Interconnection System Impact Study Report
Generation Interconnection Request # GI-2016-13

200MW Solar Photovoltaic Generating Facility
Boone - Comanche 230kV Substation
Pueblo County, Colorado

Xcel Energy - Transmission Planning West
Xcel Energy
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Executive Summary

The GI-2016-13 is a 200MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Point of Interconnection (POI) requested is a tap on the Comanche – Boone 230kV line, at approximately five (5) miles from the Boone Substation. The tap position on the line will require building a new substation to accommodate the generation interconnection, which will be referred to in this report as "GI-2016-13 230kV Switching Station". The proposed Commercial Operation Date (COD) and backfeed date of the Generating Facility are December 31, 2020 and June 30, 2019, respectively. Based on the 36-month construction timeframe associated with the construction of the required transmission system improvements and the delays expected due to construction outage restrictions, the proposed back-feed date is not achievable.

Per the interconnection request, GI-2016-13 was studied for both Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). For both ERIS and NRIS evaluations, the 200MW rated output of GI-2016-13 is assumed to be delivered to Public Service Company of Colorado (PSCo) native load, so existing PSCo generation is used as its sink.

The results of the single contingency analysis (P1 and P2-1) are given in Table 2. The overloads on the Boone – MidwayPS 230kV line can be mitigated by replacing the present limiting Tower Structure of the Boone-MidwayPS 230kV transmission line, which will result in a new rating of 470MVA. The cost of the PSCo Network Upgrades to mitigate overloads on the Boone – MidwayPS 230kV line is given in Table 7.

Western Area Power Administration (WAPA), CSU and TSGT have been identified as Affected Systems for GI-2016-13. PSCo has informed the Affected Systems regarding the contingency overloads on their facilities. Mitigation measures for each of the contingency overloads on the Affected Systems must be identified and addressed by the Affected Systems in order for GI-2016-13 to achieve NRIS of 200MW.

The transient stability analysis determined that all generating units are stable (remain in synchronism), display positive damping and the maximum transient voltage dips are within the acceptable dynamic performance criteria.

The short-circuit and breaker duty analysis determined that no breaker replacements are needed at the POI station and/or in neighboring PSCo stations.

The total estimated cost of the PSCo transmission system improvements required for GI-2016-13 to qualify for:

- **ERIS is $12.579 Million (Tables 5 and 6); and**
- **NRIS is $12.734 Million (Tables 5, 6 and 7)**

The ERIS and NRIS results above are contingent upon the mitigation of all overloads and

Network Upgrades identified in Attachment 1.

If there is a change in status of one or more higher-queued Interconnection Requests due to withdrawal from the queue or changing from NRIS to ERIS, and the Network Upgrades identified for the higher queued Interconnection Requests are not constructed, the Network Upgrade costs would become the responsibility of GI-2016-13 to the extent they are necessary to interconnect GI-2016-13. A restudy will be performed as needed to identify the new Network Upgrade responsibilities.

For GI-2016-13 interconnection:

NRIS (after required transmission system improvements) = 200MW

ERIS (after required transmission system improvements) = 200MW (output delivery assumes the use of existing firm or non-firm capacity of the PSCo Transmission System on an as-available basis)

Note: NRIS or ERIS, in and of itself, does not convey transmission service.

Introduction

The GI-2016-13 (GI) is a 200MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Generating Facility will be comprised of GE-LV5 1500V inverters which will connect to 0.55/34.5kV, 2MVA generator step up transformers. The generator step up transformers will interface with one 34.5/230/13.8kV, 135/180/225MVA Main Step-up Transformer which will interconnect to the Boone – Comanche 230kV line using a Generator Interconnection Customer owned 230kV tie-line. The Point of Interconnection (POI) requested by the Interconnection Customer is a tap on the Boone – Comanche 230kV line, at approximately five (5) miles from the Boone Substation. The tap position on the line will require building a new substation to accommodate the Generating Facility interconnection, which will be referred to in this report as "GI-2016-13 230kV Switching Station". The geographical location of the transmission system near the POI is shown in Figure 1 below.

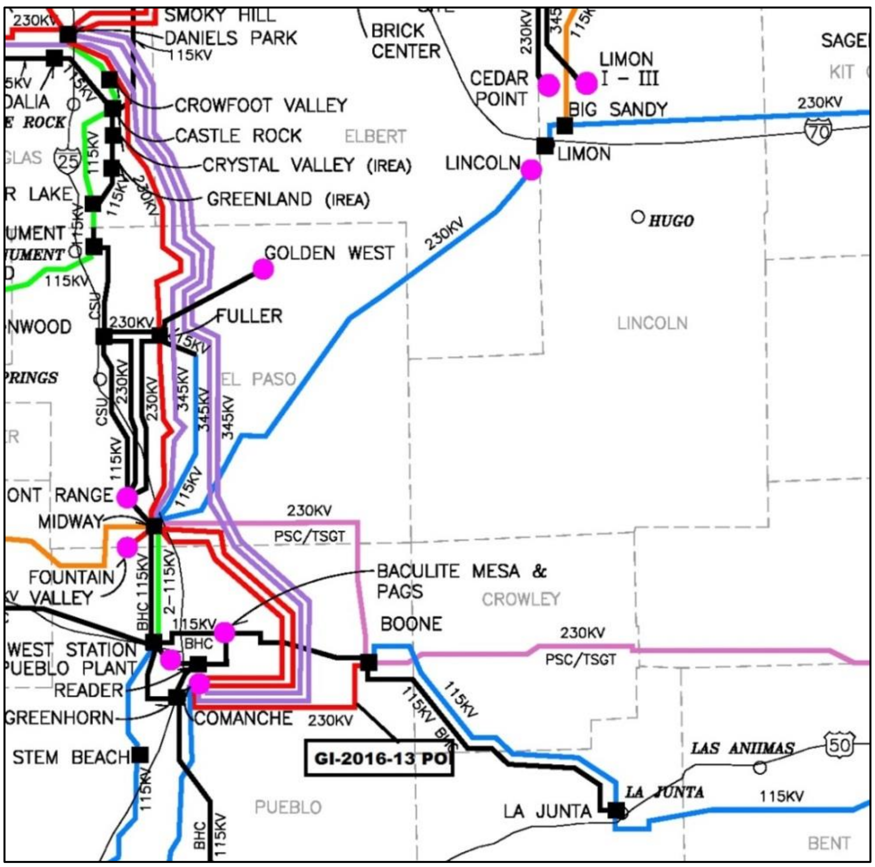

Figure 1 - GI-2016-13 Point of Interconnection and Study Area

The original Commercial Operation Date (COD) proposed was December 31, 2018. Later, in an email received on June 27, 2017, the Customer has changed the COD to December 31, 2020. The proposed back-feed date is June 30, 2020. Based on the 36-month construction timeframe associated with the required transmission system improvements, the proposed back-feed date is not achievable.

The main purpose of this Interconnection System Impact Study is to determine the system impact of interconnecting 200MW of new generation on the Boone – Comanche 230kV line. Per the Interconnection Study Request, the GI was studied for both Energy Resource Interconnection Service (ERIS)[1] and Network Resource Interconnection Service (NRIS)[2]. For both ERIS and NRIS evaluations, the 200MW rated output of the GI is assumed to be delivered to Public Service Company of Colorado (PSCo) network load, so existing PSCo generation is used to sink the GI output.

<u>Study Scope and Analysis Criteria</u>

The scope of this report includes steady state (power flow) analysis, transient stability analysis, short circuit analysis, and scoping level cost estimates. The power flow analysis identifies thermal and voltage violations in the PSCo system and the neighboring systems as a result of the interconnection of the GI. Several single contingencies were studied. The transient stability analysis verifies that all generating units within the PSCo transmission system and the neighboring systems remain stable (in synchronism), have positive damping and satisfy acceptable dynamic performance criteria. The short circuit analysis determines the maximum available fault current at the POI and identifies if any circuit breaker(s) within the PSCo station(s) exceed their breaker duty ratings and need to be replaced.

PSCo adheres to applicable NERC Reliability Standards and WECC Reliability Criteria, as well as its internal transmission planning criteria for studies. The steady state analysis criteria are as follows:

<u>P0 - System Intact conditions</u>:
Thermal Loading: <=100% of the normal facility rating
Voltage range: 0.95 to 1.05 per unit

<u>P1 & P2-1 – Single Contingencies:</u>
Thermal Loading: <=100% Normal facility rating
Voltage range: 0.90 to 1.10 per unit
Voltage deviation: <=8% of pre-contingency voltage

The study area is the electrical system consisting of PSCo's transmission system and the neighboring transmission systems that may be impacted by or that could impact interconnection of the GI. The study area for GI-2016-13 includes WECC designated zones 121, 700, 703, 704, 705, 709, 710, 712, 752 and 757.

[1] Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

[2] Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission system (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as all other Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

The same list of contingencies was run on the benchmark case and the study case, and the results were compared.

For PSCo facilities, thermal violations attributable to the GI included any facilities without a pre-existing thermal violation but resulted in a thermal loading >100% post the GI addition and contributed to an incremental loading increase of 2% or more to the benchmark case loading. For non-PSCo facilities, thermal violations attributed to the GI include all new facility overloads with a thermal loading of >100% and existing thermal overloads that increased by 1% or more from the benchmark case overload post the GI addition.

