Generator Interconnection Facility Study Report

for the

[redacted]

for

[redacted]

in

Malheur County, Oregon

January 3, 2023

FACILITY STUDY REPORT (FSR)

[redacted]

Project GI #622

January 3, 2023

1. General Facility Description

[redacted] ("Interconnection Customer") has stated that the proposed project will consist of three 218 MVA [redacted] in Malheur County, Oregon and connect to Idaho Power Company (IPC)'s and PacifiCorp's jointly owned 500 kV [redacted] transmission line. The total project output as studied is 600 MW. PacifiCorp is [redacted] is identified as an Affected Party to this Project. As an Affected Party and operator of the transmission line at the requested Point of Interconnection ("POI"), PacifiCorp will conduct its own Affected System studies for this Project and determine the scope, cost estimate and milestone dates for identified Network Upgrades and interconnection facility requirements.

Contact Information for Interconnection Customer is as follows:

[redacted]

A Standard Large Generator Interconnection Agreement (the "LGIA") under IPC's Open Access Transmission Tariff (OATT) between the Interconnection Customer and IPC (Transmission Provider) for the 600 MW [redacted], specifically Generator Interconnection Project #622 ("Project"), will be prepared for this Project. The LGIA will be a definitive agreement that contains terms and conditions that supersedes this FSR.

Project Queue and Affected Systems:

If an earlier queued project that is responsible for providing additional transmission capacity should drop out of the queue, a later queued project that may have been relying on at least a portion of any "surplus" capacity may then be faced with additional project costs for transmission capacity additions of their own. As of the date of this report, there are projects in the queue (GI #530, GI #551, GI #557, GI #567, GI #570 or GI #587, GI #588, GI #590, GI #604, GI #605, GI #619, GI #620, and GI #621) ahead of the 600 MW [redacted] for which costs related to transmission capacity upgrades or additions could be passed on to the Project should changes be made to their queue position or generation output.

Additionally PacifiCorp's interconnection GI C1-44 400 MW project, proposed to be connected to the [redacted]e 500 kV line, [redacted] east of [redacted] Substation, is recognized as a senior queued project to this Project.

1.1 Interconnection Point

The Interconnection Facilities are located [redacted] west of the Idaho-Oregon state border [redacted] in Malheur County, Oregon. Because the Project's requested connection point is on a 500 kV transmission jointly owned by Idaho Power and PacifiCorp but operated by PacifiCorp at the requested location, the details of the specific POI will be determined by PacifiCorp in its Affected System studies.

1.2 Point of Change of Ownership

The Interconnection Facilities are located [redacted] of the Idaho/Oregon state border near the coordinates [redacted] in Malheur County, Oregon. Because the Project's requested connection point is on a 500 kV transmission jointly owned by Idaho Power and PacifiCorp but operated by PacifiCorp at the requested location, the details of the specific POI will be determined by PacifiCorp in its Affected System studies.

1.3 Interconnection Customer's Facilities

The Interconnection Customer's Facilities [redacted] are located [redacted] northwest of IPC's Hemingway Substation. The Interconnection Customer will install the 500 kV tie line(s), hydro turbines, disconnect switches, distribution collector system, transformers (including main step-up transformers), appropriate grounding measures, and associated auxiliary equipment. Interconnection Customer will build 500 kV facilities to the Point of Change of Ownership.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Generator Output Limit Control

The Interconnection Customer will install equipment to receive signals from IPC Grid Operations for Generation Output Limit Control ("GOLC") - see Section 3 Operating Requirements and Appendix A.

1.4.2 Local Service

The Interconnection Customer is responsible to arrange for local service to their site, as necessary.

1.4.3 Generator Technical Information & Drawings

Interconnection Customer shall provide draft design prints during FSR development containing technical information, like impedances, and equipment brand and models. After construction, the Interconnection Customer shall submit to IPC all the as-built information, including prints with the latest approved technical information and commissioning test results.

