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June 28, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-108

Re: Docket No. UM 2032 – Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

Attention Filing Center:

Attached for filing in the above-captioned docket is the Joint Utilities' Response to NewSun Energy LLC's Motion to Compel Discovery.

Please contact this office with any questions.

Thank you,

Alisha Till

Alisha Till
Paralegal

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 2032

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities.	**JOINT UTILITIES' RESPONSE TO NEWSUN ENERGY LLC'S MOTION TO COMPEL DISCOVERY**

In accordance with OAR 860-001-420(4), Idaho Power Company (Idaho Power), Portland General Electric Company (PGE), and PacifiCorp dba Pacific Power (PacifiCorp) (together, the Joint Utilities) submit this Response to NewSun Energy LLC's (NewSun) Motion to Compel Discovery (Motion) filed on May 28, 2021.

Over five months have passed since the Administrative Law Judge (ALJ) Traci Kirkpatrick stayed these proceedings to accommodate NewSun's desire to file a motion to compel. Since the day NewSun issued its discovery requests that are the subject of this dispute, and throughout the time period since, the Joint Utilities have engaged in timely, responsive, and reasonable communications with NewSun about NewSun's requests and have provided responsive and appropriate materials consistent with the Public Utility Commission of Oregon's (Commission) discovery requirements. Now, months after the parties concluded their conferrals, and months after the Joint Utilities provided NewSun with supplemental responses to NewSun's discovery requests, NewSun has filed its Motion. The Joint Utilities respectfully request that the Motion be denied.

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In its Motion, NewSun argues that it cannot develop a position in this docket with respect to who "benefits" from Qualifying Facility (QF) Network Upgrades (and thus, in NewSun's view, who should be financially responsible for them), unless the Joint Utilities provide NewSun with more information than has been provided. NewSun states that it needs additional information related to two separate issues: (1) system benefits, and (2) validating differences between QFs and non-QFs.[1] First, the Public Utility Commission of Oregon (OPUC) Staff (Staff) has taken the position in its testimony, and the Joint Utilities and others have agreed, that an exploration of the "system benefits" question should be addressed in Phase II of this docket. Second, the Joint Utilities have again reasonably and appropriately responded to NewSun's data requests, providing significant and appropriate volumes of responsive material.[2] To the extent NewSun seeks additional information, NewSun's requests are unreasonably cumulative, duplicative, burdensome, outside the scope of this proceeding, or overly broad. NewSun has articulated no colorable explanation for its assertion that additional information is necessary or appropriate.

I. BACKGROUND

A. Despite the months-long history of NewSun's motion to compel, at every juncture the Joint Utilities have engaged in timely, responsive, reasonable communications with NewSun.

The Commission officially opened docket UM 2032 on September 10, 2019. Judge Kirkpatrick adopted an Issues List on May 22, 2020, and a Phase I procedural schedule on July 1, 2020. Discovery began shortly thereafter. The Joint Utilities filed Opening Testimony on August 24, 2020.

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[1] NewSun's Motion to Compel at 1-3 (Motion) (May 28, 2021).

[2] The Joint Utilities' responses to NewSun's "system benefits" DRs are attached hereto. Attachment A, UM 2032 Idaho Power Discovery; Attachment B, UM 2032 PGE Discovery; Attachment C, UM 2032 PacifiCorp Discovery.

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NewSun waited to seek intervention until October 14, 2020—over a year after the docket opened and only five days before Staff and intervenors were scheduled to file response testimony. Notably, NewSun's Petition to Intervene in this docket made the affirmation that NewSun's participation would not delay the docket. The Administrative Law Judge's ruling granting NewSun's intervention made this affirmation a condition of NewSun's participation. Staff and intervenors, including NewSun, filed Response Testimony on October 30, 2021. On December 11, 2020, Staff, the Joint Utilities, and intervenors filed Reply Testimony in accordance with the procedural schedule. NewSun elected not to file Reply Testimony.

NewSun issued its first discovery requests to each of the Joint Utilities on January 6, 2021, just 16 days before parties were scheduled to file the final round of testimony to close out Phase I of this docket. NewSun issued 47 data requests to PacifiCorp, 46 to PGE,[3] and 40 to Idaho Power, some of which had as many as 16 sub-parts.[4] Many of the discovery requests sought information that the Joint Utilities had already provided in response to earlier data requests from Staff and other parties.

Consistent with the Commission's rules, the Joint Utilities notified NewSun that they intended to object to several of the data requests and requested a conference with NewSun to discuss the objections and to seek clarification because many of the requests were vague and unclear. The Joint Utilities and NewSun conferred for the first time on January 19, 2021. That same day, NewSun filed a motion requesting another procedural delay to allow NewSun additional time to file testimony.

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[3] NewSun also requested supplemental information from PGE in an email dated May 11, 2021.
[4] *See* Attachment D, NewSun's Data Requests to the Joint Utilities.

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Despite the volume of NewSun's discovery requests, the Joint Utilities worked diligently to respond without requiring additional delays in the procedural schedule. The Joint Utilities provided responses on January 20, 2021.

On January 21, 2021, NewSun emailed Judge Kirkpatrick to inform her that NewSun intended to file a motion to compel. On that same day, Judge Kirkpatrick temporarily suspended the procedural schedule pending resolution of NewSun's motion to compel.

B. NewSun revised and clarified its data requests through the conferral process, which concluded on February 26, 2021.

Based on NewSun's representation that it intended to file a motion to compel, on January 27, 2021, the Joint Utilities reached out to NewSun to confer in an attempt to resolve the dispute, as required by the Commission's rule, OAR 860-001-0500(5). The Joint Utilities and NewSun scheduled a conference on February 9, 2021. The morning of February 9, 2021, NewSun asked to reschedule the conference for later in the week.

The discovery conference was then rescheduled to February 19, 2021. During the discussions, NewSun revised and clarified several of its data requests. For example, NewSun's data request (DR) 10 to PacifiCorp (PAC DR 10), NewSun's DR 9 to PGE (PGE DR 9), and NewSun's DR 8 to Idaho Power (IPC DR 8) requested extensive information related to "Network Upgrades" and therefore the Joint Utilities' discovery responses provided information related to Network Upgrades. During the conferral process, however, NewSun effectively revised the data requests by clarifying their intent was not to limit the request to just Network Upgrades, even though that is what the request stated.[5]

Following up on the February 19th conference, NewSun and the Joint Utilities agreed to continue discussions the following week. On February 22, 2021, NewSun emailed Judge Kirkpatrick to inform her that that the conferral process was ongoing. On February 26, 2021, the Joint Utilities and NewSun held their second and final discovery conference. During that conference, the Joint Utilities agreed to provide certain supplemental discovery responses based on NewSun's clarifications and NewSun's agreement to narrow the scope of certain requests.

C. The Joint Utilities provided supplemental discovery responses after the conferral process.

Based on the results of the conferral process, the Joint Utilities provided supplemental discovery responses in early March. The Joint Utilities provided supplemental responses in March 2021.

D. NewSun waited over three months to file its Motion.

After the conferral process concluded and the Joint Utilities provided supplemental responses, the Joint Utilities emailed NewSun on March 18, 2021, regarding the status of the motion to compel. NewSun responded that they were in the process of reviewing the supplemental discovery responses and expected to know more the following week.

The Joint Utilities then heard nothing from NewSun until May 11, 2021, when NewSun emailed several additional clarifying questions. The Joint Utilities responded and then on May 28, 2021, NewSun filed its Motion.

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[5] The term "Network Upgrades" has been defined by FERC in the interconnection context. It refers to interconnection-driven upgrades to a utility's transmission system (as opposed to its distribution system). The Joint Utilities noted this definition in their Opening Testimony. *See* Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/7 (Oct. 19, 2020); Staff and others have agreed this definition is appropriate. *See* Staff/100, Moore/7 at 7-10 (Oct. 30, 2020).

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II. LEGAL STANDARD

The Commission has adopted the Oregon Rules of Civil Procedure for contested case proceedings.[6] However, the Commission's specific discovery rules supersede these more general rules to the extent they are inconsistent.[7] In 2010, the Commission adopted several rules to "provide more thorough guidelines for discovery in Commission proceedings" by providing "general limits to discovery" requests.[8] OAR 860-001-0500(2) provides that: "Discovery that is unreasonably cumulative, duplicative, burdensome, or overly broad is not allowed.

Discovery is a feature of a contested-case proceeding. The purpose of contested-case proceedings is to allow the Commission to make a decision on a formal record where the parties have the opportunity to conduct discovery, offer testimony under oath, and provide the opportunity for cross-examination.[9] Contested-case proceedings are used by the Commission to address issues of significance where fact-finding is important, and to ensure that parties (1) have a fair opportunity to present evidence and argument on the issues raised, and (2) are able to respond to all evidence and argument offered by other parties.[10] The fact that the Commission uses contested-case proceedings in a particular docket does not open the door to discovery that is outside the scope of

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[6] OAR 860-001-0000(1); *Citizens' Util. Bd. of Or. v. Or. Pub. Util. Comm'n*, 128 Or App 650, 655 (1994) ("[The Commission] has adopted the Oregon Rules of Civil Procedure (ORCP) as its own procedure.").

[7] OAR 860-001-0000(1) ("The Oregon Rules of Civil Procedure (ORCP) . . . apply in contested case and declaratory ruling proceedings unless inconsistent with these rules, a Commission order, or an Administrative Law Judge (ALJ) ruling."); *see also Nw. Pub. Commc'ns Council v. Or. Pub. Util. Comm'n*, 805 F Supp 2d 1058, 1069 (D Or 2011) (acknowledging that written procedures under OAR 860 and the Oregon Rules of Civil Procedure govern discovery in Commission proceedings); *cf.* ORS 174.020(2) ("When a general provision and a particular provision are inconsistent, the latter is paramount to the former so that a particular intent controls a general intent . . . .").

[8] *In re Pub. Util. Comm'n of Or. Revisions to the Admin. Rules Regarding Practice & Procedure*, Docket No. AR 535, Order No. 10-400 at 18 (Oct. 14, 2010). AWEC's predecessor organization, the Industrial Customers of Northwest Utilities (ICNU), was a party to these rule changes and supported the changes to the discovery rules, which it characterized as "common sense revisions." Docket No. AR 535, ICNU Final Comments at 3 (Apr. 20, 2010).

[9] OPUC Internal Operating Guidelines at 15-16.

[10] *Id.*

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the docket, nor to discovery that is unreasonably cumulative, duplicative, burdensome, or overly broad.[11]

III. ARGUMENT

A. NewSun is entitled to no relief on its System Benefits DRs.

NewSun's "System Benefits DRs" [12] are data requests that NewSun describes as seeking "basic information on upgrades to the transmission system." NewSun argues that it needs the responses to understand the potential benefits of various types of Network Upgrades made to utility transmission systems so that it can develop its position that customers, rather than QFs, should be responsible for the costs caused by QF interconnections. NewSun argues that it is critical to obtain this information in Phase I of this docket.

In fact, the data requests as NewSun now describes them are not "basic," but incredibly onerous and, in some cases, impossible to answer. The data requests effectively ask the Joint Utilities to perform detailed audits of their historical transmission system investments going back nearly a decade; to provide NewSun with more detail on those transmission system investments than the Commission requires in order to evaluate their prudency in a rate case; and to conduct detailed studies on individual transmission system investments that, in some cases, the utilities have never performed.

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[11] OAR 860-001-0500(2).

[12] NewSun's "System Benefits" DRs encompass all of the following: Idaho Power Response to NewSun DR 8, PGE Response to NewSun DR 9, PAC Response to NewSun DR 10, collectively the "Transmission System Benefits DRs," Attachment A at 8-11, Attachment B at 3-6, Attachment C at 4-21; Idaho Power Response to NewSun DR 9, PGE Response to NewSun DR 10, PAC Response to NewSun DR 11, collectively the "No System Benefit DRs," Attachment A at 12, Attachment B at 9-10, Attachment C at 32-33; and PAC Response to NewSun DR 19, the "Prineville Load Service Study DR," Attachment C at 22-26.

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In addition, NewSun propounded a separate DR on PacifiCorp seeking detailed load service-study and assumption information for an area of PacifiCorp's system where PacifiCorp has made investments based on requests for load service, not generator interconnection. Responding to this DR would require PacifiCorp to effectively conduct an audit and restudy of its historical investments made under the Commission's policies for load service—an issue outside the scope of this docket—which NewSun attempts to justify as a "helpful case study" for the Commission on the benefits of non-interconnection-related transmission system investments.

As the Joint Utilities will explain, NewSun is entitled to no relief on its System Benefit DRs. First, to the extent NewSun's DRs are actually intended to support NewSun's testimony about what types of "system benefits" might be eligible for retail rate recovery, the DRs are either premature or too late, but either way will eventually necessitate some ALJ guidance on the scope of Phase I of this docket. Second, the DRs are overly burdensome and, in some instances, impossible to answer, and the information provided by each of the utilities is significant, reasonable, and more than enough to allow NewSun to develop its position in this docket.[13]

1. NewSun's "system benefit" requests are either premature or too late.

The parties' testimony filed to date has focused on the two issues identified for Phase I of this docket:

> (1) Who should be required to pay for Network Upgrades necessary to interconnect the QF to the host utility?
>
> (2) Should on-system QFs be required to interconnect to the host utility with Network Resource Interconnection [Service] (NRIS) or should QFs have the option to interconnect with Energy Resource Interconnection Service (ERIS) or an

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[13] The Joint Utilities believed, after conferral with NewSun, that the supplemental responses each of them provided to NewSun months ago would satisfy NewSun based on the parties' discussions. Counsel for the Joint Utilities appear to have misunderstood NewSun. Nevertheless, the Joint Utilities will focus on the substantive issue of whether NewSun's motion to compel is justified, which it is not.

interconnection service similar to ERIS?[14]

With respect to the first issue (the issue implicated by NewSun's "system benefit" arguments), the Joint Utilities took the position in testimony that the Commission's existing QF interconnection policies are appropriate and should be retained. That is, the Joint Utilities argued for the continuation of existing Commission precedent, which currently holds that QFs should be required to pay for Network Upgrades necessary to connect them to a host utility unless the QF can demonstrate "quantifiable system-wide benefits" that would entitle the QF to some level of reimbursement.[15]

In response, Staff filed testimony on October 30, 2020, that also generally supported retention of the Commission's existing policies, but noting that, with respect to Issue 1, Staff "is concerned that [the Commission's] policies for the treatment of Network Upgrade costs for QFs are not currently being implemented, or at least, is concerned with how they are implemented," in part because no methodology has been developed for identifying and calculating "quantifiable system benefits."[16]

Subsequent events are important for understanding the Joint Utilities' position on the issue of scoping Phase I, and for understanding why NewSun is incorrect in asserting that the Joint Utilities are seeking to unilaterally change the scope of Phase I (and thus unfairly limit the scope

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[14] ALJ Ruling: Issues List Adopted at 2.
[15] *See, e.g.,* Joint Utilities/300, Wilding-Macfarlane-Williams/6 (Dec. 11, 2020). Staff and some intervenors served broad discovery requests on the Joint Utilities seeking to understand the facts relevant to this inquiry almost two years ago, and by August 2019, the Joint Utilities began providing Staff and other intervenors with significant volumes of information responsive to those requests.
[16] Staff/100, Moore/6, 15. Around the same time Staff filed its testimony, approximately a year into the case, NewSun filed a petition to intervene. That petition was granted subject to the ALJ's condition that, "[NewSun's] participation will not unreasonably broaden the issues, burden the record, or delay the proceedings." ALJ Ruling: Petition to Intervene Granted (Oct. 28, 2020).

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of discovery in Phase I). Seeking to understand Staff's position on what types of "system benefits" might in Staff's view be eligible for retail rate recovery, PGE (on behalf of the Joint Utilities) propounded discovery asking Staff to explain how it believed such benefits might be identified or quantified—a critical issue the Commission must address in this docket if it agrees with Staff's position that QFs should be reimbursed for some type of benefit. Significantly, Staff responded that it was "not aware of a definition of system benefits that has been adopted by the Commission," and that "Staff proposes that a mechanism to identify and compensate QFs for the system benefits of any Network Upgrade above the QF's avoided Network Upgrade be addressed in Phase II."[17]

PGE (on behalf of the Joint Utilities) also asked Staff to provide more information about what types of benefits might be eligible for retail rate recovery, to identify who Staff believed to be the appropriate beneficiary (from a cost-allocation perspective) of a Network Upgrade under the Commission's policy (for example, must it be a retail customer? Could it be a transmission customer?) and asked Staff to explain how and when such a benefit could be quantified. Staff responded that "these are all good questions that Staff foresees addressing in Phase II of this investigation" because "Staff has not yet formed a position on these questions."[18] Staff further clarified that Phase II should investigate whether system benefits are related to serving retail load more efficiently and how one might value increases in the capacity of the transmission system.[19] *In short, Staff acknowledged that there was little or no clarity from the Commission on the "system benefits" issue, that Staff was not yet in a position to articulate its own position on the issue, and that Staff believed Phase II was the appropriate place for the issue to be investigated.*

[17] Joint Utilities/301 at 34-35; *id.* at 39-40.
[18] Joint Utilities/301 at 34-35.
[19] Joint Utilities/301 at 41.

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Parties filed their next round of testimony on December 11, 2020. By that point, Staff's position that the "system benefits" issue should be explored in Phase II was baked into the development of this docket. The Joint Utilities' testimony presumed this would be the case,[20] and testimony from others reflected this same understanding.[21] Notably, NewSun declined to file any testimony on December 11, 2020, and thereby declined to elevate its belief—now articulated strongly in its Motion—that the "system benefits" issue *must* be addressed in Phase I of this docket. Instead, NewSun sat silently on the sidelines while parties filed testimony that assented to Staff's position and assumed "system benefits" would be addressed in Phase II.

Having sat out a round of testimony where it could have made its position on this issue known, NewSun, along with the rest of the parties, approached the final round of testimony, which was due on January 22, 2021. As the end of the procedural schedule for testimony drew to a close, NewSun propounded extensive, burdensome discovery on the Joint Utilities, seeking voluminous amounts of information on a wide range of basic issues. Many of these data requests were ambiguous and unfocused; many ignored the volumes of information that have already been provided to other parties in this docket on the same issues; others were manifestly overbroad and unduly burdensome; still others went well beyond the scope of the docket; and finally, others asked for information that, if the data requests were read literally (as presumably they should be), would take extended periods of time for the Joint Utilities to answer, to the extent developing answers was possible. The Joint Utilities were required to respond to this discovery *two days* before the

[20] Joint Utilities/300 Wilding-Macfarlane-Williams/20.

[21] For example, Interconnection Customer Coalition (ICC) witness John Lowe stated in his December 11, 2020 testimony, "I believe the answer is clear that users and beneficiaries should pay the costs of Network Upgrades, and I support proceeding to a Phase II to explore options for ensuring this result." ICC/200, Lowe/4-5 (Dec. 11, 2020), Staff/100, Moore/35; Joint Utilities/300, Wilding-Macfarlane-Williams/6.

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final round of Phase I testimony was due, testimony that in theory would close out the record on Phase I of the docket.

Despite the overbroad, unduly burdensome, and manifestly objectionable nature of many of the requests, the Joint Utilities worked hard to provide NewSun with extensive amounts of responsive information while simultaneously finalizing their final piece of testimony. Before NewSun had even reviewed the Joint Utilities' responses, however, NewSun moved for a stay of these proceedings. The docket was then stayed for approximately four-and-a-half months.

Now, NewSun has filed a motion that vigorously argues the importance of addressing the issue of "system benefits" in Phase I of this docket[22] and asks the Joint Utilities to provide data related to whether and how other users and beneficiaries of the transmission system may benefit from transmission system upgrades.[23] Even if this issue were appropriate for Phase I given the development of the record in this proceeding and the expectations established by Staff's testimony, the Joint Utilities have provided NewSun with all the information it is reasonable for them to provide. The Commission should deny NewSun's motion, move this docket forward, and order parties to file their final round of testimony that, consistent with Staff's position, leaves investigation and development of the "system benefits" issue for Phase II.[24]

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[22] NewSun now argues that the Joint Utilities' objection amounts to a unilateral revision of the issues list. Motion at 6. NewSun's argument mischaracterizes the Joint Utilities' position and ignores the record.
[23] Motion at 5.
[24] Addressing the foundational issues related to "quantifiable system-wide benefits" in Phase II makes sense because the issues are all complex and important questions that must be answered before the Commission can adopt policies implementing a "quantifiable system-wide benefit" standard. Given that Staff has yet to form a position on these issues, the Joint Utilities agree that it is premature to include this issue in Phase I.

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2. If the ALJ deems NewSun's System Benefits DRs to be timely, the scope and schedule for Phase I of this proceeding will need to be reevaluated.

If, on the other hand, the ALJ agrees with NewSun's assertion that it is critical to investigate and address the issue of "system benefits" in Phase I of this docket, the Joint Utilities would ask the ALJ to reevaluate the schedule and scoping for completing Phase I. Before the Commission can decide whether certain interconnection-driven transmission system investments provide customer benefits sufficient to justify making retail customers responsible for those costs, rather than QFs, the Commission needs a robust record on the issue. As explained above, the Commission has not been clear about what types of "system benefits" it believes would qualify for retail rate recovery, a critical issue in this docket, nor how any such benefits might be quantified. If the issue is to be put before the Commission in this phase for resolution, all parties, including Staff, should be given an opportunity to take a position on the issue and have other parties engage with Staff's position on the record. With one round of testimony left in Phase I, the creation of an adequate record on this issue is not possible unless the schedule is reevaluated and additional rounds of testimony added.

3. The Joint Utilities responses were comprehensive, robust, and entirely adequate.

As the Joint Utilities will explain, even if the Commission concludes the "system benefits" issue should be addressed in Phase I, NewSun's Motion seeking additional information on the issue is baffling. The Joint Utilities have provided NewSun with extensive amounts of responsive data that is more than adequate for NewSun to develop and articulate its own view about what types of "system benefits" it believes the Commission should recognize as eligible for retail rate recovery. Requiring the Joint Utilities to provide anything beyond what has already been provided

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would add nothing meaningful to the inquiry and would only be additionally and unduly burdensome to provide.

B. The Joint Utilities responded appropriately to NewSun's Transmission System Benefit DRs (PAC DR 10, PGE DR 9, IPC DR 8).

In PAC DR 10, PGE DR 9, and IPC DR 8, NewSun asked the same question to each of the Joint Utilities:

> *For each network upgrade constructed since January 1, 2014, please provide:*
>
> *a. The cost of the network upgrade,*
>
> *b. Where [the utility] first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),*
>
> *c. How the network upgrade was funded (e.g., utility funded, queue number funded, other),*
>
> *d. Whether the network upgrade was included in rate base or whether [the utility] intends to include it in rate base,*
>
> *e. If the network upgrade was included in rate base, the rate of return earned on the network upgrade,*
>
> *f. The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others),*
>
> *g. The net increase or decrease in transmission customer rates that resulted from the network upgrade*

The Joint Utilities objected to these DRs on a number of grounds, including the fact that they were overly broad and unduly burdensome, but provided voluminous data in response to this request. Before responding to the request, the Joint Utilities also informed NewSun that subpart

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(f) (which NewSun claims is one of the "most crucial pieces of information"[25]) was vague because it was unclear what NewSun was asking for. Moreover, it appeared to ask for the utilities to conduct studies and develop extensive amounts of information the utilities either did not have or did not know how to develop. The Joint Utilities conferred with NewSun before the responses were due. NewSun was unable to provide any additional explanation of what it was specifically seeking and why the request was relevant. Thus, the Joint Utilities' responses maintained their objection to subpart (f) on the basis that its scope and meaning were unclear, and that it was overburdensome and inappropriate to the extent it was intended to require the utilities to develop some sort of new information.