The voltage violations attributed to the GI included any new voltage range and voltage deviation violations.

Transient stability criteria require that all generating machines remain in synchronism and all power swings should be well damped (positive damping) following a contingency event. Also, transient voltage performance should meet the following WECC Disturbance-Performance criteria:

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for all contingencies
- For all contingencies, following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- For contingencies without a fault, voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds

Serial Cumulative Power Flow Case Creation

The Base Case used for the power flow analysis originated from the 2023HS case built for the 2018 TPL1 Work Group of the Colorado Coordinated Planning Group (CCPG). As part of the case build effort for the TPL1 work group, the case was reviewed by PSCo and neighboring utilities within the CCPG foot print. All transmission planned projects in PSCo's 10 year transmission plan that are expected to be in-service before July 2023 are modeled in the Base Case, consistent with the case season and year. These projects are described at: (http://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/Q1_2019_Transmission_Plan.pdf)

This includes the following projects:

- Shortgrass 345kV Switching Station – ISD 2020
- Shortgrass – Cheyenne Ridge 345kV line – ISD 2020
- Graham Creek 115kV Substation – ISD 2021
- Husky 230/115kV Substation – ISD 2021
- Cloverly 115kV Substation – ISD 2021

- Ault – Husky 230kV line – ISD 2021
- Husky - Graham Creek – Cloverly 115kV line – ISD 2021
- Monument – Flying Horse 115kV Series Reactor – ISD 2021
- Gilman – Avon 115kV line – ISD 2022
- Upgrade Villa Grove – Poncha 69kV Line – ISD 2021
- Upgrade Poncha – San Luis Valley 115kV line – ISD 2021

The following PSCo FAC8 terminal equipment upgrade operational and maintenance projects for which PSCo has plans to increase the line ratings have been modeled at their future ratings in the Base Case:

- Waterton – Martin2 tap 115kV line was modeled at 189MVA
- Malta – Twin Lakes 115kV line was modeled at 143MVA
- Twin Lakes – Otereo 115kV line was modeled at 143MVA
- Otero – Buena Vista 115kV line was modeled at 150MVA
- Buena Vista – Ray Lewis 115kV line was modeled at 136MVA
- Ray Lewis – Poncha 115kV line was modeled at 164MVA
- Arapahoe – SantaFe – Daniels Park 230kV line was modeled at 560MVA
- Daniels Park – Prairie1 230kV line was modeled at 576MVA
- Greenwood – Monaco 230kV line was modeled at 503MVA
- Leetsdale – Monaco 230kV line was modeled at 470MVA
- Poncha – Smelter town 115kV line was modeled at 114MVA
- San Luis Valley – Sargent 115kV line was modeled at 120MVA

The Base Case also modeled the Sargent – Poncha 115kV line closed.

The following additional changes were made to the Tri-State Generation and Transmission (TSGT) model in the Base Case per further review and comment from TSGT:

- 30MW San Isabel Solar tapping Ludlo Tap – Pinon Canyon 115kV line
- 80MW TSGT_0809 solar facility tapping Gladstone – Walsenburg 230kV line
- 80MW TSGT_STEM_PV solar facility at Stem Beach 115kV bus
- Fuller – Vollmer – Black Squirrel 115 kV line modeled at 173 MVA

The following additional changes were made to the Black Hills Energy (BHE) model in the Base Case per further review and comment from BHE:

- Fountain Valley – DesertCove 115kV line was modeled at 171MVA. Planned upgrade project in 1/2021
- Fountain Valley – MidwayBR 115kV line was modeled at 171MVA. Planned upgrade project in 1/2021
- Pueblo West Substation – ISD 1/2021
- Skyline Ranch Substation – ISD 10/2021
- West Station – Greenhorn 115kV line Rebuild – ISD 9/2022

The following additional changes were made to the Colorado Springs Utilities (CSU) model in the Base Case per further review and comment from CSU:

- The Cottonwood – Tesla 34.5kV line is modeled open and Kettle Creek – Tesla 34.5kV line is modeled closed on the CSU system
- Grazing Yak Solar – ISD 2020
- Cottonwood 230/115kV auto-transformer replacement – ISD 2019
- Nixon – Kelker 230kV line uprate – ISD 2019

The Base Case model includes the existing PSCo generation resources at the time of this study.

The Base Case was updated to include the higher-queued generation with LGIAs (active or suspended) and their associated Network Upgrades. In addition, all higher-queued generation in the current PSCo Generation Interconnection Request (GIR) queue and their associated Network Upgrades are modeled. The higher-queued LGIAs modeled are GI-2009-8, GI-2010-8, GI-2014-2, GI-2014-12, GI-2014-13 and GI-2014-14. The higher-queued GIRs modeled are: GI-2014-6, GI-2014-8, GI-2014-9, GI-2016-4, GI-2016-7, GI-2016-9, and GI-2016-12. While the higher-queued NRIS requests are dispatched at 100% nameplate, the higher-queued ERIS requests are dispatched at 0MW.

The following PSCo Network Upgrades identified in the higher-queued GIRs are modeled in the GI-2016-13 Base Case:

- MidwayPS 230/115kV, 100MVA transformer replaced with 150MVA unit – Network Upgrade assigned to GI-2014-12
- Increase Greenwood – Prairie3 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-7
- Increase Daniels Park – Fuller 230kV line rating to 577MVA – Network Upgrade assigned to GI-2016-7
- San Luis Valley – Poncha 230kV line #2 – Network Upgrade assigned to GI-2016-9
- PonchaBR – MidwayPS 230kV line – Network Upgrade assigned to GI-2016-9
- Increase Ray Lewis – Buena Vista Tap 115kV line rating to 150MVA – Network Upgrade assigned to GI-2016-9
- Increase Daniels Park – Prairie3 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
- Increase Daniels Park – Prairie1 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
- Increase Daniels Park – Fuller 230kV line rating to 802MVA – Network Upgrade assigned to GI-2016-9
- Increase Greenwood – Prairie1 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-9
- Increase Greenwood – Monaco 230kV rating to 637MVA – Network Upgrade assigned to GI-2016-9
- Increase Leetsdale – Monaco 230kV line rating to 503MVA – Network Upgrade assigned to GI-2016-12

- Replace MidwayPS 230/115kV, 150MVA transformer with 280MVA capable unit – Network Upgrade assigned to GI-2016-12
- Second Midway 345/230kV, 560MVA transformer – Network Upgrade assigned to GI-2016-12
- Second Waterton 345/230kV, 560MVA transformer – Network Upgrade assigned to GI-2016-12

The Benchmark Case was created from the Base Case by changing the generation dispatch to reflect a heavy south to north flow on the Comanche – Midway – Jackson Fuller – Daniels Park transmission system. This was accomplished by adopting the generation dispatch given in Table 1 below. The generation dispatch of the neighboring systems was provided by those neighboring utilities.

Table 1 – Generation Dispatch Used to Stress the Benchmark Case (MW is Gross Capacity)

Bus Name	ID	Status	PGen (MW)	PMax (MW)	Owner
APT_DSLS 4.1600	G1	0	0	10	BHE
BAC_MSA GEN113.800	G1	1	90	90	BHE
BAC_MSA GEN213.800	G1	1	90	90	BHE
BAC_MSA GEN413.800	G1	1	35	40	BHE
BAC_MSA GEN413.800	G2	1	35	40	BHE
BAC_MSA GEN413.800	S1	1	20	24.8	BHE
BAC_MSA GEN513.800	G1	1	30	40	BHE
BAC_MSA GEN513.800	G2	1	30	40	BHE
BAC_MSA GEN513.800	S1	1	20	24.8	BHE
BAC_MSA GEN613.800	G1	1	0	40	BHE
BUSCHRNCH_LO0.7000	1	1	20	60	BHE
BUSCHRWTG1 0.7000	G1	1	14	28.8	BHE
E_CANON 69.000	G1	0	0	8	BHE
PP_MINE 69.000	G1	0	0	3	BHE
PUB_DSLS 4.1600	G1	0	0	10	BHE
R.F.DSLS 4.1600	G1	0	10	10	BHE
RTLSNKWNDLO 0.7000	G1	1	22	60	BHE
ALMSACT1 13.800	G1	0	17	17	PSCo
ALMSACT2 13.800	G2	0	19	14	PSCO
COGENTRIX_PV34.500	S3	1	19.5	30	PSCO
COMAN_1 24.000	1	1	357	360	PSCO
COMAN_2 24.000	C2	1	365	365	PSCO
COMAN_3 27.000	C3	1	788	780	PSCO
COMAN_PV 34.500	S1	1	102	120	PSCO
CO_GRN_E 34.500	W1	1	64.8	81	PSCo

CO_GRN_W 34.500	W2	1	64.8	81	PSCo
FTNVL1&2 13.800	G1	1	36	40	PSCO
FTNVL1&2 13.800	G2	1	36	40	PSCO
FTNVL3&4 13.800	G3	1	36	40	PSCO
FTNVL3&4 13.800	G4	1	36	40	PSCO
FTNVL5&6 13.800	G5	1	36	40	PSCO
FTNVL5&6 13.800	G6	1	36	40	PSCO
GSANDHIL_PV 34.500	S1	1	12.4	19	PSCO
JKFULGEN 0.6900	W1	1	200	249.43	PSCO
LAMAR_DC 230.00	DC	0	101	210	PSCO
SOLAR_GE 34.500	S2	1	19.5	30	PSCO
SUNPOWER 34.500	S1	1	33.8	52	PSCO
TWNBUTTE 34.500	W1	1	60	75	PSCO
SI_GEN 0.6000	1	1	6.1	30	TSGT
STEM_PV 0.4800	PV	1	80	100	TSGT
TBII_GEN 0.6900	W	1	60	76	TSGT
TSGT_0809 0.6200	PV	1	80	100	TSGT

For the power flow analysis, the Study Case for GI-2016-13 was created by adding the GI-2016-13 model to the Benchmark Case. The GI was modeled using the modeling data provided by the Customer. The modeling data was missing the Primary Frequency Response characteristics in the REPC_a model as required per PSCo Open Access Transmission Tariff Attachment N, so they were modeled using the following settings:

	Customer Data	**Modified Data**
frqflg	0	1
Ddn	20	20
Dup	0	-20
Fdbd1	0	-0.0006
Fdbd2	0	0.0006

The 200MW output of GI-2016-13 was sunk uniformly to the PSCo units outside the study area.

