INTERCONNECTION SYSTEM IMPACT STUDY REPORT FOR PROJECT GI-1402

TOTAL REQUESTED OUTPUT OF 200 MW IN MEADE COUNTY, SD

WESTERN AREA POWER ADMINISTRATION

GI-1402: Queue Date: February 24, 2014; In-Service Date: December 2016

Primary Point of Interconnection: Maurine – New Underwood 230 kV line
Secondary Point of Interconnection: New Underwood 230 kV Bus

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Basin Electric Power Cooperative **Western Area Power Administration**	ABB Report #: 2014-E-13939	
Interconnection System Impact Study Report – Project # GI-1402	Issued: July 6, 2015	# Pages 38 + Appendices

EXECUTIVE SUMMARY

Western Area Power Administration (WAPA) commissioned ABB Inc., to perform an Interconnection System Impact Study (ISIS) for the interconnection of a 200 MW solar farm in Meade County, SD. The proposed generating project is queued in the WAPA/BEPC/Heartland Integrated System "IS" generator interconnection queue with a queue number of GI-1402. The primary point of interconnection of the proposed project is the Maurine – New Underwood 230 kV line, approximately 10 miles from New Underwood in Meade County, SD. An alternate or secondary point of interconnection at the New Underwood 230 kV bus was also studied.

This included an assessment of the impact of the proposed project based on steady-state, constrained interface, short-circuit and stability analysis. The study evaluated the impact of the proposed project and various mitigation strategies were evaluated at both points of interconnection.

A summary of the study results is presented below:

Steady-State Analysis

Steady-state analysis was performed for near-term (2014/2015) and out-year (2024) conditions. For the purposes of this analysis, the proposed project was dispatched to the MISO footprint to the east of the Twin Cities.

Impacts were observed on several local area transmission facilities. The extent of the impact depends on the status of some prior-queued generator interconnections in the study area (See Section 3.1 for details; based on the available information, some of these prior-queued interconnections have not been approved for transmission service as of the time of this study). In general, system performance is worse with these prior-queued interconnections that do not have approval for transmission service. Transmission constraints for the Primary and Secondary points of interconnection with these prior-queued interconnections included are presented for informational purposes only because it is unknown whether the prior-queued projects will proceed with transmission service. See Appendix D.

Analysis was also performed to determine possible injection constraints without the aforementioned prior-queued projects that have not been approved for transmission service. Tables 1 and 2 list the observed injection constraints for interconnection at the Primary POI in the near-term and out-year cases, respectively. These constraints will limit the ability of the proposed project to inject the full 200 MW at the Primary POI. There were no such injection constraints for interconnection at the Secondary POI.

Mitigation is necessary in order to accommodate the entire requested amount of 200 MW from the proposed project for interconnection at the Primary POI. At a minimum, the following system upgrades are required to mitigate the injection constraints:

- Upgrade Maurine 230/115 kV transformer to 175 MVA emergency
- Upgrade Maurine – Newell 115 kV line to 112 MVA emergency
- Upgrade Newell – Elk Creek 115 kV line to 102 MVA emergency
- Upgrade Elk Creek – Rapid City 115 kV line to 101 MVA emergency

System upgrades are not required for interconnection at the Secondary POI because no injection constraints were observed in the Secondary POI cases.

Maximum Allowable Injection

A sensitivity analysis was performed to determine the maximum allowable injection for project GI-1402 such that it does not overload those lines included in the list of injection constraints presented previously. For the purposes of this analysis, the above-mentioned upgrades were not included. Results show that the maximum allowable injection is 66.5 MW (Primary POI) and 200 MW (Secondary POI). See Section 3.3 for details.

Constrained Interface Analysis

The study evaluated the impact of the proposed project on constrained interfaces in the MAPP and MISO systems. They are provided for informational purposes only, to identify potential third party flow gate issues for the requested delivery component of the transmission.

Short Circuit Analysis

Short-circuit analysis was performed to evaluate the impact of the proposed project on fault currents at nearby substations. A comparison of the post-project fault currents to the minimum breaker capability of the existing breakers at the local substations indicates that there is adequate interrupting capability following the addition of the proposed project.