1. During the conferral process, NewSun expanded its request and asked for specific additional information, which the Joint Utilities provided.

During the conferral process, NewSun complained that the Joint Utilities had applied a too-narrow interpretation of the term "Network Upgrades." The Joint Utilities interpreted the term "Network Upgrades" the way it has been defined through the course of this proceeding, and the way it has been defined by the Commission and the Federal Energy Regulatory Commission (FERC), and even by NewSun's own witnesses.[26] Specifically, "Network Upgrades" refers to investments in a utility's transmission system necessitated by a request for interconnection. In response to the information provided by the Joint Utilities, NewSun complained that when it was asking about "Network Upgrades," it did not mean interconnection-driven transmission system investments. It meant *any* kind of transmission system investment, made for any reason

[25] Motion at 7.

[26] See Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/7.

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whatsoever.[27] NewSun explained that it was seeking significantly more information—information related to all transmission system investments, even those that are not Network Upgrades. Regardless, during the conferral process NewSun ultimately narrowed its request in subpart (f) and asked the Joint Utilities to provide a list of major transmission system upgrades (not Network Upgrades) in Oregon, along with the cost of the upgrade and the reason for the upgrade.[28]

Following the conferral process, each of the Joint Utilities issued supplemental responses to the DRs in early March that they understood provided the information that NewSun had requested. NewSun never responded to the supplemental responses to indicate that they were deficient or that NewSun was still seeking additional information in response to PAC DR 10, PGE DR 9, and IPC DR 8.

NewSun now claims that the Joint Utilities' supplemental responses did not provide a sufficient description of the benefits each transmission system upgrade provided to their system. It is unclear, however, what more the Joint Utilities could provide to explain the need for the types of transmission system upgrades. For example, Idaho Power's responses indicate that the majority of the 34 transmission system investments identified were made for maintenance purposes or to replace aging infrastructure. PacifiCorp referred NewSun to the testimony in its recent rate case where PacifiCorp explained the reasons for all of its major transmission investments since 2014. It also provided NewSun with a spreadsheet of PacifiCorp's smaller pro forma transmission system investments annotated with the justification for including each of the investments in retail rates.

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[27] Motion at 7.

[28] Specifically with respect to PacifiCorp's assertion that the DR, as a general matter, was manifestly overbroad and unduly burdensome given PacifiCorp's large, six-state system, NewSun clarified that it was not looking for the "Encyclopedia Britannica," but that a list of transmission system investments of various types and the rationale for their construction would suffice.

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PGE similarly provided NewSun a list of 19 transmission upgrade projects and the justifications for the upgrades, which primarily focused on the maintenance, repair, replacement or building of equipment to address damaged or aging infrastructure. It was the Joint Utilities' understanding, after conferral with NewSun, that this information would be adequate. To the extent NewSun has not yet developed a position for why QF Network Upgrades should be paid for by retail customers, it is not due to a lack of data.[29]

2. The Joint Utilities provided voluminous data related to interconnection-driven Network Upgrades.

NewSun argues that, "[l]imiting discovery to only interconnection-driven network upgrades does not provide an adequate data set to analyze the types of benefits that transmission level upgrades provide."[30] The data set is adequate. The Joint Utilities have provided extensive interconnection-driven Network Upgrade data for facilities on their systems,[31] including information regarding the facility size, location, Network Upgrade costs, the applicable funding mechanism, interconnection studies, etc. NewSun fails to explain why this information is insufficient to allow it to develop its position in this docket.

Moreover, NewSun's repeated request to require the Joint Utilities to better articulate, quantify, or otherwise demonstrate the *benefits* of transmission system investments assumes the Joint Utilities collect some type of information beyond what the Joint Utilities actually have, and misunderstands how the utilities evaluate and analyze potential system upgrades. The Joint

[29] Indeed, when Staff was asked to define "system benefits," they could not do so because it depends on a myriad of factors that in the context of this docket remain unclear.
[30] Motion at 11.
[31] PGE informed NewSun that PGE has not constructed any Network Upgrades—as that term is defined by FERC—on its transmission system associated with a generator interconnection since 2010. However, after conferral with NewSun, PGE understood NewSun to be requesting transmission upgrades more broadly. Accordingly, PGE provided NewSun information for 19 major transmission upgrades since 2018.

Utilities evaluate their transmission systems based on the regulatory requirements imposed on them (requirements for reliability, least-cost load service, etc.) and conduct studies required by FERC or the Commission. Utilities do not go beyond those requirements by studying and evaluating each possible Network Upgrade for any additional potential benefit it *might* bring, and thus the Joint Utilities cannot provide such information to NewSun. As explained in the Joint Utilities' testimony, it is unclear how a utility would quantify the benefit of a specific transmission system investment because utilities do not decide where and when to make transmission system investments by ascribing a quantifiable value to increased capacity of the system, for example, and how to use that quantification to drive investment decisions.[32] In short, it is simply unclear how the utilities can describe the benefits of specific transmission system investments in more detail than was already provided.

3. Individual Utility Responses to the "Transmission System Benefit" DRs (PAC DR 10, PGE DR 9, IPC DR 8).

a. IPC DR 8

In its initial response to IPC DR 8, Idaho Power reasonably understood that the request asked for information related to only Network Upgrades. Therefore, Idaho Power provided the following:

Idaho Power referred to the data previously provided in response to OPUC DR 12.[33] Idaho Power's response to OPUC DR 12 addressed every interconnection-driven Network Upgrade since 2010 and identified the location of the upgrade, the jurisdiction, the cost, how the Network Upgrade was funded (i.e., who paid and whether it was upfront), and whether there was cost

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[32] Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/10.

[33] Idaho Power Response to OPUC DR 12, Attachment A at 18-22.

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reimbursement. The provided data covered 81 different interconnection customers in both Oregon and Idaho.

Idaho Power also included an attachment as part of its response, which NewSun did not include with the Motion. The attachment[34] provided yet more information related to 47 interconnections. The attachment identifies the project interconnection queue number, the state, project ownership, who had jurisdiction over the interconnection, Network Upgrade costs, type of interconnection service, nameplate capacity, and generator type.

In addition to the information provided in response to OPUC DR 12, NewSun also had access to Idaho Power's response to OPUC DR 13, which identified all Network Upgrades constructed between 2001 and 2019 that are included in Idaho Power's rate base.[35]

NewSun also had access to Idaho Power's response to Northwest and Intermountain Power Producers Coalition (NIPPC) DR 7,[36] which provided the following information for every QF that has interconnected to Idaho Power's system in Oregon the last six years: queue number, project name, interconnection service type, nameplate capacity, generator type, interconnection study costs, interconnection actual costs, explanation of variances between estimated and actual interconnection costs, Network Upgrade estimated cost, Network Upgrade actual costs, explanation of variances between estimated and actual Network Upgrade costs, and project owner.

Even though NewSun's data request referenced only Network Upgrades, Idaho Power's response also pointed NewSun to information that is publicly available on its OASIS site that

[34] Idaho Power Response to OPUC DR 12 Attach, Attachment A at 21-22.
[35] Idaho Power Response to OPUC DR 13, Attachment A at 23.
[36] Idaho Power Response to NIPPC DR 7, Attachment A at 24-25.

identifies all of Idaho Power's transmission system investments going back to October 2015 that were greater than $250,000.

Idaho Power's response also explained how Network Upgrades (and transmission system investments generally) are identified. The Joint Utilities' testimony further explained generally how transmission system investments are identified through rigorous transmission system planning processes.[37] Idaho Power further explained when Network Upgrades are included in rate base and identified its current rate of return, which has been in effect since 2012.

In response to subpart (f), which asked for the "incremental transmission operations resulting from the Network Upgrade," Idaho Power objected because it was unclear what the request referred to. During the conferral process, Idaho Power learned that NewSun's request was intended to encompass upgrades to the transmission system more broadly—not just Network Upgrades associated with interconnection or transmission service, as that term has been defined by FERC and used by the Commission and parties to this proceeding. Specifically, Idaho Power understood that NewSun sought information regarding major transmission system upgrades Idaho Power has completed in Oregon, the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects it is interested in, NewSun mentioned constructing a new transmission line, reconductoring a transmission line, constructing a new substation, and adding breakers, disconnects, or communications equipment. In response, on March 8, 2021, Idaho Power issued a supplemental response to subpart (f) that provided the information NewSun had requested as part of the conferral process.

[37] *See, e.g.,* Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/17-20.

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b. PGE DR 9

For DR 9, PGE reasonably understood that the request asked for information related only to Network Upgrades. In its initial response, PGE directed NewSun to PGE's Responses to OPUC Data Request Nos. 12 and 13 where PGE informed Staff that PGE has not constructed any Network Upgrades on its transmission system associated with a generator interconnection since 2010.[38] After conferral with NewSun, PGE understood that NewSun's requests were intended to encompass upgrades to the transmission system more broadly—not just Network Upgrades associated with interconnection or transmission service, as that term has been defined by FERC and used by the Commission and parties to this proceeding. Specifically, PGE understood that NewSun was seeking information regarding "major" transmission system upgrades PGE has completed, the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects it is interested in, NewSun mentioned constructing a new transmission line, reconductoring a transmission line, or constructing a new substation.

Because NewSun's requests used the term "network upgrades," which are the subject of this docket, PGE maintains that its initial responses were complete and adequate. Based on PGE's new understanding that NewSun's requests in DR 9 were intended to encompass upgrades to the transmission system more broadly, PGE objected that the requests were overly broad and unduly burdensome. PGE also objected that the information requested in DR 9 relates to an issue that PGE understands is outside the scope of Phase I and may be addressed in Phase II of this proceeding.

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[38] PGE Response to NewSun DR 9, Attachment B at 4; *see also* PGE Response to OPUC DR 12, Attachment B at 7 ("PGE has not constructed any Network Upgrades on its transmission system associated with generator interconnection that the Company included or sought to include in its most recently filed general rate case."); PGE Response to OPUC DR 13, Attachment B at 8.

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Notwithstanding and without waiving these objections, PGE provided NewSun Attachment 009 and 018A , which contains 19 major transmission upgrades PGE has constructed since 2018, along with the cost of the upgrade and the reason for the upgrade. Without providing any argument or evidence why PGE's supplemental response fails to address NewSun's request to receive information concerning "comparable transmission system upgrades",[39] NewSun has not provided in the Motion any basis for burdening PGE with additional discovery.

c. PAC DR 10

In its initial response to PAC DR 10, PacifiCorp reasonably understood the term "Network Upgrades" to refer to generator interconnection-driven Network Upgrades as defined by PacifiCorp's Open Access Transmission Tariff (OATT), a definition that Commission Staff, the Joint Utilities, and even NewSun's witnesses[40] have used throughout the course of this docket. With that understanding, PacifiCorp provided NewSun with information regarding Network Upgrades identified in interconnection studies, and publicly available on PacifiCorp's OASIS, and referred NewSun to PacifiCorp's responses to OPUC data requests propounded in this docket, including OPUC DRs 13 and 14, which provided extensive information on subparts (a) through (d). Finally, PacifiCorp provided specific answers to subsections (d) and (e).[41] PacifiCorp also

[39] Motion at 11.
[40] *See* NewSun Response to PGE DR 32, Attachment B at 140.
[41] *See* PAC Response to NewSun DR 10, Attachment C at 4-7. PacifiCorp's response to OPUC DR 13 addressed every interconnection-driven deliverability Network Upgrade since 2010 and identified the location of the upgrade, the jurisdiction, the cost, how the Network Upgrade was funded (i.e., who paid and whether it was upfront), and whether there was cost reimbursement. PAC Response to OPUC DR 13, Attachment C at 34-44. In addition to the information provided in response to OPUC DR 13, NewSun also had access to PacifiCorp's response to OPUC DR 14, which addressed Network Upgrades constructed since 2010 that are included in PacifiCorp's rate base. PAC Response to OPUC DR 14, Attachment C at 45-48. NewSun also had access to PacifiCorp's response to NIPPC DR 8, which provided the following information for every QF that has interconnected to PacifiCorp's system in the last 30 years: queue number, project name, interconnection service type, nameplate capacity, generator type,

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objected to NewSun DR 10 on various grounds, including that certain information requests were overly broad and unduly burdensome, and that subpart (f) was vague and ambiguous. With respect to subpart (f), it was not evident what "incremental transmission operations resulting from the Network Upgrade" was intended to address; moreover, this subpart was inappropriate to the extent it might require PacifiCorp to conduct some unspecified new studies of its multi-state system.

During the conferral process, NewSun explained that its DRs were not limited to "Network Upgrades," despite their saying so, and stated that NewSun was seeking detailed information on *any* type of transmission system upgrade PacifiCorp may have constructed on its large, multi-state transmission system over the past seven years. When PacifiCorp explained during the conferral process that the requests, even if otherwise appropriate, would require a massive undertaking that could take months to perform on such a huge system, and that they were far too broad, PacifiCorp understood NewSun to significantly scale back the scope of its request to a "representative list" of transmission system upgrades and an explanation for the cost-recovery rationale for each upgrade. Specifically, PacifiCorp understood that NewSun sought information regarding major transmission system upgrades PacifiCorp has made on its system, including the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects it is interested in, NewSun mentioned constructing a new transmission line, reconductoring a transmission line, constructing a new substation, and adding breakers, disconnects, or communications equipment.

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interconnection study costs, interconnection actual costs, explanation of variances between estimated and actual interconnection costs, Network Upgrade estimated cost, Network Upgrade actual costs, explanation of variances between estimated and actual Network Upgrade costs. PAC Response to NIPPC DR 8, Attachment C at 51-55.

Following the conferral process, on March 5, 2021, PacifiCorp provided NewSun with information it believed was responsive to NewSun's comments.[42] Nevertheless, PacifiCorp pointed NewSun to PacifiCorp's recent rate case testimony, in which PacifiCorp filed testimony supporting all of its major transmission system investments made since 2013, and also provided NewSun with a 14-page chart identifying each of PacifiCorp's pro forma, smaller transmission system investments as a robust, representative sample of the types of transmission system investments utilities make and the rationale for their construction.[43] The chart identified the investment, the cost of the investment, the rationale for the investment, and its location on PacifiCorp's system. As NewSun noted, "PacifiCorp listed over 80 categories of upgrades and discussed each category's high-level system benefits."[44]

Now, NewSun argues that PacifiCorp's response is inadequate to assist in developing its testimony on the potential "system benefits" of QF interconnection-driven Network Upgrades. According to NewSun, NewSun needs detailed information across PacifiCorp's six-state transmission system detailing transmission system investments that "*is only slightly more detailed that [sic] what PacifiCorp was able to provide in its rate case[.]*"[45] This request is overbroad and unduly burdensome. NewSun has the tools and information to take a position on what types of interconnection-driven Network Upgrades should be entitled to retail cost recovery (the issue at hand) with the information in its possession, without requiring PacifiCorp to conduct an audit of

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[42] PacifiCorp did so despite PacifiCorp's view that the rationale underlying interconnection-driven Network Upgrades (the subject of this docket) is completely different from the rationale supporting construction of many other types of transmission system upgrades.
[43] PAC Response to NewSun DR 10, Attachment C at 4-21.
[44] Motion at 11.
[45] Motion at 12 (emphasis added). PacifiCorp's recent rate case addressed PacifiCorp's capital investments since 2013.

all of its historical transmission system investments and deliver more information to NewSun than the Commission requires in a rate case.[46]

A review of the material provided to NewSun makes clear that PacifiCorp provided NewSun with a tremendous volume of information regarding Network Upgrades, the focus of this docket, and also a robust set of information describing PacifiCorp's transmission system investments. Moreover, PacifiCorp has provided extensive amounts of additional information to NewSun, Staff, and NIPPC in discovery on transmission system investments made to accommodate generation, their cost treatment, the rationale for that treatment, and more. Please see Attachment E, UM 2032 PacifiCorp Summary of Key Discovery at, for a list of the extensive amounts of information PacifiCorp has made available to parties (including NewSun) in this docket on this issue.

C. PacifiCorp responded appropriately to NewSun's "Prineville Load-Service Study" DR (PAC DR 19).

In a single DR directed only to PacifiCorp, NewSun seeks volumes of information specifically related to PacifiCorp's investments made to serve new retail customer load in the Prineville area.[47] NewSun has characterized PAC DR 19 as another "system benefits" question. In this DR, however, NewSun seeks extensive information about retail load-service-related investments (a through g), transmission service rights (h and j), avoided-cost rates (k and l), wholesale power contract rates (l), the viability of hypothetical commercial transactions and their associated revenues (l and m), and copies of a variety of types of correspondence (n) related to the

[46] It is not even clear how this large amount of information—on top of similar information in NewSun's possession—would add to NewSun's ability to articulate how QF-driven Network Upgrades should be entitled to retail rate recovery.
[47] PAC Response to NewSun DR 19, Attachment C at 22-26.

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Prineville area of PacifiCorp's system—an area NewSun claims "could provide a useful case study," but where PacifiCorp understands NewSun may have significant commercial interests.[48] The information sought in PAC DR 19 is both overly broad and incredibly detailed. It seeks at various points irrelevant, highly commercially sensitive, and incomprehensive information. NewSun's Motion should be denied with respect to PAC DR 19.

1. NewSun's DR 19 to PacifiCorp.

NewSun's DR 19 stated as follows:

> *Regarding PacifiCorp's Ochoco to Corral transmission line and associated upgrades to PacifiCorp's system and substations, and PacifiCorp's load service in the Prineville area, please provide:*
>
> *(a) Where PacifiCorp identified the need for the upgrades (e.g., load growth, interconnection request, transmission request, or other),*
>
> *(b) How the upgrades were funded (e.g., utility funded, queue number funded, other),*
>
> *(c) The existing load and forecast load upon which PacifiCorp relied in justifying the upgrade, including the MVa rating of the loads that triggered the upgrades, including the dates of the associated load interconnection requests, the load initial and current projected on-line dates, and the status of each load service,*
>
> *(d) The cost of the upgrades,*
>
> *(e) How the upgrades were funded (e.g., utility funded, queue number funded, other),*
>
> *(f) Whether the upgrade were included in rate base or whether PacifiCorp intends to include it in rate base,*
>
> *(g) If the upgrades were included in rate base, the rate of return earned on the upgrades,*
>
> *(h) Describe how PacifiCorp serves its load in the Prineville area, including to what extent PacifiCorp relies on contiguous transmission from other areas of the PacifiCorp system, (i) Confirm whether the Prineville service area and Bend and Redmond service areas are electrically contiguous for PacifiCorp, and what the transfer capacity is within PacifiCorp's system in*

[48] During PacifiCorp's queue reform proceeding, NewSun indicated to the Commission that it was developing projects in the Prineville area. *See, e.g.,* Docket No. UM 2108, Transcript of August 12, 2020, Public Meeting at 90-91.

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the area, as well as what the transfer capacity and monthly average and peak energy service from BPA at each point of service from BPA in the area, including Pilot Butte and Ponderosa substation,

(j) Describe what long term rights PacifiCorp has on the California-Oregon Intertie (aka the COI aka the AC Intertie) and how PacifiCorp uses these rights and other short term procurement via the COI to serve Prineville area load,

(k) Provide a comparison for the Prineville area between when interconnections and loads were requested, including comparative timing, along with the available avoided cost rates at the time of each request,

(l) Provide a summary of the power contract rates for facilities constructed or contracted to be constructed in the Prineville area, whether those facilities were ER or NR, what the likely network upgrades would have been for any ER facility that was (or is being) constructed if it had been required to be NR instead. Compare the PPA prices for these facilities at the time of contracting with the avoided cost rates available to the QFs which sought interconnections and PPAs in this area,

(m) Please provide PacifiCorp's analysis based on the information in (k) and (l) as to whether the prospective QFs in its interconnection queue and/or otherwise seeking PPAs from PacifiCorp would have likely been economically viable based on these numbers were such facilities allowed ER interconnections and been allowed refundability of network upgrades. How does this compare to the number of actual facilities for which interconnection was requested in the Prineville area system (i.e. on lines directly connected to Ponderosa substation)? Please provide a total of all calculated revenues which would have been associated with any facilities which would have reasonably been likely to be economically viable per prior question; please make such calculations based on estimated facility energy production that would have resulted during the term of the resultant PPA using avoided cost pricing that would have been available at the time, and

(n) Provide copies of all correspondence, load service studies, upgrades requested, and upgrades implemented, including associated cost estimates and who paid for those upgrades, associated with PacifiCorp's service of the Prineville actual and prospective loads, particularly at Ponderosa substation, including a summary of all related lobbying efforts, contacts with BPA executive management, and contact with other elected officials, including the governor's office, Senator Merkely, Senator Widen, and Congressman Walden, and any related requests made for support or action by these officials related to load service in the Prineville area and the justifications for these requests. Please summarize the comparative timing of these upgrades relative to the PacifiCorp load queue requests and loads in service, associated capacities, and a comparison of any differences in

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how generation interconnection studies for the area treated load requests with respect to power flow studies and justification of network upgrades related to service of these load requests, whether such upgrades where performed by PacifiCorp or BPA.

2. PacifiCorp's initial response and supplemental response after conferral.

PacifiCorp objected to this data request on the grounds that the information sought is not reasonably calculated to lead to the discovery of admissible evidence in this docket, and that it is overly broad and unduly burdensome.[49] In PacifiCorp's view, the request, which seeks voluminous amounts of information related to load-service assessments; studies and engineering efforts related to accommodating customer load service requests; and PacifiCorp's communications with public officials, among other things, has no bearing on the issues in this docket. Moreover, the DR is not only outside the scope of this docket, it is breathtakingly sweeping.

Upon conferral with NewSun, PacifiCorp understood that the purpose of DR 19, like DR 10, was to seek more information about potential "benefits" of transmission system investments so that NewSun could formulate a position on why retail ratepayers, not QFs, should bear the costs of QF interconnection. Although PacifiCorp maintained its objections to DR 19 throughout the conferral process, PacifiCorp nevertheless offered to provide NewSun with additional information about PacifiCorp's transmission system investments to allow NewSun to understand why such investments are made, and how utilities justify them for rate recovery purposes. PacifiCorp supplemented its response to NewSun DR 10 with this information (see the prior discussion on

[49] PAC Response to NewSun DR 19, Attachment C at 22-23. In its supplemental response to DR 19, PacifiCorp understood DRs 10 and 19 to be seeking information for the same reason, and thus PacifiCorp also referred to its response to DR 10.

NewSun's DR 10 to PacifiCorp). PacifiCorp simultaneously supplemented its response to DR 19 as follows:

> *PacifiCorp reiterates its objections to this request. To the extent NewSun has identified this as a request seeking to understand the types of transmission system upgrades constructed by utilities and the rationale for such construction, notwithstanding and without waiving its objections, the Company responds as follows: Please refer to the Company's 1st Supplemental response to NewSun Information Request 1.10.*[50]

As noted above, PacifiCorp provided NewSun with extensive amounts of material related to the Network Upgrades constructed on its system in response to NewSun DR 10, and pointed NewSun to the information in PacifiCorp's most recent rate case describing PacifiCorp's transmission system investment since 2013. PacifiCorp also provided NewSun with a 14-page chart detailing, as NewSun notes, "over 80 categories of upgrades and discussed each category's high-level system benefits."[51]

3. NewSun's Motion.

Despite having access to significant amounts of data and information relevant to the issues in this docket,[52] NewSun nevertheless continues to seek detailed information about every aspect of PacifiCorp's retail load service in the Prineville area on the grounds that NewSun lacks

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[50] PAC Supplemental Response to NewSun DR 10, PAC First Supplemental Response to NewSun DR 19, Attachment C at 6-10, 24-26.

