Interim Availability Interconnection System Impact Study for Generator Interconnection

GEN-2016-036

March 2018
Generator Interconnection

Revision History

Date	Author	Change Description
3/7/2018	SPP	Interim Availability Interconnection System Impact Study (IAISIS) for Generator Interconnection Request GEN-2016-036 Report Revision 0 Issued

Executive Summary

GEN-2016-036 (Interconnection Customer) has requested an Interim Availability Interconnection System Impact Study (IAISIS) under Section 11A of Attachment V (Generator Interconnection Procedures - GIP) to the Southwest Power Pool Open Access Transmission Tariff (OATT) for 44.6 MW of wind generation to be interconnected with Energy Resource Interconnection Service (ERIS) into the integrated transmission system of Western Area Power Administration (WAPA) in Chippewa County, Minnesota. GEN-2016-036 has requested this IAISIS to determine the impacts of interconnecting to the transmission system before all required Network Upgrades identified in the DISIS-2016-001 (or most recent iteration) Impact Study can be placed into service.

This IAISIS addresses the effects of interconnecting the generator to the rest of the transmission system for the system topology and conditions as expected on December 31, 2018. GEN-2016-036 is requesting the interconnection of sixteen (16) GE 2.5 MW and two (2) GE 2.3 MW wind turbines and associated facilities interconnecting at the Granite Falls 115 kV substation Chippewa County Minnesota. For this IAISIS, power flow, stability and short circuit analysis was conducted. The IAISIS assumes that only the higher queued projects listed within Table 1 of this study might go into service before the completion of all Network Upgrades identified within
Table *2* of this report. If additional generation projects, listed within Table 3, with queue priority equal to or higher than the study project request rights to go into commercial operation before all Network Upgrades identified within
Table 2 of this report are completed, this IAISIS may need to be restudied to ensure that interconnection service remains for the customer’s request.

Power flow and stability analysis from this IAISIS has determined that the GEN-2016-036 request can interconnect 44.6 MW of generation with Energy Resource Interconnection Service (ERIS) on 12/31/2018 prior to the completion of the required Network Upgrades, listed within
Table 2 of this report. Should any other projects, other than those listed within Table 1 of this report, come into service an additional study may be required to determine if any limited operation service is available. It should be noted that although this IAISIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customers may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

In accordance with FERC Order 827 GEN-2016-036 will be required to provide dynamic reactive power within the power factor range of 0.95 leading (absorbing Vars from the network) to 0.95 lagging (providing Vars to the network) at continuous rated power output at the high side of the generator substation.

The power flow analysis for this IAISIS observed constraints on Affected Systems and the Limited Operation amounts provided within this IAISIS report are subject to Affected System Interim Availability Interconnection System Impact Study analysis and results. Should the Interconnection

Customer elect to continue with IAISIS, the Interconnection Customer will need to coordinate with the Affected System Parties for Affected System Interim Availability Interconnection System Impact Study or an equivalent study. Affected System constraints with 3% distribution impact factor are in the Appendix A (Affected System Thermal Constraints) and Appendix B (Affected System Voltage Constraints). Any additional Affected System constraints observed in the DISIS-2016-002 or latest restudy could be evaluated by the Affected System party for the Affected System Interim Availability Interconnection System Impact Study.

Transient stability analysis for this IAISIS has determined that GEN-2016-036 request will be limited to a maximum of 44.6 MW output. No other transient stability issues were observed for the transmission system for the forty-one (41) selected faults for the limited operation interconnection of GEN-2016-036 and the analysis shows that the generator will meet Low Voltage Ride-Through (LVRT) requirements of FERC Order #661A. As discussed above, this amount may be reduced further dependent upon system conditions at the time of the outage.

Nothing in this study should be construed as a guarantee of delivery or transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the Customer.

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Purpose

GEN-2016-036 (Interconnection Customer) has requested a Limited Operation System Impact Study (IAISIS) under the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection requests into the integrated transmission system of Western Area Power Administration (WAPA).

The purpose of this study is to reevaluate the impacts of interconnecting GEN-2016-036 request with a total of 44.6 MW comprised of sixteen (16) GE 2.5MW wind turbines and two (2) GE 2.3MW and associated facilities interconnecting at the Granite Falls 115 kV substation Chippewa County Minnesota. The Interconnection Customer has requested this amount to be studied with Energy Resource Interconnection Service (ERIS) to commence on or around December 2018. Additionally, Interconnection Customer has requested this IAISIS analysis be conducted without accounting for the GEN-2017-103 generation.

Both power flow and transient stability analysis were conducted for this Limited Operation Interconnection Service. Limited Operation Studies are conducted under GIA Section 11A.

The IAISIS considers the Base Case as well as all Generating Facilities (and with respect to (b) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the IAISIS is commenced:

a) are directly interconnected to the Transmission System;
b) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
c) have a pending higher queued Interconnection Request to interconnect to the Transmission System listed in Table 1; or
d) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study executing an interconnection agreement and commencing commercial operation, may require a re-study of this IAISIS at the expense of the Customer.

Nothing within this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service rights. Should the Customer require transmission service, those rights should be requested through SPP's Open Access Same-Time Information System (OASIS).

This IAISIS study included prior queued generation interconnection requests. Those listed within Table 1 are the generation interconnection requests that are assumed to have rights to either full or partial interconnection service prior to the requested December 2018 in-service for this IAISIS. Also listed in Table 1 are both the amount of MWs of interconnection service expected at the effective time of this study and the total MWs requested of interconnection service, the fuel type, the point of interconnection (POI), and the current status of each particular prior queued request.

Table 1: Generation Requests Included within IAISIS

Project	MW	Total MW	Fuel Source	POI	Status
ASGI-2016-005	20	20	Wind	Tap White Lake - Stickeny 69kV	Northwestern Queued Request
ASGI-2016-006	20	20	Wind	Mitchell	Northwestern Queued Request
ASGI-2016-007	20	20	Wind	Kimball 69kV	Northwestern Queued Request
G176	100	100	Wind	Yankee 115kV	
G255	100	100	Wind	Yankee 115kV	MISO Queued Request
G586	30	30	Wind	Yankee 115kV	MISO Queued Request
G736	200	200	Wind	Big Stone South 230kV	
GEN-2002-009IS (GI-0209)	40	40	Wind	Ft Thompson 69kV [Hyde 69kV]	Commercial Operation
GEN-2007-013IS (GI-0713)	50	50	Wind	Wessington Springs 230kV	Commercial Operation
GEN-2007-014IS (GI-0714)	100	100	Wind	Wessington Springs 230kV	Commercial Operation
GEN-2007-023IS (GI-0723)	50	50	Wind	Formit-Summit 115kV	On Suspension
GEN-2009-001IS (GI-0901)	200	200	Wind	Groton-Watertown 345kV	On Schedule
GEN-2009-018IS (GI-0918)	100	100	Wind	Groton 115kV	Commercial Operation
GEN-2010-001IS (GI-1001)	99	99	Wind	Bismarck-Glenham 230kV	On Schedule
GEN-2010-003IS (GI-1003)	34	34	Wind	Wessington Springs 230kV	Commercial Operation
GEN-2012-014IS (GI-1214)	99.5	99.5	Wind	Groton 115kV	On Schedule
GEN-2013-001IS (GI-1301)	90	90	Wind	Summit-Watertown 115kV	On Suspension
GEN-2013-009IS (GI-1309)	19.5	19.5	Wind	Redfield NW 115kV	Commercial Operation
GEN-2014-001IS (GI-1401)	103.7	103.7	Wind	Newell-Maurine 115kV	IA Pending
H081	200	200	Wind	Brookings County – Lyon County 345kV	
J436	150	150	Wind	Big Stone South 345kV	MISO Queued Request
J437	150	150	Wind	Big Stone South 345kV	MISO Queued Request
J442	200	200	Wind	Big Stone 230kV	MISO Queued Request
J432	98	98	Wind	Brookings 345kV	Under Study DPP-2016-FEB-West
J460	200	200	Wind	Brookings County – Lyon County 345kV	Under Study DPP-2016-FEB-West
J488	151.8	151.8	Wind	Big Stone – Ellendale 345kV	Under Study DPP-2016-FEB-West
J489	151.8	151.8	Wind	Big Stone – Ellendale 345kV	Under Study DPP-2016-FEB-West
J493	150	150	Wind	Big Stone – Brookings 345kV	Under Study DPP-2016-FEB-West

Table 1: Generation Requests Included within IAISIS

Project	MW	Total MW	Fuel Source	POI	Status
J510	284.5	284.5	CT	Big Stone – Brookings 345kV	Under Study DPP-2016-FEB-West
J525	50	50	Solar	Lake Wilson 69kV	Under Study DPP-2016-FEB-West
J526	300	300	Wind	Big Stone – Brookings 345kV	Under Study DPP-2016-FEB-West

This IAISIS was required because the Interconnection Customer is requesting interconnection prior to the completion of all of their required upgrades listed within the latest iteration of their Definitive Interconnection System Impact Study (DISIS).

Table *2* below lists the required upgrade projects for which these requests have cost responsibility. GEN-2016-036 was included within the DISIS-2016-002 that will be studied in spring 2018 and posted end of first quarter, 2018. Once posted these reports will be located at the following Generation Interconnection Study URL:

http://sppoasis.spp.org/documents/swpp/transmission/GenStudies.cfm?YearType=2016_Impact_Studies

Table 2: Upgrade Projects not included but Required for Full Interconnection Service

Upgrade Project	Type	Description	Status	Study Assignment
J438 POI-Parnell 161kV	Rebuild	Structure Replacements	Affected System Impact Study	DPP 2016 West
J438 POI-Parnell 161kV	Rebuild	Structure Replacements.	Affected System Impact Study	DPP 2016 West
J531 POI-Hazleton 345kV	Rebuild	Reconductor 28.1 miles of 345kV line. Replace 14.6 miles of structures.	Affected System Impact Study	DPP 2016 West
J475 substation xfmr			Affected System Impact Study	DPP 2016 West
J498 POI-Grimes 345kV	Rebuild	Reconfigure Raun Sub. Replace structures on J498-Grimes 345kV.	Affected System Impact Study	DPP 2016 West

Table 2: Upgrade Projects not included but Required for Full Interconnection Service

Upgrade Project	Type	Description	Status	Study Assignment
J530 POI-Hills 345kV	Rebuild	Structure replacements and terminal equipment upgrades.	Affected System Impact Study	DPP 2016 West
Split Rock-White 345kV	Uprate	Line in currently rated 1075 MVA for SN/SE, no mitigation required.	Affected System Impact Study	DPP 2016 West
Brookings Co-White 345kV #2	Reterminal	Uprate White terminal equipment.	Affected System Impact Study	DPP 2016 West
Helena-Scott Co 345kV		Line has an emergency rating of 1515 MVA.	Affected System Impact Study	DPP 2016 West
Panther-McLeod 230kV	Rebuild	Remediate 4 Structures.	Affected System Impact Study	DPP 2016 West
Big Stone-Blair 230kV	Uprate	Mitigation required for DPP 2015 Aug will increase the rating to 601.8 MVA.	Affected System Impact Study	DPP 2015 Aug
Hankinson-Forman 230kV	Uprate	Line clearance mitigations and terminal equipment upgrades.	Affected System Impact Study	DPP 2016 West
Oakes-Forman 230kV	Uprate	Line clearance mitigations and terminal equipment upgrades.	Affected System Impact Study	DPP 2016 West
Oakes-Ellendale 230kV	Uprate	Line clearance mitigations and terminal equipment upgrades. Ellendale MVP 230kV bus will be built to 796 MVA.	Affected System Impact Study	DPP 2016 West
Marshalltown-Blairstown 115kV	Rebuild	Raise/replace structures to reach 123 MVA.	Affected System Impact Study	DPP 2016 West
Blairstown-Prairie Ckt 115kV	Rebuild	Raise structures to reach a minimum rating of 114 MVA.	Affected System Impact Study	DPP 2016 West

Table 2: Upgrade Projects not included but Required for Full Interconnection Service

Upgrade Project	Type	Description	Status	Study Assignment
Killdeer 345/161 kV transformer	Build	Add a second transformer.	Affected System Impact Study	DPP 2016 West
Emery-Colby 161 kV	Upgrade	Upgrade approx. 0.5 miles of 161 kV – new rating 418 MVA.	Affected System Impact Study	DPP 2016 West
Boone Jct-Sub T Fort Dodge 161 kV	Rebuild	Re-conductor line and terminal equipment.	Affected System Impact Study	DPP 2016 West
Traer-Dysart 161 kV	None	Not a constraint, line currently rated at 276 MVA.	Affected System Impact Study	DPP 2016 West
Henry Co-Denmark 161 kV	Rebuild	Raise/replace 4 spans to 223 MVA.	Affected System Impact Study	DPP 2016 West
Henry Co-Jeff 161 kV	Rebuild	Raise/replace 4 spans to 223 MVA.	Affected System Impact Study	DPP 2016 West
Wapello-Jeff 161 kV	Rebuild	Line is conductor limited at 240 MVA. Rebuild 22.6 miles of 161 kV with T2-795 ACSR.	Affected System Impact Study	DPP 2016 West
Powershiek-Reasnor 161 kV	Rebuild	Line is conductor limited at 327 MVA. Rebuild 20.7 miles of 161 kV with T2-795 ACSR.	Affected System Impact Study	DPP 2016 West
Adams S-Beaver Ckt 161 kV	Rebuild	Rebuild 15 miles 636 ACSR 161 kV line.	Affected System Impact Study	DPP 2016 West
Council Bluffs-S3456 345 kV	Rebuild	Upgrade terminal equipment; Replace structure.	Affected System Impact Study	DPP 2016 West
Raun-S3451 345 kV	Rebuild	Upgrade terminal equipment; Rebuild 63 miles line.	Affected System Impact Study	DPP 2016 West
Raun-Tekamah 161 kV	Rebuild	Reconfigure Raun Sub to eliminate Raun 0270 Con.	Affected System Impact Study	DPP 2016 West

Table 2: Upgrade Projects not included but Required for Full Interconnection Service

Upgrade Project	Type	Description	Status	Study Assignment
Grimes-Sycamore 345kV #1	None	No mitigation required.	Affected System Impact Study	DPP 2016 West
Grimes-Sycamore 345 kV #2	Rebuild	Terminal equipment upgrades; Add breaker between Grimes 345/161 kV transformer 9T1 and Grimes-Sycamore 345 kV CKT 1 to eliminate CON.	Affected System Impact Study	DPP 2016 West
Grimes-Granger Tap 161 kV	Reconductor	Reconductor Line.	Affected System Impact Study	DPP 2016 West
Granger Tap – 108th & 54th 161 kV	Reconductor	Reconductor line and terminal equipment.	Affected System Impact Study	DPP 2016 West
Bondurant-Sycamore 345 kV	Rebuild	Structure replacements and terminal equipment upgrades.	Affected System Impact Study	DPP 2016 West
Bondurant-Montezuma 345 kV	Rebuild	Structure replacements and terminal equipment upgrades.	Affected System Impact Study	DPP 2016 West
Franklin-Wall Lake 161 kV	Rebuild	Structure replacements.	Affected System Impact Study	DPP 2016 West
Sub 56-Walcott 345 kV	Rebuild	Add breakers at Sub T Haskins to change CON by removing loss of Hills-Sub T 345 kV.	Affected System Impact Study	DPP 2016 West
Walcott-Sub 92 345 kV	Rebuild	Add breakers at Sub T Haskins to change CON by removing loss of Hills-Sub T 345 kV. Replace structures and terminal equipment.	Affected System Impact Study	DPP 2016 West
Ellendale-Aberdean Jct 115 kV	Rebuild	Ellendale 115 kV bus will be rebuilt to 318 MVA; A switching substation at A-Tap (Aberdean Jct) will be built in 2019.	Affected System Impact Study	DPP 2016 West
Glenham 230/115/41.6 kV transformer	New	New Glenham 230/115/41.6 kV transformer	Affected System Impact Study	DPP 2016 West

Table 2: Upgrade Projects not included but Required for Full Interconnection Service

Upgrade Project	Type	Description	Status	Study Assignment
Seneca-Genoa 161 kV	Reconductor	Reconductor line.	Affected System Impact Study	DPP 2016 West
Seneca-Grae 161 kV	Reconductor	Reconductor line.	Affected System Impact Study	DPP 2016 West
DISIS-2016-002		Possible DISIS-2016-002 Upgrades.	Pending	DISIS2016-002

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study executing an interconnection agreement and commencing commercial operation, may require a re-study of this IAISIS at the expense of the Interconnection Customer.

The higher or equally queued projects that were not included in this study are listed in Table 3. While this list is not all-inclusive, it is a list of the most probable and affecting prior-queued requests that were not included within this IAISIS, either because no request for an IAISIS has been made or the request is on suspension, etc.