Stability Analysis

Stability analysis was performed considering both the Primary and Secondary POIs. Results of the analysis show that interconnection at the Primary POI is not possible due to significant stability criteria violations following local faults, but it is possible to interconnect at the Secondary POI. No mitigation is needed for regional faults, assuming interconnection at the Secondary POI. Results show that no stability problems exist with this interconnection if GI-1402 is connected to the New Underwood 230 kV East bus. Interconnection at the New Underwood 230 kV West Bus may or may not be possible due to criteria violations following local faults – this depends on the interconnection of prior-queued project GI-1401. At the time this study was completed, there were two possible interconnection options for project GI-1401 (325 MW at Maurine 230 kV –or- 103 MW on the Maurine – Newell 115 kV line). If project GI-1401 interconnected at 325 MW at the Maurine 230 kV bus, then it would not be possible to interconnect GI-1402 at the New Underwood 230 kV West bus. However, if GI-1401 proceeded at 103 MW on the Maurine – Newell 115 kV line, then GI-1402 can interconnect at the New Underwood 230 kV East or West buses. After completion of this study GI-1401 decided to proceed at 103 MW on the Maurine-Newell 115 kV line. See Section 6 for details.

Cost Estimate for Network Upgrades

Preliminary conceptual cost-estimates associated with the network upgrades required for GI-1402 (200 MW) to interconnect were provided by WAPA and are shown in Tables 3 and 4 below. These are non-binding good faith cost estimates for planning purposes and are for information only. These estimates will be further developed and refined in the Facility Study.

Table 1: Steady-State Injection Constraints for Interconnection on Maurine – New Underwood 230 kV Line (Near-term Cases)

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Table 2: Steady-State Injection Constraints for Interconnection on the Maurine – New Underwood 230 kV Line (Out-Year Cases)

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Table 3: GI-1402 Conceptual Cost Estimate for Interconnection of 200 MW (Primary Point of Interconnection)

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Table 4: GI-1402 Conceptual Cost Estimate for Interconnection of 200 MW (Secondary Point of Interconnection)

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1 INTRODUCTION

1.1 DESCRIPTION OF PROJECT

Western Area Power Administration (WAPA) commissioned ABB Inc. to perform an Interconnection System Impact Study for the interconnection of a 200 MW solar farm queued in the WAPA/BEPC/Heartland Integrated System "IS" generator interconnection queue with a queue number of GI-1402.

The primary point of interconnection of this project is on the Maurine – New Underwood 230 kV line, approximately ten (10) miles from New Underwood. An alternate or secondary point of interconnection at the New Underwood 230 kV bus was also studied. Figure 1 shows a diagram of the transmission system in the vicinity of the proposed project. The projected in-service date for the GI-1402 project is December 2016.

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Figure 1: Geographic Location of Project GI-1402 [CEII REMOVED]

2 STUDY METHODOLOGY

2.1 STEADY-STATE ANALYSIS

The purpose of steady-state analysis is to analyze the impact of the proposed project on transmission system facilities under steady-state conditions. It involves two distinct analyses: thermal analysis and voltage analysis.

A "study area" was defined to represent the areas of interest which included: WAPA (area 652), GRE (615), OTP (620), XEL (600), MDU (661), NPPD (640) and MEC (635).

2.1.1 Thermal Analysis

Transmission facilities rated 100 kV and above in the study area were monitored. For the purposes of this analysis, Rate A is the continuous facility rating and Rate B is the emergency rating.

System Intact Analysis:

The incremental impact of the proposed project on thermal loading of transmission facilities under system intact conditions was evaluated by comparing transmission system power flows with and without the proposed project. For this purpose, full ac power flow solutions were used.

The criteria to flag thermal overloads is 100% of continuous facility rating (Rate A in the power flow model). MAPP DRS Guidelines [2] were used to identify Significantly Affected Facilities (SAF). According to these guidelines, all overloaded facilities that have a TDF (Transfer Distribution Factor) greater than 5% of the generation additions (without plant vs. with plant) were flagged as SAF.

Contingency Analysis:

The contingency list included single branch outages in the monitored systems, plus Category B and Category C outages in the Dakotas, Minnesota and Nebraska. Contingencies were solved with phase shifters, switched shunts and transformer taps enabled. Thermal violations were flagged based on the Rate A data for facilities (from the power flow model). Post-contingency power flows in excess of 100% of Rate A were flagged. Facility loadings with and without the proposed project were tabulated and compared.

