required construction outages to build the new 345 kV substations and the new 345 kV and 138 kV lines will be reviewed further in the Interconnection Facilities Study, along with outages required for the other identified Network Upgrades. Any requested outage must be cleared through an ATC screening process and be formally submitted (outage is logistically supported with a work order and associated construction resources) to the Midwest ISO for approval. The Midwest ISO studies outages based on the submitted queue position within their outage scheduling database.

In order for G833/J022 and G834/J023 to interconnect, the required Network Upgrades and Interconnection Facilities must be completed.

1.1 Injection Limits[1]

The injection limits are identified in Tables A.1 and A.2 in Appendix A and are listed below. The thermal study identified no steady-state thermal violations for NERC Category A (intact system).

The study identified two steady-state thermal violations for NERC Category B (N-1) events that meet the criteria for injection limits:

1. Point Beach-New North Switching Station 345 kV Line (Point Beach-Sheboygan Energy Center L111 east)
2. New East substation-Cedarsauk 345 kV line (Edgewater-Cedarsauk 796L41 southern section)

As documented in the G833/4-J022/3 Interim Operation Re-study Report, the Point Beach-Sheboygan Energy Center line will be uprated independently by ATC for improvement due to MISO energy market impacts.

The Network Upgrades for these injection limits are described in Section 1.4 and are required for either ERIS or NRIS for the full 118 MW of requested interconnection service of G833/4-J022/3.

[1] See Appendix F, Section F3.1 for a definition of what transmission overloads qualify as injection limits.

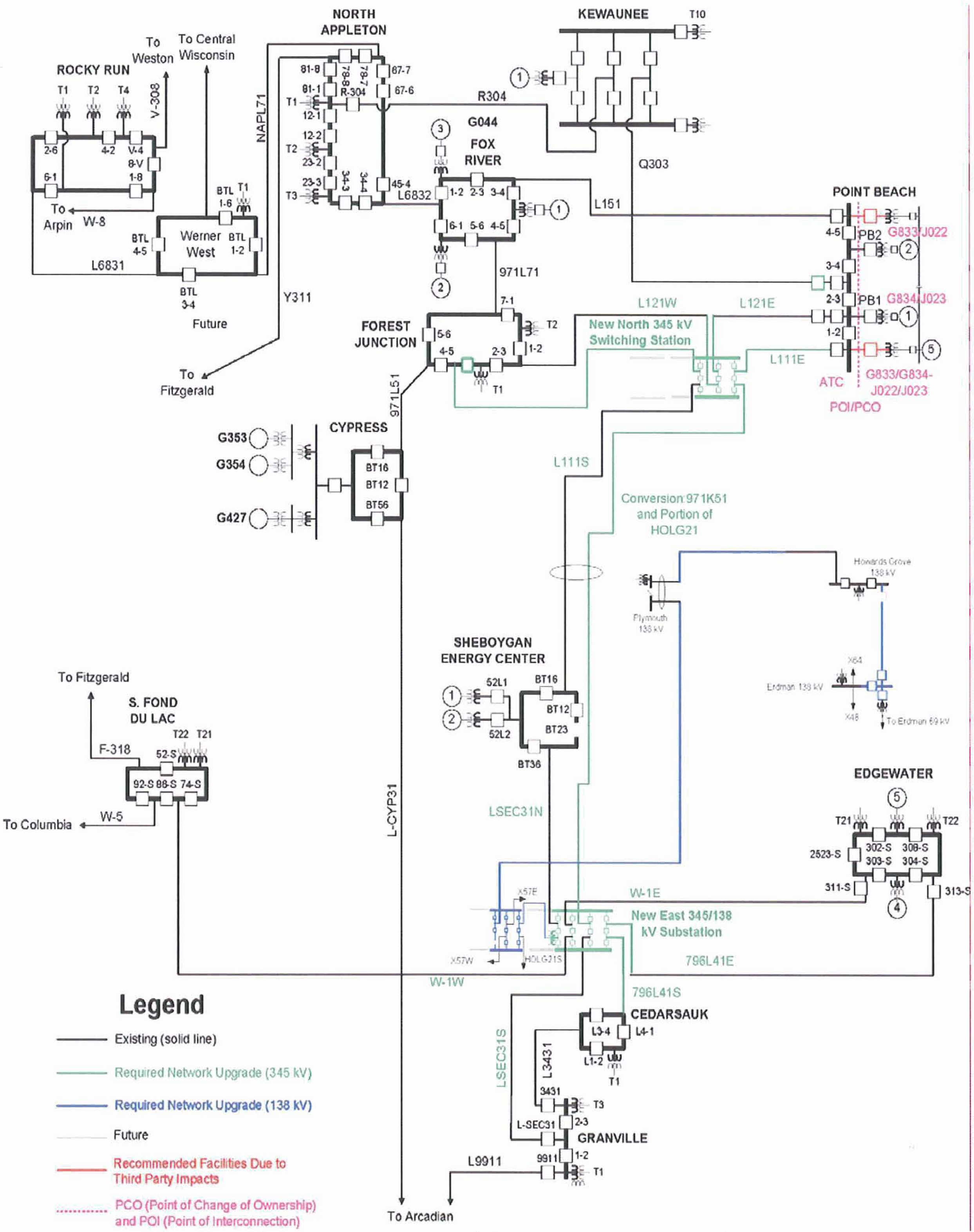


Figure 1.1 – Conceptual One Line Diagram of the 2011 System with G833/J022 and G834/J023 and Required Network Upgrade

1.2 Generating Facility Operation Restrictions

Various potential thermal constraints are shown in Table A.7 and A.8 in Appendix A for Category C.3 events. In general, re-dispatching generators in the local area may relieve the loadings on the constraints. Since thermal constraints will be mitigated in the day-ahead and real-time market through the MISO binding constraint procedure, no operating restrictions are listed for the thermal constraints.

Three potential thermal constraints were found for Category C.5 event, which is the outage of two circuits on a multi-circuit tower. No operating restrictions are listed for these thermal constraints because the New East-Cedarsauk 345 kV line shown in Table A.9 will be uprated as one of the Network Upgrades required for G833/4-J022/3 and the other two constraints, which can be mitigated by local generation redispatch, are not considered as thermal constraints due to G833/4-J022/3.

With all Network Upgrades assumed in-service and the revised Minimum Excitation Limiter settings for Point Beach and Kewaunee units maintained at the level described in Appendix I, there are no generation restrictions due to stability issue for the conditions studied.

1.3 Generating Facility Requirements

Point Beach Power System Stabilizers

The existing Point Beach Power System Stabilizers (PSS) are required due to inadequate rotor angle damping under certain system conditions. The G833/J022 and G834/J023 projects will continue to require the use of PSS on the Point Beach units. This study incorporated the modified PSS information supplied by the Interconnection Customer and it assumed that the PSS for each unit was in-service for each simulation. The re-tuning of the PSS should be reviewed and commissioned by experienced professionals. The results of the on-site PSS tuning, including the parameters expressed in terms of the appropriate power system stabilizer models in the Siemens PTI PSS/E program, must be provided to ATC prior to the commercial operation of each upgraded unit. ATC will then test the performance of the Point Beach units with the tuned parameters in the computer simulations to ensure that rotor angle damping is within criteria.

Auxiliary Transformers T1X03 and T2X03 High-Side Breakers

ATC recommends that new 2 cycle 345 kV circuit breakers and adequate relaying be installed on the high-side of Point Beach auxiliary transformers T1X03 and T2X03 to avoid a trip of the Point Beach units for a breaker failure event (Table 1.4).

The current configuration of the Point Beach substation is shown in Figure 1.2. Due to the current design where the Bulk Electric System equipment is providing the primary fault protection for the T1X03 and T2X03, the following events would occur for a fault on the T1X03 or T2X03 equipment, including a fault at the 13.8 kV level:

1. For a fault on T1X03,
    a. With normal clearing, 345 kV bus #1 will be removed from service and result in the loss of the network connection to Sheboygan Falls Energy Center substation via 345 kV line L111.
    b. With delayed clearing on 345 kV bus tie 1-2, 345 kV bus #1 and 345 kV bus #2 will be removed from service and result in the loss of the following elements:
        i. 345 kV line L111 to Sheboygan Falls Energy Center substation,
        ii. 345 kV line L121 to Forest Junction substation and
        iii. Point Beach generating unit #1.
2. For a fault on T2X03,
    a. With normal clearing, 345 kV bus #5 will be removed from service and result in the loss of the network connection to Fox River substation via 345 kV line L151.
    b. With delayed clearing on 345 kV bus tie 4-5, 345 kV bus #4 and 345 kV bus #5 will be removed from service and result in the loss of the following elements:
        i. 345 kV line L151 to Fox River substation and
        ii. Point Beach generating unit #2.

The addition of new 2 cycle 345 kV circuit breakers will eliminate the loss of 345 kV (i.e. Bulk Electric System) elements for the more probable normal fault clearing events and will substantially reduce the impact of certain delayed clearing events by eliminating a trip of a Point Beach generating unit. ATC recommends these circuit breaker additions to improve the reliability of the transmission network and power plant interconnection, bringing the substation configuration closer to current ATC design standards.

<u>Reduction of Auxiliary Transformers T1X03 and T2X03 Primary Clearing Times</u>

ATC also recommends, regardless of whether or not the recommended T1X03 and T2X03 2 cycle 345 kV circuit breakers are installed, that the existing 5.1 cycle auxiliary transformer 345 kV fault primary clearing time should be reduced to 4.0 cycle to prevent loss of synchronism on the Point Beach and Kewaunee generators for high side faults on these auxiliary transformers cleared in primary time until the proposed solution in place (see G833/4-J022/3 Interim Operation Study Report). With the proposed solution and the planned Kewaunee bus reconfiguration assumed in-service, no stability issues were identified without the recommended circuit breakers. The existing primary clearing time is acceptable with the present system configuration and generation levels. With the addition of G833/4-J022/3, failure to reduce these fault clearing times to the recommended times would result in loss of synchronism on the generators for the faults until completion of the proposed solution.

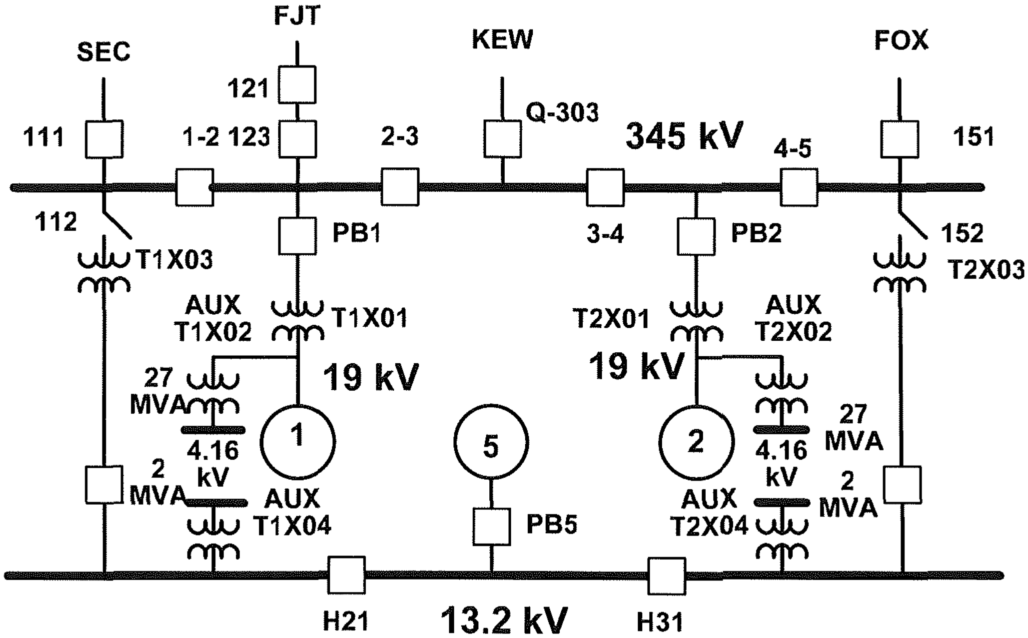


Figure 1.2 – Existing Point Beach Substation Configuration

Power Factor Capability
The G833/4-J022/3 customer has submitted a generating facility design capable of maintaining power delivery at continuous rated power output at the POI (Point of Interconnection) at all power factors over 0.95 leading (when a facility is consuming reactive power from the transmission system) to 0.94 lagging (when a facility is supplying reactive power to the transmission system). For the steady-state scenarios examined, study results indicate that satisfactory system performance is achieved by supplying a range of -211.3 to 233.4 Mvars (gross) to the system. In addition, study done with minimum excitation limits assumed in-service also showed adequate results.

Plant Specific Voltage Requirements
The Point Beach Nuclear Plant has specific 345 kV voltage range requirements. The preferred range is 352 kV (1.020 pu) to 354 kV (1.026 pu), the normal range is 351 kV (1.017 pu) to 358 kV (1.037 pu) and the maximum permissible is 348.5 kV (1.010 pu) to 362 kV (1.049 pu). A new high voltage limit of 360 kV has been proposed by the plant and incorporated into this study. Any voltage outside the maximum permissible range is a voltage limitation as described in the plant technical specifications.

1.4 Network Upgrades

In addition to the Network Upgrades listed below, both Point Beach units and the Kewaunee unit will be required to maintain the revised Minimum Excitation Limit settings on these units to ensure stable operation for a variety of fault conditions. The proposed limits are lower than the settings required in the Interim Operations Restudy Report and can be found in Appendix I.

Existing Network Upgrades Required Before G833/4-J022/3 Operation (See Table 1.1)

Injection Upgrades
Analysis prior to G833/J022 and G834/J023 found no required system upgrades due to injection limits.

Voltage Related
Analysis prior to G833/J022 and G834/J023 found no unacceptable voltages.

Breaker Duty Related
No existing over-duty circuit breaker conditions were found to be significantly (i.e. ≥1%) impacted prior to the addition of G833/J022 and G834/J023. Therefore, no over-dutied circuit breakers are identified in Table 1.1.

Network Upgrades Required Due to G833/J022 and G834/J023 Addition (See Table 1.2.a)
The preliminary, good faith estimate of schedule indicates that all of the Network Upgrades can be in-service within 8-10 years of an executed Generator Interconnection Agreement.

Stability Upgrades (see Table 1.2.a)
To achieve adequate system stability with G833/J022 and G834/J023 in service, the following Network Upgrades are required. See Table 1.2.a for more details:

1) An eight position (expandable to twelve) 345 kV and six position (expandable to ten) 138 kV breaker-and-a-half scheme substation located at the intersection of the existing 345 kV lines W-1 (Edgewater-South Fond Du Lac) and L-SEC31 (Sheboygan Energy Center-Granville). A new 345/138 kV transformer capable of at least 500/625 MVA for SN and SE needs to be installed at the new substation. The existing 345 kV lines W-1, L-SEC31 and 796L41 (Edgewater-Cedarsauk) are looped into the new substation. The existing 138 kV line X-57 (South Sheboygan Falls-Mullet River) and the line from Holland are looped into the substation. New 138 kV line from Plymouth is terminated at the substation (see also item 6).
2) A six position (expandable to ten) breaker-and-a-half scheme substation located near the intersection of the existing 345 kV line L111 (Point Beach-Sheboygan Energy Center) and the existing 138 kV line L90 (Shoto - Glenview). The existing 345 kV lines L111 and L121 (Point Beach-Forest Junction) are looped into the new switching station.
3) Conversion of the existing lines 971K51 (Forest Junction-Howard Grove 138 kV line) and portion of HOLG21 (Howards Grove-Plymouth #4-Holland 138 kV line) to 345 kV (~48 miles). It is terminated at Forest Junction and New East 345/138 kV substation and then looped into the new North 345 kV switching station.
4) Construction of new double circuit 345 kV lines to loop the line 796L41 into the new East substation (~1.1 miles)
5) Construction of new double circuit 345 kV lines to loop the line L121 into the new North switching station (~3.2 miles)
6) Construction of new 138 kV lines to form new East-Plymouth-Howards Grove-Erdman 138 kV lines (~16 miles).

Injection Upgrades (see Table 1.2.a)
In summary, the study identified the following line segment which will need to be upgraded to achieve the necessary rating.

- Cedarsauk-New East 345-kV line 796L41 south (24.1 miles) must be uprated to obtain a minimum summer emergency rating of 960 MVA or higher. The required rating (960 MVA) is from Table A.7 (NERC C.3). This value was selected as the target rating to address potential overloads of the line under various multiple contingency events evaluated.
- Point Beach-New North 345 kV line L111 (51.1 miles) must be uprated to obtain a minimum summer emergency rating of 754 MVA or higher. ATC has a planned project, as an independent economic benefit project, for the Point Beach-Sheboygan Energy Center line uprate to a summer emergency rating of 1095 MVA (1834 A), which is higher than the required rating for G833/4-J022/3. The proposed in-service date of the line uprate project is April 25, 2010 (ATC Project PR03208).

Voltage Related
None

Breaker Duty Related
None

Network Resource Interconnection Service (NRIS) Related
MISO performed the generator deliverability analysis needed for G833/J022 and G834/J023 to qualify for NRIS. No additional upgrades were identified to qualify for NRIS for the entire requested amount.

Typical planning level cost estimates for new and rebuilt facilities in the American Transmission Company (ATC) footprint are listed in Appendix G for the Interconnection Customer's reference.

1.5 Interconnection Facilities

Interconnection Facilities include all facilities and equipment that are located between the interconnecting generator's Generating Facility and the POI. Note that the POI is the terminal in the Point Beach 345-kV Substation where each unit will inject its power output, while the Point of Change of Ownership (PCO) may be a different element within the same 345-kV substation. The G833/J022 and G834/J023 Interconnection Facilities already exist. Table 1.3 describes the new facilities owned by the Interconnection Customer and the Transmission Owner respectively.

1.6 Further Study

In order for G833/J022 and G834/J023 to interconnect, the required Network Upgrades and Interconnection Facilities must be completed. The Interconnection Customer will have to submit the Definitive Planning Continuation milestones (M3) prior to entering the Facilities Study for this project. An Interconnection Facilities Study will specify in more detail the time and cost of the equipment, engineering, procurement and construction of the system upgrades identified in this ISIS report.

Table 1.1– Existing System Upgrades Required before Operation of G833/J022 and/or G834 /J023

Location	Facilities	Reason
None		

Table 1.2.a – Required "Long-Term" Network Upgrades (Fix 11) due to the Addition of G833/J022 and/or G834 /J023 (For more detail, see Appendix J)

Location	Facilities	Reason	Good Faith Cost Estimate (Assumed In-service Date: 2018)
Cedarsauk-East Switching Station 345 kV line (796L41 south)	**Item #1** – Increase the line clearance and upgrade terminal equipment (CTs) on Cedarsauk 345 kV ring buses to obtain a minimum Summer Emergency rating of 960 MVA (1607 Amps). Look at plan and profile and Patrol to observe any close wire crossings and adjust to obtain a minimum Summer Emergency rating of 960 MVA (1607 Amps).	Injection Limit	$402,141
Point Beach-New North 345-kV line (L111 east)	**Item #2** – Increase 345 kV line clearance to obtain a minimum Summer Emergency rating of 754 MVA (1262 Amps). ATC has a planned project, as an independent economic benefit project, for the L111 uprate to a summer emergency rating of 1095 MVA (1834 A) higher than the required rating for G833/4-J022/3. The proposed in-service date of the line uprate project is April 25, 2010 (ATC Project PR03208).	Injection Limit	Existing ATC project will satisfy rating needs
A New 345/138 kV Substation at the Intersection of lines W-1 and L-SEC31. (East Substation)	**Item #3.1** - An eight position (expandable to twelve) 345 kV and a six position (expandable to ten) 138 kV breaker-and-a-half scheme substation located at the intersection of the existing 345 kV lines W-1 (Edgewater-South Fond Du Lac) and L-SEC31 (Sheboygan Energy Center-Granville). Provisions to be made to expand the 345 kV bus for four additional future 345 kV transmission facilities (e.g. a 345/138 kV transformer, 2nd 345 kV line to South Fond du Lac, 2nd 345 kV line in the direction of Saukville, 345 kV shunt inductor). - Design and construct new 345 kV substation facilities per ATC substation design standards. Minimum SN bus rating of 5000 Amps. Use ATC 345 kV Standard for ratings of CT's, switches, jumpers, etc connected to bus. - Install a new 345/138 kV transformer capable of at least 500/625 MVA for SN and SE. Select transformer based on ATC transformer standard - Install 12 new 345 kV circuit breakers capable of 3000 A, 50 kA, 2-cycle, Complete IPO Gas Circuit Breakers (GCB). - Install 32 new 345 kV disconnect switches capable of 3000 A at a minimum. - The existing lines W-1, L-SEC31 and 796L41 (Edgewater-Cedarsauk) are looped into the new substation. Northern portion of HOLG21, converted to 345 kV, is terminated at the new substation. - Design and construct new 138 kV substation facilities per ATC substation design standards. Minimum SN bus rating of	Stability Upgrades	Cost of Item #3.1 ~ #3.6.a $129,554,079 (T-line: $70,356,942, Substation: $59,197,137) Cost of Item #3.1 ~ #3.6.b $243,714,953 (T-line: $184,517,816 Substation: $59,197,137)

	3000 Amps. Use ATC 138 kV Standard for ratings of CT's, switches, jumpers, etc connected to bus. - Install 8 new 138 kV circuit breakers capable of at least 3000 A, 40 kA, 3-cycle, Non-IPO Installation Gas Circuit Breakers (GCB) - Install 21 new 138 kV disconnect switches capable of 3000 A at a minimum. - Provisions to be made to expand the 138 kV bus for four additional future 138 kV transmission facilities (e.g. a future 345/138 kV transformer, other future 138 kV transmission facility such as capacitor bank, potential split of X57 into two circuits (existing: 2-795 ACSR)). Purchasing sufficient land to accommodate future expansion is required. - Terminate the not-converted southern portion of the HOLG21 138 kV line at the new East 138 kV substation and loop the existing line X57 into the substation. - Terminate new 138 kV line from the Plymouth #4 138 kV substation (reference: Item 3.6)		
A New Switching Station in the area of the Intersection of lines L111 and L90. (North Switching Station)	**<u>Item 3.2</u>** - A six position (expandable to ten) breaker-and-a-half scheme substation in the area of the intersection of the existing 345 kV line L111 (Point Beach-Sheboygan Energy Center) and the existing 138 kV line L90 (Shoto - Glenview). Provisions to be made to expand the 345 kV bus for four additional future 345 kV transmission facilities (e.g. new 345 kV line to East, new 345 kV line to North or 345 kV shunt inductor, two 345/138 kV transformers). - Design and construct new 345 kV substation facilities per ATC substation design standards. Minimum SN bus rating of 5000 Amps. Use ATC 345 kV Standard for ratings of CT's, switches, jumpers, etc connected to bus. - Install 9 new 345 kV circuit breakers capable of 3000 A, 50 kA, 2-cycle, Complete IPO Gas Circuit Breakers (GCB). - Install 24 new 345 kV disconnect switches capable of 3000 A at a minimum. - Lines L111 and L121 are looped into the new switching station in addition to converted 971K51(Forest Junction-Howards Grove 138 kV line) - Provisions for a future 138 kV substation with eight position breaker and a half configuration to terminate existing lines L90, 971K51, two future 345/138 kV transformers, other future 138 kV transmission facility such as capacitor bank and future 138 kV line to the northeast or south. Purchasing sufficient land to accommodate future expansion is required.		
Forest Junction 345 kV Substation	**<u>Item 3.3</u>** - Re-terminate converted line (971K51) to 345 kV substation - Install a new 345 kV circuit breaker capable of 3000 A, 50 kA, 2-cycle, Complete IPO Gas Circuit Breakers (GCB). - Install 3 new disconnect switches capable of 3000 A at a minimum. - Use ATC 345 kV Standard for ratings of CT's, switches, jumpers, etc connected to bus.		
Howards Grove 138 kV substation	**<u>Item 3.4</u>** - Terminate new 138 kV line from Erdman - Install a new disconnect switch capable of 3000 A at a minimum. - Provision for a future line breaker - Design and construct new 138 kV substation facilities per ATC substation design standards. Use ATC 138 kV Standard for ratings of CT's, switches, jumpers, etc connected to bus.		

Erdman 138 kV substation	**Item 3.5** - Terminate new 138 kV line from Howards Grove - Install 6 new disconnect switches capable of 3000 A at a minimum. - Install 3 new 138 kV circuit breakers capable of at least 3000 A, 40 kA, 3-cycle, Non-IPO Installation Gas Circuit Breakers (GCB) - Extend the existing 138 kV bus to accommodate a new 138 kV line from Howards Grove. Minimum SN bus rating of 3000 Amps. Use ATC 138 kV Standard for ratings of CT's, switches, jumpers, etc connected to bus. - Relocate the termination point of the existing Erdman 138/69 kV transformer to the new 138 kV bus		

Conversion of existing 138 kV line to 345 kV, Construction of new 345 and 138 kV lines	**Item 3.6.a (Assumes reconductoring)**
	- Construct new double-circuit 345 kV lines (roughly 1 mile) to loop the existing 796L41 into the East switching station. Use bundled T2-556 ACSR or equivalent. Required ratings are 1910/2639 MVA (3196/4416 amps) for SN/SE. CPCN application to PSCW may be required.
	- Construct a new double-circuit 345 kV line on new right of way using Bundled T2-556 ACSR or equivalent in order to loop L121 into the new North switching station. Length: ~ 3 miles, Required Ratings: 1910/2639 MVA (3196 / 4416 Amps for SN/SE). CPCN application to PSCW may be required.
	- Convert the existing 971K51 138 kV line to 345 kV (Forest Jct-Howards Grove: ~38.72 mile). Convert portion (~9.13 mile) of HOLG21 (Howards Grove-Plymouth-Holland) to 345 kV line. Review the conditions of the existing double circuit structures. Reconductor the converted line using 2156 ACSR (2257/2973 Amps for SN/SE) or equivalent. It is assumed that the existing structures are designed for new heavy conductors. The converted 971K51 will be looped into the new North 345 kV switching station. The converted HOLG21 line side will be terminated at the new East 345 kV substation. Retain the existing double circuit 138 kV segments going into Howards Grove and Plymouth #4 138 kV substations
	- To form New East-Plymouth #4-Howards Grove-Erdman 138 kV lines,
	  o Construct a new 138 kV line from new East 138 kV substation to the point where the existing double circuit 138 kV lines go into Plymouth #4. Use T2-477 ACSR or equivalent. Length: ~6 miles, Ratings: 1455/2014 Amps for SN/SE
	  o Construct a new 138 kV line from the Plymouth #4 double circuit loop ends to the point where the existing double circuit 138 kV lines go into Howards Grove. Use T2-477 ACSR or equivalent. Length: ~3.2 miles, Ratings: 1455/2014 Amps for SN/SE. One of the existing double circuits going into Howards Grove 138 kV substation will be de-energized.
	  o Construct a new 138 kV line from Howards Grove to Erdman using T2-477 ACSR or equivalent. Length: ~6.6 miles, Ratings: 1455/2014 Amps for SN/SE
	Item 3.6.b (Assumes rebuilding structures)
	Same as Item 3.6a except the following sub-item.
	- Convert the existing 971K51 138 kV line to 345 kV (Forest Jct-Howards Grove: ~38.72 mile). Convert portion (~9.13 mile) of HOLG21 (Howards Grove-Plymouth-Holland) to 345 kV line. Review the conditions of the existing double circuit structures. If the existing double circuit structures		

	cannot hold double circuit 345 kV lines (2156 ACSR or equivalents), replace the existing structures to new structures. Expand the existing right of way to accommodate the new structures.		
Point Beach 345 kV Substation	**<u>Item 3.7</u>** Isolate Q-303 line fault in primary time at Point Beach. This requires Point Beach 345 kV Circuit Breaker Addition **(345 kV, 3000 A, 50 kA, Gas CB, IPO)** in series with the existing Q-303 Circuit Breaker to isolate line fault in primary time.	Stability Upgrades	Roughly $1,014,000 (in 2011 dollar)
	TOTAL *		$131 million (with Item 3.6.a assumed) $ 246million (with Item 3.6.b assumed)

* Note: The cost range of the proposed project has been updated from the draft report to a range of costs due to the uncertain condition of the existing 345/138 kV double circuit structures reported from ATC Asset Management in their recent review of the draft system impact study. The condition of the existing 345/138 kV structures will be evaluated as part of the detailed engineering study during the Facilities Study.

Table 1.2.b – Required "Interim"[3] Network Upgrades for Thermal and Stability Issues due to the Addition of G833/J022 and/or G834/J023

Location	Facilities	Reason	In-service Date	Good Faith Cost Estimate (Y2009)
Cypress-Arcadian 345-kV line	**Item #1** –Look at plan and profile and Patrol to observe any close wire crossings and adjust to obtain a minimum Summer Emergency rating of 572 MVA (957.3 A).	Injection Limit	5/1/2010	$1.7 M
Point Beach-Sheboygan Energy Center 345-kV line	**Item #2 –** L111 requires a minimum summer emergency rating of 596 MVA (997.4 A). PRF PR03208 requires a minimum summer emergency rating of 1120 MVA with a proposed in-service date of Spring 2010. Completion of PRF PR03208 accomplishes the requirements for G833 and G834.	Injection Limit	5/1/2010	Not required since existing ATC project will satisfy rating needs
North Appleton 345 kV Bus	**Item #3** – R-304 Fault at Kewaunee Protection Improvement - North Appleton R-304 Circuit Breaker Replacement with 2 cycle Circuit Breaker implemented for Independent Pole Operation **(345 kV, 3000 A, 50 kA, Gas CB, IPO)** in order to achieve 4.5 cycles remote primary clearing time. With Kewaunee bus reconfiguration project and Item #3 assumed in-service, R-304 fault clearing times become 3.5[1] cycles local primary, 8.5[1] cycles local delayed and 4.5[2] cycles remote primary by reducing the remote clearing time by 2.0 cycles	Stability Upgrades	5/1/2010	$1 M
Point Beach 345 kV Bus	**Item #4** –Point Beach Faults Protection Improvements. Item 4A: Achieve L111 clearing times of 3.5 cycles local primary, 8.0 cycles local delayed and 4.5 cycles remote primary by reducing local delayed clearing time 1.0 cycles. It requires Point Beach L111 SBF Breaker Failure Relay replacement with an SEL-352, and the existing Line 111 SEL-221F backup relay replacement with an SEL-421. Item 4B: Achieve L151 clearing times of 3.5 cycles local primary, 8.5 cycles local delayed and 4.5 cycles remote primary by reducing local delayed clearing time 0.5 cycles. It requires Point Beach L151 SBF Breaker Failure Relay replacement with an SEL-352, and the existing Line 151 SEL-221F backup relay replacement with an SEL-421 (note 8.0 cycles delayed clearing time can be obtained with Item 4B implemented). Item 4C: Isolate Q-303 line fault in primary time at Point Beach. This requires Point Beach 345 kV Circuit Breaker Addition **(345 kV, 3000 A, 50 kA, Gas CB, IPO)** in series with the existing Q-303 Circuit Breaker to isolate line fault in primary time. Item 4D: Achieve breaker B23 clearing times of 11 cycles local delayed by reducing local delayed clearing time 1 cycle. It requires relay setting change (without Breaker Failure relay replacement) for Failure of Point Beach Bus Tie 2-3 to achieve no more than 11 cycle total breaker failure clearing time for bus faults Item 4E: Replace L121 SEL-221F backup relay with SEL-421 to provide better maintenance and operating flexibility during a L121 relay outage	Stability Upgrades	5/1/2011	$1.8 M
TOTAL				**$ 4.5 M**

Note 1 – Clearing times at Kewaunee with Kewaunee Bus Reconfiguration in-service
Note 2 – Clearing time achieved by implementing item #3
Note 3 – Based on Interim Operations Restudy Report.

Table 1.3 – Required Interconnection Facilities for G833/J022 and G834/J023

Entity	Facilities	Cost Estimate (Y2018)
Transmission Owner	None.	NA
G833/J022 and G834/J023 Interconnection Customer	Minimum Excitation Limiter setting maintained at the level described in Appendix I. Required Minimum Excitation Limits: 12 MVAR (gross) or higher **Note:** These facilities are to be provided by the generator interconnection customer. Hence, cost estimate is not applicable.	NA

Table 1.4 – Recommended Facilities at Point Beach Due To G833/J022 and G834/J023

Entity	Facilities	Cost Estimate (Y2018)
G833/J022 and G834/J023 Interconnection Customer	Recommended improvements to the Point Beach substation design. Add 345 kV, 3000A, 50 kA, 2 cycle gas Circuit Breakers on the high side of Point Beach auxiliary transformers T1X03 and T2X03 with adequate primary and breaker failure relaying. For the potential stability issue that may occur until the proposed solution in place, reduce Auxiliary Transformer T1X03 primary fault clearing time from 5.1 cycles to 4.0 cycles and Auxiliary Transformer T2X03 from 5.1 cycles to 4.0 cycles. **Note:** These facilities are to be provided by the generator interconnection customer. Hence, cost estimate is not applicable.	NA

Table 1.5 – Required Facilities Due To Third Party Impact of G833/J022 and G834/J023

Entity	Facilities	Cost Estimate (Y2018)
Kewaunee	Required Minimum Excitation Limit at Kewaunee G1: -20 MVAR (gross) or higher **Note:** These facilities are to be provided by Kewaunee owned by Dominion. Hence, cost estimate is not applicable.	NA

2. Criteria, Methodology and Assumptions

2.1 Study Criteria

All relevant MISO-adopted NERC Reliability Criteria and the American Transmission Company contingency criteria are to be met for thermal, voltage and angular stability analysis. Details of the analysis criteria used in this study can be found in Appendix F.

2.2 Study Methodology

The results of this study are subject to change. The results of the study are based on data provided by the Generator and other ATC system information that was available at the time the study was performed, and the injection study does not guarantee deliverability to the MISO energy market. If there are any significant changes in the generator and controls data, earlier queue Generator Interconnection Requests, related Transmission Service Requests, or ATC transmission system development plans, then the results of this study may also change significantly. Therefore, this request is subject to restudy. The Generator is responsible for communicating any significant generating facility data changes in a timely fashion to MISO and ATC prior to commercial operation.

2.2.1 Competing Generation Requests

ATC determined in its judgment that four Interconnection Requests with an earlier Queue Position may impact the G833/J022 and G834/J023 study results. G427, G590, G611 and G773 are included in all of the thermal analysis cases. Because of their location on the 138 kV system, G590, G611 and G773 were not included in the stability models.

Public information related to the MISO Interconnection Request queue can be found at:
http://www.midwestmarket.org/page/Generator%20Interconnection
and the Interconnection Requests specific to the ATC footprint can be found at:
http://oasis.midwestiso.org/documents/ATC/Cluster_8_Queue.html.

Table 2.1 – Competing Generation Requests

Queue Number	MW	Commercial Operation Date	Geographical Location
G427	98	TBD (suspended)	Cypress 345 kV Substation
G590	98	TBD (suspended)	Tecumseh Rd 138 kV Substation
G611	100.5	12-31-2011	Elkhart Lake-Forest Junction 138 kV line
G773	150	12-01-2012	Forest Junction-Lost Dauphin 138 kV line

2.2.2 Power Flow Analysis Methods

Thermal overloads were identified using AC power flow solutions. All AC power flow solutions utilized actual equipment ratings in MVA (i.e. 0% TRM) along with real and reactive power flows. A 5% TRM was factored in the computation of required MVA rating for the limiting elements.

All AC power flow solutions were performed using the Power Flow module of the Power System Simulation/Engineering-30.3.2 (PSS/E, Version 30.3.2) program from Siemens Power Technologies, Inc (PTI). This program is accepted industry-wide for power flow analysis.