[51] Motion at 11; Attachment C at 8-21. PacifiCorp has the largest transmission system of the Joint Utilities.

[52] *See* Attachment E, describing some of the types of information PacifiCorp, like the other utilities, has made available to the parties on these issues to date. NewSun now has access to volumes of information about PacifiCorp's generator interconnection studies, transmission service request studies, and its study processes copies of PacifiCorp Transmission's interconnection studies for PacifiCorp's state-jurisdictional QFs, including superseded studies and cost information related to those studies; information on cost allocation and rate treatment of interconnection and transmission costs; an interactive Excel spreadsheet allowing a party to calculate approximate retail rate impacts of any particular Network Upgrade cost; rate case information describing how and why PacifiCorp makes certain transmission system investments and the types of rationales it uses when seeking rate recovery; and more. It has detailed explanations for the difference between ERIS and NRIS, as well as the Joint Utilities' explanation for their own policy positions on QF Network Upgrade costs.

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sufficient information about the "benefits" of transmission system investments to make a case regarding how QF interconnection costs should be treated. NewSun contends that requiring PacifiCorp to undertake a massive, time-consuming, analysis and compilation of sweeping amounts of information related to its Prineville service territory "could provide a useful case study" for the Commission so the Commission might "understand the different types of transmission level upgrades and what types of benefits they convey to the system. [53]

PacifiCorp strongly disagrees. First, the Commission understands the benefits of constructing new facilities for retail customer load service. The primary task of a utility is to provide electric service to customers within its service territory, and the question of how to address the costs of serving a new customer is a question fundamental to utility regulation. The OPUC policy approved for PacifiCorp is reflected in PacifiCorp's Oregon Rule 13.

Second, to the extent NewSun wishes to argue that there should be parity in the way the Commission treats the costs needed to provide service to new retail customers and the way it treats Network Upgrade costs required to accommodate QF generation, NewSun has everything it needs to make that argument. It is unclear how undertaking a massive "case study" on load service in PacifiCorp's heavily constrained Prineville area would tend to prove or not prove any issue in this docket.

Third, the ERIS/NRIS discussion in NewSun's Motion does not support its point. NewSun seeks to connect DR 19 to the issues in this docket by stating that generators seeking NRIS in the Prineville area have had trouble obtaining interconnection service, whereas generators seeking

[53] Motion at 15.

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ERIS sometimes have had different results.[54] This is because NRIS, unlike ERIS, takes deliverability into account, and thus is a more comprehensive type of interconnection service. This is an uncontested fact in this docket, and it is the reason QFs are asking the Commission to allow them to obtain ERIS, rather than NRIS. The difference between ERIS and NRIS is discussed at length in the Joint Utilities' testimony and even in NewSun's testimony, and PacifiCorp has provided in discovery significant amounts of data on the issue.[55] Constraints in Prineville may indeed make interconnection more costly, particularly for NRIS, but NewSun does not need a "case study" to make the point. Moreover, a "case study" on Prineville load service is not probative of the ERIS/NRIS question, nor any other issue in this docket.

Finally, PacifiCorp would observe that NewSun's DR 19 goes far beyond a "case study" on how a utility addresses load-service requests. For example, a number of subparts of DR 19 question PacifiCorp's study assumptions for Prineville load service, apparently probing whether PacifiCorp is accurately studying its system when assessing a request to add a new retail customer. Some subparts ask broad questions about the potential commercial viability of QFs or other generators in the area, questions PacifiCorp cannot answer, while other subparts seek highly sensitive commercial data from PacifiCorp customers.

Finally, subsection (n) lacks focus entirely. Even if, hypothetically, the request sought a reasonable subset of information within the scope of this docket, it would nevertheless be impossible to answer, seeking "copies of all correspondence, load service studies, upgrades requested, and upgrades implemented, including associated cost estimates and who paid for those

[54] Motion at 16-17.
[55] *See e.g.,* NewSun/100, Rahman/9, 13-17 (Oct. 30, 2020) (describing ERIS and NRIS and noting the fact that NRIS includes any deliverability-driven Network Upgrades).

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upgrades, associated with PacifiCorp's service of the Prineville actual and prospective loads, particularly at Ponderosa substation, including a summary of all related lobbying efforts, contacts with BPA executive management, and contact with other elected officials, including the governor's office, Senator Merkely, Senator Widen, and Congressman Walden, and any related requests made for support or action by these officials related to load service in the Prineville area and the justifications for these requests. Please summarize the comparative timing of these upgrades relative to the PacifiCorp load queue requests and loads in service, associated capacities, and a comparison of any differences in how generation interconnection studies for the area treated load requests with respect to power flow studies and justification of network upgrades related to service of these load requests, whether such upgrades where performed by PacifiCorp or BPA."[56]

NewSun has offered no meaningful support for its motion to compel a response to DR 19; moreover, it may not have been forthcoming about the significant commercial interests it has in the Prineville area of PacifiCorp's system. If Judge Kirkpatrick is inclined to grant NewSun's Motion on any element of NewSun's DR 19, PacifiCorp respectfully requests that NewSun's request be narrowed to a request for some representative load service studies conducted in various locations on PacifiCorp's Oregon system, which would allow NewSun to understand how such studies are performed. To the extent Judge Kirkpatrick is inclined to grant NewSun's Motion in any other respect, and particularly to the extent Judge Kirkpatrick is inclined to order PacifiCorp to provide a "case study" on the Prineville area, PacifiCorp would respectfully request a discovery

[56] PacifiCorp believes DR 19 is wholly inappropriate and has not objected to each element of the DR in detail. Doing so would lengthen this response to a degree that PacifiCorp believes would be overly burdensome to the ALJ, and go beyond the limited explanations provided by NewSun in support of the DR. If, however, the ALJ believes the parties should engage on the details of NewSun's DR 19 with more specificity, PacifiCorp would respectfully ask for an opportunity to provide that additional detail.

conference involving only PacifiCorp and NewSun so that PacifiCorp can provide the basis for its understanding of NewSun's interests in the Prineville area of PacifiCorp's system on a confidential basis, and to discuss whether certain types of information sought by NewSun may require a heightened protective order.[57]

D. The Joint Utilities responded appropriately to NewSun's "No System Benefit" DRs (PAC DR 11, PGE DR 10, IPC DR 9).

The next set of NewSun DRs also addresses the issue of system benefits. In this set, NewSun asks each utility to study historical QF Network Upgrades and inform NewSun which of those QF-driven Network Upgrades provided *no benefit*. NewSun asked each utility the following:

> *Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?*

Each of the Joint Utilities responded to this question in essentially the same way—there are no QF-funded Network Upgrades that have provided benefits to the transmission system. Idaho Power' response stated:

> *Idaho Power objects that this request is overly broad and unduly burdensome. Idaho Power further objects that the phrase "any benefits to the transmission system" is vague and ambiguous. The Joint Utilities have explained their position regarding system-wide benefits in their testimony. Subject to and without waiving the foregoing, Idaho Power provides the following response: Any QF-funded network upgrades would be designed only as needed and necessary to interconnect the QF, and if the QF is selling its output to Idaho Power, to have the QF's generation be designated as a network resource. Upgrades related to QF interconnections are not driven by a need to meet other customer load or system capacity requirements.*[58]

PacifiCorp's initial response stated:

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[57] Due to regulatory restrictions, PacifiCorp is not free to publicly discuss any details of NewSun's commercial interests or how they may relate to the details of this data request.
[58] Idaho Power Response to NewSun DR 9, Attachment A at 12.

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PacifiCorp objects to this data request because the request is overly broad and unduly burdensome to the extent it asks PacifiCorp to analyze all qualifying facility (QF) funded Network Upgrades going back to 2005. Moreover, the phrase "any benefits to the transmission system" is vague and ambiguous. The term "benefits" is vague and has not been defined. Please refer to Joint Utilities/300, Wilding-Macfarlane-Williams/18-19. Please also refer to the Public Utility Commission of Oregon (OPUC) staff's response to PGE Data Request 05 (The Commission has never defined the term system-wide "benefits" as it applies to Network Upgrades incurred to interconnect QFs.).[59]

PacifiCorp supplemented the initial response on March 5, 2021, and stated:

In further support of the Company's response to NewSun Information Request 1.11 dated January 20, 2021, the Company responds further as follows:

PacifiCorp reiterates its objections to this request. Moreover, the data request relates to issues outside the scope of Phase 1 of this proceeding, and that may be addressed in Phase 2. Notwithstanding and without waiving its objections, the Company responds as follows:

Any qualifying facility (QF) funded network upgrade would be driven solely by a QF's interconnection and designed only as needed and necessary to interconnect the QF. Any qualifying facility (QF) funded network upgrade would be driven solely by a QF's interconnection and designed only as needed and necessary to interconnect the QF.[60]

PGE's response stated:

PGE objects that the phrase "any benefits to the transmission system" is vague and ambiguous. The Joint Utilities have explained their position regarding system-wide benefits in their testimony. Notwithstanding and without waiving this objection: PGE has not constructed any QF-funded Network Upgrades on its transmission system. Please see PGE's Response to Staff Data Request No. 12.[61]

NewSun takes issue with the objection proffered by PacifiCorp and PGE that "system benefits" is vague and undefined.[62] But NewSun entirely ignores the substantive responses that were provided by all the Joint Utilities notwithstanding the objections. Each utility responded that

[59] PAC Response to NewSun DR 11, Attachment C at 32.
[60] PAC Supplemental Response to NewSun DR 11, Attachment C at 33.
[61] PGE Response to NewSun DR 10, Attachment B at 9-10.
[62] Motion at 13-14.

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Network Upgrades required to interconnect QFs have not provided system benefits (regardless of how that term is defined). The Joint Utilities' response was consistent with their testimony, which described in detail why QF-driven Network Upgrades do not provide generalized system benefits,[63] and with other discovery responses provided to NewSun.[64] Because the Joint Utilities have already provided complete responses, there is nothing more to compel them to provide.

E. NewSun is entitled to no relief on its DRs intended to "validate practical differences and/ or similarities between QFs and non-QFs." (PGE DR 6, DR 7, DR 19; PAC DR 6, 8, 24; IPC DR 5, 7, 18).

NewSun groups the above-referenced DRs together as requests intended to "validate practical differences and/or similarities between QFs and non-QFs in terms of their PPAs, interconnections, and transmission arrangements."[65]

1. Idaho Power DR 5, 7, 18.

Although the Motion refers generally to IPC DRs 5, 7, and 18, Idaho Power understands that the relief sought applies to only IPC DR 7, which requested the following information:

For each generator that has submitted an interconnection application to Idaho Power from January 1, 2014 until present please provide the following:

a. Queue Number,

b. Project name,

c. Date of interconnection request,

d. Interconnection request status,

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[63] See, e.g., Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/17-20.

[64] *See, e.g.,* Idaho Power to NewSun DR 12, Attachment A at 13 ("Any upgrades identified and constructed in the QF interconnection process are required because they are necessary to provide adequate transmission or interconnection capacity for the interconnecting QF. In other words, when Idaho Power's interconnection studies of the QF indicate that upgrades are necessary, it is because they are necessary to provide adequate transmission or interconnection capacity. Upgrades related to QF interconnections are not driven by a need to meet other customer load or system capacity requirements.")

[65] Motion at 3.

e. Nameplate capacity,

f. Project location (county and state),

g. Generation technology type (wind, solar, etc.),

h. Whether the project requested interconnection as a QF selling 100% of its net output to Idaho Power (at initial application or at any point during the interconnection process) and whether it switched from this QF status to non-QF status, and the date it switched (or vice-versa, if it first requested interconnection as a non-QF and later switched to QF),

i. Any interconnection studies not publicly available online, including any prior studies which have been superseded by the studies that are posted on the website,

j. The interconnection agreement, if one was executed,

k. The developer or developers that submitted the interconnection application,

l. The in-service date, if operating, or scheduled commercial operation date if not,

m. Regarding NR and ER interconnection service:

1. Which service type was requested at initial application,

2. Which service type was studied in each of the Feasibility, System Impact, and Facilities studies,

3. Which service type the project ultimately interconnected under,

n. Regarding network upgrade costs (identified in ER or NR or both):

1. Estimated network upgrade costs in each of the Feasibility, System Impact, and Facilities studies,

2. Final network upgrade costs assigned to the generator,

3. Whether the network upgrades were ultimately constructed or are under construction,

o. Provide a comparative table for all interconnection requests showing the key features of ER/NR (initial and final), interconnection and network upgrade costs (initial and final), withdrawal status, GIA execution, operational status, and QF status.

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p. Summarize the comparative outcomes of ER interconnection vs NR interconnection applications as relates interconnection and generator outcomes for projects in the following GIR size ranges: 0-10, 11-20, 21-40, 41-60, 61-80. Indicate withdrawal rates and summary numbers, interconnection agreements signed, and average final interconnection costs including network upgrades.

In response, Idaho Power provided a detailed spreadsheet for 47 different projects that have requested interconnection in Oregon. Idaho Power understands from the Motion, that NewSun is requesting that Idaho Power provide the same information for all generators interconnected in Idaho as well. But NewSun has not explained why additional information is required, particularly given the burdensomeness of preparing that information.

NewSun suggests that obtaining Idaho data may be helpful because "different states' implementation could be informative."[66] But NewSun never identifies what those different implementation policies might be. Idaho Power explained that it applies the same interconnection practices and policies in both Oregon and Idaho, so there is no meaningful difference between those two states.[67] Without more, NewSun has not provided any basis for burdening Idaho Power with additional discovery given the volume of material that has already been provided.

2. PAC DR 6, 8, 24.

Although NewSun identified all three of these DRs as subjects of its Motion, PacifiCorp understands that NewSun is only seeking additional information regarding PAC DR 6. Specifically, NewSun asks the Commission to order PacifiCorp to expand the data set for which it provided responses to NewSun from Oregon, for which PacifiCorp provided all of the data

[66] Motion at 20.

[67] *See, e.g.,* Idaho Power Response to NewSun DR 5, Attachment A at 2-6 (explaining all QFs and non-QFs are designated network resources regardless of geographic location); Idaho Power Response to NewSun DR 20, Attachment A at 14 (explaining Oregon and Idaho study process and requirements); Idaho Power Response to OPUC DRs 5 and 6, Attachment A at 16-17.

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NewSun requested, to all six of PacifiCorp's states. As explained below, NewSun's request is unjustified.

In DR 6, NewSun asked for all power purchase agreements (PPAs) under which PacifiCorp purchases power including the following information: (a) Project name, (b) Nameplate capacity, (c) Term of power purchases, (d) Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other, (e) Whether the facility is certified as a qualifying facility under PURPA, (f) Under what interconnection rules/process the facility was interconnected, (g) Whether the facility interconnected as ERIS or NRIS, (h) The cost of Network Upgrades funded under the interconnection agreement, (i) Whether the generator is eligible to receive refunds for its Network Upgrades funded under the interconnection agreement, (j) The type of transmission service, (k) The entity that submitted the transmission service request, and (l) The cost of Network Upgrades funded under the transmission service request.

PacifiCorp objected to this data request on various grounds, including that it was overbroad and unduly burdensome, but nevertheless provided NewSun with information responsive to the request. During discovery conferences with NewSun, PacifiCorp learned that the intended purpose of a number of NewSun's requests and their multiple subparts was to elicit information that would allow NewSun to trace specific generators through the interconnection and transmission service request (TSR) processes. The information initially provided by PacifiCorp, though responsive to NewSun's data request as written, did not make these "linkages," because PacifiCorp did not understand that NewSun was asking it to make these connections. PacifiCorp explained during the conferral process that PacifiCorp does not compile information or keep records in this manner in the normal course of business, that making the "linkages" across would be challenging to compile for all PPAs, in the event it was even possible, and that it would require time-consuming

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investigation by PacifiCorp personnel and must be done one generator at a time. Thus, to the extent NewSun was asking PacifiCorp to "link up" generators associated with all PPAs from the interconnection process through the TSR process, PacifiCorp emphasized that the data request was overly broad and unduly burdensome[68]. To the extent NewSun further asked PacifiCorp to perform various types of analyses on each generator to generate data for NewSun about such linkages, the data request was likewise overly broad and unduly burdensome.

Nevertheless, and in spite of these objections, PacifiCorp personnel pulled information from all of its designated network resources (DNRs) in Oregon (a list of more than 70 projects, including all PPAs—QF or non-QF—under which PacifiCorp purchases power in Oregon), and provided a table "linking up" the interconnection queue numbers and TSR queue numbers for each facility, to the extent that information exists. The interconnection queue number allows NewSun to access the generator's interconnection studies on PacifiCorp's Open Access Same-Time Information System (OASIS), including detailed information about the generator, the generator's interconnection service request (including interconnection service type), and upgrades and upgrade costs identified by those studies. The associated TSR queue number allows NewSun to access the same generator's transmission service request on OASIS, including the requesting party, the type of transmission service requested, any upgrades needed to effectuate the transmission service, and the upgrade costs.[69]

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[68] *See* PAC Response to NewSun DR 6, Attachment C at 59-68.

[69] NewSun has access to *all* of the transmission and interconnection studies for all six of PacifiCorp's states, but because the interconnection and transmission queues are not linked, and because they do not identify generators by name (only by separately processed queue numbers), it is a challenge to "link up" the projects in the way NewSun requests.

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PacifiCorp understands from the Motion that NewSun is requesting that PacifiCorp provide the same information for all generators interconnected in Utah, Wyoming, Idaho, California, and Washington, as well. But NewSun has not explained why additional information is required, particularly given the burdensomeness of preparing that information. NewSun suggests that obtaining data from Utah, Wyoming, Idaho, California, and Washington may be helpful because "different states' implementation could be informative."[70] But NewSun never identifies what those different implementation policies might be. PacifiCorp has explained that it applies the same interconnection practices and policies in both Oregon and its other states, so there is no meaningful difference between them.[71] NewSun already has access to interconnection and transmission service studies from each of PacifiCorp's six states, all of which are available on OASIS. NewSun has not provided any basis for burdening PacifiCorp with additional discovery given the volume of material that has already been provided.

In any case, PacifiCorp's Oregon information set is robust and provides NewSun with all the information it needs to understand the relationships between interconnection studies (ERIS vs NRIS) and TSR studies, the explanation NewSun originally raised during the conferral process. NewSun has provided no explanation for why an even larger, more burdensome set of "linkages" is necessary to understand how the linkages between interconnection (ERIS vs NRIS) and TSR studies work, or how adding additional (but similar) information for QFs in Idaho, California, Wyoming, Utah, or Washington would move NewSun's understanding forward.

[70] Motion at 20.

[71] *See, e.g.,* PAC Response to NewSun DR 25, Attachment C at 81-82;PAC Response to OPUC DRs 7 and 8, Attachment C at 84-87.

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Moreover, to the extent NewSun is now arguing in its Motion that *another* purpose of the DRs was to "validate practical differences" between QFs and non-QFs, NewSun's Motion lacks merit. The Joint Utilities have provided massive amounts of information about how they are treated differently and why this is the case.[72] To the extent NewSun's DR is intended to probe the Joint Utilities' view on this point, the position the Joint Utilities have actually taken is that differential treatment of QFs and non-QFs is founded on the different regulatory schemes under which QFs and competitive generators operate. These differences include PURPA's must-take requirements (in lieu of any competitive requirements for QFs), its requirement that QF power be delivered on firm transmission, and FERC's prohibition on curtailing QFs except in system emergencies, among other things. NewSun has not shown how its overbroad and unduly burdensome request is designed to address this issue, or how its burdensome DRs would tend to demonstrate that the Joint Utilities' position on this point is more or less likely to be true.

Please see Attachment C, detailing the extensive information PacifiCorp has provided on the issue of the differences between QFs and non-QFs, their studies, the treatment of QFs and their Network Upgrade costs in each of PacifiCorp's states, the rationale for treating them differently from non-QFs, the potential cost-shifting that could result from treating QFs and non-QFs the same from a cost-responsibility perspective, etc. To the extent NewSun is asserting a lack of information on this issue as a rationale for ordering PacifiCorp to respond to its overly broad and unduly burdensome request, the assertion is unfounded.

[72] *See* Attachment E.

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3. PGE DR 6, 7, 19.

NewSun submitted DRs 6, 7, and 19 to PGE on January 6, 2020. PGE's discussions with NewSun, as well as PGE's initial and supplemental responses to NewSun DRs 6, 7, and 19 are discussed below.

a. PGE DR 6

NewSun's DR 6 to PGE requested the following:

Please list all power purchase agreements under which PGE purchases power including:

a. Project name,

b. Nameplate capacity,

c. Term of power purchases,

d. Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,

e. Whether the facility is certified as a qualifying facility under PURPA,

f. Under what interconnection rules/process the facility was interconnected,

g. Whether the facility interconnected as ERIS or NRIS,

h. The cost of network upgrades funded under the interconnection agreement,

i. Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,

j. The type of transmission service,

k. The entity that submitted the transmission service request,

l. The cost of network upgrades funded under the transmission service request.

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In its initial response, PGE objected that DR 6 is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.[73] Notwithstanding and without waiving these objections, PGE directed NewSun to PGE's Responses to NIPPC Data Request Nos. 1, 2, 3, 4, 7, 8, 31, and 33[74]; PGE's Response to OPUC Data Request Nos. 5, 8, and 12[75]; docket RE 143 (PGE's informational filing of QF contracts); and PGE's small and large generator interconnection queues, which are publicly available on OASIS.[76]

PGE asserted that it does not track and compile information regarding the interconnection arrangements of the resources from which it purchases under non-QF PPAs or the off-system QFs from which it purchases, and that all QFs directly interconnected to PGE are interconnected with NRIS.[77] Furthermore, PGE informed NewSun that it does not compile information regarding the off-system transmission arrangements of resources from which it purchases.[78] Finally, PGE informed NewSun that PGE has not constructed any Network Upgrades on PGE's transmission system associated with requests for transmission service from PGE.[79]

After conferral with NewSun, PGE understood that the intent of the requests in DR 6 was to allow NewSun to trace specific generators through the interconnection and transmission-service-request processes to evaluate the Joint Utilities' testimony that Network Upgrades can be shifted from the interconnection process to the transmission-service-request process when a

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[73] PGE Response to NewSun DR 6, Attachment B at 11-14.
[74] Attachment B at 11-14.
[75] Attachment B at 11-14.
[76] *See* PGE Response to NewSun DR 6, Attachment B at 11-14.
[77] PGE Response to NewSun DR 6, Attachment B at 11-14.
[78] PGE Response to NewSun DR 6, Attachment B at 11-14.
[79] PGE Response to NewSun DR 6, Attachment B at 11-14.