A power flow analysis was performed and the results of the Benchmark Case and Study Case were compared to determine the impacts of the interconnection of GI-2016-13. The steady state analysis was performed using PTI's PSSE Ver. 33.6.0 program and the ACCC contingency analysis tool.

Transient stability analysis was performed using General Electric's PSLF Ver.21.0_02 program. Three phase faults were simulated for selected single and multiple contingencies using standard clearing times. The voltage and frequency of transmission buses in the study area, and the relative rotor angle of generators in the study area were recorded and analyzed. PSLF's DYTOOLS EPCL program was used to simulate the disturbances.

Power Flow Analysis Results

The results of the single contingency analysis (P1 and P2-1) are given in Table 2 below.

Table 2 Power Flow Analysis Results

Note – Thermal overloads for single contingencies are calculated using the normal rating of the facility. All overloads are in red.

Table 2 – Summary of Thermal Violations from Single Contingency Analysis										
				Facility Loading Without GI-2016-13		Facility Loading With GI-2016-13				
Monitored Facility (Line or Transformer)	Type	Owner	Branch Rating MVA (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	% Change	NERC Single Contingency	Network Upgrade Assigned to GI
Boone – MidwayPS 230kV	Line	PSCo	418	N/A	N/A	424.3	101.5%	N/A	Boone – GI-2016-13 230kV	GI-2016-13
Lamar Co – Lamar C2 230kV	Line	TSGT	239	223.2	93.4%	240.2	100.5%	7.1%	Boone – MidwayPS 230kV	GI-2016-13
Midway 230kV bus tie	Line	WAPA	432	388.4	89.9%	436.7	101.1%	11.2%	MidwayPS – Fuller 230kV	GI-2016-13
Palmer Lake – Monument 115kV	Line	CSU	108	159.4	147.6%	173.0	160.2%	12.6%	Daniels Park – Fuller 230kV	GI-2014-8
Brairgate S – Cottonwood S 115kV	Line	CSU	150	169.0	112.7%	173.1	115.4%	2.7%	Cottonwood N – KettleCreek S 115kV	GI-2014-8
Cottonwood N – KettleCreek S 115kV	Line	CSU	162	175.1	108.1%	179.3	110.7%	2.6%	Brairgate S – Cottonwood S 115kV	GI-2014-12
Kelker E – Templeton 115kV	Line	CSU	131	140.2	107.0%	143.4	109.5%	2.5%	Kelker W – Rock Island 115kV	GI-2016-7
Kelker W – Rock Island 115kV	Line	CSU	162	167.0	103.1%	170.4	105.2%	2.1%	Kelker E – Templeton 115kV	GI-2016-9
Monument – Gresham 115kV	Line	CSU	145	152.8	105.4%	163.6	112.8%	7.4%	Daniels Park – Fuller 230kV	GI-2016-9
Vollmer – Fuller 115kV	Line	TSGT	173	190.6	110.2%	201.4	116.4%	6.2%	Daniels Park – Fuller 230kV	GI-2016-7

Table 2 – Summary of Thermal Violations from Single Contingency Analysis										
				Facility Loading Without GI-2016-13		Facility Loading With GI-2016-13				
Monitored Facility (Line or Transformer)	Type	Owner	Branch Rating MVA (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	% Change	NERC Single Contingency	Network Upgrade Assigned to GI
Vollmer – Black Squirrel 115kV	Line	TSGT	173	190.5	110.1%	201.4	116.4%	6.3%	Daniels Park – Fuller 230kV	GI-2016-7
Black Forest - Black Squirrel MV 115kV	Line	TSGT	143	161.4	112.9%	172.2	120.4%	7.5%	Daniels Park – Fuller 230kV	GI-2016-7

The following new facility overloads are caused by the addition of GI-2016-13:

- Boone – MidwayPS 230kV line loading increased to 101.5%. The line does not overload in the Benchmark Case (PSCo facility)
- Lamar Co – Lamar C2 230kV line loading increased from 93.4% to 100.5% (TSGT facility)
- Midway 230kV bus tie loading increased from 89.9% to 101.1% (Western Area Power Administration (WAPA) facility)

The overloads on the Boone – MidwayPS 230kV line can be mitigated by replacing the existing limiting Tower Structure of the Boone - MidwayPS 230kV transmission line, which will result in a new rating of 470MVA. The cost of this PSCo Network Upgrade is given in Table 7 below. In addition to the new overloads listed above, GI-2016-13 caused an increase in the Benchmark Case overloads in the CSU and TSGT systems. Therefore, Western Area Power Administration (WAPA), CSU and TSGT have been identified as Affected Systems for GI-2016-13. For facility overloads that existed in the Benchmark Case, where the addition of GI-2016-13 caused an increase in the pre-existing Benchmark Case overload, the pre-existing overloads are assigned to the higher-queued GIs as noted in Table 2 above. However, GI-2016-13 is responsible to mitigate overloads on facilities caused by the GI-2016-13 project itself, taking into consideration the Network Upgrades that would be mitigated by the higher queued projects.

PSCo has informed the Affected Systems regarding the contingency overloads on their facilities. Mitigation measures for each of the contingency overloads on the Affected Systems must be identified and addressed by the Affected Systems in order for GI-2016-13 to achieve NRIS of 200MW.

The Interconnection Customer is responsible to design and build the GI to meet the Primary Frequency Response as required by OATT. As stated in the "Serial Cumulative Power Flow Case Creation" section, the modeling data provided by the Customer has been modified to account for the Primary Frequency Response requirements stated in PSCo OATT. These modifications are based on engineering judgement and only reflect modifications to modeling data.

Voltage Regulation and Reactive Power Capability

The Interconnection Customer is required to interconnect its Large Generating Facility with PSCo's Transmission System in accordance with the *Xcel Energy Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater Than 20 MW* (available at:

http://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Interconnection/Interconnections-POL-TransmissionInterconnectionGuidelineGreat20MW.pdf).

Accordingly, the following voltage regulation and reactive power capability requirements at the POI are applicable to this interconnection request:

- To ensure reliable operation, all Generating Facilities interconnected to the PSCo transmission system are expected to adhere to the *Rocky Mountain Area Voltage Coordination Guidelines (RMAVCG)*. Accordingly, since the POI for this interconnection request is located within Southeast Colorado - Region 4 defined in the *RMAVCG*; the applicable ideal transmission system voltage profile range is 1.02 – 1.03 per unit at regulated buses and 1.0 – 1.03 per unit at non-regulated buses.
- Xcel Energy's OATT (Attachment N effective 10/14/2016) requires all non-synchronous Generator Interconnection Customers to provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging at the high side of the generator substation. Furthermore, Xcel Energy requires every Generating Facility to have dynamic voltage control capability to assist in maintaining the POI voltage schedule specified by the Transmission Operator as long as the Generating Facility does not have to operate outside its 0.95 lag – 0.95 lead dynamic power factor range capability.
- It is the responsibility of the Interconnection Customer to determine the type (switched shunt capacitors and/or switched shunt reactors, etc.), the size (MVAR), and the locations (34.5kV or 230kV bus) of any additional static reactive power compensation needed within the generating plant in order to have adequate reactive capability to meet the +/- 0.95 power factor and the 1.0 – 1.03 per unit voltage range standards at the POI.

  Finally, it is the responsibility of the Interconnection Customer to compensate their generation tie-line to ensure minimal reactive power flow under no load conditions.

The Interconnection Customer is required to demonstrate to the satisfaction of PSCo Transmission Operations prior to the commercial in-service date of the generating plant that it can safely and reliably operate within the required power factor and voltage ranges (noted above).

Transient Stability Study Results

The transient stability analysis for GI-2016-13 simulated nine disturbances in the Study Case.

