Xcel Energy

Interconnection System Impact Study Report
Request # GI-2007-5

50 MW Wind Expansion of Cedar Creek, Near Grover, Colorado

PSCo Transmission Planning
December 3, 2008

A. Executive Summary

On December 12, 2007 Public Service Company of Colorado (PSCo) Transmission Planning received a generation interconnection request to determine the system impacts associated with a 50 MW expansion near the existing 300 MW Cedar Creek wind turbine generation facility and injecting the combined wind generation output into the PSCo transmission system at the Keenesburg 230 kV Switching Substation in Weld County Colorado. The customer requested a commercial operation date for the expansion of December 31, 2010. The study request indicated that the generation would be delivered for PSCo load. This generation interconnection request was studied as a stand-alone project only.

This request was studied as both a Network Resource (NR)[1], and as an Energy Resource (ER)[2]. These investigations included steady-state power flow, short-circuit studies and transient stability analysis. The request was studied as a stand-alone project only, with no evaluations made of other potential new generation requests that may exist in the Large Generator Interconnection Request (LGIR) queue, other than the generation projects that are already approved and planned to be in service by the summer of 2010. The main purpose of this study was to evaluate the potential impact on the PSCo transmission infrastructure as well as that of neighboring entities, when injecting a total of 350 MW of generation into the Keenesburg 230 kV bus, and delivering the additional generation to native PSCo loads. The costs to interconnect the project with the transmission system at Keenesburg Substation have been evaluated by PSCo Engineering. This study considered facilities that are part of the PSCo transmission system as well as monitoring other nearby entities' regional transmission systems.

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[1] **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.

[2] **Energy Resource Interconnection Service (ER 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

Stand Alone Results

The stand-alone analysis consisted of a comparative study of the system behavior with the addition of the Customer's 50 MW expansion project to the PSCo system compared with that associated with the existing PSCo system. The delivery of power from the 50 MW expansion project to PSCo will be at the same POI as the existing wind facility. Therefore, the analysis focused on evaluating impacts from the Keenesburg POI. The generation from the existing facilities and the 50 MW GI-2007-5 expansion (referred to collectively as Cedar Creek Wind Energy or CCWE) was modeled in the power flow cases in two ways - modeled at full output of approximately 350 MW, or modeled with the expansion off line (a CCWE 300 MW output). The power flow model used in this study is a 2010 budget model with heavy summer load and moderately heavy stressed north-to-south (HSHN) flows.

Energy Resource (ER)

Energy Resource Interconnection Service (ER) is 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.

The System Impact Study determined that firm transmission capacity for the 50 MW wind generation facility expansion is not available due to existing overloads and firm transmission commitments and is not possible without the construction of network reinforcements. Non-firm transmission capability may be available depending on marketing activities, dispatch patterns, generation levels, demand levels, import path levels (TOT3, etc.) and the operational status of transmission facilities.

Network Resource (NR)

Network Resource Interconnection Service is an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers. A Network Resource is any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Network Resource Interconnection Service in and of itself does not convey transmission service.

In addition to the delivery of 300 MW from the initial Cedar Creek facility, the full 50 MW generation output of the GI-2007-5 expansion project could be provided to PSCo after reinforcements to the PSCo transmission system have been completed. PSCo will complete these reinforcements through its capital budget process for transmission upgrades.

Transmission Proposal

The total estimated cost of the recommended system upgrades to interconnect the project is approximately **$40,000** and includes:

- $40,000 for PSCo-Owned, Customer-Funded Interconnection Facilities
- $0 for PSCo-Owned, PSCo-Funded Network Upgrades for Interconnection
- $0 for PSCo Network Upgrades for Delivery. This assumes that PSCo completes the network upgrade projects that have been identified and included in the PSCo Transmission Capital Budget.

The transmission study indicates that approximately 20 MVAR of reactors will likely be required for the customer's wind generating plant to maintain a power factor within the range of 0.95 leading to 0.95 lagging near minimum generation levels, measured at the POI. This would be needed whenever the Customer facilities are off-line while the Customer is connected to the POI receiving house power. In addition, about 45 MVAR of switched capacitors will be needed to meet the voltage criteria at the POI near maximum generation (with RMEC out-of-service). More detailed studies should be performed by the Customer to ensure that proposed wind generation facility will display acceptable performance during the commissioning testing.