Table 3: Higher or Equally Queued GI Requests not included within IAISIS

Project	MW	Total MW	Fuel Source	POI	Status
GEN-2016-087	98.9	98.9	Wind	Bismarck-Glenham 230kV	Interconnection Facility Study in progress
GEN-2016-092	250.7	250.7	Wind	Tap Leland Olds-Ft Thompson 345kV	DISIS Study in progress
GEN-2016-103	250.7	250.7	Wind	Tap Leland Olds-Ft Thompson 345kV	DISIS Study in progress
GEN-2016-164	7.92	7.92	Wind	Groton 115kV	DISIS Study in progress

Nothing in this System Impact Study constitutes a request for transmission service or grants the Interconnection Customer any rights to transmission service.

Facilities

Generating Facility

The Interconnection Customer's request to interconnect a total of 44.6 MW is comprised of sixteen (16) GE 2.5 MW wind turbines and two (2) GE 2.3 MW wind turbines and associated facilities.

Interconnection Facilities

The POI for GEN-2016-036 Interconnection Customer is the Granite Falls 115kV substation in Chippewa County Minnesota. Figure *1* depicts the one-line diagram of the local transmission system including the POI as well as the power flow model representing the requests.

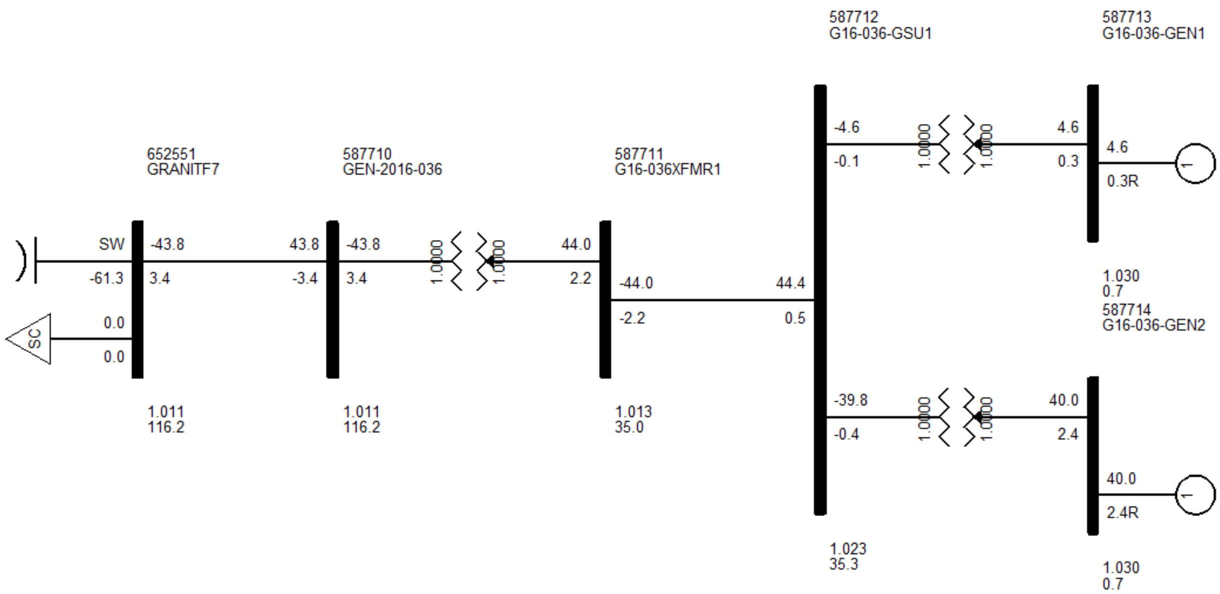


Figure 1: Proposed POI Configuration and Request Power Flow Model

Base Case Network Upgrades

The Network Upgrades included within the cases used for this IAISIS study are those facilities that are a part of the SPP Transmission Expansion Plan, Balanced Portfolio, or Integrated System (IS) Integration Study projects that have in-service dates prior to the GEN-2016-036 requested in-service date of December 31, 2018. These facilities have an approved Notification to Construct (NTC), or are in construction stages and expected to be in-service at the effective time of this study. No other upgrades were included for this IAISIS. If for some reason, construction on these projects is delayed or discontinued, a restudy may be needed to determine the interconnection service availability of the Customer.

Power Flow Analysis

Power flow analysis is used to determine if the transmission system can accommodate the injection from the request without violating thermal or voltage transmission planning criteria.

Model Preparation

Power flow analysis was performed using modified versions of the 2015 series of transmission service request study models including the 2016 Winter Peak (16WP), 2017 Spring (17G), and 2017 Summer Peak (17SP), 2020 Light (20L), and 2020 Summer (SP) and Winter (WP) peak seasonal models. To incorporate the Interconnection Customers' request, a re-dispatch of existing generation within SPP was performed with respect to the amount of the Customers' injection.

For Variable Energy Resources (VER) (solar/wind) in each power flow case, Energy Resource Interconnection Service (ERIS), is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas is dispatched at 20% nameplate of maximum generation. These projects are dispatched across the SPP footprint using load factor ratios.

Peaking units are not dispatched in the 2017 spring and 2020 light, or in the "High VER" summer and winter peaks. To study peaking units' impacts, the 2016 winter peak, 2017 summer peak, and 2020 summer and winter peaks, models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested Network Resource Interconnection Service (NRIS) are dispatched in an additional analysis into the interconnecting Transmission Owner's (T.O.) area at 100% nameplate with Energy Resource Interconnection Service (ERIS) only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

For this IAISIS, only the previous queued requests listed in Table 1 were assumed to be in-service at 100% dispatch.

Study Methodology and Criteria

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned.

For Energy Resource Interconnection Service (ERIS), thermal overloads are determined for system intact (n-0) (greater than 100% of Rate A - normal) and for contingency (n-1) (greater than 100% of Rate B – emergency) conditions.

The overloads are then screened to determine which of generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage based conditions (n-1), or
- 3% DF on contingent elements that resulted in a non-converged solution.

Interconnection Requests that requested Network Resource Interconnection Service (NRIS) are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Flowgates for SPP and first tier Non-SPP control area are monitored. Additional NERC Flowgates are monitored in second tier or greater Non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

Results

The IAISIS ACCC analysis indicates that the Interconnection Customer can interconnect its generation into the WAPA transmission system before all required upgrades listed within the DISIS-2016-001 study or latest iteration can be placed into service. Should any other GI projects, other than those listed within Table 1 of this report, come into service, an additional study may be required to determine if any limited operation service is available.

ACCC results for the IAISIS can be found in Table 4 and 5 below. Table 4 power flow analysis results assume system conditions as of December 31, 2018 without GEN-2017-103 generation. Split Rock to White latest rating of 1075 MVA sufficient for mitigation. Under this assumption GEN-2016-036 could interconnect up to 44.6 MW of Interconnection Service.

Table 5 has the overloads that are less than 20% TDF and are **not for transmission reinforcement mitigation. Generator Interconnection Energy Resource** Interconnection Service (ERIS) analysis doesn't mitigate with additional transmission reinforcement requirements for those issues in which the affecting GI request has less than a 20% OTDF. Table 5 is provided for informational purposes only so that the Interconnection Customer understands there may be operational conditions when they may be required to reduce their output to maintain system reliability. See Appendix H for full details

The power flow analysis for this IAISIS observed constraints on Affected Systems and the Limited Operation amounts provided within this IAISIS report are subject to Affected System Interim Availability Interconnection System Impact Study analysis and results. Should the Interconnection Customer elect to continue with IAISIS, the Interconnection Customer will need to coordinate with the Affected System Parties for Affected System Interim Availability Interconnection System Impact Study or an equivalent study. Affected System constraints with 3% distribution impact factor are in the Appendix A (Affected System Thermal Constraints) and Appendix B (Affected System Voltage Constraints). Any additional Affected System constraints observed in the DISIS-2016-001 or latest restudy could be evaluated by the Affected System party for the Affected System Interim Availability Interconnection System Impact Study.

Curtailment and System Reliability

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Power Flow Analysis

Table 4: Interconnection Thermal Constraints for Transmission Reinforcement Mitigation of IAISIS @ 44.6MW

Season	Dispatch Group	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Max MW Available	Contingency
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19578	126.5904	44.6	GRE-CEDARMT3345.00 - HELENA 345KV CKT 2
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19578	126.5904	44.6	GRE-CEDARMT3345.00 - HELENA 345KV CKT 1
20SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.21141	124.3753	44.6	LAKEFIELD 3 - LKFLDXL3 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19536	123.3373	44.6	P12:230:UMZW:# 1786 #: GF IN MN. GF-MNVLTAP LINE FAULT
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19533	123.3317	44.6	MN VALLEY TAP - PANTHER 230KV CKT 1
20SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.18385	122.6827	44.6	SYSTEM INTACT
20SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20679	121.0136	44.6	HELENA - SHEAS LK3 345.00 345KV CKT 1
20SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.21141	120.5604	44.6	FIELD SOUTH - WILMARTH 345KV CKT 1
20SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.21141	120.5276	44.6	FIELD NORTH - FIELD SOUTH 345KV CKT 1
20SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.21141	120.501	44.6	FIELD NORTH - LKFLDXL3 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.18466	120.4555	44.6	SYSTEM INTACT
20SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20437	120.1426	44.6	SHEAS LK3 345.00 - WILMARTH 345KV CKT 1
20L	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19511	119.6069	44.6	GRE-CEDARMT3345.00 - HELENA 345KV CKT 1
20L	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19511	119.6069	44.6	GRE-CEDARMT3345.00 - HELENA 345KV CKT 2
20L	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20694	119.382	44.6	HELENA - SHEAS LK3 345.00 345KV CKT 1
20L	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20455	118.1354	44.6	SHEAS LK3 345.00 - WILMARTH 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20762	116.7157	44.6	HELENA - SHEAS LK3 345.00 345KV CKT 1
20L	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.2116	116.2208	44.6	LAKEFIELD 3 - LKFLDXL3 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.2052	116.0339	44.6	SHEAS LK3 345.00 - WILMARTH 345KV CKT 1
20WP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20707	115.5981	44.6	LAKEFIELD 3 - LKFLDXL3 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.21223	115.5688	44.6	FIELD SOUTH - WILMARTH 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.21223	115.536	44.6	FIELD NORTH - FIELD SOUTH 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.21223	115.5075	44.6	FIELD NORTH - LKFLDXL3 345KV CKT 1
20L	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.1842	114.2265	44.6	SYSTEM INTACT
20WP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20707	113.4373	44.6	FIELD SOUTH - WILMARTH 345KV CKT 1
20WP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20707	113.3999	44.6	FIELD NORTH - FIELD SOUTH 345KV CKT 1
20WP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.17998	112.9643	44.6	SYSTEM INTACT
20WP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20249	112.5296	44.6	HELENA - SHEAS LK3 345.00 345KV CKT 1
20WP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.20012	111.7229	44.6	SHEAS LK3 345.00 - WILMARTH 345KV CKT 1
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19578	126.5904	44.6	GRE-CEDARMT3345.00 - HELENA 345KV CKT 2
25SP	15ALL	G16_036	TO->FROM	SPLIT ROCK - WHITE 345KV CKT 1	717	717	0.19578	126.5904	44.6	GRE-CEDARMT3345.00 - HELENA 345KV CKT 1

Power Flow Analysis

Table 5: Constraints not for Transmission Reinforcement Mitigation of IAISIS @ 44.6MW

Season	Dispatch Group	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Contingency
				Available Upon Request					

Table 6: Interconnection Voltage Constraints for Transmission Reinforcement Mitigation of IAISIS @ 44.6MW

MONITORED ELEMENT	TC Voltage (PU)	Voltage Differ (PU)	VINIT (PU)	VMIN (PU)	VMAX(PU)	TDF	CONTINGENCY	COMMENTS
'NUNDRWD 230KV'	1.05302	0.0530195	1.04501	0.9	1.05	0.08161	GEN652007 1-G14_001IS_3 0.6900'	Voltage constraints mitigated by turning on shunt at NUNDRWD-LNX 230kV Bus
'MAURINE 230KV'	1.05178	0.0517797	1.04075	0.9	1.05	0.08161	'GEN652007 1-G14_001IS_3 0.6900'	
'NUNDRWD-LNX3230.00 230KV'	1.05302	0.0530195	1.04501	0.9	1.05	0.08161	'GEN652007 1-G14_001IS_3 0.6900'	
'RCDC EAST 4230.00 230KV'	1.068251	0.0682505	1.05943	0.9	1.05	0.08161	'GEN652007 1-G14_001IS_3 0.6900'	
'DRY CREEK 7115.00 115KV'	1.052315	0.0523149	1.04066	0.9	1.05	0.08161	'GEN652007 1-G14_001IS_3 0.6900'	
'RCDC EAST 4230.00 230KV'	1.050028	0.0500277	1.05943	0.9	1.05	0.08161	GEN659118 1-LARAMIE RIVER UNIT1'	

Stability Analysis

Transient stability analysis is used to determine if the transmission system can maintain angular stability and ensure bus voltages stay within planning criteria bandwidth during and after a disturbance while considering the addition of a generator interconnection request.

Model Preparation

Transient stability analysis was performed using modified versions of the 2015 series of Model Development Working Group (MDWG) dynamic study models including the 2016 winter, 2017 and 2025 summer peak dynamic cases. The cases were adapted to resemble the power flow study cases with regards to prior queued generation requests and topology. Finally, the prior queued and study generation was dispatched into the SPP footprint. Initial simulations are then carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

Disturbances

The forty-one (41) contingencies were identified for the Limited Operation scenario for use in this study. These faults are listed within Table 8. These contingencies included three-phase faults and single-phase line faults at locations defined by SPP. Single-phase line faults were simulated by applying fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice.

With exception to transformers, the typical sequence of events for a three-phase and single-phase fault is as follows:

1. apply fault at particular location
2. continue fault for five (5) cycles, clear the fault by tripping the faulted facility
3. after an additional twenty (20) cycles, re-close the previous facility back into the fault
4. continue fault for five (5) additional cycles
5. trip the faulted facility and remove the fault

Transformer faults are typically only performed for three-phase faults, unless otherwise noted. Additionally the sequence of events for a transformer is to 1) apply a three-phase fault for five (5) cycles and 2) clear the fault by tripping the affected transformer facility. Unless otherwise noted there will be no re-closing into a transformer fault.

Table 8: Contingencies Evaluated for Limited Operation

Contingency Number and Name		Description
1	FLT_01_GraniteFalls_Canby_115kV_3PH	3 phase fault on Granite Falls (652551) to Canby (620211) 115kV Ckt 1, near Granite Falls. a. Apply fault at the near Granite Falls 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT_02_GraniteFalls_MarshallTS3_115kV_3PH	3 phase fault on Granite Falls (652551) to Marshall Tap "S3" (652508) 115kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
3	FLT_03_GraniteFalls_MinnesotaValley_115kV_3PH	3 phase fault on Granite Falls (652551) to Minnesota Valley (603030) 115kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT_04_GraniteFalls_GraniteFalls230_115_230kV_3PH	3 phase fault on Granite Falls 115kV (652551) to 230kV (652550) to 13.8kV (652292) Xfmr Ckt 1, near Granite Falls 115kV. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
5	FLT_05_Canby_DawsonTap_115kV_3PH	3 phase fault on Canby (620211) to Dawson Tap (620173) 115kV Ckt 1, near Canby. a. Apply fault at the Canby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT_06_Canby_Burr_115kV_3PH	3 phase fault on the Canby (620211) to Burr (620212) 115kV Ckt 1, near Canby. a. Apply fault at the Canby 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Contingency Number and Name		Description
7	FLT_07_DawsonTap_Louisburg_115kV_3PH	3 phase fault on Dawson Tap (620173) to Louisburg (620206) 115kV Ckt 1, near Dawson Tap. a. Apply fault at the Dawson Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT_08_Burr_Toronto_115kV_3PH	3 phase fault on to Burr (620212) to Toronto (620210) 115kV Ckt 1, near Burr. a. Apply fault at the Burr 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
9	FLT_09_MarshallTap_ErieRd_115kV_3PH	3 phase fault on Marshall Tap “S3” (652508) to Erie Rd (658072) 115kV Ckt 1, near Marshall Tap. a. Apply fault at the Marshall Tap 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT_10_ErieRd_Saratoga_115kV_3PH	3 phase fault on Erie Rd (658072) to Saratoga (658074) 115kV Ckt 1, near Erie Rd. a. Apply fault at the Erie Rd 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
11	FLT_11_MinnesotaValley_Maynard_115kV_3PH	3 phase fault on Minnesota Valley (603030) to Maynard (603177) 115kV Ckt 1, near Minnesota Valley. a. Apply fault at the Minnesota Valley 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT_12_MinnesotaValley_RedFallsTap_115kV_3PH	3 phase fault on Minnesota Valley (603030) to Red Falls Tap (613310) 115kV Ckt 1, near Red Falls Tap. a. Apply fault at the Red Falls Tap 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Contingency Number and Name		Description
13	FLT_13_MinnesotaValley_MinnesotaValley230_115_230kV_3PH	3 phase fault on Minnesota Valley 115kV (603030) Minnesota Valley 230kV (602008) to Minnesota Valley 13.8kV (605729) Xfmr Ckt 6, near Minnesota Valley 115kV. a. Apply fault at the Minnesota Valley 115kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
14	FLT_14_Maynard_KerkhovenT_115kV_3PH	3 phase fault on Maynard (603177) to Kerkhoven Tap (603267) 115kV Ckt 1, near Maynard. a. Apply fault at the Maynard 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
15	FLT_15_GraniteFalls230_Morris_230kV_3PH	3 phase fault on Granite Falls (652550) to Morris (652554) 230kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT_16_GraniteFalls230_Appledorn_230kV_3PH	3 phase fault on Granite Falls (652550) to Appledorn (652582) 230kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
17	FLT_17_GraniteFalls230_Blair_230kV_3PH	3 phase fault on Granite Falls (652550) to Blair (652503) 230kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT_18_GraniteFalls230_MinnesotaValleyT_230kV_3PH	3 phase fault on Granite Falls (652550) to Minnesota Valley Tap (602009) 230kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Contingency Number and Name		Description
19	FLT_19_GraniteFalls230_WillmarGRE_230kV_3PH	3 phase fault on Granite Falls (652550) to Willmar (GRE) (602009) 230kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT_20_GraniteFalls230_MinnesotaValley230_230kV_3PH	3 phase fault on Granite Falls (652550) to Minnesota Valley (602008) 230kV Ckt 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
21	FLT_21_Appledorn_Watertown_230kV_3PH	3 phase fault on Appledorn (652582) to Watertown (652530) 230kV Ckt 1, near Appledorn. a. Apply fault at the Appledorn 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT_22_Blair_BigStone_230kV_3PH	3 phase fault on Blair (652503) to Big Stone (620314) 230kV Ckt 1, near Blair. a. Apply fault at the Blair 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
23	FLT_23_Watertown3_G09001IST_345kV_3PH	3 phase fault on Watertown (652529) to G09_001IST (620314) 345kV Ckt 1, near Watertown. a. Apply fault at the Watertown 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT_24_Watertown3_WATERTNLNX3_345kV_3PH	3 phase fault on Watertown (652529) to WATERTN-LNX3 (652829) 345kV Ckt 1, near Watertown. a. Apply fault at the Watertown 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
25	FLT_25_Watertown_Watertown3_230_345kV_3PH	3 phase fault on Watertown 230 kV (652530) to (652529) 345 kV to 13.8 kV (652237) Ckt 1, near Watertown. a. Apply fault at the Watertown 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.