2.2.3 Stability Analysis

ATC recently conducted extensive stability analysis of the area near the Point Beach generators and determined that there were no generation limitations for intact and single outage conditions, with the existing Power System Stabilizers (PSS) in service, and prior to requests G833/J022 and G834/J023. Simulations were performed with G833/J022 and/or G834/J023 in service to determine the stability impacts that attributed to the additional generation with the latest dynamic data submitted to MISO for J022/J023. Any violations of the stability study criteria (in Appendix F) identified with the increased generation in service can be attributed to the G833/J022 and G834/J023 interconnection request and are documented in this report.

For the analysis, the proposed Point Beach Power System Stabilizers are assumed in-service. Simulated/tested clearing times shown in each table in Appendix C contains the required planning margin described in Section 3.2.

The stability and grid disturbance performance analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-29 (PSS/E, Version 29.5.1) program from Power Technologies, Inc (PTI). This program is accepted industry-wide for dynamic stability analysis.

2.3 Base Cases

2.3.1 Power Flow Analysis (Steady State)

Base cases used in the thermal and voltage analysis for this study were developed based upon the 2013 Summer Peak and Summer Off-Peak MISO Definitive Planning Phase (DPP) Cycle 2 Models developed from 2013 MISO Transmission Expansion Plan (MTEP) models built in 2008. According to MISO, the existing generators in the DPP Cycle 2 models were dispatched to serve the control area load, and the remaining generators were dispatched based on contracts.

Based on the new MISO Generation Interconnection Business Practice Manual (BPM), all wind generation including competing wind generation was dispatched at 20% of nameplate capacity for summer peak load conditions and 100% for summer off-peak load conditions.

For the AC power flow analysis, half of the output of G833/J022 and G834/J023 was delivered to the WAPA control area and the remaining half was delivered to the TVA control area. This dispatch pattern in the AC analysis was used to mimic delivery to the MISO footprint.

2.3.2 Stability Analysis (Dynamics)

The 2010 50% of system peak load base case used in the stability analysis was developed based upon the ATC 2009 Ten Year Assessment 50% peak load dynamics-ready model from the 2007 Series NERC MMWG cases. The ATC area was replaced with the 2010 planned and proposed projects and load and generation was set to expected levels. The Kewaunee bus reconfiguration project planned for 2011 was also modeled in the study cases. All local and competing generators were dispatched at full output in accordance with ATC's generator interconnection study methodology. The resulting additional generation was delivered to ComEd (75%) and Northern States Power (25%) control areas.

Two stability scenarios were studied for G833/J022 and G834/J023. Specifically, high local generation and low local generation models were created. Only the wind generator (G427) located at Cypress 345-kV substation was considered as the competing generator for stability analysis based on the assumption that other wind generators connected at 138 kV would not significantly impact the stability results. For the high generation scenario, in addition to Point Beach, all local generation (Kewaunee, Fox River, Sheboygan Energy, South Fond du Lac and Cypress) were modeled with maximum generation. Weston Units 3 and 4 were also in service. For the low generation scenario, the same dispatch was used except that the Fox Energy, Sheboygan Energy, Cypress and South Fond du Lac were modeled as off-line.

Table 2.3.1 – Key generation status with G833/4-J022/3

Units	Low Generation Scenario	High Generation Scenario
Point Beach Unit 1 (G834/J023)	642.96 MW (Gross)	642.96 MW (Gross)
Point Beach Unit 2 (G833/J023)	642.96 MW (Gross)	642.96 MW (Gross)
Kewaunee	603 MW (Gross)	603 MW (Gross)
Cypress	0 MW	258 MW
South Fond du Lac generators	0 MW	352 MW
Fox Energy Center	0 MW	632 MW
Sheboygan Energy Center	0 MW	346.8 MW

2.3.3 Deliverability Analysis

The deliverability analysis case was developed by MISO following the MISO deliverability study methodology. Details on the MISO deliverability study methodology can be found in the whitepaper posted at the following link: MISO Deliverability Whitepaper (see Appendix E for complete URL).

2.4 Generation Facility

2.4.1 Generating Facility Modeling

The G833/J022 and G834/J023 projects are increases to the existing capacity of Point Beach generating units and are modeled by changing the existing representation in the planning cases so that the total gross real power is 642.96 MW for each unit. The voltage regulation set point of each machine was 102.03% (352 kV) of nominal at the POI to reflect preferred plant operation.

Later, as shown in Appendix H, various voltage regulation set points of the generators were studied to evaluate the dynamic stability performance of each option in terms of minimum MVAR limitation of Point Beach and Kewaunee.

Dynamic model changes that have been reported to ATC have been incorporated into the Point Beach generator stability models. In addition, the generator step up transformers will be replaced as part of the G833/J022 and G834/J023 projects and these modifications were incorporated into the model.

After the units are physically modified and prior to initial unit synchronization, final generator dynamic models should be provided so that operational studies confirming the results of this study can be completed.

The actual clearing times determined using information from the Interconnection Customer and used for the analysis contained in this report are:

1. For GSU transformers T1X01 and T2X01, the primary clearing time is 4.5 cycles and the breaker failure clearing time is 12.5 cycles for bus breakers and 13.0 cycles for line breakers.
2. For auxiliary transformers T1X03 and T2X03, the primary clearing time is 5.1 cycles and the breaker failure clearing time is 12.3 cycles for bus breakers and 23.5 cycles for line breakers.

It should be noted that the actual clearing times listed above do not contain any ATC planning margins. Also, the actual clearing times assume the recommended high side auxiliary transformers breakers are not installed.

2.4.2 Voltage Sag Criteria

Based on the voltage sag criteria information provided by the Interconnection Customer on March 13 2009, 19 kV and 345 kV bus voltage relay settings at Point Beach were also modeled and monitored during for the dynamic stability study.

Table 2.4.2 – 19 kV and 345 kV bus voltage relay settings at Point Beach

Bus KV		Drop Out Voltage	Reset Voltage	Minimum Time Delay
19 kV		84.6%	86.2%	1.5 seconds
345 kV	1st criteria	74.3%	75.7%	1.0 second
	2nd criteria	94.1%	95.7%	1.5 seconds

2.4.3 Synchronizing and Energization of Substation/Generator Step-Up Transformers

ATC's standard design is for synchronization of the generator to occur at the interconnection customer's high-side (i.e. transmission voltage) circuit breaker. Exceptions to this standard must be requested for examination during the interconnection study.

The Point Beach nuclear units are presently undergoing design development to support the inclusion of generator breakers in their Iso-phase Bus connections. The generator breaker(s) will be positioned so as to enable a generating unit trip at the generator output voltage level/position without the need to de-energize the main transformers. Since the high voltage side breakers will remained closed, the power plant auxiliary buses are intended to be powered via the backfeed Main Transformers and the Iso-phase bus direct-connected Unit Auxiliary Transformers. This arrangement eliminates the presently needed high speed transfer of auxiliary busses to the grid-connected Startup Transformer upon a generating unit trip, and will also serve to resolve present marginal bus voltage issues. For purposes of the grid studies, the generator breakers are considered to be in place and operable at the time of startup of the generating units at their increased levels of output.

A generator step-up transformer will require the initial energization to occur from the transmission grid. Prior to initial energization, the Interconnection Customer must permanently install mitigation equipment (e.g., pre-insertion resistors on the high-side transformer circuit breaker) or commission a technical study of the initial energization event to ensure that the initial energization of the transformer will not result in any unacceptable impact to ATC or interconnected customers.

2.4.4 Unit Black Start and ATC Black Start Plan Participation

Generating units interconnecting with the ATCLLC transmission system must report black start requirements to ATCLLC. Additionally, the customer and ATCLLC must discuss the unit's participation in the ATCLLC system black start plan.

3. Analysis Results

3.1 Power Flow Analysis Results

The intact system, single contingency and multiple contingency thermal analyses in this report used AC analysis under 2013 Summer Peak and Off-Peak load conditions with the proposed solution in service.

3.1.1 Power Factor Capability and Voltage Requirements

Power Factor Capability
The G833/4-J022/3 customer has submitted a generating facility design capable of maintaining power delivery at continuous rated power output at the POI (Point of Interconnection) at all power factors over 0.95 leading (when a facility is consuming reactive power from the transmission system) to 0.94 lagging (when a facility is supplying reactive power to the transmission system). For the steady-state scenarios examined, study results indicate that satisfactory system performance is achieved by supplying a range of -211.3 to 233.4 Mvars (gross) to the system.

Plant Specific Voltage Requirements
The Point Beach Nuclear Plant has specific 345 kV voltage range requirements. The preferred range is 352 kV (1.020 pu) to 354 kV (1.026 pu), the normal range is 351 kV (1.017 pu) to 358 kV (1.037 pu) and the maximum permissible is 348.5 kV (1.010 pu) to 362 kV (1.049 pu). A new high voltage limit of 360 kV has been proposed by the plant and incorporated into this study. Any voltage outside the maximum permissible range is a voltage limitation as described in the plant technical specifications.

3.1.2 Results of Intact System and Single Contingencies (N-1)

3.1.2.1 Base Case Analyses

With the proposed solution modeled, the analysis was conducted using the cases developed based upon the 2013 Summer Peak (100% load conditions) and Off-Peak (roughly 70% load conditions) MISO DPP Cycle 2 models. All wind generation including competing wind generation was dispatched at 20% of nameplate capacity for summer peak load conditions and 100% for summer off-peak conditions. For the summer off-peak model, the Fox Energy generating units and one of the two Sheboygan Energy units were out of service. The remaining Sheboygan Energy unit was on-line at 90 MW in the 2013 Summer Off-Peak model.

This study identified two transmission element steady-state thermal violations as injection limits due to G833/4-J022/3 for NERC Category B (N-1) events for the 2013 Summer Off-Peak model and one injection limit was identified for NERC Category B (N-1) events for the 2013 Summer Peak model. The injection limits are

- Point Beach Bus 1-New North 345 kV line (L111 east). The line is overloaded with the outage of Point Beach Bus 2-New North 345 kV line (L121 east). Distribution factor is not available because the contingency pair is created by the proposed new North switching station and it does not exist in the base model prior to G833/4-J022/3.

- New East-Cedarsauk 345 kV line (796L41 south). The line is overloaded with the outage of new East-Granville 345 kV line. Distribution factor is not available because the contingency pair is created by the proposed new East substation and it does not exist in the base model prior to G833/4-J022/3.

A summary of the thermal violations due to G833/4-J022/3 is presented in Tables A.1 and A.2 in Appendix A.

L111, Point Beach Bus 1-(New North)-Sheboygan Energy Center 345 kV line, will be uprated as an independent economic benefit project (1095 MVA SE with ATC Project PR03208 assumed in-service), required ratings are given but these are lower than those required for ATC Project PR03208.

The maximum allowable output without Network Upgrades for injection limits is presented in Table A.13 in Appendix A. As shown in this table, the maximum real power output for injection limits without any system upgrades is 0 MW for all conditions studied.

Voltage analysis shows that no Transmission System voltage limits will be violated as a result of the interconnection of G833/4-J022/3 (see Tables A.3 and A.4 in Appendix A).

3.1.3 Results of Double Contingencies (N-1-1)

3.1.3.1 NERC Category C.3 Contingencies (N-1-1)

Thermal and voltage constraints were evaluated for NERC Category C events (N-1-1 contingencies) in the electrical proximity of G833/4-J022/3 for the 2013 Summer Peak and Off-Peak models with the proposed solution in service. The double contingency constraints are not required to be resolved for the generator to attain either Energy Resource or Network Resource Interconnection Service status. The purpose of the N-1-1 analysis is to reveal potential violations under prior outage conditions.

Thermal violations under a selected number of N-1-1 contingencies were evaluated using AC analysis. The distinct thermal violations identified from the 2013 Summer Peak and Off-Peak load condition models used in the study are listed in Table A.7 and A.8 in Appendix A.

The results of this analysis are supplied for information only since no operating restrictions will be created for thermal N-1-1 limits. In the day-ahead and real-time market, MISO will utilize a binding constraint procedure to mitigate transmission system overloads. This process may result in curtailment of generation and could affect G833/4-J022/3 for the contingencies noted in this N-1-1 analysis.

3.1.3.2 NERC Category C.5 Contingencies

The Transmission System local to the selected Point of Interconnection was reviewed for facilities that could be defined as double contingencies that correspond to NERC Category C.5 events (i.e. two circuits on shared tower). Table 3.1 shows all NERC Category C.5 events that were considered local and potentially limiting the proposed interconnection. Three overloads were found for the Category C.5 events studied. Two of them are not considered as a problem due to G833/4-J022/3:

- Lau Rd-Elkhart Lake 138 kV line. Approximately 2.9% of the increased generation flowing on this line with New East-Cedarsauk and Holland-Charter Industrial-Saukville 138 kV line which is relatively minor impact and below the 5% distribution factor cutoff in the MISO BPM. Therefore, it is not considered as a problem due to G833/4-J022/3. In addition, the thermal overload can be mitigated by generation redispatch in the local area.
- Elkhart Lake-Saukville 138 kV line. Approximately 0.5% of the increased generation flowing on this line with New East-Cedarsauk and Holland-Charter Industrial-Saukville 138 kV line which is relatively minor impact and below the 5% distribution factor cutoff. Therefore, it is not considered as a problem due to G833/4-J022/3. In addition, the thermal overload can be mitigated by generation redispatch in the local area.
- New East-Cedarsauk 345 kV line (796L41 south). The line is overloaded with the outage of Cypress-Arcadian 345 kV line and Germantown-Maple-Saukville 138 kV line. Distribution factor is not available because it is a new line created by the new East substation.

As discussed in Section 3.1.2.1, the new East-Cedarsauk 345 kV line will be uprated to 960 MVA SE, which is higher than the required rating shown in Table A.9 as one of the required Network Upgrades (see Table 1.2.a).

The Category C.5 results are shown in Tables A.9 and A.10 in Appendix A.

Table 3.1 – NERC Category C.5 Events Reviewed[1]

Contingency Pairs	
Point Beach – Forest Junction 345-kV Line 121	Forest Junction – Meeme – Howards Grove 138-kV Line 971K51
Point Beach – Sheboygan Energy 345-kV Line 111	Forest Junction – Meeme – Howards Grove 138-kV Line 971K51
Point Beach – Sheboygan Energy 345-kV Line 111	Howards Grove – PM4 – Holland 138-kV Line HOLG21
Sheboygan Energy – Granville 345-kV Line L-SEC31	Howards Grove – PM4 – Holland 138-kV Line HOLG21
Sheboygan Energy – Granville 345-kV Line L-SEC31	Holland – Charter Industrial – Saukville 138-kV Line 8222
Cypress – Arcadian 345-kV Line L-CYP31	Saukville – Maple – Germantown 138-kV Line 2642
Sheboygan Energy Center-East 345-kV Line L-SEC31 north	Howards Grove – PM4 – Holland 138-kV Line HOLG21
Granville-East 345-kV, Line L-SEC31 south	Howards Grove – PM4 – Holland 138-kV Line HOLG21
East-Cedarsauk 345-kV Line 796L41 south	Holland-Charter-Saukville 138-kV Line 8222
East-Cedarsauk 345-kV Line 796L41 south	East-Edgewater 345-kV Line 796L41 east
Edgewater-Cedarsauk 345-kV	Edgewater-South Fond du Lac 345-kV

Line 796L41	Line W-1
Edgewater-East 345-kV #2 Line W-1 east	Edgewater-East 345-kV #1 Line 796L41 east
Lau Rd (G611)-Elkhart Lake 138-kV Line 4035	Tecumseh Rd-Meyer Rd 138-kV Line 40561
Point Beach Bus 1-North 345 kV line	Point Beach Bus 2-North 345 kV line
North-Sheboygan Energy Center 345 kV line	North-East 345 kV line
Sheboygan Energy Center-East 345 kV line	North-East 345 kV line
North-Forest Junction 345 kV line #1	North-Forest Junction 345 kV line #2

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit tower.

3.2 Stability Analysis Results

The stability analysis in this study was done for the following grid disturbance scenarios:

1. Three-phase fault cleared in primary time with an otherwise intact system (NERC Cat. B);
2. Single line-to-ground fault on both circuits of a double circuit structure with an otherwise intact system (NERC Cat. C);
3. Single line-to-ground fault on a bus with an otherwise intact system (NERC Cat. C);
4. Three-phase fault cleared in primary clearing time with a prior outage of any other transmission element (NERC Cat C); and
5. Three-phase fault cleared in delayed clearing time (e.g., breaker failure condition or zone 2 trip due to communication-based protection system failure) with an otherwise intact system (NERC Cat D).

In general, for any grid disturbance, the proposed generation's dynamic response must not degrade the system stability performance. Recent stability analysis of the area near Point Beach found no stability problems for (a) three-phase fault cleared in primary time with an otherwise intact system, (b) single line-to-ground fault on both circuits of a double circuit structure with an otherwise intact system, and (c) three-phase fault cleared in delayed clearing time with an otherwise intact system. In addition, that analysis found no stability problems for three-phase faults cleared in primary clearing time under prior outage conditions with proposed Power System Stabilizers (PSS) in-service. The only existing issue is a potential stability problem with a fault on 345-kV line Q-303 (Point Beach to Kewaunee) under the prior outage condition of 345-kV line R-304 (Kewaunee to North Appleton). However, this issue is addressed by the existing operating guide, which requires Kewaunee generation to be reduced to 382 MW (net) for thermal reasons.

For the G833/J022 and G834/J023 analysis, it is assumed that the Power System Stabilizers are in-service for all simulations.

For existing system components, actual existing breaker clearing times were simulated. Wherever clearing times faster than existing settings are required, a notation is made. For new system components, the clearing times used in this study are as follows:

Primary Clearing (Local):	3.5 cycles;
Delayed Clearing (Local Breaker Failure):	9.0 cycles;
Primary Clearing (Remote End):	4.5 cycles

A planning margin of 1.0 cycle is required between any studied (simulated/tested) clearing time and the maximum expected clearing time of the system protection equipment (i.e. relay and circuit breaker operation). This 1.0 cycle is added to the local primary clearing time for primary clearing simulations and the local breaker failure time for breaker failure simulations. If a fault is cleared using Independent Pole Operation (IPO) breakers, it is assumed that only one phase of the breaker will fail, so that after the primary clearing time, a three phase to ground fault will become a single line-to-ground fault until it is cleared by the breaker failure relaying. No margin is added to the primary clearing times during breaker failure simulations.

In addition to examining angular stability of the generation, voltage recovery at Point Beach was also monitored to ensure acceptable performance under Point Beach's requirements. These requirements for 345 kV and 19 kV voltages are listed in Table 2.4.2. If no stability issue was identified with G833/4-J022/3 and without the proposed solution, no additional stability analysis with the proposed solution was performed since the proposed solution improves stability response by tying together critical transmission elements and providing an additional 345 kV line in parallel with the existing 345 kV lines (portion of L111, L121 and L-SEC31).

Results of the stability analysis are summarized in Appendix C.

3.2.1 Results of Primary Clearing of Three-Phase Faults under Intact System Conditions

The 13 faults listed in Table 3.2.1 were simulated as 3-phase faults cleared in primary time under intact system conditions. No stability problems were identified. These results are summarized in Table C.1 in Appendix C.

Table 3.2.1 – Simulated Single Circuit 3-Phase Faults Cleared in Primary Time

Faulted Element	Fault Location	Description
L111	Point Beach 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L121	Point Beach 345 kV	Point Beach-Forest Junction 345 kV Line
L151	Point Beach 345 kV	Point Beach-Fox River 345 kV Line
Q-303	Point Beach 345 kV	Point Beach-Kewaunee 345 kV Line
Q-303	Kewaunee 345 kV	Point Beach-Kewaunee 345 kV Line
R-304	Kewaunee 345 kV	Kewaunee-North Appleton 345 kV Line
L151	Fox River 345 kV	Point Beach-Fox River 345 kV Line
L6832	Fox River 345 kV	Fox River-North Appleton 345 kV Line
971L71	Fox River 345 kV	Fox River-Forest Junction 345 kV Line
L111	Sheboygan Energy 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L-SEC31	Sheboygan Energy 345 kV	Sheboygan Energy-Granville 345 kV Line
L-CYP31	Cypress 345 kV	Cypress-Arcadian 345 kV Line
KEW T10 H	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer

3.2.2 Results of Primary Clearing SLG Faults on Two Circuits of a Multiple Circuit Lines

The transmission system near Point Beach contains eight double circuit lines of concern (Table 3.2.2). Three phase faults were simulated on both ends of the double circuit, for a total of sixteen simulated events, to simplify the simulations. If a generator is not stabe for the three phase fault, a single line to ground fault would then be studied. No stability problems were identified. These results are summarized in Table C.2 in Appendix C.

Table 3.2.2 – Simulated Intact System Double Circuit Single Line-to-Ground Faults

Fault 1		Fault 2	
Element	Location	Element	Location
111–Pt. Beach -Sheboygan Energy 345 kV	38.5% from POB	971K51-Forest Jct.-Howard's Grove 138 kV	33.9% from FJT
111-Pt. Beach -Sheboygan Energy 345 kV	16.3% from SEC	971K51-Forest Jct.-Howard's Grove 138 kV	6.3% from HOG
111-Pt. Beach -Sheboygan Energy 345 kV	SEC	HOGL21-Howard's Grove-Holland 138 kV	46.8% from HOL
111-Pt. Beach -Sheboygan Energy 345 kV	15.7% from SEC	HOGL21-Howard's Grove-Holland 138 kV	12.3% from HOG
121-Pt. Beach -Forest Junction 345 kV	FJT	971K51-Forest Jct.-Howard's Grove 138 kV	FJT
121-Pt. Beach -Forest Junction 345 kV	42.3% from FJT	971K51-Forest Jct.-Howard's Grove 138 kV	33.9% from FJT
L-SEC31-Sheboygan Energy-Granville 345 kV	GVL	3431-Granville-Saukville 345 kV	GVL
L-SEC31-Sheboygan Energy-Granville 345 kV	26.7% from GVL	3431-Granville-Saukville 345 kV	25.3% from SAU
L-SEC31-Sheboygan Energy-Granville 345 kV	43.5% from GVL	8231-Sukville-Barton 138 kV	36.4% from BRT
L-SEC31-Sheboygan Energy-Granville 345 kV	48.3% from GVL	8231-Sukville-Barton 138 kV	36.4% from SAU
L-CYP31-Cypress-Arcadian 345 kV	32.0% from ADN	2642-Saukville-Germantown 138 kV	34.2% from SAU
L-CYP31-Cypress-Arcadian 345 kV	16.6% from ADN	2642-Saukville-Germantown 138 kV	GER
L-CYP31-Cypress-Arcadian 345 kV	10.8% from ADN	2661-Germantown-Bark River 138 kV	31.5% from GER
L-CYP31-Cypress-Arcadian 345 kV	16.6% from ADN	2661-Germantown-Bark River 138 kV	GER
L-CYP31-Cypress-Arcadian 345 kV	10.8% from ADN	9911-Granville-Arcadian 345 kV	45.4% from GVL
L-CYP31-Cypress-Arcadian 345 kV	ADN	9911-Granville-Arcadian 345 kV	ADN

3.2.3 Results of Primary Fault Clearing During a Prior Outage

Primary fault clearing under prior outage conditions simulated all of the events listed in Table 3.2.1 under the outages listed in Table 3.2.3.

Table 3.2.3 – Simulated Prior Outage Elements

Element	Description
L111	Point Beach-Sheboygan Energy 345 kV Line
L121	Point Beach-Forest Junction 345 kV Line
L151	Point Beach-Fox River 345 kV Line
Q-303	Point Beach-Kewaunee 345 kV Line
R-304	Kewaunee-North Appleton 345 kV Line
L6832	Fox River-North Appleton 345 kV Line
971L71	Fox River-Forest Junction 345 kV Line
L-SEC31	Sheboygan Energy -Granville 345 kV Line
L-CYP31	Cypress-Arcadian 345 kV Line
NAPL71	North Appleton-Werner West 345 kV Line
971L51	Forest Junction-Cypress 345 kV Line
Y-311	North Appleton-Fitzgerald 345 kV Line
T10	Kewaunee 345/138 kV Transformer
POB 1-2, 2-3, 3-4, 4-5	Point Beach 345 kV Breakers 1-2, 2-3, 3-4, 4-5
FOX 1-2, 2-3, 3-4, 4-5, 5-6, 6-1	Fox River 345 kV Breakers 1-2, 2-3, 3-4, 4-5, 5-6, 6-1
SEC BT12, BT23, BT36, BT16	Sheboygan Energy 345 kV Breakers BT12, BT23, BT36, BT16
CYP BT16, BT12, BT56	Cypress 345 kV Breakers BT16, BT12, BT56
FJT 1-2, 2-3, 4-5, 5-6, 7-1	Forest Junction 345 kV Breakers 1-2, 2-3, 4-5, 5-6, 7-1

Two events with generation instability were found for prior outage scenarios (Table C.3 in Appendix C), which are

- Fault on L121 (Point Beach-Forest Junction) under the outage of Point Beach 345 kV breaker 2-3
- Fault on R-304 (North Appleton-Kewaunee) under the outage of 6832 (Fox River-North Appleton) followed by a fault on R-304 (Kewaunee-North Appleton)

Both prior outage stability problems were not found with the addition of the proposed solution. Until completion of the proposed solution, the following operating restrictions already documented in the G833/4-J022/3 Interim Operation Re-study Report are required under the prior outage conditions to eliminate the stability problems:

- G2 at 600 MW (gross) under prior outage condition of 6832 (North Appleton-Fox River 345 kV line)
- G1 at 580 MW (gross) under prior outage condition of Point Beach Bus Tie 2-3

The existing stability problems, an R-304 fault with Q-303 out of service or a Q-303 fault with R-304 out of service, can be eliminated by reducing Kewaunee generation. Based on the future Kewaunee operating restrictions associated with the planned Kewaunee Bus Reconfiguration Project (see Figure 1.1), angular stability will be maintained. This is an existing limitation that will not be made better or worse by the addition of G833/4-J022/3 and their associated Network Upgrades.

Table C.12 presents result for a three phase fault under the worst critical prior outage condition at the new East Switching Station (Fix 2 in Appendix H, part of the proposed solution), which is assumed to be a fault on the East-Cedarsauk 345 kV line under the outage of East-Granville 345 kV line. This is assumed to be the worst prior outage event because the outage of the East-Granville 345 kV line results in the highest flow on the 345 kV lines out of the new East substation, particularly on the East-Cedarsauk 345 kV line. The simulation provides the required clearing times for the new switching station and did not identify any stability problems that cannot be mitigated by the installation of 2 cycle 345 kV circuit breakers and high-speed relaying. Additional simulation is not performed with the proposed solution since stability response will only improve.

3.2.4 Results of Three-Phase Fault Delayed Clearing under Intact System Conditions

Delayed (breaker failure) 3-phase fault clearing under otherwise intact system was simulated for the events listed in Table 3.2.4.

No stability problems were identified with the interim upgrades described in the G833/4-J022/3 Interim Operation Re-study Report which include relay upgrades at Point Beach, breaker replacement at North Appleton and a breaker addition at Point Beach.

Table 3.2.4 – Simulated 3-Phase Faults Cleared in Delayed Time

Faulted Element	Fault Location	Description
L111	Point Beach 345 kV	Point Beach-Sheboygan Energy 345 kV Line

L151	Point Beach 345 kV	Point Beach-Fox River 345 kV Line
Q-303	Point Beach 345 kV	Point Beach-Kewaunee 345 kV Line
R-304	North Appleton 345 kV	North Appleton-Kewaunee 345 kV Line
L121	Forest Junction 345 kV	Forest Junction-Point Beach 345 kV Line
971L51	Forest Junction 345 kV	Forest Junction-Cypress 345 kV Line
971L71	Forest Junction 345 kV	Forest Junction-Fox River 345 kV Line
L151	Fox River 345 kV	Point Beach-Fox River 345 kV Line
L6832	Fox River 345 kV	Fox River-North Appleton 345 kV Line
971L71	Fox River 345 kV	Fox River-Forest Junction 345 kV Line
L111	Sheboygan Energy 345 kV	Point Beach-Sheboygan Energy 345 kV Line
L-SEC31	Sheboygan Energy 345 kV	Sheboygan Energy-Granville 345 kV Line
L-CYP31	Cypress 345 kV	Cypress-Arcadian 345 kV Line
971L51	Cypress 345 kV	Cypress-Forest Junction 345 kV Line
Q-303	Kewaunee 345 kV	Point Beach-Kewaunee 345 kV Line
R-304	Kewaunee 345 kV	Kewaunee-North Appleton 345 kV Line
KEW T10 H	Kewaunee 345 KV	Kewaunee 345/138 kV Transformer

Table C.11 presents results for three phase faults with breaker failure at the new East Switching Station (with Fix 2 in Appendix H, part of the proposed solution) for an otherwise intact system. These simulations provide the required clearing times for the new switching station and did not identify any stability problems that cannot be mitigated by the installation of 2 cycle 345 kV circuit breakers and high-speed relaying. Additional simulation is not performed with the proposed solution since stability response will only improve.

3.2.5 Point Beach Bus, Generator Step Up and Auxiliary Transformer Faults

3.2.5.1 Point Beach 345 kV Bus Fault Clearing

Table C.5 presents results for single-line-to-ground bus faults with breaker failure at Point Beach using existing system clearing times. These simulations did not identify any Network Upgrades or other required changes for G833/4-J022/3 for these faults.

3.2.5.2 Generator Step-Up (GSU) Transformer Fault Clearing (T1X01 and T2X01)

Tables C.6 and C.8 present results for single-line-to-ground (intact system with delayed clearing) and three phase (primary clearing under N-1 conditions) GSU faults. Simulating these faults with existing clearing times did not result in any generators going unstable. Therefore, there are no upgrades necessary due to these faults.

3.2.5.3 Auxiliary Transformer Fault Clearing (T1X03 and T2X03)

Table C.7 presents results for single-line-to-ground (intact system with delayed clearing) auxiliary transformer faults. Simulating these faults with existing clearing times did not result in any generators going unstable. Therefore, there are no upgrades necessary due to these faults.

Table C.9 presents results for three phase (primary clearing under both intact and prior outage conditions) T1X03 and T2X03 faults. Without the proposed solution, simulating these faults with existing clearing times (i.e. 5.1 cycles) resulted in generators going unstable for various different outages for T1X03 faults and for T2X03 faults. However, the stability problems were not found with the addition of the proposed solution. Until the proposed solution in place, generator stability can be maintained for all N-1 conditions if T1X03 clearing time is reduced to 4.0 cycles and T2X03 clearing time is reduced to 4.0 cycles.

3.2.6 Unit Outage

Unit outages were simulated for the events listed in Table 3.2.5. As shown in Table C.10 in Appendix C, no stability problems were found for the three interim scenarios, and no cascading failure was identified for the loss of these units.

Table 3.2.5 – Unit Outage

Unit Tripped
Point Beach G1
Point Beach G2
Point Beach G1 and G2
Kewaunee (most severe among the units near by Point Beach)

3.2.7 Stability Results Summary

The improvements in system stability required for G833/4-J022/3 are provided by the proposed solution described in this report. It eliminates all of the stability problems created by G833/4-J022/3. In addition, the proposed solution allows the wider MVAR operating range at Point Beach and Kewaunee as described in Appendix H. More details can be found in Appendix H which discusses alternatives to the proposed solution.

3.3 Short-Circuit & Breaker Duty Analysis Results

Although this project is to increase generation at an existing generator, the effect of the proposed solution, changes in Point Beach generator impedance and GSU impedance will affect system short circuit currents.

Fault currents with and without contribution from G833/4-J022/3 for three-phase and single line-to-ground faults are given in Table D.1 in Appendix D. The corresponding Thevenin equivalent impedances are given in Table D.2.

The minimum short circuit current at the G833/4-J022/3 POI bus occurs when Q-303 (Point Beach-Kewanee), Point Beach G1 and G2 are not in service. The three-phase and single line-to-ground fault currents for this weak source condition are also given in Table D.1.

Short circuit current analysis with the revised generator and GSU impedances as well as the proposed solution showed that, for circuit breakers impacted by more than 1% (Table D.3), none of these breakers were over-dutied due to the addition of G833/4-J022/3 and associated upgrades. Therefore, no circuit breaker replacements due to increased fault currents are needed for G833/4-J022/3 generator interconnection requests.

Although an over-dutied breaker is found at the low side of Edgewater T22, it is an existing problem since it is already over-dutied prior to G833/4-J022/3. The over-dutied breaker will be evaluated and replaced by ATC Asset Maintenance.

3.4 Deliverability Analysis Results

Deliverability analysis was performed by MISO for these requests. No additional upgrades beyond those discussed in the previous sections were identified to achieve Network Resource Interconnection Service (NRIS).

NRIS certification does not guarantee a resource to serve a specific load or to operate during any particular set of operating circumstances. Additionally, certification of deliverability makes no guarantee as to price of available resources. Congestion charges may, in fact, be extremely high.

Appendix A: Power Flow Analysis Results

Table A.1 – Identified Thermal Violations Due to G833/4-J022/3
Summer Off-Peak 2013 (70% Load) Delivery to MISO for NERC Category A and B events (TDF>5%)
Proposed Solution in Service, Competing Wind Farms at 100% output

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1,2]	Worst Contingency[3]	TDF (%)	Injection Limit	Potential Solution Identified
Elkhart Lake-Saukville 138 kV line	88 SE	93 SE	New East-Cedarsauk 345 kV line	-1.2	No	No[4]
Elkhart Lake-Lau Rd (G611) 138 kV line	96 SE	112 SE	New East - Cedarsauk 345 kV line	-1.25	No	Yes[5]
New North-Point Beach Bus 1 345 kV line	488 SE	754 SE	New North-Point Beach 345 kV bus 2 line	N/A	Yes	Yes[6]
New East-Cedarsauk 345 kV line	653 SE	797 SE	New East-Granville 345 kV line	N/A	Yes	No[7]

1. Includes provision for 5% TRM. The required ratings are calculated using AC analysis in PSS/E dispatching 100% of power from G833/4-J022/3 to MISO.
2. SN = Summer Normal, SE = Summer Emergency
3. Local Special Protection Systems are included if designed to operate for NERC Category A or B events
4. Distribution factor was calculated assuming that Edgewater-Cedarsauk 345 kV line as the contingency corresponding to New East-Cedarsauk 345 kV line. The line is limited by the existing line conductor (1-477 and 1-4/0 ACSR, 33.73 mile)
5. Distribution factor was calculated assuming that Edgewater-Cedarsauk 345 kV line as the contingency corresponding to New East-Cedarsauk 345 kV line. The line will be uprated to 112 MVA per G611/G927 G-T interconnection. It is limited by the existing line conductor (4/0 ACSR, 28.9 mile: Forest Junction-Elkhart Lake)
6. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010
7. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE (required for new East Switching Station option-Fix 2). The existing line rating is limited by the line clearance (2156 ACSR @ 129F).