The Interconnection Agreement (IA) requires that certain conditions be met, as follows:

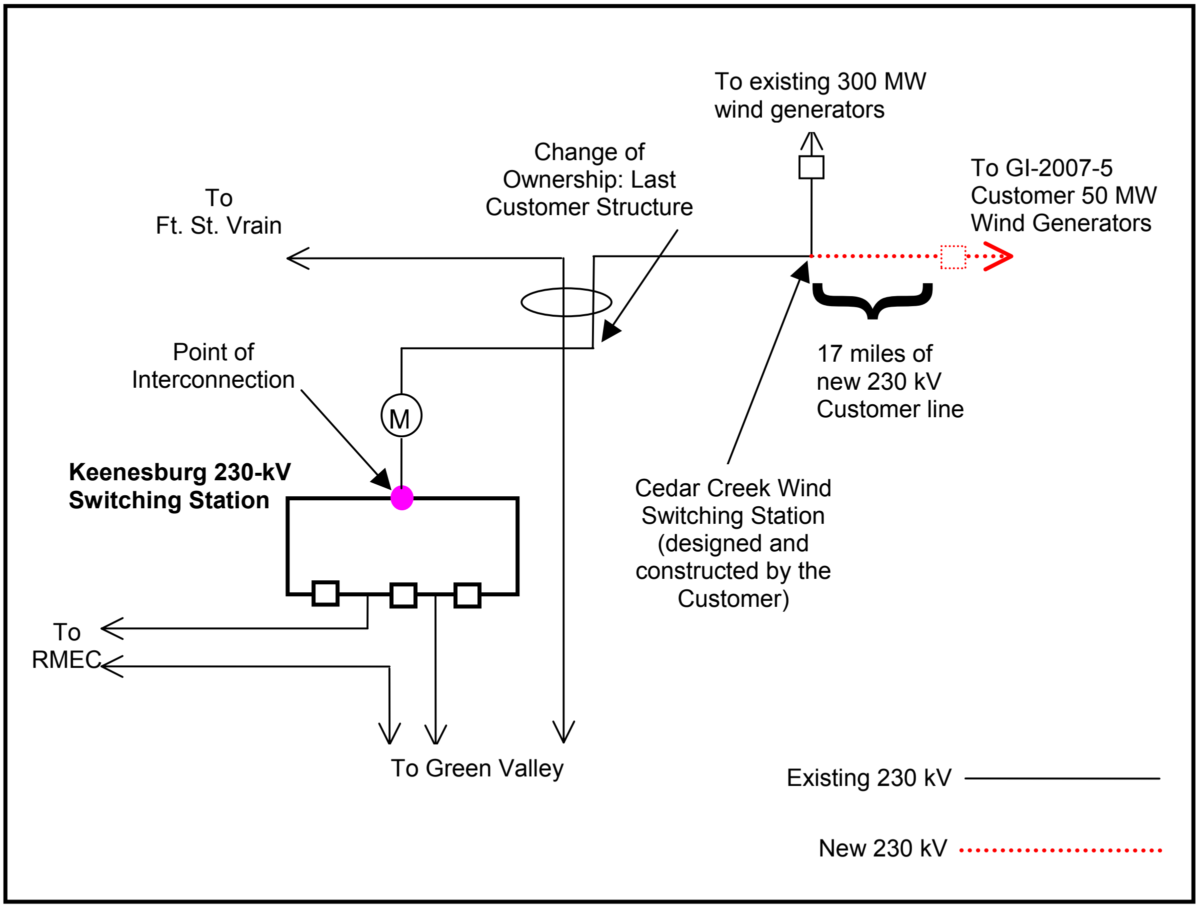
1. The conditions of the Large Generator Interconnection Guidelines (LGIG) are met.

2. A single point of contact is given to Operations to manage the transmission system reliably for all wind projects delivering power at the Keenesburg POI.

3. PSCo will require testing of the full range of 0 MW to 350 MW of the combined original 300 MW wind project plus 50 MW expansion associated with GI-2007-5. These tests will include, but not be limited to, power factor control, and voltage control as measured at the Keenesburg POI 230 kV bus for various generation output levels (0 to 350 MW) of the overall wind generation facility.

4. The Customer must show that the power factor at the POI is within the required +/-0.95 power factor range at all levels of generation and that the voltage levels and changes are within reliability criteria as measured at the POI for the full range of testing (including generator off-line conditions).