Contingency Number and Name		Description
26	FLT_26_MinnesotaValleyT_MinnesotaValley230_230kV_3PH	3 phase fault on Minnesota Valley Tap (602009) to Minnesota Valley (602008) 230kV Ckt 1, near Minnesota Valley Tap. a. Apply fault at the Minnesota Valley Tap 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
27	FLT_27_MinnesotaValleyT_PantherGRE_230kV_3PH	3 phase fault on Minnesota Valley Tap (602009) to Panther (GRE) (615529) 230kV Ckt 1, near Minnesota Valley Tap. a. Apply fault at the Minnesota Valley Tap 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT_28_MinnesotaValleyT_HazelCreek_230kV_3PH	3 phase fault on Minnesota Valley Tap (602009) to Hazel Creek (601053) 230kV Ckt 1, near Minnesota Valley. a. Apply fault at the Minnesota Valley 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
29	FLT_29_HazelCreek_HAZELCK4_230_345kV_3PH	3 phase fault on Hazel Creek 230 kV (601053) to (601054) 345 kV to 13.8 kV (605753) Ckt 1, near Hazel Creek. a. Apply fault at the Hazel Creek 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
30	FLT_30_WillmarGRE_Paynesville_230kV_3PH	3 phase fault on Willmar (GRE) (602009) to Paynesville (602036) 230kV Ckt 1, near Willmar. a. Apply fault at the Willmar 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
31	FLT_31_GraniteFalls_CanbySB_115kV_1PH	**Single phase fault with stuck breaker** on the Granite Falls (652551) to Canby (620211) 115kV Ckt 1, near Granite Falls. a. Apply fault at Granite Falls 115kV bus. b. At 5 cycles, open the faulted line. c. At 15 cycles, clear the fault and trip: Granite Falls 115kV (652551) to 230 kV (652550) to 13.74kV (652297) Xfmr Ckt 1, Granite Falls 115kV (652551) to 69kV (652298) to 13.2kV (652288) Xfmr Ckt 1, and Granite Falls (652551) to Marshall Tap “S3” (652508) 115kV Ckt 1

Contingency Number and Name		Description
32	FLT_32_GraniteFalls_MinnesotaValleySB_115kV_1PH	**Single phase fault with stuck breaker** on the Granite Falls (652551) to Minnesota Valley (603030) 115kV Ckt 1, near Granite Falls. a. Apply fault at Granite Falls 115kV bus. b. At 5 cycles, open the faulted line. c. At 15 cycles, clear the fault and trip: Granite Falls 115kV (652551) to 230 kV (652550) to 13.8kV (652292) Xfmr Ckt 1 and Granite Falls 115kV (652551) capacitor bank
33	FLT_33_GraniteFalls230_AppledornSB_230kV_1PH	**Single phase fault with stuck breaker** on the Granite Falls (652550) to Appledorn (652582) 230kV Ckt 1, near Granite Falls. a. Apply fault at Granite Falls 115kV bus. b. At 5 cycles, open the faulted line. c. At 15 cycles, clear the fault and trip: Granite Falls (652550) to Minnesota Valley Tap (602009) 230kV Ckt 1, Granite Falls (652550) to Morris (652554) 230kV Ckt 1, Granite Falls 115kV (652551) to 230 kV (652550) to 13.74kV (652297) Xfmr Ckt 1, and Granite Falls 230kV (652550) capacitor bank (1x40.7Mvar)
34	FLT_34_GraniteFalls230_BlairSB_230kV_1PH	**Single phase fault with stuck breaker** on the Granite Falls (652550) to Blair (652503) 230kV Ckt 1, near Granite Falls. a. Apply fault at Granite Falls 115kV bus. b. At 5 cycles, open the faulted line. c. At 15 cycles, clear the fault and trip: Granite Falls 115kV (652551) to 230 kV (652550) to 13.8kV (652292) Xfmr Ckt 1, Granite Falls (652550) to Paynesville (602036) 230kV Ckt 1, Granite Falls (652550) to Minnesota Valley (602008), and Granite Falls 230kV (652550) capacitor bank (1x40.7Mvar)
35	FLT_35_Canby_GraniteFallsSB_115kV_1PH	**Single phase fault with stuck breaker** on the Canby (620211) to Granite Falls (652551) 115kV Ckt 1, near Canby. a. Apply fault at Canby 115kV bus. b. At 5 cycles, open the faulted line. c. At 15 cycles, clear the fault and trip: Canby 115kV (620211) to 41.6 kV (620111) Xfmr Ckt 1, Canby (620211) to Burr (620212) 115kV Ckt 1, and Canby (620211) to Dawson Tap (620173) 115kV Ckt 1
36	FLT_36_Burr_MariettaPO_115kV_3PH	**(Prior Outage)** Canby (620211) to Dawson Tap (620173) 115kV Ckt 1 out of service then 3 phase fault on Burr (620212) to Marietta (620213) 115kV Ckt 1, near Burr. Switch Canby (620211) to Dawson Tap (620173) 115kV Ckt 1 out of service then solve. a. Apply fault at the Burr 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Contingency Number and Name		Description
37	FLT_37_GraniteFalls230_WillmarGREPO_230kV_3PH	**(Prior Outage)** Minnesota Valley Tap (602009) to Panther (GRE) (615529) 230kV Ckt 1 out of service then 3 phase fault on Granite Falls (652550) to Willmar (GRE) (602009) 230kV Ckt 1, near Granite Falls. Minnesota Valley Tap (602009) to Panther (GRE) (615529) 230kV Ckt 1 out of service then solve. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
38	FLT_38_GraniteFalls230_BlairPO_230kV_3PH	**(Prior Outage)** Granite Falls (652550) to Appledorn (652582) 230kV Ckt 1 out of service then 3 phase fault on Granite Falls (652550) to Blair (652503) 230kV Ckt 1, near Granite Falls. Granite Falls (652550) to Appledorn (652582) 230kV Ckt 1 out of service then solve. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
39	FLT_39_GraniteFalls_MarshallTS3PO_115kV_3PH	**(Prior Outage)** Granite Falls (652551) to Canby (620211) 115kV Ckt 1 out of service then 3 phase fault on Granite Falls (652551) to Marshall Tap "S3" (652508) 115kV Ckt 1, near Granite Falls. Granite Falls (652551) to Canby (620211) 115kV Ckt 1 out of service then solve. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
40	FLT_40_Burr_J493_115kV_3PH	3 phase fault on to Burr (620212) to J493 (587620) 115kV Ckt 1, near Burr. a. Apply fault at the Burr 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
41	FLT_41_Burr_Marietta_115kV_3PH	3 phase fault on to Burr (620212) to Marietta (620213) 115kV Ckt 1, near Burr. a. Apply fault at the Burr 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Results

Results of the stability analysis are summarized in Table 9. These results are valid for GEN-2016-036 interconnecting with a generation amount up to 44.6 MW. Beyond the note below, no stability problems were seen.

Note: In all seasons, the DISTR1 relays on all 115kV lines coming out of Minnesota Valley caused those lines to trip for the contingencies 3, 11, 12, 13 and 14 (No contingency tripped all three lines, but all three tripped on at least one of those contingencies.). Because of this, those contingencies were run twice each, one with the DISTR1 relays on, one off. Additionally, those contingencies were run with GEN-2016-036 and its associated lines turned off. With the study generators off, the same trips occurred. Therefore, this was deemed a pre-existing condition.

Table 9: Fault Analysis Results for Limited Operation

Contingency Number and Name		2017SP	2016WP	2025SP
1	FLT_01_GraniteFalls_Canby_115kV_3PH	Stable	Stable	Stable
2	FLT_02_GraniteFalls_MarshallTS3_115kV_3PH	Stable	Stable	Stable
3	FLT_03_GraniteFalls_MinnesotaValley_115kV_3PH	Stable[1]	Stable[1]	Stable[1]
4	FLT_04_GraniteFalls_GraniteFalls230_115_230kV_3PH	Stable	Stable	Stable
5	FLT_05_Canby_DawsonTap_115kV_3PH	Stable	Stable	Stable
6	FLT_06_Canby_Burr_115kV_3PH	Stable	Stable	Stable
7	FLT_07_DawsonTap_Louisburg_115kV_3PH	Stable	Stable	Stable
8	FLT_08_Burr_Toronto_115kV_3PH	Stable	Stable	Stable
9	FLT_09_MarshallTap_ErieRd_115kV_3PH	Stable	Stable	Stable
10	FLT_10_ErieRd_Saratoga_115kV_3PH	Stable	Stable	Stable
11	FLT_11_MinnesotaValley_Maynard_115kV_3PH	Stable[1]	Stable[1]	Stable[1]
12	FLT_12_MinnesotaValley_RedFallsTap_115kV_3PH	Stable[1]	Stable[1]	Stable[1]
13	FLT_13_MinnesotaValley_MinnesotaValley230_115_230kV_3PH	Stable[1]	Stable[1]	Stable[1]
14	FLT_14_Maynard_KerkhovenT_115kV_3PH	Stable[1]	Stable[1]	Stable[1]
15	FLT_15_GraniteFalls230_Morris_230kV_3PH	Stable	Stable	Stable
16	FLT_16_GraniteFalls230_Appledorn_230kV_3PH	Stable	Stable	Stable
17	FLT_17_GraniteFalls230_Blair_230kV_3PH	Stable	Stable	Stable
18	FLT_18_GraniteFalls230_MinnesotaValleyT_230kV_3PH	Stable	Stable	Stable
19	FLT_19_GraniteFalls230_WillmarGRE_230kV_3PH	Stable	Stable	Stable
20	FLT_20_GraniteFalls230_MinnesotaValley230_230kV_3PH	Stable	Stable	Stable
21	FLT_21_Appledorn_Watertown_230kV_3PH	Stable	Stable	Stable
22	FLT_22_Blair_BigStone_230kV_3PH	Stable	Stable	Stable
23	FLT_23_Watertown3_G09001IST_345kV_3PH	Stable	Stable	Stable
24	FLT_24_Watertown3_WATERTNLNX3_345kV_3PH	Stable	Stable	Stable
25	FLT_25_Watertown_Watertown3_230_345kV_3PH	Stable	Stable	Stable
26	FLT_26_MinnesotaValleyT_MinnesotaValley230_230kV_3PH	Stable	Stable	Stable
27	FLT_27_MinnesotaValleyT_PantherGRE_230kV_3PH	Stable	Stable	Stable
28	FLT_28_MinnesotaValleyT_HazelCreek_230kV_3PH	Stable	Stable	Stable
29	FLT_29_HazelCreek_HAZELCK4_230_345kV_3PH	Stable	Stable	Stable
30	FLT_30_WillmarGRE_Paynesville_230kV_3PH	Stable	Stable	Stable
31	FLT_31_GraniteFalls_CanbySB_115kV_1PH	Stable	Stable	Stable
32	FLT_32_GraniteFalls_MinnesotaValleySB_115kV_1PH	Stable	Stable	Stable
33	FLT_33_GraniteFalls230_AppledornSB_230kV_1PH	Stable	Stable	Stable
34	FLT_34_GraniteFalls230_BlairSB_230kV_1PH	Stable	Stable	Stable
35	FLT_35_Canby_GraniteFallsSB_115kV_1PH	Stable	Stable	Stable
36	FLT_36_Burr_MariettaPO_115kV_3PH	Stable	Stable	Stable
37	FLT_37_GraniteFalls230_WillmarGREPO_230kV_3PH	Stable	Stable	Stable
38	FLT_38_GraniteFalls230_BlairPO_230kV_3PH	Stable	Stable	Stable
39	FLT_39_GraniteFalls_MarshallTS3PO_115kV_3PH	Stable	Stable	Stable
40	FLT_40_Burr_J493_115kV_3PH	Stable	Stable	Stable
41	FLT_41_Burr_Marietta_115kV_3PH	Stable	Stable	Stable

[1] See note preceding Table 9.

FERC LVRT Compliance

FERC Order #661A places specific requirements on wind farms through its Low Voltage Ride Through (LVRT) provisions. For Interconnection Agreements signed after December 31, 2006, wind farms shall stay on line for faults at the POI that draw the voltage down at the POI to 0.0 pu.

Fault contingencies were developed to verify that wind farms remain on line when the POI voltage is drawn down to 0.0 pu. These contingencies are shown in Table 10.

Table 10: LVRT Contingencies

Contingency Number and Name		Description
1	FLT_01_GraniteFalls_Canby_115kV_3PH	3 phase fault on Granite Falls (652551) to Canby (620211) 115kV Ckt 1.
2	FLT_02_GraniteFalls_MarshallTS3_115kV_3PH	3 phase fault on Granite Falls (652551) to Marshall Tap “S3” (652508) 115kV Ckt 1.
3	FLT_03_GraniteFalls_MinnesotaValley_115kV_3PH	3 phase fault on Granite Falls (652551) to Minnesota Valley (603030) 115kV Ckt 1.

The required prior queued project wind farms remained online for the fault contingencies described in this section as well as the fault contingencies described in the Disturbances section of this report. GEN-2016-036 is found to be in compliance with FERC Order #661A.

Power Factor Analysis

In accordance with FERC Order 827 GEN-2016-036 will be required to provide dynamic reactive power within the power factor range of 0.95 leading (absorbing Vars from the network) to 0.95 lagging (providing Vars to the network) at continuous rated power output at the high side of the generator substation.

Reduced Wind Generation Analysis

A low wind analysis has been performed for the GEN-2016-036 Interconnection Request. SPP performed this low wind analysis for excessive capacitive charging current for the addition of the Interconnection Request facilities. The high side of the each Interconnection Customer's transformer will interconnect to The Point of Interconnection (POI).

The project generators and capacitors (if any) were turned off in the base case. The resulting reactive power injection into the transmission network comes from the capacitance of the project's transmission lines and collector cables is shown in Figure A-1 and C-2.

Final shunt reactor requirement for each project with the model information provided to SPP is shown in Table 11. It is the interconnection customer's responsibility to design and install the reactive compensation equipment necessary to control the reactive power injection at the POI. If an equivalent means of compensation is installed, the reactive power required may vary with system conditions (e.g. a higher compensation amount is required for voltages above unity at the POI and a lower compensation amount is required for voltages below unity at the POI).

Table 11*:* Summary of Reduced Wind Generation Analysis

Request	Point of Interconnection (POI)	Reactor Size (Mvar)
GEN-2016-036	Granite Falls 115kV (652551)	2.0

Short Circuit Analysis

The short circuit analysis was performed on the 2017 & 2025 Summer Peak power flow cases using the PSS/E ASCC program. Since the power flow model does not contain negative and zero sequence data, only three-phase symmetrical fault current levels were calculated at the point of interconnection up to and including five levels away.