Table 3 Transient Stability Analysis Results

Stability Scenarios						
#	Fault Location	Fault Type	Facility Tripped	Clearing Time (cycles)	Post-Fault Voltage Recovery	Angular Stability
1	Boone 230kV	3ph	Boone 230/115kV Transformer	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
2	Boone 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
3	Boone 230kV	3ph	Boone – Comanche 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
4	Boone 230kV	3ph	Boone – Midway 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
5	Comanche 345 kV	3ph	Comanche#3 generator	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
6	Lamar 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
7	MidwayPS 230kV	3ph	All Fountain Valley gas units	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
8	MidwayPS 345kV	3ph	MidwayPS – Waterton 345kV line & Midway 230/345kV xfmr	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
9	Comanche 345kV	3ph	Comanche – Daniels Park 345kV	Primary (4.0)	Maximum transient	Stable with positive

			1 &2		voltage dips within criteria	damping

As shown in Table 3 above, the interconnection of GI-2016-13 produced no adverse system stability impact. The following results were obtained for every case and disturbance analyzed:

- ✓ No machines lost synchronism with the system
- ✓ No transient voltage drop violations were observed
- ✓ Machine rotor angles displayed positive damping

Transient stability plots showing surrounding bus voltages, bus frequencies, generator terminal voltages, generator relative angles, generator speeds, and generator power output for each of the disturbances run for each study scenario have been created and documented in Appendix A. Furthermore, it is the responsibility of the Interconnection Customer to ensure that its generating facility is capable of meeting the voltage ride-through and frequency ride-through (VRT and FRT) performance specified in the NERC Reliability Standard PRC-024.

Short Circuit and Breaker Duty Analysis

The calculated short circuit levels and Thevenin system equivalent impedances at the GI-2016-13 230kV Switching Station POI are shown in Table 4.

Table 4 – Short Circuit Parameters at the GI-2016-13 Switching Station Tapping Comanche - Boone 230kV Line

	Before GI-2016-13 Interconnection	After GI-2016-13 Interconnection
Three Phase Current	8199A	8349A
Single Line to Ground Current	5905A	6005A
Positive Sequence Impedance	1.919+j16.026 ohms	1.877+j15.741 ohms
Negative Sequence Impedance	1.931+j16.032 ohms	1.889+j15.747 ohms
Zero Sequence Impedance	8.837+j34.233 ohms	8.751+j33.694 ohms

A preliminary breaker duty study did not identify any circuit breakers that became over-dutied"[3] as a result of adding this generation.

Costs Estimates and Assumptions

The Transmission Provider has specified and estimated the cost of the equipment, engineering, procurement and construction work needed to interconnect GI-2016-13. The results of the

[3] "Over-dutied" circuit breaker: A circuit breaker whose short circuit current (SCC) rating is less than the available SCC at the bus.

engineering analysis for facilities owned by the Transmission Provider are summarized in Tables 5 and 6.

Table 5: "Transmission Provider's Interconnection Facilities" includes the nature and estimated cost of the Transmission Provider's Interconnection Facilities and an estimate of the time required to complete the construction and installation of such facilities.

Table 6: "Network Upgrades Required for Interconnection (applicable for either ERIS or NRIS)" includes the nature and estimated cost of the Transmission Provider's Network Upgrades necessary to accomplish the interconnection and an estimate of the time required to complete the construction and installation of such facilities.

Upgrades identified in Tables 5 and 6 are illustrated in Figure 2 which shows the physical and electrical connection of the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System. The one-line diagram also identifies the electrical switching configuration of the interconnection equipment including, without limitation: the transformer, switchgear, meters, and other station equipment.

The Transmission Provider has also specified and estimated the cost of the equipment, engineering, procurement and construction work of additional Network Upgrades required for NRIS. The results of the engineering analysis for facilities owned by the Transmission Provider are summarized in Table 7.

Table 7: "Additional Network Upgrades Required for NRIS" includes the nature and estimated cost of the Transmission Provider's additional Network Upgrades required for NRIS and an estimate of the time required to complete the construction and installation of such facilities.

Conclusion:

The total estimated cost of the PSCo transmission system improvements required for GI-2016-13 to qualify for:

- **ERIS is $12.579 Million (Tables 5 and 6); and**
- **NRIS is $12.734 Million (Tables 5, 6 and 7)**

For GI-2016-13 interconnection:

NRIS (after required transmission system improvements) = 200MW

ERIS (after required transmission system improvements) = 200MW (output delivery assumes the use of existing firm or non-firm capacity of the PSCo Transmission System on as as-available basis).

The ERIS and NRIS results above are contingent upon the mitigation of all overloads and Network Upgrades identified in Attachment 1.

If there is a change in status of one or more higher-queued Interconnection Requests due to withdrawal from the queue or changing from NRIS to ERIS, and the Network Upgrades identified for the higher-queued Interconnection Requests are not constructed, the Network Upgrade costs could become the responsibility of GI-2016-13 to the extent they are necessary to interconnect GI-2016-13. A restudy will be performed as needed to identify the new Network Upgrade responsibilities and Contingent Facilities required for GI-2016-13.

Note: NRIS or ERIS, in and of itself, does not convey transmission service.

Table 5 –Transmission Provider's Interconnection Facilities

Element	Description	Cost Est. (Millions)
PSCo's New 230kV Switching Station – GI-2016-13 230kV Switching Station	The new equipment includes: • One 230kV gang switch • Three 230kV arresters • Three 230kV Metering CT/PT Combination Units • Two 230kV Line Traps • One 230kV CCVT • Power Line Carrier System • Station controls • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures • Associated transmission line communications, fiber, relaying and testing.	**$1.046**
	Transmission line tap into substation.	**$0.050**
	Siting and Land Rights support for siting studies, land and ROW acquisition and construction	**$0.020**
	Total Cost Estimate for Transmission Provider's Interconnection Facilities	**$1.116**

Time Frame	Site, design, procure and construct	36 Months

Table 6 - Network Upgrades Required for Interconnection (applicable for either ERIS or NRIS) *

Element	Description	Cost Est. (Millions)
PSCo's New 230kV Switching Station – GI-2016-13 230kV Switching Station	The new equipment includes: • Nine 230kV gang switches • Six 230kV arresters • Two 230kV Line Traps • Nine 230kV CCVT's • Four 230kV Deadend Towers • Three 230kV Gas Circuit Breakers • One 27x55 Electrical Equipment Enclosure • Station Controls • Associated foundations and structures • Associated electrical equipment, bus, wiring and grounding • Associated foundations and structures	$8.988
PSCo's Comanche – GI-2016-13 230kV switching station 230kV line	Addition of one 230kV Line trap, and upgrade for associated line relaying.	$1.051
PSCo's Boone – GI-2016-13 230kV switching station 230kV line	Addition of one 230kV Line trap, and upgrade for associated line relaying.	$1.089
	Siting and Land Rights support for substation construction	$0.335
	Total Cost Estimate for Network Upgrades for Interconnection	$11.463
Time Frame	Site, design, procure and construct	36 Months

*** Contingent upon completion of the Network Upgrades for Interconnection listed in #1 #2 of Attachment 1.**

Table 7 –Network Upgrades Required for NRIS *

Element	Description	Cost Est. (Millions)
Boone – Midway 230kV Line	Replace structure 276	$0.155
	Total Cost Estimate for Network Upgrades for Delivery (NRIS)	$0.155
Time Frame	Site, design, procure and construct	18 Months
	Total Project Estimate	$12.734

*** Contingent on completion of Network Upgrades listed in Attachment 1**

Cost Estimate Assumptions

- Appropriations level cost estimates for Interconnection Facilities and Network/Infrastructure Upgrades for Delivery have a specified accuracy of +/- 30%.
- Estimates are based on 2019 dollars (appropriate contingency and escalation applied).
- Labor is estimated for straight time only – no overtime included.
- Lead times for materials were considered for the schedule.
- Estimates are developed assuming typical construction costs for previously completed projects. These estimates include all applicable labor and overheads associated with the siting support, engineering, design, material/equipment procurement, construction, testing and commissioning of these new substation and transmission line facilities.
- PSCo (or its Contractor) crews will perform all construction, wiring, and testing and commissioning for PSC owned and maintained facilities.
- The estimated time to site, design, procure and construct the Transmission Provider's Interconnection Facilities and Network Upgrades for ERIS is approximately 36 months after authorization to proceed has been obtained.
- The estimated time to site, design, procure and construct the network upgrades for delivery for is approximately 18 months after authorization to proceed has been obtained.
- A Certificate of Public Convenience and Necessity (CPCN) will be required for the construction of Transmission Provider Interconnection Facilities and the Network Upgrades for NRIS.
- The Solar Generation Facility is not in PSCo's retail service territory. Therefore, no costs for retail load metering are included in these estimates.
- Line and substation bus outages will be necessary during the construction period. Outage availability could potentially be problematic and further extend the estimated site, design, procure and construction time, causing further delays to the requested back-feed date .
- Estimates do not include the cost for any Customer owned equipment and associated design and engineering.
- The Customer will be required to design, procure, install, own, operate and maintain a Load Frequency/Automated Generation Control (LF/AGC) RTU at the Customer Substation. PSCo / Xcel will need indications, readings and data from the LF/AGC RTU.
- Power Quality Metering (PQM) will be required on the Customer's 230kV line terminating into the POI.
- Customer will string optical ground wire (OPGW) cable into the substation as part of their transmission line construction scope.