Table A.2 – Identified Thermal Violations Due to G833/4-J022/3
Summer Peak 2013 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>5%)
Proposed Solution in Service, Competing Wind Farms at 20% Output

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1,2]	Worst Contingency[3]	TDF (%)	Injection Limit	Potential Solution Identified
New North-Point Beach Bus 1 345 kV line	488 SE	678 SE	New North-Point Beach 345 kV bus 2 line	N/A	Yes	Yes[4]

1. Includes provision for 5% TRM. The required ratings are calculated using AC analysis in PSS/E dispatching 100% of power from G833/4-J022/3 to MISO.
2. SN = Summer Normal, SE = Summer Emergency
3. Local Special Protection Systems are included if designed to operate for NERC Category A or B events
4. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010

Table A.3 – Identified Voltage Violations Due to G833/J022 and G834/J023 Summer Off-Peak 2013 (70% Load) Delivery to MISO for NERC Category A & B events (ΔV > 0.1 p.u.), Proposed Solution in Service, Competing Wind Farms at 100% output

Limiting Element	Worst Contingency	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

Table A.4 – Identified Voltage Violations Due to G833/J022 and G834/J023 Summer Peak 2013 (100% Load) Delivery to MISO for NERC Category A & B events (ΔV > 0.1 p.u.), Proposed Solution in Service, Competing Wind Farms at 20% output

Limiting Element	Worst Contingency	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

Table A.5 – Voltage Measurements at the Point Beach 345-kV Substation with Proposed Solution, Summer 2013 Peak Load with Selected Contingencies[1] (Without and With Minimum Excitation Limits)

Contingency	Voltage[2] (p.u.)					MVAR output (Gross)	
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5	Point Beach G1	Point Beach G2
Intact System	1.0203	1.0203	1.0203	1.0203	1.0203	64.62	64.62
Point Beach BS 2-3	1.0203	1.0203	1.0203	1.0203	1.0203	81.95	35.02
Point Beach BS 2 – New North 345-kV Line 121	1.0203	1.0203	1.0203	1.0203	1.0203	65.48	65.48
Point Beach BS 1-2	1.0168	1.0203	1.0203	1.0203	1.0203	62.04	62.04
Point Beach BS 4-5[3]	1.0203	1.0203	1.0203	1.0203	1.0224	72.05	72.05
Point Beach BS 3-4	1.0203	1.0203	1.0203	1.0203	1.0203	77.15	74.01
Point Beach BS 5 – Fox River 345-kV Line 151	1.0203	1.0203	1.0203	1.0203	1.0203	73.11	73.11
Forest Junction – Fox River 345-kV Line 971L71	1.0202	1.0203	1.0203	1.0203	1.0203	83.48	83.48
Point Beach BS 1 –New North 345-kV Line 111	1.0203	1.0203	1.0203	1.0203	1.0203	64.85	64.85
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.0203	1.0203	1.0203	1.0203	1.0203	75.68	75.68
Forest Junction – Cypress 345-kV Line 971L51	1.0203	1.0203	1.0203	1.0203	1.0203	69.67	69.67
Forest Junction 345/138-kV Transformer T1	1.0203	1.0203	1.0203	1.0203	1.0203	58.27	58.27
Forest Junction 345/138-kV Transformer T2	1.0203	1.0203	1.0203	1.0203	1.0203	58.27	58.27
Fox River – N. Appleton 345-kV Line 6832	1.0203	1.0203	1.0203	1.0203	1.0203	64.53	64.53
Sheboygan Energy – New East 345-kV Line L-SEC31 North	1.0202	1.0203	1.0203	1.0203	1.0203	74.75	74.75
Fox Energy Center Unit CT 1	1.0203	1.0203	1.0203	1.0203	1.0203	63.16	63.16
Fox Energy Center Unit CT 2	1.0203	1.0203	1.0203	1.0203	1.0203	63.17	63.17
Fox Energy Center Unit ST	1.0203	1.0203	1.0203	1.0203	1.0203	62.63	62.63
Sheboygan Energy Center Unit #1	1.0203	1.0203	1.0203	1.0203	1.0203	72.96	72.96
Sheboygan Energy Center Unit #2	1.0203	1.0203	1.0203	1.0203	1.0203	72.96	72.96
Point Beach Unit #1[4]	1.0203	1.0203	1.0203	1.0203	1.0203	0	72.16
Point Beach Unit #2[5]	1.0203	1.0203	1.0203	1.0203	1.0203	72.16	0
Kewaunee G1	1.0203	1.0203	1.0203	1.0203	1.0203	66.29	66.29
Point Beach Units #1 & #2[6]	1.0194	1.0194	1.0194	1.0194	1.0195	0	0

1. Included for Interconnection Customer's defined voltage levels:
    a. Preferred: 352-kV to 354-kV
    b. Normal: 351-kV to 358-kV
    c. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table A.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0203 p.u. (352 kV).
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. Both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA.

Table A.6 – Voltage Measurements at the Point Beach 345-kV Substation with Proposed Solution, Summer 2013 Off-Peak Load with Selected Contingencies[1] (Without and With Minimum Excitation Limits)

Contingency	Voltage[2] (p.u.)					MVAR output (Gross)	
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5	Point Beach G1	Point Beach G2
Intact System	1.0202	1.0203	1.0203	1.0203	1.0203	114.61	114.61
Point Beach BS 2-3	1.0202	1.0203	1.0203	1.0203	1.0202	138.22	80.31
Point Beach BS 2 – New North 345-kV Line 121	1.0201	1.0203	1.0203	1.0203	1.0202	113.99	113.99
Point Beach BS 1-2	1.0113	1.0203	1.0203	1.0203	1.0202	109.49	109.49
Point Beach BS 4-5[3]	1.0202	1.0203	1.0203	1.0203	1.0136	110.13	110.13
Point Beach BS 3-4	1.0202	1.0203	1.0203	1.0203	1.0202	148.05	112.96
Point Beach BS 5 – Fox River 345-kV Line 151	1.0202	1.0203	1.0203	1.0203	1.0203	114.68	114.68
Forest Junction – Fox River 345-kV Line 971L71	1.0202	1.0203	1.0203	1.0203	1.0203	117.67	117.67
Point Beach BS 1 – New North 345-kV Line 111	1.0203	1.0203	1.0203	1.0203	1.0202	113.09	113.09
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.0202	1.0203	1.0203	1.0203	1.0203	117.99	117.99
Forest Junction – Cypress 345-kV Line 971L51	1.0202	1.0203	1.0203	1.0203	1.0202	120.07	120.07
Forest Junction 345/138-kV Transformer T1	1.0202	1.0203	1.0203	1.0203	1.0203	107.62	107.62
Forest Junction 345/138-kV Transformer T2	1.0202	1.0203	1.0203	1.0203	1.0203	107.62	107.62
Fox River – N. Appleton 345-kV Line 6832	1.0202	1.0203	1.0203	1.0203	1.0203	107.89	107.89
Sheboygan Energy – New East 345-kV Line L-SEC31 North	1.0202	1.0203	1.0203	1.0203	1.0202	114.03	114.03
Fox Energy Center Unit CT 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit CT 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit ST	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sheboygan Energy Center Unit #1	1.0202	1.0203	1.0203	1.0203	1.0202	127.41	127.41
Sheboygan Energy Center Unit #2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Point Beach Unit #1[4]	1.0202	1.0203	1.0203	1.0203	1.0203	0	149.52
Point Beach Unit #2[5]	1.0202	1.0203	1.0203	1.0203	1.0203	149.52	0
Kewaunee G1	1.0202	1.0203	1.0203	1.0203	1.0203	93.72	93.72
Point Beach Units #1 & #2[6]	1.0178	1.0178	1.0178	1.0178	1.0178	0	0

1. Included for Interconnection Customer's defined voltage levels:
    a. Preferred: 352-kV to 354-kV
    b. Normal: 351-kV to 358-kV
    c. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table A.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0203 p.u (352 kV).
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. Both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA.
7. Fox Energy Center Units and Sheboygan Energy Center Unit #2 are off-line in the study case.

Table A.7 – Identified Thermal Violations under select NERC Category C.3 events[1] (TDF>5%), Summer Off-Peak 2013 70% Load Delivery to MISO with Proposed Solution, Competing Wind Farms at 100% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
Cypress-Arcadian 345 kV line	488 SE	559 SE	New East-Granville 345 kV line New East-Cedarsauk 345 kV line	N/A	No[4]
Lau Rd (G611)-Elkhart Lake 138 kV line	96 SE	144 SE		N/A	No[5]
Elkhart Lake-Saukville 138 kV line	88 SE	122 SE		N/A	No[6]
New East-Holland 138 kV line	283 SE	330 SE		N/A	No[7]
Holland-Charter Steel 138 kV line	283 SE	296 SE		N/A	No[8]
Granville 345/138 kV transformer T3	478 SE	541 SE	Cypress-Arcadian 345 kV line Granville 345 kV bus tie 1-2	10.7	No[9]
New North-Point Beach bus 2 345 kV line	883 SE	965 SE	New North-Point Beach bus 1 345 kV line Point Beach 345 kV bus tie 4-5 or Point Beach-Fox River 345 kV line	N/A	No[10]
New North-Point Beach bus 1 345 kV line	488 SE	985 SE	New North-Point Beach bus 2 345 kV line Point Beach-Fox River 345 kV line	N/A	No[11]
New North-Sheboygan Energy Center 345 kV line	488 SE	608 SE	New North-New East 345 kV line Cypress-Arcadian 345 kV line	N/A	No[12]
New East-Cedarsauk 345 kV line	653 SE	960 SE	New East-Granville 345 kV line Cypress-Arcadian 345 kV line	N/A	No[13]

1. NERC Category C.3 events studied are limited to the concurrent outage of two elements without manual system adjustments between outages. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.
2. Includes provision for 5% TRM. The required ratings are calculations using AC analysis in PSS/E dispatching G833/J022 and G834/J023 to all MISO generation.
3. SE = Summer Emergency
4. The line will be uprated to at least 572 MVA as part of G833/4-J022/3 interim upgrades. Whether additional 12 MVA is achievable without any significant constraints needs to be confirmed with Project Team. Generation redispatch using local generators would address the issue.
5. Generation redispatch using local generators would address the issue. The line will be uprated to 112 MVA per G611/G927 G-T interconnection. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (4/0 ACSR, 28.9 mile: Forest Junction-Elkhart Lake).
6. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (1-477 and 1-4/0 ACSR, 33.73 mile)
7. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (1033.5 at 167F, approximate length from new East substation to Holland: 8.2 miles)
8. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (1033.5 at 167F, length: 15 miles)
9. Generation redispatch using the local generators would address the issue. It is limited by the transformer (504 MVA SE) and equipment associated with the transformer. The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.

10. Generation redispatch using local generators or taking the bus tie out of service during Point Beach generation refueling outage window would address the issue. It is limited by the portion of the existing line conductor (1-2156 ACSR, approximate length: 21 mile). The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
11. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010. The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
12. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010. The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
13. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE (required for new East Switching Station option). The existing line rating is limited by the line clearance (2156 ACSR @ 129F)

Table A.8 – Identified Thermal Violations under select NERC Category C.3 events[1] (TDF>5%), Summer Peak 2013 100% Load Delivery to MISO with Proposed Solution, Competing Wind Farms at 20% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
Forest Junction-Fox River 345 kV line	1096 SE	1229 SE	North Appleton-Fox River 345 kV line Point Beach 345 kV bus tie 3-4	48.0	No[4]
Kewaunee-East Krok 138 kV line	287 SE	306 SE	North Appleton-Kewaunee 345 kV line Point Beach 345 kV bus tie 2-3	5.8	No[5]
New North-Point Beach bus 1 345 kV line	488 SE	889 SE	New North-Point Beach bus 2 345 kV line North Appleton-Kewaunee 345 kV line	N/A	No[6]
New East-Cedarsauk 345 kV line	653 SE	689 SE	New East-Granville 345 kV line Cypress-Arcadian 345 kV line	N/A	No[7]

1. NERC Category C.3 events studied are limited to the concurrent outage of two elements without manual system adjustments between outages. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.
2. Includes provision for 5% TRM. The required ratings are calculations using AC analysis in PSS/E dispatching G833/J022 and G834/J023 to all MISO generation.
3. SE = Summer Emergency
4. Generation redispatch using local generators or taking the bus tie out of service during Point Beach generation refueling outage window would address the issue. It is limited by the portion of the existing line conductor (1-2156 ACSR, 11.32 mile). The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
5. Generation redispatch using local generators would address the issue. It is limited by the terminal equipment.
6. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010.
7. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE (required for new East Switching Station option). The existing line rating is limited by the line clearance (2156 ACSR @ 129F)

Table A.9 – Identified Thermal Violations under select NERC Category C.5 events[1] (TDF>5%), Summer Off-Peak 2013 70% Load Delivery to MISO with Proposed Solution, Competing Wind Farms at 100% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
Lau Rd (G611)-Elkhart Lake 138 kV line	96 SE	120 SE	New East-Cedarsauk 345 kV line Holland-Charter Steel-Saukville 138 kV line	2.9	No[4]
Elkhart Lake-Saukville 138 kV line	88 SE	100 SE	New East-Cedarsauk 345 kV line Holland-Charter Steel- Saukville 138 kV line	0.5	No[5]
New East-Cedarsauk 345 kV line	653 SE	688 SE	Cypress-Arcadian 345 kV line Germantown-Maple-Saukville 138 kV line	N/A	No[6]

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.
2. Includes provision for 5% TRM. The required ratings are calculations using AC analysis in PSS/E dispatching G833/J022 and G834/J023 to all MISO generation
3. SE = Summer Emergency
4. Distribution factor was calculated assuming that Edgewater-Cedarsauk 345 kV line as the contingency corresponding to New East-Cedarsauk 345 kV line. Generation redispatch using local generators would address the issue. The line will be uprated to 112 MVA per G611/G927 G-T interconnection. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (4/0 ACSR, 28.9 mile: Forest Junction-Elkhart Lake).
5. Distribution factor was calculated assuming that Edgewater-Cedarsauk 345 kV line as the contingency corresponding to New East-Cedarsauk 345 kV line. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (1-477 and 1-4/0 ACSR, 33.73 mile).
6. Generation redispatch using local generators would address the issue. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE (required for new East Switching Station option). The existing line rating is limited by the line clearance (2156 ACSR @ 129F).

Table A.10 – Identified Thermal Violations under select NERC Category C.5 events[1] (TDF>5%), Summer Peak 2013 100% Load Delivery to MISO with Proposed Solution, Competing Wind Farms at 20% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
None identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.

Table A.11 – Identified Voltage Violations under select NERC Category C.5 events[1] Summer Off-Peak 2013 70% Load Delivery to MISO, with Proposed Solution, Competing Wind Farms at 100% output

Limiting Element	Worst Contingency[1]	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.

Table A.12 – Identified Voltage Violations under select NERC Category C.5 events[1] Summer Peak 2013 100% Load Delivery to MISO, with Proposed Solution, Competing Wind Farms at 20% output

Limiting Element	Worst Contingency[1]	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.

Table A.13 – Maximum Allowable Generation for G833/J022 and G834/J023, With Stability Upgrades, Without Thermal Upgrades for Injection Limits

Limiting Element	Worst Contingency	Model Description[1]	G833/4-J022/3 Max Output with ATC Planned and Proposed Projects[2] (MW)
New North-Point Beach Bus 1 345 kV line	New North-Point Beach 345 kV bus 2 line	MISO Summer Peak and Off-Peak 2013, 70% and 100% Loads	118 MW[3]
New East-Cedarsauk 345 kV line	New East-Granville 345 kV line	MISO Summer Off-Peak 2013, 70% Load	0 MW

1. Study models are built based on the MISO DPP Cycle 2 models (April 2009 Versions)
2. Planned and Proposed projects from the latest ATC Ten Year Assessment report (http://www.atc10yearplan.com/).
3. Max output allowed with the planned ATC Project PR03208 in-service line. It uprates Line L111 to 1095 MVA (1834 A). Estimated in-service date is 4/25/2010.

Appendix B: Operation Restrictions

Table B.1 – Summary of Identified Generation Restrictions due to Stability Constraints (With New Kewaunee substation, With Proposed Solution in service, With Minimum Excitation Limits at Point Beach and Kewaunee)

None

Appendix C: Stability Analysis Results

Nomenclature

K or KEW:	Kewaunee
P or POB:	Point Beach (P1 and P2)
S or SEC:	Sheboygan Energy Center
F or FOX:	Fox Energy
NAP:	North Appleton
GVL:	Granville
CYP:	Cypress
ADN:	Arcadian
FJT	Forest Junction
TH:	Thilmany
L111:	Point Beach-Sheboygan Energy Center 345 kV line
L121:	Point Beach-Forest Junction 345 kV line
Q-303:	Point Beach-Kewaunee 345 kV line
L151:	Point Beach-Fox Energy 345 kV line
R-304:	Kewaunee-North Appleton 345 kV line
NAPL71:	North Appleton-Werner West 345 kV line
CYP31:	Cypress-Arcadian 345 kV line
6832:	North Appleton-Fox Energy Center 345 kV line
T10:	Kewaunee T10 345/138 kV transformer
SEC31:	Sheboygan Energy Center-Granville 345 kV line
H:	High side
KWH:	Kewaunee T10 High side
KWL:	Kewaunee T10 Low side
POBxy:	Point Beach bus tie xy
Y311	North Appleton-Fitzgerald 345 kV line
CCT:	Critical Clearing Time

Note: The simulated clearing times and critical clearing times (CCT) noted in Appendix C contains planning margin described in Section 3.2

Table C.1 – Stability Results for Faults Clearing in Primary Time under Intact System Conditions (With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

Event File	Element Faulted	Fault Location	Faulted End Breakers	Remote Location	Remote End Breakers	Event Notes	Simulated Clearing	High Generation	Low Generation
FltPOBSEC	L111	POB	111	SEC	1-2, 1-6	No SPS	4.5/4.5	OK	OK
FltPOBFJT	L121	POB	121, 123	FJT	1-2, 2-3		4.5/4.5	OK	OK
FltPOBFOX	L151	POB	151	FOX	2-3, 3-4	No SPS	4.5/4.5	OK	OK
FltPOBKEW	Q-303	POB	Q-303	KEW	Q-303 New 1 and 2	No SPS	4.5/4.5	OK	OK
FltKEWPOB	Q-303	KEW	Q-303 New 1 and 2	POB	Q-303		4.5/4.5	OK	OK
FltKEWNAP	R-304	KEW	R-304 New 1 and 2	NAP	R-304		4.5/6.5	OK	OK
FltFOXPOB	L151	FOX	2-3, 3-4	POB	151		4.5/4.5	OK	OK
FltFOXNAP	L6832	FOX	1-2, 6-1	NAP	34-3, 34-4, 45-4, 67-6		4.5/4.5	OK	OK
FltFOXFJT	971L71	FOX	4-5, 5-6	FJT	5-6, 7-1		4.5/4.5	OK	OK
FltSECPOB	L111	SEC	1-2, 1-6	POB	111		4.5/4.5	OK	OK
FltSECGVL	L-SEC31	SEC	1-2, 3-6	GVL	L-SEC31		4.5/6.5	OK	OK
FltCYPADN	L-CYP31	CYP	1-2, 5-6	ADN	L-CYP31		4.5/4.5	OK	OK
FltKEWXFH	T10	KWH	T10 High Side	KWL	T10 Low Side		5.5/5.5	OK	OK

Table C.2 - Stability Results for Double Circuit Single Line-to-Ground Faults Cleared in Primary Time under Intact System Conditions (With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

Event File	Fault #1	Fault #1 Location	Fault #2	Fault #2 Location	Simulated Clearing time	High Gen	Low Gen
DC3-111-971K51-1	L111 - Point Beach-Sheboygan 345 kV	38.5% from POB	971K51 - Forest Junction-Howard's Grove 138 kV	33.9% from FJT	6.5/6.5	OK	OK
DC3-111-971K51-2	L111 - Point Beach-Sheboygan 345 kV	16.3% from SEC	971K51 - Forest Junction-Howard's Grove 138 kV	6.3% from HOG	6.5/6.5	OK	OK
DC3-111-HOLG21-1	L111 - Point Beach-Sheboygan 345 kV	SEC	HOGL21 - Howard's Grove-Holland 138 kV	76.9% from HOL	6.5/6.5	OK	OK
DC3-111-HOLG21-2	L111 - Point Beach-Sheboygan 345 kV	15.7% from SEC	HOGL21 - Howard's Grove-Holland 138 kV	31.4% from HOG	6.5/6.5	OK	OK
DC3-121-971K51-1	L121-Pt. Beach-Forest Junction 345 kV	FJT	971K51 - Forest Junction-Howard's Grove 138 kV	FJT	6.5/6.5	OK	OK
DC3-121-971K51-2	L121-Pt. Beach-Forest Junction 345 kV	42.3% from FJT	971K51 - Forest Junction-Howard's Grove 138 kV	33.9% from FJT	6.5/6.5	OK	OK
DC3-SEC31-3431-1	L-SEC31 - Sheboygan-Granville 345 kV	GVL	3431 - Granville-Saukville 345 kV	GVL	7.5/7.5	OK	OK
DC3-SEC31-3431-2	L-SEC31-Sheboygan-Granville 345 kV	26.7% from GVL	3431 - Granville-Saukville 345 kV	25.3% from SAU	7.5/7.5	OK	OK
DC3-SEC31-8231-1	L-SEC31-Sheboygan-Granville 345 kV	43.5% from GVL	8231 - Saukville-Barton 138 kV	36.4% from BRT	7.5/7.5	OK	OK
DC3-SEC31-8231-2	L-SEC31-Sheboygan-Granville 345 kV	48.3% from GVL	8231 - Saukville-Barton 138 kV	36.4% from SAU	7.5/7.5	OK	OK
DC3-9932-2642-1	L- CYP31 - Cypress-Arcadian 345 kV	32.0% from ADN	2642 - Saukville-Germantown 138 kV	34.2% from SAU	7.5/7.5	OK	OK
DC3-9932-2642-2	L- CYP31 - Cypress-Arcadian 345 kV	16.6% from ADN	2642 - Saukville-Germantown 138 kV	GER	7.5/7.5	OK	OK
DC3-9932-2661-1	L- CYP31 - Cypress-Arcadian 345 kV	10.8% from ADN	2661 - Germantown-Bark River 138 kV	31.5% from GER	8.5/8.5	OK	OK
DC3-9932-2661-2	L- CYP31 - Cypress-Arcadian 345 kV	16.6% from ADN	2661 - Germantown-Bark River 138 kV	GER	8.5/8.5	OK	OK
DC3-9932-9911-1	L- CYP31 - Cypress-Arcadian 345 kV	10.8% from ADN	9911 - Granville-Arcadian 345 kV	45.4% from GVL	7.5/7.5	OK	OK
DC3-9932-9911-2	L- CYP31 - Cypress-Arcadian 345 kV	ADN	9911 - Granville-Arcadian 345 kV	ADN	7.5/7.5	OK	OK

Table C.3 – Stability Results for 3-Phase Faults Cleared in Primary Time under Prior Outage Condition Units Tripping (With G833/4-J022/3, With New Kewaunee substation, With and Without Proposed Solution)

Note: Among various contingencies evaluated, only faults with stability issues are listed in Table C.3.

Primary Clearing Time, Prior Outage: 6832 (Fox Energy-North Appleton 345 kV line)													
								High Generation			Low Generation		
Event File	Element Faulted	Fault Location	Faulted End Breakers	Remote Location	Remote End Breakers	Event Notes	Simulated Clearing	Without New East Switching Station	With New East Switching Station (4.5/4.5** cycle tested)	With Proposed solution (Fix 11) (4.5/4.5** cycle tested)	Without New East Switching Station	With New East Switching Station (4.5/4.5** cycle tested)	With Proposed solution (Fix 11) (4.5/4.5** cycle tested)
FltKEWNAP	R-304	KEW	R-304 New 1 and 2	NAP	R-304		4.5/6.5	K,P,F*	OK	OK	OK	OK	OK

* Stable at 4.5/4.5 with G2 restricted to 600 MW gross (G2 restriction 600 MW gross with R-304 breaker at NAP replaced)

** 4.5 cycles at remote end achieved by R-304 breaker replacement at North Appleton as documented in the G833/4-J022/3 Interim Operation Re-study Report

Primary Clearing Time, Prior Outage: POB 2-3 (Point Beach 345 kV bus tie 2-3)													
								High Generation			Low Generation		
Event File	Element Faulted	Fault Location	Faulted End Breakers	Remote Location	Remote End Breakers	Event Notes	Simulated Clearing	Without New East Switching Station	With New East Switching Station (Fix2)	With Proposed solution (Fix 11)	Without New East Switching Station	With New East Switching Station	With Proposed solution (Fix 11)
FltPOBFJT	L121	POB	121, 123	FJT	1-2, 2-3		4.5/4.5	P1 **	OK	OK	P1 *	OK	OK

* To be stable at 4.5/4.5, G1 needs to be restricted to 580 MW gross

** To be stable at 4.5/4.5, G1 needs to be restricted to 620 MW gross

Table C.4 – Stability Results for 3-Phase Faults Cleared in Delayed (Breaker Failure) Time under Intact Conditions, Units Tripping (With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

Intact System Breaker Failure Events - April 2011 and beyond, W/ new Kewaunee Substation

Event	Element	Fault	Remote	Event	Simulated	High Gen		Low Gen			
File	Faulted	Location	Location	Notes	clearing time	Existing	3.5/9.5/4.5	Existing	3.5/9.5/4.5	3.5/9.25/4.5	3.5/9.0/4.5
BFIPOBSEC	L111	POB	SEC	T1X03 Tripped, Aux Moved	3.5/10.0/4.5	P,K	OK	P,K	P,K	P,K *	OK
BFIPOBFOX	L151	POB	FOX	T2X03 Tripped, Aux Moved	3.5/10.0/4.5	OK	OK	P,K *	OK	OK	OK
BFIPOBKEW	Q-303	POB	KEW	Future: Delay POB Split, No T10 Trip	3.5/10.0/4.5	OK	OK	P2	P2 **	OK	OK
BFIKEWPOB	Q-303	KEW	POB	Delay KEW T10 Trip	3.5/10.0/4.5	OK	OK	OK	OK	OK	OK
BFIKEWNAP2	R-304	KEW	NAP	Delay KEW T10 Trip	3.5/10.0/6.5	OK	OK	P,K ***	OK	OK	OK
BFIKEWXFH2	KEW T10	KWH	KWL	Future (Existng No BF possible)	3.5/10.0/4.5	OK	OK	OK	OK	OK	OK
BFINAPKEW2	R-304	NAP	KEW	Split NAP Primary, Transformer Trip BF	5.5/14.25/4.5	OK	OK	OK	OK	OK	OK
BFIFJTPOB	L121	FJT	POB	Trips Transformer	3.5/10.5/4.5	OK	OK	OK	OK	OK	OK
BFIFJTCYP	971L51	FJT	CYP	Trips Line 971L71	3.5/10.5/4.5	OK	OK	OK	OK	OK	OK
BFIFJTFOX	971I71	FJT	FOX	Trips Line 971L51	3.5/10.5/4.5	OK	OK	OK	OK	OK	OK
BFIFOXPOB2	L151	FOX (2)	POB	BF Trips Fox Unit 1	3.5/10.5/4.5	OK	OK	OK	OK	OK	OK
BFIFOXNAP2	L6832	FOX (2)	NAP	BF Trips Fox Unit 2	3.5/10.0/4.5	OK	OK	OK	OK	OK	OK
BFIFOXFJT2	971L71	FOX (2)	FJT	BF Trips Fox Unit 2	3.5/10.0/4.5	OK	OK	OK	OK	OK	OK
BFISECPOB1	L111	SEC (1)	POB	Do Not Trip Gen (worst case)	3.5/10.5/4.5	OK	OK	OK	OK	OK	OK
BFISECGVL1	L-SEC31	SEC (1)	GVL	Do Not Trip Gen (worst case)	3.5/10.5/6.5	OK	OK	OK	OK	OK	OK
BFICYPADN	L-CYP31	CYP	ADN	Trips CYP Units	3.5/10.5/4.5	OK	OK	OK	OK	OK	OK
BFICYPFJT	971L51	CYP	FJT	Trips CYP Units	3.5/10.5/4.5	OK	OK	OK	OK	OK	OK

* 8.0 cycle clearing time will be achieved by relay upgrades scheduled for 2011 (see the G833/4-J022/3 Interim Operation Re-Study Report).
** The fault will be cleared in primary time due to a breaker addition in series with Q-303 scheduled for 2011 (see the G833/4-J022/3 Interim Operation Re-Study Report). *Breaker failure is not possible with the upgrade.*
*** According to protection, breaker failure clearing time will become 8.5 cycles with the planned Kewaunee bus reconfiguration project in-service. In addition, R-304 breaker at North Appleton will be replaced by 2010 (see the G833/4-J022/3 Interim Operation Re-Study Report)

Table C.5 – Stability Results for Point Beach Bus Single Line-to-Ground Faults Cleared in Delayed Time under Intact Conditions (With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

Fault Location	Breaker Failure Element tripped	Simulated Clearing	High Gen	Low Gen
POB Bus 1	POB-SEC	4.75/24.5	OK	OK
POB Bus 1	POB Bus 1-2	4.75/12.5	OK	OK
POB Bus 2	POB Bus 2-1	4.75/12.5	OK	OK
POB Bus 2	POB Bus 2-3	4.75/12.5	OK	OK
POB Bus 3	POB Bus 3-2	4.75/12.5	OK	OK
POB Bus 3	POB-KEW	4.75/12.5	OK	OK
POB Bus 3	POB Bus 3-4	4.75/12.5	OK	OK
POB Bus 4	POB Bus 4-3	4.75/12.5	OK	OK
POB Bus 4	POB Bus 4-5	4.75/12.5	OK	OK
POB Bus 5	POB Bus 5-4	4.75/12.5	OK	OK
POB Bus 5	POB-FOX	4.75/24.5	OK	OK

Table C.6 – Stability Results for GSU Single Line-to-Ground Faults Cleared in Delayed Time under Intact Conditions, Units Tripping (With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

POB GSU BF Faults				
Fault Location	Breaker Failure Element tripped	Simulated Clearing	**High Gen**	**Low Gen**
POB Unit 1 GSU	POB Bus 2	4.5/13.5/14.0*	OK	OK
POB Unit 2 GSU	POB Bus 4	4.5/13.5	OK	OK

* - Primary Clearing Time/Bus Breaker Failure Time/Line Breaker Failure Time (GSU #1 Only)

Table C.7 – Stability Results for Auxiliary Transformer High Side Single Line-to-Ground Faults Cleared in Delayed Time under Intact Conditions, Units Tripping

(With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

Faulted Element	Breaker Failure Element Tripped	High Gen	Low Gen
		5.1/24.5	5.1/24.5
POB AUX1 HS	POB-SEC @ SEC	OK	OK
POB AUX2 HS	POB-FOX @ FOX	OK	OK
Faulted Element	Breaker Failure Element Tripped	5.1/13.3*	5.1/13.3*
POB AUX1 HS	POB Bus 2**	OK	OK
POB AUX2 HS	POB Bus 4***	OK	OK

* - The Stability Model Time Step is 0.25 cycles, so a 13.3 cycle fault actually clears in 13.5 cycles.
** - POB-Forest Junction 345 kV line Trips, POB Generator 1 is Isolated.
*** - POB Generator 2 is isolated

Table C.8 – Stability Results for GSU Three Phase 345 kV Faults Cleared in Primary (5.5 cycles, including 1 cycle margin) Time under Intact and Prior Outage Conditions, Units Tripping

(With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

Fault	Prior Outage	High Gen	Low Gen
FltPBGSU1	None	OK	OK
FltPBGSU1	111	OK	OK
FltPBGSU1	121	OK	OK
FltPBGSU1	151	OK	OK
FltPBGSU1	Q-303	OK	OK
FltPBGSU1	R-304	OK	OK
FltPBGSU1	6832	OK	OK
FltPBGSU1	971L71	OK	OK
FltPBGSU1	L-SEC31	OK	OK
FltPBGSU1	L-CYP31	OK	OK
FltPBGSU1	T10	OK	OK
FltPBGSU1	NAPL71	OK	OK
FltPBGSU1	971L51	OK	OK
FltPBGSU1	Y-311	OK	OK
FltPBGSU1	B12	OK	OK
FltPBGSU1	B23	OK	OK
FltPBGSU1	B34	OK	OK
FltPBGSU1	B45	OK	OK

Fault	Prior Outage	High Gen	Low Gen
FltPBGSU2	None	OK	OK
FltPBGSU2	111	OK	OK
FltPBGSU2	121	OK	OK
FltPBGSU2	151	OK	OK
FltPBGSU2	Q-303	OK	OK
FltPBGSU2	R-304	OK	OK
FltPBGSU2	6832	OK	OK
FltPBGSU2	971L71	OK	OK
FltPBGSU2	L-SEC31	OK	OK
FltPBGSU2	L-CYP31	OK	OK
FltPBGSU2	T10	OK	OK
FltPBGSU2	NAPL71	OK	OK
FltPBGSU2	971L51	OK	OK
FltPBGSU2	Y-311	OK	OK
FltPBGSU2	B12	OK	OK
FltPBGSU2	B23	OK	OK
FltPBGSU2	B34	OK	OK
FltPBGSU2	B45	OK	OK

Table C.9 – Stability Results for Auxiliary Transformer High Side 3-Phase Faults Cleared in Primary Time (6.1 cycles, including 1 cycle margin) under Intact and Prior Outage Conditions (With G833/4-J022/3, With New Kewaunee substation, With and Without Proposed Solution)

Fault (Aux 1)	Prior Outage	Without East Switching Station		With East Switching Station		With Proposed Solution (Fix 11)	
		High Generation (5.75/6.1)	Low Generation (5.75/6.1)	High Generation (5.75/6.1)	Low Generation (5.75/6.1)	High Generation (5.75/6.1)	Low Generation (5.75/6.1)
FltPOBAX1	None	OK	OK	OK	OK	OK	OK
FltPOBAX1	111	OK	OK	OK	OK	OK	OK
FltPOBAX1	121	OK	OK	OK	P,K (5.5/6.0 stable)	OK	OK
FltPOBAX1	151	OK	OK	OK	OK	OK	OK
FltPOBAX1	Q-303	OK	OK	OK	OK	OK	OK
FltPOBAX1	R-304	K,P (5.5/6.0 stable)	K,P (5.5/6.0 stable)	P,K (5.5/6.0 stable)	P,K (5.5/6.0 stable)	OK	OK
FltPOBAX1	6832	K,P,F (5.0/6.0 stable)	OK	P,K,F (5.0/6.0 stable)	OK	OK	OK
FltPOBAX1	971L71	OK	OK	OK	OK	OK	OK
FltPOBAX1	L-SEC31	OK*	OK	OK*	OK	OK	OK
FltPOBAX1	L-CYP31	K,P,F (5.0/6.0 stable)	OK	P,K,F (5.0/6.0 stable)	OK	OK	OK
FltPOBAX1	T10	OK	OK	OK	OK	OK	OK
FltPOBAX1	NAPL71	K,P,F (5.5/6.0 stable)	OK	P,K,F (5.5/6.0 stable)	OK	OK	OK
FltPOBAX1	971L51	OK	OK	OK	OK	OK	OK
FltPOBAX1	Y-311	K,P,F (5.5/6.0 stable)	OK	P,K,F (5.5/6.0 stable)	OK	OK	OK
FltPOBAX1	B12	OK	OK	OK	OK	OK	OK
FltPOBAX1	B23	OK	OK	OK	OK	OK	OK
FltPOBAX1	B34	OK	OK	OK	OK	OK	OK
FltPOBAX1	B45	OK	OK	OK	OK	OK	OK

*SEC Gens Isolated

Fault (Aux 2)	Prior Outage	Without East Switching Station		With East Switching Station		With Proposed Solution (Fix 11)	
		High Generation (5.75/6.1)	Low Generation (5.75/6.1)	High Generation (5.75/6.1)	Low Generation (5.75/6.1)	High Generation (5.75/6.1)	Low Generation (5.75/6.1)
FltPOBAX2	None	OK	OK	OK	OK	OK	OK
FltPOBAX2	111	OK	P (uv 19 kV at 1.521sec, 345 kV B1 1st-1.096 sec, 2nd-1.562 sec) (5.5/6.0 stable)	OK	P (uv 19 kV at 2.175 sec, 345 kV B1 1st-1.75 sec, 2nd- 2.2 sec) (5.5/6.0 stable)	OK	OK
FltPOBAX2	121	P1 (uv 345kV B1 1st-1.183sec, 2nd-1.571 sec) (5.5/6.0 stable)	K,P (5.0/6.0 stable)	OK	OK	OK	OK
FltPOBAX2	151	OK	OK	OK	OK	OK	OK
FltPOBAX2	Q-303	OK	OK	OK	OK	OK	OK
FltPOBAX2	R-304	OK	K,P (5.0/6.0 stable)	OK	OK	OK	OK
FltPOBAX2	6832	OK	OK	OK	OK	OK	OK
FltPOBAX2	971L71	OK	OK	OK	OK	OK	OK
FltPOBAX2	L-SEC31	K,P,S (5.0/6.0 stable)	K,P (5.5/6.0 stable)	P,K,S (5.0/6.0 stable)	P,K (5.5/6.0 stable)	OK	OK
FltPOBAX2	L-CYP31	OK	OK	OK	OK	OK	OK
FltPOBAX2	T10	OK	OK	OK	OK	OK	OK
FltPOBAX2	NAPL71	OK	OK	OK	OK	OK	OK
FltPOBAX2	971L51	OK	OK	OK	OK	OK	OK
FltPOBAX2	Y-311	OK	OK	OK	OK	OK	OK
FltPOBAX2	B12	OK	K,P (5.5/6.0 stable)	OK	P,K (5.5/6.0 stable)	OK	OK
FltPOBAX2	B23	OK	OK	OK	OK	OK	OK
FltPOBAX2	B34	OK**	OK**	OK**	OK**	OK**	OK**
FltPOBAX2	B45	OK	OK	OK	OK	OK	OK

*POB Unit 2 Isolated

Table C.10 – Stability Results for Kewaunee and Point Beach Generation Outage under Intact Conditions (With G833/4-J022/3, With New Kewaunee substation, Without Proposed Solution)

UNIT TRIP	Trip time (sec)	High Gen	Low Gen
POB G1	0.15	OK	OK
POB G2	0.15	OK	OK
POB G1G2	0.15	OK	OK
KEW	0.15	OK	OK

Table C.11 – Stability Results for 3-Phase Faults at East Switching Station (Fix 2) Cleared in Delayed Time under Intact Conditions, (With G833/4-J022/3, With New Kewaunee substation, With only East switching Station (Fix 2, part of proposed solution))*

Event File	Element Faulted	Fault Location	Remote Location	Event Notes	Simulated clearing time	High Gen	Low Gen
BFIESSEDGW1	W-1East	New East	Edgewater	Trips W-1 West	3.5/10.0/5.0	OK	OK
BFIESSSFL	W-1 West	New East	S. Fond du Lac	Trips W-1 East	3.5/10.0/5.0	OK	OK
BFIESSSEC	L-SEC31 North	New East	Sheboygan Energy Center	Trips L-SEC31 South	3.5/10.0/5.0	OK	OK
BFIESSGVL	L-SEC31 South	New East	Granville	Trips L-SEC31 North	3.5/10.0/5.0	OK	OK
BFIESSEDG796	796L41 East	New East	Edgewater	Trips 796L41 South	3.5/10.0/5.0	OK	OK
BFIESSSAU	796L41 South	New East	Cedarsauk	Trips 796L41 East	3.5/10.0/5.0	OK	OK

* Not re-run with the proposed solution (Fix 11) since stability will only improve

*Table C.12** – Stability Results for 3-Phase Faults at East Switching Station (Fix 2) Cleared in Primary Time under Critical Prior Outage Condition,*

(With G833/4-J022/3, With New Kewaunee substation, With only East switching Station (Fix 2, part of proposed solution))

Primary Clearing Time, Prior Outage: New East-Granville 345 kV line*, New KEW Sub, New East sub								
Event	Element	Fault	Faulted End	Remote	Remote End	Simulated	High Gen	Low Gen
File	Faulted	Location	Breakers	Location	Breakers	Clearing	Base	Base
FltESSSAU	New East-Cedasauk*	New East	Two new breakers	SEC	4-1, 3-4	4.5/4.5	OK	OK

* Fault on East-Cedarsauk 345 kV line under prior outage of East-Granville 345 kV line is evaluated as the worst prior outage event because, among the prior outage conditions at the new East switching station (Fix2), the outage of East-Granville 345 kV line results in the highest power flow on the 345 kV lines out of new East switching station, particularly on the East-Cedarsauk 345 kV line.