Short Circuit Analysis was conducting using flat conditions with the following PSS/E ASCCC program settings:

- BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
- GENERATOR P=0, Q=0
- TRANSFORMER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
- LINE CHARGING=0.0 IN +/-/0 SEQUENCE
- LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
- LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
- DC LINES AND FACTS DEVICES BLOCKED
- TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

Results

The results of the short circuit analysis are shown in Appendix D.

Conclusion

GEN-2016-036 (Interconnection Customer) has requested a Limited Operation System Impact Study under the Southwest Power Pool Open Access Transmission Tariff (OATT) for a total of 44.6 MW of wind generation to be interconnected with Energy Resource Interconnection Service (ERIS) into the Transmission System of Western Area Power Administration (WAPA) in Chippewa County, Minnesota. The point of interconnection will be Granite Falls 115 kV substation. GEN-2016-036 under GIA Section 11A, have requested this Limited Operation Interconnection Study (IAISIS) to determine the impacts of interconnecting to the transmission system before all required Network Upgrades identified in the DISIS-2016-001 (or most recent iteration) Impact Study can be placed into service. Additionally, Interconnection Customer has requested this IAISIS analysis be conducted without accounting for the GEN-2017-103 generation.

Power flow analysis from this IAISIS has determined that the GEN-2016-036 request can interconnect 44.6 MW of generation with Energy Resource Interconnection Service (ERIS) prior to the completion of the required Network Upgrades, listed within
Table 2 of this report. The power flow interconnection service amount would be limited by the IAISIS amount determined by the transient stability analysis as mentioned below. Should any other projects, other than those listed within Table 1 of this report, come into service an additional study may be required to determine if any limited operation service is available. Refer to Table 4 for the Limited Operation Interconnection Service available due to interconnection constraints.

The stability analysis identified instability on all 115 kV lines coming out of Minnesota Valley. Further analysis identified this to be a pre-existing condition.

The power flow analysis for this IAISIS observed constraints on Affected Systems and the Limited Operation amounts provided within this IAISIS report are subject to Affected System Interim Availability Interconnection System Impact Study analysis and results. Should the Interconnection Customer elect to continue with IAISIS, the Interconnection Customer will need to coordinate with the Affected System Parties for Affected System Interim Availability Interconnection System Impact Study or an equivalent study. Affected System constraints with 3% distribution impact factor are in the Appendix A (Affected System Thermal Constraints) and Appendix B (Affected System Voltage Constraints). Any additional Affected System constraints observed in the DISIS-2016-002 or latest restudy could be evaluated by the Affected System party for the Affected System Interim Availability Interconnection System Impact Study.

The stability analysis has determined that all 44.6 MW of generation can interconnect prior to the completion of the Network Upgrades, listed within
Table *2* of this report. Additionally, GEN-2016-036 was found to be in compliance with FERC Order #661A when studied as listed within this report.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this IAISIS at the expense of the Customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

Appendices

A: Reduced Wind Generation Analysis Results

Below figures are from the 2016WP model with identified upgrades in-service. The other 2 cases (2017SP and 2025SP) were almost identical since the Interconnection Request facilities design is the same in all cases.

Figure A-1: GEN-2016-036 with generators turned off

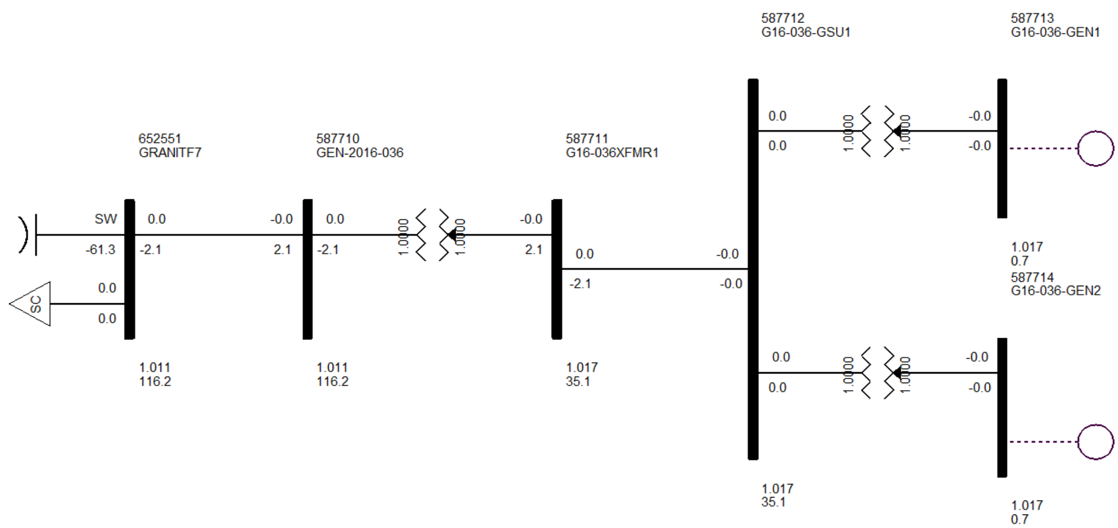
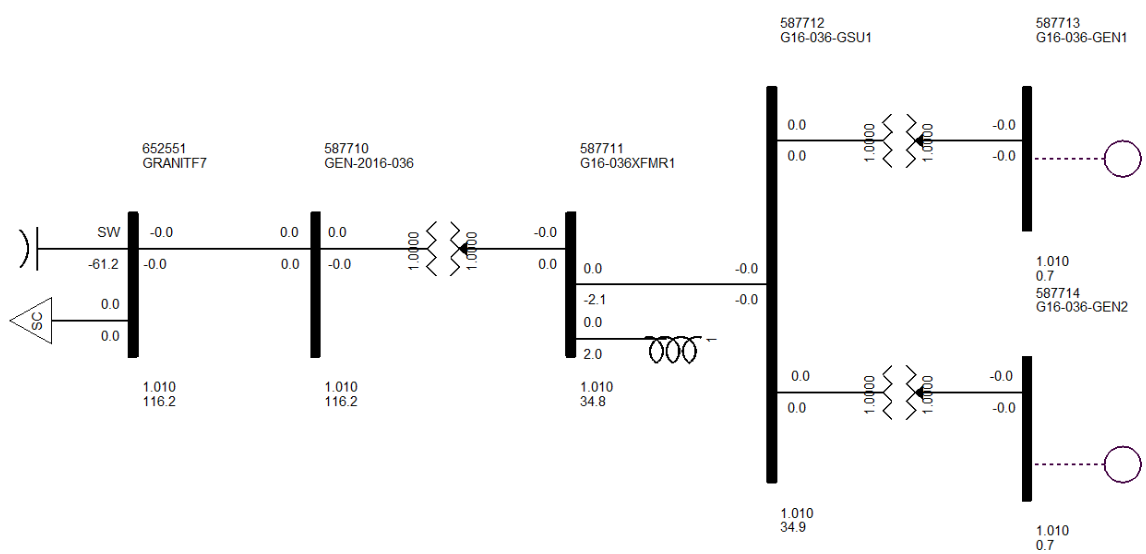


Figure A-2: GEN-2016-036 with generators turned off and shunt reactors added to the customer 34.5kV substation



B: Short Circuit Analysis Results

17SP

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                              PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS          TUE, FEB 20 2018
9:28
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 17S WITH MMWG 15S, MRO 16W TOPO/16S PROF, SERC 16S

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                                   THREE PHASE FAULT
X---------- BUS ----------X          /I+/    AN(I+)
652551 [GRANITF7    115.00] AMP    17183.0   -82.33
587710 [GEN-2016-036115.00] AMP    17183.0   -82.33
603030 [MINVALY7    115.00] AMP    16217.6   -82.04
620211 [CANBY  7    115.00] AMP     4305.0   -71.03
652298 [GRANITF8    69.000] AMP     3398.3   -88.18
652508 [S3     7    115.00] AMP     8533.8   -77.90
652550 [GRANITF4    230.00] AMP    12636.9   -82.63
602008 [MINVALT4    230.00] AMP    12518.6   -82.75
602009 [MNVLTAP4    230.00] AMP    12482.4   -82.75
603177 [MAYNARD7    115.00] AMP     7317.6   -79.06
603257 [MINVALY CAP7115.00] AMP    16107.3   -81.91
605045 [MINNVAL8    69.000] AMP     9398.2   -78.21
613310 [REDFLST7    115.00] AMP     6400.1   -80.93
619975 [GRE-WILLMAR4230.00] AMP     5286.0   -80.70
620173 [DAWS TP7    115.00] AMP     3161.8   -67.66
620212 [BURR   7    115.00] AMP     4140.9   -72.86
652503 [BLAIR  4    230.00] AMP     8821.3   -83.63
652552 [MARS ER7    115.00] AMP     7812.6   -77.75
652554 [MORRIS 4    230.00] AMP     4615.1   -81.27
652582 [APPLEDORN 4 230.00] AMP     6955.8   -82.40
658072 [ERIE RD7    115.00] AMP    11101.1   -79.30
587620 [J493        115.00] AMP     4140.9   -72.86
601053 [HAZEL CK4   230.00] AMP    11347.1   -83.49
602036 [PAYNES 4    230.00] AMP     4020.7   -79.34
603028 [FRANKLN7    115.00] AMP    10902.0   -81.70
603160 [HONNERR7    115.00] AMP     4407.2   -78.82
603267 [KERKHOVENTP7115.00] AMP     5319.0   -78.52
605005 [MAYNARD8    69.000] AMP     4980.1   -73.89
605046 [YELWMED8    69.000] AMP     4232.9   -65.26
605049 [BUSH PK8    69.000] AMP     6555.2   -71.65
605053 [GRNFLCY8    69.000] AMP     8645.6   -75.99
605055 [SACRDHT8    69.000] AMP     3996.3   -60.28
615529 [GRE-PANTHER4230.00] AMP     6198.8   -81.89
619977 [GRE-WILLMAR869.000] AMP     6408.9   -83.94
620174 [DAWSON 7    115.00] AMP     3102.6   -67.57
620206 [LOUSBRG7    115.00] AMP     3204.0   -67.77
620210 [TORONTO7    115.00] AMP     1860.6   -73.60
620213 [MARIETT7    115.00] AMP     3787.3   -71.49
620314 [BIGSTON4    230.00] AMP     8819.9   -83.59
652224 [BLAIR  8    69.000] AMP     2569.2   -88.28
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652530	[WATERTN4 230.00]	AMP	13304.0	-84.50
652553	[MOORHED4 230.00]	AMP	6858.1	-81.89
652555	[MORRIS 7 115.00]	AMP	7362.2	-77.34
652604	[APPLEDORN 8 69.000]	AMP	2494.1	-89.03
658070	[MMU 7ST7 115.00]	AMP	11331.2	-79.38
658074	[SARATOG7 115.00]	AMP	9993.1	-78.98
601054	[HAZEL CK3 345.00]	AMP	7876.3	-84.60
603004	[FTRIDLY7 115.00]	AMP	5518.0	-73.80
603034	[PYNSVIL7 115.00]	AMP	7759.4	-78.26
605006	[MAYNARL8 69.000]	AMP	4920.8	-73.52
605050	[MNTVDEO8 69.000]	AMP	1863.7	-52.68
605052	[MNARDTP8 69.000]	AMP	4924.1	-71.28
605056	[RENVILL8 69.000]	AMP	3198.4	-54.27
605087	[FRANKLN8 69.000]	AMP	11057.7	-80.07
613300	[R.FALLS7 115.00]	AMP	3958.1	-78.41
615530	[GRE-PANTHER869.000]	AMP	7835.3	-78.64
615644	[GRE-CEDARMT7115.00]	AMP	12979.7	-84.67
616002	[GRE-JOHNJCT7115.00]	AMP	4673.9	-70.83
616005	[GRE-KERKHO 7115.00]	AMP	4272.1	-75.26
617914	[GRE-KANDYOH869.000]	AMP	2769.8	-72.63
617919	[GRE-SVEATAP869.000]	AMP	4002.8	-75.89
619019	[GRE-MLRY TP869.000]	AMP	7273.5	-78.36
619940	[HUC-MCLEOD 4230.00]	AMP	5933.9	-82.80
619982	[WMU-PRIAM 7115.00]	AMP	4086.4	-78.31
619987	[WMU-WILMRSO869.000]	AMP	6196.1	-83.34
620208	[BRUCE TP 115.00]	AMP	1261.1	-71.37
620214	[BIGSTON7 115.00]	AMP	9991.8	-82.86
620218	[MOROTP 7 115.00]	AMP	5564.1	-76.59
620325	[BROWNSV4 230.00]	AMP	5193.2	-82.10
652435	[FARGO 4 230.00]	AMP	9942.4	-82.44
652514	[HURON 4 230.00]	AMP	10659.0	-83.78
652529	[WATERTN3 345.00]	AMP	9327.1	-85.32
652531	[WATERTN7 115.00]	AMP	12064.6	-85.05
652587	[MOORHED7 115.00]	AMP	6170.0	-82.69
652614	[CARPENTER 4 230.00]	AMP	6741.7	-83.44
652630	[WATERTNCAP 4230.00]	AMP	13304.0	-84.50
658068	[MARSHAL7 115.00]	AMP	12166.9	-79.95
658076	[MMU SW 7 115.00]	AMP	10417.4	-79.66
658102	[GRANTCO7 115.00]	AMP	6302.9	-73.42
658114	[APPLETN7 115.00]	AMP	3446.3	-68.44
601048	[LYON CO 3 345.00]	AMP	11528.5	-84.42
602006	[SHEYNNE4 230.00]	AMP	10802.8	-82.69
602014	[BLUE LK4 230.00]	AMP	7184.3	-86.81
603003	[SWAN LK7 115.00]	AMP	6267.8	-75.26
603010	[LKYNKTN7 115.00]	AMP	12187.8	-81.88
603039	[WAKEFLD7 115.00]	AMP	9004.6	-74.89
603046	[LYON CO7 115.00]	AMP	17293.2	-84.26
603201	[W NEWU7 115.00]	AMP	5017.0	-74.27
603251	[FTRIDLY CAP7115.00]	AMP	5504.7	-73.77
603256	[PYNSVIL CAP7115.00]	AMP	7733.5	-78.21
605007	[CLARCTY8 69.000]	AMP	2729.8	-66.13
605042	[EMMET R8 69.000]	AMP	3194.9	-54.10
605047	[GRNVALY8 69.000]	AMP	8068.4	-79.74
605051	[FIESTAC8 69.000]	AMP	2225.8	-62.56
605077	[BIRDISL8 69.000]	AMP	7776.5	-76.39
605086	[FARFXNU8 69.000]	AMP	3883.8	-60.86
605119	[PAYNES 8 69.000]	AMP	7697.2	-75.76
605129	[BIRCH R8 69.000]	AMP	8736.8	-77.44
605130	[RDWDFLTG 69.000]	AMP	2041.0	-51.54
605281	[FTRIDGL8 69.000]	AMP	5970.2	-73.64
613312	[R FALLS EAST115.00]	AMP	3416.9	-76.96
615365	[GRE-BENSON 7115.00]	AMP	4783.3	-77.96
615643	[GRE-CEDARMT3345.00]	AMP	11879.0	-84.21