Figure 1 Simple Diagram of the Keenesburg Interconnection



B. Introduction

PSCo Transmission received a large generator interconnection request (GI-2007-5) to interconnect 20 Clipper 2.5 MW Liberty Series wind turbines, with a total generation capability of 50 MW, with a commercial operation date of December 31, 2009. The proposed project would be located near the existing 300 MW Cedar Creek wind farm, near Grover, Colorado, and for study purposes represents a 50 MW expansion of the overall wind farm. The GI-2007-5 project would be connected with a new 17-mile 230-kV line to the wind farm end of the existing 72-mile 230 kV transmission line. The existing 230 kV transmission line would deliver the total output from the existing facility and the GI-2007-5 project to the Keenesburg switching station, the POI with PSCo.

The Customer has requested that this project be evaluated as a Network Resource (NR) and an Energy Resource (ER), with the energy delivered to PSCo customers.

C. Study Scope and Analysis

The Generator System Impact Study evaluated the transmission impacts associated with the proposed interconnection of an additional 50 MW of new wind generation at Cedar Creek with delivery of all power to the POI at Keenesburg. The study consisted of steady-state power flow and transient stability analyses.

The power flow analysis provided a preliminary identification of any thermal or voltage limit violations resulting from the interconnection, and for an NR request, a preliminary identification of network upgrades required to deliver the proposed generation to PSCo loads. The short circuit analysis completed for the GI-2007-5 Feasibility Study showed that the fault current levels for all buses studied are within the interrupting ratings of the breakers; therefore the project and associated infrastructure will not cause the fault current to exceed the circuit breaker ratings. The transient stability analysis provided simulations of the system behavior during and immediately after severe disturbances to determine whether the additional generation could adversely impact system operation.

PSCo adheres to NERC / WECC Reliability Criteria, as well as internal Company criteria for planning studies. The following criteria were used for the study:

- For system intact conditions, transmission system bus voltages must be maintained between 0.95 and 1.05 per-unit of system nominal / normal conditions, and steady-state power flows must be maintained under 1.0 per-unit of all elements' thermal (continuous current or MVA) ratings.
- Operationally, PSCo endeavors to maintain a transmission system voltage profile at 230 kV regulating buses in the Metro Denver-Boulder-Ft. Lupton region[2]

[2] The Metro Denver-Boulder-Ft.Lupton region and its associated ideal, acceptable and emergency steady state voltage ranges are defined in the Rocky Mountain Voltage Coordination Guidelines revised July 2006. These guidelines were developed by the Voltage Coordination Guidelines Subcommittee (VCGS)

between 1.02 p.u. and 1.03 p.u. A regulating bus is any transmission or generation bus with controllable VAR's. The Keensburg 230 kV POI is considered a regulating bus.

- Following a single contingency element outage, transmission system steady state bus voltages must remain within 0.90 per-unit to 1.10 per-unit (and between 0.92 per-unit and 1.07 per-unit at load buses for PRPA, and power flows under 1.0 per-unit of the elements' continuous thermal ratings.

For this project, potential affected parties include the Western Area Power Administration (WAPA), and Tri-State Generation and Transmission. These parties will receive a copy of this system impact report.

D. Power Flow Study Models

The power flow studies were based on a PSCo-developed 2010 heavy summer base case that originated from the study model developed in early 2008 as part of PSCo's normal annual Five-Year Transmission Capital Budget project identification process. These budget case models are developed from Western Electricity Coordinating Council (WECC) approved models, modified as appropriate for PSCo planned and approved projects and associated topology. Load levels reflect 2010 heavy summer peak system conditions. The case reflects the addition of the Comanche Project. The Comanche Project includes the addition of the 750-MW Comanche #3 unit, two Comanche – Daniels Park 345 kV circuits, two Comanche – MidwayPS 230 kV circuits, the Midway – Fuller – Daniels Park 230 kV line and the MidwayPS – Waterton 345 kV transmission line (with a 560-MVA MidwayPS 345-230 kV transformer). The Waterton substation includes a 560-MVA 345-230 kV transformer and two 100-MVA 230-115 kV transformers.