As in the system intact analysis, MAPP DRS Guidelines were used to identify Significantly Affected Facilities (SAF). Facilities with a TDF greater than 3% were included in the SAF list.

2.1.2 Voltage Analysis

Voltages at buses rated 100 kV and above inside the study area were monitored for possible pre- and post-contingency voltage violations in accordance with reference [1]. In accordance with MAPP DRS Guidelines, those buses having a voltage deviation greater than 0.01 pu (without plant vs. with plant) are considered significantly affected.

2.1.3 Criteria for Identifying and Mitigating Interconnection Constraints

SAFs in the electrical vicinity of the Maurine and New Underwood substations are considered to be interconnection constraints. These constraints will limit the ability of the proposed project to inject power into the grid. Transmission upgrades will be required to resolve these constraints.

2.1.4 Constrained Interface Analysis

The purpose of the constrained interface analysis is to calculate the impact of the proposed project on specified constrained interfaces in the MAPP and MISO transmission systems. The MAPP DFCALC constrained interface analysis program was used for this purpose.

2.2 SHORT-CIRCUIT ANALYSIS

The purpose of short-circuit analysis is to determine fault current levels at the point of interconnection, both before and after the addition of the proposed project. Three-phase and single-line-to-ground faults were simulated at the point of interconnection and the impact of the proposed project on the increase in fault currents was determined.

2.3 STABILITY ANALYSIS

The purpose of the stability analysis is to determine whether the MAPP system would meet stability criteria following commissioning of the proposed GI-1402 project. To that end, local and regional faults were simulated to assess the impact of the proposed project on transmission system stability.

3 STEADY STATE ANALYSIS

3.1 MODEL DEVELOPMENT

The pre-project cases for this analysis were developed by WAPA based on the 2013 MRO series models. These cases were developed using the 6-digit UMTAG package dated 01-22-2014. Cases were developed for the following study years and system conditions.

- 2014 Summer Off-Peak (so14)
- 2015 Summer Peak (sp15)
- 2015 Winter Peak (wp15)
- 2024 Summer Peak (sp24)
- 2024 Winter Peak (wp24)

The out-year cases include the following major transmission lines that are not included in the near-term cases:

- Ellendale – Big Stone 345 kV line
- Big Stone – Brookings County 345 kV line
- Antelope Valley – Tioga 345 kV line[1]
- Bison – Alexandria – Quarry – Monticello 345 kV line (included in 2015 and 2024 cases, but not in the 2014 case)

Prior-queued projects included in these cases are listed in Table 3-1. It should be noted that this is not an all-inclusive list.

The corresponding post-project cases were developed by adding the proposed GI-1402 solar farm and dispatching it to the MISO footprint to the east of the Twin Cities.

Two sets of pre- and post-project cases were developed to evaluate the impact of the proposed project.

- Interconnection Cases: These cases include prior-queued generation projects that have been approved for interconnection (as of the time of the study) – these projects may (or may not) have rights to deliver power to the transmission system.

- Transmission Rights Cases: These cases include prior-queued projects that have been approved for both interconnection and delivery service i.e., projects that have transmission rights (as of the time of the study).

Both the initial Interconnection Cases and the Transmission Rights Cases were provided by WAPA. Modeling assumptions for the following prior-queued projects were updated to create the final pre-project Interconnection and Transmission Rights Cases.

- GI-0515: Disconnected (project withdrawn from the IS generation interconnection queue)
- GI-1301: Dispatch adjusted to 90 MW (as per IS queue)

[1] This 345 kV line includes the following sections: AVS - Charlie Creek #2 + Charlie Creek - Judson 345 + Judson - Tande 345 kV line (Tande is located close to Neset and Tioga).

The Transmission Rights Cases were further developed according to comments from MEC and MDU. In all cases, a wind farm at Macksburg was added and dispatched according to seasonal projections (information provided by MEC).

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Additionally, dispatches of the wind farms at SHD and LGR were adjusted for each case (information provided by MEC).

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The proposed project will be required to mitigate injection constraints seen in the Transmission Rights Cases; constraints in Interconnection Cases are "for information only."

The single-line diagrams for the pre- and post-project Transmission Rights Cases are shown in Appendix A.