** Not re-run with the proposed solution (Fix 11) since stability will only improve

Appendix D: Short Circuit / Breaker Duty Analysis Results

Table D.1 – Maximum and Minimum Fault Duties at the G833/4-J022/3 Point of Interconnection

	Maximum Fault Duty (Amps)		Minimum Fault Duty* (Amps)	
	Single-phase	Three-Phase	Single-phase	Three-Phase
Existing system	23293.9	21160.4	9288	11100.6
With G833/4 (J022/3) with new Kewaunee (May 2011~beyond)	24801.6	22017	9288.2	11100.7
With G833/4 (J022/3) with new Kewaunee and new East Switching Station	25448.4	22749.3	9786.8	11954.8
With G833/4 (J022/3) with new Kewaunee and the Proposed Solution (Fix11)	26615.1	23988.7	10915.9	13402.2

* POB G1 and G2 offline and Q-303 out of service

Table D.2 – Thevenin Equivalent Impedances in Ohms corresponding to Maximum Fault Duty

	Pos Seq.	Neg. Seq.	Zero Seq.
Existing system	0.492146+ j 9.400272	0.563439+ j 9.4053	0.589203+ j 6.794582
With G833/4 (J022/3) with new Kewaunee (May 2011~beyond)	0.500629+ j 9.033035	0.774579+ j 9.021229	0.483616+ j 5.974935
With G833/4 (J022/3) with new Kewaunee and potential East sub	0.483549 + j 8.742337	0.734901 + j 8.732362	0.491449 + j 5.944132
With G833/4 (J022/3) with new Kewaunee and the Proposed Solution (Fix11)	0.455713 + j 8.290790	0.685388 + j 8.282391	0.496780 + j 5.818807

Table D.3 – Breaker Fault Duty Analysis for Breakers

Breaker Fault Duty Analysis (Red Cell for >1% Increase in Fault Current, Pink Cell for <5% in Breaker Margin)

				Three Phase Fault Analysis												
				Derated Breaker Rating	Symmetrical Fault Current (amps)				Change in Fault Current from Existing System			Breaker Margin (%)				
Substation	Bus Name	KV	Breaker	(kA)	Existing system	With G833/4 (J022/3) with new Kewaunee (May 2011-beyond)	With G833/4 (J022/3) with new Kewaunee and New East Switching Station	With G833/4 (J022/3) with new Kewaunee and Proposed Solution	With G833/4 (J022/3) with new Kewaunee (May 2011-beyond) (%)	With G833/4 (J022/3) with new Kewaunee and New East Switching Station (%)	With G833/4 (J022/3) with new Kewaunee and Proposed Solution (%)	Existing system	With G833/4 (J022/3) with new Kewaunee (May 2011-beyond)	With G833/4 (J022/3) with new Kewaunee and New East Switching Station	With G833/4 (J022/3) with new Kewaunee and Proposed Solution
FOREST_JUNCTION	ForestJct_4	138	BSK-45 (Transf 2)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_1	138	BSK-12 (KK971K11)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_2	138	BSK-23 (KK971K21)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_3	138	BSK-34 (KK971K31)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_5	138	BSK-56 (KK8222)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_6	138	BSK-67 (E-57)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_8	138	BSK-89 (Transf 1)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_9	138	BSK-910 (KK971K91)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_10	138	BSK-1011 (KK4035)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct_11	138	BSK-1112 (KK72851)	50	35599	35867	35926	37101	0.8%	0.9%	4.2%	24	23.8	23.7	19.2
FOREST_JUNCTION	ForestJct1	345	BS-L12 (Transf 2)	50	18716	18887	18986	22991	0.9%	1.4%	22.8%	62.6	62.2	62	54
FOREST_JUNCTION	ForestJct2	345	BS-L23 (L121)	50	18716	18887	18986	22991	0.9%	1.4%	22.8%	62.6	62.2	62	54
FOREST_JUNCTION	ForestJct3	345	BS-L45 (Transf 1)	50	18716	18887	18986	22991	0.9%	1.4%	22.8%	62.6	62.2	62	54
FOREST_JUNCTION	ForestJct5	345	BS-L56 (L971L51)	50	18716	18887	18986	22991	0.9%	1.4%	22.8%	62.6	62.2	62	54
FOREST_JUNCTION	ForestJct7	345	BS-L71(971L71)	50	18716	18887	18986	22991	0.9%	1.4%	22.8%	62.6	62.2	62	54
FOX_RIVER_SWITCH_Y	AR FOX_Bus_3	345	BSL-34	50	21345	21556	21648	22987	1.0%	1.4%	7.7%	57	56.9	56.7	54
FOX_RIVER_SWITCH_Y	AR FOX_Bus_5	345	BSL-56	50	21345	21556	21648	22987	1.0%	1.4%	7.7%	57	56.9	56.7	54
FOX_RIVER_SWITCH_Y	AR FOX_Bus_1	345	BSL-12	50	21345	21556	21648	22987	1.0%	1.4%	7.7%	57	56.9	56.7	54
FOX_RIVER_SWITCH_Y	AR FOX_GSU1_311	345	BSL-45	50	21345	21556	21648	22987	1.0%	1.4%	7.7%	57	56.9	56.7	54
FOX_RIVER_SWITCH_Y	AR FOX_GSU2_311	345	BSL-61	50	21345	21556	21648	22987	1.0%	1.4%	7.7%	57	56.9	56.7	54
FOX_RIVER_SWITCH_Y	AR FOX_Bus_2	345	BSL-23	50	21345	21556	21648	22987	1.0%	1.4%	7.7%	57	56.9	56.7	54
NORTH_APPLETON	NAP_Bus_G4	138	LINE 6842	63	39630	39791	39841	40461	0.4%	0.5%	2.1%	37.1	36.8	36.8	35.8
NORTH_APPLETON	NAP_Bus_G4	138	K37	63	39555	39720	39769	40428	0.4%	0.5%	2.2%	37.2	37	36.9	35.8
NORTH_APPLETON	NAP_Bus_G4	138	TRF 1, 138 KV	63	37422	37560	37598	38165	0.4%	0.5%	2.0%	40.6	40.4	40.3	39.4
NORTH_APPLETON	NAP_Bus_G5	138	TRF 2, 138 KV	63	36817	36950	36987	37536	0.4%	0.5%	2.0%	41.6	41.3	41.3	40.4
NORTH_APPLETON	NAP_Bus_G5	138	LINE 6851	63	39737	39906	39956	40629	0.4%	0.6%	2.2%	36.9	36.7	36.6	35.5
NORTH_APPLETON	NAP_Bus_G6	138	TRF 3, 138 kV	63	37531	37670	37708	38171	0.4%	0.5%	1.7%	40.4	40.2	40.1	39.4
NORTH_APPLETON	NAP_Bus_G4	138	CAP 4	63	41005	41177	41227	41902	0.4%	0.5%	2.2%	34.9	34.6	34.6	33.5
NORTH_APPLETON	NAP_Bus_G4	138	BUS SECT 4-5	63	33172	33286	33319	33800	0.3%	0.4%	1.9%	47.3	47.2	47.1	46.3
NORTH_APPLETON	NAP_Bus_G4	138	6843 GCB	63	39717	39883	39932	40589	0.4%	0.5%	2.2%	37	36.7	36.6	35.6
NORTH_APPLETON	NAP_Bus_G5	138	CAP 5	63	41005	41177	41227	41902	0.4%	0.5%	2.2%	34.9	34.6	34.6	33.5
NORTH_APPLETON	NAP_Bus_G5	138	BUS SECT 5-6	63	33729	33840	33874	34236	0.3%	0.4%	1.5%	46.5	46.3	46.2	45.7
NORTH_APPLETON	NAP_Bus_G5	138	LINE 6853	63	38944	39107	39156	39803	0.4%	0.5%	2.2%	38.2	37.9	37.8	36.8
NORTH_APPLETON	NAP_Bus_G6	138	CAP 6	63	41005	41177	41227	41902	0.4%	0.5%	2.2%	34.9	34.6	34.6	33.5
NORTH_APPLETON	NAP_Bus_G6	138	6862 GCB	63	39720	39884	39933	40573	0.4%	0.5%	2.1%	37	36.7	36.6	35.6
NORTH_APPLETON	NAP_Bus_G6	138	LINE I113	63	38391	38546	38594	39200	0.4%	0.5%	2.1%	39.1	38.8	38.7	37.8
NORTH_APPLETON	NAP_345B_L1	345	BUS SECT 12-1	40	22585	22759	22814	23313	0.8%	1.0%	3.2%	43.5	43.1	43	41.7
NORTH_APPLETON	NAP_345B_L34	345	BS34-4	40	22585	22759	22814	23313	0.8%	1.0%	3.2%	43.5	43.1	43	41.7
NORTH_APPLETON	NAP_345B_L1	345	LINE R304	39.8	20599	20692	20741	21201	0.5%	0.7%	2.9%	38.4	38.3	38.2	36.8
NORTH_APPLETON	NAP_345B_L81	345	BS 81-8	39.8	22585	22759	22814	23313	0.8%	1.0%	3.2%	31.9	31.7	31.6	30.1
NORTH_APPLETON	NAP_345B_L12	345	BUS SECT 12-2	40	22585	22759	22814	23313	0.8%	1.0%	3.2%	43.5	43.1	43	41.7
NORTH_APPLETON	NAP_345B_L1	345	BS 81-1	50	22585	22759	22814	23313	0.8%	1.0%	3.2%	54.8	54.5	54.4	53.4
NORTH_APPLETON	NAP_345B_L4	345	BS 45-4	50	22585	22759	22814	23313	0.8%	1.0%	3.2%	54.8	54.5	54.4	53.4
NORTH_APPLETON	NAP_345B_L6	345	BS 67-6	50	22585	22759	22814	23313	0.8%	1.0%	3.2%	54.8	54.5	54.4	53.4
NORTH_APPLETON	NAP_345B_L67	345	BS 67-7	50	22585	22759	22814	23313	0.8%	1.0%	3.2%	54.8	54.5	54.4	53.4
NORTH_APPLETON	NAP_345B_L3	345	BS 34-3	38	22585	22759	22814	23313	0.8%	1.0%	3.2%	38.9	38.7	38.6	37.3
NORTH_APPLETON	NAP_345B_L7	345	BS 78-7	50	22585	22759	22814	23313	0.8%	1.0%	3.2%	54.8	54.5	54.4	53.4
NORTH_APPLETON	NAP_345B_L78	345	BS 78-8	50	22585	22759	22814	23313	0.8%	1.0%	3.2%	54.8	54.5	54.4	53.4
NORTH_APPLETON	NAP_345B_L2	345	BUS SECT 23-2	42	22585	22759	22814	23313	0.8%	1.0%	3.2%	35.4	35.2	35.1	33.7
NORTH_APPLETON	NAP_345B_L23	345	BUS SECT 23-3	42	22585	22759	22814	23313	0.8%	1.0%	3.2%	35.4	35.2	35.1	33.7
POINT_BEACH	POINT_BCH_B1	345	BS 1-2	40	18618	19478	19502	21978	4.6%	4.7%	18.0%	48.8	49.1	49	43
POINT_BEACH	POINT_BCH_B2	345	BS 2-3	40	14119	14716	14724	14930	4.2%	4.2%	5.7%	62.4	62.4	62.4	61.9
POINT_BEACH	POINT_BCH_B3	345	BS 3-4	40	16687	17265	18077	19423	3.5%	8.3%	16.4%	56.1	56.3	54.5	51.2
POINT_BEACH	POINT_BCH_B4	345	BS 4-5	40	18970	19853	20651	21968	4.7%	8.9%	15.8%	48	48.3	46.5	43.3
POINT_BEACH	POINT_BCH_B1	345	LINE 111	50	18618	19478	19502	21978	4.6%	4.7%	18.0%	59	59.2	59.2	54.4
POINT_BEACH	POINT_BCH_B2	345	LINE 121(Bkr 121)	50	18935	19840	20624	22212	4.8%	8.9%	17.3%	58.4	58.6	57.1	54
POINT_BEACH	POINT_BCH_B2	345	LINE 123(Bkr 123)	50	18935	19840	20624	22212	4.8%	8.9%	17.3%	58.4	58.6	57.1	54
POINT_BEACH	POINT_BCH_B3	345	LINE Q303	50	16320	16994	17843	19180	4.1%	9.3%	17.5%	64	64.5	63	60.4
POINT_BEACH	POINT_BCH_B5	345	LINE 151	50	19069	19952	20748	22064	4.6%	8.8%	15.7%	58.2	58.4	56.9	54.4
SHEBOYGAN ENERGY C	EN SEC_Bus_1	345	BT12	50	10050	10091	20139	22623	0.4%	100.4%	125.1%	79.3	79.2	59	54.2
SHEBOYGAN ENERGY C	EN SEC_Bus_1	345	BT16	50	10050	10091	20139	22623	0.4%	100.4%	125.1%	79.3	79.2	59	54.2
SHEBOYGAN ENERGY C	EN SEC_ Bus 3	345	BT36	50	10050	10091	20139	22623	0.4%	100.4%	125.1%	79.3	79.2	59	54.2
EDGEWATER	EDG 138	138	470-S	20	16219	16222	17501	22465	0.0%	7.9%	38.6%	1	1	-7.4	-34.4
EDGEWATER	EDG 138	138	847-S	40	17544	17547	19663	22434	0.0%	12.1%	27.9%	46	46	39.3	31.7
EDGEWATER	EDG 138	138	370-S	40	12844	12846	13495	18961	0.0%	5.1%	47.6%	61.5	61.5	59.4	44.9
EDGEWATER	EDG 138	138	861-S	40	19867	19871	22104	26671	0.0%	11.3%	34.2%	40	40	33	20.6
EDGEWATER	EDG 138	138	843-S	40	19870	19874	22107	26590	0.0%	11.3%	33.8%	40	40	33	20.8
EDGEWATER	EDG 138	138	854-S	40	19870	19874	22107	26591	0.0%	11.3%	33.8%	40	40	33	20.8
EDGEWATER	EDG 138	138	884-S	40	17724	17727	19374	23506	0.0%	9.3%	32.6%	45.9	45.9	40.6	29.7
EDGEWATER	EDG 138	138	865-S	40	19867	19871	22104	26671	0.0%	11.3%	34.2%	40	40	33	20.6
EDGEWATER	EDG 138	138	826-S	40	22290	22294	25060	28605	0.0%	12.4%	28.3%	32.6	32.6	24	14.8
EDGEWATER	EDGEWATER	345	311-S	40	10893	10895	16472	17994	0.0%	51.2%	65.2%	57.7	57.7	37.6	32.2
EDGEWATER	EDGEWATER	345	313-S	40	10403	10406	17878	19695	0.0%	71.9%	89.3%	59.5	59.5	32.7	26.4
EDGEWATER	EDGEWATER	345	465-S	50	14743	14748	19519	21804	0.0%	32.4%	47.9%	68.8	68.7	59.1	54.8
EDGEWATER	EDGEWATER	345	2523-S	50	14837	14843	19615	21926	0.0%	32.2%	47.8%	68.6	68.6	59	54.6
EDGEWATER	EDGEWATER	345	302-S	40	14837	14843	19615	21926	0.0%	32.2%	47.8%	49.3	49.3	33.8	26.8
EDGEWATER	EDGEWATER	345	303-S	40	14837	14843	19615	21926	0.0%	32.2%	47.8%	49.3	49.3	33.8	26.8
EDGEWATER	EDGEWATER	345	304-S	40	14837	14843	19615	21926	0.0%	32.2%	47.8%	49.3	49.3	33.8	26.8
EDGEWATER	EDGEWATER	345	308-S	40	14837	14843	19615	21926	0.0%	32.2%	47.8%	49.3	49.3	33.8	26.8
KEWAUNEE	KEW 138kV	138	F-84	37	10646	20469	20639	20960	92.3%	93.9%	96.9%	65.1	34.3	33.8	32.8
KEWAUNEE	KEW 138kV	138	Y-51	37.2	11489	21077	21246	21569	83.5%	84.9%	87.7%	63.6	33	32.5	31.5
KEWAUNEE	KEW 138kV	138	1066E	38.9	13820	23143	23316	23660	67.5%	68.7%	71.2%	59.2	30.6	30.1	29.1
KEWAUNEE	KEW 138kV	138	1066W	38.9	13820	23143	23316	23660	67.5%	68.7%	71.2%	59.2	30.6	30.1	29.1
KEWAUNEE	KEW 138kV	138	22	40	13820	23143	23316	23660	67.5%	68.7%	71.2%	60.4	32.5	32.1	31.1
KEWAUNEE	KEWAUNEE B1	345	R-304	38	16413	17155	17649	18480	4.5%	7.5%	12.6%	42.2	41.2	39.8	37.3
KEWAUNEE	KEWAUNEE B1	345	3450	40	13752	14814	15307	16140	7.7%	11.3%	17.4%	56.6	52.6	51.3	49
KEWAUNEE	KEWAUNEE B1	345	3451	40	16413	17418	17852	18683	6.1%	8.8%	13.8%	45.1	47.2	46.1	43.8
KEWAUNEE	KEWAUNEE B2	345	Q-303	40	12737	13149	13661	14504	3.2%	7.3%	13.9%	59.4	59.5	58.2	56
KEWAUNEE	KEWAUNEE B2	345	1099	40	18125	19613	20045	20878	8.2%	10.6%	15.2%	39.8	36.8	35.7	33.3
S FONDULAC	S FONDULAC	138	382-S	40	23124	23129	23727	24081	0.0%	2.6%	4.1%	31.2	31.1	29.4	28.5
S FONDULAC	S FONDULAC	138	314-S	40	22612	22618	23334	24100	0.0%	3.2%	6.6%	32.6	32.5	30.5	28.6
S FONDULAC	S FONDULAC	138	336-S	40	23183	23188	23833	24386	0.0%	2.8%	5.2%	31	31	29.1	27.8
S FONDULAC	S FONDULAC	138	394-S	40	24512	24519	25226	25953	0.0%	2.9%	5.9%	27.7	27.7	25.7	23.9
S FONDULAC	S FONDULAC	138	1772-S	40	24512	24519	25226	25953	0.0%	2.9%	5.9%	27.7	27.7	25.7	23.9
S FONDULAC	S FONDULAC	138	1979-S	40	24512	24519	25226	25953	0.0%	2.9%	5.9%	27.7	27.7	25.7	23.9
S FONDULAC	S FONDULAC	138	1899-S	40	24512	24519	25226	25953	0.0%	2.9%	5.9%	27.7	27.7	25.7	23.9
S FONDULAC	S FONDULAC	138	320-S	40	24512	24519	25226	25953	0.0%	2.9%	5.9%	27.7	27.7	25.7	23.9
S FONDULAC	SFL 345	345	92-S	37.5	14942	14954	16803	17096	0.1%	12.5%	14.4%	50.7	50.6	45.2	44.5
S FONDULAC	SFL 345	345	52-S	40	14942	14954	16803	17096	0.1%	12.5%	14.4%	53.7	53.7	48.7	47.9
S FONDULAC	SFL 345	345	74-S	40	14942	14954	16803	17096	0.1%	12.5%	14.4%	53.7	53.7	48.7	47.9
S FONDULAC	SFL 345	345	86-S	40	14942	14954	16803	17096	0.1%	12.5%	14.4%	53.7	53.7	48.7	47.9

				Single Phase Fault Analysis												
				Derated Breaker Rating	Symmetrical Fault Current (amps)				Change in Fault Current from Existing System			Breaker Margin (%)			
Substation	Bus Name	KV	Breaker	(kA)	Existing system	With G833/4 (J022/3) with new Kewaunee (May 2011-beyond)	With G833/4 (J022/3) with new Kewaunee and New East Switching Station	With G833/4 (J022/3) with new Kewaunee and Proposed Solution	With G833/4 (J022/3) with new Kewaunee (May 2011-beyond) (%)	With G833/4 (J022/3) with new Kewaunee and New East Switching Station (%)	With G833/4 (J022/3) with new Kewaunee and Proposed Solution (%)	Existing system	With G833/4 (J022/3) with new Kewaunee (May 2011-beyond)	With G833/4 (J022/3) with new Kewaunee and New East Switching Station	With G833/4 (J022/3) with new Kewaunee and Proposed Solution
FOREST_JUNCTION	ForestJct_4	138	BSK-45 (Transf 2)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_1	138	BSK-12 (KK971K11)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_2	138	BSK-23 (KK971K21)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_3	138	BSK-34 (KK971K31)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_5	138	BSK-56 (KK8222)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_6	138	BSK-67 (E-57)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_8	138	BSK-89 (Transf 1)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_9	138	BSK-910 (KK971K91)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_10	138	BSK-1011 (KK4035)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct_11	138	BSK-1112 (KK72851)	50	36810	37024	37060	38439	0.6%	0.7%	4.4%	23.5	23.9	23.8	19.7
FOREST_JUNCTION	ForestJct1	345	BS-L12 (Transf 2)	50	17947	18081	18141	21666	0.7%	1.1%	20.7%	64.1	63.8	63.7	56.7
FOREST_JUNCTION	ForestJct2	345	BS-L23 (L121)	50	17947	18081	18141	21666	0.7%	1.1%	20.7%	64.1	63.8	63.7	56.7
FOREST_JUNCTION	ForestJct3	345	BS-L45 (Transf 1)	50	17947	18081	18141	21666	0.7%	1.1%	20.7%	64.1	63.8	63.7	56.7
FOREST_JUNCTION	ForestJct5	345	BS-L56 (L971L51)	50	17947	18081	18141	21666	0.7%	1.1%	20.7%	64.1	63.8	63.7	56.7
FOREST_JUNCTION	ForestJct7	345	BS-L71(971L71)	50	17947	18081	18141	21666	0.7%	1.1%	20.7%	64.1	63.8	63.7	56.7
FOX_RIVER_SWITCH_Y	AR FOX_Bus_3	345	BSL-34	50	21507	21682	21744	22847	0.8%	1.1%	6.2%	57	56.6	56.5	54.3
FOX_RIVER_SWITCH_Y	AR FOX_Bus_5	345	BSL-56	50	21507	21682	21744	22847	0.8%	1.1%	6.2%	57	56.6	56.5	54.3
FOX_RIVER_SWITCH_Y	AR FOX_Bus_1	345	BSL-12	50	21507	21682	21744	22847	0.8%	1.1%	6.2%	57	56.6	56.5	54.3
FOX_RIVER_SWITCH_Y	AR FOX_GSU1_311	345	BSL-45	50	21507	21682	21744	22847	0.8%	1.1%	6.2%	57	56.6	56.5	54.3
FOX_RIVER_SWITCH_Y	AR FOX_GSU2_311	345	BSL-61	50	21507	21682	21744	22847	0.8%	1.1%	6.2%	57	56.6	56.5	54.3
FOX_RIVER_SWITCH_Y	AR FOX_Bus_2	345	BSL-23	50	21507	21682	21744	22847	0.8%	1.1%	6.2%	57	56.6	56.5	54.3
NORTH_APPLETON	NAP_Bus_G4	138	LINE 6842	63	37910	38028	38059	38602	0.3%	0.4%	1.8%	39.8	39.6	39.6	38.7
NORTH_APPLETON	NAP_Bus_G4	138	K37	63	37924	38045	38077	38638	0.3%	0.4%	1.9%	39.8	39.6	39.6	38.7
NORTH_APPLETON	NAP_Bus_G4	138	TRF 1, 138 KV	63	35313	35410	35435	35929	0.3%	0.3%	1.7%	43.9	43.8	43.8	43
NORTH_APPLETON	NAP_Bus_G5	138	TRF 2, 138 KV	63	34332	34423	34446	34926	0.3%	0.3%	1.7%	45.5	45.4	45.3	44.6
NORTH_APPLETON	NAP_Bus_G5	138	LINE 6851	63	38079	38202	38235	38805	0.3%	0.4%	1.9%	39.6	39.4	39.3	38.4
NORTH_APPLETON	NAP_Bus_G6	138	TRF 3, 138 KV	63	35370	35467	35491	35923	0.3%	0.3%	1.6%	43.9	43.7	43.7	43
NORTH_APPLETON	NAP_Bus_G4	138	CAP 4	63	39205	39330	39362	39933	0.3%	0.4%	1.9%	37.8	37.6	37.5	36.6
NORTH_APPLETON	NAP_Bus_G4	138	BUS SECT 4-5	63	31681	31764	31785	32234	0.3%	0.3%	1.7%	49.7	49.6	49.5	48.8
NORTH_APPLETON	NAP_Bus_G4	138	6843 GCB	63	38033	38154	38186	38751	0.3%	0.4%	1.9%	39.6	39.4	39.4	38.5
NORTH_APPLETON	NAP_Bus_G5	138	CAP 5	63	39205	39330	39362	39933	0.3%	0.4%	1.9%	37.8	37.6	37.5	36.6
NORTH_APPLETON	NAP_Bus_G5	138	BUS SECT 5-6	63	32056	32137	32158	32536	0.3%	0.3%	1.5%	49.1	49	49	48.4
NORTH_APPLETON	NAP_Bus_G5	138	LINE 6853	63	37364	37484	37515	37951	0.3%	0.4%	1.6%	40.7	40.5	40.5	39.8
NORTH_APPLETON	NAP_Bus_G6	138	CAP 6	63	39205	39330	39362	39933	0.3%	0.4%	1.9%	37.8	37.6	37.5	36.6
NORTH_APPLETON	NAP_Bus_G6	138	6862 GCB	63	37859	37978	38009	38573	0.3%	0.4%	1.9%	39.9	39.7	39.7	38.8
NORTH_APPLETON	NAP_Bus_G6	138	LINE I113	63	36922	37036	37068	37593	0.3%	0.4%	1.8%	41.4	41.2	41.2	40.3
NORTH_APPLETON	NAP_345B_L1	345	BUS SECT 12-1	40	20755	20873	20906	21256	0.6%	0.7%	2.4%	48.1	47.8	47.7	46.9
NORTH_APPLETON	NAP_345B_L34	345	BS34-4	40	20755	20873	20906	21256	0.6%	0.7%	2.4%	48.1	47.8	47.7	46.9
NORTH_APPLETON	NAP_345B_L1	345	LINE R304	39.8	18925	18984	19014	19343	0.3%	0.5%	2.2%	42.4	42.6	42.5	41.4
NORTH_APPLETON	NAP_345B_L81	345	BS 81-8	39.8	20755	20873	20906	21256	0.6%	0.7%	2.4%	36.8	37.1	37	35.9
NORTH_APPLETON	NAP_345B_L12	345	BUS SECT 12-2	40	20755	20873	20906	21256	0.6%	0.7%	2.4%	48.1	47.8	47.7	46.9
NORTH_APPLETON	NAP_345B_L1	345	BS 81-1	50	20755	20873	20906	21256	0.6%	0.7%	2.4%	58.5	58.3	58.2	57.5
NORTH_APPLETON	NAP_345B_L4	345	BS 45-4	50	20755	20873	20906	21256	0.6%	0.7%	2.4%	58.5	58.3	58.2	57.5
NORTH_APPLETON	NAP_345B_L6	345	BS 67-6	50	20755	20873	20906	21256	0.6%	0.7%	2.4%	58.5	58.3	58.2	57.5
NORTH_APPLETON	NAP_345B_L67	345	BS 67-7	50	20755	20873	20906	21256	0.6%	0.7%	2.4%	58.5	58.3	58.2	57.5
NORTH_APPLETON	NAP_345B_L3	345	BS 34-3	38	20755	20873	20906	21256	0.6%	0.7%	2.4%	46.1	46.3	46.3	45.3
NORTH_APPLETON	NAP_345B_L7	345	BS 78-7	50	20755	20873	20906	21256	0.6%	0.7%	2.4%	58.5	58.3	58.2	57.5
NORTH_APPLETON	NAP_345B_L78	345	BS 78-8	50	20755	20873	20906	21256	0.6%	0.7%	2.4%	58.5	58.3	58.2	57.5
NORTH_APPLETON	NAP_345B_L2	345	BUS SECT 23-2	42	20755	20873	20906	21256	0.6%	0.7%	2.4%	40.1	40.4	40.3	39.2
NORTH_APPLETON	NAP_345B_L23	345	BUS SECT 23-3	42	20755	20873	20906	21256	0.6%	0.7%	2.4%	40.1	40.4	40.3	39.2
POINT_BEACH	POINT_BCH_B1	345	BS 1-2	40	20835	22332	22307	24545	7.2%	7.1%	17.6%	44.7	44.2	44.2	38.6
POINT_BEACH	POINT_BCH_B2	345	BS 2-3	40	15080	16054	16060	16224	6.5%	6.5%	7.6%	61.1	59.9	59.8	59.4
POINT_BEACH	POINT_BCH_B3	345	BS 3-4	40	17363	18376	19028	20223	5.8%	9.6%	16.5%	55.9	54.1	52.4	49.4
POINT_BEACH	POINT_BCH_B4	345	BS 4-5	40	20995	22507	23216	24464	7.2%	10.6%	16.5%	43.8	43.7	42	38.8
POINT_BEACH	POINT_BCH_B1	345	LINE 111	50	20990	22476	22415	24646	7.1%	6.8%	17.4%	55.4	55	55.2	50.7
POINT_BEACH	POINT_BCH_B2	345	LINE 121(Bkr 121)	50	21054	22572	23275	24857	7.2%	10.5%	18.1%	54.9	54.9	53.4	50.3
POINT_BEACH	POINT_BCH_B2	345	LINE 123(Bkr 123)	50	21054	22572	23275	24857	7.2%	10.5%	18.1%	54.9	54.9	53.4	50.3
POINT_BEACH	POINT_BCH_B3	345	LINE Q303	50	17990	19265	20016	21267	7.1%	11.3%	18.2%	60.8	61.5	60	57.5
POINT_BEACH	POINT_BCH_B5	345	LINE 151	50	21192	22692	23404	24654	7.1%	10.4%	16.3%	54.6	54.6	53.2	50.7
SHEBOYGAN ENERGY C	EN SEC_Bus_1	345	BT12	50	9077	9105	18379	20492	0.3%	102.5%	125.8%	81.5	81.5	63.2	59
SHEBOYGAN ENERGY C	EN SEC_Bus_1	345	BT16	50	9077	9105	18379	20492	0.3%	102.5%	125.8%	81.5	81.5	63.2	59
SHEBOYGAN ENERGY C	EN SEC_ Bus 3	345	BT36	50	9077	9105	18379	20492	0.3%	102.5%	125.8%	81.5	81.5	63.2	59
EDGEWATER	EDG 138	138	470-S	20	18100	18102	19266	23516	0.0%	6.4%	29.9%	-14	-14	-21.6	-46
EDGEWATER	EDG 138	138	847-S	40	20229	20232	22281	24805	0.0%	10.1%	22.6%	36	36	29.5	22.3
EDGEWATER	EDG 138	138	370-S	40	14314	14315	14894	19493	0.0%	4.1%	36.2%	56.7	56.7	55	42.7
EDGEWATER	EDG 138	138	861-S	40	22423	22426	24508	28492	0.0%	9.3%	27.1%	30.1	30	23.4	12
EDGEWATER	EDG 138	138	843-S	40	22479	22482	24570	28467	0.0%	9.3%	26.6%	29.9	29.9	23.3	12.1
EDGEWATER	EDG 138	138	854-S	40	22483	22486	24576	28491	0.0%	9.3%	26.7%	29.9	29.9	23.3	12.1
EDGEWATER	EDG 138	138	884-S	40	19239	19241	20653	23992	0.0%	7.3%	24.7%	39.3	39.3	34.7	25.3
EDGEWATER	EDG 138	138	865-S	40	22421	22424	24506	28490	0.0%	9.3%	27.1%	30.1	30	23.4	12
EDGEWATER	EDG 138	138	826-S	40	24451	24454	26990	30091	0.0%	10.4%	23.1%	23.8	23.7	15.7	7.2
EDGEWATER	EDGEWATER	345	311-S	40	13030	13033	18277	19643	0.0%	40.3%	50.8%	49.2	49.2	29	24
EDGEWATER	EDGEWATER	345	313-S	40	12772	12775	19526	21121	0.0%	52.9%	65.4%	50.2	50.2	24.6	18.7
EDGEWATER	EDGEWATER	345	465-S	50	16476	16481	21021	23066	0.0%	27.6%	40.0%	63.8	63.8	54.5	50.5
EDGEWATER	EDGEWATER	345	2523-S	50	16671	16675	21235	23310	0.0%	27.4%	39.8%	63.3	63.3	54	49.8
EDGEWATER	EDGEWATER	345	302-S	40	16671	16675	21235	23310	0.0%	27.4%	39.8%	40.7	40.7	25.6	19
EDGEWATER	EDGEWATER	345	303-S	40	16671	16675	21235	23310	0.0%	27.4%	39.8%	40.7	40.7	25.6	19
EDGEWATER	EDGEWATER	345	304-S	40	16671	16675	21235	23310	0.0%	27.4%	39.8%	40.7	40.7	25.6	19
EDGEWATER	EDGEWATER	345	308-S	40	16671	16675	21235	23310	0.0%	27.4%	39.8%	40.7	40.7	25.6	19
KEWAUNEE	KEW 138kV	138	F-84	37	10827	21876	22008	22260	102.1%	103.3%	105.6%	65.1	31.7	31.2	30.3
KEWAUNEE	KEW 138kV	138	Y-51	37.2	11335	22398	22527	22778	97.6%	98.7%	101.0%	63.9	30.7	30.2	29.3
KEWAUNEE	KEW 138kV	138	1066E	38.9	13287	24273	24401	24663	82.7%	83.6%	85.6%	60.5	29	28.6	27.7
KEWAUNEE	KEW 138kV	138	1066W	38.9	13287	24273	24401	24663	82.7%	83.6%	85.6%	60.5	29	28.6	27.7
KEWAUNEE	KEW 138kV	138	22	40	13287	24273	24401	24663	82.7%	83.6%	85.6%	61.6	31	30.6	29.7
KEWAUNEE	KEWAUNEE B1	345	R-304	38	17279	18252	18628	19268	5.6%	7.8%	11.5%	40.7	40.7	39.5	37.5
KEWAUNEE	KEWAUNEE B1	345	3450	40	12752	14206	14514	15053	11.4%	13.8%	18.0%	64	57.9	57	55.5
KEWAUNEE	KEWAUNEE B1	345	3451	40	17279	18252	18628	19268	5.6%	7.8%	11.5%	43.7	43.7	42.6	40.7
KEWAUNEE	KEWAUNEE B2	345	Q-303	40	11572	12085	12382	12890	4.4%	7.0%	11.4%	68.9	68.3	67.6	66.4
KEWAUNEE	KEWAUNEE B2	345	1099	40	18557	20389	20705	21323	9.9%	11.6%	14.9%	40.1	37.5	36.4	34.6
S FONDULAC	S FONDULAC	138	382-S	40	26259	26263	26825	27141	0.0%	2.2%	3.4%	17.5	17.5	15.8	14.9
S FONDULAC	S FONDULAC	138	314-S	40	25856	25861	26552	27220	0.0%	2.7%	5.3%	19.3	19.3	17.2	15.4
S FONDULAC	S FONDULAC	138	336-S	40	26222	26227	26880	27375	0.0%	2.5%	4.4%	17.6	17.6	15.6	14.3
S FONDULAC	S FONDULAC	138	394-S	40	27573	27578	28262	28909	0.0%	2.5%	4.8%	13.9	13.9	11.9	10.1
S FONDULAC	S FONDULAC	138	1772-S	40	27573	27578	28262	28909	0.0%	2.5%	4.8%	13.9	13.9	11.9	10.1
S FONDULAC	S FONDULAC	138	1979-S	40	27573	27578	28262	28909	0.0%	2.5%	4.8%	13.9	13.9	11.9	10.1
S FONDULAC	S FONDULAC	138	1899-S	40	27573	27578	28262	28909	0.0%	2.5%	4.8%	13.9	13.9	11.9	10.1
S FONDULAC	S FONDULAC	138	320-S	40	27573	27578	28262	28909	0.0%	2.5%	4.8%	13.9	13.9	11.9	10.1
S FONDULAC	SFL 345	345	92-S	37.5	12163	12169	13221	13376	0.0%	8.7%	10.0%	57.7	57.6	54.5	54
S FONDULAC	SFL 345	345	52-S	40	12163	12169	13221	13376	0.0%	8.7%	10.0%	60.3	60.3	57.3	56.9
S FONDULAC	SFL 345	345	74-S	40	12163	12169	13221	13376	0.0%	8.7%	10.0%	60.3	60.3	57.3	56.9
S FONDULAC	SFL 345	345	86-S	40	12163	12169	13221	13376	0.0%	8.7%	10.0%	60.3	60.3	57.3	56.9