The first phase of development at Cedar Creek (300.5 MW) achieved full commercial operation in December 2007 and consists of 221 MW of Mitsubishi 1000A wind turbines and 79.5 MW of GE 1.5 MW wind turbines. The Mitsubishi turbines are 1.0 MW induction generators and each has 0.34 MVAR of switched capacitors near its terminals. The GE machines are 1.5 MW doubly-fed induction generators with LVRT II. The collector system for the first stage operates at 34.5 kV and is arranged in two essentially equal sub-networks, with each connected to the 230 kV substation bus with identical 100/133/167 MVA transformers. In addition to the reactive power support provided by the GE wind turbines, there is a 54 MVAR switched capacitor bank at each of the two 34.5 kV substation buses and a total of 12 MVAR of DVAR[3] capability, with 4 MVAR on each of the 34.5 kV substation buses and the remainder split between the two overhead 34.5 kV feeders. The 54 MVAR switched capacitor bank should be adjusted between 0 and 45 MVAR depending upon the total generation from the original 300 MW

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of the Colorado Coordinated Planning Group (CCPG). CCPG is a reliability coordination group composed of Colorado and neighboring area utilities.

[3] DVAR is an acronym for the "Dynamic VAR reactive compensation system". A DVAR provides a source of dynamic VAR's for a wide range of operational needs. A DVAR can be used to support a stable point of interconnection for a large-scale wind farm.

wind farm, with 45 MVAR online with high levels of generation. To establish the benchmark case for this study, the representation of the existing 300 MW wind farm reflected a somewhat simplified 34.5 kV collector system, with equivalencing of lateral feeders but maintaining the size of all relevant generators, switched capacitors and DVAR systems and the relative locations of the generators along the main 34.5 kV feeders.

The proposed 50 MW expansion at Cedar Creek is expected to consist of 20 Clipper Windpower 2.5 MW Liberty series wind turbines. Detailed collector system information including configuration, conductor size, and impedance data was provided by the developer. This data was aggregated so as to provide an equivalent configuration with adequate detail to evaluate voltage levels by the wind turbines during system disturbances. The collector system for this 50 MW expansion is connected to a single 35/45/55 MVA 230-34.5 kV transformer (9.0 % reactance on a 35 MVA Base). A 17-mile 230 kV transmission line will be built as part of this project, connecting this expansion to the existing Cedar Creek 230 kV bus at the initial wind farm. Based upon generator data that was provided, the generators' reactive capability chart was taken into account, and generator reactive power output was set to 0.357 MVAR for each 2.5 MW generator. As discussed later in the report, the studies show that additional MVAR support will be required to enable power factor or voltage control capability to meet the interconnection requirement at the Keenesburg POI.

The PSCo control area (Area 70) wind generation facilities, other than GI-2007-5 and the existing 300 MW at Cedar Creek (collectively referred to herein as CCWE), were dispatched to approximately 12% of facility ratings, consistent with other similar planning study models.

Two main power flow case model generation dispatch scenarios were evaluated: a reference model without the proposed wind farm expansion but with the 300 MW output from the existing Cedar Creek facility; and a model with additional power delivered to the Keenesburg 230 kV bus from the 50 MW expansion for GI-2007-5. The GI-2007-5 output displaced other PSCo control area generation by 50 MW, in the southern part of the PSCo system. In particular, this was accomplished by decreasing the generation by 50 MW at Comanche 2.

E. Power Flow Study Process

Automated contingency power flow studies were completed on all case models using the PSS®MUST program, switching out single elements one at a time for all of the elements (lines and transformers) in control areas 70 (PSCo) and 73 (WAPA RM). Upon switching each element out, the program re-solves with all voltage taps and switched shunt devices locked, and control area interchange adjustments disabled.

F. Power Flow Results

The stand-alone results reflect that the 50 MW expansion and the 300 MW existing wind farm generation interconnecting at the Keenesburg 230 kV bus are modeled in the power flow case at full output, or approximately 350 MW, and the rest of the generation and loads in the power flow model reflect a heavy summer load 2010 case. The contingency studies were performed for both the "with GI-2007-5" generation expansion, and the reference model without the expansion but with the 300 MW existing facility, and the results listing the overloaded elements (power flows in excess of their continuous rating) were compared. The results are listed in Table 1 below.