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generator interconnects with ERIS instead of NRIS. PGE noted that the potential for upgrade-shifting from the interconnection process to the transmission service request process that NewSun sought to confirm is a straightforward application of the OATT and related FERC orders, meaning that if deliverability-related upgrades are not studied and assessed during the interconnection process (*i.e.*, in the case of an ERIS interconnection), those deliverability-related upgrades would be studied and assessed during the transmission service request process if the generating facility is interconnecting to (and delivering on) the purchasing utility's system. In addition, PGE reiterated its objections that the additional information NewSun requested is voluminous and would be extremely burdensome to compile, if it were even available. However, PGE provided the following supplemental response in an effort to respond directly to the narrower question that PGE understood NewSun was asking:

> *As PGE has explained in testimony and in response to other data requests, all of PGE's on-system QFs [are] interconnected with NRIS. Of the on-system, non-QF resources that PGE owns or purchases power from, only one generator originally interconnected with ERIS. As PGE previously indicated in response to NewSun Data Request No. 20, "PGE's Port Westward 2 generating facility interconnected with ERIS. No network upgrades were required to designate Port Westward 2 as a network resource because sufficient transmission capacity existed on PGE's system to deliver the output to PGE's network load." Port Westward 2 is located near PGE's Port Westward 1 and Beaver facilities. When developing and interconnecting Port Westward 2, PGE's Merchant Function knew that it already possessed sufficient transmission capacity to deliver Port Westward 2's output to PGE's load and therefore decided to interconnect the facility using ERIS.*[80]

Finally, to the extent NewSun was interested in identifying the magnitude of Network Upgrades that could be shifted if a generator interconnected with ERIS, PGE directed NewSun to Attachment 001A to PGE's response to OPUC Data Request No. 1, which shows the

[80] PGE Supplemental Response to NewSun DR 6, Attachment B at 11-14.

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deliverability-driven Network Upgrades PGE has identified in system impact studies for two large generators, one of which is a QF with more than $10 million in deliverability-driven Network Upgrades.

On May 11, 2021, counsel for NewSun sent an email to counsel for the Joint Utilities requesting additional information. One of the requests, directed to PGE, was that PGE supplement its response to DR 6 by providing information that NewSun could use to link generation facilities that have a PPA to their interconnection and transmission arrangements. In a follow-up call, counsel for NewSun clarified that NewSun requested that PGE update its attachments provided in responses to NIPPC DR 1 and NIPPC DR 33 by providing queue numbers.

In its second supplemental response, PGE provided NewSun an updated Attachment A to NIPPC DR 1, which includes the queue number for projects where applicable. With respect to the projects listed on Attachment A to NIPPC DR 33, PGE informed NewSun that all of these projects except Covanta and Yamhill are off-system, and therefore do not have PGE queue numbers. Furthermore, PGE notified NewSun that both the Covanta and Yamhill projects predate the queue concept. Finally, in response to a question posed by counsel for NewSun in the May 11, 2021 email, PGE informed NewSun that if a generator wishes to negotiate a non-QF PPA, PGE does not check to determine whether or not that generator might be certified with FERC as a QF.

PGE understands its second supplemental response to have addressed NewSun's concerns identified in the Motion as NewSun has not otherwise indicated that PGE's second supplemental response to DR 6 was insufficient.[81]

[81] Motion at 20-21.

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Moreover, to the extent that NewSun requests that PGE make its interconnection studies publicly available on OASIS,[82] those studies were already accessible on OASIS or otherwise provided as attachments.[83] To help NewSun find the studies on the website, PGE provided a third supplemental response on June 16, 2021 describing the pathway to the interconnection studies for small QF generators and directed NewSun again to PGE's response to NIPPC DR 3, where PGE attached the interconnection studies and restudies for two large QF generators that identified Network Upgrades.

b. PGE DR 7

NewSun's DR 7 to PGE requested the following:

> *For each qualifying facility that has requested a power purchase agreement (PPA) with PGE from January 1, 2014 until present please provide the following:*
>
> *a. Project name,*
>
> *b. Date of PPA request,*
>
> *c. Nameplate capacity,*
>
> *d. Project location (county and state),*
>
> *e. Generation technology type (wind, solar, etc),*
>
> *f. Interconnecting utility,*

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[82] "NewSun is also not able to understand what types of upgrades were included in the interconnection and/or transmission studies because PGE's OASIS (unlike PacifiCorp and Idaho Power) does not make studies publicly available. PGE should therefore be required to produce those studies in this docket or otherwise make them publicly accessible on OASIS for use in this docket." Motion at 20-21.

[83] It is PGE's understanding that counsel for NewSun is referring to the folder for large QF interconnection studies, with the following pathway: Generation Interconnection → Interconnection Studies and Cases → Interconnection Studies and Cases Website. To comply with FERC Order No. 845 and requirements to protect customers' sensitive business information, interconnection studies for large projects are kept on a SharePoint website where access to the public is available by submitting a request form to PGE. Because of this security measure to protect customers' confidential information, PGE provided the relevant large QF interconnection studies identifying Network Upgrades as attachments in the Company's response to NIPPC DR 3, Attachment B at 28-112.

g. The power purchase agreement, if one was executed,

h. The developer or developers that requested or negotiated the power purchase agreement,

i. The in-service date, if operating, or scheduled commercial operation date if not,

In its response,[84] PGE objected that this request was overly broad and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

Notwithstanding and without waiving these objections, PGE directed NewSun to PGE's Response to NIPPC Data Request No. 1, docket RE 143, and provided Attachment 7A. Attachment 7A, in particular, is a table of existing and proposed PURPA QFs, which includes the project name, developer, project location, nameplate capacity, commercial operation date, and date the PPA was requested. Accordingly, without NewSun specifically detailing in the Motion how PGE's response to DR 7 is insufficient, NewSun has not provided any basis for burdening PGE with additional discovery.

c. PGE DR 19

NewSun's DR 19 to PGE requested the following:

Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

a. Queue Number,

b. Project name,

c. Date of transmission service request,

d. Transmission service request status,

[84] PGE Response to NewSun DR 7, Attachment B at 126-134.

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e. Nameplate capacity,

f. Project location (county and state),

g. Generation technology type (wind, solar, etc),

h. Type of transmission service,

i. Point of receipt and point of delivery,

j. Any transmission service request studies not publicly available online,

k. The transmission service agreement, if one was executed,

l. The in-service date, if operating, or scheduled commercial operation date if not,

m. Whether the output from the generator is delivered to PGE's retail load,

n. Whether the generator is a qualifying facility,

o. Whether the generator is on-system or off system,

p. Whether the generator is interconnected using ERIS or NRIS,

q. Regarding network upgrade costs:

1. Estimated network upgrade costs in any transmission service studies,

2. Final network upgrade costs assigned to the request,

3. Whether the network upgrades were ultimately constructed or are under construction[.]

In its initial response,[85] PGE objected that this request was overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

[85] PGE Response to NewSun DR 19, Attachment B at 135-138.

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Notwithstanding and without waiving these objections, PGE provided NewSun Attachment 19A for information regarding the confirmed, currently active, yearly, point-to-point transmission service requests, noting the following:

> *A point-to-point transmission service request is not associated with a specific generator. Therefore, PGE cannot respond to subparts (b), (e), (f), (g), (l), (m), (n), (o), or (p) for each transmission service request. To the extent this request is asking about network integration transmission service, a list of designated network resources is available on OASIS and in PGE's Response to NIPPC Data Request No. 1. All QFs directly interconnected to PGE received NRIS. PGE has not constructed any Network Upgrades on its system associated with requests for transmission service from PGE.*[86]

PGE further provided NewSun Confidential Attachment 19B.

In addition, PGE provided NewSun a supplemental response to DR 19, which mirrored PGE's supplemental response for NewSun's DR 6 to PGE (*see* above).

Without providing any argument or evidence why PGE's initial and supplemental responses to DR 19 are insufficient, NewSun has not provided any basis in the Motion for burdening PGE with additional discovery.

IV. CONCLUSION

The Joint Utilities have reasonably and appropriately responded to NewSun's data requests, providing significant and appropriate volumes of responsive material on each of the data requests for which NewSun seeks relief. To the extent NewSun seeks more information, NewSun's requests are either unjustifiably broad and unduly burdensome, or seek information the Joint Utilities simply do not have. NewSun has articulated no colorable explanation for its

[86] PGE Attach A to NewSun DR 19, Attachment B at 135-138.

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assertion that additional information is necessary or appropriate. The Joint Utilities respectfully ask that NewSun's Motion be denied.

Dated June 28, 2021

MCDOWELL RACKNER GIBSON PC

____

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 2032

Joint Utilities' Response to NewSun Energy

LLC's Motion to Compel Discovery

Attachment A

UM 2032 Idaho Power Discovery

June 28, 2021

Attachment A: List of Included UM 2032 Idaho Power Discovery

- UM 2032 Idaho Power Response to NewSun DR 005
- UM 2032 Idaho Power Supp Response to NewSun DR 005
- UM 2032 Idaho Power Response to NewSun DR 008
- UM 2032 Idaho Power Supp Response to NewSun DR 008
- UM 2032 Idaho Power to NewSun DR 008 Supp Attach
- UM 2032 Idaho Power Response to NewSun DR 009
- UM 2032 Idaho Power Response to NewSun DR 012
- UM 2032 Idaho Power Response to NewSun DR 020
- UM 2032 Idaho Power Response to OPUC DR 005
- UM 2032 Idaho Power Response to OPUC DR 006
- UM 2032 Idaho Power Response to OPUC DR 012
- UM 2032 Idaho Power Phase II Response to OPUC DR 012
- UM 2032 Idaho Power to OPUC DR 012 Attach (redacted)
- UM 2032 Idaho Power Response to OPUC DR 013
- UM 2032 Idaho Power Response to NIPPC DR 007
- UM 2032 Idaho Power to NIPPC DR 007 Attach

NEWSUN DATA REQUEST NO. 5:

Please list all power purchase agreements under which Idaho Power purchases power including:

a. **Project name,**
b. **Nameplate capacity,**
c. **Term of power purchases,**
d. **Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,**
e. **Whether the facility is certified as a qualifying facility under PURPA,**
f. **Under what interconnection rules/process the facility was interconnected,**
g. **Whether the facility interconnected as ERIS or NRIS,**
h. **The cost of network upgrades funded under the interconnection agreement,**
i. **Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,**
j. **The type of transmission service,**
k. **The entity that submitted the transmission service request,**
l. **The cost of network upgrades funded under the transmission service request.**

IDAHO POWER COMPANY'S RESPONSE TO NEWSUN DATA REQUEST NO. 5:

Idaho Power objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

Subject to and without waiving the foregoing objection, Idaho Power responds as follows: Idaho Power's responses to subparts a. – f. are in the table below:

a.	b.	c.	d.	e.	f.
Project Name	Nameplate Capacity	Contract Term	Contract Type	PURPA QF	Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")
American Falls Solar II, LLC	20.00	20	PURPA	Yes	Schedule 72
American Falls Solar, LLC	20.00	20	PURPA	Yes	Schedule 72
Arena Drop	0.45	20	PURPA	Yes	Schedule 72
Baker City Hydro	0.24	15	PURPA	Yes	Off-System
Baker Solar Center	15.00	20	PURPA	Yes	OCGIR
Bannock County Landfill	3.20	20	PURPA	Yes	Schedule 72
Barber Dam	3.70	35	PURPA	Yes	Schedule 72
Bennett Creek Wind Farm	21.00	20	PURPA	Yes	Schedule 72
Benson Creek Windfarm	10.00	20	PURPA	Yes	OCGIR
Birch Creek	0.07	20	PURPA	Yes	Schedule 72
Black Canyon #3	0.13	20	PURPA	Yes	Schedule 72
Black Canyon Bliss Hydro	0.03	20	PURPA	Yes	Schedule 72
Blind Canyon	1.63	20	PURPA	Yes	Schedule 72
Box Canyon	0.30	20	PURPA	Yes	Schedule 72

a. Project Name	b. Nameplate Capacity	c. Contract Term	d. Contract Type	e. PURPA QF	f. Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")
Briggs Creek	0.60	20	PURPA	Yes	Schedule 72
Brush Solar	2.75	20	PURPA	Yes	OCGIR
Burley Butte Wind Park	21.30	20	PURPA	Yes	Schedule 72
Bypass	9.96	35	PURPA	Yes	Schedule 72
Camp Reed Wind Park	22.50	20	PURPA	Yes	Schedule 72
Canyon Springs	0.11	20	PURPA	Yes	Schedule 72
Cassia Wind Farm LLC	10.50	20	PURPA	Yes	Schedule 72
Cedar Draw	1.55	20	PURPA	Yes	Schedule 72
Clear Springs Trout	0.56	20	PURPA	Yes	Schedule 72
Cold Springs Windfarm	23.00	20	PURPA	Yes	Schedule 72
Crystal Springs	2.44	35	PURPA	Yes	Schedule 72
Curry Cattle Company	0.25	15	PURPA	Yes	Schedule 72
Desert Meadow Windfarm	23.00	20	PURPA	Yes	Schedule 72
Dietrich Drop	4.50	35	PURPA	Yes	Schedule 72
Durbin Creek Windfarm	10.00	20	PURPA	Yes	OCGIR
Eightmile Hydro Project	0.36	20	PURPA	Yes	Schedule 72
Elk Creek	2.00	35	PURPA	Yes	Schedule 72
Fall River	9.10	35	PURPA	Yes	Schedule 72
Fargo Drop Hydroelectric	1.27	20	PURPA	Yes	Schedule 72
Faulkner Ranch	0.87	35	PURPA	Yes	Schedule 72
Fighting Creek Landfill Gas	3.06	15	PURPA	Yes	Off-System
Fisheries Dev.	0.26	50	PURPA	Yes	Schedule 72
Fossil Gulch Wind	10.50	20	PURPA	Yes	Schedule 72
Geo-Bon #2	0.93	35	PURPA	Yes	Schedule 72
Golden Valley Wind Park	12.00	20	PURPA	Yes	Schedule 72
Grand View PV Solar Two	80.00	20	PURPA	Yes	Schedule 72
Grove Solar Center, LLC	6.00	20	PURPA	Yes	OCGIR
Hailey CSPP	0.04	5	PURPA	Yes	Schedule 72
Hammett Hill Windfarm	23.00	20	PURPA	Yes	Schedule 72
Hazelton A	8.10	15	PURPA	Yes	Schedule 72
Hazelton B	7.60	35	PURPA	Yes	Schedule 72
Head of U Canal Project	1.28	20	PURPA	Yes	Schedule 72
Hidden Hollow Landfill Gas	3.20	20	PURPA	Yes	Schedule 72
High Mesa Wind Project	40.00	20	PURPA	Yes	Schedule 72
Horseshoe Bend Hydro	9.50	35	PURPA	Yes	Schedule 72
Horseshoe Bend Wind	9.00	20	PURPA	Yes	Off-System
Hot Springs Wind Farm	21.00	20	PURPA	Yes	Schedule 72
Hyline Solar Center, LLC	9.00	20	PURPA	Yes	OCGIR
ID Solar 1	40.00	20	PURPA	Yes	Schedule 72
Jett Creek Windfarm	10.00	20	PURPA	Yes	OCGIR
Jim Knight	0.34	35	PURPA	Yes	Schedule 72
Koyle Small Hydro	1.25	20	PURPA	Yes	Schedule 72
Lateral #10	2.06	20	PURPA	Yes	Schedule 72

a. Project Name	b. Nameplate Capacity	c. Contract Term	d. Contract Type	e. PURPA QF	f. Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")
LeMoyne Hydro	0.08	10	PURPA	Yes	Schedule 72
Lime Wind Energy	3.00	20	PURPA	Yes	OCGIR
Little Wood River Ranch II	1.25	20	PURPA	Yes	Schedule 72
Little Wood Rvr Res	2.85	20	PURPA	Yes	Schedule 72
Littlewood / Arkoosh	0.87	35	PURPA	Yes	Schedule 72
Low Line Canal	8.20	20	PURPA	Yes	Schedule 72
Low Line Midway Hydro	2.50	20	PURPA	Yes	Schedule 72
Lowline #2	2.79	35	PURPA	Yes	Schedule 72
Magic Reservoir	9.07	35	PURPA	Yes	Schedule 72
Mainline Windfarm	23.00	20	PURPA	Yes	Schedule 72
Malad River	1.17	20	PURPA	Yes	Schedule 72
Marco Ranches	1.20	20	PURPA	Yes	Schedule 72
Mile 28	1.50	35	PURPA	Yes	Schedule 72
Milner Dam Wind	19.92	20	PURPA	Yes	Schedule 72
Mitchell Butte	2.09	45	PURPA	Yes	OCGIR
Mora Drop Hydro	1.85	20	PURPA	Yes	Schedule 72
Morgan Solar	3.00	20	PURPA	Yes	OCGIR
Mt. Home Solar 1, LLC	20.00	20	PURPA	Yes	Schedule 72
Mud Creek S and S	0.52	20	PURPA	Yes	Schedule 72
Mud Creek/White	0.21	35	PURPA	Yes	Schedule 72
Murphy Flat Power, LLC	20.00	20	PURPA	Yes	Schedule 72
North Gooding Main Hydro	1.30	20	PURPA	Yes	Schedule 72
Ontario Solar Center	3.00	20	PURPA	Yes	OCGIR
Open Range Solar Center	10.00	20	PURPA	Yes	OCGIR
Orchard Ranch Solar, LLC	20.00	20	PURPA	Yes	Schedule 72
Oregon Trail Wind Park	13.50	20	PURPA	Yes	Schedule 72
Owyhee Dam Cspp	5.00	40	PURPA	Yes	OCGIR
Payne's Ferry Wind Park	21.00	20	PURPA	Yes	Schedule 72
Pico Energy, LLC	2.13	10	PURPA	Yes	Schedule 72
Pigeon Cove	1.75	20	PURPA	Yes	Schedule 72
Pilgrim Stage Station Wind	10.50	20	PURPA	Yes	Schedule 72
Pocatello Waste	0.46	35	PURPA	Yes	Schedule 72
Pristine Springs #1	0.13	20	PURPA	Yes	Schedule 72
Pristine Springs #3	0.20	20	PURPA	Yes	Schedule 72
Prospector Windfarm	10.00	20	PURPA	Yes	OCGIR
Railroad Solar Center, LLC	4.50	20	PURPA	Yes	OCGIR
Reynolds Irrigation	0.26	35	PURPA	Yes	Schedule 72
Rock Creek #1	2.17	20	PURPA	Yes	Schedule 72
Rock Creek #2	1.90	35	PURPA	Yes	Schedule 72
Rockland Wind Farm	80.00	25	PURPA	Yes	Schedule 72
Ryegrass Windfarm	23.00	20	PURPA	Yes	Schedule 72
Sagebrush	0.43	35	PURPA	Yes	Schedule 72
Sahko Hydro	0.50	10	PURPA	Yes	Schedule 72

a. Project Name	b. Nameplate Capacity	c. Contract Term	d. Contract Type	e. PURPA QF	f. Idaho Power tariff Schedule 72 ("Schedule 72") or Oregon Commission Generator Interconnection Rules ("OCGIR")
Salmon Falls Wind	22.00	20	PURPA	Yes	Schedule 72
Sawtooth Wind Project	22.00	20	PURPA	Yes	Schedule 72
Schaffner	0.53	35	PURPA	Yes	Schedule 72
Shingle Creek	0.22	5	PURPA	Yes	Schedule 72
Shoshone #2	0.58	35	PURPA	Yes	Schedule 72
Shoshone CSPP	0.36	20	PURPA	Yes	Schedule 72
Simcoe Solar, LLC	20.00	20	PURPA	Yes	Schedule 72
Simplot - Pocatello	15.90	3	PURPA	Yes	Schedule 72
SISW LFGE	5.00	20	PURPA	Yes	Schedule 72
Snake River Pottery	0.09	8	PURPA	Yes	Schedule 72
Snedigar	0.50	20	PURPA	Yes	Schedule 72
Tamarack CSPP	6.25	20	PURPA	Yes	Schedule 72
Tasco - Nampa	2.00	5	PURPA	Yes	Schedule 72
Tasco - Twin Falls	3.00	1	PURPA	Yes	Schedule 72
Thousand Springs Wind Park	12.00	20	PURPA	Yes	Schedule 72
Thunderegg Solar Center, LLC	10.00	20	PURPA	Yes	OCGIR
Tiber Dam	7.50	20	PURPA	Yes	Off-System
Trout-Co	0.24	35	PURPA	Yes	Schedule 72
Tuana Gulch Wind Park	10.50	20	PURPA	Yes	Schedule 72
Tuana Springs Expansion	35.70	20	PURPA	Yes	Schedule 72
Tunnel #1	7.00	42	PURPA	Yes	OCGIR
Two Ponds Windfarm	23.00	20	PURPA	Yes	Schedule 72
Vale Air Solar Center, LLC	10.00	20	PURPA	Yes	OCGIR
Vale I Solar	3.00	20	PURPA	Yes	OCGIR
White Water Ranch	0.16	20	PURPA	Yes	Schedule 72
Willow Spring Windfarm	10.00	20	PURPA	Yes	OCGIR
Wilson Lake Hydro	8.40	35	PURPA	Yes	Schedule 72
Yahoo Creek Wind Park	21.00	20	PURPA	Yes	Schedule 72
Coleman Hydro	0.80	20	PURPA	Yes	Schedule 72
Durkee Solar	3.00	20	PURPA	Yes	OCGIR
MC6 Hydro	2.10	20	PURPA	Yes	Schedule 72
Elkhorn Wind	100.65	25	RFP	N/A	OCGIR
Neal Hot Springs Unit #1	22	25	RFP	N/A	OCGIR
Raft River Unit #1	13	25	RFP	N/A	Off-System
Jackpot Holdings, LLC	120	20	Bi-Lateral	N/A	Schedule 72

g. All PURPA Qualifying Facilities and Non-PURPA facilities interconnected to Idaho Power's system and under contract to deliver their generation to the Company are designated as Network Resources.

h. See the Excel spreadsheet attached to the Company's Response to NIPPC DR No. 7 and Confidential Excel spreadsheet attached to the Company's Response to Staff's IR No. 12.

i. See Idaho Power's response to subpart h.

j. Idaho Power holds network transmission capacity on behalf of all PURPA Qualifying Facilities and Non-PURPA facilities under contract to deliver their generation to Idaho Power pursuant to the completion of any transmission system upgrades, at the generation facility's expense, required to serve network load with generation from the contracted facility.

k. Idaho Power's Power Supply business unit submits the transmission service request for facilities under contract to deliver their generation to the Company.

l. See Idaho Power's response to subpart h.

<u>NEWSUN DATA REQUEST NO. 5</u>:

Please list all power purchase agreements under which Idaho Power purchases power including:

a. **Project name,**
b. **Nameplate capacity,**
c. **Term of power purchases,**
d. **Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,**
e. **Whether the facility is certified as a qualifying facility under PURPA,**
f. **Under what interconnection rules/process the facility was interconnected,**
g. **Whether the facility interconnected as ERIS or NRIS,**
h. **The cost of network upgrades funded under the interconnection agreement,**
i. **Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,**
j. **The type of transmission service,**
k. **The entity that submitted the transmission service request,**
l. **The cost of network upgrades funded under the transmission service request.**

<u>IDAHO POWER COMPANY'S SUPPLEMENTAL RESPONSE TO NEWSUN DATA REQUEST NO. 5</u>:

l. Idaho Power's prior response to parts h and l cross-referenced the Company's attachment in response to Staff IR No. 12, which provided network upgrade actual costs. For the purpose of clarification:

- The provided costs for PURPA projects in Idaho Power's process constitute both the interconnection-related network upgrades and the transmission service-related network upgrades.
- For the PPAs and the exchange agreement listed in the Company's response to Staff IR No. 12 (Elkhorn, Neal Hot Springs and Arrowrock), there were no transmission service-related network upgrades for the service Idaho Power currently provides.
- For the Jackpot Holdings agreement included in the original response to this DR, the estimated transmission service network upgrade costs total $10,483,000.