Appendix E: Deliverability Analysis Results

Table E.1 – Deliverability Analysis Restrictions

Limiting Element	Contingency	G833/4-J022/3 MW Deliverable	Potential Solution
None identified.		118 MW (100%)	

For a full description of the Midwest ISO Generator deliverability process, follow the "Deliverability Study Whitepaper" link that can be found at:
http://www.midwestmarket.org/publish/Document/3e2d0_106c60936d4_-767f0a48324a?rev=4

(Navigate to: www.midwestmarket.org > Planning > Generator Interconnection > Generator Deliverability Tests)

Appendix F: Study Criteria

Study Criteria

F.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 six categories of contingency conditions:

1. Three-phase fault cleared in primary time with an otherwise intact system.
2. Three-phase fault cleared in delayed clearing time (i.e. breaker failure conditions) with an otherwise intact system.
3. Three-phase fault cleared in primary clearing time with a pre-existing outage of any other transmission element.
4. Single Line Ground (SLG) bus section fault cleared in primary clearing time with an otherwise intact system.
5. SLG internal breaker fault cleared in primary clearing time with an otherwise intact system.
6. SLG fault of double circuits on common tower cleared in primary time with an otherwise intact system.

For power flow analysis, contingencies include:

1. N-1 contingencies – all lines and transformers operated at 69kV and above in the following control areas/zones: ATC Planning Zones 1-5 and ties to those zones and all branches of voltage level 69kV and above in the Dairyland Power Cooperative, Northern States Power Control Area, Commonwealth Edison, and Alliant Energy West control areas.
2. Selected N-2 and multiple contingencies that ATCLLC has determined to be significant.

F.2 Monitored Elements

F.2.1 Intact System, N-1, N-2 and Special Multiple Contingency Evaluation Using Linear Transfer Analysis Methods

All load carrying elements operated at 69kV and above in the following control areas/zones were studied: ATCLLC Planning Zones 1-5 and ties to those zones, and all branches of voltage level 69kV and above in the Dairyland Power Cooperative, Northern States Power Control Area, Commonwealth Edison, and Alliant Energy West control areas.

A Transmission Reliability Margin (TRM) of 5% must be applied to the MVA ratings of each monitored ATCLLC element. Violations reported will be based upon the adjusted MVA rating.

F.3 Thermal Loading Criteria

F.3.1 Injection Violations

Generation injection violations include: 1) thermal violations of the transmission elements that connect the Generator to the rest of the transmission network (outlet congestion); 2) thermal violations of the transmission elements that have a transfer distribution factor (TDF) ≥ 5% for NERC Category A (system intact) conditions and TDF ≥ 20% for NERC Category B contingencies anywhere in the studied system in relation to real power injected at the Point of Interconnection (POI) when delivered to all of MISO; or 3) thermal violations created by the loss of a transmission element connected to the generator interconnection substation.

F.3.2 Operating Restriction Calculation

$$\text{Allowable Output} = \frac{\text{Equipment Rating} - [\text{Line Flow} - (\text{Generation Output} * \text{TDF})]}{\text{TDF}}$$

F.4 Steady State Under Voltage Criteria

F.4.1 Intact System, N-1 and Special Multiple Contingency Evaluation Using ACCC

Under intact system conditions, the voltage magnitude of all transmission system buses with a decrease of 0.01 per unit due to the Generator must not be lower than 0.95 per unit. Under contingency conditions, the voltage magnitude of all transmission system buses with a decrease of 0.01 per unit, due to the Generator, must not be lower than 0.90 per unit.

F.4.2 N-2 Contingency Evaluation

Power flow solutions must converge for a selected number of N-2 contingencies in the electrical proximity of the studied Generator. Divergence of a power flow solution indicates potential voltage collapse. A "fix" must be identified for any non-converging power flow simulation and may include generator operating restrictions. [Note: Non-convergence may be due to solution settings such as switched shunt operation and/or LTC action.]

F.5 Angular Stability Criteria

Critical Clearing Time (CCT) is a period relative to the start of a fault, within which all generators in the system remain stable (synchronized). CCT is obtained from simulation. Maximum Expected Clearing Time (MECT) determines a period of time that is needed to clear a fault using the existing system facilities. MECT is dictated by the existing system facilities. In any contingency, if the computed CCT is less than the MECT plus a margin determined by ATC (1.0 cycle for studies using estimated generator data and 0.5 cycles for studies using confirmed generator data), it is considered an unstable situation and is unacceptable. Otherwise, it is considered acceptable transient stability performance.

Longer time-domain simulations must be performed on faults cleared at the CCT to examine dynamic stability. Simulations will typically cover 20 seconds of system dynamics and machine angle oscillations must meet the damping criteria in the ATC Planning Criteria.

Note that ATC stability criteria and NERC stability criteria differ on the study assumptions used for breaker failure analysis. ATC study criterion models breaker failure by modeling a three-phase fault during the primary time, reduced to SLG fault if the failed breaker is an Independent Pole Operated (IPO) breaker during delayed clearing and cleared at the end of the delayed clearing time. On the other hand, NERC study criterion assumes a single line-to-ground fault for the entire breaker failure analysis. Hence, the CCT computed from ATC stability criteria is always less than or equal to the value computed using the NERC study criteria. This report assumes ATC stability criteria unless otherwise stated.

The time-domain simulations must also be reviewed for compliance with the transient and dynamic voltage standards in the ATC Planning Criteria. Voltages of all transmission system buses must recover to be at least 70% of the nominal system voltages immediately after fault removal and 80% of the nominal system voltages in 2.0 second after fault removal.

Appendix G: Typical Planning Level Cost Estimates

Typical Transmission Line and Substation Capital Costs – March 16, 2006

It should be noted that the costs listed are merely representative for projects within each category. Actual project costs can vary, in some cases dramatically, based on the scope, location and particular design of the project. Capital costs include material, labor, licensing, design, land acquisition, environmental mitigation fees if applicable and project close-out. While some projects require additional costs of generator redispatch during construction outages, such costs are very project specific and have not been included in the estimates below.

Cost estimates for 345kV, 138kV, 115kV, 69kV T-Lines and Substations:

- New transmission line cost estimates include new structures, foundations, insulators, hardware, conductor, and easements shown in dollars per mile. No distribution underbuild costs are included.

- Rebuilt transmission line cost estimates include 100% new structures, foundations, insulators, hardware, and conductor on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Reconductor transmission line cost estimates include 10 ~ 30% new structures & foundations, 100% new conductor, insulators, and hardware on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Uprate 69kV to 69kV or 138kV to 138kV transmission line cost estimates include 25% new structures, foundations to increase clearances, reuse existing conductor, insulators, and hardware on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Uprate 69kV to 138kV transmission line cost estimates include 25% new structures, foundations to increase clearances, 100% new insulators, and hardware, and reuse existing conductor on existing ROW/easements shown in dollars per mile. No distribution underbuild costs are included.

- Routing an existing transmission line into a new substation typically requires two terminals, particularly at 100 kV and above.

- New substation cost estimate includes purchase and prepare site, control house, switches, bus, structures, breakers, and protection shown in dollars per terminals, transformers, and breakers at each voltage.

- Installing a new transformer in a substation requires two terminals, one at the higher voltage and one at the lower voltage. Thus, a new 345-138 kV substation that incorporates an existing 345 kV line and two 138 kV transmission lines, all of which exist near the new substation site, would require three 345 kV terminals and five 138 kV terminals. Two spare terminals that include disconnect switches and bus, but no breaker, for each voltage, should be provided for future growth.

- Transformer costs are shown for typical transformer sizes in each class, 500 MVA, 345/138 kV, and 345/115 kV; 100 MVA, 138/69 kV and 115/69 kV.

Typical Transmission Line and Substation Project Capital Costs

TRANSMISSION FACILITY TYPICAL CAPITAL COST UNIT IN 2006 $	
New 345 kV single circuit line rural ~ urban	$1,600,000 ~ $2,200,000/Mile
New 345 kV double circuit line rural ~ urban	$3,000,000 ~ $3,600,000/Mile
New 345 kV HPFF single circuit UG line (w/o terminals)	$10,000,000/Mile
New 345 kV HPFF UG line 2 terminals with shunt reactors	$8,900,000
New 345 kV HPFF UG line 2 terminals without shunt reactors	$4,300,000
New 138 kV single circuit line rural ~ urban	$630,000 ~ $800,000/Mile
New 138 kV double circuit line rural ~ urban	$900,000 ~ $1,100,000/Mile
New 138 kV XLPE 1,200A single circuit UG line (w/ terminals)	$3,500,000/Mile
New 138 kV HPFF 1,200A single circuit UG line (w/ terminals)	$3,500,000/Mile
New 69 kV single circuit line rural ~ urban	$450,000 ~ $585,000/Mile
New 69 kV double circuit line rural ~ urban	$650,000 ~ $770,000/Mile
New 69 kV XLPE 550A single circuit UG line (w/ terminals)	$2,500,000/Mile
New 69 kV HPFF single circuit underground line (w/ terminals)	$2,800,000/Mile
Rebuild 138 kV to 138 kV single circuit	$530,000 ~ $700,000/Mile
Rebuild 138 kV to 138 kV double circuit	$800,000 ~ $1,000,000 /Mile
Rebuild 69 kV to 138 kV, single circuit	$530,000 ~ $670,000/Mile
Rebuild 69 kV to 69 kV, single circuit	$280,000 ~ $330,000/Mile
Reconductor 138 kV or 115 kV line, single circuit	$210,000/Mile
Reconductor 69 kV line, single circuit	$117,000/Mile
Uprate 138 kV to 138 kV single circuit	$125,000 ~ $200,000/Mile
Uprate 69 kV to 138 kV single circuit	$350,000 ~ $375,000/Mile
Uprate 69 kV to 69 kV single circuit	$125,000 ~ $150,000/Mile
345 kV substation terminal[1]	$550,000 each
345kV gas circuit breaker[2]	$754,000 each
138 kV or 115 kV substation terminal[1]	$450,000 each
138kV gas circuit breaker[2]	$390,000 each
69 kV substation terminal[1]	$375,000 each
69kV gas circuit breaker[2]	$310,000 each
345/138 kV transformer[4] (transformer only $2,700,000[3])	$5,000,000 each
138/69 kV transformer[6] (transformer only $1,405,000[5])	$2,500,000 each

Notes:
All substation costs are in year 2006 dollars.
[1] includes dead end structure, line switch and line terminal relays
[2] includes breaker, two maintenance switches, breaker failure relay, controls
[3] 300/400/500 MVA unit includes high and low side switches and transf. relays
[4] includes transformer[3], 2-345kV GCBs[2] and 2-138kV GCBs[2]
[5] 100 MVA unit, includes high side and low side switches and transf. relays
[6] includes transformer[5], 2-138kV GCBs[2], and 1-69kV GCB[2]

Appendix H: Alternatives Considered

The transmission system near Point Beach has five large generating stations (Point Beach, Kewaunee, Fox River, Sheboygan Energy Center, and Cypress) with a total generating capability of approximately 3000 MW and only four 345 kV lines connecting this generation to the rest of the system. Three additional wind generation projects with a total rated generation of approximately 350 MW and queue positions below G833/4-J022/3 (G590, G611, and G773) are located on the Fox Valley 138 kV system near Forest Junction. These three projects were not modeled in the G833-4 study stability analysis because of their location on the 138 kV system, but they were modeled in the study's thermal analysis. This combination of high generation and relatively few transmission outlets produces stability issues with the existing system strength and fault clearing times, in particular at Kewaunee and North Appleton which have slower breakers and longer clearing times than other area busses.

As documented in the G833/4-J022/3 Interim Operation Re-study Report, the possible unit restrictions and/or interim system upgrades are identified and planned to accommodate the G833/4-J022/3 during the interim periods. After implementation of the upgrades needed for "interim" operation, there are several issues that must be addressed to ensure that the Point Beach generation increase is reliable beyond temporary operation. The issues are:

(1) Generator instability due to the isolation of Point Beach Generator 1 on L111 (Point Beach-Sheboygan) which occurs when Point Beach 345 kV breaker 2-3 is out of service and L121 (Point Beach-Forest Junction 345 kV) trips,
(2) Generator instability due to the outage of 6832 (Fox River-North Appleton) followed by a fault on R-304 (Kewaunee-North Appleton),
(3) Most significantly, limitations on Point Beach and Kewaunee generating unit reactive power output at all hours. Generator instability was identified for fault conditions when Point Beach and Kewaunee units produce relatively small reactive power output (over-excitation) or absorbs reactive power from transmission system (under-excitation). Reactive power output from a synchronous machine has an impact on the transient stability of the unit. Typically, the lower the excitation on a generating unit, the unit tends to be less stable under a fault condition. The results of the interim operation study indicate that a certain level of reactive power output (over-excitation) needs to be maintained to ensure generation stability in anticipation of critical fault conditions. The units may not be allowed to reduce their MVAR outputs, reducing their effectiveness in controlling system voltage

As described in the Interim Operation Re-study Report, for temporary operation, Issue (1) and (2) should be mitigated by reducing generation at Point Beach to 580 MW (G1 gross) and 600 MW (G2 gross) respectively, and Issue (3) should be mitigated by maintaining MVAR output from Point Beach and Kewaunee to a certain level through the use of Minimum Excitation Limiter settings. Issue (1) may be addressed by a long term solution such as reconfiguring the existing Point Beach substation such that Point Beach Unit #1 cannot be isolated on 345-kV line L111. However, a more robust long term solution such as a new 345 kV line and/or substation will be needed to address Issue (2) and Issue (3). Issues (2) and (3) can not be solved by reconfiguring Point Beach such as ring bus configuration because the issues are primarily due to the limited number of 345-kV outlets out of Fox Valley area for the amount of generation located in this area.

As shown in Appendix H.1, various options are being studied to identify a Network Upgrade that:

- Addresses the generation instability issues under prior outage conditions,
- Provides a wider operating envelope for the local transmission system and the interconnected generators by permitting generating unit operation at unity or under-excited conditions
- Provides better maintenance and operations flexibility during planned or unplanned transmission outage conditions by tying together critical transmission elements in strategic locations and, possibly, providing an additional transmission outlet, and
- Relieves loadings under intact and contingency conditions on the existing 138 kV and 345 kV lines running from Fox Valley area to the south by providing an additional transmission outlet.

Appendix H.1 presents a description of the various options considered as well as geographic representations of the various options.

To screen and select options for further consideration, the dynamic stability study was performed. The Power System Stabilizer (PSS) models supplied by the customer for both units #1 and #2 were assumed in-service. Scenarios with each solution option were built from the high and low generation cases used for the dynamic stability study for the Interim Operation Re-study. The high generation scenario consists of all generation on-line in the Point Beach area, which primarily stresses the system for prior transmission outage conditions due to the limited number of 345-kV outlets from this area. The low generation scenario is similar to the high generation scenario except the Fox Energy and Sheboygan Energy gas-fired power plants are off-line, which primarily stresses the system for breaker failure conditions due to the lower system inertia.

As shown in Appendix H.1 and Appendix H.2, thirteen different options were evaluated for transient stability performance by applying the critical faults identified in the Interim Operation Re-study listed under the period with completion of the G833/4 and J022/3 requests and completion of the Kewaunee bus reconfiguration project. The critical faults are:

- Fault on L111 (Point Beach-Sheboygan Energy Center) at Point Beach with breaker failure
- Fault on L151 (Point Beach-Fox River) at Point Beach with breaker failure
- Fault on Q-303 (Point Beach-Kewaunee) at Point Beach with breaker failure. The Q-303 breaker failure may be able to be disregarded if a breaker is added in series with the existing Q-303 breaker at Point Beach as described in the interim operation study report.
- Fault on R-304 (Kewaunee-North Appleton) at Kewaunee with breaker failure
- Fault on R-304 (Kewaunee-North Appleton) at Kewaunee with prior outage of 6832 (North Appleton-Fox River)
- Fault on L121 (Point Beach-Forest Junction) at Point Beach with prior outage of Point Beach 345 kV bus tie 2-3

Two types of stability analyses were performed to screen and measure the robustness of each option. As shown in Section H.2.1 of Appendix H.2, the maximum critical clearing time was identified under the critical faults for each option. For this specific study, Point Beach and Kewaunee 345 kV voltage schedule was set to 352 kV to maintain Point Beach 345-kV bus voltage at the low end of the preferred voltage range and set MVAR output from Kewaunee and Point Beach to typical historical levels. The maximum critical clearing time is the slowest fault clearing time for which no units will lose synchronism. Thus, the longer clearing time for an option represents a more robust system solution.

The second type of analysis is shown in Section H.2.2 of Appendix H.2. This analysis examined the minimum allowable MVAR output from the Point Beach and Kewaunee units while maintaining synchronism for the critical faults by varying the voltage schedule of these generators. This analysis should not be interpreted as permitting or requiring a change in voltage schedule to the values noted in the table. Rather, varying the voltage schedule is simply a method for varying the excitation on the unit. This analysis identifies the options that allow generating unit operation at unity or leading (i.e. under-excited) power factor, or at least provide a foundation to achieve the wider operating envelop through additional transmission reinforcement in the area that may be needed in the future.

Among the thirteen options studied, four options were identified as alternatives due to their dynamic stability performance. These options are described more fully in Section H.3.1 of Appendix H.3 and are summarized as:

1. Fix 2 (new "East" 345 kV switching station),
2. Fix 5 (new "East" and new "North" 345 kV switching stations with a new 345 kV line, ~32 miles),
3. Fix 11 (new "East" 345/138 kV substation and new "North" 345 kV switching substation with conversion of existing 138 kV line to 345 kV, ~48 miles) and
4. Fix 13 (new "East" 345 kV switching station and approximately 41 miles of new double circuit 345/138 kV lines from Forest Junction to the "East" substation).

These options were selected because they address stability issues adequately, provide a wider operating range (except Fix 2) of MVAR output from Point Beach and Kewaunee, unload parallel facilities and provide an alternate route since the Certificate of Public Convenience and Necessity (CPCN) process at the Public Service Commission of Wisconsin (PSCW) requires both route and system alternatives. Based on the further analysis, Fix 11 is selected as the proposed solution because it:

- Achieves the widest operating envelop for the local transmission system and the interconnected generators by permitting generating unit operation to unity or under-excited conditions.
- Addresses the transient stability issues with certain level of MVAR output maintained from Point Beach and Kewaunee.
- Achieves better maintenance and operations flexibility during planned or unplanned transmission outage conditions by tying together critical transmission elements in strategic locations and providing an additional transmission outlet.
- Unloads the existing 138 kV and 345 kV lines running from Fox Valley area to the south under intact and contingency conditions by providing an additional transmission outlet. As a benefit, the proposed solution (Fix 11) would also help Wisconsin to accommodate potential future wind development in the area.
- Fix 2 is a common facility required for Fix 5, Fix 11 and Fix 13. However, Fix 2 does not immediately allow wider MVAR operating range unless additional transmission reinforcement shown in Fix 5, 11 and 13 are combined and implemented with Fix 2.

- Although Fix 5 and Fix 13 immediately allow wider MVAR operating range, they are not better than Fix 11 (see Appendix H.3).
- Fix 11 (roughly $129 million) would require relatively less construction cost than Fix 5 (roughly $182.3 million) and Fix 13 (roughly $219.3 million). As noted in Table 1.2, the cost of Fix 11 may increase depending on the condition of the existing double circuit 345/138 kV structures (L111, portion of L-SEC31, 971K51 and portion of HOLG21). More detailed analysis will be performed during the Facilities Study to determine the condition of the existing structures.
- Compared to Fix 11, significant challenge is expected for Fix 5 and Fix 13 primarily due to relatively extensive new right-of-way for new 345 kV and (or) 138 kV lines.

Options rejected from further consideration are

- Fix 1 (new West 345 kV switching station): it does not address the stability issue under prior outage of Point Beach bus tie 2-3. Generally, it does not provide better stability performance than Fix 2 (new East 345 kV switching station).
- Fix 1 plus Fix 2 (new West and East 345 kV switching stations): constructing East and West 345 kV switching stations together does not significantly improve stability response.
- Fix 3 (new West 345 kV switching station and a new 345 kV line from Forest Junction to West): This option also requires new 345 kV line (~42 miles) from Forest Junction to new West switching station. It does not address the stability issue under prior outage of Point Beach bus tie 2-3. In addition, this does not provide any significant improvement than new East 345 kV switching station.
- Fix 6 (a new second 345 kV line from North Appleton to Fox River): This option requires constructing a new second 345 kV line (~9.8 miles) from North Appleton to Fox River. It does not address the stability issue under prior outage of Point Beach bus tie 2-3. It provides better stability response only under prior outage of 6832.
- Fix 7 (new East 345 kV substation and new North 345 kV switching station and conversion of 971K51 and portion of existing 138 kV line HOLG21 to 345 kV): This option requires converting approximately 48 miles of existing 138 kV line to 345 kV in addition to building a new East and North 345 kV stations. It also requires constructing new 138 kV lines (~ 16 miles) to continue serving the existing 138 kV substations and installing a new 345/138 kV transformer at new East Switching Station. This option provides significant improvement in stability response. However, it is not selected for further analysis since this option does not provide better stability performance than Fix 11 (Fix 7 plus 345 kV line L121, which is a Point Beach outlet, looped into North switching station) for a fault on L111 with breaker failure at Point Beach.
- Fix 8 (Fix 5 plus 345/138 kV transformer at North Substation, loop 971K51 into the North 138 kV substation): In general, this option does not provide significantly better stability response than Fix 5 (new North and East 345 kV line, ~32 miles) which is selected for further analysis. It appears that installing a new 345/138 kV transformer at North substation and looping the existing line 971K51 does not provide significant benefit from a stability perspective.
- Fix 9 (Fix 8 plus converting Forest Junction-North 138 kV line to 345 kV): In addition to implementing Fix 8, this option also requires converting Forest Junction-North 138 kV

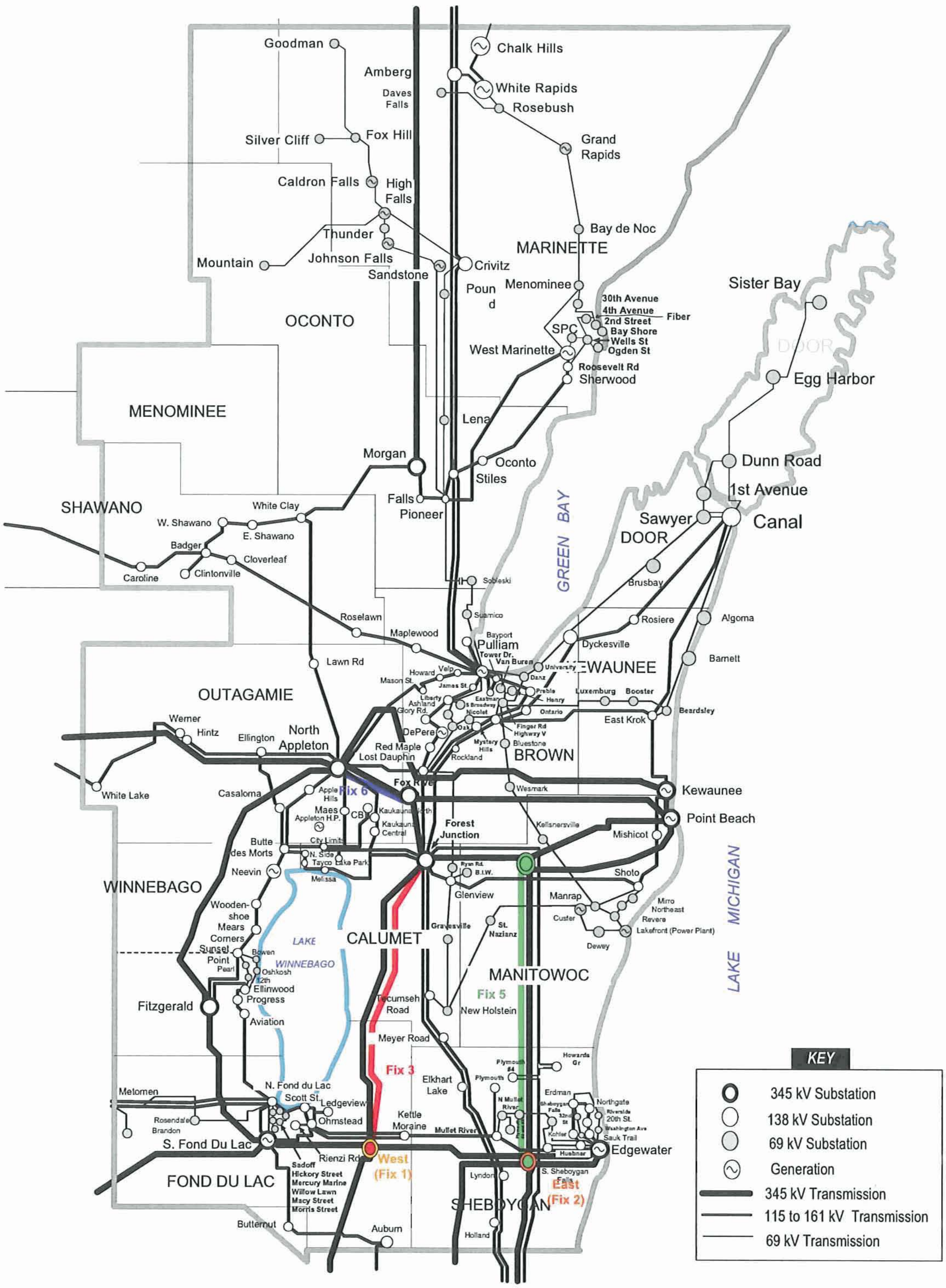
line (~16 miles) to 345 kV. For similar reason described for Fix 8, it is not selected for further analysis.

- Fix 10 (new North switching station): This option requires constructing only the North 345 kV switching station. It does not address the stability issue under prior outage of 6832. In general, it does not perform better than Fix 2 from a stability perspective.
- Fix 14 (Fix 7 without looping 796L41 (Edgewater-Cedarsauk 345kV) into new East Switching Station): This option was tested to understand the impact of looping 796L41 into the new East Switching Station. No significant stability impact was identified due to 796L41 looped into the new East Switching Station. However, looping 796L41 into new East Switching Station is preferred primarily because it will reduce the exposure to the outage of the existing Edgewater-Cedarsauk 345 kV line (~33.29 miles).

Appendix H.1.