Table 1 Branch Overloads

** From bus ** ** To bus ** CKT	Branch Rating	Loading as % of Branch Rating: Bench-mark Case	Loading as % of Branch Rating: With GI-2007-5	Contingency
70047 BARRLAKE 230 70048 GREENVAL 230 1	159.0	188.3	193.0	70192 FTLUPTON 230 70529 JLGREEN 230 1
70048 GREENVAL 230 70526 IMBODEN 230 1	435.0	102.3	105.2	70048 GREENVAL 230 70528 SPRUCE 230 1
70048 GREENVAL 230 70590 RMEC 230 1	834.0	103.7	108.9	70048 GREENVAL 230 70820 KEENSBG 230 1
70048 GREENVAL 230 70820 KEENSBG 230 1	834.0	103.8	108.9	70048 GREENVAL 230 70590 RMEC 230 1
70107 CHEROKEE 230 70324 LACOMBE 230 1	444.0	100.2	101.7	70266 LOOKOUT 230 70480 WESTPS 230 1
70461 WASHINGT 230 70529 JLGREEN 230 1	413.0	105.3	105.9	70192 FTLUPTON 230 70605 HENRYLAK 230 1
70526 IMBODEN 230 70528 SPRUCE 230 1	435.0	100.7	103.5	70048 GREENVAL 230 70528 SPRUCE 230 1

The contingency analysis indicated several overloaded circuits that would experience increases in flows of 2.5 MW or more (5% of the GI-2007-5 50 MW expansion). In reviewing these circuits, many of these circuit limitations will be eliminated through the PSCo Capital Construction Budget Process. It should be noted that the rating of the Green Valley-Barr Lake 230 kV line (Circuit No. 5759) is 159 MVA in the base case; however, the actual rating of the branch is 506 MVA based on the Substation/Transmission Facility Equipment Ratings FAC-009 list. Therefore, the reported contingency overloads of this element can be ignored. The ratings of the Green Valley–Imboden and Imboden–Spruce 230 kV circuits are being increased from 435 to 490 MVA. These circuit limitations will be eliminated through the PSCo Capital Construction Budget Process. Through the same process, the Cherokee–Lacombe 230 kV circuit rating will increase such that it will not be overloaded under contingency conditions with the additional generation.

Table 1 shows that the contingency flow of the Washington–JL Green 230 kV line (rated at 413.0 MVA) would increase from 434.9 MVA to 437.4 MVA (a 2.5 MVA increase) due to the 50 MW GI-2007 expansion. Bundling the 1-1272 kcmil jumper at Washington Substation would eliminate the contingency overload (see Table 2 below). Since the JLGreen Substation is owned by Tri-State, PSCo does not know if there are equipment limitations at that substation that could impact the line rating. Tri-State will be provided a copy of the system impact study report so that they can verify the ratings of the terminations at the JL Green Substation for the Washington-JL Green 230 kV line.

Table 2 Washington-JL Green 230 kV Line Rating

Limiting Element	Rating of Limiting Element	Proposed Capital Budget Project	Next Limiting Element
Washington Substation 1-1272 kcmil aluminum jumper.	1037 amps (413.1 MVA using a 2 ft/sec wind speed assumption[4])	Bundle the 1-1272 kcmil aluminum jumper at Washington Substation (Washington-JL Green 230 kV line) with a second 1272 kcmil aluminum jumper (Rating of bundled jumper is 826.2 MVA).	Washington-JL Green 230 kV line conductor (single 1272 kcmil having a rating of 579 MVA using a 4 ft/sec wind speed assumption).

The contingency flow of the Green Valley-Keenesburg 230 kV line (rated at 834.0 MVA in the case but 789.2 MVA based on the Substation/Transmission Facility Equipment Ratings FAC-009) would increase from 865.7.9 MVA to 908.2 MVA (a 42.5 MVA increase) due to the GI-2007-5 expansion. Replacing the 2.5" aluminum tube bus with a 5" aluminum bus at Green Valley Substation would eliminate the contingency overload (see Table 3 below). The Keenesburg Substation is owned by PSCo and there are no limitations at Keenesburg that would limit the line rating to less than the rating of the conductor (965 MVA).

Table 3 Green Valley-Keenesburg 230 kV Line Rating

Limiting Element	Rating of Limiting Element	Proposed Capital Budget Project	Next Limiting Element
Green Valley Substation 2.5 " aluminum tube bus	1981 amps (789.2 MVA at 230 kV)	Replace the 2.5" aluminum tube bus at Green Valley Substation (Green Valley-Keenesb urg 230 kV line) with a 5" aluminum tube having a rating of 3850 amps (1533.7 MVA at 230 kV)	Line conductor (bundled 954 kcmil) of the Green Valley-Keenesburg 230 kV line with a rating of 2422 amps (964.8 MVA at 230 kV with 4 ft/sec wind speed assumption).