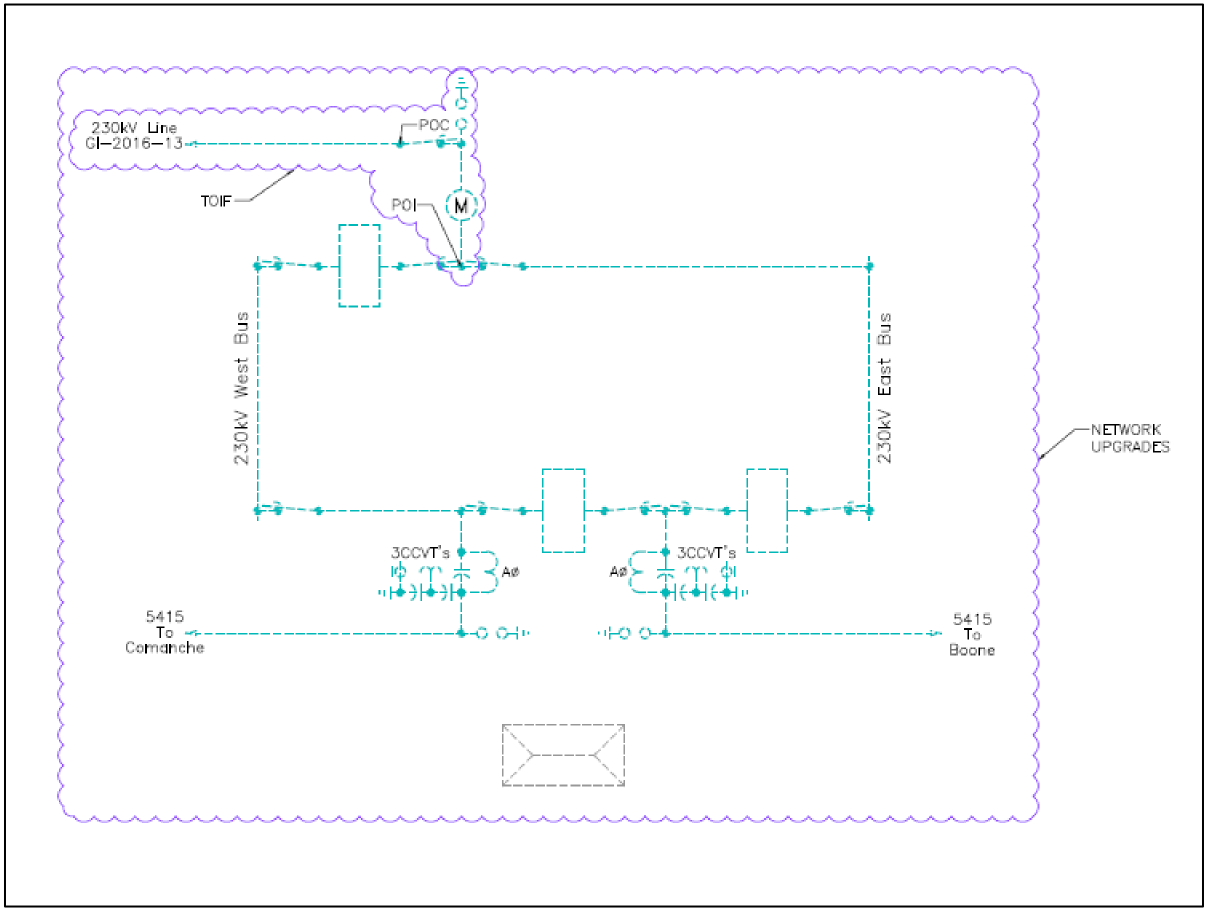

Figure 2 – Preliminary one-line of the new GI-2016-13 230kV Switching Station POI Tapping Comanche – Boone 230kV Line

Attachment 1 – **Contingent Facilities Assigned to GI-2016-13**

Following is the list of the unbuilt Interconnection Facilities and Network Upgrades upon which the GI-2016-12 request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for re-studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

1. Network Upgrades for Interconnection identified for higher-queued Generation Interconnection Requests: None
2. Network Upgrades for Interconnection assigned to GI-2016-13 (refer to Table 2 and 3 of this report)
3. The following Network Upgrades assigned to the higher-queued Generation Interconnection Requests
   - MidwayPS 230/115kV, 100MVA transformer replaced with 150MVA unit – Network Upgrade assigned to GI-2014-12
   - Increase Greenwood – Prairie3 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-7
   - Increase Daniels Park – Fuller 230kV line rating to 577MVA – Network Upgrade assigned to GI-2016-7
   - Increase Ray Lewis – Buena Vista Tap 115kV line rating to 150MVA – Network Upgrade assigned to GI-2016-9
   - Increase Daniels Park – Prairie3 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
   - Increase Daniels Park – Prairie1 230kV line rating to 797MVA – Network Upgrade assigned to GI-2016-9
   - Increase Daniels Park – Fuller 230kV line rating to 802MVA – Network Upgrade assigned to GI-2016-9
   - Increase Greenwood – Prairie1 230kV line rating to 637MVA – Network Upgrade assigned to GI-2016-9
   - Increase Greenwood – Monaco 230kV rating to 637MVA – Network Upgrade assigned to GI-2016-9
   - Increase Leetsdale – Monaco 230kV line rating to 503MVA – Network Upgrade assigned to GI-2016-12
   - Replace MidwayPS 230/115kV, 150MVA transformer with 280MVA capable unit – Network Upgrade assigned to GI-2016-12
   - Second Midway 345/230kV, 560MVA transformer – Network Upgrade assigned to GI-2016-12
   - Second Waterton 345/230kV, 560MVA transformer – Network Upgrade assigned to GI-2016-12

4. The following Network Upgrades required for GI-2016-12 (refer to Table 5 above for PSCo facilities costs)
   - Uprate the Boone – MidwayPS 230kV line to 470MVA (PSCo facility)

- Project to be identified by TSGT to uprate the Lamar – Lamar_C2 230kV line to 241 MVA
- Project to be identified by WAPA to uprate the Midway 230kV bus tie to 437MVA

There are Network Upgrades needed to mitigate incremental overloads on the pre-existing Affected Systems facility overloads caused by GI-2016-12 (as listed in Table 5 above). The GI Customer is responsible for working with the Affected System and the higher-queued GI to make sure the Network Upgrades are in-service before the GI can achieve full NRIS as requested.

5. The following unbuilt transmission projects modeled in the Base Case
   - PSCo's Monument – Flying Horse 115kV Series Reactor project
   - PSCo's project to upgrade Villa Grove – Poncha 69kV Line
   - PSCo's project to upgrade Poncha – San Luis Valley 115kV line
   - PSCo's terminal upgrade project to uprate the Waterton – Martin2 tap 115kV line to 189MVA
   - PSCo's terminal upgrade project to uprate the Malta – Twin Lakes 115kV line to 143MVA
   - PSCo's terminal upgrade project to uprate the Twin Lakes – Otero 115kV line to 143MVA
   - PSCo's terminal upgrade project to uprate the Otero – Buena Vista 115kV line to 150MVA
   - PSCo's terminal upgrade project to uprate the Buena Vista – Ray Lewis 115kV line to 136MVA
   - PSCo's terminal upgrade project to uprate the Ray Lewis – Poncha 115kV line to 164MVA
   - PSCo's terminal upgrade project to uprate the Arapahoe – SantaFe – Daniels Park 230kV to 560MVA
   - PSCo's terminal upgrade project to uprate the Daniels Park – Prairie1 230kV line to 576MVA
   - PSCo's terminal upgrade project to uprate the Greenwood – Monaco 230kV line to 503MVA
   - PSCo's terminal upgrade project to uprate the Leetsdale – Monaco 230kV line to 470MVA
   - PSCo's terminal upgrade project to uprate the Poncha – Smelter town 115kV line to 114MVA
   - PSCo's terminal upgrade project to uprate the San Luis Valley – Sargent 115kV line to 120MVA
   - TSGT's planned project to uprate the Fuller – Vollmer – Black Squirrel 115 kV line to 173 MVA
   - BHE's planed project to uprate the Fountain Valley – DesertCove 115kV line to 171MVA

- BHE's planned project to uprate the Fountain Valley – MidwayBR 115kV line to 171MVA
- BHE's Pueblo West Substation
- BHE's Skyline Ranch Substation
- BHE's West Station – Greenhorn 115kV line Rebuild project
- CSU's project to close Tesla - Cottonwood 34.5kV line and open the Kettle Creek – Tesla 34.5kV line
- CSU's new Cottonwood 230/115kV auto-transformer replacement
- CSU's Nixon – Kelker 230kV line uprate project

The higher-queued GIRs modeled in this study report are: GI-2009-8, GI-2010-8, GI-2014-2, GI-2014-6, GI-2014-8, GI-2014-9, GI-2014-12, GI-2014-13, GI-2014-14, GI-2016-4, GI-2016-7, GI-2016-9 and GI-2016-12. In case of withdrawal of any of these higher-queued GIs or change in status from NRIS to ERIS, the Contingent Facilities assigned to GI-2016-13 would be updated as needed.