Table 3-1: Prior-queued Projects

Project Queue Number	Location/Description	Size (MW)
GI-0708	Culbertson	120
G645	Ladish 1 (Ladish 115 kV)	99
G788	Ladish 115 kV	
G752	Hettinger 230 kV	150
G723	Heskett 115 kV	7
J003	Baker 115 kV	19.5
GI-0614A	Culbertson Waste Heat	7.5
GI-0508	Ecklund (Wilton 1)	49.5
GI-0615	Ecklund (Wilton 2)	49.5
GI-0715	Hilken 230 kV (Baldwin; Wilton 3)	100
GI-0727	Bismarck-Garrison 230 kV	102.4
GI-0926	Dickinson-Mandan 230 kV	200
GI-1001	Glenham-Bismarck 230 kV	99
GI-1007	Antelope Valley 345 kV	172.5
GI-1105, GI-1205, GI-1207	Stateline 115 kV	150
GI-1202, GI-1204, GI-1208	Hay Butte 115 kV	150
GI-1212	Wolf Point-Circle 115 kV	75
GI-1301	Summit – Watertown 115 kV line	80
GI-1309	Redfield NW 115 kV	19.5
GI-1401	Maurine – Newell 115 kV line	325

3.2 STEADY STATE ANALYSIS RESULTS

Contingency analysis was performed in two steps as described below:

First, a DC power flow analysis (DCCC) was performed in order to identify Significantly Affected Facilities (SAF) and limiting contingencies. This step was performed on both the Interconnection Cases and Transmission Rights Cases and utilized contingencies described in Section 2.1.1.

Next, limiting contingencies in the Transmission Rights DC power flow analysis results were selected for further evaluation with full AC power flow solution. In addition, single contingencies on branches connected to the following buses were also simulated using AC analysis.

- Maurine 230 kV
- Maurine 115 kV
- Elk Creek 115 kV
- Rapid City 115 kV
- New Underwood 115 kV
- New Underwood 230 kV

3.2.1 DC Power Flow Results

The DC power flow results for the Primary and Secondary POI Interconnection Cases are shown in Appendix D and are for information only. Injection constraints are highlighted in yellow.

3.2.2 Near-Term Power Flow Results (AC Analysis)

The AC power flow results for near-term transmission rights cases are shown in Table 3-2 (Primary POI) and in Table 3-3 (Secondary POI). These tables show the Significantly Affected Facilities associated with the interconnection of the proposed project.

<u>Thermal Analysis</u>

Table 3-2 shows significantly affected facilities for interconnection at the Primary POI. In particular, several transmission lines became loaded over and above respective emergency ratings following the loss of the New Underwood – POI 230 kV line. This contingency induces thermal overloads in the underlying 115 kV transmission network between the Maurine and New Underwood substations. This is primarily due to the inability of those lines to handle the full output of the 200 MW solar farm following the aforementioned contingency. In general, power attempts to route to the Maurine 230 kV bus, and then through the 115 kV lines into the New Underwood substation. The following transmission facilities highlighted in yellow are considered injection constraints:

1. Maurine 230/115 kV Transformer
2. Maurine - Newell 115 kV Line
3. Newell - Elk Creek 115 kV Line
4. Elk Creek - Rapid City 115 kV Line

No injection constraints were observed for interconnection at the Secondary POI.

Voltage Analysis

Buses whose voltages were adversely impacted following the addition of the proposed project with impacts greater than 0.01 pu were considered significantly affected. No buses in the monitored area exhibited such behavior.

Table 3-2: Significantly Affected Facilities for Primary Point of Interconnection, Thermal Analysis (Near-Term Transmission Rights Cases)

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Table 3-3: Significantly Affected Facilities for Secondary Point of Interconnection, Thermal Analysis (Near-Term Transmission Rights Cases; Contingency Case Conditions)

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3.2.3 Out-Year Power Flow Results (ACCC)

The AC power flow results for the out-year transmission rights cases are shown in Table 3-4 (Primary POI) and Table 3-5 (Secondary POI).

Thermal Analysis

Table 3-4 shows injection constraints near the Primary POI on the following transmission facilities:

1. Maurine 230/115 kV Transformer
2. Maurine - Newell 115 kV Line
3. Newell - Elk Creek 115 kV Line
4. Elk Creek - Rapid City 115 kV Line

As in the near-term examination, no injection constraints exist near the Secondary POI, as shown in Table 3-5.

Voltage Analysis

As in the near-term cases, the out-year Transmission Rights Cases did not exhibit significant voltage impacts.