<u>NEWSUN DATA REQUEST NO. 8</u>:

For each network upgrade constructed since January 1, 2014, please provide:

a. **The cost of the network upgrade,**
b. **Where Idaho Power first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),**
c. **How the network upgrade was funded (e.g., utility funded, queue number funded, other),**
d. **Whether the network upgrade was included in rate base or whether Idaho Power intends to include it in rate base,**
e. **If the network upgrade was included in rate base, the rate of return earned on the network upgrade,**
f. **The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others),**
g. **The net increase or decrease in transmission customer rates that resulted from the network upgrade**

<u>IDAHO POWER COMPANY'S RESPONSE TO NEWSUN DATA REQUEST NO. 8</u>:

Idaho Power objects that this request is overly broad and unduly burdensome. Moreover, part (f) is vague and ambiguous. It is not clear what "incremental transmission operations resulting from the network upgrade" refers to. Subject to and without waiving the foregoing objection the Company provides the following response:

a. Information regarding network upgrades identified in interconnection studies is already available in response to Staff Data Request No. 12 and others in this docket.
b. Idaho Power engages in robust and comprehensive planning processes through which economic transmission upgrades are identified. The collective set of planning processes may involve a series of different study requirements, collectively, those requirements are comprehensive and systematic, and cover the range of transmission system investment decisions made by the utility. For example, Idaho Power's integrated resource planning (IRP) group engages in least-cost, least-risk planning in order to evaluate the best way to meet the load needs of utility customers, which may include consideration of cost-effective transmission system investment estimates associated with supply options—estimates that are supplied by the utility's transmission function and supported by regular, extensive study work performed to identify investments needed for reliability.
c. See a) above
d. To the extent network upgrades were paid for Idaho Power, Idaho Power will seek to include them in rate base. If network upgrades are paid for by a third party, they are not included.
e. Idaho Power's currently authorized rate of return in Oregon is 7.757 percent, established in its most recent Oregon general rate case in 2012

Additional information on network upgrades can be found in:
- The Excel file included as an attachment to this data request
- Idaho Power's FERC Form 1 filed with the Oregon Public Utility Commission annually

- Schedule 10 to our Transmission Revenue Requirement posting, which is available on our Public OASIS site under the IPCO Transmission Rate folder, in Excel files dating back a number of years with the most recent file titled "2020-10-01 to 2021-09-30"

NEWSUN DATA REQUEST NO. 8:

For each network upgrade constructed since January 1, 2014, please provide:

- **a. The cost of the network upgrade,**
- **b. Where Idaho Power first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),**
- **c. How the network upgrade was funded (e.g., utility funded, queue number funded, other),**
- **d. Whether the network upgrade was included in rate base or whether Idaho Power intends to include it in rate base,**
- **e. If the network upgrade was included in rate base, the rate of return earned on the network upgrade,**
- **f. The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others),**
- **g. The net increase or decrease in transmission customer rates that resulted from the network upgrade**

IDAHO POWER COMPANY'S SUPPLEMENTAL RESPONSE TO NEWSUN DATA REQUEST NO. 8:

f) After conferral with NewSun, Idaho Power understands that NewSun's requests were intended to encompass upgrades to the transmission system more broadly—not just Network Upgrades associated with interconnection or transmission service, as that term has been defined by FERC and used by the Commission and parties to this proceeding. Specifically, Idaho Power understands that NewSun seeks information regarding major transmission system upgrades Idaho Power has completed, the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects it is interested in, NewSun mentioned constructing a new transmission line, reconductoring a transmission line, constructing a new substation, and adding breakers, disconnects, or communications equipment.

Please see the attached Excel file for a list of Oregon-sited transmission system projects (other than projects associated with QFs and other PPAs) greater than $250,000 that Idaho Power has completed since 2014, along with the cost of and the reason for each project. The Excel spreadsheet attached to Idaho Power's initial response to this data request listed all QF- and PPA-related network upgrades.

Year	Description	Amount	Category
2014	Replaced Lime 061A 69kV power circuit breaker	$ 280,397.61	Aging Infrastructure Replacement
2014	Capitalized maintenance associated with the Vale - Unity 69kV line	$ 434,844.18	Maintenance
2014	Capitalized maintenanced associated with the Gem - Jordan Valley 69kV line	$ 318,972.96	Maintenance
2014	Reconductor of the Oxbow - Pallette 230kV line	$ 1,863,166.74	Ground Clearance
2014	Rebuild of Brownlee - Halfway 69kV line	$ 907,552.58	Maintenance/Aging Infrastructure
2015	Capitalized maintenance on GEMM-JNVY 69kV line	$ 251,361.30	Maintenance
2015	Replacement of fire damaged structures on Quartz to Ontario 138kV line	$ 263,830.35	Replacement of Fire Damaged Structures
2015	Replacement of structures on Gem to Jordan Valley 69kV line	$ 741,640.37	Maintenance/Aging Infrastructure
2015	Replacement of fire damaged structures on Brownlee to Quartz Junction 230kV line	$ 573,466.30	Replacement of Fire Damaged Structures
2016	Capitalized maintenance on Ontario to Quartz 138kV line	$ 334,593.73	Maintenance
2016	Rebuild of Oxbow to Halfway 69kV line.	$ 2,665,693.50	Maintenance/Aging Infrastructure
2016	Capitalized maintenance on Quartz - North Powder - LaGrande 230kV line.	$ 1,350,970.30	Maintenance
2016	Capitalized maintenance on Brownlee to Quartz 230kV line.	$ 1,453,377.65	Maintenance
2016	Repairs of Ontario to Quartz 138kV line.	$ 585,460.50	Maintenance
2016	Repairs of Pine Creek to Hells Canyon 69kV line.	$ 291,472.38	Maintenance
2017	Replacement of Quartz substation line protection and circuit breakers.	$ 834,139.83	Aging Infrastructure Replacement
2017	Replacement of Oxbow switchyard circuit breakers.	$ 462,394.70	Aging Infrastructure Replacement
2017	Repairs of Pallette - Imnaha 230kV line.	$ 381,141.24	Maintenance
2017	Repairs of Vale - Drewsy 69kV line.	$ 615,037.47	Maintenance
2018	Replacment of Ontario 69kV circuit breakers, 138kV circuit switcher, and 69kV airbreak.	$ 526,752.01	Aging Infrastructure Replacement
2018	Replacement of Ontario 230kV Series Capacitor Controls.	$ 1,912,006.24	Aging Infrastructure Replacement
2018	Replacement of Quartz substation circuit breakers and line protection systems.	$ 259,440.23	Aging Infrastructure Replacement
2018	Rebuild of section of Emmet - Ontario 69kV line	$ 287,469.34	Maintenance
2018	Capitalized maintenance on Drewsey - Sandhill 69kV line.	$ 361,275.01	Maintenance
2018	Capitalized maintenance on Vale - Unity 69kV line.	$ 588,043.31	Maintenance
2019	Replacement of Hines substation 138/115kV transformer	$ 1,389,214.53	Aging Infrastructure Replacement/Increase Capacity
2019	Capitalized maintenance on Oxbow - Lolo 230kV line	$ 2,186,283.89	Maintenance
2019	Capitalized maintenance on Weiser - Quartz 69kV	$ 285,019.56	Maintenance
2019	Capitalized maintenance on Emmett - Ontario 69kV line	$ 255,524.90	Maintenance
2020	Quartz bus protection replacement	$ 1,089,828.31	Aging Infrastructure Replacement
2020	10 year Ontario - Quartz Inspection and repair	$ 2,118,399.34	Maintenance
2020	Repairs to Vale-Juntura-Drewsey	$ 1,743,096.58	Maintenance
2020	Pallette Junction - Hurricane 10 year maintenance	$ 425,198.20	Maintenance
2020	Replace Hines relaying	$ 699,609.54	Aging Infrastructure Replacement

NEWSUN DATA REQUESTS NO. 9:

Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?

IDAHO POWER COMPANY'S RESPONSE TO NEWSUN DATA REQUEST NO. 9:

Idaho Power objects that this request is overly broad and unduly burdensome. Idaho Power further objects that the phrase "any benefits to the transmission system" is vague and ambiguous. The Joint Utilities have explained their position regarding system-wide benefits in their testimony.

Subject to and without waiving the foregoing, Idaho Power provides the following response: Any QF-funded network upgrades would be designed only as needed and necessary to interconnect the QF, and if the QF is selling its output to Idaho Power, to have the QF's generation be designated as a network resource. Upgrades related to QF interconnections are not driven by a need to meet other customer load or system capacity requirements.

NEWSUN DATA REQUEST NO. 12:

Referring to Joint Utilities/200 (Wilding-Macfarlane-Williams) at 11, please identify all upgrades on the utility's system in Oregon that were required solely to provide adequate transmission capacity for the interconnecting QF.

IDAHO POWER COMPANY'S RESPONSE TO NEWSUN DATA REQUEST NO. 12:

Idaho Power objects that this request is lacking in foundation in that it is unclear how the referenced testimony relates to the requested information. The request regarding "all upgrades" is overly broad, and the phrase "constructed solely to provide adequate transmission capacity for the interconnecting QF" is vague and ambiguous.

Subject to and without waiving the foregoing objection, Idaho Power provides the following response: Any upgrades identified and constructed in the QF interconnection process are required because they are necessary to provide adequate transmission or interconnection capacity for the interconnecting QF. In other words, when Idaho Power's interconnection studies of the QF indicate that upgrades are necessary, it is because they are necessary to provide adequate transmission or interconnection capacity. Upgrades related to QF interconnections are not driven by a need to meet other customer load or system capacity requirements.

NEWSUN DATA REQUEST NO. 20:

For each State in which Idaho Power operates, please:

a. **Describe which set of procedures Idaho Power uses to interconnect qualifying facilities that propose to sell 100% of their net output to Idaho Power,**
b. **Describe which set of procedures Idaho Power uses to interconnect qualifying facilities that propose to sell less than 100% of their net output to Idaho Power,**
c. **Indicate for (a) and (b) whether QFs have the option to select ERIS or NRIS,**
d. **Indicate for (a) and (b) whether QFs receive refunds for the cost of network upgrades,**
e. **Describe the cost allocation and refund policy for network upgrades; compare these policies based on whether the QF interconnected as a FERC or state-jurisdictional interconnection?**
f. **How would these answers differ if a prospective otherwise equivalent generator proposed interconnection but it did not seek to sell 100% of its output under a mandatory purchase contract to Idaho Power? For example, in each situation, if the potential QF were a 40 MW solar-only facility that was eligible for certification as a QF.**

IDAHO POWER COMPANY'S RESPONSE TO NEWSUN DATA REQUEST NO. 20:

a. In Oregon Idaho Power follows the procedures outlined in Staff DR No. 5. In Idaho, Idaho Power follows Schedule 72 (see also Staff DR No. 6). These procedures are also described on Idaho Power's public website at https://www.idahopower.com/about-us/doing-business-with-us/generator-interconnection/purpa-qf-interconnections/. From a planning study perspective, Idaho Power follows the Large Generator Interconnection Procedures (OATT - Attachment M) or Small Generator Interconnection Procedures (OATT - Attachment N). In addition, Idaho Power's Load-Serving Operations group will submit a transmission service request (TSR) seeking to make the QF a designated network resource or otherwise eligible for delivery using firm transmission service under the OATT process.

b. The portion of the generator that was intended to be sold to Idaho Power under a PURPA Power Purchase Agreement would be interconnected under the process described in item (a). Network Resource Interconnection Service and firm point-to-point transmission service studies are evaluated at the Interconnection Customer's stated output. See also response (a) above. Output in excess of this amount would be addressed under the Large Generator Interconnection Procedures (Attachment M) or Small Generator Interconnection Procedures (Attachment N). If Idaho Power is not purchasing the surplus output, then Idaho Power would not submit a TSR for transmission service for that output. Rather, a third-party would need to submit the TSR using the procedures outlined in the OATT to request firm or non-firm transmission service on Idaho Power's transmission system.

c. Qualifying facilities are required to interconnect with NRIS in Idaho and in Oregon. See Staff DR Nos. 5 and 6.

d. Generators interconnecting as a QF under the procedures described in item (a) do not receive refunds for the cost of network upgrades from Idaho Power in either Oregon or Idaho. See Staff Dr. Nos. 5 and 6. In Idaho, there is a possibility that a QF may receive reimbursement for certain upgrades that it originally funds, if a later interconnection customer can use the same upgrades within five years of the upgrades' completion. In that case, the reimbursement is provided by the later customer, not by Idaho Power. See Staff DR No. 17.

   Generators interconnecting under the OATT's Large Generator Interconnection Procedures or Small Generator Interconnection Procedures, including situations described in item (b), are required by those procedures to fund the cost of Network Upgrades, as that term is defined in those procedures, and are eligible for reimbursement as further described in Staff DR No. 16.

e. See item (d) above. QFs fund the upgrades required to interconnect them to Idaho Power's system and are not refunded by Idaho Power. Staff DR Nos. 5 and 6 provide additional information on this and on the treatment of the costs. FERC-jurisdictional generators are cost allocated and reimbursed in accordance with the Large Generator Interconnection Procedures or Small Generator Interconnection Procedures under the OATT process. FERC-jurisdictional generators fund the costs of Network Upgrades, as that term is defined in the Large Generator Interconnection Procedures and Small Generator Interconnection Procedures, and are eligible for reimbursement for those costs as further described in Staff DR No. 16.

f. See item (b) above. The QF-portion of the generator would be addressed under the processes described in items (a), (c) and (d) above. The non-QF portion of the generator would be addressed under the Large Generator Interconnection Procedures (Attachment M) or Small Generator Interconnection Procedures (Attachment N) of Idaho Power's OATT.

TOPIC/KEYWORD: Network Resource Interconnection Service Requirement

STAFF'S INFORMATION REQUEST NO. 5:

Please indicate the date on which the Company began requiring Oregon QFs to interconnect using Network Resource Interconnection Service.

a. Please provide any announcements, business practices, or other supporting documentation.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 5:

For QF interconnections, Idaho Power has always assumed that the QF is delivering energy to serve Idaho Power's load since PURPA was enacted in 1978. QF interconnections must address deliverability to load because of PURPA's must-purchase obligation. Including a deliverability analysis in the interconnection study. is consistent with Network Resource Interconnection Service (NRIS). NRIS and ERIS were first articulated and defined by FERC for large generator interconnections in Order No. 2003 (issued July 24, 2003, revised Open Access Transmission Tariff language effective January 20, 2004). Since then and consistent with Commission orders discussed below, Idaho Power has used the NRIS process for studying QFs (both in Oregon and Idaho) that interconnect with its system because the NRIS study includes the deliverability analysis required for QFs to be designed as a Network Resource used to serve Idaho Power's load.

On June 8, 2009, in Order No. 09-196 in docket AR 521, the Commission adopted a policy requiring state-jurisdictional generators to pay for all interconnection costs "necessitated by the interconnection of [the] small generator facility."[1] That docket included QFs but was not exclusively applicable to QFs. On April 7, 2010, in Order No. 10-132 in docket UM 1401, which addressed large QF interconnections, the Commission made clear—consistent with its findings in AR 521—that QFs are required to pay for all interconnection costs caused by their interconnection, and also accepted the utilities' comments noting that, in the context of PURPA, the scope of this requirement includes the costs of NRIS. Furthermore, the Commission made clear in docket UM 1401 that the Commission was required to treat interconnection costs under PURPA differently from FERC's treatment of interconnection costs, because cost allocation policies for FERC-jurisdictional interconnections do not "face[] the limitation of the avoided cost rate."[2] Thus, the Commission has consistently required QFs to pay for the interconnection costs caused by their interconnection, under both state law and PURPA.

[1] Order No. 09-196 at 5,
[2] Order No. 10-132 at 3-4.

TOPIC/KEYWORD: Network Resource Interconnection Service Requirement

STAFF'S INFORMATION REQUEST NO. 6:

For each state outside of Oregon in which the Company interconnects QFs, please indicate:

a. **The required interconnection service type(s) for QFs, including documentation for this requirement, including the date in which the requirement was put in place.**

b. **How QF Network Upgrade costs are allocated, including between transmission customers and between ratepayers in different states, including documentation for this practice.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 6:

(a) Besides Oregon, Idaho Power interconnects QFs in the state of Idaho. The Idaho Public Utilities Commission has not used the term "Network Resource Interconnection Service" in defining the interconnection requirements for QFs selling their output to Idaho utilities, but has long required that QFs pay all interconnection costs. The Idaho Commission first adopted this requirement in 1980 in a rulemaking regarding QFs (Order No. 15746, Case No. P-300-12). This requirement is memorialized in Idaho Power's schedule for the interconnection of non-utility generation in Idaho, in Idaho Commission-approved Schedule 72, and has been since 1991. (Order No. 23631, Case No. IPC-E-90-20). Schedule 72 states that the interconnecting generator shall pay for all interconnection costs, including costs of upgrades to the transmission or distribution systems that may be required as a result of the interconnection. Idaho Power Rate Schedule 72, sheet 72-14. Consistent with the requirements that QFs pay for all costs to interconnect to Idaho Power's system, Idaho Power studies Idaho QFs for NRIS.

(b) Under the Company's Oregon Schedule 85 and Idaho Schedule 72, the QFs are required to pay all network upgrade costs associated with their projects. The investments in the network upgrades are recorded to FERC Account 101 – Electric Plant in Service ("Account 101") with an equivalent offset to Contributions in Aid-of-Construction within Account 101, resulting in no rate impact associated with the network upgrades to Idaho Power's retail or transmission customers. Because there is no rate impact, nothing is allocated to retail or transmission customers in either state.

TOPIC/KEYWORD: Customer Indifference

STAFF'S INFORMATION REQUEST NO. 12:

Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of Network Upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please list all Network Upgrades that the Company has constructed since 2010. Please also include Network Upgrades that would match this definition if the reference to large generating facility were replaced with small generating facility. Please include the following information for each year since the upgrade was in service through 2019 inclusive:

a. **Interconnection queue number of the generator(s) that triggered the upgrade.**

b. **Whether the generator(s) are owned by the Company.**

c. **Cost of the upgrade borne by the generator(s).**

d. **Cost of the upgrade borne by ratepayers.**

e. **Cost of the upgrade borne by other transmission customers.**

f. **Transmission revenues generated by the upgrade.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 12:

Please see the attached confidential Excel file for the requested information, as revised by Staff's "phase one" revisions to the above data request. The Company is still preparing its response to Staff's "phase two" request, which is expected no later than October 8, 2020.

For reference, the phase one data is included as follows:

- List all network upgrades put in service since 2010 - 2019 - per generator is ok
- Queue#
- Location of generator (state)
- Ownership of generator
- Jurisdiction over interconnection
- Total cost of the network upgrades constructed for that Queue#

TOPIC/KEYWORD: Customer Indifference

STAFF'S INFORMATION REQUEST NO. 12:

Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of Network Upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please list all Network Upgrades that the Company has constructed since 2010. Please also include Network Upgrades that would match this definition if the reference to large generating facility were replaced with small generating facility. Please include the following information for each year since the upgrade was in service through 2019 inclusive:

a. **Interconnection queue number of the generator(s) that triggered the upgrade.**

b. **Whether the generator(s) are owned by the Company.**

c. **Cost of the upgrade borne by the generator(s).**

d. **Cost of the upgrade borne by ratepayers.**

e. **Cost of the upgrade borne by other transmission customers.**

f. **Transmission revenues generated by the upgrade.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 12 (Phase Two):

Per Staff's email dated September 23, 2020, this request was revised to include the following in phase two of this information request.

- For each customer's network upgrades identified in Phase one between 2010 - 2019, provide
    - Total cost (Column F)
    - The portion of the total cost provided by interconnection customer. Please specify whether the portion was provided by interconnection customer upfront or in some other way. (Columns G and H)
    - Whether interconnection customer was or is being reimbursed for their contribution to network upgrades and by whom. (Column I)
    - If interconnection customer did not provide all upfront capital for network upgrades, identify who also contributed to upfront capital (i.e., IPC merchant function), and specify what portion they provided and whether this entity(s) is being reimbursed (i.e., from IPC transmission revenues). (Column K and L)
- For the most recent year that transmission revenue data is available, please provide the share of the transmission revenues that can be assigned to the aggregate of network upgrades identified in phase one.

Please see the attached Excel file for the requested detail information. The Company estimates the share of the transmission revenues that can be assigned to the aggregate of network upgrades identified in phase one to be approximately $3.4 million, using the same high-level methodology described in the Company's response to Staff's Information Request No. 2.

Project Name	Queue #	State	Ownership	Jurisdiction	Network Upgrade Actual Cost	Cost Provided by Interconnection Customers	Provided Upfront or Some Other Way	Interconnection customer being Reimbursed? By Whom?	Other Contribution to Upfront Capital	Reimbursed through Transmission Revenue
REDACTED	120	OR	Third Party	FERC	$ 3,430,000	$ 3,430,000	Upfront	Idaho Power	None	No
REDACTED	179	OR	Third Party	FERC	$ 692,361	$ 692,361	Upfront	Idaho Power	None	No
REDACTED	233	OR	Third Party	PURPA	$ 404,220	$ 404,220	Upfront	None	None	No
REDACTED	401	OR	Third Party	PURPA	$ 3,030,912	$ 3,030,912	Upfront	None	None	No
REDACTED	402	OR	Third Party	PURPA	***	***	Upfront	None	None	No
REDACTED	403	OR	Third Party	PURPA	***	***	Upfront	None	None	No
REDACTED	404	OR	Third Party	PURPA	***	***	Upfront	None	None	No
REDACTED	405	OR	Third Party	PURPA	***	***	Upfront	None	None	No
REDACTED	412	OR	Third Party	PURPA	$ 1,637,126	$ 1,637,126	Upfront	None	None	No
REDACTED	413	OR	Third Party	PURPA	$ 3,348,998	$ 3,348,998	Upfront	None	None	No
REDACTED	414	OR	Third Party	PURPA	$ 215,493	$ 215,493	Upfront	None	None	No
REDACTED	419	OR	Third Party	PURPA	$ 1,015,988	$ 1,015,988	Upfront	None	None	No
REDACTED	424	OR	Third Party	PURPA	$ 1,838,420	$ 1,838,420	Upfront	None	None	No
REDACTED	425	OR	Third Party	PURPA	$ 759,115	$ 759,115	Upfront	None	None	No
REDACTED	510	OR	Third Party	PURPA	$ 86,541	$ 86,541	Upfront	None	None	No
REDACTED	511	OR	Third Party	PURPA	$ 36,000	$ 36,000	Upfront	None	None	No
REDACTED	512	OR	Third Party	PURPA	$ 38,000	$ 38,000	Upfront	None	None	No
REDACTED	519	OR	Third Party	PURPA	$ -	$ -	Upfront	None	None	No
REDACTED	525	OR	Third Party	PURPA	$ 694,035	$ 694,035	Upfront	None	None	No