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616001 [GRE-WALDEN 7115.00] AMP     4755.9   -76.43
616003 [GRE-GRACEV 7115.00] AMP     3531.5   -69.19
616240 [GRE-EDEN TP869.000] AMP     3987.9   -62.00
617915 [GRE-SVEA   869.000] AMP     3586.4   -71.69
617923 [GRE-SPICERT869.000] AMP     2318.9   -71.05
618419 [GRE-MLVILTP869.000] AMP     7724.5   -78.02
619941 [HUC-MCLEOD 7115.00] AMP     9554.7   -82.16
619983 [WMU-PRIAM  869.000] AMP     5899.2   -79.91
619990 [WMU-WILMR E869.000] AMP     6142.7   -82.45
620170 [EFERGUS7    115.00] AMP     9963.9   -79.19
620205 [BRUCE  7    115.00] AMP     1245.6   -70.89
620209 [HETLAND7    115.00] AMP      996.6   -70.39
620215 [HIWY12 7    115.00] AMP     8782.4   -81.77
620216 [ORTONVL7    115.00] AMP     7214.7   -79.59
620289 [CORRELL7    115.00] AMP     3823.9   -69.52
620327 [HANKSON4    230.00] AMP     6131.9   -81.38
652001 [G13_001IST  115.00] AMP     5095.1   -77.31
652175 [G09_001IST  345.00] AMP     5749.6   -85.59
652242 [WATERT18    69.000] AMP     3857.1   -87.10
652436 [FARGO  7    115.00] AMP    10409.6   -83.62
652444 [JAMESTN4    230.00] AMP     8203.8   -82.42
652500 [ARLNGTN7    115.00] AMP     4237.4   -76.45
652504 [BROOKNG7    115.00] AMP     6948.9   -80.98
652507 [FTTHOMP4    230.00] AMP    19594.8   -85.54
652515 [HURON  7    115.00] AMP    15002.2   -83.73
652829 [WATERTN-LNX3345.00] AMP     9327.1   -85.32
658078 [SOUTH E7    115.00] AMP    10664.5   -79.22
658087 [MPSOPP 7    115.00] AMP     5622.8   -79.89
658088 [WTREAST7    115.00] AMP     9369.5   -81.26
658094 [WTRPELI7    115.00] AMP     8348.2   -80.56
658104 [ELBOWLK7    115.00] AMP     5891.6   -75.13
658204 [MMUSW CAP1 7115.00] AMP    10005.1   -79.96
658205 [MMUSW CAP2 7115.00] AMP    10005.1   -79.96
658206 [MMUSS CAP 7 115.00] AMP    12166.9   -79.95
659196 [CARPENTER 8 69.000] AMP     3163.5   -87.92
659205 [BRDLAND4    230.00] AMP     9678.2   -84.13
```

25SP

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                          PSS®E-32.2.0 ASCC SHORT CIRCUIT CURRENTS           TUE, FEB 20 2018
9:28
2015 MDWG FINAL WITH 2013 MMWG, UPDATED WITH 2014 SERC & MRO
MDWG 2025S WITH MMWG 2024S, MRO & SERC 2025 SUMMER

OPTIONS USED:
    - FLAT CONDITIONS
         - BUS VOLTAGES SET TO 1 PU AT 0 PHASE ANGLE
         - GENERATOR P=0, Q=0
         - TRANSFOMRER TAP RATIOS=1.0 PU and PHASE ANGLES=0.0
         - LINE CHARGING=0.0 IN +/-/0 SEQUENCE
         - LOAD=0.0 IN +/- SEQUENCE, CONSIDERED IN ZERO SEQUENCE
         - LINE/FIXED/SWITCHED SHUNTS=0.0 AND MAGNETIZING ADMITTANCE=0.0 IN +/-/0 SEQUENCE
         - DC LINES AND FACTS DEVICES BLOCKED
         - TRANSFORMER ZERO SEQUENCE IMPEDANCE CORRECTIONS IGNORED

                               THREE PHASE FAULT
X---------- BUS ----------X          /I+/    AN(I+)
652551 [GRANITF7    115.00] AMP    17555.5   -82.24
587710 [GEN-2016-036115.00] AMP    17555.5   -82.24
603030 [MINVALY7    115.00] AMP    16489.6   -81.98
620211 [CANBY  7    115.00] AMP     4615.3   -70.92
652298 [GRANITF8    69.000] AMP     3406.9   -88.18
652508 [S3     7    115.00] AMP     8819.2   -78.05
652550 [GRANITF4    230.00] AMP    13002.7   -82.57
602008 [MINVALT4    230.00] AMP    12857.9   -82.70
602009 [MNVLTAP4    230.00] AMP    12819.8   -82.69
603177 [MAYNARD7    115.00] AMP     7364.2   -79.02
603257 [MINVALY CAP7115.00] AMP    16375.6   -81.85
605045 [MINNVAL8    69.000] AMP     9447.9   -78.19
613310 [REDFLST7    115.00] AMP     6423.7   -80.92
619975 [GRE-WILLMAR4230.00] AMP     5326.7   -80.66
620173 [DAWS TP7    115.00] AMP     3308.5   -67.29
620212 [BURR   7    115.00] AMP     4526.7   -72.69
652503 [BLAIR  4    230.00] AMP     9796.8   -83.80
652552 [MARS ER7    115.00] AMP     8050.2   -77.88
652554 [MORRIS 4    230.00] AMP     4647.1   -81.24
652582 [APPLEDORN 4 230.00] AMP     7088.7   -82.38
658072 [ERIE RD7    115.00] AMP    11690.3   -79.67
587620 [J493        115.00] AMP     4526.7   -72.69
601053 [HAZEL CK4   230.00] AMP    11609.1   -83.47
602036 [PAYNES 4    230.00] AMP     4036.5   -79.32
603028 [FRANKLN7    115.00] AMP    10957.2   -81.70
603160 [HONNERR7    115.00] AMP     4418.4   -78.81
603267 [KERKHOVENTP7115.00] AMP     5338.3   -78.49
605005 [MAYNARD8    69.000] AMP     4993.3   -73.86
605046 [YELWMED8    69.000] AMP     4244.4   -65.23
605049 [BUSH PK8    69.000] AMP     6579.0   -71.61
605053 [GRNFLCY8    69.000] AMP     8687.4   -75.96
605055 [SACRDHT8    69.000] AMP     4003.5   -60.24
615529 [GRE-PANTHER4230.00] AMP     6240.9   -81.86
619977 [GRE-WILLMAR869.000] AMP     6422.4   -83.94
620174 [DAWSON 7    115.00] AMP     3243.7   -67.20
620206 [LOUSBRG7    115.00] AMP     3353.2   -67.37
620210 [TORONTO7    115.00] AMP     2180.9   -73.72
620213 [MARIETT7    115.00] AMP     4046.6   -71.01
620314 [BIGSTON4    230.00] AMP    15925.7   -85.00
652224 [BLAIR  8    69.000] AMP     2587.0   -88.32
652530 [WATERTN4    230.00] AMP    14327.4   -84.81
652553 [MOORHED4    230.00] AMP     6886.7   -81.87
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652555 [MORRIS 7    115.00] AMP     7415.4   -77.28
652604 [APPLEDORN 8 69.000] AMP     2499.1   -89.05
658070 [MMU 7ST7    115.00] AMP    11910.8   -79.72
658074 [SARATOG7    115.00] AMP    10643.5   -79.56
601054 [HAZEL CK3   345.00] AMP     8053.4   -84.62
603004 [FTRIDLY7    115.00] AMP     5528.4   -73.78
603034 [PYNSVIL7    115.00] AMP     7781.3   -78.26
605006 [MAYNARL8    69.000] AMP     4933.7   -73.49
605050 [MNTVDEO8    69.000] AMP     1865.4   -52.65
605052 [MNARDTP8    69.000] AMP     4936.9   -71.24
605056 [RENVILL8    69.000] AMP     3202.0   -54.24
605087 [FRANKLN8    69.000] AMP    11089.8   -80.07
613300 [R.FALLS7    115.00] AMP     3967.1   -78.40
615530 [GRE-PANTHER869.000] AMP     7851.3   -78.63
615644 [GRE-CEDARMT7115.00] AMP    13060.7   -84.69
616002 [GRE-JOHNJCT7115.00] AMP     4785.4   -70.61
616005 [GRE-KERKHO 7115.00] AMP     4283.2   -75.22
617914 [GRE-KANDYOH869.000] AMP     2772.3   -72.62
617919 [GRE-SVEATAP869.000] AMP     4008.0   -75.88
619019 [GRE-MLRY TP869.000] AMP     7318.5   -78.38
619940 [HUC-MCLEOD 4230.00] AMP     5951.5   -82.79
619982 [WMU-PRIAM  7115.00] AMP     4096.7   -78.29
619987 [WMU-WILMRSO869.000] AMP     6208.3   -83.34
620208 [BRUCE TP    115.00] AMP     1592.8   -72.23
620214 [BIGSTON7    115.00] AMP    12435.4   -84.12
620218 [MOROTP 7    115.00] AMP     5590.7   -76.54
620322 [BSSOUTH4    230.00] AMP    15845.3   -85.13
620325 [BROWNSV4    230.00] AMP     5893.7   -82.15
652435 [FARGO  4    230.00] AMP    10002.9   -82.41
652514 [HURON  4    230.00] AMP    10851.2   -83.73
652529 [WATERTN3    345.00] AMP    10078.8   -85.60
652531 [WATERTN7    115.00] AMP    13627.9   -85.40
652587 [MOORHED7    115.00] AMP     6181.8   -82.68
652614 [CARPENTER 4 230.00] AMP     6845.9   -83.44
652630 [WATERTNCAP 4230.00] AMP    14327.4   -84.81
658068 [MARSHAL7    115.00] AMP    12761.1   -80.25
658076 [MMU SW 7    115.00] AMP    10945.3   -80.05
658102 [GRANTCO7    115.00] AMP     6118.2   -73.70
658114 [APPLETN7    115.00] AMP     3622.3   -68.02
 11120 [G736        230.00] AMP     2248.3   -79.57
 11130 [J442        230.00] AMP     5918.5   -80.66
601048 [LYON CO 3   345.00] AMP    11961.0   -84.45
602006 [SHEYNNE4    230.00] AMP    10868.0   -82.66
602014 [BLUE LK4    230.00] AMP     7191.9   -86.80
603003 [SWAN LK7    115.00] AMP     6281.2   -75.23
603010 [LKYNKTN7    115.00] AMP    12471.1   -81.97
603039 [WAKEFLD7    115.00] AMP     9016.5   -74.88
603046 [LYON CO7    115.00] AMP    17903.3   -84.34
603201 [W NEWU7     115.00] AMP     5025.6   -74.25
603251 [FTRIDLY CAP7115.00] AMP     5515.1   -73.75
603256 [PYNSVIL CAP7115.00] AMP     7755.3   -78.20
605007 [CLARCTY8    69.000] AMP     2733.6   -66.10
605042 [EMMET R8    69.000] AMP     3198.5   -54.06
605047 [GRNVALY8    69.000] AMP     8124.9   -79.77
605051 [FIESTAC8    69.000] AMP     2228.3   -62.53
605077 [BIRDISL8    69.000] AMP     7792.5   -76.37
605086 [FARFXNU8    69.000] AMP     3886.9   -60.84
605119 [PAYNES 8    69.000] AMP     7707.3   -75.76
605129 [BIRCH R8    69.000] AMP     8756.8   -77.43
605130 [RDWDFLTG    69.000] AMP     2041.9   -51.53
605281 [FTRIDGL8    69.000] AMP     5977.3   -73.62
613312 [R FALLS EAST115.00] AMP     3423.6   -76.95
615365 [GRE-BENSON 7115.00] AMP     4794.1   -77.92
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615643 [GRE-CEDARMT3345.00] AMP    12103.2   -84.22
616001 [GRE-WALDEN 7115.00] AMP     4772.8   -76.39
616003 [GRE-GRACEV 7115.00] AMP     3594.5   -69.00
616240 [GRE-EDEN TP869.000] AMP     3991.5   -61.98
617915 [GRE-SVEA   869.000] AMP     3590.5   -71.68
617923 [GRE-SPICERT869.000] AMP     2320.6   -71.03
618419 [GRE-MLVILTP869.000] AMP     7739.9   -78.01
619941 [HUC-MCLEOD 7115.00] AMP     9567.9   -82.16
619983 [WMU-PRIAM  869.000] AMP     5910.6   -79.89
619990 [WMU-WILMR E869.000] AMP     6152.7   -82.44
620170 [EFERGUS7    115.00] AMP     8186.3   -78.07
620205 [BRUCE  7    115.00] AMP     1568.4   -71.62
620209 [HETLAND7    115.00] AMP     1346.9   -71.95
620215 [HIWY12 7    115.00] AMP    10482.6   -82.69
620216 [ORTONVL7    115.00] AMP     8154.5   -80.15
620289 [CORRELL7    115.00] AMP     4047.3   -69.11
620327 [HANKSON4    230.00] AMP     6527.5   -81.37
620417 [BSSOUTH3    345.00] AMP    10884.2   -85.62
652001 [G13_001IST  115.00] AMP     5233.8   -77.07
652175 [G09_001IST  345.00] AMP     6291.3   -86.14
652242 [WATERT18    69.000] AMP     3943.7   -87.20
652436 [FARGO  7    115.00] AMP    10447.5   -83.61
652444 [JAMESTN4    230.00] AMP     8292.4   -82.39
652500 [ARLNGTN7    115.00] AMP     4351.5   -76.27
652504 [BROOKNG7    115.00] AMP     7203.2   -80.97
652507 [FTTHOMP4    230.00] AMP    20056.6   -85.39
652515 [HURON  7    115.00] AMP    15219.3   -83.66
652829 [WATERTN-LNX3345.00] AMP    10078.8   -85.60
658078 [SOUTH E7    115.00] AMP    11153.6   -79.51
658087 [MPSOPP 7    115.00] AMP     5632.6   -79.88
658088 [WTREAST7    115.00] AMP    10803.5   -82.06
658094 [WTRPELI7    115.00] AMP     9345.7   -80.96
658104 [ELBOWLK7    115.00] AMP     5752.1   -75.31
658204 [MMUSW CAP1 7115.00] AMP    10490.7   -80.34
658205 [MMUSW CAP2 7115.00] AMP    10490.7   -80.34
658206 [MMUSS CAP 7 115.00] AMP    12761.1   -80.25
659196 [CARPENTER 8 69.000] AMP     3170.3   -87.93
659205 [BRDLAND4    230.00] AMP     9831.6   -84.10
```

C: MISO Affected System Impact Study

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Midcontinent Independent System Operator (MISO)

Affected System Impact Study
SPP GEN-2016-036

Draft Report

REP-0181
Revision #01

February 2018

Submitted By:
Mitsubishi Electric Power Products, Inc. (MEPPI)
Power Systems Engineering Division
Warrendale, PA

Title: **Affected System Impact Study SPP GEN-2016-036: Draft Report REP-0181**
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EXECUTIVE SUMMARY

The Midcontinent Independent System Operator ("MISO") requested an Affected System Impact Study ("SIS") for the Southwest Power Pool ("SPP") Definitive Interconnection System Impact Study ("DISIS") generator GEN-2016-036. This report documents the impact of GEN-2016-036 in the SPP generator queue on the MISO transmission system. The SPP study project is listed in Table ES-1.

Table ES-1
Interconnection Project Evaluated

Queue #	Capacity	Service	Fuel Type	Area	Proposed Point of Interconnection
GEN-2016-036	44.2	ER	Wind	NPPD	Granite Falls 115 kV

No voltage constraints were identified for 2021 Summer Peak Scenario or the 2021 Summer Shoulder Scenario. All bus voltages remained with transmission owner criteria or did not deviate by more than 0.01 p.u. post-contingency from the pre-project voltage.

No transient stability constraints were identified for the addition of GEN-2016-036 in the 2021 Summer Shoulder scenario. The post-project case showed similar performance as the respective pre-project case and did not affect the transient stability of the system.

The project will be subject to MISO's Annual ERIS/Annual Interim Deliverability evaluation to determine constraints in the MISO system on an annual basis until SPP study cycle DISIS-2016-002 studies are complete, and all NUs identified in DISIS-2016-002 Affected System Study (if any) are in operation.

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SECTION 1: BACKGROUND AND OBJECTIVE

The objective of this report is to provide MISO with the deliverables for the "Affected System Impact Study SPP GEN-2016-036." MISO requested an Affected System Impact Study for one generation interconnection for 2021 Summer Shoulder conditions and 2021 Summer Peak conditions, which required a steady-state analysis, short-circuit analysis, low voltage ride through analysis, and stability analysis. The study project, GEN-2016-036, has an in-service date (ISD) of December 31, 2018.

The Siemens Power Technologies International PSS/E power system simulation program Version 33.10.0 and PowerGEM's TARA 1701 was used for this study. MISO provided the steady-state database cases for 2021 Summer Shoulder and 2021 Summer Peak conditions and stability database for 2021 Summer Shoulder conditions. This impact study required a steady-state analysis to determine if any SPP study projects contribute to thermally overloaded lines or bus voltages that exceed normal or emergency operating conditions. The short-circuit analysis was performed to determine high level breaker duty ratings after interconnecting the study project.

The low voltage ride through (LVRT) analysis was performed to determine the performance of the dynamic model and ensure no adverse impacts are observed. The stability analysis was performed to determine if any SPP study projects contribute to adverse impacts on the MISO transmission system including generator tripping, rotor angle oscillation instability, voltage recovery issues, and voltage instability. Table 1-1 is a description of GEN-2016-036. Refer to Appendix B for one-line diagrams of the project and the point of interconnection.

Table 1-1
Interconnection Project Evaluated

Queue #	Capacity	Service	Fuel Type	Area	Proposed Point of Interconnection
GEN-2016-036	44.6	ER	Wind	NPPD	Granite Falls 115 kV

SECTION 2: MODEL DEVELOPMENT

This section describes the changes made to the steady-state and stability databases provided by MISO to MEPPI. The following DPP February 2016 West Phase II study case load profiles were used for the study (include MISO queue projects up to DPP-2016-FEB with in-service dates before 12/31/2018):

- Steady-State Cases
  - 2021 Summer Shoulder
    - StudyCase-MISO17_2022_SH90__TA_Pass3-DPP 2016-FEB_West_171127.sav
  - 2021 Summer Peak
    - StudyCase-MISO17_2022_SUM__TA_Pass3-DPP 2016-FEB_West_171127.sav
- Stability Case
  - 2021 Summer Shoulder
    - StudyCase-2022_SH90_DS_171127.sav

The "pre-project" cases were developed based on the above power flow cases by making several changes which include:

- Removing queued generation with in-service dates after 12/31/2018
- Adding/dispatching queued generation with provisional generator interconnection agreements (PGIA).
- Removing transmission projects with in-service dates after 12/31/2018
- Re-dispatch generation in the MISO Classic region.

Refer to table 2-1 for a list of generators that were removed from all cases listed above.