Attachment A – Standalone SIS Report (For Information Only)

Executive Summary

This attachment provides the results of GI-2016-13 studied without higher queued projects not yet in-service or their associated upgrades in the model and is for informational purposes only.

The power flow analyses identified the several overloads on the PSCo system and the Affected Systems.

PSCO has a planned FAC8 related Network Upgrade project to mitigate the pre-existing overload on the Waterton – Martin2tap 115kV line overload (new rating will be 181MVA). The new FAC8 rating on this line will be sufficient to mitigate the post-GI overload after GI-2016-13 interconnection. Hence, the cost of this FAC8 network upgrade project on the Waterton – Martin2tap 115kV line is not attributed to the GI-2016-13 interconnection; however, the project needs to be in-service before GI-2016-13 interconnection. The Daniels Park – Prairie1 230kV line and Greenwood – Monaco 230kV line overloads increased from 94.8% to 102.8% and 97.0% to 105.5% respectively after the addition of GI-2016-13 interconnection. Both the lines are contingent network facilities for the GI-2016-13 interconnection to have full 200MW NRIS or ERIS. The cost of the terminal equipment network upgrades for these two lines are given in Table-4.

The transient stability analysis determined that all generating units are stable (remain in synchronism), display positive damping and the maximum transient voltage dips are within acceptable dynamic performance criteria.

The short-circuit and breaker duty analysis determined that no breaker replacements are needed at the POI station and/or in neighboring PSCo stations.

The total estimated cost of the recommended system improvements to interconnect the GI-2016-13 project when evaluated on a standalone basis include:

- $ 0.987 million for Transmission Provider's Interconnection Facilities
- $ 1.065 million for Network Upgrades required for Interconnection (either ERIS or NRIS)
- $ 0.084 million for additional Network Upgrades for NRIS

The total estimated (illustrative) cost of the transmission system improvements required for GI-2016-13 to qualify for:

- **ERIS is $2.052 Million (Tables 2 and 3); and**
- **NRIS is $2.136 Million (Tables 2, 3 and 4)**

Introduction

The GI-2016-13 is a 200MW solar photovoltaic generation facility that will be located in Pueblo County, Colorado. The Generating Facility will be comprised of GE-LV5 1500V inverters which will connect to 0.55/34.5kV, 2MVA generator step up transformers. The generator step up transformers will interface with one 34.5/230/13.8kV, 135/180/225MVA Main Step-up Transformer which will interconnect to the Boone – Comanche 230kV line using a Generator Interconnection Customer owned 230kV tie-line. The POI requested by the Interconnection Customer is a tap on the Boone – Comanche 230kV line, at approximately five (5) miles from the Boone Substation. The tap position on the line will constitute building a new substation to accommodate the GI interconnection, which will be referred to in this report as "GI-2016-13 230kV Switching Station".

The main purpose of this Interconnection System Impact Study is to determine the system impact of interconnecting 200 MW of new generation on the Boone – Comanche 230kV line without higher queued projects not yet in-service or their associated upgrades in the model and is for informational purposes only. As per the Interconnection Study Request, GI-2016-13 was studied for both Energy Resource Interconnection Service (ERIS)[4] and Network Resource Interconnection Service (NRIS)[5]. For both ERIS and NRIS evaluation, the 200 MW rated output of GI-2016-13 is assumed to be delivered to PSCo network load, so existing PSCo generation is used to adjust generation.

The original Commercial Operation Date (COD) proposed was December 31, 2018. Later, in an email received on June 27, 2017, the Customer has changed the COD to December 31, 2020. Based on the typical construction timeframes for similar projects, backfeed data is assumed to be June 30, 2020.

Study Scope and Analysis Criteria

The scope of this report includes steady state (power flow) analysis, transient stability analysis, short circuit analysis and scoping level cost estimates with +/-30% accuracy. The power flow analysis identifies thermal and voltage violations in the PSCo system and the Affected System(s) as a result of the interconnection of the GI. Several single contingencies were studied. Short circuit analysis determines the maximum available fault current at the POI and determines if any breakers at the POI and/or in the neighboring PSCo stations exceed their breaker duty ratings and need to be replaced.

[4] Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

[5] Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission system (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as all other Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

PSCo adheres to applicable NERC Reliability Standards & Western Electricity Coordinating Council (WECC) Reliability Criteria, as well as its internal transmission planning criteria for studies. The steady state analysis criteria are as follows:

P0 - System Intact conditions:

Thermal Loading: <=100% of the normal facility rating

Voltage range: 0.95 to 1.05 per unit

P1-P2 – Single Contingencies:

Thermal Loading: <=100% Normal facility rating

Voltage range: 0.90 to 1.10 per unit

Voltage deviation: <=5% of pre-contingency voltage

The study area is the electrical system consisting of PSCo's transmission system and the affected party's transmission system that may be impacted or that could impact interconnection of GI-2016-13. The study area for GI-2016-13 includes WECC designated zones 121, 700, 703, 704, 705, 709, 710, 712, 752 and 757.

Transient stability criteria require that all generating machines remain in synchronism and all power swings should be well damped following a contingency event. Also, transient voltage performance should meet the following WECC Disturbance-Performance criteria:

- Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for all contingencies
- For all contingencies, following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- For contingencies without a fault, voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds

Standalone Power Flow Analysis

The study was performed using the Western Electricity Coordinating Council (WECC) 2022HS1 power flow case released on 08/31/2016. The generation dispatch in the WECC base case was adjusted to create a heavy south to north flow on the Comanche – Midway – Jackson Fuller – Daniels Park transmission system. This was accomplished by adopting the generation dispatch given in Table-7 below. Two power flow models were created from the 2022HS1 case – a Benchmark case which models the planned transmission system topology before the proposed GI-2016-13 interconnection and a study case that includes the 200MW from GI-2016-13.

The GI-2016-13 was modeled using the power flow and dynamic modeling data provided by the GI Customer.

The steady state analysis was performed using PTI's PSSE Ver. 33.10.0 program and the ACCC contingency analysis tool. The results of the single contingency analysis are given in Table-5.

- Daniels Park – Prairie1 230kV line loading increased from 94.8% to 102.8% (PSCo facility)

- Greenwood – Monaco 230kV line loading increased from 97.0% to 105.5% (PSCo facility)
- Waterton – Martin2tap 115kV line loading increased from 106.3% to 111.7% (PSCo facility)
- Midway 230kV bus tie loading increased from 84.1% to 101.9% (WAPA facility)
- Fountain Valley – DesertCove 115kV line loading increased from 82.9% to 106.0% (BHCE facility)
- Fountain Valley – MidwayBR 115kV line loading increased from 85.7% to 109.6% (BHCE facility)
- Palmer Lake – Monument 115kV line loading increased from 107.0% to 126.7% (CSU facility)
- Brairgate South – Cottonwood South 115kV line loading increased from 116.0% to 125.5% (CSU facility)
- Cottonwood North – Kettle Creek South 115kV line loading increased from 116.8% to 127.0% (CSU facility)
- Kelker N 230/115kV xfmr loading increased from 106.8% to 109.9% (CSU facility)
- Kelker S 230/115kV xfmr loading increased from 105.4% to 108.4% (CSU facility)
- Monument – Flyinghorse 115kV line loading increased from 97.5% to 115.9% (CSU facility)
- Monument – Flyinghorse 115kV line loading increased from 97.5% to 115.9% (CSU facility)
- KettleCreek N – Flyinghorse S 115kV line loading increased from 94.3% to 110.4% (CSU facility)

PSCO has a planned FAC8 related Network Upgrade project to mitigate the pre-existing overload on the Waterton – Martin2tap 115kV line overload (new rating will be 181MVA). The new FAC8 ratings on this line will be sufficient to mitigate the post-GI overload after GI-2016-13 interconnection. Hence, the cost of this FAC8 network upgrade project on the Waterton – Martin2tap 115kV line is not attributed to the GI-2016-13 interconnection; however, the project needs to be in-service before GI-2016-13 interconnection. The Daniels Park – Prairie1 230kV line and Greenwood – Monaco 230kV line overloads increased from 94.8% to 102.8% and 97.0% to 105.5%, respectively, after the addition of GI-2016-13 interconnection. Both the lines are contingent network facility for the GI-2016-13 interconnection to have full 200MW NRIS or ERIS. The cost of the terminal equipment network upgrades for these two lines are given in Table-4.

Transient stability analysis was performed using General Electric's PSLF Ver.21.0_02 program. A study case was created by modeling GI-2016-13 in the 2022HS1 case. Three phase faults were simulated for selected single and multiple contingencies using standard clearing times. Bus voltage, bus frequency, and generator angle were recorded and analyzed. Also, any generators that went out of synchronism were recorded. PSLF's DYTOOLS EPCL program was used to simulate the disturbances.

Voltage Regulation and Reactive Power Capability

Interconnection Customer is required to interconnect its Large Generating Facility with PSCo's Transmission System in accordance with the *Xcel Energy Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater Than 20 MW* (available at: http://www.transmission.xcelenergy.com/staticfiles/microsites/Transmission/Files/PDF/Interconnection/Interconnections-POL-TransmissionInterconnectionGuidelineGreat20MW.pdf).