*** Queue #'s 401-405 all served by the same transmission line, substation and upgrades

** Completed prior to 2010 and should have been excluded from Phase 1 response. Left on the list for consistency.

Project Name(s)	Queue #	State	Ownership	Jurisdiction	Network Upgrade Actual Cost	Cost Provided by Interconnection Customers	Provided Upfront or Some Other Way	Interconnection customer being Reimbursed? By Whom?		Other Contribution to Upfront Capital	Reimbursed through Transmission Revenue
REDACTED	128/134	ID	Third Party	IPUC	$ 403,313	$ 403,313	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	132	ID	Third Party	IPUC	$ 102,238	$ 102,238	Upfront	None		None	No
REDACTED	136	ID	Idaho Power	FERC	$ 4,111,618	$ 4,111,618	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	154	ID	Third Party	IPUC	$ 124,413	$ 124,413	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	155/299/357	ID	Third Party	IPUC	$ 1,065,252	$ 1,065,252	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	157	ID	Third Party	IPUC	$ 3,466,658	$ 3,466,658	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	159/300	ID	Third Party	IPUC	$ 3,386,636	$ 3,386,636	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	186/187/195/196	ID	Third Party	IPUC	$ 882,840	$ 882,840	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	192	ID	Third Party	IPUC	$ 81,139	$ 81,139	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	194	ID	Third Party	IPUC	$ 121,709	$ 121,709	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	203	ID	Third Party	IPUC	$ 908,759	$ 908,759	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	207	ID	Third Party	IPUC	$ 410,524	$ 410,524	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	239/313	ID	Idaho Power	FERC	$ 22,545,109	$ 22,545,109	Upfront	Idaho Power		Idaho Power	No
REDACTED	256	ID	Third Party	FERC	$ 202,778	$ 202,778	Upfront	None		None	No
REDACTED	293	ID	Third Party	IPUC	$ 4,734,237	$ 4,734,237	Upfront	None		None	No
REDACTED	296	ID	Third Party	IPUC	$ 42,571	$ 42,571	Upfront	None		None	No
REDACTED	301	ID	Third Party	IPUC	$ 1,103,270	$ 1,103,270	Upfront	None		None	No
REDACTED	309/329	ID	Third Party	IPUC	$ 264,108	$ 264,108	Upfront	None		None	No
REDACTED	317	ID	Third Party	IPUC	$ 1,755,946	$ 1,755,946	Upfront	Idaho Power	1	Idaho Power	No
REDACTED	334	ID	Third Party	IPUC	$ 318,581	$ 318,581	Upfront	None		None	No
REDACTED	336/337/338/339/340/341/373/374/375/376/377/378	ID	Third Party	IPUC	$ 876,909	$ 876,909	Upfront	None		None	No
REDACTED	348	ID	Third Party	IPUC	$ 108,557	$ 108,557	Upfront	None		None	No
REDACTED	380	ID	Third Party	IPUC	$ -	$ -	Upfront	None		None	No
REDACTED	382	ID	Third Party	IPUC	$ 114,341	$ 114,341	Upfront	None		None	No
REDACTED	394/395/397	ID	Third Party	IPUC	$ 73,883	$ 73,883	Upfront	None		None	No
REDACTED	400	ID	Third Party	IPUC	$ -	$ -	Upfront	None		None	No
REDACTED	406	ID	Third Party	IPUC	$ 211,239	$ 211,239	Upfront	None		None	No
REDACTED	409	ID	Third Party	IPUC	$ 117,761	$ 117,761	Upfront	None		None	No
REDACTED	410	ID	Third Party	IPUC	$ -	$ -	Upfront	None		None	No
REDACTED	418	ID	Third Party	IPUC	$ 244,695	$ 244,695	Upfront	None		None	No
REDACTED	426	ID	Third Party	IPUC	$ 378,190	$ 378,190	Upfront	None		None	No
REDACTED	428	ID	Third Party	IPUC	$ 2,901,258	$ 2,901,258	Upfront	None		None	No
REDACTED	429	ID	Third Party	IPUC	$ -	$ -	Upfront	None		None	No
REDACTED	431	ID	Third Party	IPUC	$ 1,842,160	$ 1,842,160	Upfront	None		None	No
REDACTED	432	ID	Third Party	IPUC	$ -	$ -	Upfront	None		None	No
REDACTED	433	ID	Third Party	IPUC	$ 82,095	$ 82,095	Upfront	None		None	No
REDACTED	435	ID	Third Party	IPUC	$ 774,676	$ 774,676	Upfront	None		None	No
REDACTED	441	ID	Third Party	IPUC	$ -	$ -	Upfront	None		None	No
REDACTED	494	ID	Third Party	IPUC	$ -	$ -	Upfront	None		None	No
REDACTED	501	ID	Third Party	IPUC	$ 177,256	$ 177,256	Upfront	None		None	No

1 These projects were all part of a "cluster group" of projects that shared network upgrade costs. The projects were refunded a portion of the cluster network upgrades by Idaho Power

** Completed prior to 2010 and should have been excluded from Phase 1 response. Left on the list for consistency.

TOPIC/KEYWORD: Customer Indifference

STAFF'S INFORMATION REQUEST NO. 13:

Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of network upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please identify all Network Upgrades matching this definition that the Company included or seeks to include in rate base in the Company's most recently filed General Rate Case. Please also include Network Upgrades that would match this definition if the reference to large generating facility were replaced with small generating facility. For all Network Upgrades identified, please indicate the following:

a. **Description of upgrade, including location, equipment, size or rating, and cost.**

b. **How that investment was identified.**

c. **How the costs were allocated to Oregon and includable in state revenue requirements, as well as each state where PacifiCorp serves retail load.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 13:

a. The following Network Upgrades have been constructed between 2001 and 2019. All have been included in either the Company's 2011 general rate case (UE 233) or Langley Gulch-specific case (UE 248).

Idaho Power Generation Projects	
Year, Name, Size (MW)	**Transmission Upgrade Cost**
2011, Langley Gulch, 345, includes expansion	$ 22,631,706
2009, Bennett Mtn – material modification, 40	$ -
2007, Evander Andrews Complex – Phase 2, 200	$ 24,522,831
2005, Bennett Mountain Power Plant, 170	$ 6,724,937
2001, Danskin 1 & 2, 90	$ 3,020,943

b. The interconnection studies performed for each specific generation resource

c. The Company assumes that Staff intended the request to refer to Idaho Power. When allocating (jurisdictionalizing) Idaho Power's rate base for the purpose of developing base rates, Idaho Power uses specific allocation factors for every plant account and/or or directly assigns costs within each plant account where appropriate, or a combination of the two. For example, transmission plant account 355 "Poles and Fixtures" is allocated between Idaho and Oregon based on relative transmission capacity utilization, except for approximately $34,000 of specifically identified assets that are directly assigned to one state or the other based on specific circumstances.

<u>NIPPC'S INFORMATION REQUEST NO. 7</u>:

For each QF that has interconnected to Idaho Power's system and achieved commercial operation in the past 30 years to sell 100 percent of the net output to Idaho Power and is thus a state-jurisdictional interconnection, provide the following information:

a. **Capacity of the facility (as measured by interconnection capacity);**

b. **Type of generation resource (e.g., wind, solar, hydropower);**

c. **Cost of Interconnection Facilities (using the definition in FERC's Order No. 2003, which is facilities up to the point of interconnection), including both costs in the final Facilities Study and the actual costs after construction was complete;**

d. **Cost of Network Upgrades (using the definition in FERC's Order No. 2003, which is facilities at or beyond the point of interconnection) including both costs in the final Facilities Study and the actual costs after construction was complete;**

e. **If the amounts for any facilities in (c) and (d) for the final Facilities Study and the actual costs after construction differ, explain the reason for the difference.**

f. **For the Network Upgrades identified in subpart D for each facility, please explain whether Idaho Power agrees that any of the facilities are used by other users of the system or Idaho Power and identify facilities not used solely by the QF.**

<u>IDAHO POWER COMPANY'S RESPONSE TO NIPPC'S INFORMATION REQUEST NO. 7</u>:

a-b: A complete list of QFs currently interconnected to Idaho Power's system and selling their net output to Idaho Power is provided in the attachment to Response No. 1.

c-d: Information for all Oregon QF interconnections since January 1, 2014, is provided in the attached spreadsheet.

e: Explanations of significant cost variances are provided in the attached spreadsheet. The GIA and Facilities Studies are conceptual estimates, the actual costs are paid for by the QF and reconciled post-construction with each project.

With respect to Section (f), the need for a particular Network Upgrade can be triggered by a specific generator, but the usage of specific components of the transmission system are not isolated for use by a single user and change over time. For purposes of this data request, all upgrades to Idaho Power's distribution or transmission system related to the project's generation have been categorized as "Network Upgrades." The studies and agreements for QF's do not categorize facilities as "Network Upgrades", rather categorizes upgrades to both distribution and transmission.

Queue #	Project Name	Network Resource (NR) or Energy Resource	a. Nameplate Capacity (MW)	b. Generator Tech Type	c. Interconnect Study Costs	Interconnect Actual Cost	Interconnect Variance	Interconnect Variance Note	d. Network Upgrade Estimate	Network Upgrade Actual Cost	e. Network Upgrade Variance	Network Upgrade Variance Note	Project Owner	Actual Toal Cost of Each Project at Substantial Completeion
401	Benson Creek Windfarm	NR	10.00	Wind	$ 2,185,000	$ 2,064,628	$ (120,372)	Actual expenses were 5.5% less than estimated. The project progressed as expected with only minor scope changes or unexpected expenses, therefore, contingency was not fully utilized	$ 4,000,000	$ 3,030,912	$ (969,088)	The difference between the estimate and actuals is 24%. The estimate included a 20% contingency. The most significant expense was the 300MVA transformer at $1.8M. The transformer was purchased near the estimated cost, construction contract costs were less than estimated. Therefore, contingency funds were not utilized.	Third Party Developer	$ 5,095,539
402	Durbin Creek Windfarm	NR	10.00	Wind	***	***	***	N/A	***	***	***	N/A	Third Party Developer	***
403	Jett Creek Windfarm	NR	10.00	Wind	***	***	***	N/A	***	***	***	N/A	Third Party Developer	***
404	Prospector Windfarm	NR	10.00	Wind	***	***	***	N/A	***	***	***	N/A	Third Party Developer	***
405	Willow Spring Windfarm	NR	10.00	Wind	***	***	***	N/A	***	***	***	N/A	Third Party Developer	***
412	Vale Air Solar Center	NR	10.00	Solar	$ 211,000	$ 236,223	$ 25,223	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc.	$ 1,498,000	$ 1,637,126	$ 139,126	Needed to bring in a mobile transformer to take an outage to do the work. Originally estimated we would be able to take the outage w/o the mobile. Additional transmission structure work needed outside of sub. A lot of labor hours to work with the FAA and city due to close proximity of airport, not originally estimated.	Third Party Developer	$ 1,873,349
413	Open Range Solar Center	NR	10.00	Solar	$ 211,000	$ 199,856	$ (11,144)	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 4,492,000	$ 3,348,998	$ (1,143,002)	Contractors were assumed in the estimate for transmission and distribution line work. We were able to use internal crews at a lower cost. Approx. $750,000 of contingency wasn't utilized	Third Party Developer	$ 3,548,854
414	Grove Solar Center	NR	6.00	Solar	$ 211,000	$ 181,646	$ (29,354)	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 138,000	$ 215,493	$ 77,493	Contractor pricing came in higher than estimated. AMI transformer needed moved to accommodate room for upgrades, not known until just before construction.	Third Party Developer	$ 397,140
419	Hyline Solar Center	NR	9.00	Solar	$ 211,000	$ 174,272	$ (36,728)	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 891,000	$ 1,015,988	$ 124,988	There were additional items that were not considered in the Facility Study estimate: comm equipment was needed at BOBN, fiber work near OXBO needed for redundancy, and marker ball strand across the river needed replaced with upgrade.	Third Party Developer	$ 1,190,260
424	Thunderegg Solar Center	NR	10.00	Solar	$ 211,000	$ 204,213	$ (6,787)	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 1,677,000	$ 1,838,420	$ 161,420	Contractor pricing came in higher than estimated by approx. $35k. Additional unforeseen costs to add cable trench, risers, conduit and demo at substation. Had to hire contractor inspectors as IPCO didn't have internal resources. Hired tree services to clear the ROW for new lines not originally estimated.	Third Party Developer	$ 2,042,633
425	Railroad Solar Center	NR	4.50	Solar	$ 237,600	$ 152,772	$ (84,828)	Contractor bid lower than estimted, contingency not utilized	$ 1,828,200	$ 759,115	$ (1,069,085)	The scope of the distibution line work was modifed after the Facility Study.	Third Party Developer	$ 911,888
510	Morgan Solar	NR	3.00	Solar	$ 250,000	$ 209,657	$ (40,343)	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 145,000	$ 86,541	$ (58,459)	The contract construction of the line rebuild was less than estimated.	Third Party Developer	$ 296,198
511	Vale 1 Solar	NR	3.00	Solar	$ 243,000	$ 213,010	$ (29,990)	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 33,000	$ 36,000	$ 3,000	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc.	Third Party Developer	$ 249,010
512	Brush Solar	NR	2.75	Solar	$ 243,000	$ 214,994	$ (28,006)	Actuals vary minimally from Facility Study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 33,000	$ 38,000	$ 5,000	Actuals vary minimally from Facility study estimate based on location, timing, conditions, etc.	Third Party Developer	$ 252,994
519	Baker City 1 Solar	NR	15.00	Solar	$ 1,409,678	$ 1,276,953	$ (132,725)	Contractor bid lower than estimted, contingency not utilized	$ 346,742	$ -	$ (346,742)	Upgrades at QUTZ and WESR sub eliminated from the scope. Internal line crews performed the work rather than contractor thereby reducing costs.	Third Party Developer	$ 1,276,953
525	Ontario Solar	NR	3.00	Solar	$ 225,000	$ 228,363	$ 3,363	Actuals vary minimally from Facility study estimate based on location, timing, conditions, etc. and contingency not utilized	$ 580,000	$ 694,035	$ 114,035	The POI was moved causing an increase. Also, comm work at BOBN to accommodate the DS1 circuits.	Third Party Developer	$ 922,398

*** Queue #'s 401-405 all served by the same transmission line, substation and upgrades

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 2032

Joint Utilities' Response to NewSun Energy

LLC's Motion to Compel Discovery

Attachment B

UM 2032 PGE Discovery

June 28, 2021

Attachment B: List of Included UM 2032 PGE Discovery

- UM 2032 PGE Supp Response to NewSun DR 009
- UM 2032 PGE Response to NewSun DR 009
- UM 2032 PGE to NewSun DR 009 and 018 Supp Attach A
- UM 2032 PGE Response to OPUC DR 012
- UM 2032 PGE Response to OPUC DR 013
- UM 2032 PGE Supp Response to NewSun DR 010
- UM 2032 PGE Response to NewSun DR 010
- UM 2032 PGE Third Supp Response to NewSun DR 006
- UM 2032 PGE Second Supp Response to NewSun DR 006
- UM 2032 PGE Supp Response to NewSun DR 006
- UM 2032 PGE Response to NewSun DR 006
- UM 2032 PGE Second Supp Response to NIPPC DR 001
- UM 2032 PGE Revised Response to NIPPC DR 001
- UM 2032 PGE Supp Response to NIPPC DR 001
- UM 2032 PGE Response to NIPPC DR 001
- UM 2032 PGE to NIPPC DR 001 Attach A
- UM 2032 PGE to NIPPC DR 001 Supp Attach A
- UM 2032 PGE to NIPPC DR 001 Revised Supp Attach A
- UM 2032 PGE Revised Response to NIPPC DR 002
- UM 2032 PGE Response to NIPPC DR 002
- UM 2032 PGE Supp Response to NIPPC DR 003
- UM 2032 PGE Response to NIPPC DR 003
- UM 2032 PGE to NIPPC DR 003 Attach A
- UM 2032 PGE to NIPPC DR 003 Attach B

- UM 2032 PGE to NIPPC DR 003 Attach C
- UM 2032 PGE to NIPPC DR 003 Attach D
- UM 2032 PGE Response to NIPPC DR 004
- UM 2032 PGE Response to NIPPC DR 007
- UM 2032 PGE Response to NIPPC DR 008
- UM 2032 PGE Response to NIPPC DR 031
- UM 2032 PGE Response to NIPPC DR 032
- UM 2032 PGE Response to NIPPC DR 033
- UM 2032 PGE to NIPPC DR 033 Attach A (redacted)
- UM 2032 PGE Response to OPUC DR 005
- UM 2032 PGE Response to OPUC DR 008
- UM 2032 PGE Response to NewSun DR 007
- UM 2032 PGE to NewSun DR 007 Attach A
- UM 2032 PGE Supp Response to NewSun DR 019
- UM 2032 PGE Response to NewSun DR 019
- UM 2032 PGE to NewSun DR 019 Attach A
- UM 2032 OPUC Response to PGE DR 5
- UM 2032 NewSun Response to PGE DR 32

March 5, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Supplemental Response to NewSun Data Request No. 009
Dated January 6, 2020

Request:

For each network upgrade constructed since January 1, 2014, please provide:

a. The cost of the network upgrade,
b. Where PGE first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),
c. How the network upgrade was funded (e.g., utility funded, queue number funded, other),
d. Whether the network upgrade was included in rate base or whether PGE intends to include it in rate base,
e. If the network upgrade was included in rate base, the rate of return earned on the network upgrade,
f. The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others),
g. The net increase or decrease in transmission customer rates that resulted from the network upgrade,

Supplemental Response:

After conferral with NewSun, PGE understands that NewSun's requests were intended to encompass upgrades to the transmission system more broadly—not just Network Upgrades associated with interconnection or transmission service, as that term has been defined by FERC and used by the Commission and parties to this proceeding. Specifically, PGE understands that NewSun seeks information regarding "major" transmission system upgrades PGE has completed, the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects it is interested in, NewSun mentioned constructing a new transmission line, reconductoring a transmission line, or constructing a new substation.

Because NewSun's requests used the term "network upgrades," which are the subject of this docket, PGE maintains that its initial responses were complete and adequate. Based on PGE's new understanding that NewSun's requests were intended to encompass upgrades to the transmission system more broadly, PGE objects that the requests are overly broad and unduly burdensome. PGE also objects that the information requested relates to an issue that PGE understands is outside the scope of Phase I and may be addressed in Phase II. Notwithstanding and without waiving these objections, PGE responds as follows:

Please see Attachment 009 and 018A, which contains major transmission upgrades PGE has constructed over the last three years, along with the cost of the upgrade and the reason for the upgrade.

Note this response applies to NewSun Data Request Nos. 9, 10, 13, 15 and 18.

Response:

Please see PGE's Responses to Staff Data Request Nos. 12 and 13.

Funding Project	Funding Project Name	Previous Year Actuals (Combined)	2018 Actuals	2019 Actuals	2020 Actuals	Projected 2021 Spend	Projected Future Years Spend (Combined)	SUM
P35802	Horizon Phase II Project	$16,448,787	$8,198,309	$443,321	$7,565	$0	$0	$25,097,983
P35834	Round Butte Transmission Upgrades	$1,815,934	$2,967,327	$1,779,458	$86,852	$33,446	$1,770,000	$8,453,017
P36039	Harborton Reliability Project PH1	$3,722,284	$8,850,687	$10,737,496	$9,273,767	$2,064,369	$0	$34,648,604
P36178	North Portland Conversion	$0	$71	$204,287	$272,970	$4,646,438	$10,125,059	$15,248,824
P36211	Shute-West Union 115 line addition	$255,700	$4,382,432	($14,671)	$59,696	$0	$0	$4,683,157
P36341	St Marys System Protection Upgrade	$0	$241,260	$2,098,872	$78,087	$809,136	$671,363	$3,898,718
P36373	Blue Lake Phase II	$257,536	$3,124,717	$13,334,199	$7,910,833	$237,563	$1,352,127	$26,216,976
P36439	Gresham Sub 115kV Rebuild	$0	$0	$1,194,029	$1,710,648	$14,000	$858,644	$3,777,321
P36666	Build Evergreen Substation	$0	$177,601	$2,000,548	$34,028	$546,000	$37,479,549	$40,237,727
P36679	Orenco Substation 115kV Rebuild	$0	$21,811	$1,017,842	$3,839,343	$219,793	$17,852,353	$22,951,142
P36680	Brookwood Substation Conversion	$0	$0	$2,455,169	$3,592,874	$24,623,153	$6,109,000	$36,780,196
P36763	Install Horizon VWR3 Transformer	$0	$0	$185,964	$2,392,927	$4,163,413	$0	$6,742,304
P36860	Canyon-Urban 115kV Reconductor	$0	$0	$15,023	$372,217	$1,323,493	$1,222,524	$2,933,257
P36907	Reconductor Murrayhill-St Marys	$0	$0	$45,640	$506,513	$4,715,043	$0	$5,267,196
P36916	Harborton Reliability Project PH2	$0	$0	$1,650,965	($159,986)	$432,495	$28,739,003	$30,662,477
P36954	Tonquin Substation Build	$0	$0	$0	$102,874	$1,208,000	$42,017,000	$43,327,874
P37062	Rebuild Grizzly-RB 500kV Towers	$0	$0	$0	$4,724,698	$0	$0	$4,724,698
P37110	Restore Bethel-RB 230 kV Line	$0	$0	$0	$803,993	$4,021,300	$0	$4,825,293
P37112	Kelley Point Reconfiguration	$0	$0	$0	$0	$393,218	$0	$393,218
Grand Total		$22,500,242	$27,964,216	$37,148,142	$35,609,898	$49,450,861	$148,196,622	$320,869,980

Project Overview/Justification

Install second bulk power transformer and 230 kV source to Horizon substation to avoid overloading equipment in the summer to meet NERC Compliance requirements.
Install a Special Protection Scheme to reduce the PRB plant impact of a System Operating Limit required to maintain system stability. Replace relays and reactors on the 500/230 kV transformer that are at the end of their life and mitigate fault current concerns. Install breakers on the two 230 kV line positions to PACW's Cove substation for reliability.
The loss of the Rivergate VWR1 transformer can result in overloads and low voltage concerns in the North Portland area (both on PGE's system and PACW's system). This project installs a new bulk power transformer at Harborton to help mitigate these concerns, meeting NERC Compliance requirements. In addition, the project sectionalizes the Rivergate-Trojan 230 kV line, which is part of the South of Allston Path, adding system flexibility.
Rebuild the existing Northern substation and convert to 115 kV. The conversion of the substation enables the existing 57 kV line to be sold to PACW, who will then utilize the line for a project to mitigate NERC Compliance concerns for both PACW and PGE. The rebuild of Northern substation eliminates antiquated equipment at the substation and installs SCADA for remote monitoring capabilities. The project also includes a rebuild of the Rivergate South substation and distribution voltage conversion from 11 kV to 13 kV at both substations. NOTE: The majority of the Future Year costs are for distribution work.
Provided third 115 kV source to both the Shute substation and the West Union substation for system redundancy and flexibility.
Installs a second substation battery at the St Marys West substation. The failure of the single battery to perform when called upon to operate at the substation will cause the protection system to be unable to clear a fault. If this fault was on the 230 kV system, this can result in load loss over 600 MW on PGE's western part of the system. A new control enclosure will also be installed for the 230 kV yard, as well as replacement of an overdutied circuit breaker per NERC Compliance requirements.
Install a second bulk power transformer at the Blue Lake substation. Install a second 115 kV ring bus with two new 115 kV lines, one to Tabor and one to McGill. This work mitigates overloads on the Blue Lake VWR2 bulk power transformer and the Blue Lake-Fairview 115 kV line, meeting NERC Compliance requirements. The installation of the second bulk power transformer enables the decommissioning of the antiquated Linneman substation. NOTE: Future Year costs are for distribution work.
Rebuilds the antiquated Gresham substation 115 kV yard to address aging equipment and seismic concerns. Replaces the main and aux buses, 16 disconnect switches, and 8 circuit breakers.
Constructs a new bulk power substation with a 230 kV yard, two 230 kV lines, two bulk power transformers, a 115 kV yard, and four 115 kV lines. This project is required to install additional bulk system capacity, mitigating NERC Compliance overloads at the Horizon substation and the west side 115 kV transmission system due to load growth in the area.
Reconductors the Orenco-Sunset 115 kV line to mitigate NERC Compliance overloads.
Rebuilds the substation to a breaker and one half configuration, improving reliability and addressing 115 kV circuit breakers that become overdutied with the energization of Evergreen substation to meet NERC Compliance requirements.
Converts the Brookwood substation to 115 kV, offloading the Cornelius-Orenco 57 kV corridor, which can experience loading and voltage concerns during summer or winter conditions. Installs two new 115 kV lines, one to Shute and one to St Marys, creating a new path from St Marys substation to the North Hillsboro area, adding system redundancy and flexibility to meet NERC Compliance requirements.
Installs a third bulk power transformer at Horizon substation to mitigate overloads on the existing bulk power transformers caused by load growth in the area, meeting NERC Compliance requirements.
Reconductors the Canyon-Urban 115 kV line to address NERC Compliance overload concerns that can occur when the South of Allston Path flows from the south to the north, and the California-Oregon Intertie flows from the south to the north. The reconductor of the line is also necessary to implement temporary system configurations during the Harborton Phase 2 Project.
Reconductors the Murrayhill-St Marys 230 kV line to address NERC Compliance overload concerns that can occur when the South of Allston Path flows from the south to the north.
Route the Horizon-St Marys-Trojan 230 kV line into Harborton, sectionalizing the line into three lines, providing flexibility on the South of Allston Path. Rebuilds the existing 115 kV system between the Harborton and Canyon substations due to the change in system topology with the source for the area moving from St Marys to Harborton. This mitigates overloads on this path as well as addresses NERC Compliance concerns on the existing Harborton-Rivergate #2 115 kV line.
Builds a new substation to serve new load growth while also addressing existing heavily-loaded distribution infrastructure in the area. The new substation will have three 115 kV sources; the third source splits the McLoughlin-Wilsonville 115 kV line, routing the McLoughlin side to Tonquin and the Wilsonville side to Rosemont. This new configuration mitigates NERC Compliance overload concerns on the Oswego-West Portland 115 kV line, the Canemah-Rosemont 115 kV line, and the Meridian-Sherwood 115 kV line.
Storm repair due to the loss of multiple 500 kV towers on the Grizzly BPA-Round Butte 500 kV line.
Wildfire repair due to the loss of multiple 230 kV structures on the Bethel-Round Butte 230 kV line.
Addresses NERC Compliance requirements on the North Portland 115 kV system.
Provides a second source to the Kelley Point substation, which is solely reliant on the Rivergate substation today.