Table 2-1
Generators Removed from Service

MISO Project Num	Trans. Owner	Point Of Interconnection	Max Output	POI Bus #	POI Bus Name	Gen Bus #
J432	XEL	Brookings 345 kV	98	601031	BRKNGCO3	61033
J460	GRE	Brookings-H081 345 kV line	200	61041, tap line from 601031 to 10215	J460 POI	61044 61045
J488	OTP	Big Stone-Ellendale 345 kV	151.8	50416, tap line from 620417 to 661097	J488&489	60421

J489	OTP	Big Stone-Ellendale 345 kV	151.8	50416, tap line from 620417 to 661097	J488&489	61421
J493	OTP	Big Stone-Brookings 345 kV	150	71031	J510 POI	60214
J495	ITCM	Ledyard-Colby 345 kV line	200	Central	J495 POI	61531 61534
J504	ITCM	Bertram-Duane Anronld 161 kV(0.5 mi from Duane Arnold)	50	71088, Tapped about 0.5 mile from Duane Arnold on Bertram-Duane Anronld 161kV line	J504 POI	71091
J506	MEC	Raun-Lakefield Jct 345 kV	200	65400, tap line from 635200 to 635400	J506 POI	15040 16040
J510	OTP	Scandinavia Township	266 sum / 284.5 win	71031, tap line from 601031 to 620417	J510 POI	71033
J523	ITCM	Adams 161 kV	50	631122	ADAMS_N5	97999
J524	MEC	Webster 161 kV	100	636001	WEBSTER5	96999
J525	XEL	Lake Wilson–Hadely 69 kV	33	618920	GRE-LKWILSN8	68922
J526	OTP	Brooking Co-Big Stone South345 kV	300	72031, tap line from 601031 to 620417	J526 POI	72034 72036
J527	MEC	Booneville-Cooper 345 kV	250	65200, tap line from 635630 to 635017	J527 POI	65203 65205
J528	MEC	Rolling Hills-Madison 345 kV	200	65300, tap line from 635100 to 635635	J528 POI	65303 65305
J530	MEC	Montezuma-Hills 345 kV	250	75730, tap line from 635730 to 636400	J530 POI	75733 75735
J534	MEC	Kossuth–Webster 345 kV	250	66000, tap line from 635369 to 636000	J534 POI	66003 66005
J535	MEC	J411–Lehigh 345 kV	210	66201, tap line from 636010 to 6201	J535 POI	66204

Refer to Table 2-2 for a list of generators with a provisional GIA with in-service dates before 12/31/18 and the corresponding dispatch.

Table 2-2
Generators with Provisional GIA

Project Number	Owner	POI	POI Bus Number	Generator Bus Number	Fuel Type	Pmax (MW)	Steady-State Case		Stability Case
							Shoulder Peak Dispatch (MW)	Summer Peak Dispatch (MW)	Shoulder Peak Dispatch (MW)
J441	XEL	Byron 345 kV Substation	613060	613061	Wind	200	200	31.2	200
J555	MEC	Montezuma, IA 50171 345kV substation	635730	65730	Wind	140	140	21.84	140
J589	METC	Regal-Summerton 138kV line	256078	56078	Wind	149	149	23.2128	149
J590	MEC	Obrien - Kossuth 345 kV line	75367	75367	Wind	90	90	14.04	90
J614	SMPA	Rice 161kV Substation	613330	613331	Wind	66	66	10.296	66
J475	MEC	Existing 345 kV Montezuma Substation	635730	65733	Wind	200	200	31.2	200
J485	RPU	West Side Substation - 5846 19th Street NW, Rochester, MN	625447	65447	Gas	47	0	46.85	46.85
J498	MEC	MEC 345 kV Grimes-Lehigh line (18 miles south of Leigh substation)	636003	636008 636009	Wind	340	340	53.04	340
J499	MEC	MEC 345 kV Fallow-Grimes line (18 miles east of Fallow substation)	636005	635585 635586	Wind	340	340	53.04	340
J529	MEC	Obrien - Kossuth 345 kV line	75368	75374 75375	Wind	250	250	39	250

Refer to Table 2-3 for a list of transmission projects that were removed from the pre-project cases due to an in-service date after 12/31/18.

Table 2-3
Transmission Service Projects Removed from Study Cases

Project Name	Project ID	PrjID
EES 16-EAI-010 Lynch - NLR Galloway	20048	9701
EES 16-ETI-001 Replace Bryan Autos	20138	9806
EAI 17-EAI-023 ISES Additional Auto bank	22815	12045
EAI 17-EAI-028 London North Series RX	22817	12041

EES_12035(17-ELN-003)_Danvl - Winnfld 230 conv	22836	12035
EES 12667 Pecan St 161 kV new sub	23397	12667

The SPP study cases were built by adding the SPP GEN-2016-036 project to the MISO pre-project cases. The detail for the interconnection request study project is listed in Table 1-1. The SPP study project and SPP higher queued projects were dispatched per MISO criteria to the entire SPP footprint, where generators were scaled in proportion to the available reserve.

SECTION 3: STEADY-STATE VOLTAGE ANALYSIS

The steady-state analysis was performed to evaluate the thermal flow and voltage impact of the SPP study generators on the MISO transmission system.

3.1 Study Assumptions

This affected system impact study was conducted with all the participating generators and higher queued SPP generators. This study group includes higher queued SPP generators and requested study SPP generators in South Dakota (east, west, and south central), North Dakota (west and east), and Nebraska. In the Summer Shoulder scenario wind plants are dispatched at 100% nameplate rating in the study group and in the summer peak scenario wind plants are dispatched at 15.6% nameplate rating. The results obtained in this analysis may change if any of the data or assumptions made during the development of the study models is revised.

3.2 Study Criteria

All interconnection requirements are based on the applicable MISO Interconnection Planning Criteria and in accordance with the NERC Reliability Standards. Steady state violations of applicable planning criteria were attributed to the SPP generation request by the usage of MISO injection criteria, and applicable local planning criteria. The simulation software that was utilized for this analysis was PowerGEM’s TARA 1701.

3.2.1 MISO Voltage Criteria

A bus is considered a voltage constraint if both of the following conditions are met. All voltage constraints must be resolved before a project can receive Interconnection Service.

1) The bus voltage is outside of applicable normal or emergency limits for the post-change case, and
2) The change in bus voltage is greater than 0.01 per unit.

3.2.2 TOS' Local Planning Criteria

A constraint is identified as a constraint if it violates applicable Transmission Owner FERC filed Local Planning Criteria.

3.3 Contingency Criteria

A comprehensive list of contingencies was considered for steady-state analysis:

- NERC Category P0 with system intact (no contingencies)
- NERC category P1, P2, P4, P5, P7 contingencies
    - Single element outages, at buses with a nominal voltage of 69 kV and above in the following areas: CWLD (area 333), AMMO (area 356), AMIL (area 357), CWLP (area 360), SIPC (area 361), WEC (area 295), MIUP (area 296), MH (area 667), ALTE (area 694), WPS (area 696), MGE (area 697), UPPC (area 698), XCEL (area 600), MP (area 608), SMMPA (area 613), GRE (area 615), OTP (area 620), ITCM (area 627), MPW (area 633), MEC (area 635), MDU (area 661), DPC (area 680), CE(area 222), NPPD (area 640), OPPD (area 645), LES (area 650), WAPA (area 652), AECI (area 330), MIPU(area 540), KCPL (area 541), KACY (area 542), BEPC-SPP (area 659), and INDN (area 545).
    - Multiple-element outages initiated by a fault with normal clearing such as multi-terminal lines, in the Dakotas, Illinois, Iowa, Manitoba, Minnesota, Missouri, and Wisconsin.
- NERC Category P3
    - Selected NERC Category P3 events provided by ad-hoc study group in the study region.

For all the contingencies and post-disturbance analyses, cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment enabled, and switched shunt adjustment enabled.

3.4 Monitored Elements

Table 3-1 is a list of elements that were monitored in the MISO area.

Table 3-1
Monitored MISO Areas

Area #	Voltage	Area ID	Area Name
295	69kV and above	WEC	Wisconsin Electric Power Company (ATC)
296	69kV and above	MIUP	Michigan Upper Peninsula (ATC)

333	69kV and above	CWLD	Columbia, MO Water and Light
356	69kV and above	AMMO	Ameren Missouri
357	69kV and above	AMIL	Ameren Illinois
360	69kV and above	CWLP	City Water Light & Power (Springfield)
361	69kV and above	SIPC	Southern Illinois Power Co.
600	69kV and above	XEL	Xcel Energy North
608	69kV and above	MP	Minnesota Power & Light
613	69kV and above	SMMPA	Southern Minnesota Municipal Power Association
615	69kV and above	GRE	Great River Energy
620	69kV and above	OTP	Otter Tail Power Company
627	69kV and above	ITCM	ITC Midwest
633	69kV and above	MPW	Muscatine Power & Water
635	69kV and above	MEC	MidAmerican Energy
661	69kV and above	MDU	Montana-Dakota Utilities Co.
680	69kV and above	DPC	Dairyland Power Cooperative
694	69kV and above	ALTE	Alliant Energy East (ATC)
696	69kV and above	WPS	Wisconsin Public Service Corporation (ATC)
697	69kV and above	MGE	Madison Gas and Electric Company (ATC)
698	69kV and above	UPPC	Upper Peninsula Power Company (ATC)

3.5 Steady-State Voltage Analysis Results

No voltage constraints were identified in the 2021 Summer Peak scenario or 2021 Summer Shoulder scenario. All bus voltages remained with applicable transmission owner criteria or did not change by more than 0.01 p.u. from the pre-project case.

SECTION 4: SHORT CIRCUIT ANALYSIS

The nominal maximum short circuit current for GEN-2016-036 for three phase faults was calculated for the POI and five buses away. The pre-project short circuit currents were compared to the post-project short circuit currents to determine the impact of the interconnecting study project for no outage conditions.

The Automatic Sequencing Fault Calculation (ASCC) function in PSS/E was utilized to perform this task. FLAT conditions were applied to pre-fault conditions and the following adjustments were utilized:

- All synchronous and asynchronous machine P and Q output was set to zero

- All transformer tap ratios were set to 1.0 p.u. and all phase shift angles were set to zero
- All generator reactance's were fixed to the subtransient reactance
- All line charging was set to zero
- All shunts were set to zero
- All loads were set to zero
- All pre-fault bus voltages were set to 1.0 p.u. and a phase shift angle of zero

The short circuit current analysis with the proposed project in-service showed, for circuit breakers impacted by more than 1%, that none of the breakers were over-dutied in the MISO area. Refer to Table 4-1 for a summary of the short circuit currents in the 2021 Summer Peak case and Table 4-2 for a summary of the short circuit currents in the 2021 Summer Shoulder case.

Table 4-1
Summary of Short Circuit Currents for 2021 Summer Peak

Bus No.	Bus Name	Bus Voltage	Short Circuit Current (Amps)		
			Pre-Project	Post-Project	Delta (%)
652551	GRANITF7	115	17048	17400	2%
652550	GRANITF4	230	12729	12868	1%
602008	MINVALT4	230	12599	12729	1%
602009	MNVLTAP4	230	12563	12692	1%
603030	MINVALY7	115	16290	16455	1%
603257	MINVALY CAP7	115	16179	16341	1%
601053	HAZEL CK4	230	11307	11397	1%

Table 4-2
Summary of Short Circuit Currents for 2021 Shoulder Shoulder

Bus No.	Bus Name	Bus Voltage	Short Circuit Current (Amps)		
			Pre-Project	Post-Project	Delta (%)
652551	GRANITF7	115	15828	16180	2%
603030	MINVALY7	115	15141	15315	1%
603257	MINVALY CAP7	115	15045	15217	1%
652550	GRANITF4	230	11489	11632	1%
602008	MINVALT4	230	11398	11533	1%
602009	MNVLTAP4	230	11368	11502	1%
601053	HAZEL CK4	230	10364	10461	1%
652582	APPLEDORN 4	230	6615	6648	1%

SECTION 5: TRANSIENT STABILITY ANALYSIS

The transient stability analysis was performed to evaluate the transient stability impact of the SPP study generators on the MISO transmission system for regional faults in the WAPA and NPPD area. The transient stability analysis was performed with PSS/E Version 33.10.0.

5.1 Study Criteria

All interconnections must be compliant with MISO criteria and will be required to provide mitigation to obtain Interconnection Service for the following:

- System instability
- Transient voltage constraints
- Damping violation

5.1.1 MISO Criteria

The faults selected for this analysis were evaluated based on the following MISO criteria:

- All on-line generating units are stable.
- No unexpected generator tripping.
- Post-fault transient voltage limits: 1.2 p.u. maximum, 0.7 p.u. minimum.
- All machine rotor angle oscillations must be positively damped with a minimum damping ratio of 0.81633% for disturbances with a fault or 1.6766% for line trips without a fault.
- Per local TO's planning criteria, specific transient voltage limits are applied to specific buses, areas, or companies that have different requirements.

A bus is considered a transient voltage constraint if both of the following conditions are met (all transient voltage constraints must be resolved before a project can receive Interconnection Service):

- The bus transient voltage is outside of specified transient voltage limits during the transient period, and
- The bus voltage is at least 0.01 p.u. worse than the pre-project case voltage for the same contingency.

5.2 List of Contingencies

The contingencies listed in Table 5-1 were simulated using the 2021 Summer Shoulder stability package. Simulations were performed using the study case. The contingencies were performed by simulating a one second state-state run followed by the disturbance and element lost as described in Table 5-1.

Table 5-1
List and Description of Stability Contingencies

Ref. No.	Fault Name	Contingency Description
1	FLT01	3 phase fault on the Granite Falls (652551) to MINVALY (603030) 115kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
2	FLT02	3 phase fault on the Granite Falls (652551) to CANBY (620211) 115kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
3	FLT03	3 phase fault on the Granite Falls (652551) to S3 (652508) 115kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
4	FLT04	3 phase fault on the Granite Falls 230/115/13.8kV (652550/652551/652297) transformer, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
5	FLT05	3 phase fault on the Granite Falls 115/69/13.8kV (652511/652298/652288) transformer, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
6	FLT06	3 phase fault on the MINVALY (603030) to REDFLST (613310) 115kV line circuit 1, near MINVALY. a. Apply fault at the MINVALY 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
7	FLT07	3 phase fault on the MINVALY (603030) to MAYNARD (603177) 115kV line circuit 1, near MINVALY. a. Apply fault at the MINVALY 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
8	FLT08	3 phase fault on the MINVALY 115/69kV (603030/605045) transformer, near MINVALY. a. Apply fault at the MINVALY 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
9	FLT09	3 phase fault on the MINVALY 230/115/13.8kV (602008/603030/605723) transformer circuit 5, near MINVALY.

		a. Apply fault at the MINVALY 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
10	FLT10	3 phase fault on the CANBY (620211) to DAWS TP (620173) 115kV line circuit 1, near CANBY. a. Apply fault at the CANBY 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
11	FLT11	3 phase fault on the CANBY (620211) to BURR (620212) 115kV line circuit 1, near CANBY. a. Apply fault at the CANBY 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
12	FLT12	3 phase fault on the S3 (652508) to ERIE RD (658072) 115kV line circuit 1, near S3. a. Apply fault at the S3 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
13	FLT13	3 phase fault on the S3 (652508) to MARS ER (652552) 115kV line circuit 1, near S3. a. Apply fault at the S3 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
14	FLT14	3 phase fault on the Granite Falls (652550) to MNVLTAP (602009) 230kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
15	FLT15	3 phase fault on the Granite Falls (652550) to APPLEDORN (652582) 230kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
16	FLT16	3 phase fault on the Granite Falls (652550) to BLAIR (652503) 230kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
17	FLT17	3 phase fault on the Granite Falls (652550) to GRE-WILLMAR (619975) 230kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
18	FLT18	3 phase fault on the Granite Falls (652550) to MORRIS (652554) 230kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

19	FLT19	3 phase fault on the Granite Falls (652550) to MINVALT (602008) 230kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
20	FLT20	**Granite Falls 115kV Stuck Breaker Scenario 1** a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. Granite Falls (652551) – CANBY (620211) 115kV d. Granite Falls (652551) – S3 (652508) 115kV
21	FLT21	**Granite Falls 115kV Stuck Breaker Scenario 2** a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. Granite Falls (652551) – MINVALY (603030) 115kV d. Granite Falls 230/115/13.8 kV (652550/652551/652297) transformer
22	FLT22	**Granite Falls 115kV Stuck Breaker Scenario 3** a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. Granite Falls 115/69/13.8 kV (652551/652298/652288) transformer d. Granite Falls 230/115/13.8 kV (652550/652551/652297) transformer
23	FLT23	**CANBY 115kV Stuck Breaker Scenario 1** a. Apply fault at the CANBY 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. CANBY (620211) – DAWS TP (620173) 115kV d. CANBY (620211) – BURR (620212) 115kV
24	FLT24	**MINVALY 115kV Stuck Breaker Scenario 1** a. Apply fault at the MINVALY 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. MINVALY (603030) – REDFLST (613310) 115kV d. MINVALY (603030) – MAYNARD (603177) 115kV
25	FLT25	**MINVALY 115kV Stuck Breaker Scenario 2** a. Apply fault at the MINVALY 115kV bus. b. Clear fault after 16 cycles and trip the following elements c. MINVALY 230/115/13.8 kV (602008/603030/605723) transformer circuit 5 d. MINVALY 230/115/13.8 kV (602008/603030/605729) transformer circuit 6
26	FLT26	**MINVALY 115kV Stuck Breaker Scenario 3** a. Apply fault at the MINVALY 115kV bus.