Accordingly, the following voltage regulation and reactive power capability requirements at the POI are applicable to this interconnection request:

- To ensure reliable operation, all Generating Facilities interconnected to the PSCo transmission system are expected to adhere to the *Rocky Mountain Area Voltage Coordination Guidelines (RMAVCG)*. Accordingly, since the POI for this interconnection request is located within Southeast Colorado - Region 4 defined in the *RMAVCG*; the applicable ideal transmission system voltage profile range is 1.02 – 1.03 per unit at regulated buses and 1.0 – 1.03 per unit at non-regulated buses.
- Xcel Energy's OATT (Attachment N effective 10/14/2016) requires all non-synchronous Generator Interconnection (GI) Customers to provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging at the high side of the generator substation. Furthermore, Xcel Energy requires every Generating Facility to have dynamic voltage control capability to assist in maintaining the POI voltage schedule specified by the Transmission Operator as long as the Generating Facility does not have to operate outside its 0.95 lag – 0.95 lead dynamic power factor range capability.
- It is the responsibility of the Interconnection Customer to determine the type (switched shunt capacitors and/or switched shunt reactors, etc.), the size (MVAR), and the locations (34.5kV or 230kV bus) of any additional static reactive power compensation needed within the generating plant in order to have adequate reactive capability to meet the +/- 0.95 power factor and the 1.02 – 1.03 per unit voltage range standards at the POI. Further, for wind generating plants to meet the LVRT (Low Voltage Ride Through) performance requirements specified in FERC Order 661-A, an appropriately sized and located dynamic reactive power device (DVAR, SVC, etc.) may also need to be installed within the generating plant. Finally, it is the responsibility of the Interconnection Customer to compensate their generation tie-line to ensure minimal reactive power flow under no load conditions.

The Interconnection Customer is required to demonstrate to the satisfaction of PSCo Transmission Operations prior to the commercial in-service date of the generating plant that it can safely and reliably operate within the required power factor and voltage ranges (noted above).

Standalone Transient Analysis

The transient stability analysis for GI-2016-13 System Impact Study simulated nine disturbances for the study case (power flow case with GI-2016-13 modeled).

It is determined that GI-2016-13 produced no adverse system stability impact. The following results were obtained for every case and disturbance analyzed:

- ✓ No machines lost synchronism with the system
- ✓ No transient voltage drop violations were observed
- ✓ Machine rotor angles displayed positive damping

Transient stability plots showing surrounding bus voltages, bus frequencies, generator terminal voltages, generator relative angles, generator speeds, and generator power output for each of the disturbances run for each study scenario have been created and documented in Appendix B.

Furthermore, it is the responsibility of the Interconnection Customer to ensure that its generating facility is capable of meeting the voltage ride-through and frequency ride-through (VRT and FRT) performance specified in the NERC Reliability Standard PRC-024.

Standalone Short Circuit and Breaker Duty Analysis

The calculated short circuit levels and Thevenin system equivalent impedances at the GI-2016-13 230kV Switching Station POI are shown in Table 1.

Table 1 – Short Circuit Parameters at the GI-2016-13 Switching Station Tapping Comanche - Boone 230kV Line

	Before GI-2016-13 Interconnection	After GI-2016-13 Interconnection
Three Phase Current	7,710A	7,710A
Single Line to Ground Current	5,636A	5,681A
Positive Sequence Impedance	1.723+j17.136 ohms	1.743+j17.136 ohms
Negative Sequence Impedance	1.766+j17.145 ohms	1.766+j17.145 ohms
Zero Sequence Impedance	9.053+j35.281 ohms	8.958+j34.725 ohms

A preliminary breaker duty study did not identify any circuit breakers that became over-dutied"[6] as a result of adding this generation.

Conclusion (for informational purposes only)

This standalone System Impact Study concludes that the GI-2016-13 interconnection cannot achieve 200MW NRIS until the identified Network Upgrades on the PSCo system and the Affected System transmission system are in-service.

[6] "Over-dutied" circuit breaker: A circuit breaker whose short circuit current (SCC) rating is less than the available SCC at the bus.

This study identifies the required transmission improvements and cost estimates assuming no higher queued projects or their associated transmission facilities are in-service and so the results are for information only.

Tables 2 - 4 below provide the cost estimates for the Transmission Provider Interconnection Facilities and Network Upgrades identified in this standalone System Impact Study. The cost responsibilities associated with these transmission system improvements shall be handled as per the current FERC guidelines.

The total estimated cost of the transmission system improvements required for GI-2016-13 to qualify for:

- **ERIS is $2.052 Million (Tables 2 and 3); and**
- **NRIS is $2.136 Million (Tables 2, 3 and 4)**

Figure 1 below represents a budgetary one-line diagram of the proposed interconnection of GI-2016-13 at the Boone 230kV POI on a standalone basis.

Illustrative Standalone Costs Estimates and Assumptions

Table 2 –Transmission Provider's Interconnection Facilities

Element	Description	Cost Est. (Millions)
PSCo's Boone 230kV Transmission Substation	Interconnect Customer to the 230kV bus at the Boone Substation. The new equipment includes: • One (1) motor operated 230kV disconnect switch • Three (3) 230kV combination CT/PT metering units • Power Quality Metering (230kV line from Customer) • Three (3) surge arresters • Two (2) relay panels • Associated bus, wiring and equipment • Associated foundations and structures • Associated transmission line communications, relaying and testing	$0.937
	Transmission line tap into substation. Conductor, hardware, and installation labor.	$0.055
	Total Cost Estimate for Transmission Provider's Interconnection Facilities	**$0.987**
Time Frame	**Site, design, procure and construct**	**18 months**

Table 3 - Network Upgrades for Interconnection (applicable for either ERIS or NRIS) *

Element	Description	Cost Estimate (Millions)
PSCo's Boone 230kV Transmission Substation	Interconnect Customer to the 230kV bus at the Boone 115kV Substation. The new equipment includes: • One (1) 230kV circuit breaker • Two (2) 230kV gang switches • One (1) 230kV CCVT • Associated communications, supervisory and SCADA equipment • Associated line relaying and testing • Associated bus, miscellaneous electrical equipment, cabling and wiring • Associated foundations and structures Associated road and site development, fencing and grounding	**$1.065**
	Siting and Land Rights support for Substation land acquisition and construction:	**$0.00**
	Total Cost Estimate for Network Upgrades for Interconnection	**$1.065**
Time Frame	**Site, design, procure and construct**	**18 Months**

Table 4 – Additional Network Upgrades for NRIS *

Element	Description	Cost Est. (Millions)
Monaco Substation	Uprated Jumpers and Associated Equipment	$0.037
Prairie Substation	Uprated Jumpers and Associated Equipment	$0.047
	Total Cost Estimate for Network Upgrades for Delivery (NRIS)	**$0.084**
Time Frame	**Site, design, procure and construct**	**18 Months**
	Total Project Estimate	**$2.136**

Cost Estimate Assumptions

- Scoping level cost estimates for Interconnection Facilities and Network Upgrades have a specified accuracy of +/- 30%.
- Estimates are based on 2017 dollars (appropriate contingency and escalation applied, AFUDC is not included).
- Labor is estimated for straight time only – no overtime included.
- Lead times for materials were considered for the schedule.
- Estimates are developed assuming typical construction costs for previously completed projects. These estimates include all applicable labor and overheads associated with the

siting support, engineering, design, material/equipment procurement, construction, testing and commissioning of these new substation and transmission line facilities.

- The Generation Facility is not in PSCo's retail service territory. Therefore, no costs for retail load metering are included in these estimates.
- PSCo (or its Contractor) crews will perform all construction, wiring, and testing and commissioning for PSC owned and maintained facilities.
- The estimated time to site, design, procure and construct the Transmission Provider's Interconnection Facilities and Network Upgrades required for Interconnection is approximately 18 months after authorization to proceed has been obtained.
- A CPCN will not be required for the interconnection facilities construction.
- Line and substation bus outages will be necessary during the construction period. Outage availability could potentially be problematic and necessitate extending the back-feed date.
- Estimates do not include the cost for any Customer owned equipment and associated design and engineering.
- The Customer will be required to design, procure, install, own, operate and maintain a Load Frequency/Automated Generation Control (LF/AGC) RTU at the Customer Substation. PSCo / Xcel will need indications, readings and data from the LFAGC RTU.
- Power Quality Metering (PQM) will be required on the Customer's 230 kV line terminating into the Boone Substation.
- Customer will string optical ground wire (OPGW) cable into the substation as part of their transmission line construction scope.