Table 3-4: Significantly Affected Facilities for Primary Point of Interconnection (Out-Year Transmission Rights Cases)

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Table 3-5: Significantly Affected Facilities for Secondary Point of Interconnection (Out-Year Transmission Rights Cases)

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3.3 SENSITIVITY ANALYSIS

A sensitivity was performed to determine the maximum allowable injection for project GI-1402 such that the transmission lines previously flagged as injection constraints are not overloaded based on their normal (Rate A) and emergency (Rate B) ratings under system-intact and contingency conditions, respectively. The analysis was performed using the transmission rights cases for the Primary POI in both near-term and out-year systems. No analysis was performed on the Secondary POI cases because no injection constraints were identified in those cases.

Near-term Transmission Rights Cases

Results show that the maximum allowable injection (FCITC) for interconnection at the Primary POI is 66.5 MW based on the 2014 summer off-peak case. This is based on the post-contingency loading on the Maurine 230/115 kV transformer following the outage of the GI-1402 POI – New Underwood 230 kV line.

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Out-year Transmission Rights Cases

The maximum allowable injection for interconnection at the Primary POI is 76.0 MW; this calculation was determined from 2024 summer peak results. This is based on the same contingency as in the near-term examination: outage of the GI-1402 POI – New Underwood 230 kV line. As was the case in the near-term case, the limiting element is the Maurine 230/115 kV transformer under contingency conditions.

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3.4 MITIGATION OF STEADY STATE VIOLATIONS

Results of Section 3.2 show the following injection constraints in the near-term and out-year Transmission Rights Cases for interconnection at the Primary POI. No injection constraints were identified for interconnection at the Secondary POI.

- Maurine 230/115 kV transformer
- Maurine – Newell 115 kV line
- Newell – Elk Creek 115 kV line
- Elk Creek – Rapid City 115 kV line

Mitigation is necessary in order to accommodate the entire requested amount of 200 MW from the proposed project for interconnection at the Primary POI. At a minimum, the following system upgrades are required to mitigate the injection constraints:

- Upgrade Maurine 230/115 kV transformer to 175 MVA emergency
- Upgrade Maurine – Newell 115 kV line to 112 MVA emergency
- Upgrade Newell – Elk Creek 115 kV line to 102 MVA emergency
- Upgrade Elk Creek – Rapid City 115 kV line to 101 MVA emergency

System upgrades are not required for interconnection at the Secondary POI because no injection constraints were observed.

4 CONSTRAINED INTERFACE ANALYSIS

The purpose of this task was to determine if the GI-1402 project would adversely impact the regional constrained interfaces (PTDF and OTDF interfaces) of the MRO system. The analysis was performed for interconnection at the Primary POI. The NMORWG DFCALC IPLAN program was used to calculate the TDFs on the near-term and out-year summer peak transmission rights power flow models with and without the proposed project. The mitigation described in Section 3.5 was not included in the models used for this analysis.

The interface and flow-gate definitions were obtained from the definition files “ties-MRO-2013series-2014-new.txt” for near-term cases and “ties-MRO-2013series-2024-new.txt” for out-year cases. Flows on some of the remote interfaces/flowgates could not be monitored due to topology differences between the case and the interface definitions. These flowgates are remote from the area of interest and no further effort was made to reconcile these differences.

Table 4-1 compares the interface flows for the near-term cases with and without the proposed project. The table shows the transfer distribution factor (in percent) for the 200 MW net power transfer from the proposed project to the sink. For the PTDF interfaces, impacts > 5% and for OTDF interfaces, impacts > 3% from pre-project condition are shown in this table. Similar results for out-year cases are shown in Table 4-2.

Mitigation may be required if it is determined that there is insufficient or no available transfer capability (ATC) on the affected MAPP constrained interfaces. This is an issue that should be addressed with the system impact study for delivery service should the proposed project go forward.

Table 4-1: Impact of GI-1402 on Constrained Interfaces (Near-Term)

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Table 4-2: Impact of GI-1402 on Constrained Interfaces (Out-Year)

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5 SHORT CIRCUIT ANALYSIS

Short-circuit calculations were performed to determine the impact of the GI-1402 project on fault current levels in the transmission system. Both points of interconnection were considered in this analysis.