1.5 Interconnection Facilities

Note because the Project's requested Point of Interconnection is on a transmission line jointly owned by Idaho Power and PacifiCorp but fully operated by PacifiCorp at the requested location, the interconnection facility requirements will be determined by PacifiCorp in separate Affected System Studies. The Interconnection Facilities will be jointly owned by Idaho Power and PacifiCorp and fully operated by PacifiCorp.

2. Estimated Milestones

These milestones will begin, and the construction schedule referenced below will only be valid, upon receipt of funding from Interconnection Customer or its authorized third party no later than the date set forth below for such payment. IPC will not commit any resources toward project construction that have not been funded by Interconnection Customer. Additionally, failure by Interconnection Customer to make the required payments as set forth in this Study by the date(s) specified below may result in the loss of milestone dates and construction schedules set forth below. In the event that the Interconnection Customer is unable to meet dates as outlined below, Interconnection Customer may request an extension of the Operation Date of up to three (3) years. Interconnection Customer's request will be evaluated by IPC to ensure Interconnection Customer's request does not negatively impact other projects in IPC's Generator Interconnection Queue. Such extension will be allowed only if IPC determines, in its sole discretion, that the extension will not negatively impact other projects in IPC's Generator Interconnection Queue. Estimated milestones, which will be updated and revised for inclusion in the LGIA in light of subsequent developments and conditions, are as follows:

Estimated Date	Responsible Party	Estimated Milestones
[DATE]	*Interconnection Customer*	*IPC receives Notice to Proceed.*
TBD	*PacifiCorp*	*Construction Agreement executed between Interconnection Customer and PacifiCorp*
6 months prior to Commissioning	*IPC*	*New generation must be modeled and submitted to the Western Energy Imbalance Market a minimum of 6 months prior to coming online, failure to submit by given lead time will results in project delay.*
TBD	*PacifiCorp*	*PacifiCorp Construction and Commissioning Complete*
5 days after switching request made to PacifiCorp Dispatch	*Interconnection Customer*	*Switch at the Point of Interconnection can be closed*
TBD	*Interconnection Customer*	*Interconnection Customer testing begins*

IPC does not warrant or guarantee the foregoing estimated milestone dates, which are estimates only. These milestone dates assume, among other things, that materials can be timely procured, labor resources are available, and that outages to the existing transmission system are available to be scheduled. Additionally, there are several matters, such as permitting issues and the performance of subcontractors that are outside the control of IPC and PacifiCorp that could delay the estimated Operation Date. For purposes of example only, federal, state, or local permitting, land division approval, identification of Interconnection Facilities location, access to proposed Interconnection Facilities location for survey and geotechnical investigation, coordination of design and construction with the Interconnection Customer, failure of IPC's or PacifiCorp's vendors to timely perform services or deliver goods, and delays in payment from Interconnection Customer, may result in delays of any estimated milestone and the Operation Date of the project. To the extent any of the foregoing are outside of the reasonable control of IPC or PacifiCorp, they shall be deemed Force Majeure events.

3. Operating Requirements

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-2014 *IEEE Recommended Practices and requirements for harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Project will be subject to reductions directed by IPC Grid Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving an analog setpoint via DNP 3.0 from IPC for GOLC. Generator Output Limit Control will be accomplished with a setpoint and discrete output control from IPC to the Project indicating maximum output allowed. For more detail see Appendix A.

Low Voltage Ride Through: The Project must be capable of riding through faults on adjacent sections of the power system without tripping due to low voltage. The interconnection projects must meet or exceed the Low Voltage Ride-Through requirements as set forth in NERC Standard PRC-024.

Frequency Response Requirements: Generator must be capable of providing Fast Frequency Response for both positive and negative frequency deviations from 60Hz (+/- 0.036 Hz) for Bulk Electric System disturbances. The required frequency response will be linear for a deviation of 0 to +/- 0.1 Hz, a response of 0% to 3% of generator capacity, with a maximum required response of 3% of generator's full capacity for as long as the generator is able to provide support or the frequency deviation is reduced to within stated limits, whichever occurs first. Provided that Generator meets the above Fast Frequency Response requirements, Company shall not curtail Interconnection Customer when such curtailments are caused by a need to comply with applicable Frequency Responsive reliability standards.