Options Studied
(Option Description and Geographical Maps)

Options	Descriptions
Fix 1	New West 345 kV Switching Station. Loop existing W-1 and CPY31 into the switching station
Fix 2	New East 345 kV Switching Station. Loop existing W-1, L-SEC31 and 796L41 into the switching station
Fix 1+ Fix 2	New West (Fix 1) and East (Fix 2) 345 kV Switching Stations with 345 kV lines looped into the switching stations
Fix 3	New West 345 kV Switching Station and Loop existing W-1 and CPY31 into the switching station (Fix 1), Build a new Forest Jct-West 345 kV line
Fix 5	New East 345 kV Switching Station and Loop existing W-1, L-SEC31 and 796L41 into the switching station (Fix 2), New North 345 kV Switching Station, Loop L111 and L121 into the North switching station, Build a new North-East 345 kV line
Fix 6	Build a new second Fox River-N Appleton 345 kV line
Fix 7	New East 345/138 kV substation and Loop existing W-1, L-SEC31 and 796L41 into the substation (Fix 2), Convert existing 971K51 and portion of HOLG21 to 345kV, Modified North 345 kV Switching Station (Loop L111 and converted 971K51 into the station), New 345/138 kV transformer at East substation, New East-Plymouth #4-Howards Grove-Erdman 138 kV line, Loop Mullet River-South Sheboygan Falls 138 kV line into the East 138 kV substation, Terminate the remaining 138 kV line to Holland at the new East substation
Fix 8	New East 345 kV Switching Station and Loop existing W-1, L-SEC31 and 796L41 into the switching station (Fix 2), New North 345/138 kV substation (Loop L111 and L121 into the station), New 345/138 kV transformer at North, Build a new North-East 345 kV line, Loop existing 971K51 (Forest Jct-Howards Gr) and L-90 (Glenview-Shoto) into the new North 138 kV substation
Fix 9	Fix 8 plus convert existing Forest Junction-North 138 kV line to 345 kV
Fix 10	New North 345 kV Switching Station only Loop L121 and L111 into the station
Fix 11	Fix 7 plus loop L121 into North substation
Fix 13	Center Line Conversion Option: New East 345 kV Switching Station and Loop existing W-1, L-SEC31 and 796L41 into the switching station (Fix 2), Rebuild/convert existing 138 kV lines 4035, 971K91, portion of 40561, portion of 8241 to double-circuit 345/138 kV, Construct a new Mullet River 138 substation near the existing Mullet River 138/69 kV substation Relocate all 138 kV facilities at the existing Mullet River 138/69 kV substation to the new Mullet River 138 kV substation, Terminate the southern portions of 8241 (Elkhart Lake-Saukville) and 40561 (Meyer Rd-Lyndon) into the new Mullet River substation to form Mullet River-Saukville and Mullet River-Lyndon Construct a new 138 kV line from Erdman to Howards Grove
Fix 14	Modified Fix 7: 796L41 (Edgewater-Cedarsauk 345kV) is not looped in the new East substation



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Wooden-shoe
Mears Corners
Sunset Point
Custer
Lakefront (Power Plant)
LAKE WINNEBAGO
CALUMET
Dewey
LAKE MICHIGAN
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Progress
Fitzgerald
Tecumseh Road
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345 kV Substation
138 kV Substation
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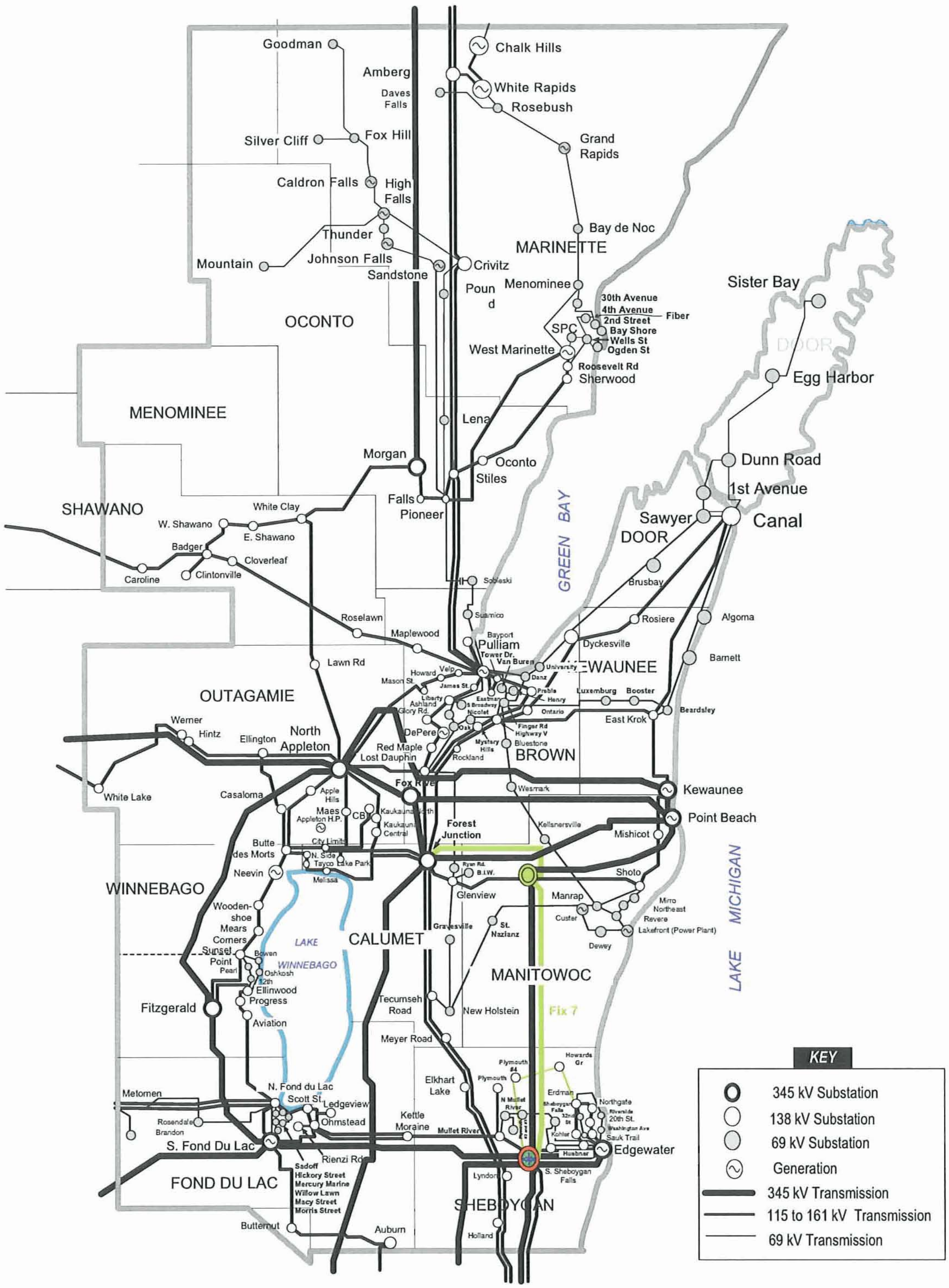
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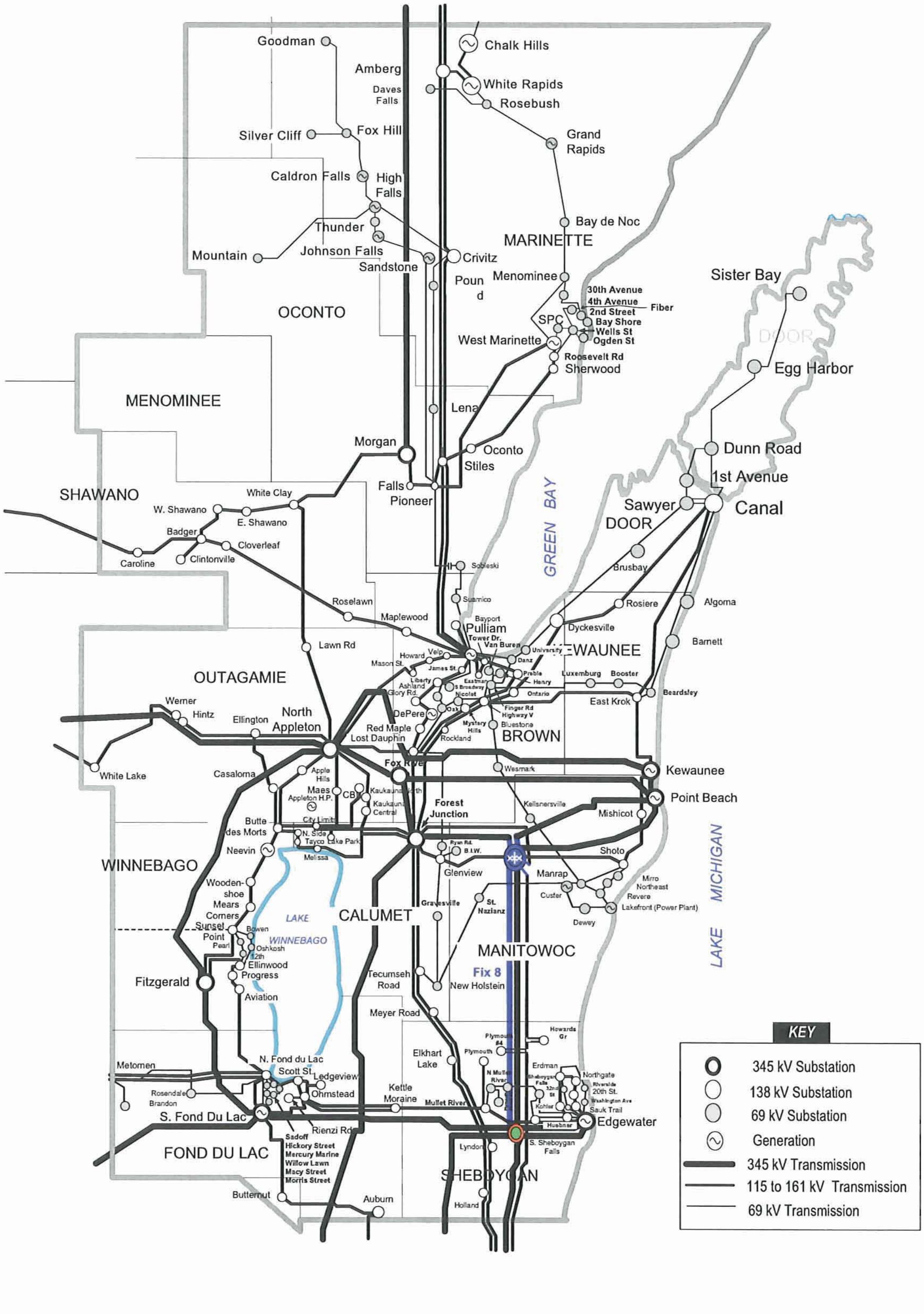
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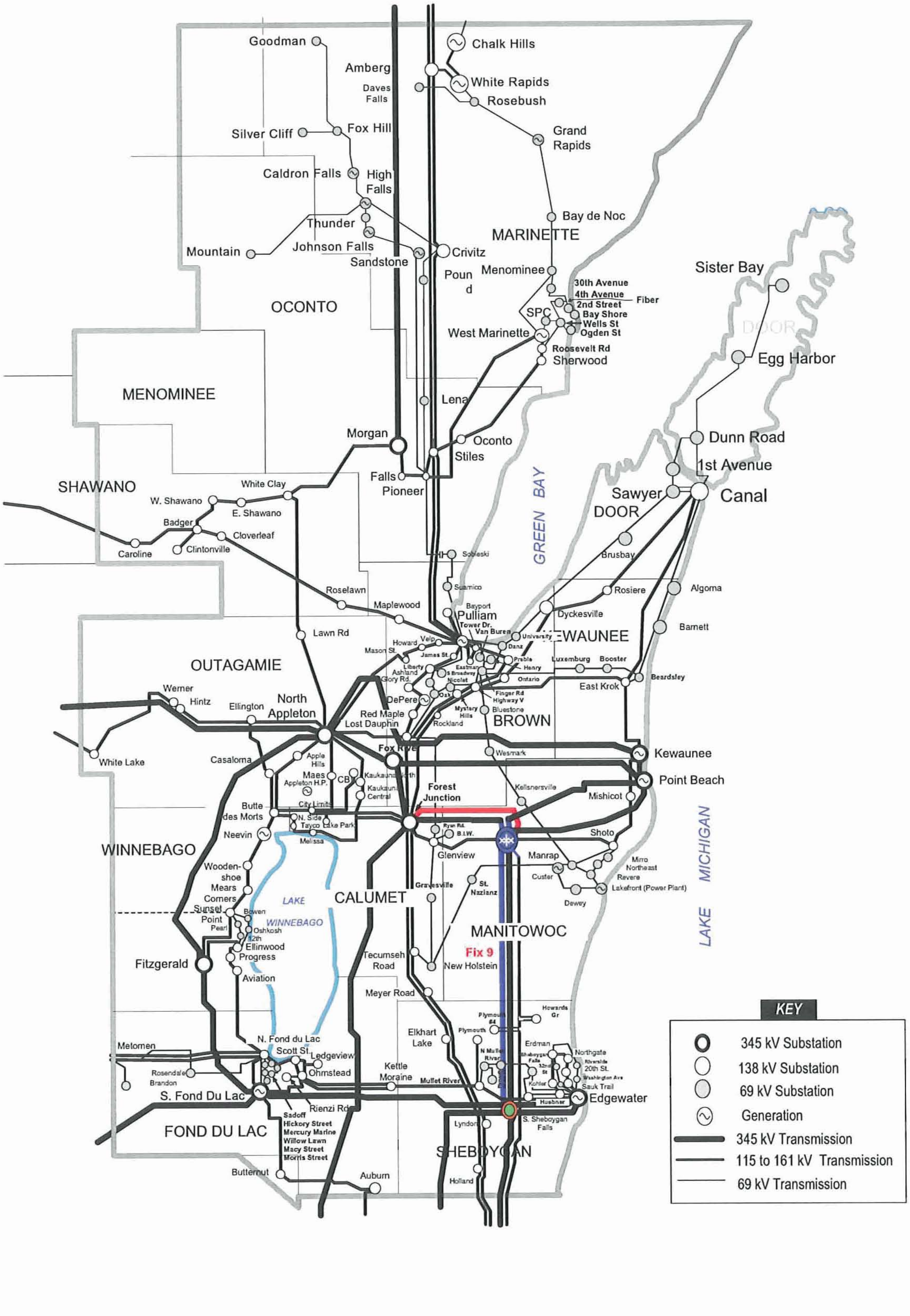

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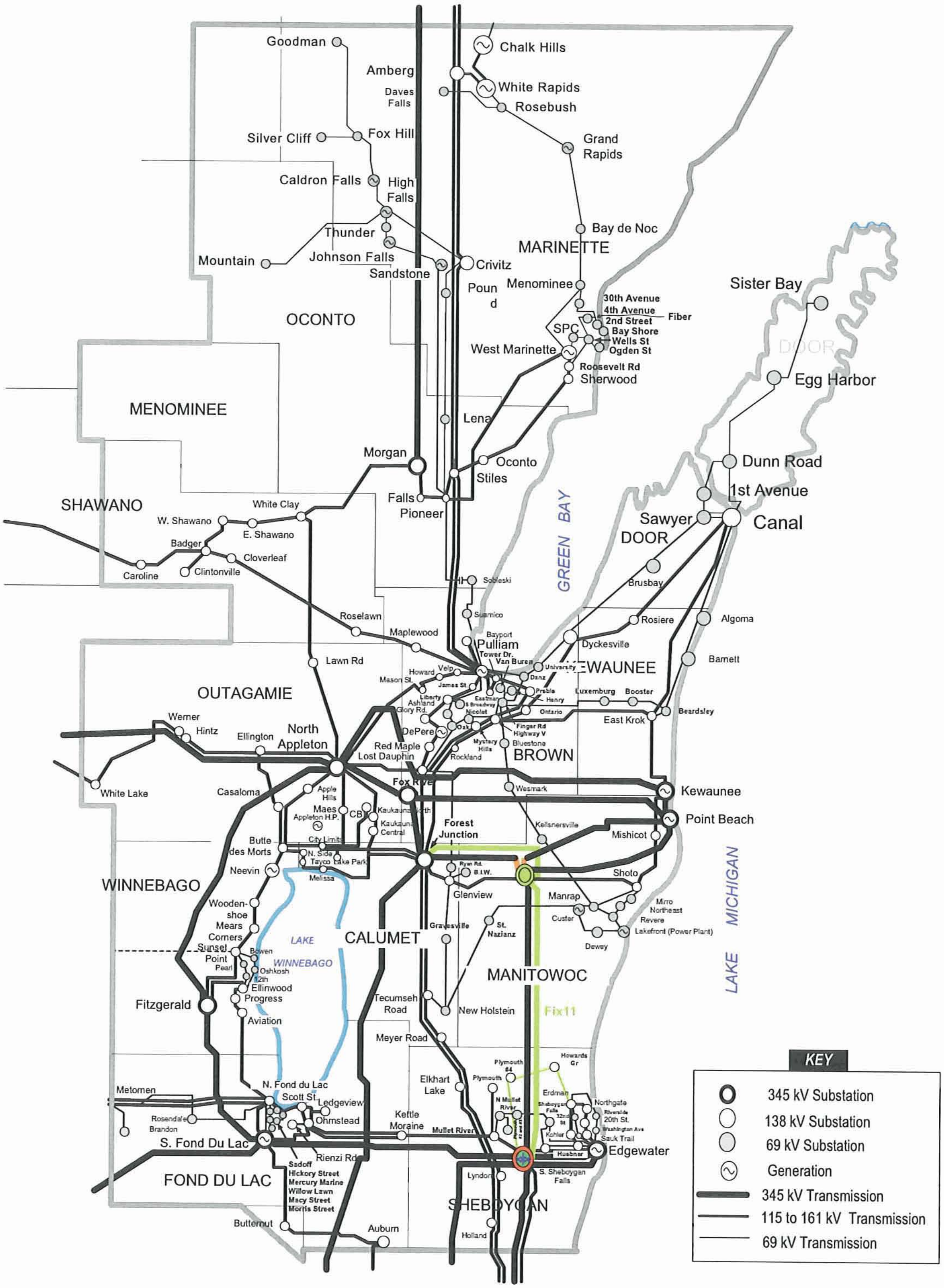
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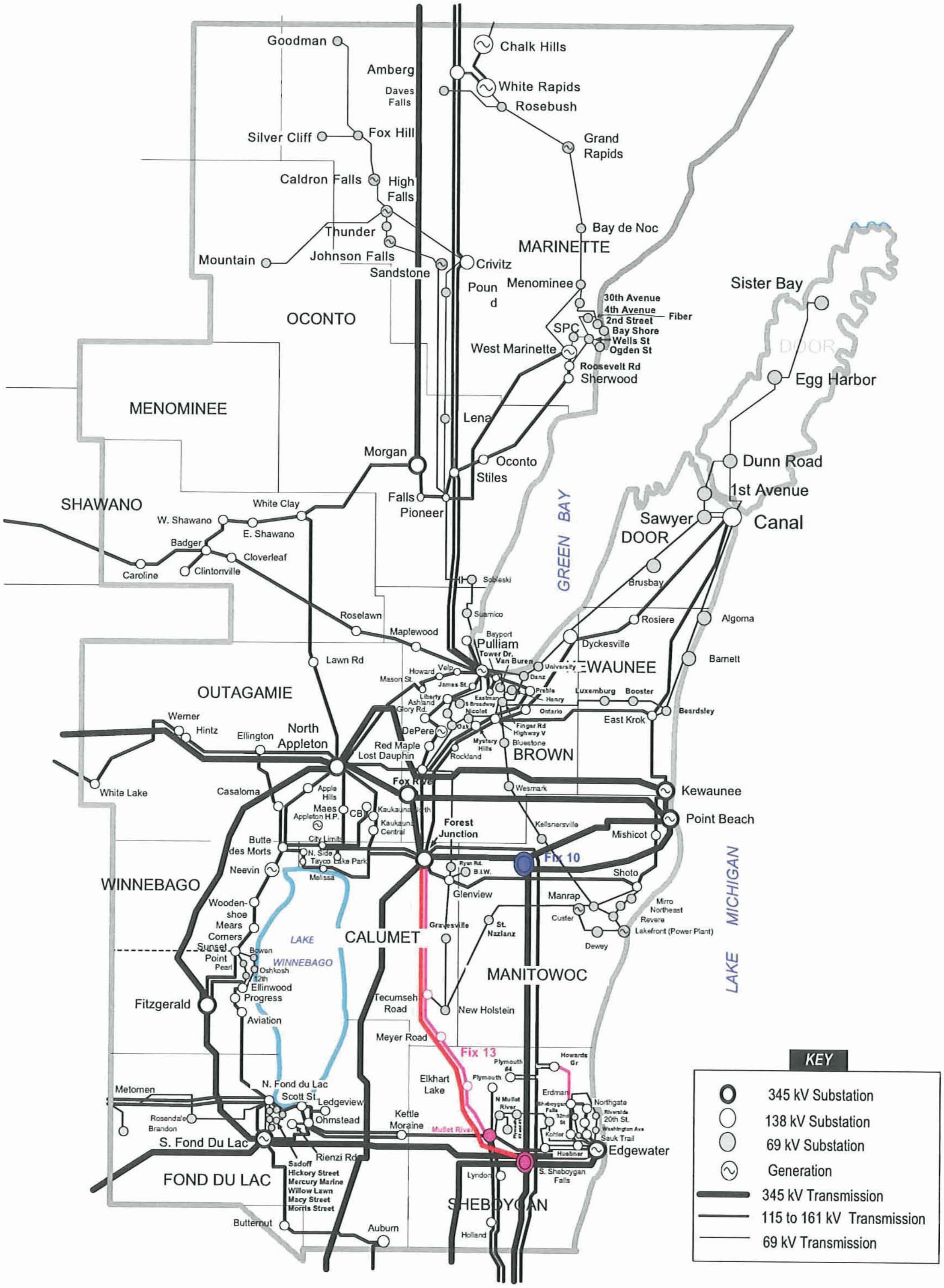
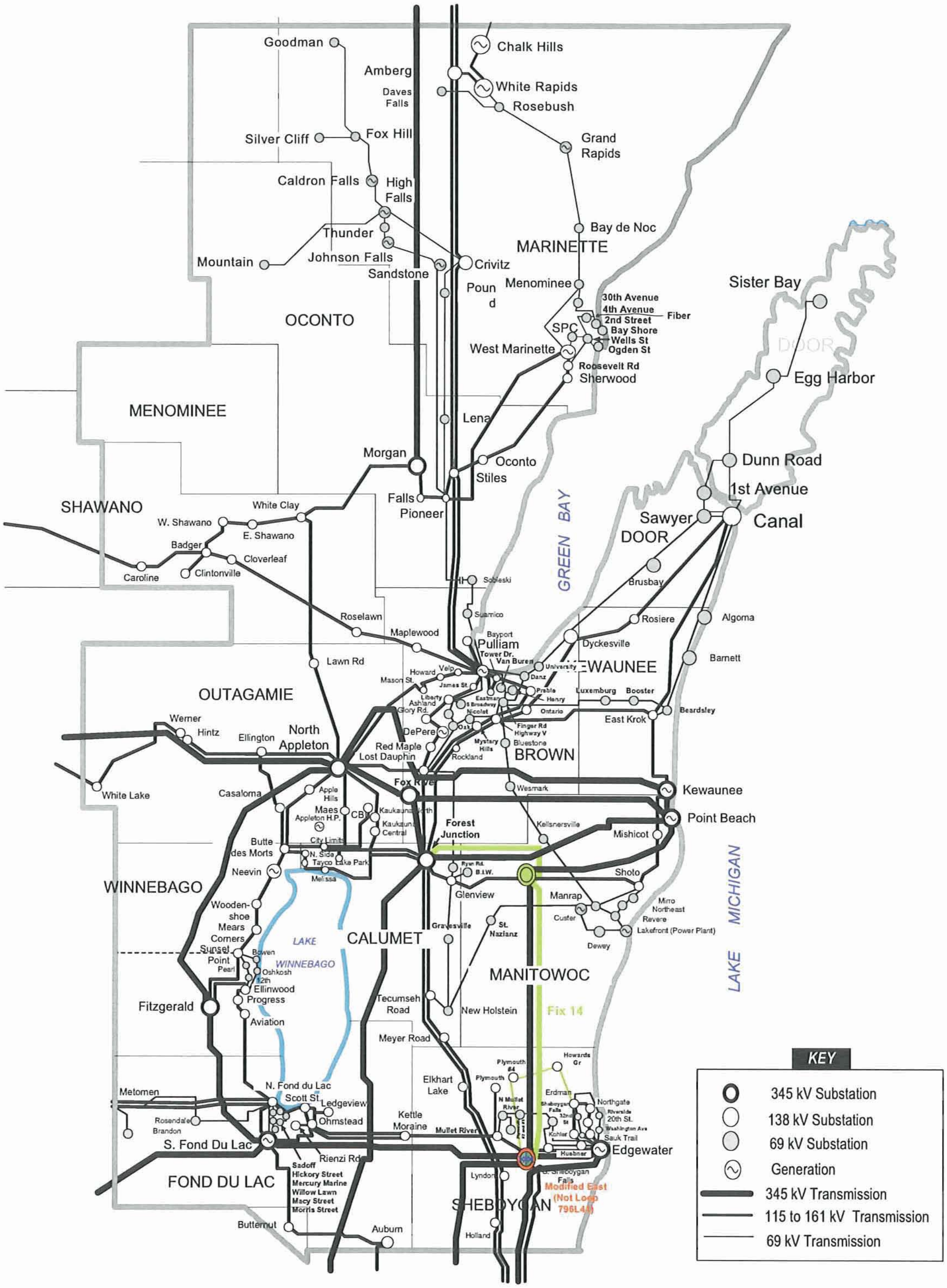
BROWN
White Lake
Casaloma
Apple Hills
Fox River
Wesmark
Kewaunee
Maes
Appleton H.P.
CB
Kaukauna North
Kaukauna Central
Forest Junction
Kellnersville
Point Beach
Butte des Morts
City Limits
N. Side
Tayco
Lake Park
Mishicot
Neevin
Melissa
Ryan Rd.
B.I.W.
Shoto
WINNEBAGO
Glenview
Manrap
Wooden-shoe
Mears Corners
Mirro
Northeast
Custer
Revere
LAKE MICHIGAN
Gravesville
St. Nazianz
Lakefront (Power Plant)
CALUMET
LAKE WINNEBAGO
Sunset Point
Bowen
Pearl
Oshkosh
Dewey
12th
MANITOWOC
Ellinwood
Progress
Fitzgerald
Tecumseh Road
New Holstein
Fix11
Aviation
Meyer Road
Howards Gr
Plymouth #4
Plymouth
Elkhart Lake
N. Fond du Lac
Metomen
Scott St.
Ledgeview
Erdman
Northgate
Riverside
20th St.
Washington Ave
Sauk Trail
Rosendale
Brandon
Ohmstead
Kettle Moraine
Mullet River
N Mullet River
Sheboygan Falls
32nd St
Kohler
S. Fond Du Lac
Rienzi Rd
Huebner
Edgewater
Sadoff
Hickory Street
Mercury Marine
Willow Lawn
Macy Street
Morris Street
FOND DU LAC
Lyndon
S. Sheboygan Falls
SHEBOYGAN
Butternut
Auburn
Holland
KEY
345 kV Substation
138 kV Substation
69 kV Substation
Generation
345 kV Transmission
115 to 161 kV Transmission
69 kV Transmission



MARINETTE
OCONTO
MENOMINEE
SHAWANO
OUTAGAMIE
WINNEBAGO
CALUMET
BROWN
DOOR
KEWAUNEE
MANITOWOC
FOND DU LAC
SHEBOYGAN
GREEN BAY
LAKE MICHIGAN
LAKE WINNEBAGO
Fix 10
Fix 13
KEY
345 kV Substation
138 kV Substation
69 kV Substation
Generation
345 kV Transmission
115 to 161 kV Transmission
69 kV Transmission


Goodman
Amberg
Daves Falls
Chalk Hills
White Rapids
Rosebush
Silver Cliff
Fox Hill
Grand Rapids
Caldron Falls
High Falls
Thunder
Johnson Falls
Mountain
Sandstone
Crivitz
Bay de Noc
MARINETTE
Menominee
30th Avenue
4th Avenue
Fiber
2nd Street
Bay Shore
Wells St
Ogden St
SPC
West Marinette
Roosevelt Rd
Sherwood
OCONTO
Sister Bay
DOOR
Egg Harbor
MENOMINEE
Lena
Morgan
Oconto
Stiles
Falls
Pioneer
Dunn Road
1st Avenue
Sawyer
Canal
DOOR
SHAWANO
White Clay
W. Shawano
E. Shawano
Badger
Cloverleaf
Caroline
Clintonville
GREEN BAY
Brusbay
Roselawn
Maplewood
Rosiere
Algoma
Pulliam
Dyckesville
Barnett
Lawn Rd
OUTAGAMIE
Luxemburg
Booster
Beardsley
East Krok
Werner
Hintz
Ellington
North Appleton
Red Maple
Lost Dauphin
Rockland
BROWN
White Lake
Casaloma
Fox River
Kewaunee
Point Beach
Forest Junction
Kellnersville
Mishicot
Butte des Morts
Neevin
Shoto
WINNEBAGO
Glenview
Manrap
CALUMET
LAKE WINNEBAGO
MANITOWOC
LAKE MICHIGAN
Fitzgerald
Tecumseh Road
New Holstein
Fix 14
Meyer Road
Elkhart Lake
Metomen
N. Fond du Lac
Scott St.
Ledgeview
Ohmstead
Kettle Moraine
Mullet River
S. Fond Du Lac
Rienzi Rd
Edgewater
FOND DU LAC
Sadoff
Hickory Street
Mercury Marine
Willow Lawn
Macy Street
Morris Street
Lyndon
Modified East (Not Loop 796L41)
SHEBOYGAN
Butternut
Auburn
Holland
KEY
345 kV Substation
138 kV Substation
69 kV Substation
Generation
345 kV Transmission
115 to 161 kV Transmission
69 kV Transmission

Appendix H.2.

Stability Study Results for Each Option

Section H.2.1: Performance of Each Option Based on Maximum Critical Clearing Time (Critical Events Studied by Increasing Clearing Times)

Section H.2.2: Performance of Each Option Based on Allowable Minimum MVAR Outputs from Point Beach and Kewaunee (Critical Events Studied at Certain Tested Clearing Times)

Nomenclature

K or KEW:	Kewaunee
P or POB:	Point Beach
FLT:	Fault cleared in primary time
BF:	Fault cleared in breaker failure time
PO:	Prior Outage
High Gen	High generation scenario
Low Gen	Low generation scenario

H.2.1: Performance of Each Option Based on Maximum Critical Clearing Time (Critical Events Studied by Increasing Clearing Times)

Estimated critical clearing time (With Kewaunee, With G833/4, at 352 kV Voltage Schedule at POB and KEW)
(For breaker failure, breaker clearing time at faulted end was increased. For primary fault, clearing time at faulted end was increased.)

Critical Events	Fix 1		Fix 2		Fix 1+2		Fix 3		Fix 5		Fix 6		Fix 7	
	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
BF L111 @ POB	10	9.5	9.25	trip at 9.25 (stable at 9.0)	10	9.5	10.5	9.5	12.5	11	9.5	9.25	11	9.5
BF L151 @ POB	11	9.5	11.5	10.5	12	10.5	11.5	10	12.5	11	10.5	9.5	12.5	11.0
BF Q-303 @ POB	10.5	9.5	10.5	9.5	10.5	9.5	10.5	9.5	11	10	10.5	9.5	11.0	10.0
BF R-304 @ KEW	12	10	12.5	11	13	11.5	12.5	10.5	14	12.5	11.5	10	13.5	12.0
FLT R-304 @ KEW- PO 6832	5.5/4.5	N/A	5.5/4.5	N/A	6.5/4.5	N/A	6.5/4.5	N/A	7.0/4.5	N/A	7.0/4.5	N/A	6.5/4.5	N/A
FLT 121 @ POB- PO B23	still trip @ 4.5/4.5	still trip @ 4.5/4.5	7.5/4.5	6.5/4.5	7.5/4.5	7.0/4.5	still trip @ 4.5/4.5	still trip @ 4.5/4.5	9/4.5	8.5/4.5	still trip @ 4.5/4.5	still trip @ 4.5/4.5	9.0/4.5	8.5/4.5

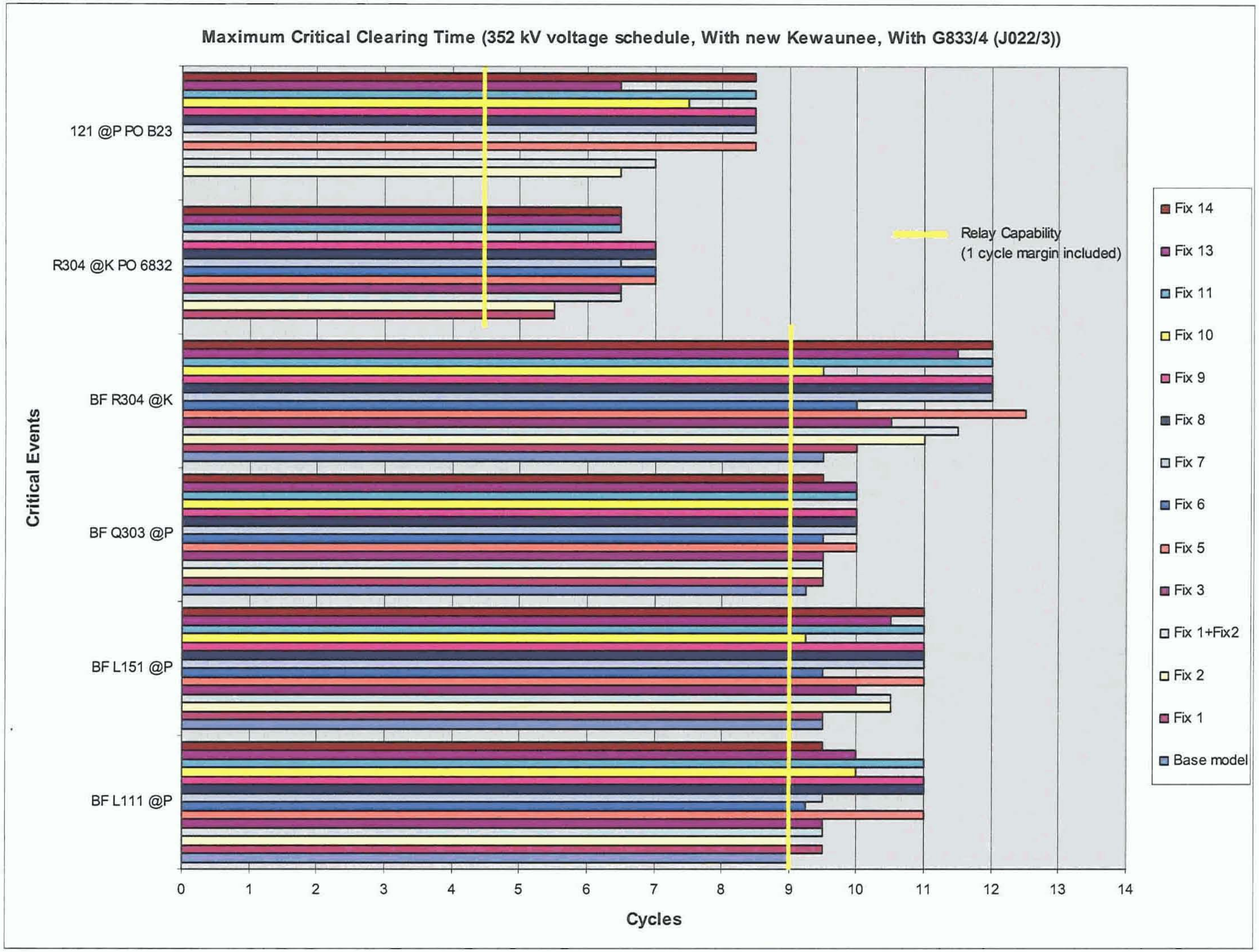
Critical Events	Fix 8		Fix 9		Fix 10		Fix 11		Fix 13		Fix 14	
	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
BF L111 @ POB	12.5	11	12	11	11	10	12	11	11	10	10.5	9.5
BF L151 @ POB	12.5	11.0	12.5	11	10	9.25	12.5	11	12	10.5	12	11
BF Q-303 @ POB	11.5	10.0	11.5	10	10	9	11	10	11	10	11	9.5
BF R-304 @ KEW	14	12.0	14	12	10.5	9.5	14	12	13	11.5	13.5	12
FLT R-304 @ KEW- PO 6832	7.0/4.5	N/A	7.0/4.5	N/A	trip at 4.5/4.5	N/A	6.5/4.5	N/A	6.5/4.5	N/A	6.5/4.5	N/A
FLT 121 @POB- PO B23	9.0/4.5	8.5/4.5	9.0/4.5	8.5/4.5	8.5/4.5	7.5/4.5	9.0/4.5	8.5/4.5	7.5/4.5	6.5/4.5	9.0/4.5	8.5/4.5

So, maximum critical clearing time for each event tested are

Critical Events	Base model (Interim 2B)	Fix 1	Fix 2	Fix 1+Fix2	Fix 3	Fix 5	Fix 6	Fix 7	Fix 8	Fix 9	Fix 10	Fix 11	Fix 13	Fix 14
BF L111 @ POB	9	9.5	9	9.5	9.5	11	9.25	9.5	11	11	10	11	10	9.5
BF L151 @ POB	9.5	9.5	10.5	10.5	10	11	9.5	11	11	11	9.25	11	10.5	11
BF Q-303 @ POB	9.25	9.5	9.5	9.5	9.5	10	9.5	10	10	10	9	10	10	9.5
BF R-304 @ KEW	9.5	10	11	11.5	10.5	12.5	10	12	12	12	9.5	12	11.5	12
R-304 @ KEW- PO 6832	trip at 4.5	5.5	5.5	6.5	6.5	7	7	6.5	7	7	trip at 4.5	6.5	6.5	6.5
121 @P PO B23	trip at 4.5	trip at 4.5	6.5	7	trip at 4.5	8.5	trip at 4.5	8.5	8.5	8.5	7.5	8.5	6.5	8.5

Options Sorted by Performance for Each Critical Event

	BF L111 @ POB		BF L151 @ POB		BF Q-303 @ POB		BF R-304 @ KEW		FLT R-304 @ K EW-PO 6832		FLT 121 @ POB- PO B23
Fix 5	11	Fix 5	11	Fix 5	10	Fix 5	12.5	Fix 5	7	Fix 5	8.5
Fix 8	11	Fix 7	11	Fix 7	10	Fix 7	12	Fix 6	7	Fix 7	8.5
Fix 9	11	Fix 8	11	Fix 8	10	Fix 8	12	Fix 8	7	Fix 8	8.5
Fix 11	11	Fix 9	11	Fix 9	10	Fix 9	12	Fix 9	7	Fix 9	8.5
Fix 10	10	Fix 11	11	Fix 11	10	Fix 11	12	Fix 1+Fix2	6.5	Fix 11	8.5
Fix 13	10	Fix 14	11	Fix 13	10	Fix 14	12	Fix 3	6.5	Fix 14	8.5
Fix 1	9.5	Fix 2	10.5	Fix 1	9.5	Fix 1+Fix2	11.5	Fix 7	6.5	Fix 10	7.5
Fix 1+Fix2	9.5	Fix 1+Fix2	10.5	Fix 2	9.5	Fix 13	11.5	Fix 11	6.5	Fix 1+Fix2	7
Fix 3	9.5	Fix 13	10.5	Fix 1+Fix2	9.5	Fix 2	11	Fix 13	6.5	Fix 2	6.5
Fix 7	9.5	Fix 3	10	Fix 3	9.5	Fix 3	10.5	Fix 14	6.5	Fix 13	6.5
Fix 14	9.5	Base model	9.5	Fix 6	9.5	Fix 1	10	Fix 1	5.5	Base model	trip at 4.5
Fix 6	9.25	Fix 1	9.5	Fix 14	9.5	Fix 6	10	Fix 2	5.5	Fix 1	trip at 4.5
Base model	9	Fix 6	9.5	Base model	9.25	Base model	9.5	Base model	trip at 4.5	Fix 3	trip at 4.5
Fix 2	9	Fix 10	9.25	Fix 10	9	Fix 10	9.5	Fix 10	trip at 4.5	Fix 6	trip at 4.5



Maximum Critical Clearing Time (352 kV voltage schedule, With new Kewaunee, With G833/4 (J022/3))
Critical Events
121 @P PO B23
R304 @K PO 6832
BF R304 @K
BF Q303 @P
BF L151 @P
BF L111 @P
Relay Capability
(1 cycle margin included)
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
Cycles
Fix 14
Fix 13
Fix 11
Fix 10
Fix 9
Fix 8
Fix 7
Fix 6
Fix 5
Fix 3
Fix 1+Fix2
Fix 2
Fix 1
Base model