The contingency flow of the Green Valley-RMEC 230 kV line (rated at 834.0 MVA in the case but 789.2 MVA based on the Substation/Transmission Facility Equipment Ratings FAC-009) will increase from 864.9 MVA to 908.2 MVA (a 43.3 MVA increase) due to the GI-2007-5 expansion. Replacing the 2.5" aluminum tube bus with a 5" aluminum bus at Green Valley Substation would eliminate the contingency overload (see Table 4). The RMEC substation is owned by RMEC and PSCo does not have the rating information for that substation. RMEC will be provided a copy of the system impact study report so that they can verify the ratings of the terminations at the RMEC Substation for the Green Valley-RMEC 230 kV line.

[4] The Washington Substation is surrounded by a high wall; therefore, PSCo must use a 2 ft/sec wind speed instead of 4 ft/sec wind speed assumption.

Table 4 Green Valley-RMEC 230 kV line Rating

Limiting Element	Rating of Limiting Element	Proposed Capital Budget Project	Next Limiting Element
Green Valley Substation 2.5 " aluminum tube bus	1981 ampes (789.2 MVA at 230 kV)	Replace the 2.5" aluminum tube bus at Green Valley Substation (Green Valley-RMEC 230 kV line) with a 5" aluminum tube bus having a rating of 3850 amps (1533.7 MVA at 230 kV)	Line conductor (bundled 954 kcmil) of the Green Valley-RMEC 230 kV line with a rating of 2422 amps (964.8 MVA at 230 kV with 4 ft/sec wind speed assumption).

These upgrades will be handled through the transmission upgrade projects in the PSCo Capital Construction Budget (2010-2014).

Network Resource (NR):

The results of this study indicate that the 50 MW increase in wind generation at CCWE delivered to the Keenesburg POI could result in the overloading of facilities in the PSCo regional transmission system. Therefore, the 50 MW NR value requested will require interconnection and Transmission Network Upgrades. After these upgrades are complete, the 50 MW generating station could be considered a network resource with firm transmission capability for the entire output of the plant to be delivered to load.

Energy Resource (ER):

The System Impact Study determined that firm transmission capacity for the 50 MW wind generation facility expansion is not available due to existing overloads and firm transmission commitments and is not possible without the construction of network reinforcements. Non-firm transmission capability may be available depending on marketing activities, dispatch patterns, generation levels, demand levels, import path levels (TOT3, etc.) and the operational status of transmission facilities.

Interconnection Requirements at the Point of Interconnection:

Interconnecting to the PSCo bulk transmission system involves the Customer adhering to certain interconnection requirements. These requirements are contained in the Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater than 20 MW (Guidelines). The Guidelines make reference to interconnection requirements from FERC Order 661A. FERC Order 661A describes the interconnection requirements for wind generation plants. In addition, PSCo System Operations conducts commissioning tests prior to the commercial in-service date for a Customer's facilities. Some of the requirements that the Customer must complete include the following:

1. A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the POI, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability.
2. The System Impact Study will investigate pertinent demand, dispatch, and outage scenarios based on the defined study area that includes the proposed POI. The study will conform to the NERC Transmission System Planning Performance Requirements (TPL standards).
3. The results of the System Impact Study (mentioned in Item 1 and 2 above) do not absolve the Customer from its responsibility to demonstrate to the satisfaction of PSCo System Operations prior to the commercial in-service date that it can safely operate within the required power factor and voltage ranges.
4. Reactive Power Control at the POI is the responsibility of the Customer. Additional Customer studies should be conducted by Customer to ensure that the facilities can meet the power factor control test and the voltage controller test when the facility is undergoing commissioning testing.
5. PSCo System Operations will require the Customer to perform operational tests prior to commercial operation that would verify that the equipment installed by the Customer meets operational requirements.
6. It is the responsibility of the Customer to determine what type of equipment (DVAR, added switched capacitors, SVC, reactors, etc.), the ratings (MVAR, voltage--34.5 kV or 230 kV), and the locations of those facilities that may be needed for acceptable performance during the commissioning testing.
7. PSCo requires the Customer to provide a single point of contact to coordinate compliance with the power factor and voltage regulation at the POI. The reactive flow at the end of 230 kV line near the POI will need to be controlled according to the Interconnection Guidelines