October 2, 2020

TO: Caroline Moore
Public Utility Commission of Oregon

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to OPUC Data Request No. 012
Dated September 10, 2020

Request:

12. Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of Network Upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please list all Network Upgrades that the Company has constructed since 2010. Please also include Network Upgrades that would match this definition if not for the reference to large generating facility. Please include the following information for each year since the upgrade was in service through 2019 inclusive:

    a. Interconnection queue number of the generator(s) that triggered the upgrade.
    b. Whether the generator(s) are owned by the Company.
    c. Cost of the upgrade borne by the generator(s).
    d. Cost of the upgrade borne by ratepayers.
    e. Cost of the upgrade borne by other transmission customers.
    f. Transmission revenues generated by the upgrade.

Response:

PGE has not constructed any Network Upgrades on its transmission system associated with a generator interconnection since 2010.

October 2, 2020

TO: Caroline Moore
Public Utility Commission of Oregon

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to OPUC Data Request No. 013
Dated September 10, 2020

Request:

13. Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of network upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please identify all Network Upgrades matching this definition that the Company included or seeks to include in rate base in the Company's most recently filed General Rate Case. Please also include Network Upgrades that would match this definition if not for the reference to large generating facility. For all Network Upgrades identified, please indicate the following:

    a. Description of upgrade, including location, equipment, size or rating, and cost.
    b. How that investment was identified.
    c. How the costs were allocated to Oregon and includable in state revenue requirements, as well as each state where PacifiCorp serves retail load.

Response:

PGE has not constructed any Network Upgrades on its transmission system associated with generator interconnection that the Company included or sought to include in its most recently filed general rate case.

March 5, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Supplemental Response to NewSun Data Request No. 010
Dated January 6, 2020

Request:

Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?

Supplemental Response:

After conferral with NewSun, PGE understands that NewSun's requests were intended to encompass upgrades to the transmission system more broadly—not just Network Upgrades associated with interconnection or transmission service, as that term has been defined by FERC and used by the Commission and parties to this proceeding. Specifically, PGE understands that NewSun seeks information regarding "major" transmission system upgrades PGE has completed, the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects it is interested in, NewSun mentioned constructing a new transmission line, reconductoring a transmission line, or constructing a new substation.

Because NewSun's requests used the term "network upgrades," which are the subject of this docket, PGE maintains that its initial responses were complete and adequate. Based on PGE's new understanding that NewSun's requests were intended to encompass upgrades to the transmission system more broadly, PGE objects that the requests are overly broad and unduly burdensome. PGE also objects that the information requested relates to an issue that PGE understands is outside the scope of Phase I and may be addressed in Phase II. Notwithstanding and without waiving these objections, PGE responds as follows:

Please see Attachment 009 and 018A, which contains major transmission upgrades PGE has constructed over the last three years, along with the cost of the upgrade and the reason for the upgrade.

Note this response applies to NewSun Data Request Nos. 9, 10, 13, 15 and 18.

<u>Response:</u>

PGE objects that the phrase “any benefits to the transmission system” is vague and ambiguous. The Joint Utilities have explained their position regarding system-wide benefits in their testimony. Notwithstanding and without waiving this objection: PGE has not constructed any QF-funded Network Upgrades on its transmission system. Please see PGE’s Response to Staff Data Request No. 12.

June 16, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Third Supplemental Response to NewSun Data Request No. 006
Dated January 6, 2020

Request:

Please list all power purchase agreements under which PGE purchases power including:

a. Project name,
b. Nameplate capacity,
c. Term of power purchases,
d. Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,
e. Whether the facility is certified as a qualifying facility under PURPA,
f. Under what interconnection rules/process the facility was interconnected,
g. Whether the facility interconnected as ERIS or NRIS,
h. The cost of network upgrades funded under the interconnection agreement,
i. Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,
j. The type of transmission service,
k. The entity that submitted the transmission service request,
l. The cost of network upgrades funded under the transmission service request.

Third Supplemental Response:

On May 11, 2021, Marie Barlow sent an email to counsel for the Joint Utilities requesting additional information. One of the requests, directed to PGE, was that PGE "provide [NewSun] with [QF] interconnection studies or make them publicly available like they are for PacifiCorp and Idaho Power."

As discussed in previous data requests, interconnection studies for small QFs are publicly available on OASIS (https://www.oasis.oati.com/pge/), with the following pathway: Generation Interconnection → Oregon Small Generator Interconnection→ Study Reports. In the update to Attachment A to NIPPC DR 1, PGE provides the queue number for small QFs where applicable. Accordingly, it is PGE's understanding that NewSun should be able to match the publicly available interconnection studies for small QF generators with their respective projects using the queue numbers in Attachment A to NIPPC DR 1.

Counsel for NewSun further claims in the email that PGE's "interconnection studies are not even publicly available on OASIS." It is PGE's understanding that counsel for NewSun is referring to the folder for large QF interconnection studies, with the following pathway: Generation Interconnection → Interconnection Studies and Cases → Interconnection Studies and Cases Website. To comply with FERC Order No. 845 and requirements to protect customers' sensitive business information, interconnection studies for large projects are kept on a SharePoint website where access to the public is available by submitting a request form to PGE.

Because of this security measure to protect customers' confidential information, PGE provided the relevant large QF interconnection studies identifying Network Upgrades as attachments in the Company's response to NIPPC DR 3. In its initial response to NewSun DR 6, PGE directed NewSun to PGE's Response to NIPPC DR 3, where PGE attached the then available interconnection studies and restudies for two large QFs identifying Network Upgrades. Project # 17-068 is Madras Solar and Project #19-081 is Jefferson Solar.

Please see Attachments 003A, 003B, and 003C for the studies, which identify all Network Upgrades.

A restudy for one of the two large QFs was recently completed on May 3, 2021. For the new restudy, please see Attachment 003D.

June 2, 2021

<u>Second Supplemental Response:</u>

On May 11, 2021, Marie Barlow sent an email to counsel for the Joint Utilities requesting additional information. One of the requests, directed to PGE, was that PGE supplement its response to DR 6 by providing information that NewSun could use to link generation facilities that have a PPA to their interconnection and transmission arrangements. In a follow up call, Ms. Barlow clarified that NewSun requests that PGE update its attachments provided in responses to NIPPC DR 1 and NIPPC DR 33 by providing queue numbers.

In the attached update to Attachment A to DR 1, PGE provides the queue number where applicable. With respect to the projects listed on Attachment A to DR 33, all of these projects except Covanta and Yamhill are off system and therefore do not have PGE queue numbers. Both the Covanta and Yamhill project predate the queue concept.

Also, in response to a question posed by Ms. Barlow in the May 11, 2021 email, if a generator wishes to negotiate a non-QF PPA, PGE does not check to determine whether or not that generator might be certified with FERC as a QF.

March 5, 2021

Supplemental Response:

After conferral with NewSun, PGE understands that the intent of these data requests was to allow NewSun to trace specific generators through the interconnection and transmission-service-request processes to evaluate the Joint Utilities' testimony that Network Upgrades can be shifted from the interconnection process to the transmission-service-request process when a generator interconnects with ERIS instead of NRIS. PGE notes that the potential for upgrade-shifting that NewSun seeks to confirm is a straightforward application of the OATT and related FERC orders. In addition, as noted in PGE's initial responses, the additional information NewSun requests is voluminous and would be extremely burdensome to compile, if it were even available. However, PGE provides this supplemental response in an effort to respond directly to the narrower question that PGE now understands NewSun is asking. PGE understands that NewSun is not interested in reviewing every transmission and interconnection study, and PGE believes that this supplemental response more efficiently and directly responds to NewSun's question than providing information about numerous interconnection and transmission service requests.

As PGE has explained in testimony and in response to other data requests, all of PGE's on-system QFs interconnected with NRIS. Of the on-system, non-QF resources that PGE owns or purchases power from, only one generator originally interconnected with ERIS.[1] As PGE previously indicated in response to NewSun Data Request No. 20, "PGE's Port Westward 2 generating facility interconnected with ERIS. No network upgrades were required to designate Port Westward 2 as a network resource because sufficient transmission capacity existed on PGE's system to deliver the output to PGE's network load." Port Westward 2 is located near PGE's Port Westward 1 and Beaver facilities. When developing and interconnecting Port Westward 2, PGE's Merchant Function knew that it already possessed sufficient transmission capacity to deliver Port Westward 2's output to PGE's load and therefore decided to interconnect the facility using ERIS.

To the extent NewSun is interested in identifying the magnitude of Network Upgrades that could be shifted if a generator interconnected with ERIS, Attachment 001A to PGE's response to Staff Data Request No. 1 shows the deliverability-driven Network Upgrades PGE has identified in system impact studies for two large generators, one of which is a QF with more than $10 million in deliverability-driven Network Upgrades.

Note this response applies to NewSun Data Request Nos. 6, 8, 19 and 20.

January 21, 2021

Response:

PGE objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

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[1] Many of PGE's on-system resource interconnected well before FERC issued Order 2003, which adopted the NRIS and ERIS concepts, and took effect on January 20, 2004. See Order 2003-A at ¶ 40.

Notwithstanding and without waiving these objections: Please see PGE's Responses to NIPPC Data Request Nos. 1, 2, 3, 4, 7, 8, 31, and 33; PGE's Response to Staff Data Request Nos. 5, 8, and 12; docket RE 143; and PGE's small and large generator interconnection queues, which are publicly available on OASIS. PGE does not track and compile information regarding the interconnection arrangements of the resources from which it purchases under non-QF PPAs or the off-system QFs from which it purchases. All QFs directly interconnected to PGE interconnected with NRIS. Similarly, PGE does not compile information regarding the off-system transmission arrangements of resources from which it purchases. PGE has not constructed any Network Upgrades on PGE's transmission system associated with requests for transmission service from PGE.

June 2, 2021

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Second Supplemental Response to NIPPC Data Request No. 001
Dated September 1, 2020

Request:

Identify each QF project PGE has entered into a contract with and identify if PGE has designated it a network resource.

Second Supplemental Response:

PGE revises Supplemental Attachment 001A to include queue numbers where applicable.

Please see the Revised Supplemental Attachment 001A.

Revised Response:

In response to NIPPC Data Request No. 031, PGE revises its initial response by adding the language in bold to avoid any confusion.

Please see Supplemental Attachment 001A.

Based on conversations with counsel for NIPPC, PGE understands that this Data Request seeks to understand why PGE has designated some QFs as network resources and not others. PGE understands that QF output must be delivered using firm transmission because QFs cannot be curtailed except in system emergencies. All of PGE's QFs that have achieved commercial operation are being delivered via firm transmission service. While PGE has designated most QFs **that have achieved commercial operation** as network resources for delivery, it has elected to deliver some QFs' output using firm point-to-point transmission service. Firm network transmission service (which is used to deliver the output of QFs designated as network resources) and firm point-to-point transmission service have the same priority code for curtailment purposes. PGE has elected to use firm point-to-point transmission for off-system QFs delivering to PGE via the PACW-PGE interface because doing so allows PGE to accept these QFs' output while also making unused transmission available for energy transfers in the Western Energy Imbalance Market, which occur via the PACW-PGE interface.

Supplemental Response:

PGE supplements its response with Supplemental Attachment 001A. This attachment includes six additional projects with PPAs that were executed in 2020, that were inadvertently omitted from the previous version.

Response:

Please see Attachment 001A.

Based on conversations with counsel for NIPPC, PGE understands that this Data Request seeks to understand why PGE has designated some QFs as network resources and not others. PGE understands that QF output must be delivered using firm transmission because QFs cannot be curtailed except in system emergencies. All of PGE's QFs that have achieved commercial operation are being delivered via firm transmission service. While PGE has designated most QFs as network resources for delivery, it has elected to deliver some QFs' output using firm point-to-point transmission service. Firm network transmission service (which is used to deliver the output of QFs designated as network resources) and firm point-to-point transmission service have the same priority code for curtailment purposes. PGE has elected to use firm point-to-point transmission for off-system QFs delivering to PGE via the PACW-PGE interface because doing so allows PGE to accept these QFs' output while also making unused transmission available for energy transfers in the Western Energy Imbalance Market, which occur via the PACW-PGE interface.

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NIPPC DR Attach 001A

Project	Technology	Capacity (MW)
PaTu Wind	Wind	9
Starbuck Properties	Solar	0.025
Country Village Estates	Solar	0.04
JC Biomethane	Biogas	1.6
Coffin Butte	Biogas	5.66
Northern Wasco PUD	Hydro	5.85
FGO	Biogas	0.37
Conduit 3	Hydro	0.172
City of Grehsam Waste Water	Hydro	0.17
Tualatin Valley Water District	Hydro	0.112
Domaine Drouhin	Solar	0.094
Fremont Solar	Solar	8
Port of Tillamook	Biogas	1.2
Bear Creek Butte	Wind	10
West Butte	Wind	10
Minikahda Hydropower Co.	Hydro	0.2
Von Family Limited Partnership	Hydro	0.2
Steel Bridge Solar	Solar	2.5
Fossil Lake	Solar	10
Lakeview	Solar	10
NorWest Energy 14	Solar	2.2
SP Solar 1	Solar	2.2
SP Solar 5	Solar	2.2
SP Solar 8	Solar	2.2
SP Solar 7	Solar	2.2
SP Solar 6	Solar	2.2
NorWest Energy 16	Solar	2.2
SP Solar 4	Solar	2.2
SP Solar 2	Solar	2.2
St. Helen's Organic Recyling	Biogas	2.4

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NIPPC DR Attach 001A

Project	Technology	Capacity (MW)
Willamina Solar	Solar	0.5
Sheep Solar	Solar	2.2
Silverton Solar	Solar	2.2
OE Solar 3	Solar	10
Butler Solar	Solar	4
Boring Solar	Solar	2.2
Starvation Solar	Solar	10
Drift Creek	Solar	2.2
Glenn Creek	Solar	2.2
OE Solar 2	Solar	5
OE Solar 1	Solar	10
Morrow Solar	Solar	10
Dayton Solar I	Solar	10
Tygh Valley Solar	Solar	10
Wasco Solar 1	Solar	10
OE Solar 4	Solar	10
Fort Rock Solar II	Solar	10
Fort Rock Solar I	Solar	10
Ballston Solar	Solar	2.2
Suntex Solar	Solar	10
Amity Solar	Solar	4
Stringtown Solar	Solar	4
Starlight Solar	Solar	4
Firwood Solar	Solar	10
Duus Solar	Solar	10
Fishback Solar	Solar	3
Bridgeport Solar	Solar	7
O'neil Creek Solar	Solar	2.2
St Louis Solar	Solar	2.2
Rafael Solar	Solar	2.2

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NIPPC DR Attach 001A

Project	Technology	Capacity (MW)
OM Power 1	Geothermal	10
Willamina Mill Solar	Solar	2.2
Palmer Solar	Solar	2.2
Energy Partners I	Biomass	10
Energy Partners II	Biomass	10
Case Creek Solar	Solar	2.2
Alfalfa Solar	Solar	10
Fort Rock Solar IV	Solar	10
Harney Solar I	Solar	10
Riley Solar	Solar	10
South Burns Solar I	Solar	10
West Hines Solar I	Solar	10
Alkali	Solar	10
Rock Garden	Solar	10
OE Solar 5	Solar	10
Day Hill Solar	Solar	2.2
Labish Solar	Solar	2.2
Brightwood Solar	Solar	10
Airport Solar	Solar	47.25
Kale Patch Solar	Solar	2.2
Evergreen BioPower	Biomass	10
Thomas Creek Solar	Solar	2.2
Yamhill Creek Solar	Solar	2.2
Stark Solar (Solar Star Oregon)	Solar	10
OE Solar 6	Solar	10
Brush Creek Solar	Solar	2.2
Daisy Solar 1	Solar	10
Tickle Creek Solar	Solar	1.85
BioGreen	Biomass	28
Volcano Solar	Solar	0.75

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project	Technology	Capacity (MW)
SSD Marion 3	Solar	2
SSD Clackamas 4	Solar	2
SSD Clackamas 2	Solar	2
Liberal Solar	Solar	10
Delaney Solar	Solar	2.5
Eagle Creek Solar	Solar	5
Eola Solar	Solar	2.2
Rock Creek Solar	Solar	2.2

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project	Technology	Capacity (MW)
PaTu Wind	Wind	9
Starbuck Properties	Solar	0.025
Country Village Estates	Solar	0.04
JC Biomethane	Biogas	1.6
Coffin Butte	Biogas	5.66
Northern Wasco PUD	Hydro	5.85
FGO	Biogas	0.37
Conduit 3	Hydro	0.172
City of Grehsam Waste Water	Hydro	0.17
Tualatin Valley Water District	Hydro	0.112
Domaine Drouhin	Solar	0.094
Fremont Solar	Solar	8
Port of Tillamook	Biogas	1.2
Bear Creek Butte	Wind	10
West Butte	Wind	10
Minikahda Hydropower Co.	Hydro	0.2
Von Family Limited Partnership	Hydro	0.2
Steel Bridge Solar	Solar	2.5
Fossil Lake	Solar	10
Lakeview	Solar	10
NorWest Energy 14	Solar	2.2
SP Solar 1	Solar	2.2
SP Solar 5	Solar	2.2
SP Solar 8	Solar	2.2
SP Solar 7	Solar	2.2
SP Solar 6	Solar	2.2
NorWest Energy 16	Solar	2.2
SP Solar 4	Solar	2.2
SP Solar 2	Solar	2.2
St. Helen's Organic Recyling	Biogas	2.4

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project	Technology	Capacity (MW)
Willamina Solar	Solar	0.5
Sheep Solar	Solar	2.2
Silverton Solar	Solar	2.2
OE Solar 3	Solar	10
Butler Solar	Solar	4
Boring Solar	Solar	2.2
Starvation Solar	Solar	10
Drift Creek	Solar	2.2
Glenn Creek	Solar	2.2
OE Solar 2	Solar	5
OE Solar 1	Solar	10
Morrow Solar	Solar	10
Dayton Solar I	Solar	10
Tygh Valley Solar	Solar	10
Wasco Solar 1	Solar	10
OE Solar 4	Solar	10
Fort Rock Solar II	Solar	10
Fort Rock Solar I	Solar	10
Ballston Solar	Solar	2.2
Suntex Solar	Solar	10
Amity Solar	Solar	4
Stringtown Solar	Solar	4
Starlight Solar	Solar	4
Firwood Solar	Solar	10
Duus Solar	Solar	10
Fishback Solar	Solar	3
Bridgeport Solar	Solar	7
O'neil Creek Solar	Solar	2.2
St Louis Solar	Solar	2.2
Rafael Solar	Solar	2.2

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project	Technology	Capacity (MW)
OM Power 1	Geothermal	10
Willamina Mill Solar	Solar	2.2
Palmer Solar	Solar	2.2
Energy Partners I	Biomass	10
Energy Partners II	Biomass	10
Case Creek Solar	Solar	2.2
Alfalfa Solar	Solar	10
Fort Rock Solar IV	Solar	10
Harney Solar I	Solar	10
Riley Solar	Solar	10
South Burns Solar I	Solar	10
West Hines Solar I	Solar	10
Alkali	Solar	10
Rock Garden	Solar	10
OE Solar 5	Solar	10
Day Hill Solar	Solar	2.2
Labish Solar	Solar	2.2
Brightwood Solar	Solar	10
Airport Solar	Solar	47.25
Kale Patch Solar	Solar	2.2
Evergreen BioPower	Biomass	10
Thomas Creek Solar	Solar	2.2
Yamhill Creek Solar	Solar	2.2
Stark Solar (Solar Star Oregon)	Solar	10
OE Solar 6	Solar	10
Brush Creek Solar	Solar	2.2
Daisy Solar 1	Solar	10
Tickle Creek Solar	Solar	1.85
BioGreen	Biomass	28
Volcano Solar	Solar	0.75

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project	Technology	Capacity (MW)
SSD Marion 3	Solar	2
SSD Clackamas 4	Solar	2
SSD Clackamas 2	Solar	2
Liberal Solar	Solar	10
Delaney Solar	Solar	2.5
Eagle Creek Solar	Solar	5
Eola Solar	Solar	2.2
Rock Creek Solar	Solar	2.2

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project	Small Gen Interconnection Queue Number	Technology	Capacity (MW)
PaTu Wind		Wind	9
Starbuck Properties		Solar	0.025
Country Village Estates		Solar	0.04
JC Biomethane		Biogas	1.6
Coffin Butte		Biogas	5.66
Northern Wasco PUD		Hydro	5.85
FGO		Biogas	0.37
Conduit 3		Hydro	0.172
City of Grehsam Waste Water		Hydro	0.17
Tualatin Valley Water District		Hydro	0.112
Domaine Drouhin		Solar	0.094
Fremont Solar		Solar	8
Port of Tillamook		Biogas	1.2
Bear Creek Butte		Wind	10
West Butte		Wind	10
Minikahda Hydropower Co.		Hydro	0.2
Von Family Limited Partnership		Hydro	0.2
Steel Bridge Solar		Solar	2.5
Fossil Lake		Solar	10
Lakeview		Solar	10
NorWest Energy 14	SPQ0002	Solar	2.2
SP Solar 1	SPQ0003	Solar	2.2
SP Solar 5	SPQ0004	Solar	2.2
SP Solar 8	SPQ0024	Solar	2.2
SP Solar 7	SPQ0019	Solar	2.2
SP Solar 6	SPQ0023	Solar	2.2
NorWest Energy 16		Solar	2.2
SP Solar 4		Solar	2.2
SP Solar 2	SPQ0026	Solar	2.2
St. Helen's Organic Recyling		Biogas	2.4
Willamina Solar	SPQ0001	Solar	0.5
Sheep Solar	SPQ0006	Solar	2.2
Silverton Solar	SPQ0005	Solar	2.2
OE Solar 3		Solar	10
Butler Solar	SPQ0012	Solar	4
Boring Solar	SPQ0010	Solar	2.2
Starvation Solar		Solar	10
Drift Creek	SPQ0007	Solar	2.2
Glenn Creek		Solar	2.2
OE Solar 2		Solar	5
OE Solar 1		Solar	10
Morrow Solar		Solar	10
Dayton Solar I		Solar	10
Tygh Valley Solar		Solar	10
Wasco Solar 1		Solar	10
OE Solar 4		Solar	10
Fort Rock Solar II		Solar	10
Fort Rock Solar I		Solar	10
Ballston Solar	SPQ0011	Solar	2.2
Suntex Solar		Solar	10
Amity Solar	SPQ0016	Solar	4
Stringtown Solar	SPQ0042	Solar	4
Starlight Solar	SPQ0015	Solar	4
Firwood Solar	SPQ0013	Solar	10
Duus Solar	SPQ0014	Solar	10
Fishback Solar		Solar	3
Bridgeport Solar		Solar	7
O'neil Creek Solar	SPQ0017	Solar	2.2
St Louis Solar	SPQ0018	Solar	2.2
Rafael Solar	SPQ0020	Solar	2.2
OM Power 1		Geothermal	10
Willamina Mill Solar	SPQ0022	Solar	2.2
Palmer Solar	SPQ0025	Solar	2.2
Energy Partners I		Biomass	10
Energy Partners II		Biomass	10
Case Creek Solar	SPQ022A	Solar	2.2

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project	Small Gen Interconnection Queue Number	Technology	Capacity (MW)
Alfalfa Solar		Solar	10
Fort Rock Solar IV		Solar	10
Harney Solar I		Solar	10
Riley Solar		Solar	10
South Burns Solar I		Solar	10
West Hines Solar I		Solar	10
Alkali		Solar	10
Rock Garden		Solar	10
OE Solar 5		Solar	10
Day Hill Solar	SPQ0027	Solar	2.2
Labish Solar	SPQ0021	Solar	2.2
Brightwood Solar	SPQ0029	Solar	10
Airport Solar		Solar	47.25
Kale Patch Solar	SPQ0028	Solar	2.2
Evergreen BioPower		Biomass	10
Thomas Creek Solar	SPQ0038	Solar	2.2
Yamhill Creek Solar	SPQ0044	Solar	2.2
Stark Solar (Solar Star Oregon)		Solar	10
OE Solar 6		Solar	10
Brush Creek Solar	SPQ0008	Solar	2.2
Daisy Solar 1		Solar	10
Tickle Creek Solar	SPQ0030	Solar	1.85
BioGreen		Biomass	28
Volcano Solar	SPQ0045	Solar	0.75
SSD Marion 3	SPQ0066	Solar	2
SSD Clackamas 4	SPQ0069	Solar	2
SSD Clackamas 2	SPQ0051	Solar	2
Liberal Solar	SPQ0085A	Solar	10
Delaney Solar	SPQ0085C	Solar	2.5
Eagle Creek Solar	SPQ0085B	Solar	5
Eola Solar	SPQ0039	Solar	2.2
Rock Creek Solar	SPQ0111	Solar	2.2

December 9, 2020

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Revised Response to NIPPC Data Request No. 002
Dated September 1, 2020

Request:

Please indicate whether PGE interconnected each state jurisdictional qualifying facility interconnection as an energy or network resource.