H.2.2: Performance of Each Option Based on Allowable Minimum MVAR Outputs from Point Beach and Kewaunee
(Critical Events Studied at Certain Tested Clearing Times)

Estimated Voltage Settings at Point Beach and Kewaunee for stable system under critical events tested
(Tested Voltage Settings are 353kV, 352 kV, 351 kV, 350 kV, 349 kV, 348 kV, 347 kV, 346 kV, 345 kV, 344 kV and 343 kV)

Critical Events (Tested Clearing Time)	Fix 1		Fix 2		Fix 1+2		Fix 3		Fix 5		Fix 6		Fix 7	
	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
BF L111 @ POB (3.5/9.25/4.5)	350 kV or higher	351 kV or higher	352 kV or higher	353 kV or higher	350 kV or higher	352 kV or higher	349 kV or higher	350 kV or higher	346 kV or higher	346 kV or higher	351 kV or higher	352 kV or higher	348 kV or higher	350 kV or higher
BF L151 @ POB (3.5/9.5/4.5)	349 kV or higher	351 kV or higher	348 kV or higher	348 kV or higher	348 kV or higher	348 kV or higher	348 kV or higher	350 kV or higher	347 kV or higher	347 kV or higher	349 kV or higher	352 kV or higher	347 kV or higher	347 kV or higher
BF Q-303 @ POB (3.5/9.25/4.5)	349 kV or higher	351 kV or higher	349 kV or higher	351 kV or higher	349 kV or higher	351 kV or higher	349 kV or higher	351 kV or higher	348 kV or higher	350 kV or higher	349 kV or higher	351 kV or higher	349 kV or higher	350 kV or higher
BF R-304 @ KEW (3.5/9.5/4.5)	347 kV or higher	349 kV	347 kV or higher	347 kV or higher	346 kV or higher	347 kV or higher	347 kV or higher	348 kV or higher	345 kV or higher	346 kV or higher	348 kV or higher	350 kV or higher	345 kV or higher	346 kV or higher
FLT R-304 @ KEW - PO 6832 (4.5/4.5)	345 kV or higher	N/A	345 kV or higher	N/A	even ok at 343 kV	N/A	even ok at 343 kV	N/A	even ok at 343 kV	N/A	even ok at 343 kV	N/A	even ok at 343 kV	N/A
FLT 121 @ POB- PO B23 (4.5/4.5)	Even trip at 352 kV	Even trip at 352 kV	344 kV or higher	even ok at 343 kV	344 kV or higher	even ok at 343 kV	Even trip at 352 kV	Even trip at 352 kV	even ok at 343 kV	even ok at 343 kV	Even trip at 352 kV	Even trip at 352 kV	even ok at 343 kV	even ok at 343 kV

Critical Events (Tested Clearing Time)	Fix 8		Fix 9		Fix 10		Fix 11		Fix 13		Fix 14	
	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
BF L111 @ POB (3.5/9.25/4.5)	346 kV or higher	346 kV or higher	346 kV or higher	347 kV or higher	348 kV or higher	349 kV or higher	347 kV or higher	347 kV or higher	348 kV or higher	349 kV or higher	349 kV or higher	350 kV or higher
BF L151 @ POB (3.5/9.5/4.5)	346 kV or higher	347 kV or higher	346 kV or higher	347 kV or higher	350 kV or higher	353 kV or higher	346 kV or higher	347 kV or higher	347 kV or higher	348 kV or higher	347 kV or higher	347 kV or higher
BF Q-303 @ POB (3.5/9.25/4.5)	348 kV or higher	350 kV or higher	348 kV or higher	350 kV or higher	350 kV or higher	353 kV or higher	349 kV or higher	350 kV or higher	348 kV or higher	350 kV or higher	349 kV or higher	351 kV or higher
BF R-304 @ KEW (3.5/9.5/4.5)	345 kV or higher	345 kV or higher	345 kV or higher	345 kV or higher	349 kV or higher	352 kV or higher	345 kV or higher	345 kV or higher	346 kV or higher	347 kV or higher	345 kV or higher	346 kV or higher
FLT R-304 @ KEW - PO 6832 (4.5/4.5)	even ok at 343 kV	N/A	even ok at 343 kV	N/A	Even trip at 354 kV	N/A	even ok at 343 kV	N/A	even ok at 343 kV	N/A	even ok at 343 kV	N/A
FLT 121 @ POB- PO B23 (4.5/4.5)	even ok at 343 kV	even ok at 343 kV	even ok at 343 kV	even ok at 343 kV	even ok at 343 kV	even ok at 343 kV	even ok at 343 kV	even ok at 343 kV	344 kV or higher	even ok at 343 kV	even ok at 343 kV	even ok at 343 kV

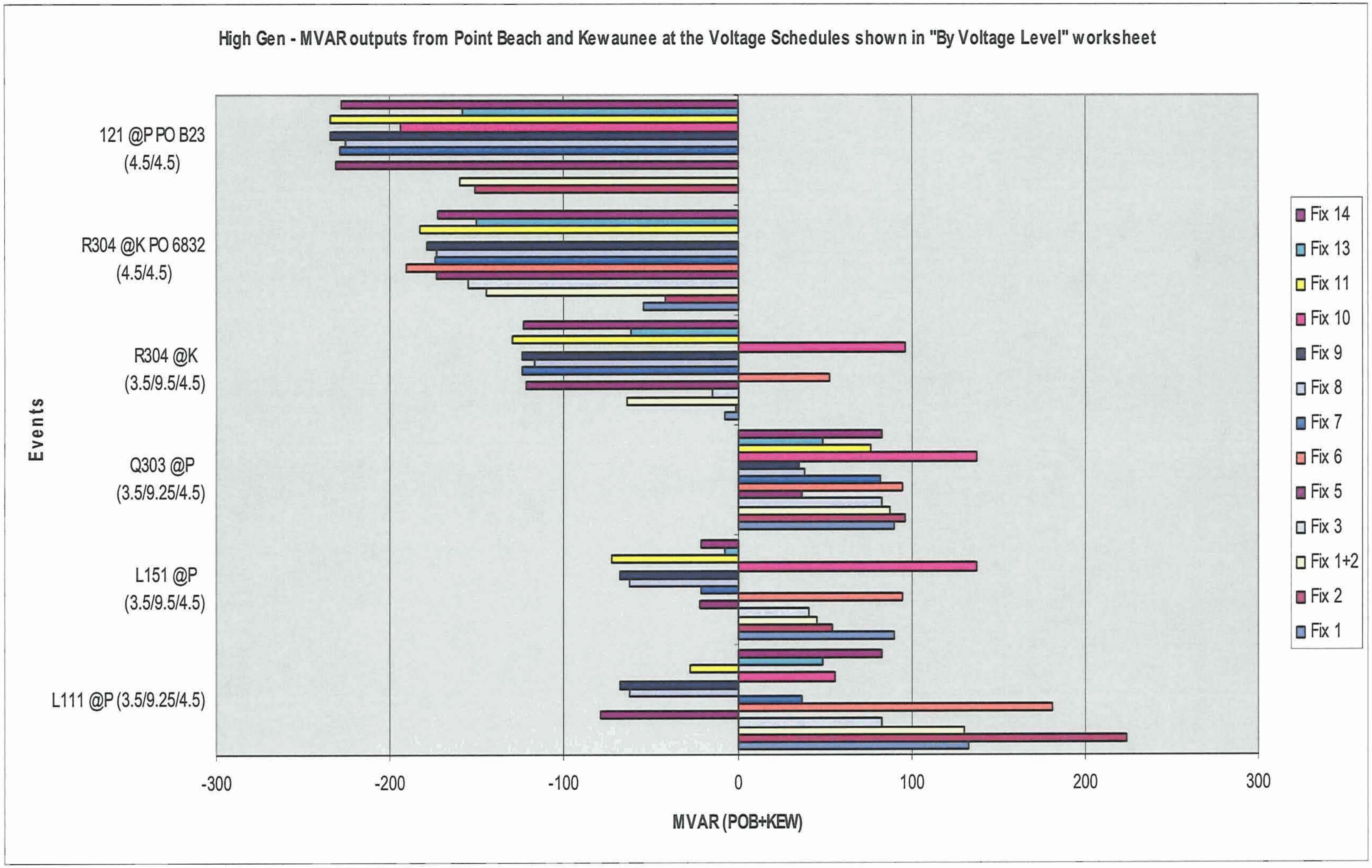
MVAR outputs from Point Beach and Kewaunee at the Estimated Voltage Schedules

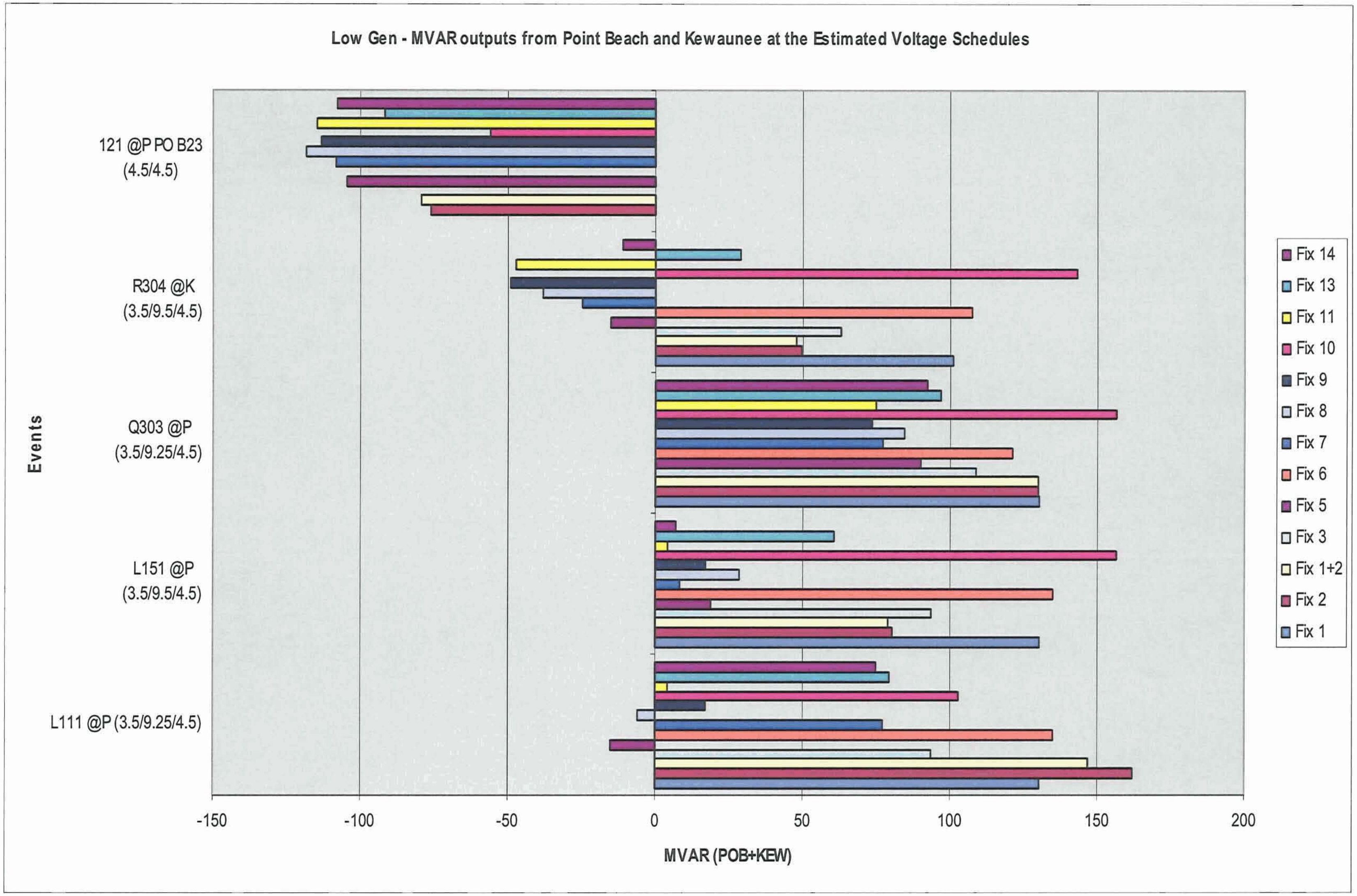
		Fix 1		Fix 2		Fix 1+2		Fix 3		Fix 5		Fix 6		Fix 7	
		High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
BF L111 @ POB (3.5/9.25/4.5)	POB G1	46.5	53.2	83.8	64.2	47.6	58.6	28.2	39.6	-19.9	7.4	69.8	55.9	17.2	35.6
	POB G2	46.5	53.2	83.8	64.2	47.6	58.6	28.2	39.6	-19.9	7.4	69.8	55.9	17.2	35.6
	KEW G1	39.4	23.8	56.7	33.7	34.9	29.5	26.7	14.3	-38.8	-30.1	41.8	23.1	2.4	5.9
	Sum (MVAR)	132.4	130.2	224.3	162.1	130.1	146.7	83.1	93.5	-78.6	-15.3	181.4	134.9	36.8	77.1
BF L151 @ POB (3.5/9.5/4.5)	POB G1	30.8	53.2	20.7	34.2	16.3	33.7	12.6	39.6	-3	-15.5	38.1	55.9	-0.5	14.2
	POB G2	30.8	53.2	20.7	34.2	16.3	33.7	12.6	39.6	-3	15.5	38.1	55.9	-0.5	14.2
	KEW G1	28.6	23.8	13.1	11.8	13.3	11.5	16	14.3	-16	-12.2	18.6	23.1	-20.3	-20.3
	Sum (MVAR)	90.2	130.2	54.5	80.2	45.9	78.9	41.2	93.5	-22	18.8	94.8	134.9	-21.3	8.1
BF Q-303 @ POB (3.5/9.25/4.5)	POB G1	30.8	53.2	36.2	52.2	31.9	52.4	28.2	45	14.4	37.7	38.1	51.1	34.7	35.6
	POB G2	30.8	53.2	36.2	52.2	31.9	52.4	28.2	45	14.4	37.7	38.1	51.1	34.7	35.6
	KEW G1	28.6	23.8	23.8	25.2	24.1	25.2	26.7	18.9	8.3	14.6	18.6	18.9	12.9	5.9
	Sum (MVAR)	90.2	130.2	96.2	129.6	87.9	130	83.1	108.9	37.1	90	94.8	121.1	82.3	77.1
BF R-304 @ KEW (3.5/9.5/4.5)	POB G1	-0.5	43	5	27.5	-14.9	26.8	-3.1	28.8	-36.5	7.4	22.6	46.3	-34.9	6.4
	POB G2	-0.5	43	5	27.5	-14.9	26.8	-3.1	28.8	-36.5	7.4	22.6	46.3	-34.9	6.4
	KEW G1	-6.4	15	-11.3	-5.6	-33.8	-5.9	-8.3	5.3	-48.8	-30.1	7.2	14.6	-54.1	-37.8
	Sum (MVAR)	-7.4	101	-1.3	49.4	-63.6	47.7	-14.5	62.9	-121.8	-15.3	52.4	107.2	-123.9	-25
FLT R-304 @ KEW - PO 6832 (4.5/4.5)	POB G1	-40	N/A	-31.4	N/A	-66.1	N/A	-72.1	N/A	-76	N/A	-65.3	N/A	-73.3	N/A
	POB G2	-40	N/A	-31.4	N/A	-66.1	N/A	-72.1	N/A	-76	N/A	-65.3	N/A	-73.3	N/A
	KEW G1	25.9	N/A	20.9	N/A	-12.2	N/A	-11	N/A	-21.1	N/A	-60	N/A	-27.1	N/A
	Sum (MVAR)	-54.1	N/A	-41.9	N/A	-144.4	N/A	-155.2	N/A	-173.1	N/A	-190.6	N/A	-173.7	N/A
FLT 121 @ POB- PO B23	POB G1			-50.5	-29.3	-59.6	-30.8			-98.7	-54.2			-99.2	-55.1

(4.5/4.5)	POB G2			-40.7	13.1	-40.4	11.4			-72.5	9.6			-69.3	6.7
	KEW G1			-60	-60	-60	-60			-60	-60			-60	-60
Sum (MVAR)		Trip	Trip	-151.2	-76.2	-160	-79.4	Trip	Trip	-231.2	-104.6	Trip	Trip	-228.5	-108.4

		Fix 8		Fix 9		Fix 10		Fix 11		Fix 13		Fix 14	
		High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
L111 @ POB (3.5/9.25/4.5)	POB G1	-14.2	9.9	-16.2	14.4	19.5	43.9	-3.6	11.9	18.3	33.2	34.7	34.6
	POB G2	-14.2	9.9	-16.2	14.4	19.5	43.9	-3.6	11.9	18.3	33.2	34.7	34.6
	KEW G1	-33.6	-25.7	-35.5	-11.8	17.2	14.9	-19.9	-19.6	12.1	12.8	13.6	5.7
Sum (MVAR)		-62	-5.9	-67.9	17	56.2	102.7	-27.1	4.2	48.7	79.2	83	74.9
L151 @ POB (3.5/9.5/4.5)	POB G1	-14.2	18.1	-16.2	14.4	49.3	61.8	-20.7	11.9	2.4	26.7	-0.6	13.7
	POB G2	-14.2	18.1	-16.2	14.4	49.3	61.8	-20.7	11.9	2.4	26.7	-0.6	13.7
	KEW G1	-33.6	-7.9	-35.5	-11.8	38.8	32.8	-31.4	-19.6	-12.3	7.3	-19.6	-20.3
Sum (MVAR)		-62	28.3	-67.9	17	137.4	156.4	-72.8	4.2	-7.5	60.7	-20.8	7.1
Q-303 @ POB (3.5/9.25/4.5)	POB G1	19	39.2	18.4	35.7	49.3	61.8	31.5	33.9	18.3	39.8	34.7	41.2
	POB G2	19	39.2	18.4	35.7	49.3	61.8	31.5	33.9	18.3	39.8	34.7	41.2
	KEW G1	0.5	5.9	-1.7	1.8	38.8	32.8	13.5	6.8	12.1	17.3	13.6	9.9
Sum (MVAR)		38.5	84.3	35.1	73.2	137.4	156.4	76.5	74.6	48.7	96.9	83	92.3
R-304 @ KEW (3.5/9.5/4.5)	POB G1	-30.6	2.1	-33.3	-1.6	34.3	57.3	-37.9	-2.9	-13.1	19.5	-35	6.9
	POB G2	-30.6	2.1	-33.3	-1.6	34.3	57.3	-37.9	-2.9	-13.1	19.5	-35	6.9
	KEW G1	-55.6	-42.3	-57.5	-45.9	27.9	28.3	-53.8	-41.4	-35.2	-10.3	-53.4	-25
Sum (MVAR)		-116.8	-38.1	-124.1	-49.1	96.5	142.9	-129.6	-47.2	-61.4	28.7	-123.4	-11.2
R-304 @ KEW - PO 6832 (4.5/4.5)	POB G1	-69.8	N/A	-72.9	N/A		N/A	-76.6	N/A	-66.6	N/A	-73.4	N/A
	POB G2	-69.8	N/A	-72.9	N/A		N/A	-76.6	N/A	-66.6	N/A	-73.4	N/A

	KEW G1	-33.9	N/A	-32.7	N/A		N/A	-29.3	N/A	-17.3	N/A	-25.8	N/A
	Sum (MVAR)	-173.5	N/A	-178.5	N/A	Trip	N/A	-182.5	N/A	-150.5	N/A	-172.6	N/A
121 @ POB - PO B23 (4.5/4.5)	POB G1	-89.7	-54.5	-98.8	-61	-59.6	-3.8	-104.1	-59.3	-57.6	-38.5	-99	-54.8
	POB G2	-75.5	-4	-75.1	7.7	-74.5	8	-69.8	4.4	-40.6	6.9	-69	6.8
	KEW G1	-60	-60	-60	-60	-60	-60	-60	-60	-60	-60	-60	-60
	Sum (MVAR)	-225.2	-118.5	-233.9	-113.3	-194.1	-55.8	-233.9	-114.9	-158.2	-91.6	-228	-108


High Gen - MVAR outputs from Point Beach and Kewaunee at the Voltage Schedules shown in "By Voltage Level" worksheet
Events
121 @P PO B23 (4.5/4.5)
R304 @K PO 6832 (4.5/4.5)
R304 @K (3.5/9.5/4.5)
Q303 @P (3.5/9.25/4.5)
L151 @P (3.5/9.5/4.5)
L111 @P (3.5/9.25/4.5)
-300
-200
-100
0
100
200
300
MVAR (POB+KEW)
Fix 14
Fix 13
Fix 11
Fix 10
Fix 9
Fix 8
Fix 7
Fix 6
Fix 5
Fix 3
Fix 1+2
Fix 2
Fix 1



Low Gen - MVAR outputs from Point Beach and Kewaunee at the Estimated Voltage Schedules
Events
121 @P PO B23 (4.5/4.5)
R304 @K (3.5/9.5/4.5)
Q303 @P (3.5/9.25/4.5)
L151 @P (3.5/9.5/4.5)
L111 @P (3.5/9.25/4.5)
-150
-100
-50
0
50
100
150
200
MVAR (POB+KEW)
Fix 14
Fix 13
Fix 11
Fix 10
Fix 9
Fix 8
Fix 7
Fix 6
Fix 5
Fix 3
Fix 1+2
Fix 2
Fix 1

Appendix H.3.
Options Selected For Further Analysis

Section H.3.1. Options Selected

Section H.3.2 Performance Comparison

Section H.3.3. Thermal Analysis for Fix 2

Nomenclature

K or KEW:	Kewaunee
P or POB:	Point Beach
FLT:	Fault cleared in primary time
BF:	Fault cleared in breaker failure time
PO:	Prior Outage
High Gen	High generation scenario
Low Gen	Low generation scenario

H.3.1. Options Selected for Further Analysis

Options	Descriptions
Fix 2	New East 345 kV Switching Station. Loop existing W-1, L-SEC31 and 796L41 into the switching station
Fix 5	New East 345 kV Switching Station and Loop existing W-1, L-SEC31 and 796L41 into the switching station (Fix 2), New North 345 kV Switching Station, Loop L111 and L121 into the North switching station, Build a new North-East 345 kV line
Fix 11	New East 345/138 kV substation and Loop existing W-1, L-SEC31 and 796L41 into the substation (Fix 2), Convert existing 971K51 and portion of HOLG21 to 345kV, Modified North 345 kV Switching Station (Loop L111 and L121 and converted 971K51 into the station), New 345/138 kV transformer at East substation, New East-Plymouth #4-Howards Grove-Erdman 138 kV line, Loop Mullet River-South Sheboygan Falls 138 kV line into the East 138 kV substation, Terminate the remaining 138 kV line to Holland at the new East substation
Fix 13	Center Line Conversion Option: New East 345 kV Switching Station and Loop existing W-1, L-SEC31 and 796L41 into the switching station (Fix 2), Rebuild/convert existing 138 kV lines 4035, 971K91, portion of 40561, portion of 8241 to double-circuit 345/138 kV, Construct a new Mullet River 138 substation near the existing Mullet River 138/69 kV substation Relocate all 138 kV facilities at the existing Mullet River 138/69 kV substation to the new Mullet River 138 kV substation, Terminate the southern portions of 8241 (Elkhart Lake-Saukville) and 40561 (Meyer Rd-Lyndon) into the new Mullet River substation to form Mullet River-Saukville and Mullet River-Lyndon Construct a new 138 kV line from Erdman to Howards Grove

H.3.2 Performance Comparison

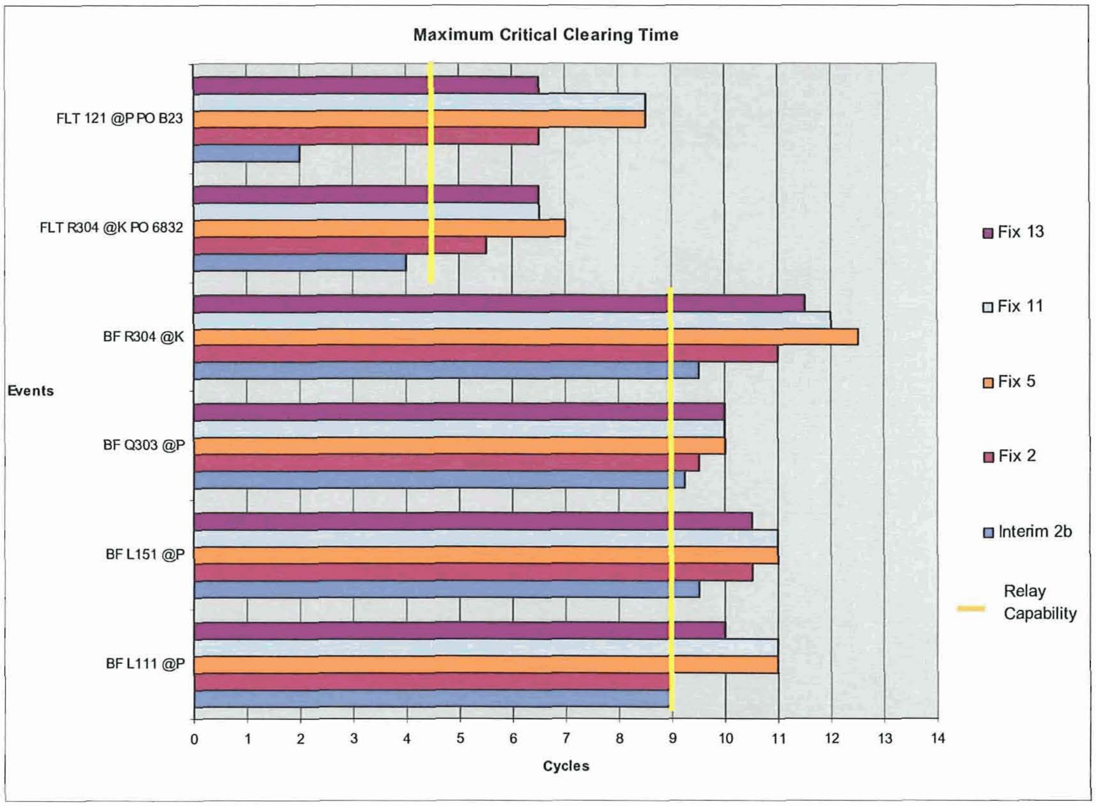
- Maximum Critical Clearing Time (Critical Events Studied by Increasing Clearing Times)

At 352 kV Voltage Schedule (POB and KEW), Maximum Critical Clearing Time for Each Event Tested

Critical Events	Interim 2b		Fix 2		Fix 5		Fix 11		Fix 13	
	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
BF L111 @ POB	9.5	9	9.25	9	12.5	11	12	11	11	10
BF L151 @ POB	N/A	9.5	11.5	10.5	12.5	11	12.5	11	12	10.5
BF Q-303 @ POB	N/A	9.25	10.5	9.5	11 (@11.5 cycle 345kV-1st-1.0 sec)	10	11	10	11	10
BF R-304 @ KEW	N/A	9.5	12.5	11	14	12.5	14	12	13 (@13.5 cycle 19kV-1.6 sec, 345kV-1st-1.388 sec, 345 kV-2nd-1.6 sec)	11.5
Flt R-304 @ K EW - PO 6832	4.0	N/A	5.5/4.5	N/A	7.0/4.5	N/A	6.5/4.5	N/A	6.5/4.5	N/A
Flt 121 @ POB-PO B23	3.5 (@4.0 cycle 345kV-2nd-1.562sec)	2.0 (@ 2.5 cycle 345kV-2nd-1.525sec)	7.5/4.5	6.5/4.5	9/4.5	8.5/4.5	9.0/4.5	8.5/4.5	7.5/4.5	6.5/4.5

In summary,

Critical Events	Maximum critical clearing time for each event tested are				
	Interim 2b	Fix 2	Fix 5	Fix 11	Fix 13
BF L111 @ POB	9	9	11	11	10
BF L151 @ POB	9.5	10.5	11	11	10.5
BF Q-303 @ POB	9.25	9.5	10	10	10
BF R-304 @ KEW	9.5	11	12.5	12	11.5
Flt R-304 @ K EW - PO 6832	4	5.5	7	6.5	6.5
Flt 121 @ POB- PO B23	2	6.5	8.5	8.5	6.5



- Allowable Minimum MVAR Outputs from Point Beach and Kewaunee (Critical Events Studied at Certain Tested Clearing Times)

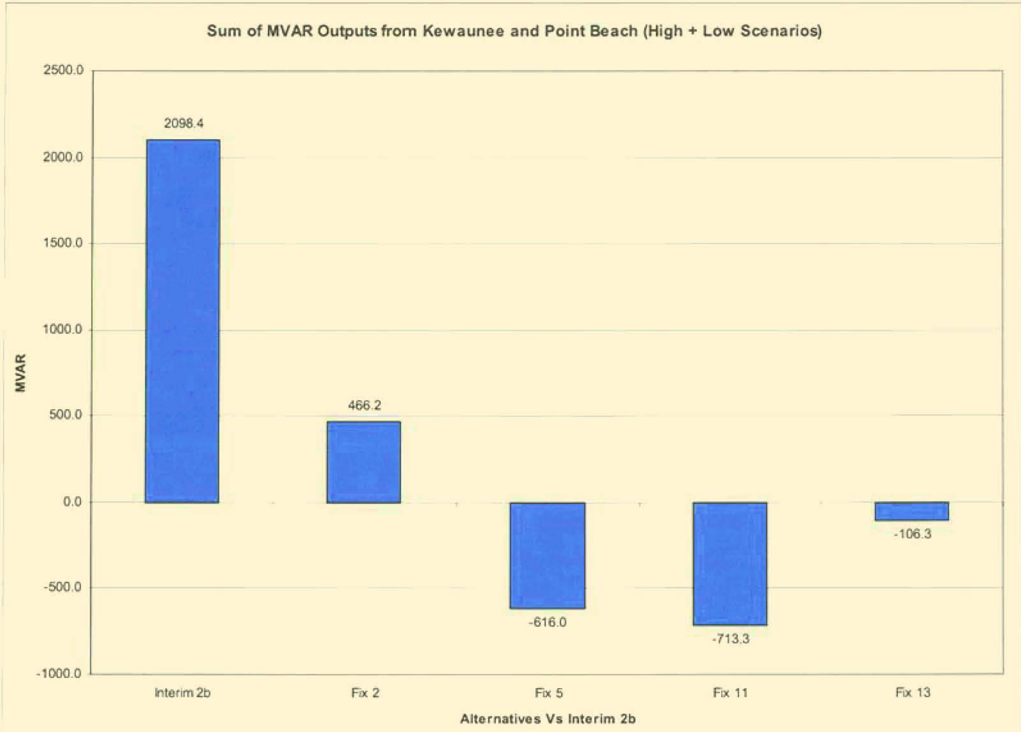
Estimated Voltage Settings at Point Beach and Kewaunee for Stable System under Critical Events Tested										
Critical Events	Interim 2b		Fix 2		Fix 5		Fix 11		Fix 13	
	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen	High Gen	Low Gen
BF L111 @ POB (3.5/**9.0**/4.5)	351 kV or higher	352 kV or higher	351 kV or higher	352 kV or higher	346 kV or higher	346 kV or higher	346 kV or higher	346 kV or higher	348 kV or higher	349 kV or higher
BF L151 @ POB (3.5/9.5/4.5)	349 kV or higher	352 kV or higher	348 kV or higher	348 kV or higher	347 kV or higher	347 kV or higher	346 kV or higher	347 kV or higher	347 kV or higher	348 kV or higher
BF Q-303 @ POB (3.5/9.25/4.5)	350 kV or higher	352 kV or higher	349 kV or higher	351 kV or higher	348 kV or higher	350 kV or higher	349 kV or higher (@348kV 19 kV-1.729 sec, 345 kV-1st-1.142 sec, 345 kV-2nd-1.758 sec)	350 kV or higher	348 kV or higher	350 kV or higher
BF R-304 @ KEW (3.5/9.5/4.5)	348 kV or higher	351 kV or higher	347 kV or higher	347 kV or higher	345 kV or higher	346 kV or higher (@345kV 19 kV-1.583 sec, 345 kV-1st-1.029 sec, 345 kV-2nd-1.604 sec)	345 kV or higher	345 kV or higher	346 kV or higher	347 kV or higher
Flt R-304 @ KEW- PO 6832 (4.5/4.5)	356 kV or higher (@355kV 19 kV-1.733 sec, 345 kV-1st-1.458 sec, 345 kV-2nd-2.071 sec)	N/A	345 kV or higher	N/A	343 kV or higher	N/A	even ok at 343 kV	N/A	even ok at 343 kV	N/A
Flt 121 @ POB - PO B23 (4.5/4.5)	354 kV or higher	360 kV	344 kV or higher	even ok at 343 kV	343 kV or higher	343 kV or higher	even ok at 343 kV	even ok at 343 kV	344 kV or higher	even ok at 343 kV

MVAR outputs from Point Beach and Kewaunee at the Estimated Voltage Schedules (High Gen)

High Gen		Interim 2b	Fix 2	Fix 5	Fix 11	Fix 13
BF L111 @ POB (3.5/**9.0**/4.5)	POB G1 (MVAR)	67.2	67.7	-19.9	-20.7	18.3
	POB G2 (MVAR)	67.2	67.7	-19.9	-20.7	18.3
	KEW G1 (MVAR)	48.9	45.6	-38.8	-31.4	12.1
	TOTAL (MVAR)	183.3	181	-78.6	-72.8	48.7
BF L151 @ POB (3.5/9.5/4.5)	POB G1 (MVAR)	35.6	20.7	-3.0	-20.7	2.4
	POB G2 (MVAR)	35.6	20.7	-3.0	-20.7	2.4
	KEW G1 (MVAR)	27.1	13.1	-16.0	-31.4	-12.3
	TOTAL (MVAR)	98.3	54.5	-22	-72.8	-7.5
BF Q-303 @ POB (3.5/9.25/4.5)	POB G1 (MVAR)	51.3	36.2	14.4	31.5	18.3
	POB G2 (MVAR)	51.3	36.2	14.4	31.5	18.3
	KEW G1 (MVAR)	37.9	23.8	8.3	13.5	12.1
	TOTAL (MVAR)	140.5	96.2	37.1	76.5	48.7
BF R-304 @ KEW (3.5/9.5/4.5)	POB G1 (MVAR)	20.1	5	-36.5	-37.9	-13.1
	POB G2 (MVAR)	20.1	5	-36.5	-37.9	-13.1
	KEW G1 (MVAR)	16.4	-11.3	-48.8	-53.8	-35.2
	TOTAL (MVAR)	56.6	-1.3	-121.8	-129.6	-61.4
Flt R-304 @ KEW - PO 6832 (4.5/4.5)	POB G1 (MVAR)	153.3	-31.4	-76	-76.6	-66.6
	POB G2 (MVAR)	153.3	-31.4	-76	-76.6	-66.6
	KEW G1 (MVAR)	154.1	20.9	-21.1	-29.3	-17.3
	TOTAL (MVAR)	460.7	-41.9	-173.1	-182.5	-150.5
Flt 121 @ POB - PO B23 (4.5/4.5)	POB G1 (MVAR)	142.3	-50.5	-98.7	-104.1	-57.6
	POB G2 (MVAR)	85.3	-40.7	-72.5	-69.8	-40.6
	KEW G1 (MVAR)	87.5	-60	-60	-60	-60
	TOTAL (MVAR)	315.1	-151.2	-231.2	-233.9	-158.2
BF Total (MVAR)		478.7	330.4	-185.3	-198.7	28.5
PO Total (MVAR)		775.8	-193.1	-404.3	-416.4	-308.7
All Total (MVAR, BF Total + PO Total)		1254.5	137.3	-589.6	-615.1	-280.2

MVAR outputs from Point Beach and Kewaunee at the Estimated Voltage Schedules (Low Gen)

Low Gen		Interim 2b	Fix 2	Fix 5	Fix 11	Fix 13
BF L111 @ POB (3.5/**9.0**/4.5)	POB G1 (MVAR)	58.6	58.2	7.4	4.8	33.2
	POB G2 (MVAR)	58.6	58.2	7.4	4.8	33.2
	KEW G1 (MVAR)	27.3	29.5	-30.1	-24.5	12.8
	TOTAL (MVAR)	144.5	145.9	-15.3	-14.9	79.2
BF L151 @ POB (3.5/9.5/4.5)	POB G1 (MVAR)	58.6	34.2	15.5	11.9	26.7
	POB G2 (MVAR)	58.6	34.2	15.5	11.9	26.7
	KEW G1 (MVAR)	27.3	11.8	-12.2	-19.6	7.3
	TOTAL (MVAR)	144.5	80.2	18.8	4.2	60.7
BF Q-303 @ POB (3.5/9.25/4.5)	POB G1 (MVAR)	58.6	52.2	37.7	33.9	39.8
	POB G2 (MVAR)	58.6	52.2	37.7	33.9	39.8
	KEW G1 (MVAR)	27.3	25.2	14.6	6.8	17.3
	TOTAL (MVAR)	144.5	129.6	90	74.6	96.9
BF R-304 @ KEW (3.5/9.5/4.5)	POB G1 (MVAR)	53.4	27.5	7.4	-2.9	19.5
	POB G2 (MVAR)	53.4	27.5	7.4	-2.9	19.5
	KEW G1 (MVAR)	22.9	-5.6	-30.1	-41.4	-10.3
	TOTAL (MVAR)	129.7	49.4	-15.3	-47.2	28.7
Flt 121 @ POB - PO B23 (4.5/4.5)	POB G1 (MVAR)	115.4	-29.3	-54.2	-59.3	-38.5
	POB G2 (MVAR)	82.3	13.1	9.6	4.4	6.9
	KEW G1 (MVAR)	83.0	-60	-60	-60	-60
	TOTAL (MVAR)	280.7	-76.2	-104.6	-114.9	-91.6
BF Total (MVAR)		563.2	405.1	78.2	16.7	265.5
PO Total (MVAR)		280.7	-76.2	-104.6	-114.9	-91.6
All Total (MVAR)		843.9	328.9	-26.4	-98.2	173.9


Sum of MVAR Outputs from Kewaunee and Point Beach (High + Low Scenarios)
MVAR
2500.0
2000.0
1500.0
1000.0
500.0
0.0
-500.0
-1000.0
2098.4
466.2
-616.0
-713.3
-106.3
Interim 2b
Fix 2
Fix 5
Fix 11
Fix 13
Alternatives Vs Interim 2b

Section H.3.3. Thermal Analysis for Fix 2 (East Switching Station)

Table H.3.3.1 – Identified Thermal Violations Due to G833/4-J022/3
Summer Off-Peak 2013 (70% Load) Delivery to MISO for NERC Category A and B events (TDF>5%)
With Fix 2 (East Switching Station) in Service, Competing Wind Farms at 100% output

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1,2]	Worst Contingency[3]	TDF (%)	Injection Limit	Potential Solution Identified
Point Beach-Sheboygan Energy Center 345 kV line	488 SE	529 SE	Cypress-Arcadian 345 kV line	52.9	Yes	Yes[4]
New East-Cedarsauk 345 kV line	653 SE	847SE	New East-Granville 345 kV line	N/A	Yes	No[5]

1. Includes provision for 5% TRM. The required ratings are calculated using AC analysis in PSS/E dispatching 100% of power from G833/4-J022/3 to MISO.
2. SN = Summer Normal, SE = Summer Emergency
3. Local Special Protection Systems are included if designed to operate for NERC Category A or B events
4. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010
5. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE. The existing line rating is limited by the line clearance (2156 ACSR @ 129F).