Momentary Cessation Requirements: Momentary cessation should not be used within the voltage and frequency ride-through curves specified in PRC-024. Use of momentary cessation is not considered "ride through" within the "No Trip" zone curves of PRC-024. The use of momentary cessation should be eliminated to the extent possible consistent with NERC's *Reliability Guideline for BPS-Connected Inverter-Based Resource Performance*

Interconnection Customer will be able to modify power plant facilities on the Interconnection Customer side of the Interconnection Point with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system and a terminal clearance is issued by IPC's Grid Operator. The specific point of isolation is identified in PacifiCorp's Facility Study Report for this Project.

4. Reactive Power

The Project must be capable of +/- 0.95 power factor operation, as measured at the high-side of the generator substation, for all MW production levels. The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from IPC for Voltage Control. The setpoint will be the desired voltage level as measured at the interconnect bus.

IPC will determine the reactive power required to be supplied by IPC to the Interconnection Customer, based upon information provided by the Interconnection Customer. IPC will specify the equipment required on IPC's system to meet the Facility's reactive power requirements. These specifications will include but not be limited to equipment specifications, equipment location, IPC-provided equipment, Interconnection Customer provided equipment, and all costs associated with the equipment, design, and installation of IPC-provided equipment. The equipment specifications and requirements will become an integral part of the LGIA. IPC-owned equipment will be maintained by IPC, with total cost of purchase, installation, operation, and maintenance, including administrative cost to be reimbursed to IPC by the Interconnection Customer.

5. Network Upgrades

IPC has no identified Network Upgrades associated with the Project as an ERIS interconnection. Network Upgrades to substations and transmission lines jointly owned by Idaho Power and PacifiCorp, but fully operated by PacifiCorp, will be identified in PacifiCorp's Affected System Studies.

It is anticipated that PacifiCorp may request IPC to provide scope and cost estimates for Network Upgrades of IPC's communication and protection systems as related to the scope and design of the interconnection station that PacifiCorp will detail in its Affected System studies. Unless and until PacifiCorp determines the scope, design and integration of the required interconnection station IPC is unable to provide any scope or cost estimation as of the date of this Facility Study.

6. Estimated Costs

All estimated interconnection facility and Network Upgrade costs will be identified in PacifiCorp's Affected System Studies for this Project.

Note Regarding Transmission Service:

This FSR is a study of a request for an Energy Resource Interconnection Service. This FSR identifies the facilities necessary to connect the Generating Facility to IPC's Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to transmission service or to deliver electricity to any specific customer or Point of Delivery.

Note Regarding LGIA:

This FSR is a study and preliminary evaluation only and does not constitute, or form the basis of, a definitive agreement related to the matters described in this FSR. Unless and until a LGIA is executed by IPC and the Interconnection Customer, no party will have any legal rights or obligations, express or implied, related to the subject matter of this FSR.

Appendix A

Generation Interconnection Control Requirements

A.1 Generator Output Limit Control (GOLC)

A.1.1 IPC requires Interconnected Power Producers to accept GOLC signals from IPC's energy management system ("EMS").

A.1.2 The GOLC signals will consist of four points shared between the IPC EMS (via the IPC RTU) and the Seller's Generator Controller ("SGC"). The IPC RTU will be the master and the SGC will be the slave.

A.1.2.1 GOLC Setpoint: An analog output that contains the MW value the Seller should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.

A.1.2.1.1 An Analog Input feedback point must be updated (to reflect the GOLC setpoint value) by the SGC upon the SGC's receipt of the GOLC setpoint change, with no intentional delay.