Item 1 makes reference to the wind generating plant maintaining a power factor within the range of 0.95 leading to 0.95 lagging, measured at the POI, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The System Impact Study examined the 50 MW expansion of GI-2007-5 along with the first phase of the Cedar Creek wind development (a 300.5 MW wind generation facility that became fully operational in December 2007). The study determined that the delivery of the full 350 MW minus losses to the POI can be accomplished within the 0.95 leading and lagging criteria as currently configured. As can be seen from Table 5 below, the facility is within criteria. With the CCWE at 350 maximum output, 336.7 MW is injected into the POI from the CCWE-Keenesburg 230 kV transmission line. The customer's facilities (line plus wind generation site) absorb 74.9 MVAR of reactive power, or a 0.976 leading power factor (CCWE-Keenesburg 230 kV line current leads the voltage at the POI). This level is within the 0.95 leading to 0.95 lagging power factor criteria.

With the RMEC units off-line, 336.9 MW is injected into the POI from the CCWE-Keenesburg 230 kV transmission line and the customer's facilities (line plus wind generation site) absorb 57.3 MVAR of reactive power, or a 0.986 leading power factor

(CCWE-Keenesburg 230 kV line current leads the voltage at the POI), still within criteria. However, the voltage at the Keenesburg 230 kV bus (POI) is less than the minimum accepted voltage (1.02 p.u.) for a controlled bus at 1.012 p.u. In order to maintain the voltage at Keenesburg within the 1.02 to 1.03 pu voltage range when the RMEC generation is not in operation or required to meet load, approximately 45 MVAR of switched capacitors are needed within the CCWE facilities.

Table 5 Reactive Power Results at the Keenesburg POI

	RMEC Generation Near Maximum		All RMEC Offline	
	No CCWE Generation	350 MW Generation at CCWE	No CCWE Generation	350 MW Generation at CCWE
Real Power Delivered to POI, MW	0.0	336.7	0.0	336.9
Reactive Power Delivered to POI, MVAR	16.4[5]	-74.9	19.8[5]	-57.3
Power Factor of CCWE Deliveries	0.0	-0.976	0.0	-0.986
Voltage at POI, pu	1.036	1.026	1.021	1.012[6]
Angle at POI, degrees	60.2	64.7	55.4	58.6
Voltage at CCWE 230 kV bus, pu	1.043	1.025	1.030	1.025

In the total absence of wind generation at the existing and proposed wind facilities, less than 20 MVAR of reactive power would be delivered to PSCo at the POI. This reactive power is due to the distributed capacitance of the customer transmission facilities. This condition reflects a scenario in which PSCo is delivering house power to the wind generation facilities. During these conditions, the power factor of the wind facility is approximately 0.0 lagging (assuming minimal house power). This power factor level is outside the 0.95 lagging to 0.95 leading required power factor range. To bring the power factor within range, an amount of reactive power of approximately 20 MVAR would need to be absorbed at the POI to account for line charging whenever the customer's wind turbines are generating minimal or no power while still connected to the system at the POI.

The voltage levels on the developer's 230 kV system and the PSCo system appear to be at acceptable levels. Based on the studies conducted, it appears that the addition of 20 MVAR of reactive power (inductors) and 45 MVAR of switched capacitors at the POI by the Customer from their facilities should allow the Customer to comply with the interconnection requirements.

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[5] With the DVAR at 0.0 MVAR at the Cedar Wind 300 MW generating facility

[6] The 1.012 p.u. voltage is outside 1.02 p.u. to 1.03 voltage range for 230 kV regulating busses in the Metro Denver-Boulder-Ft. Lupton region as defined in the Rocky Mountain Voltage Coordination Guidelines revised July 2006.

G. Dynamic Stability Analysis and Results

Transient stability studies determine the response of a transmission system to the occurrence of faults, tripping of generators, tripping of transmission lines, or tripping of loads. These studies evaluate generator frequency and internal generator rotor angles, bus voltages, and power flows before, during and after a disturbance to determine if the system remains stable after a disturbance. In addition, FERC Order 661A requires a wind generating plant to be able to remain on-line during voltage disturbances up to the time periods and associated voltage levels set for in the Low Voltage Ride-Through (LVRT) capability standard.

Transient stability analyses were performed. Three-phase fault contingencies in the study region were simulated for the study. For this analysis, dynamic models for the existing[7] Cedar Creek 300 MW facility reflecting the GE and Mitsubishi turbines along with the DVAR systems were used for both the case without the GI-2007-5 50 MW expansion project and the case without the GI-2007-5 50 MW expansion project. The machine models for the Clipper wind turbines were used for the 50 MW expansion project. No separate dynamic reactive power equipment, in the form of a CVAR system, was included for the GI-2007-5 project.