5.1 MODEL DEVELOPMENT

The pre- and post-project cases for this analysis were developed starting from the post-project short-circuit case used in the GI-1301 System Impact Study. See reference [3]. These short-circuit models were developed starting from Case "2012-post-GI-1301-poi2-v29.sav." The proposed project was then added as specified to develop the post-project cases.

5.2 SHORT CIRCUIT ANALYSIS ASSUMPTIONS

Activity ASCC in PSS/E was used to calculate the fault current at selected buses in the vicinity of the proposed project (see Section 5.3). Flat assumptions (1.0 pu voltage at all buses) were used to derive the fault current levels.

5.3 SHORT CIRCUIT ANALYSIS RESULTS

All buses 69 kV and above in WAPA (area 652), XEL (600), 618 (GRE) and 626 (OTP) were studied. Buses where the fault currents increased by 100 A or more (post-project vs. pre-project) were retained. Results for the Primary POI are tabulated in Table 5-1; results for the Secondary POI are tabulated in Table 5-2.

Table 5-1: Comparison of Pre- and Post-Project Fault Currents for Interconnection at the Primary POI

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Table 5-2: Comparison of Pre- and Post-Project Fault Currents for Interconnection at the Secondary POI

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6 STABILITY ANALYSIS

The purpose of this analysis was to determine whether the MAPP system would meet stability criteria following commissioning of the proposed project. Local and regional contingencies were simulated under 2016 summer off-peak conditions. Stability analysis was performed at both the Primary and Secondary points of interconnection for GI-1402.

6.1 MODEL DEVELOPMENT

The pre- and post-project cases for this analysis were developed starting from the cases included in the November 11, 2014 Stability Package developed by BEPC and WAPA. This package utilizes PTI PSS/E™ Rev 32.1 and Version 11.1 of the Intel Visual Fortran Compiler.

The pre-project case for this analysis was developed from a 2016 high-transfer summer off-peak case developed by BEPC. Several modifications were made to this case prior to use in this study. The following is a summary of some of the relevant assumptions that went into developing this case:

- North Dakota Coal Field generators are modeled at URGE levels
- South Dakota hydros are modeled at URGE levels
- South Dakota wind units in the electrical vicinity of Maurine and New Underwood substations are dispatched at 100% of nameplate – these included the following projects:
    - GI-1401 (325 MW wind farm at Maurine 230 kV)
    - G752 (150 MW wind farm at Hettinger 230 kV)
    - GI-1209 (99 MW wind farm on Ft. Randall – Lake Platte 230 kV line)
- All other wind in ND and SD is generally modeled at 20% of nameplate.
- Peaking units are modeled off-line (these include Groton, Culbertson, Pioneer, Lonesome Creek etc.)
- Southwest Minnesota Wind is modeled at 1500 MW.
- HVDC line flows are modeled as follows:
    - Square Butte – Arrowhead DC: 550 MW
    - Rapid City DC (RCDC): 200 MW East to West
    - Miles City Converter Station (MCCS): 150 MW West to East

  Note: A separate stability case was developed with the RCDC and MCCS flows reversed.

The following major transmission projects are included in the case:

- Bemidji – Grand Rapids 230 kV line
- Center – Grand Forks 345 kV line
- Fargo – St. Cloud – Monticello 345 kV lines
- Brookings – Hampton County 345 kV line
- Riel 345 kV substation

Flows on the major interfaces in Northern MAPP were modeled as follows:

- Manitoba Hydro Export (MHEX): Approx. 2175 MW in the north to south direction
- Minnesota – Wisconsin Export (MWEX): Approx. 1611 MW in the west to east direction
- Flows on the North Dakota Export (NDEX) interface were not constrained.

Given the proximity of the proposed project to the Rapid City DC line, two sets of pre-project cases were developed:

- Case *a11-s716aa.sav:* RCDC: 200 MW E → W; MCCS: 150 MW W → E (these assumptions bias the flow on the Hettinger – Bison – Maurine 230 kV line in a north to south direction)

- Case *b11-s716aa.sav:* RCDC: 200 MW W → E; MCCS: 150 MW E → W (these assumptions bias the flow on the Maurine – Bison – Hettinger 230 kV line in a south to north direction)

After developing the pre-project case, four post-project cases were developed by adding project GI-1402 as noted below and dispatching it at 200 MW against the MISO footprint east of the Twin Cities. The four post-project cases are as follows:

<u>GI-1402 at Primary POI on the New Underwood – Maurine 230 kV line</u>:

- Case a21-s716aa.sav: RCDC: 200 MW E → W; MCCS: 150 MW W → E

- Case b21-s716aa.sav: RCDC: 200 MW W → E; MCCS: 150 MW E → W

<u>GI-1402 at Secondary POI on the New Underwood 230 kV bus</u>:

- Case a22-s716aa.sav: RCDC: 200 MW E → W; MCCS: 150 MW W → E

- Case b22-s716aa.sav: RCDC: 200 MW W → E; MCCS: 150 MW E → W

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6.2 FAULT DEFINITIONS

Stability analysis was performed on the cases derived in the previous section to determine the impact of the proposed project. A limited number of faults were run. These included critical regional faults in Northern MAPP (see Table 6-1) and local faults in the project vicinity (see Table 6-2 and Table 6-3 for Primary and Secondary POI faults, respectively).

Local faults were developed as follows:

- For interconnection at the Primary POI, a three-breaker ring bus was assumed at the point of interconnection on the New Underwood – Maurine 230 kV line.

- For interconnection at the Secondary POI, the proposed project is connected directly to the New Underwood 230 kV bus (faults involving connection at the New Underwood 230kV East Bus, and separately at the West Bus, were developed).

In accordance with the analysis performed in reference [5], prior-queued project GI-1401 is assumed to be interconnected at the Maurine 230 kV bus (breaker configuration "B" described in reference [5] was assumed).

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Table 6-1: List of Faults for Stability Analysis – Regional Disturbances

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Table 6-2: List of Faults for Stability Analysis – Local Disturbances, Primary POI

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Table 6-3: List of Faults for Stability Analysis – Local Disturbances, Secondary POI

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6.3 SIMULATION RESULTS

Results of the stability analysis for GI-1402 are given below. Results are provided for both regional and local area faults. Simulation summary tables for these faults are given in Appendix F.

6.3.1 Primary POI

Interconnection at the Primary POI is not feasible from the standpoint of stability due to issues associated with results from local fault analysis. See below.

6.3.1.1 Local Disturbances

Fault bh3 met stability criteria. The following faults, however, exhibited stability criteria violations:

- Faults bg3, bq1 and bq4: *(CEII Removed)* The system cannot support this amount of injection at the Maurine 230 kV bus, a significant portion of which is thrust on to the 115 kV network between Maurine and New Underwood, thus resulting in voltage collapse.

- Fault bh1: *(CEII Removed)* The network cannot support this amount of power, thus causing a voltage collapse condition.

- Fault bn1: *(CEII Removed)*

6.3.1.2 Regional Disturbances

Regional disturbances were not simulated considering interconnection of GI-1402 at the Primary POI due to the stability results of local disturbances deeming interconnection at this POI infeasible.

6.3.2 Secondary POI

Interconnection at the Secondary POI is feasible from the standpoint of stability. However, the project must be interconnected at the New Underwood 230 kV East bus. See below.

6.3.2.1 Local Disturbances

The following faults exhibited stability criteria violations. All other local faults met stability criteria.

- Fault bt1: *(CEII Removed)*

- Fault bt4: *(CEII Removed)*

Based on the above results, interconnection of project GI-1402 at the New Underwood 230 kV West Bus aggravates stability performance. Interconnection at the New Underwood 230 kV East Bus is acceptable.

6.3.2.2 Regional Disturbances

All regional faults were seen to be stable. The following faults, however, exhibited stability criteria violations:

- Fault pas: *(CEII Removed)*
- Fault oas: *(CEII Removed)*

Figure 6-1: Voltage at New Underwood 115 kV bus following fault bt1, pre- and post-project [CEII REMOVED]

Figure 6-2: Voltage at New Underwood 115 kV bus following fault dt1, post-project
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Figure 6-3: Voltage at New Underwood 115 kV bus following fault bt4, pre- and post-project [CEII REMOVED]

Figure 6-4: Voltage at New Underwood 115 kV bus following fault dt4, post-project
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6.4 Sensitivity with Prior-Queued Project GI-1401 Reduced to 103 MW

A sensitivity was performed to evaluate stability of project GI-1402 with project GI-1401 interconnected at its Primary POI on the Maurine – Newell 115 kV line at a reduced dispatch of 103 MW. This reduced injection level was studied at the request of the GI-1401 generation developer. The sensitivity was performed considering interconnection of project GI-1402 at both its Primary and Secondary POIs.