		b. Clear fault after 16 cycles and trip the following elements c. MINVALY 230/115/13.8 kV (602008/603030/605723) transformer circuit 5 d. MINVALY (603030) – MAYNARD (603177) 115kV
27	FLT27	**Granite Falls 230kV Stuck Breaker Scenario 1** a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 16 cycles and trip the following elements c. Granite Falls (652550) – BLAIR (652503) 230kV d. Granite Falls (652550) – APPLEDORN (652582) 230kV
28	FLT28	**Granite Falls 230kV Stuck Breaker Scenario 2** a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 16 cycles and trip the following elements c. Granite Falls (652550) – MNVLTAP (602009) 230kV d. Granite Falls (652550) – MINVALT (602008) 230kV
29	FLT29	**Granite Falls 230kV Stuck Breaker Scenario 3** a. Apply fault at the Granite Falls 230kV bus. b. Clear fault after 16 cycles and trip the following elements c. Granite Falls (652550) – GRE-WILLMAR (619975) 230kV d. Granite Falls (652550) – MINVALT (602008) 230kV
30	FLT30	**Prior outage on the Granite Falls (652551) – MINVALY (603030) 115 kV line circuit 1** 3 phase fault on the Granite Falls (652551) to CANBY (620211) 115kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
31	FLT31	**Prior outage on the Granite Falls (652551) – MINVALY (603030) 115 kV line circuit 1** 3 phase fault on the Granite Falls (652551) to S3 (652508) 115kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
32	FLT32	**Prior outage on the Granite Falls (652551) – MINVALY (603030) 115 kV line circuit 1** 3 phase fault on the Granite Falls 230/115/13.8kV (652550/652551/652297) transformer, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
33	FLT33	**Prior outage on the Granite Falls (652551) – MINVALY (603030) 115 kV line circuit 1**

		3 phase fault on the Granite Falls 115/69/13.8kV (652511/652298/652288) transformer, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
34	FLT34	**Prior outage on the Granite Falls (652551) – S3 (652508) 115 kV line circuit 1** 3 phase fault on the Granite Falls (652551) to CANBY (620211) 115kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
35	FLT35	**Prior outage on the Granite Falls (652551) – S3 (652508) 115 kV line circuit 1** 3 phase fault on the Granite Falls (652551) to S3 (652508) 115kV line circuit 1, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted line.
36	FLT36	**Prior outage on the Granite Falls (652551) – S3 (652508) 115 kV line circuit 1** 3 phase fault on the Granite Falls 230/115/13.8kV (652550/652551/652297) transformer, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
37	FLT37	**Prior outage on the Granite Falls (652551) – S3 (652508) 115 kV line circuit 1** 3 phase fault on the Granite Falls 115/69/13.8kV (652511/652298/652288) transformer, near Granite Falls. a. Apply fault at the Granite Falls 115kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.

Fault scenarios were first simulated using the post-project cases. After the contingencies were completed, the results were reviewed and evaluated against the criteria in section 3.3. If any contingency exhibited voltage instability, angular instability, or voltage deviation outside of stated criteria, the pre-project case was simulated for the respective contingency to compare the results. Any new stability or angular issues attributed to the study project were flagged and reported.

Before the contingencies were simulated, a non-fault event was simulated for five seconds to verify that "flatline" conditions are obtained for the post-project case. Refer to Figure 5-1 for a representative voltage plot and Figure 5-2 for the real and reactive power output of GEN-2016-036 to confirm flatlines were achieved before simulating any contingencies.

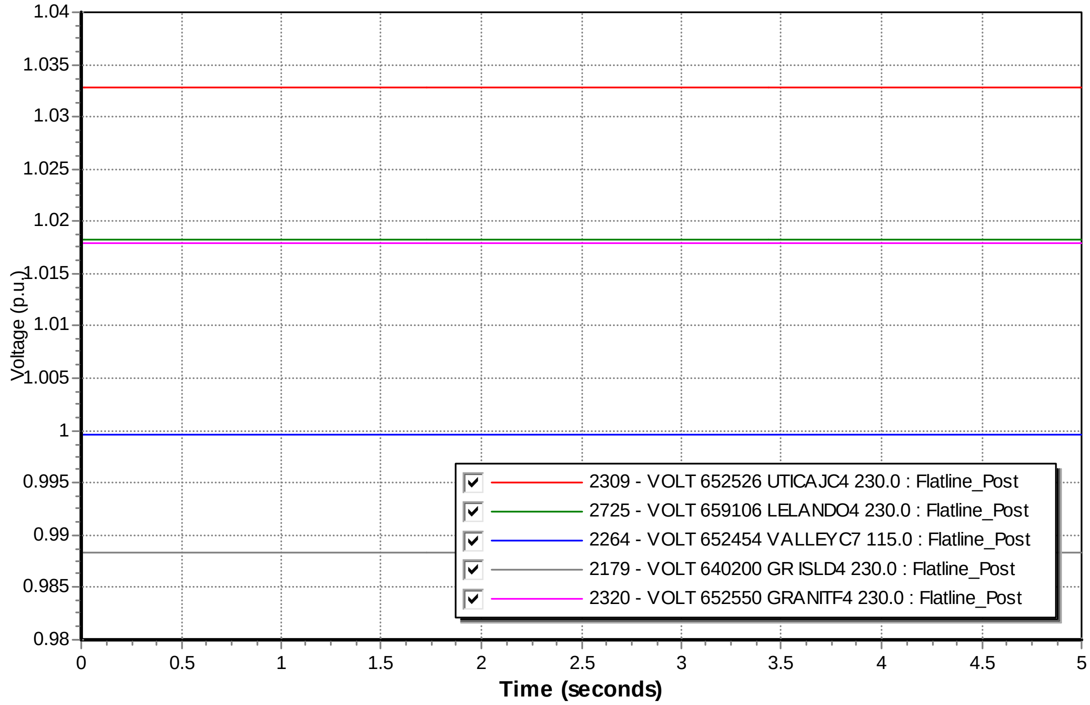

Figure 5-1: Representative voltage plot confirming flatlines.

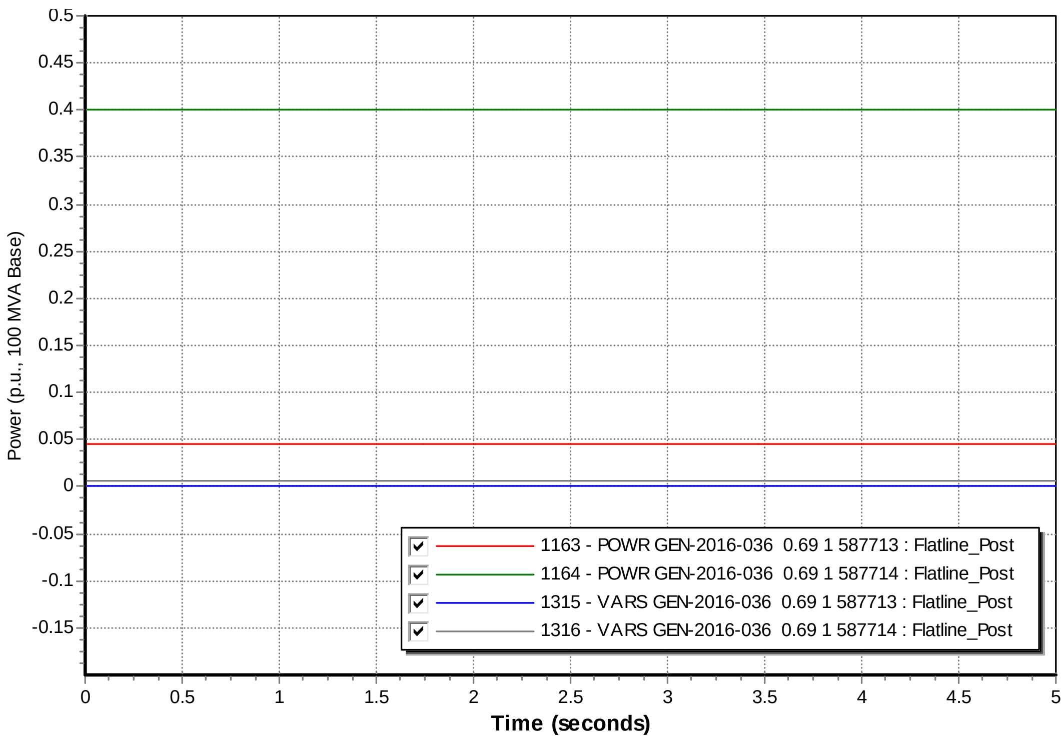

Figure 5-2: Representative real and reactive power plot confirming flatlines.

5.3 Transient Stability Analysis Results

This section lists the results from the low voltage ride through test and the transient stability analysis.

5.3.1 Low Voltage Ride-Through Test

A low voltage ride-through test was performed at the POI to verify that no generation was tripped and that GEN-2016-036 showed acceptable response when the voltage at the POI was forced to 0.0 p.u. for 9 cycles. It was observed that GEN-2016-036 remained online and showed acceptable recovery following the 9 cycle fault. Refer to Figure 5-3 for a plot of the voltage at the terminals of the plant and at the POI and Figure 5-4 for the real and reactive power response of GEN-2016-036.

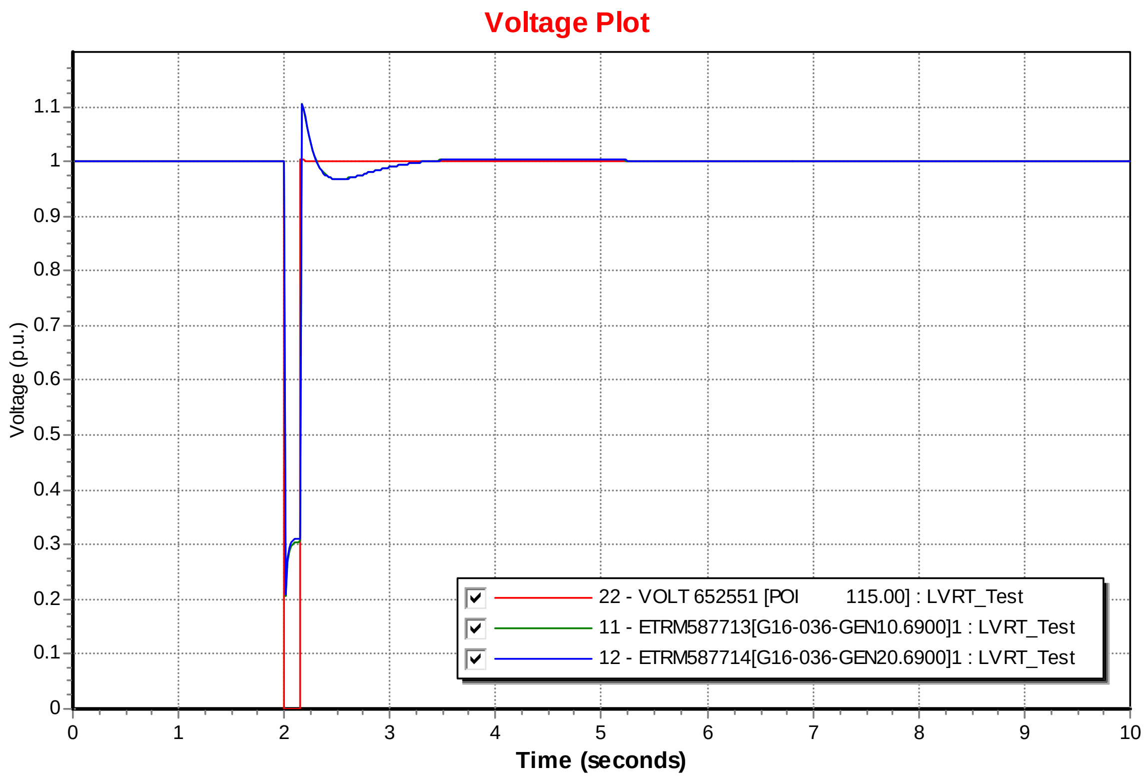

Figure 5-3: Representative voltage plot for the LVRT test.

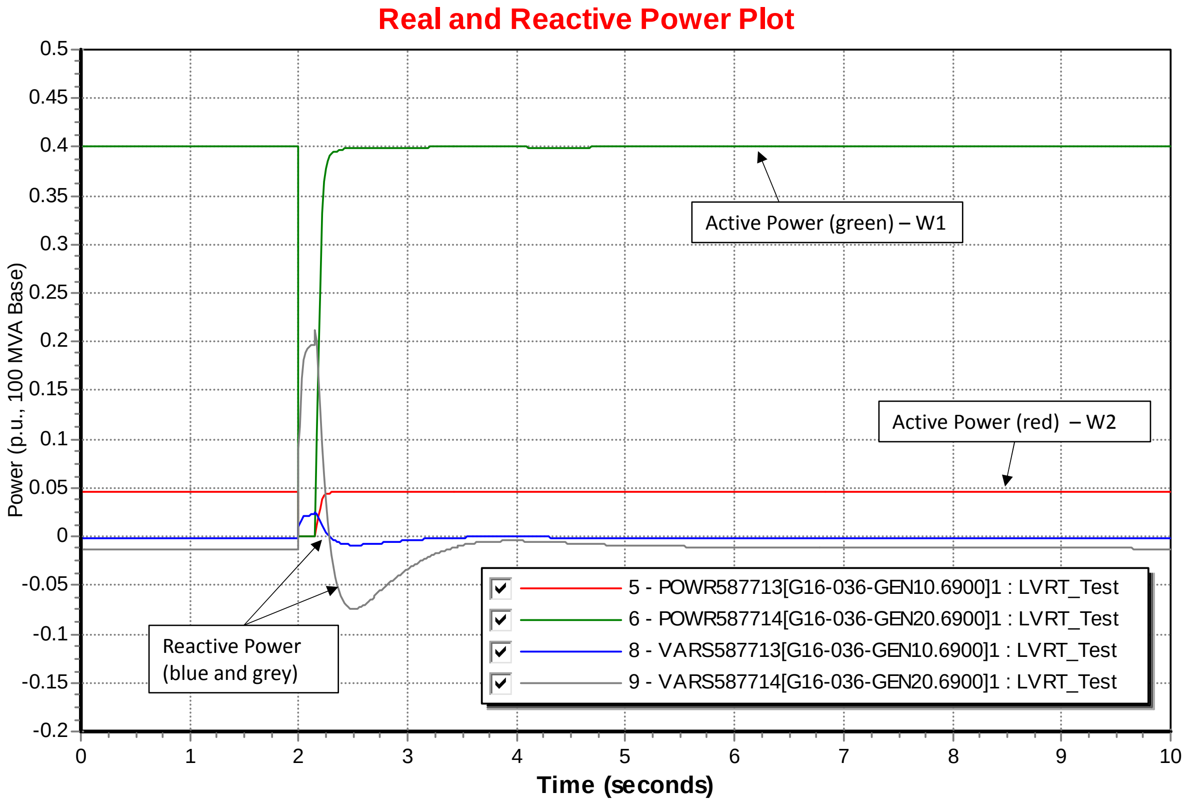

Figure 5-4: Representative real and reactive power plot for GEN-2016-036.

5.3.2 Summer Shoulder (2021) Transient Stability Analysis

Stability results for the 2021 Summer Shoulder case showed no stability constraints for the disturbances simulated for this study (refer to Table 5-1 for a list and description of contingencies).

5.4 Transient Stability Analysis Conclusions

The LVRT test showed GEN-2016-036 had acceptable voltage and power recovery when a 9 cycle fault was applied and cleared at the POI. Also, no transient stability constraints were identified for the addition of GEN-2016-036 in the 2021 Summer Shoulder scenario. The post-project case showed similar performance as the respective pre-project case and did not affect the transient stability of the system.

SECTION 6: CONCLUSIONS

The report presents the results of the system impact of SPP's GEN-2016-036 has on the MISO transmission system for 2021 Summer Peak and 2021 Summer Shoulder scenarios.

No voltage constraints were identified for 2021 Summer Peak scenario or the 2021 Summer Shoulder scenario. All bus voltages remained with transmission owner criteria or did not deviate by more than 0.01 p.u. post-contingency from the pre-project voltage.

No transient stability constraints were identified for the addition of GEN-2016-036 in the 2021 Summer Shoulder scenario. The post-project case showed similar performance as the respective pre-project case and did not affect the transient stability of the system.

The project will be subject to MISO's Annual ERIS/Annual Interim Deliverability evaluation to determine constraints in the MISO system on an annual basis until SPP study cycle DISIS-2016-002 studies are complete, and all NUs identified in DISIS-2016-002 Affected System Study (if any) are in operation.