A number of severe system disturbances, in the form of 3-phase faults, close to the POI were studied. These are summarized in Table 6 below. The results of the simulations indicate that the system would be stable before, during and after the contingencies. All system oscillations were positively damped. All generation remained online after the fault was cleared except for those units isolated by the fault.

Table 6 Stability Results

Faulted End	Circuit Faulted	Result
Keenesburg	Keenesburg - CCWE 230 kV	Stable, generation disconnected
Keenesburg	Keenesburg - Green Valley 230 kV	Stable
Keenesburg	Keenesburg - RMEC 230 kV	Stable
CCWE 230 kV	One CCWE 167 MVA 230-34.5 kV transformer	Stable, generation disconnected

H. Costs Estimates and Assumptions

The estimated total cost for the required upgrades is approximately **$40,000.**

The estimated costs shown are (+/-30%) estimates in 2008 dollars and are based upon typical construction costs for previously performed similar construction. These estimated costs include all applicable labor and overheads associated with the engineering, design, and construction of these new PSCo facilities. This estimate did not include the cost for any other Customer owned equipment and associated design and engineering.

[7] The 300 MW Cedar Creek Wind Energy Project came on line in Colorado in October 2007.

This estimate does not include any network reinforcements that may be required to meet the interconnection guidelines as required by PSCo in the Interconnection Guidelines for Transmission Interconnected Producer-Owned Generation Greater than 20 MW (Guidelines). Other projects are included in the PSCo Capital Budget process and are assumed to be in-service by the commercial in-service date of the 50 MW expansion.

Since this project intends to use the interconnection for the existing 300 MW Cedar Creek Wind Facilities GI-2006-1(i) at the Keenesburg Substation, there will be only minimal costs of approximately $40,000 associated with the interconnection required for this 50 MW expansion project GI-2007-5.

The following tables lists the improvements required to accommodate the interconnection and the delivery of the Project. The cost responsibilities associated with these facilities shall be handled as per current FERC guidelines. System improvements are subject to change upon more detailed analysis.

Table 7 PSCo Owned; Customer Funded Interconnection Facilities

Element	Description	Cost Est. Millions
Keenesburg Switchyard	Miscellaneous work needed to interconnect the 50 MW expansion project: • Relaying and testing • SCADA/EMS modifications	**$0.04**
Total	**Transmission Provider's Interconnection Facilities**	**$0.04**
Time Frame	**Substation and Transmission**	**6 Months**

Table 8 PSCo Owned; PSCo Funded Interconnection Facilities

Element	Description	Cost Estimate (Millions)
Keenesburg Switchyard	**No interconnection facilities required**	**$0.00**
	Total Cost Estimate for PSCo-Owned, PSCo-Funded Interconnection Facilities	**$0.00**
Time Frame	**Site, engineer, procure and construct**	**0 Months**

Table 9 PSCo Network Upgrades for Delivery

Element	Description	Cost Est. (Millions)
PSCo's Transmission Network	**Transmission projects developed by PSCo through its capital budget process. These include:** • **Bundle the 1-1272 kcmil aluminum jumper at Washington Substation (Washington-JL Green 230 kV line) with a second 1272 kcmil aluminum**	N/A

Element	Description	Cost Est. (Millions)
	jumper. • Replace the 2.5" aluminum tube bus at Green Valley Substation (Green Valley-Keenesburg 230 kV line) with a 5" aluminum tube bus. • Replace the 2.5" aluminum tube bus at Green Valley Substation (Green Valley-RMEC 230 kV line) with a 5" aluminum tube bus.	
	Total Cost Estimate for PSCo Network Upgrades for Delivery	N/A
Time Frame	Network Upgrades for Delivery – to be constructed via the PSCo Capital Budget Construction Process and are expected to require approximately 12 to 18 months to complete.	N/A
	Total Cost of Project	$0.00

Assumptions

- The cost estimates provided are "Scoping Estimates" with an accuracy of +/- 30%.
- Estimates have not been escalated. Estimates are based on 2008 dollars.
- There is no contingency added to the estimates. AFUDC is not included.
- PSCo (or its Contractor) crews will perform all construction and wiring associated with PSCo-owned and maintained facilities.
- No new substation land required. Substation work to be completed within existing property boundaries.