Table H.3.3.2 – Identified Thermal Violations Due to G833/4-J022/3
Summer Peak 2013 (100% Load) Delivery to MISO for NERC Category A and B events (TDF>5%)
With Fix2 (East Switching Station) in Service, Competing Wind Farms at 20% Output

Limiting Element	Existing Rating (MVA)	Required Rating (MVA)[1,2]	Worst Contingency	TDF (%)	Injection Limit	Potential Solution Identified
None Identified	-	-	-	-	-	-

Table H.3.3.3 – Identified Voltage Violations Due to G833/J022 and G834/J023 Summer Off-Peak 2013 (70% Load) Delivery to MISO for NERC Category A & B events ($\Delta V > 0.1$ p.u.), With Fix2 (East Switching Station) in Service, Competing Wind Farms at 100% output

Limiting Element	Worst Contingency	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

Table H.3.3.4 – Identified Voltage Violations Due to G833/4-J022/3 Summer Peak 2013 (100% Load) Delivery to MISO for NERC Category A & B events ($\Delta V > 0.1$ p.u.), With Fix2 (East Switching Station) in Service, Competing Wind Farms at 20% output

Limiting Element	Worst Contingency	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

Table H.3.3.5.1 – Voltage Measurements at the Point Beach 345-kV Substation with Fix2 (East Switching Station), Summer 2013 Peak Load with Selected Contingencies[1] (Without Minimum Excitation Limits)

Contingency	Voltage[2] (p.u.)					MVAR output (Gross)	
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5	Point Beach G1	Point Beach G2
Intact System	1.0203	1.0203	1.0203	1.0203	1.0203	59.48	59.48
Point Beach BS 2-3	1.0203	1.0203	1.0203	1.0203	1.0203	76.74	34.61
Point Beach BS 2 – Forest Junction 345-kV Line 121	1.0203	1.0203	1.0203	1.0203	1.0203	49.98	49.98
Point Beach BS 1-2	1.025	1.0203	1.0203	1.0203	1.0203	64.13	64.13
Point Beach BS 4-5[3]	1.0203	1.0203	1.0203	1.0203	1.0224	66.8	66.8
Point Beach BS 3-4	1.0203	1.0203	1.0203	1.0203	1.0203	65.2	74.01
Point Beach BS 5 – Fox River 345-kV Line 151	1.0203	1.0203	1.0203	1.0203	1.0203	67.86	67.86
Forest Junction – Fox River 345-kV Line 971L71	1.0203	1.0203	1.0203	1.0203	1.0203	83.37	83.37
Point Beach BS 1 – Sheboygan Energy 345-kV Line 111	1.0203	1.0203	1.0203	1.0203	1.0203	65.28	65.28
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.0203	1.0203	1.0203	1.0203	1.0203	74.81	74.81
Forest Junction – Cypress 345-kV Line 971L51	1.0203	1.0203	1.0203	1.0203	1.0203	63.95	63.95
Forest Junction 345/138-kV Transformer T1	1.0203	1.0203	1.0203	1.0203	1.0203	54.03	54.03
Forest Junction 345/138-kV Transformer T2	1.0203	1.0203	1.0203	1.0203	1.0203	54.03	54.03
Fox River – N. Appleton 345-kV Line 6832	1.0203	1.0203	1.0203	1.0203	1.0203	64.57	64.57
Sheboygan Energy – New East 345-kV Line L-SEC31 North	1.0203	1.0203	1.0203	1.0203	1.0203	77.24	77.24
Fox Energy Center Unit CT 1	1.0203	1.0203	1.0203	1.0203	1.0203	61.43	61.43
Fox Energy Center Unit CT 2	1.0203	1.0203	1.0203	1.0203	1.0203	61.43	61.43
Fox Energy Center Unit ST	1.0203	1.0203	1.0203	1.0203	1.0203	59.56	59.56
Sheboygan Energy Center Unit #1	1.0203	1.0203	1.0203	1.0203	1.0203	68.03	68.03
Sheboygan Energy Center Unit #2	1.0203	1.0203	1.0203	1.0203	1.0203	68.03	68.03
Point Beach Unit #1[4]	1.0204	1.0203	1.0203	1.0203	1.0203	0	61.94
Point Beach Unit #2[5]	1.0204	1.0203	1.0203	1.0203	1.0203	61.94	0
Kewaunee G1	1.0204	1.0203	1.0203	1.0203	1.0203	63.83	63.83
Point Beach Units #1 & #2[6]	1.0196	1.0196	1.0196	1.0196	1.0196	0	0

1. Included for Interconnection Customer's defined voltage levels:
   a. Preferred: 352-kV to 354-kV
   b. Normal: 351-kV to 358-kV
   c. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table H.3.3.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0203 p.u. (352 kV).
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. Both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA.

Table H.3.3.5.2 – Voltage Measurements at the Point Beach 345-kV Substation with Fix2 (East Switching Station), Summer 2013 Peak Load with Selected Contingencies[1] (With Minimum Excitation Limits)

Contingency	Voltage[2] (p.u.)					MVAR output (Gross)	
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5	Point Beach G1	Point Beach G2
Intact System	1.0207	1.0207	1.0207	1.0207	1.0207	68	68
Point Beach BS 2-3	1.0203	1.0203	1.0211	1.0211	1.0212	76.74	68
Point Beach BS 2 – Forest Junction 345-kV Line 121	1.0212	1.0211	1.0211	1.0211	1.0212	68	68
Point Beach BS 1-2	1.025	1.0205	1.0205	1.0205	1.0205	68	68
Point Beach BS 4-5[3]	1.0204	1.0204	1.0204	1.0204	1.0224	68	68
Point Beach BS 3-4	1.0204	1.0204	1.0204	1.0203	1.0203	68	74.01
Point Beach BS 5 – Fox River 345-kV Line 151	1.0203	1.0203	1.0203	1.0203	1.0203	68	68
Forest Junction – Fox River 345-kV Line 971L71	1.0203	1.0203	1.0203	1.0203	1.0203	83.37	83.37
Point Beach BS 1 – Sheboygan Energy 345-kV Line 111	1.0204	1.0204	1.0204	1.0204	1.0205	68	68
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.0203	1.0203	1.0203	1.0203	1.0203	74.82	74.82
Forest Junction – Cypress 345-kV Line 971L51	1.0205	1.0205	1.0205	1.0205	1.0205	68	68
Forest Junction 345/138-kV Transformer T1	1.0209	1.0209	1.0209	1.0209	1.0209	68	68
Forest Junction 345/138-kV Transformer T2	1.0209	1.0209	1.0209	1.0209	1.0209	68	68
Fox River – N. Appleton 345-kV Line 6832	1.0208	1.0208	1.0208	1.0208	1.0208	68	68
Sheboygan Energy – New East 345-kV Line L-SEC31 North	1.0203	1.0203	1.0203	1.0203	1.0203	77.24	77.24
Fox Energy Center Unit CT 1	1.0206	1.0206	1.0206	1.0206	1.0206	68	68
Fox Energy Center Unit CT 2	1.0206	1.0206	1.0206	1.0206	1.0206	68	68
Fox Energy Center Unit ST	1.0207	1.0207	1.0207	1.0207	1.0207	68	68
Sheboygan Energy Center Unit #1	1.0203	1.0203	1.0203	1.0203	1.0203	68.03	68.03
Sheboygan Energy Center Unit #2	1.0203	1.0203	1.0203	1.0203	1.0203	68.03	68.03
Point Beach Unit #1[4]	1.0205	1.0204	1.0204	1.0204	1.0205	0	68
Point Beach Unit #2[5]	1.0205	1.0204	1.0204	1.0204	1.0205	68	0
Kewaunee G1	1.0209	1.0209	1.0209	1.0209	1.0209	68	68
Point Beach Units #1 & #2[6]	1.0196	1.0196	1.0196	1.0196	1.0196	0	0

1. Included for Interconnection Customer's defined voltage levels:
   d. Preferred: 352-kV to 354-kV
   e. Normal: 351-kV to 358-kV
   f. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table H.3.3.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0203 p.u (352 kV).
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. Both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA.

Table H.3.3.6.1 – Voltage Measurements at the Point Beach 345-kV Substation with Fix2 (East Switching Station), Summer 2013 Off-Peak Load with Selected Contingencies[1] (Without Minimum Excitation Limits)

Contingency	Voltage[2] (p.u.)					MVAR output (Gross)	
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5	Point Beach G1	Point Beach G2
Intact System	1.0202	1.0203	1.0203	1.0203	1.0202	114.64	114.64
Point Beach BS 2-3	1.0203	1.0203	1.0203	1.0203	1.0202	132.69	86.09
Point Beach BS 2 – Forest Junction 345-kV Line 121	1.0202	1.0203	1.0203	1.0203	1.0202	104.49	104.49
Point Beach BS 1-2	1.0141	1.0203	1.0203	1.0203	1.0202	113.65	113.65
Point Beach BS 4-5[3]	1.0202	1.0203	1.0203	1.0203	1.011	106.77	106.77
Point Beach BS 3-4	1.0203	1.0203	1.0203	1.0203	1.0202	137.6	120.76
Point Beach BS 5 – Fox River 345-kV Line 151	1.0202	1.0203	1.0203	1.0203	1.0203	110.83	110.83
Forest Junction – Fox River 345-kV Line 971L71	1.0202	1.0203	1.0203	1.0203	1.0203	117.65	117.65
Point Beach BS 1 – Sheboygan Energy 345-kV Line 111	1.0203	1.0203	1.0203	1.0203	1.0202	115.52	115.52
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.0202	1.0203	1.0203	1.0203	1.0202	122.02	122.02
Forest Junction – Cypress 345-kV Line 971L51	1.0202	1.0203	1.0203	1.0203	1.0202	120.41	120.41
Forest Junction 345/138-kV Transformer T1	1.0202	1.0203	1.0203	1.0203	1.0202	108.13	108.13
Forest Junction 345/138-kV Transformer T2	1.0202	1.0203	1.0203	1.0203	1.0202	108.13	108.13
Fox River – N. Appleton 345-kV Line 6832	1.0202	1.0203	1.0203	1.0203	1.0202	109.03	109.03
Sheboygan Energy – New East 345-kV Line L-SEC31 North	1.0203	1.0203	1.0203	1.0203	1.0202	115.37	115.37
Fox Energy Center Unit CT 1[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit CT 2[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit ST[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sheboygan Energy Center Unit #1	1.0202	1.0203	1.0203	1.0203	1.0202	126.03	126.03
Sheboygan Energy Center Unit #2[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Point Beach Unit #1[4]	1.0203	1.0203	1.0203	1.0203	1.0203	0	148.1
Point Beach Unit #2[5]	1.0203	1.0203	1.0203	1.0203	1.0203	148.1	0
Kewaunee G1	1.0203	1.0203	1.0203	1.0203	1.0202	97.36	97.36
Point Beach Units #1 & #2[6]	1.0178	1.0178	1.0178	1.0178	1.0177	0	0

1. Included for Interconnection Customer's defined voltage levels:
    a. Preferred: 352-kV to 354-kV
    b. Normal: 351-kV to 358-kV
    c. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table H.3.3.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0203 p.u (352 kV).
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. Both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA.
7. Fox Energy Center Units and Sheboygan Energy Center Unit #2 are off-line in the study case.

Table H.3.3.6.2 – Voltage Measurements at the Point Beach 345-kV Substation with Fix2 (East Switching Station), Summer 2013 Off-Peak Load with Selected Contingencies[1] (With Minimum Excitation Limits)

Contingency	Voltage[2] (p.u.)					MVAR output (Gross)	
	Point Beach Bus #1	Point Beach Bus #2	Point Beach Bus #3	Point Beach Bus #4	Point Beach Bus #5	Point Beach G1	Point Beach G2
Intact System	1.0202	1.0203	1.0203	1.0203	1.0202	114.64	114.64
Point Beach BS 2-3	1.0203	1.0203	1.0203	1.0203	1.0202	132.69	86.09
Point Beach BS 2 – Forest Junction 345-kV Line 121	1.0202	1.0203	1.0203	1.0203	1.0202	104.49	104.49
Point Beach BS 1-2	1.0141	1.0203	1.0203	1.0203	1.0202	113.65	113.65
Point Beach BS 4-5[3]	1.0202	1.0203	1.0203	1.0203	1.011	106.77	106.77
Point Beach BS 3-4	1.0203	1.0203	1.0203	1.0203	1.0202	137.6	120.76
Point Beach BS 5 – Fox River 345-kV Line 151	1.0202	1.0203	1.0203	1.0203	1.0203	110.83	110.83
Forest Junction – Fox River 345-kV Line 971L71	1.0202	1.0203	1.0203	1.0203	1.0203	117.65	117.65
Point Beach BS 1 – Sheboygan Energy 345-kV Line 111	1.0203	1.0203	1.0203	1.0203	1.0202	115.52	115.52
Point Beach BS 3 – Kewaunee 345-kV Line Q-303	1.0202	1.0203	1.0203	1.0203	1.0202	122.02	122.02
Forest Junction – Cypress 345-kV Line 971L51	1.0202	1.0203	1.0203	1.0203	1.0202	120.41	120.41
Forest Junction 345/138-kV Transformer T1	1.0202	1.0203	1.0203	1.0203	1.0202	108.13	108.13
Forest Junction 345/138-kV Transformer T2	1.0202	1.0203	1.0203	1.0203	1.0202	108.13	108.13
Fox River – N. Appleton 345-kV Line 6832	1.0202	1.0203	1.0203	1.0203	1.0202	109.03	109.03
Sheboygan Energy – New East 345-kV Line L-SEC31 North	1.0203	1.0203	1.0203	1.0203	1.0202	115.37	115.37
Fox Energy Center Unit CT 1[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit CT 2[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fox Energy Center Unit ST[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sheboygan Energy Center Unit #1	1.0202	1.0203	1.0203	1.0203	1.0202	126.03	126.03
Sheboygan Energy Center Unit #2[7]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Point Beach Unit #1[4]	1.0203	1.0203	1.0203	1.0203	1.0203	0	145.2
Point Beach Unit #2[5]	1.0203	1.0203	1.0203	1.0203	1.0203	145.2	0
Kewaunee G1	1.0203	1.0203	1.0203	1.0203	1.0202	97.36	97.36
Point Beach Units #1 & #2[6]	1.0178	1.0178	1.0178	1.0178	1.0177	0	0

1. Included for Interconnection Customer's defined voltage levels:
   a. Preferred: 352-kV to 354-kV
   b. Normal: 351-kV to 358-kV
   c. Maximum Permissible: 348.5-kV to 362-kV, any voltage outside of the Maximum Permissible range would be identified in Table H.3.3.3 as a Voltage Violation
2. The planning case used models both Point Beach units as regulating the respective POI bus voltage at the Point Beach substation to 1.0203 p.u (352 kV).
3. Point Beach Bus Section #5 is isolated from both Point Beach generating units for this contingency. The planning case used models the T2X03 345/13.2-kV transformer isolated at this bus with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus.
4. This contingency is intended to model the emergency trip of Point Beach Unit #1. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
5. This contingency is intended to model the emergency trip of Point Beach Unit #2. Assumes the 13.2-kV bus is split, separating the auxiliary loads. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. The Auxiliary load fed from the generator GSU (23.4 MW and 13.9 MVAR) does not trip and is not moved. The Control Area replacement power was imported from TVA.
6. This contingency is intended to model an emergency dual unit trip modeled by the outage of each Point Beach generating unit, but maintaining the auxiliary load connection to the transmission system. Transformer T1X03 is connected to Bus Section #1 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus and Transformer T2X03 is connected to Bus Section #5 with 2.5 MW and 2.1 MVAR of load at the 13.2-kV bus. Both generator Auxiliary loads are fed from their generator GSUs (23.4 MW and 13.9 MVAR each) and do not trip and are not moved. The Control Area replacement power was imported from TVA.
7. Fox Energy Center Units and Sheboygan Energy Center Unit #2 are off-line in the study case.

Table H.3.3.7 – Identified Thermal Violations under select NERC Category C.3 events[1] (TDF>5%), Summer Off-Peak 2013 70% Load Delivery to MISO with Fix2 (East Switching Station), Competing Wind Farms at 100% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
Point Beach-Sheboygan Energy Center 345 kV line	488 SE	666 SE	Cypress-Arcadian 345 kV line and North Appleton-Fitzgerald 345 kV line	81.1 %	Yes[4]
New East-Cedarsauk 345 kV line	653 SE	997 SE	New East-Granville 345 kV line and Cypress-Arcadian 345 kV line	N/A	No[5]
Elkhart Lake-Saukville 138 kV line	88 SE	146 SE	New East-Granville 345 kV line and New East-Cedarsauk 345 kV line	N/A	No[6]
Cypress-Arcadian 345 kV line	488 SE	584 SE		N/A	No[7]
Lau Rd (G611)-Elkhart Lake 138 kV line	96 SE	166 SE		N/A	No[8]
Granville 345/138 kV transformer T1	504 SE	541 SE	New East-Cedarsauk 345 kV line and Granville 345 kV bus tie 2-3	N/A	No[9]
Granville 345/138 kV transformer T3	478 SE	544 SE	Cypress-Arcadian 345 kV line and Granville 345 kV bus tie 1-2	12.3 %	No[10]

1. NERC Category C.3 events studied are limited to the concurrent outage of two elements without manual system adjustments between outages. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.
2. Includes provision for 5% TRM. The required ratings are calculations using AC analysis in PSS/E dispatching G833/J022 and G834/J023 to all MISO generation.
3. SE = Summer Emergency
4. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010.
5. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE. The existing line rating is limited by the line clearance (2156 ACSR @ 129F)
6. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (1-477 and 1-4/0 ACSR, 33.73 mile)
7. The line will be uprated to at least 572 MVA as part of G833/4-J022/3 interim upgrades. Whether additional 14 MVA is achievable without any significant constraints needs to be confirmed with Project Team. Generation redispatch using local generators would address the issue.
8. The line will be uprated to 112 MVA per G611/G927 G-T interconnection. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (4/0 ACSR, 28.9 mile: Forest Junction-Elkhart Lake)
9. Generation redispatch using the local generators would address the issue. It is limited by the transformer. The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
10. Generation redispatch using the local generators would address the issue. It is limited by the transformer (504 MVA SE) and equipment associated with the transformer. The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.

Table H.3.3.8 – Identified Thermal Violations under select NERC Category C.3 events[1] (TDF>5%), Summer Peak 2013 100% Load Delivery to MISO with Fix2 (East Switching Station), Competing Wind Farms at 20% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
Point Beach-Forest Junction 345 kV line	883 SE	944 SE	New East-Sheboygan Energy Center 345 kV line and Point Beach 345 kV bus tie 2-3	46 %	No[4]
Forest Junction-Fox River 345 kV line	1096 SE	1229 SE	North Appleton-Fox River 345 kV line and Point Beach 345 kV bus tie 3-4	48.1 %	No[5]
Point Beach-Sheboygan Energy Center 345 kV line	488 SE	649 SE	Point Beach 345 kV bus tie 2-3 and Point Beach-Forest Junction 345 kV line	52.9 %	Yes[6]
Neevin-Woodenshoe 138 kV line	332 SE	355 SE	New East-Sheboygan Energy Center 345 kV line and North Appleton-Fitzgerald 345 kV line	N/A	No[7]
Kewaunee-East Krok 138 kV line	287 SE	322 SE	New East-Sheboygan Energy Center 345 kV line and North Appleton-Kewaunee 345 kV line	N/A	No[8]
New East-Cedarsauk 345 kV line	653 SE	756 SE	New East-Granville 345 kV line and New East-South Fond du Lac 345 kV line	N/A	No[9]

1. NERC Category C.3 events studied are limited to the concurrent outage of two elements without manual system adjustments between outages. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.
2. Includes provision for 5% TRM. The required ratings are calculations using AC analysis in PSS/E dispatching G833/J022 and G834/J023 to all MISO generation.
3. SE = Summer Emergency
4. Generation redispatch using local generators or taking the bus tie out of service during Point Beach generation refueling outage window would address the issue. It is limited by the portion of the existing line conductor (1-2156 ACSR, 30.75 mile). The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
5. Generation redispatch using local generators or taking the bus tie out of service during Point Beach generation refueling outage window would address the issue. It is limited by the portion of the existing line conductor (1-2156 ACSR, 11.32 mile). The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
6. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010. The bus tie outage is not considered as NERC Category B contingency, but it is listed in the table for informational purpose.
7. Generation redispatch using local generators would address the issue. It is limited by the existing line conductor (1-795 ACSR, 4.4 mile)
8. Generation redispatch using local generators would address the issue. It is limited by the terminal equipment.
9. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE. The existing line rating is limited by the line clearance (2156 ACSR @ 129F)

Table H.3.3.9 – Identified Thermal Violations under select NERC Category C.5 events[1] (TDF>5%), Summer Off-Peak 2013 70% Load Delivery to MISO with Fix2 (East Switching Station), Competing Wind Farms at 100% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
Point Beach-Sheboygan Energy Center 345 kV line	488 SE	529 SE	Germantown-Maple-Saukville 138 kV line and Cypress-Arcadian 345 kV line	52.6 %	Yes[4]
New East-Cedarsauk 345 kV line	653 SE	870 SE	New East-Granville 345 kV line and Howard Grove-Plymouth #4-Holland 138 kV line	N/A	No[5]

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.
2. Includes provision for 5% TRM. The required ratings are calculations using AC analysis in PSS/E dispatching G833/J022 and G834/J023 to all MISO generation
3. SE = Summer Emergency
4. The line will be uprated to 1095 MVA (1834 A) per ATC Project PR03208. Estimated in-service date is 4/25/2010
5. Portion (~24 miles) of the existing line 796L41 (~33.3 miles) going southerly to Cedarsauk 345 kV line needs to be uprated to achieve at least 997 MVA SE. The existing line rating is limited by the line clearance (2156 ACSR @ 129F).

Table H.3.3.10 – Identified Thermal Violations under select NERC Category C.5 events[1] (TDF>5%), Summer Peak 2013 100% Load Delivery to MISO with Fix2 (East Switching Station), Competing Wind Farms at 20% output

Limiting Element	Existing Rating (MVA)	Required Rating[2,3] (MVA)	Worst Double Contingency	TDF (%)	Potential Solution Identified
None identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.

Table H.3.3.11 – Identified Voltage Violations under select NERC Category C.5 events[1] Summer Off-Peak 2013 70% Load Delivery to MISO, with Fix2 (East Switching Station), Competing Wind Farms at 100% output

Limiting Element	Worst Contingency[1]	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.

Table H.3.3.12 – Identified Voltage Violations under select NERC Category C.5 events[1] Summer Peak 2013 100% Load Delivery to MISO, with Fix2 (East Switching Station), Competing Wind Farms at 20% output

Limiting Element	Worst Contingency[1]	Voltage (p.u.)		ΔV (p.u.)	Potential Solution Identified
		Pre G833/4-J022/3	Post G833/4-J022/3		
None Identified	-	-	-	-	-

1. NERC Category C.5 events studied are limited to the simultaneous outage of any two circuits of a multi-circuit towerline. The transmission elements studied are local 345-kV and 138-kV facilities determined relevant based on engineering judgment.

Appendix I: Minimum Excitation Limits at Point Beach and Kewaunee with Proposed Solution

Minimum Excitation Limits (MELs) at Point Beach and Kewaunee with Proposed Solution

Based on the study results in Section H.3.2 of Appendix H.3, the minimum excitation limit study results with the proposed solution (Fix 11) is tabulated in Table I.1. With all Network Upgrades of G833/4-J022/3 in-service and based on the study results shown in Table I.1 in this ISIS report, the Point Beach and Kewaunee units would need to maintain the following minimum excitation levels to ensure synchronism of these and nearby generators:

- Post completion of the Proposed Solution and the Kewaunee bus reconfiguration project (With both Point Beach Units #1 and #2 upgraded)
  - Point Beach G1 and G2: 12 MVAR or higher per unit (gross)
  - Kewaunee G1: -19 MVAR or higher (gross)
- Table I.1 proves that installing a new Q-303 breaker in series with the existing breaker which is one of the G833/4-J022/3 "Interim" Network Upgrades is also beneficial for long-term system operation because Q-303 breaker failure appears to the most restrictive contingency causing less improvement in MELs. This is same for alternatives Fix 5 and Fix 13.

Table I.1. Minimum Excitation Limit Study Results (With G833/4-J022/3, With Proposed Solution and Kewaunee Reconfiguration Complete)

With Proposed Solution (KV and gross MVAR level at POB and KEW for stable system under critical faults)			
Critical Fault under Intact (tested clearing times)	High Gen Scenario (Gross MVAR)	Low Gen Scenario (Gross MVAR)	Comment
L111 BF @ POB (3.5/**9.0**/4.5)	346 kV or higher (POB G1: -20.7 POB G2: -20.7 KEW G1: -31.4)	346 kV or higher (POB G1: 4.8 POB G2: 4.8 KEW G1: -24.5)	Thus, minimum excitation limits with Proposed Solution in-service and Point Beach unit 1 & 2 upgraded) are: POB G1: 11.9 MVAR gross POB G2: 11.9 MVAR gross KEW G1: -19.6 MVAR gross (Assuming Q-303 series breaker at Point Beach installed) * Result of Q303 BF is valid only if Q303 relays are upgraded instead of a new Q303 series breaker
L151 BF @ POB (3.5/9.5/4.5)	346 kV or higher (POB G1: -20.7 POB G2: -20.7 KEW G1: -31.4)	347 kV or higher (POB G1: 11.9 POB G2: 11.9 KEW G1: -19.6)	
Q303 BF @ POB * (3.5/9.25/4.5) (see comment)	349 kV or higher * (POB G1: 31.5 POB G2: 31.5 KEW G1: 13.5)	350 kV or higher * (POB G1: 33.9 POB G2: 33.9 KEW G1: 6.8)	
R304 BF @ KEW (3.5/9.5/4.5)	345 kV or higher (POB G1: -37.9 POB G2: -37.9 KEW G1: -53.8)	345 kV or higher (POB G1: -2.9 POB G2: -2.9 KEW G1: -41.4)	

Appendix J: Project One Line Diagram of Propose Solution (Fix 11 and Uprating New East-Cedarsauk 345 kV line)

Note:

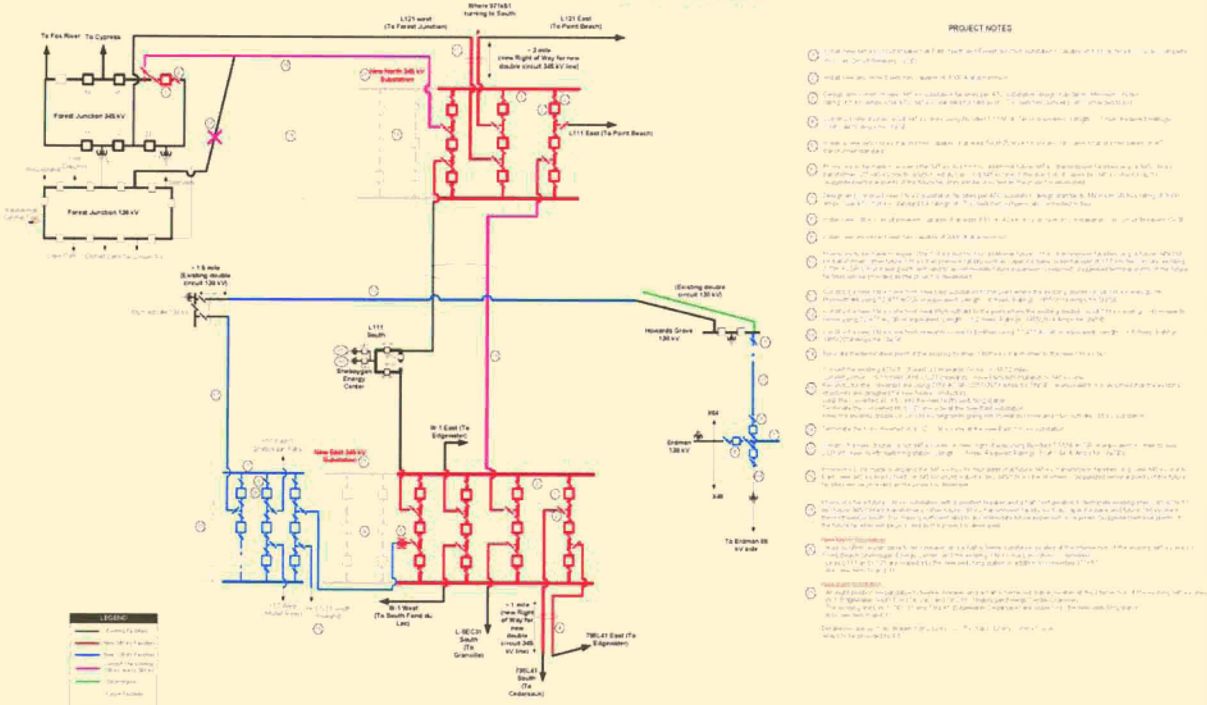
The project diagram does not show the required long-term network upgrade at the Point Beach substation (e.g. adding a new breaker in series with the existing Q303 line breaker) because the Q-303 breaker addition is already required for interim period operation.

G833/J022-G834/J023

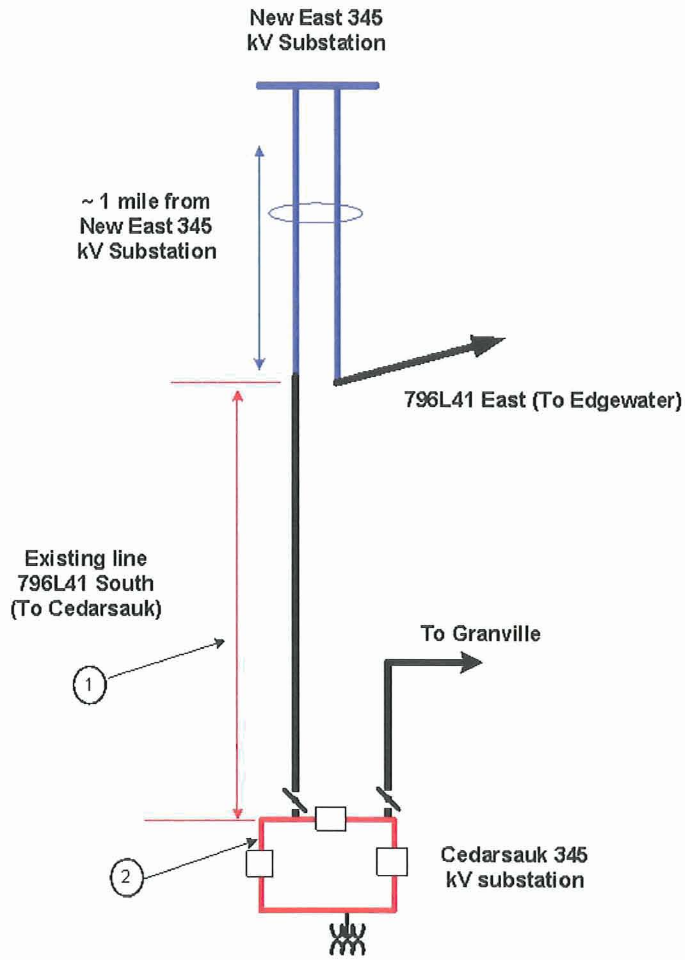
Fix 11:

New North 345 kV Switching Station (L111, L121), New East 345 kV Switching Station (W-1, SEC31, 796L41), Convert the The existing 138 kV line to 345 kV line (971K51, portion of HOLG21)

IN-SERVICE DATE: June 1, 2010



< Uprate Southern Portion of the existing line 796L41 to Cedarsauk 345 kV substation >



PROJECT NOTES

1. Perform line clearance study and uprate the southern portion of the existing line 796L41 to Cedarsauk 345 kV substation to at least 960 MVA (SE). If some of the existing structures need to be replaced with new structures, the new structures should be designed for ATC standard operating temperatures (200/300F for SN/SE).

2. Upgrade 1200:5 (3000:5 full) CTs on the Cedarsauk 345 kV ring bus to achieve at least 960 MVA (SE)