6.4.1 Case Development

Cases for this analysis were developed from cases a13-s716aa and b13-s716aa used in the GI-1401 System Impact Study [5]. No modifications were made to these cases aside from the connection of project GI-1402 to the appropriate POI. Summaries of these cases are given below:

- Case *a23-s716aa.sav:* GI-1402 at Primary POI, RCDC: 200 MW E → W; MCCS: 150 MW W → E (these assumptions bias the flow on the Hettinger – Bison – Maurine 230 kV line in a north to south direction)

- Case *b23-s716aa.sav:* GI-1402 at Primary POI, RCDC: 200 MW W → E; MCCS: 150 MW E → W (these assumptions bias the flow on the Maurine – Bison – Hettinger 230 kV line in a south to north direction)

- Case *a24-s716aa.sav:* GI-1402 at Secondary POI, RCDC: 200 MW E → W; MCCS: 150 MW W → E

- Case *b24-s716aa.sav:* GI-1402 at Secondary POI, RCDC: 200 MW W → E; MCCS: 150 MW E → W

6.4.2 Fault Definitions for Sensitivity Cases

Local faults for the sensitivity cases are similar to those in previous analysis (Section 6.2), though some faults were added or eliminated based on the assumed breaker configuration at Maurine 230 kV. Regional faults for the sensitivity analysis were unchanged. Descriptions of local faults for both the Primary and Secondary POIs are given in Table 6-4 and Table 6-5 below.

Table 6-4: List of Faults for Stability Analysis, Primary POI Sensitivity Cases – Local Disturbances

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Table 6-5: List of Faults for Stability Analysis, Secondary POI Sensitivity Cases – Local Disturbances

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6.4.3 Sensitivity Simulation Results

All regional faults and local faults associated with GI-1402 at its Secondary POI were seen to be stable, and GI-1402 and prior-queued projects continued to remain on-line during all local and regional disturbances. However, faults bqs and bqz, both Primary POI-associated faults, resulted in voltage collapse conditions. This behavior is assessed below.

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Summaries of local fault results for the Primary and Secondary POI are given in Table 6-6 and Table 6-7, respectively.

Figure 6-5: Voltages at New Underwood 115 kV and New Underwood 230 kV buses, simulation of fault bqs [CEII REMOVED]

Figure 6-6: Voltages at New Underwood 115 kV and New Underwood 230 kV buses, simulation of fault bqz [CEII REMOVED]

Table 6-6: Local area stability results, Primary POI
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Table 6-7: Local area stability results, Secondary POI
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6.5 CONCLUSIONS

Results of the stability analysis show that interconnection at the Primary POI is not possible due to significant stability criteria violations following local faults, but it is possible to interconnect at the Secondary POI. No mitigation is needed for regional faults, assuming interconnection at the Secondary POI. Results show that no stability problems exist with this interconnection if GI-1402 is connected to the New Underwood 230 kV East bus. Interconnection at the New Underwood 230 kV West Bus may or may not be possible due to criteria violations following local faults – this depends on the interconnection of prior-queued project GI-1401. At the time this study was completed, there were two possible interconnection options for project GI-1401 (325 MW at Maurine 230 kV -or- 103 MW on the Maurine – Newell 115 kV line). If project GI-1401 interconnected at 325 MW at the Maurine 230 kV bus, then it would not be possible to interconnect GI-1402 at the New Underwood 230 kV West bus. However, if GI-1401 proceeded at 103 MW on the Maurine – Newell 115 kV line, then GI-1402 can interconnect at the New Underwood 230 kV East or West buses. After completion of this study GI-1401 decided to proceed at 103 MW on the Maurine-Newell 115 kV line.

7 REFERENCES

[1] "MAPP Members Reliability Criteria and Study Procedures Manual", Version 1.1, September 2013.

[2] "MAPP Design Review Subcommittee Policies and Procedures", Prepared by MAPP Design Review Subcommittee Members, Version 2.2b, March 2013.

[3] "Interconnection System Impact Study Report for Project GI-1301", Prepared by ABB Inc., May 15, 2014.

[5] "Interconnection System Impact Study Report for Project GI-1401", Prepared by ABB Inc., June 2, 2015.