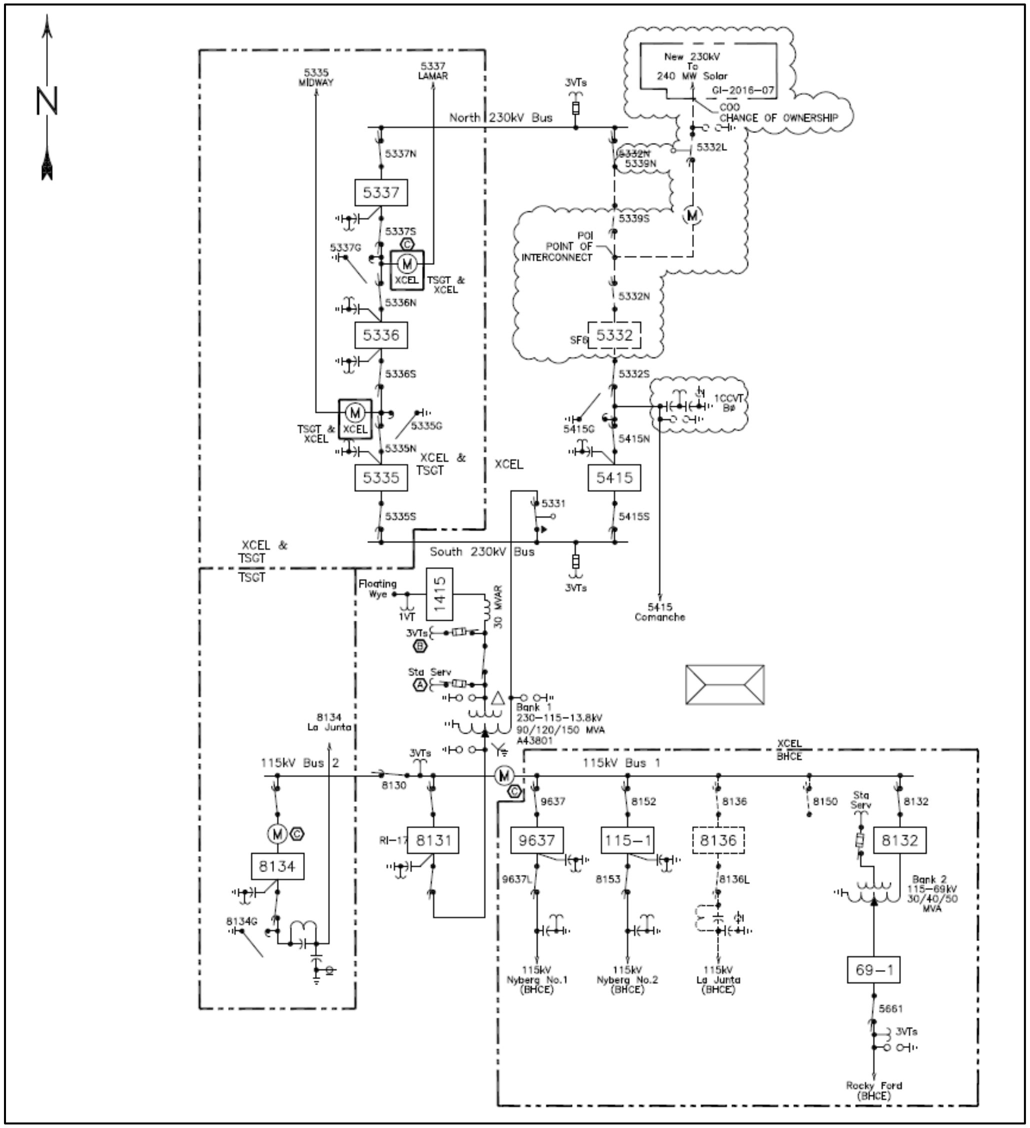

Figure 1 – Preliminary one-line of GI-2016-13 Switching Station at the Primary POI

Appendix – B

Power Flow Analysis Results

Note – Thermal overloads for single contingencies are calculated using the normal rating of the facility. All overloads are in red.

Table 5 – Summary of Thermal Violations from Single Contingency Analysis									
				Facility Loading Without GI-2016-13		Facility Loading With GI-2016-13			
Monitored Facility (Line or Transformer)	Type	Owner	Branch Rating MVA (Norm/Emer)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	N-1 Flow MVA (Norm)	N-1 Flow % of Rating (Norm)	% Change	NERC Single Contingency
Daniels Park – Prairie1 230kV	Line	PSCo	478/478	453.1	94.8%	491.4	102.8%	8.0%	Daniels Park – Prarire3 230kV line
Fountain Valley – DesertCove 115kV	Line	BHCE	119/119	98.6	82.9%	126.1	106.0%	23.1%	Boone – MidwayPS 230kV line
Fountain valley – MidwayBR 115kV	Line	BHCE	115/115	98.5	85.7%	126.0	109.6%	23.9%	Boone – MidwayPS 230kV line
Greenwood – Monaco 230kV	Line	PSCo	405/481	392.8	97.0%	427.3	105.5%	8.5%	Smoky – Buckley 230kV line
Midway 230kV bus tie	Line	WAPA	430/478	361.6	84.1%	438.2	101.9%	17.8%	MidwayPS – Fuller 230kV line
Palmer Lake – Monument 115kV	Line	CSU	142/157	151.9	107.0%	179.9	126.7%	19.7%	Daniels Park – Fuller 230kV line
Waterton – Martin2tap 115kV	Line	PSCo	127/140	135.0	106.3%	141.9	111.7%	5.4%	SodaLakes 230/115kV xfmr

Table 5 – Summary of Thermal Violations from Single Contingency Analysis									
				Facility Loading Without GI-2016-13		Facility Loading With GI-2016-13			
Monitored Facility (Line or Transformer)	**Type**	**Owner**	**Branch Rating MVA (Norm/Emer)**	**N-1 Flow MVA (Norm)**	**N-1 Flow % of Rating (Norm)**	**N-1 Flow MVA (Norm)**	**N-1 Flow % of Rating (Norm)**	**% Change**	**NERC Single Contingency**
Briargate S – Cottonwood S 115kV	Line	CSU	150/192	174	116.0%	188.2	125.5%	9.5%	Cottonwood N – KettleCreek S 115kV line
Cottonwood N – KettleCreek S 115kV	Line	CSU	162/180	189.2	116.8%	205.7	127.0%	10.2%	Briargate S – Cottonwood S 115kV line
Kelker N 230/115kV	Xfmr	CSU	280/319	299.0	106.8%	307.7	109.9%	3.1%	Kelker S 230/115kV Xfmr
Kelker S 230/115kV	Xfmr	CSU	280/322	295.1	105.4%	303.5	108.4%	3.0%	Kelker N 230/115kV Xfmr
Monument – Flying Horse 115kV	Line	CSU	142/157	138.4	97.5%	164.6	115.9%	18.4%	Daniels Park – Fuller 230kV line
Flying Horse – Kettle Creek S 115kV	Line	CSU	162/180	152.8	94.3%	178.8	110.4%	16.1%	Daniels Park – Fuller 230kV line

Table-6 Transient Stability Analysis Results

Stability Scenarios						
#	Fault Location	Fault Type	Facility Tripped	Clearing Time (cycles)	Post-Fault Voltage Recovery	Angular Stability
1	Boone 230kV	3ph	Boone 230/115kV Transformer	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
2	Boone 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
3	Boone 230kV	3ph	Boone – Comanche 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
4	Boone 230kV	3ph	Boone – Midway 230kV	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
5	Comanche 345 kV	3ph	Comanche#3 generator	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
6	MidwayPS 230kV	3ph	All Fountain Valley gas units	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
7	MidwayPS 345kV	3ph	MidwayPS – Waterton 345kV line & Midway 230/345kV xfmr	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping
8	Comanche 345kV	3ph	Comanche – Daniels Park 345kV 1 &2	Primary (4.0)	Maximum transient voltage dips within criteria	Stable with positive damping
9	Lamar 230kV	3ph	Lamar – Boone 230kV line and all generation at Lamar	Primary (5.0)	Maximum transient voltage dips within criteria	Stable with positive damping

Table 7 – Generation Dispatch in the Study area (MW is Gross Capacity)

PSCo:

Bus	Gen ID	MW
Comanche PV	S1	102
Comanche	C1	357
Comanche	C2	365
Comanche	C3	795
Lamar DC Tie	DC	101
Fountain Valley	G1	36
Fountain Valley	G2	36
Fountain Valley	G3	36
Fountain Valley	G4	36
Fountain Valley	G5	36
Fountain Valley	G6	36
Colorado Green	W1	64.8
Colorado Green	W2	64.8
Twin Butte	W1	60
Twin Butte-II	W1	60
Jackson Fuller	W1&W2	151.9

BHE:

Bus	Gen ID	MW
BUSCHWRTG1	G1	28.8
BUSCHWRTG2	G2	28.8
BUSCHWRTG2	G3	28.8
E Canon	G1	0
PP_MINE	G1	0
PuebloDiesels	G1	0
Pueblo Plant	G1	0
Pueblo Plant	G2	0.0
R.F. Diesels	G1	0.0
Airport Diesels	G1	0.0
Canyon City	C1	0
Canyon City	C1	0
Baculite 1	G1	90
Baculite 2	G1	90
Baculite 3	G1	40.0
Baculite 3	G2	40.0
Baculite 3	S1	24

Baculite 4	G1	20
Baculite 4	G2	24
Baculite 4	S1	24
Baculite 5	G1	0

CSU:

Bus	Gen ID	MW
Birdsale1	1	0.0
Birdsale 2	1	0.0
Birdsale 3	1	0.0
RD_Nixon	1	220.5
Tesla	1	13.2
Drake 5	1	0.0
Drake 6	1	80.6
Drake 7	1	137.1
Nixon CT 1	1	0.0
Nixon CT 2	1	0.0
Front Range CC 1	1	137.3
Front Range CC 2	1	136.9
Front Range CC 3	1	161.3