APPENDIX A: STEADY-STATE STUDY CONTINGENCIES

Table A-1
Steady-State Study Contingencies

Con File	Con Type	Number of Contingencies
DPP-2016Feb-West_Ph2_Outlet_Contingency.con	P1	66
DPP_2016Feb-West_Ph2_Master-P1-West-1.con	P1	10349
DPP_2016Feb-West_Ph2_Master-P1-Other-1.con	P1	5432
DPP_2016Feb-West_Ph2_Master-P1-Other-2.con	P1	4560
P1_AMRN_MTEP17-2022TA.con	P1	714
P1_CWLD_MTEP17-2022TA.con	P1	19
P1_CWLP_MTEP17-2022TA.con	P1	60
P1_PPI_MTEP17-2022TA.con	P1	5
P1_SIPC_MTEP17-2022TA.con	P1	22
ComEd_RTEP_Cat_P1.con	P1	467
P1_AECI_MTEP17-2022TA.con	P1	24
P1_CE_MTEP17-2022TA.con	P1	27
P1_WAPA_MTEP17-2022TA.con	P1	53
P1-4_AMRN_MTEP17-2022TA.con	P1	25
P1-4_CWLP_MTEP17-2022TA.con	P1	7
P1-4_SIPC_MTEP17-2022TA.con	P1	2
P1-4_WAPA_MTEP17-2022TA.con	P1	2
20170808_CHC-NLL_Eden2.con	P1	19
MEC-DPP2016FEB West Ph2 2022 Cat P1 09.15.2017.con	P1	148
P1_AMES_MTEP17-2022TA.con	P1	9
P1_ATC_MTEP17-2022TA.con	P1	1359
P1_BEPC_MTEP17-2022TA.con	P1	3
P1_CBPC_MTEP17-2022TA.con	P1	2
P1_CFU_MTEP17-2022TA.con	P1	10
P1_CIPCO_MTEP17-2022TA.con	P1	10
P1_DPC_MTEP17-2022TA.con	P1	119
P1_ITCM_MTEP17-2022TA.con	P1	421
P1_MDU_MTEP17-2022TA.con	P1	119
P1_MP_MTEP17-2022TA.con	P1	510
P1_MPC_MTEP17-2022TA.con	P1	34
P1_MPW_MTEP17-2022TA.con	P1	31
P1_XEL_MTEP17-2022TA.con	P1	1270
P1-4_ATC_MTEP17-2022TA.con	P1	166

P1-4_DPC_MTEP17-2022TA.con	P1	3
P1-4_GRE_MTEP17-2022TA.con	P1	31
P1-4_ITCM_MTEP17-2022TA.con	P1	23
P1-4_MDU_MTEP17-2022TA.con	P1	14
P1-4_MP_MTEP17-2022TA.con	P1	45
P1-4_MPC_MTEP17-2022TA.con	P1	7
P1-4_OTP_MTEP17-2022TA.con	P1	25
P1-4_SMMPA_MTEP17-2022TA.con	P1	2
P1-4_XEL_MTEP17-2022TA.con	P1	64
P2-P7_AMRN_MTEP17-2022TA1.con	P2-P7	1064
P2-P7_CWLD_MTEP17-2022TA.con	P2-P7	18
P2-P7_CWLP_MTEP17-2022TA.con	P2-P7	60
P2-P7_PPI_MTEP17-2022TA.con	P2-P7	5
P2-P7_SIPC_MTEP17-2022TA.con	P2-P7	2
ComEd_RTEP_Cat_P2-P7.con	P2-P7	1164
P2-P7_AECI_MTEP17-2022TA.con	P2-P7	15
P2-P7_CE_MTEP17-2022TA.con	P2-P7	79
P2-P7_WAPA_MTEP17-2022TA.con	P2-P7	17
MEC-DPP2016FEB West Ph2 2022 Cat P2 09.15.2017.con	P2	704
MEC-DPP2016FEB West Ph2 2022 Cat P5 09.15.2017.con	P5	98
MEC-DPP2016FEB West Ph2 2022 Cat P7 09.15.2017.con	P7	44
P2-P7_AMES_MTEP17-2022TA.con	P2-P7	10
P2-P7_ATC_MTEP17-2022TA.con	P2-P7	2166
P2-P7_BEPC_MTEP17-2022TA.con	P2-P7	4
P2-P7_CBPC_MTEP17-2022TA.con	P2-P7	11
P2-P7_CFU_MTEP17-2022TA.con	P2-P7	17
P2-P7_CIPCO_MTEP17-2022TA.con	P2-P7	52
P2-P7_DPC_MTEP17-2022TA.con	P2-P7	68
P2-P7_GRE_MTEP17-2022TA.con	P2-P7	239
P2-P7_ITCM_MTEP17-2022TA.con	P2-P7	480
P2-P7_MDU_MTEP17-2022TA.con	P2-P7	150
P2-P7_MP_MTEP17-2022TA.CON	P2-P7	365
P2-P7_MPC_MTEP17-2022TA.con	P2-P7	115
P2-P7_MPW_MTEP17-2022TA.CON	P2-P7	210
P2-P7_MRES_MTEP17-2022TA.CON	P2-P7	40
P2-P7_OTP_MTEP17-2022TA.con	P2-P7	222
P2-P7_RPU_MTEP17-2022TA.con	P2-P7	30
P2-P7_SMMPA_MTEP17-2022TA.con	P2-P7	39

P2-P7_XEL_MTEP17-2022TA.con	P2-P7	1319

APPENDIX B: STUDY PROJECT ONE-LINE DIAGRAMS

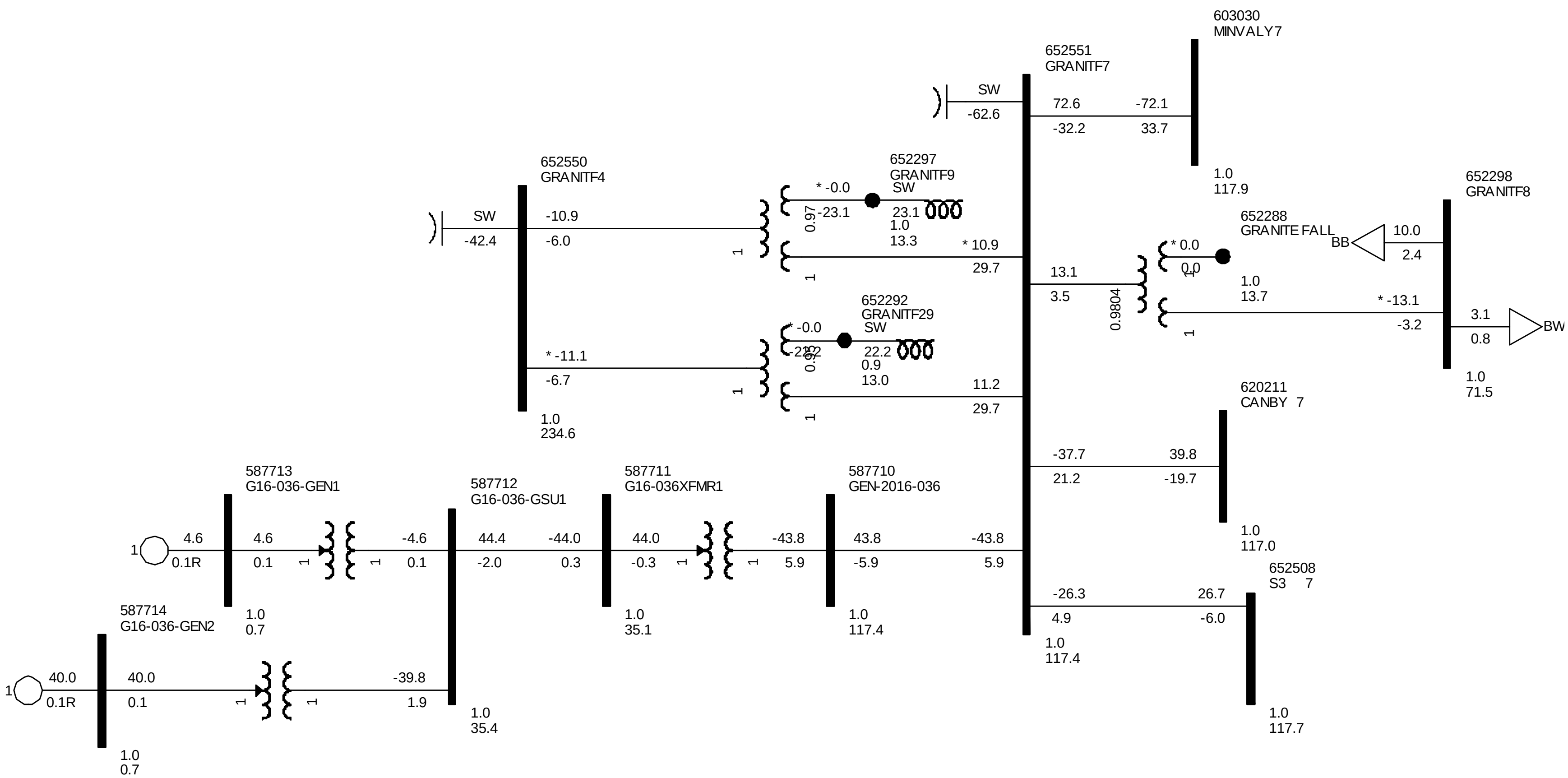

Figure B-1: Power flow one-line diagram for interconnection project at the Granite Falls 115kV POI (GEN-2016-036).

APPENDIX C: STUDY PROJECT DYNAMIC DATA

C.1 GEN-2016-036

```
/ ***************GEN-2016-036**************
/
/ POI @ Granite Falls 115kV Substation (652551)
/
/ GEN-2016-036
/
/ (2.3 MW X 2 units) + (2.5 MW X 16 units)= 44.6 MW total
/
/ GE 2.3MW-116     +   GE 2.5MW (1.x)
/
/ Pmax=44.60MW | Pgen= 44.6MW
/
/ PF = +/- 0.90
587714 'USRMDL' 1  'GEWTG2'  1 1 4 18 3 5
         0       16        0        0
       2.5      0.8      0.5      0.9     1.22                 1.2
         2      0.4      0.8       10 2.00E-02        0
         0      0.5    0.167      0.9    0.925                   0 /
587714 'USRMDL' 1  'GEWTE2'  4 0 12 67 18 9
    587714        0        0        1        0        0
         0        0        0        1        0        0
       0.5                 2                 1                   0                 0          5.00E-02   3
       0.6              1.12          4.00E-02    0.436             -0.436      1.12          2.00E-02
      0.45             -0.45       60              0.41                0.9
       1.1                40               0.5                1.45          5.00E-02
  5.00E-02        1               0.15             0.96             0.9994
    1.0006              1.04                 1                   1                 1
       0.4                 1               0.2                   1              0.25
        -1                14                25                   3              -0.9
         8               0.2                10                   1               1.7
      1.22              1.25                 5                   0                 0
         0          2.50E-03        1                  5.5                 0.1
        -1               0.1                 0                 0.1              -0.1
       0.7             0.144            -0.144 /
587714 'USRMDL' 1  'GEWTT1'     5   0   1   5   4   3   0
      2.96        0        0     1.88      1.5 /
587714  'USRMDL'  '1'  'GEWGD1'  505  0  1  6  0  4  0
        9999.0  5.0000  30.000  9999.0  9999.0
        30.000/
587714  'USRMDL'  '1'  'GEWTA2'  505  0  0  9  1  4
        20.000  0.0000  27.000  -4.0000  0.0000  1.2250
        56.5000  104.00  1200.0/
587714  'USRMDL'  '1'  'GEWTP2'  505  0  1  10  3  3  0
        0.30000  150.00  25.000  3.0000  30.000
        -4.0000  27.000  -10.000  10.000  1.0000/
58771400  'USRMSC'  'GEWPLT2'  512  0  2  0  0  17  587714  '1'/
 /ZVRT
 58771401  'VTGTPAT'  587714  587714  '1'  0.40000  5.0000  1.00000  0.80000E-01/
 58771402  'VTGTPAT'  587714  587714  '1'  0.60000  5.0000  1.70000  0.80000E-01/
 58771403  'VTGTPAT'  587714  587714  '1'  0.70000  5.0000  2.5000  0.80000E-01/
 58771404  'VTGTPAT'  587714  587714  '1'  0.75000  5.0000  3.0000  0.80000E-01/
 58771405  'VTGTPAT'  587714  587714  '1'  0.85000  5.0000  10.0000  0.80000E-01/
 58771406  'VTGTPAT'  587714  587714  '1'  0.90000  5.0000  600.0000  0.80000E-01/
 58771407  'VTGTPAT'  587714  587714  '1'  0.00000  1.1200  300.000  0.80000E-01/
 58771408  'VTGTPAT'  587714  587714  '1'  0.00000  1.1500  30.0000  0.80000E-01/
 58771409  'VTGTPAT'  587714  587714  '1'  0.00000  1.2000  2.0000  0.80000E-01/
 58771410  'VTGTPAT'  587714  587714  '1'  0.00000  1.58771300  0.5000  0.80000E-01/
 58771411  'VTGTPAT'  587714  587714  '1'  0.00000  1.3800  0.3000  0.80000E-01/
 58771412  'VTGTPAT'  587714  587714  '1'  0.00000  1.5000  0.0300  0.80000E-01/
 58771413
/
/
```

```
/ * 2 x GE 2.3MW ****
/
587713 'USRMDL' 1 'GEWTG2' 1 1 4 18 3 5
        0       2       0       0
      2.3     0.8     0.5     0.9    1.22              1.2
        2     0.4     0.8      10  2.00E-02      0
        0     0.5   0.167     0.9   0.925               0 /
587713 'USRMDL' 1 'GEWTE2' 4 0 12 67 18 9
   587713       0       0       1       0       0
        0       0       0       1       0       0
      0.5               2               1               0               0          5.00E-02   3
      0.6            1.12        4.00E-02   0.436          -0.436    1.12          2.00E-02
     0.45           -0.45      60           0.41              0.9
      1.1              40             0.5             1.45       5.00E-02
 5.00E-02       1            0.15           0.96           0.9994
   1.0006            1.04               1               1               1
      0.4               1             0.2               1            0.25
       -1              14              25               3            -0.9
        8             0.2              10               1             1.7
     1.22            1.25               5               0               0
        0        2.50E-03       1             5.5             0.1
       -1             0.1               0             0.1            -0.1
      0.7         0.15652        -0.15652 /
587713 'USRMDL' 1 'GEWTT1'   5  0  1  5  4  3  0
     3.22       0       0    1.88     1.5 /
 587713  'USRMDL'  '1'  'GEWGD1'  505  0  1  6  0  4  0
         9999.0  5.0000  30.000  9999.0  9999.0
         30.000/
 587713  'USRMDL'  '1'  'GEWTA2'  505  0  0  9  1  4
         20.000  0.0000  27.000  -4.0000  0.0000  1.2250
         56.5000  104.00  1200.0/
 587713  'USRMDL'  '1'  'GEWTP2'  505  0  1  10  3  3  0
         0.30000  150.00  25.000  3.0000  30.000
         -4.0000  27.000  -10.000  10.000  1.0000/
 58771300  'USRMSC'  'GEWPLT2'  512  0  2  0  0  17  587713  '1'/
/ZVRT
 58771301  'VTGTPAT'  587713  587713  '1'  0.40000  5.0000  1.00000  0.80000E-01/
 58771302  'VTGTPAT'  587713  587713  '1'  0.60000  5.0000  1.70000  0.80000E-01/
 58771303  'VTGTPAT'  587713  587713  '1'  0.70000  5.0000  2.5000  0.80000E-01/
 58771304  'VTGTPAT'  587713  587713  '1'  0.75000  5.0000  3.0000  0.80000E-01/
 58771305  'VTGTPAT'  587713  587713  '1'  0.85000  5.0000  10.0000  0.80000E-01/
 58771306  'VTGTPAT'  587713  587713  '1'  0.90000  5.0000  600.0000  0.80000E-01/
 58771307  'VTGTPAT'  587713  587713  '1'  0.00000  1.1200  300.000  0.80000E-01/
 58771308  'VTGTPAT'  587713  587713  '1'  0.00000  1.1500  30.0000  0.80000E-01/
 58771309  'VTGTPAT'  587713  587713  '1'  0.00000  1.2000  2.0000  0.80000E-01/
 58771310  'VTGTPAT'  587713  587713  '1'  0.00000  1.58771300  0.5000  0.80000E-01/
 58771311  'VTGTPAT'  587713  587713  '1'  0.00000  1.3800  0.3000  0.80000E-01/
 58771312  'VTGTPAT'  587713  587713  '1'  0.00000  1.5000  0.0300  0.80000E-01/
 58771313  'VTGTPAT'  587713  587713  '1'  0.00000  1.6000  0.0100  0.80000E-01/
```

APPENDIX D: TRANSIENT STABILITY ANALYSIS PLOTS

Refer to separate document for plots of the contingencies performed for 2021 Summer Shoulder scenario.