A.1.2.2 GOLC On/Off: A discrete output (DO) control point with pulsing Trip/Close controls. Following a "GOLC On" control (DNP Control Code "Close/Pulse On"), the SGC will run power output back to the MW value specified in the GOLC Setpoint. Following a "GOLC Off" control (DNP Control Code "Trip/Pulse On"), the Seller is free to run to maximum possible output.

A.1.2.2.1 A Discrete Input (DI) feedback point must be updated (to reflect the last GOLC DO Control Code received) by the SGC upon the SGC's receipt of the GOLC DO control, with no intentional delay. The feedback DI should latch to an OFF state following the receipt of a "GOLC OFF" control and it should latch to an ON state following the receipt of an "GOLC ON" control.

A.1.3 If a GOLC control is issued, it is expected to see MW reductions start within 1 minute and plant output to be below the GOLC Setpoint value within 10 minutes.

A.2 Voltage Control

A.2.1 IPC requires Transmission-Interconnected Power Producers to accept voltage control signals from IPC's EMS when they are connected to IPC's transmission system.

A.2.2 The voltage control will consist of one setpoint and one feedback point shared between the IPC EMS and the SGC.

A.2.3 The setpoint will contain the desired target voltage for plant operation. This setpoint will have a valid control range between 0.95 and 1.05 per unit ("p.u.") of nominal system voltage.

A.2.4 The control will always be active, there is no digital supervisory point like the Curtail On/Off control above.

A.2.4.1 When a setpoint change is issued an Analog Input feedback point must be updated (to reflect the voltage control setpoint value) by the SGC upon the SGC's receipt of the voltage control setpoint change, with no intentional delay.

A.2.4.2 When a setpoint change is received by the SGC, the voltage control system should react with no intentional delay.

A.2.4.3 The voltage control system should operate at the voltage indicated by the setpoint with an accuracy of +/- 0.5% of the nominal system voltage.

A.2.5 The Seller should supervise this control by setting up "reasonability limits", i.e. configure a reasonable range of values for this control to be valid. As an example, they will accept anything in the valid control range (between 0.95 and 1.05 p.u.) but reject values outside this range. If they were fed an erroneous value outside the valid range, their control system would default to the last known, good value.

A.3 Generation Interconnection Data Points Requirements

Digital Inputs to IPC (DNP Obj. 01, Var. 2)			
Index	Description	State (0/1)	Comments:
0	GOLC Off/On (Control Feedback)	Off/On	Feedback provided by Seller
1	FREQUENCY RESPONSE OFF/ON (Control Feedback)	Off/On	Feedback provided by Seller
2	52A Seller Main Breaker (if present)	Open/Closed	Sourced at substation
3	52A Seller Capacitor Breaker (if present)	Open/Closed	Sourced at substation

Digital Outputs to Seller(DNP Obj. 12, Var. 1)		
Index	Description	Comments:
0	GOLC Off/On	Control issued by IPC
1	Frequency Response Off/On	Control issued by IPC

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint Value Received (Feedback)	32767	-32768	TBD	TBD	MW	Provided by Seller
1	Voltage Control Setpoint Value Rec'd (Feedback)	32767	-32768	TBD	TBD	kV	Provided by Seller
2	Maximum Park Generating Capacity	32767	-32768	TBD	TBD	MW	Provided by Seller
3	Ambient Temperature	32767	-32768	327.67	-327.68	DEG C	Provided by Seller
4	Wind Direction	32767	-32768	327.67	-327.68	Deg from North	Provided by Seller
5	Wind Speed	32767	-32768	327.67	-327.68	M/S	Provided by Seller
6	Relative Humidity	32767	-32768	TBD	TBD	%	Provided by Seller
7	Global Horizontal Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Seller
8	Plane of Array Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Seller
9	SPARE						
10	SPARE						
11	SPARE						
12	SPARE						
13	SPARE						
14	SPARE						
15	SPARE						
16	SPARE						

17	SPARE						

Analog Outputs to Seller(DNP Obj. 41, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Control issued by IPC
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Control issued by IPC
2	SPARE						
3	SPARE						
4	SPARE						
5	SPARE						
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						