Revised Response:

In response to NIPPC Data Request No. 032, PGE provides this revised response.

PGE objects that the phrase "interconnected . . as an energy or network resource" is vague and ambiguous. PGE interprets the request to be asking about whether PGE interconnected QFs using Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS). Notwithstanding this objection and subject to this interpretation, PGE responds as follows:

To the best of PGE's knowledge, PGE did not interconnect any QFs between the time that FERC's Order 2003, which adopted the concepts of NRIS and ERIS, took effect and the time that the Commission adopted NRIS as its policy. Since NRIS became the Commission's policy for QFs, PGE has interconnected all QFs using NRIS.

Response:

To the best of PGE's knowledge, PGE did not interconnect any QFs between the time that FERC's Order 2003, which adopted the concepts of NRIS and ERIS, took effect and the time that the Commission adopted NRIS as its policy. Since NRIS became the Commission's policy for QFs, PGE has interconnected all QFs using NRIS.

June 16, 2021

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Supplemental Response to NIPPC Data Request No. 003
Dated September 1, 2020

Request:

For each state jurisdictional qualifying facility interconnection, please provide (or identify a publicly available location for accessing) the feasibility study, system impact study, facilities study, interconnection study, the final accounting with actual interconnection costs, and identify all network upgrades.

Supplemental Response:

PGE supplements its response with Attachment 003D. This attachment includes a recently completed interconnection restudy that identifies Network Upgrades for Project #19-081.

Please see Attachment 003D.

Please also see PGE's Response to NIPPC DR 044A.

September 18, 2020

Response:

Based on conversations with counsel for NIPPC, PGE understands "interconnection study" means "interconnection agreement." In addition, PGE understands that this request encompasses only interconnections for which Network Upgrades were identified. PGE has conducted one or more interconnection studies for 179 small QFs since 2014, and none of those studies has identified Network Upgrades on PGE's transmission system. PGE's small generator interconnection studies conducted since 2017 are publicly available on PGE's OASIS website.

PGE has conducted one or more interconnection studies that identified Network Upgrades for two large QFs. Please see Attachments 003A, 003B, and 003C for the studies, which identify all Network Upgrades. Neither of these QFs has signed an interconnection agreement to date

Portland General Electric Company

Interconnection Feasibility Study

Interconnection Request:

17-068 (80 MW [redacted] Solar Project)

Portland General Electric Transmission

Transmission and Reliability Services

Study (Originally) Issued: June 15, 2018

Amended Study Issued: October 2, 2015

Interconnection Feasibility Study for LGIP #17-068

Interconnection Feasibility Study for LGIP #17-068

Table of Contents

[009931/350567/2]

Interconnection Feasibility Study for LGIP #17-068

I. Introduction

On October 05, 2017, Portland General Electric Transmission ("PGET"), the Transmission Provider[1], received a completed Generation Interconnection Request from the Interconnection Customer, including the necessary deposit, pursuant to the Large Generator Interconnection Procedures ("LGIP") in PGE's FERC Open Access Transmission Tariff ("OATT"), for the connection of a new Generation Facility to PGE's Transmission System. The Interconnection Request seeks to interconnect a 80 MW solar facility ("[redacted] Solar Project") located in Jefferson County, Oregon, to PGE's Transmission System with a Point of Interconnection approximately 4.9 miles north of PGE's existing Round Butte substation on the Pelton-Round Butte 230kV generator lead line.

As set forth in Attachment O of PGE's OATT, the Transmission Provider assigned the number #17-068 to this Interconnection Request at the time it entered the queue.

On February 8, 2018, PGET received the executed Interconnection Feasibility Study (IFS) Agreement with the appropriate deposit from the Interconnection Customer.

This Interconnection Feasibility Study ("IFS") provides the study results for the Interconnection Customer's request #17-068 for Network Resource Interconnection Service ("NRIS") and Energy Resource Interconnection Service ("ERIS").

II. Interconnection Feasibility Study Scope

The primary purpose of the Interconnection Feasibility Study ("IFS") is to preliminarily evaluate the feasibility of the Interconnection Customer's proposed interconnection at the designated Point of Interconnection, and any required system additions necessary to accommodate that request. An IFS normally consists of a maximum flow test (NRIS only), a power flow analysis, and a short circuit analysis. The following objectives are required to be met through this IFS:

- Documentation of the assumptions used in the study.
- Documentation of any system impacts (i.e., thermal overloads or voltage limit violations) observed in meeting the NERC/WECC System Performance Criteria, that are adverse to the reliability of the electric system, as a result of the proposed Interconnection.

[1] With the exception of those terms that are defined herein, capitalized terms used throughout this document have the same meaning as such terms are defined in PGE's Open Access Transmission Tariff (OATT).

- Documentation of other transmission providers' transmission systems that are impacted, and identification of these transmission providers as Affected Systems.

- Documentation of fault interrupting equipment with short circuit capability limits that are exceeded as a result of the proposed interconnection.

- A list of facility additions and upgrades that the applicable power flow and short circuit analyses determine to be required to accommodate the requested interconnection service.

- A non-binding, good faith estimate of the cost responsibilities for making the required additions and system upgrades necessary to accommodate the request.

- A non-binding, good faith estimate of the time to construct the required additions and system upgrades necessary to accommodate the request.

Pursuant to Section 6.2 of Attachment O to the OATT, this IFS considers the Base Case as well as all generating facilities that, on the date the study was commenced: (i) were directly interconnected to PGE's Transmission System; (ii) were interconnected to Affected Systems and may have an impact on the Interconnection Request(s); (iii) (with respect to both generating facilities and identified PGE Transmission System upgrades associated with any higher queued interconnection request) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and (iv) have no queue position but have executed a Large Generator Interconnection Agreement ("LGIA") or requested that an unexecuted LGIA be filed with FERC.

As of the date this IFS commenced, there were no Generating Facilities that lacked a queue position but had executed an LGIA or requested that an unexecuted LGIA be filed with FERC that would impact, or be impacted by, the proposed Plan of Service resulting from the studies conducted to-date for this Generation Interconnection Request.

III. Interconnection Feasibility Study Assumptions

The IFS considerations include the following assumptions for system conditions for all stages and seasons:

- The Interconnection Customer's requested interconnection in-service date of December 01, 2019.

- Generation Facilities that have no queue position but have executed an LGIA or have requested an unexecuted LGIA be filed with FERC. (Please note: There are no un-queued generation facilities.)
- Generating Facilities and identified PGE Transmission System upgrades associated with higher queued interconnections that have a pending higher queued Interconnection Request to interconnect to PGE's Transmission System.
- Projects and Generating Facilities interconnecting to neighboring utilities that could have an impact on the Interconnection Request. Any such projects identified are described in Section IV below and included in the Study Cases (defined below) prior to the Preliminary Plan of Service.
- Projects identified in PGE's annual progress report to WECC that are scheduled to be on-line prior to the [redacted] Solar Project's expected in-service date, are outlined in Section IX below.
- [redacted] Solar Project was modeled at its maximum capability of 80 MW in all studies.
- The Point of Interconnection for [redacted] Solar Project will be approximately 4.9 miles north of PGE's existing Round Butte substation on the Pelton-Round Butte 230kV generator lead line.
- The nominal voltage level at the Point of Interconnection will be 230 kV.
- The Interconnection Customer will design, permit, build and maintain the 230 kV line from the Interconnection Customer's generation site to the Point of Interconnection.
- The West of Cascades (WOCS) path was stressed to 4027 MW (North) and 2831 MW (South) in the heavy summer case, as baseline
- The California-Oregon intertie (COI) path was stressed to 4612 MW North-South in the heavy summer case as baseline.

IV. Interconnection Feasibility Study Benchmark Case Development

Benchmark Cases are the seasonally adjusted Western Electricity Coordinating Council ("WECC") Base Cases to which additions are made to reflect higher queued interconnection and transmission service requests as well as additions for transmission projects being planned by PGET and by other transmission providers. Benchmark Cases provide the starting points for studying a new interconnection and/or transmission service request.

Interconnection Feasibility Study for LGIP #17-068

The WECC Base Cases were chosen based on which cases were available at the time of the Interconnection Request and were determined to best represent system conditions in the time frame the Interconnection Customer's interconnection service is expected to be placed in-service.

The Benchmark Cases used in this IFS were developed from summer-peak and winter-peak load base cases compiled by WECC and posted for member use. The summer-peak Base Case used the WECC 2021 Heavy Summer 2 case. The winter-peak Base Case used the WECC 2020-21 Heavy Winter 1 case.

The following changes were made to each of these WECC Base Cases:

- PGE customer loads were adjusted to match the 1-in-5 summer and winter peak load levels forecasted for the PGE service territory.
- The proposed plan of service for the higher queued 100MW Interconnection Request at Bethel (**Request # 16-061**) was also added to the WECC Base Cases. It was modeled at its maximum capabilities in discharging mode (i.e. 100MW).
- The proposed plan of service for the higher queued 400MW Interconnection Request at Fort Rock (**Request # 17-065**) was also added to the Base Cases. It was modeled at its maximum capabilities of 400MW.
- The proposed plan of service for the higher queued 200MW Interconnection Request at Rivergate (**Request # 17-066**) was also added to the Base Cases. It was modeled at its maximum capabilities in discharging mode (i.e. 200MW).
- The proposed plan of service for the higher queued 200MW Interconnection Request at Harborton (**Request # 17-067**) was also added to the Base Cases. It was modeled at its maximum capabilities in discharging mode (i.e. 200MW).
- Modeling of the BPA transmission system was also changed to include a known battery storage project in BPA's interconnection queue that could have an impact on the Interconnection Request. BPA Request #G0528 is located near this Generator Interconnection and has an earlier requested in-service date, June 30, 2017. The BPA battery storage project was modeled at maximum output of 150 MW for the heavy summer and heavy winter Study Cases (defined below).
- The Base Cases were modified to include modeling of all study assumptions, including firm transfers, in order to evaluate potential impacts of the Plan of Service on the parallel transfer paths.
- The proposed plans of service for higher queued Interconnection Requests were also added to the WECC Base Cases. Generation associated with these Interconnection Requests are modeled at their maximum power outputs in both the summer-peak and winter-peak Base Cases, as noted below:

- Preliminary power flow analysis using the Benchmark Cases revealed existing thermal overloads for various contingency conditions. These thermal overloads are existing concerns, and are not attributable to this interconnection.

V. Preliminary Plan Of Service

A Preliminary Plan of Service that is intended to satisfy the Interconnection Customer's request for Generation Interconnection was developed in this IFS.

This Preliminary Plan of Service for NRIS interconnection requires the addition of the following Network Upgrades to PGE's existing Transmission System:

- New 3-position 230 kV ring bus on the Pelton-Round Butte 230 kV generator lead line.
- New 4-position 500 kV ring bus at the Round Butte substation.
- A second 500 MVA 500/230 kV transformer at PGE's Round Butte Substation.
- An additional 230 kV breaker position at PGE's Bethel Substation.
- A 500 MVA, 500/230 kV transformer at PGE's Bethel Substation.
- A 500 MVA, 500 kV phase-shifting transformer at PGE's Round Butte Substation with 500 kV line and bus side breakers.
- Conversion of PGE's 99 mile Bethel-Round Butte 230 kV line to a 500 kV line.

The Preliminary Plan of Service for NRIS is depicted in the following diagram:

Interconnection Feasibility Study for LGIP #17-068

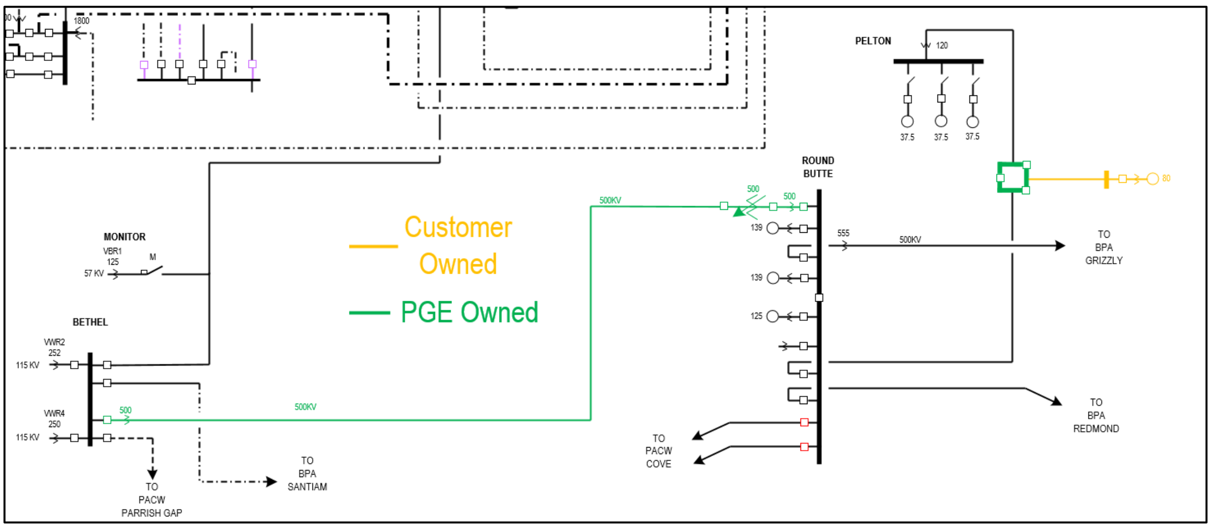

Figure 1: Solar Project Preliminary Proposed Plan of Service for NRIS Interconnection.

This Preliminary Plan of Service for ERIS interconnection requires the addition of the following Network Upgrades to PGE's existing Transmission System:

- New 3-position 230 kV ring bus on the Pelton-Round Butte 230 kV generator lead line

The Preliminary Plan of Service for ERIS is depicted in the following diagram:

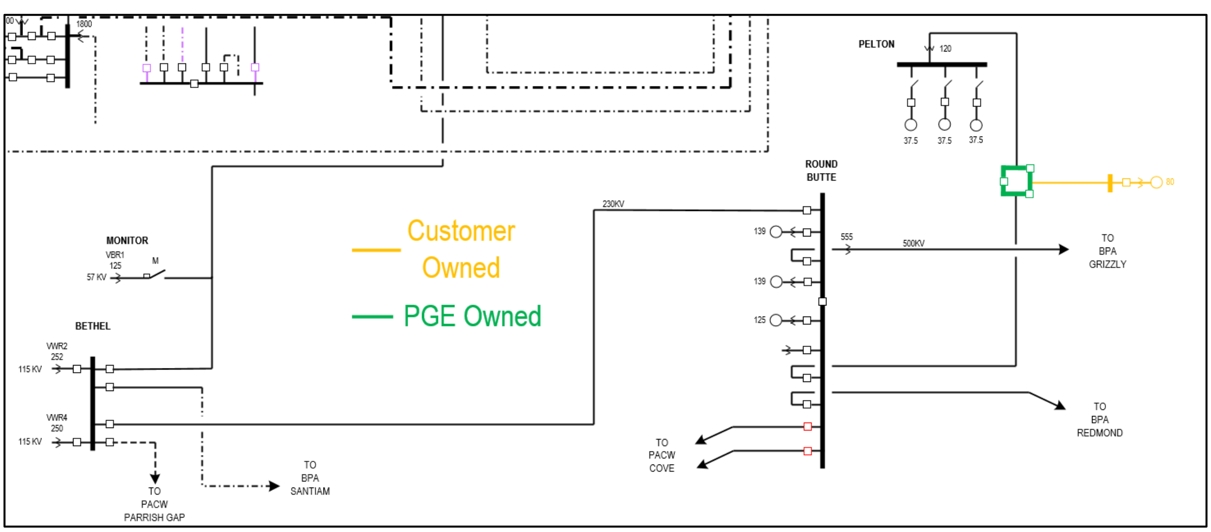

Figure 2: Solar Project Preliminary Proposed Plan of Service for ERIS Interconnection.

Modeling for the Preliminary Plan of Service is added to the seasonally adjusted Benchmark Cases to produce the "Study Cases" used in the analyses that follow. In preparation for NRIS studies, the generation added by this Interconnection Request was balanced by reductions in

Benchmark Case generation at both Upper Columbia and “Mid-Columbia” hydro generating facilities.

VI. Interconnection Feasibility Study Methodology

A variety of electrical system simulations and associated assessments are needed to ensure that specified performance standards will be met following the addition of either of the Preliminary Plans of Service for this Interconnection Request. Simulations and assessments typically addressed in an IFS include the following:

A.	Maximum Flow Test	(NRIS only)
B.	Power Flow Analysis	(NRIS & ERIS)
C.	Short Circuit Analysis	(NRIS & ERIS)

The study area includes the entire Northwest transmission system.

Each of these analyses may reveal shortcomings in the Preliminary Plan of Service that require design changes or other forms of mitigation in order to meet the specified performance standards. Each analysis is performed on a version of the Preliminary Plan of Service that includes all design changes and mitigations required by earlier analyses; this is referred to as the Working Plan of Service. The Working Plan of Service that meets the performance standards for all analyses becomes the Proposed Plan of Service.

A. Maximum Flow Testing

Network Resource Interconnection Service (“NRIS”) requires the Transmission Provider to conduct the necessary studies and to construct the upgrades needed to integrate the generating facility in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers. NRIS allows the Interconnection Customer’s generating facility to be designated as a Network Resource, up to its full output, on the same basis as existing Network Resources interconnected to the Transmission Provider’s Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. PGET interprets this to mean that the Transmission System must be capable of providing firm service to the Interconnection Customer year round from the new Point of Interconnection to PGE’s native load. It is therefore necessary to demonstrate that the entire output of the Project can be met for each peak load season in order to confirm that firm transmission can be made available.

The demonstration of this available transmission capability can be achieved by applying the Maximum Flow Test (“MFT”) methodology, which is also utilized in the transmission path rating process at the WECC[2]. The purpose of the MFT is to identify the maximum power flow that can occur on a transmission path under realistic conditions. This maximum power flow sets a high limit on the rating that can be used for a transmission path. However, operating limits may be lower due to interactions with other existing paths that are part of the WECC's path rating process.

In order for NRIS from the Interconnection Customer's proposed Point of Interconnection to be feasible, the MFT must show that PGE's Transmission System can carry the additional power flows for the Interconnection Customer's generation on top of the power flows already required by existing commitments and higher queued transmission service requests. This means that the power flow delivered by the Working Plan of Service must be sufficient to accommodate the output from Interconnection Customer's generation plant.

Allowed Benchmark Case changes to maximize power delivery by the Working Plan of Service, are:

- Addition of the new generation, at rated output, at the Point of Interconnection.
- Offsetting reductions in output from other generators.
- Other changes to regional generation dispatch and to import/export levels.

  (Please note: the addition of fictitious elements such as generators, loads, lines, or phase shifters, are not allowed.)

Failure to meet the above maximum power flow requirement will necessitate a redesign to increase capacity or provide some other form of mitigation that results in meeting the power flow and performance requirements.

B. <u>Power Flow Analysis</u>

The North American Electric Reliability Corporation's ("NERC") Reliability Standards require that all elements comprising the Bulk Electric System remain within their established thermal and voltage limits, following loss of a single element (NERC Category P1) and loss of two or more elements (NERC Category P2-P7). In addition, the WECC's System Performance Criteria require that the percentage change in bus voltages cannot exceed 8% for NERC Category P1 contingencies.

The Power World™ Version 20 power flow program is used to simulate power flows and voltage levels for a representative range of possible Category P1-P7 contingencies.

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[2] See WECC document "Overview Of Policies And Procedures For Regional Planning Project Review, Project Rating Review, And Progress Reports"

Interconnection Feasibility Study for LGIP #17-068

Representative contingencies subjected to power flow simulation include:

- Contingencies affecting the Bulk Electric System that are routinely used in planning process studies, including known problem N-1-1 (P6) contingencies in the PGE service territory.
- Contingencies used by neighboring transmission providers in their planning processes for the area.
- Contingencies involving facilities being added in support of this Generation Interconnection Request.

The list of simulated contingencies is included in Appendix 1. Each contingency is simulated against the following load periods: peak summer and peak winter Study Cases. The simulation results for each contingency are assessed for compliance with the following NERC and WECC system performance requirements:

i) Thermal Loading Limits
Pre-contingency power flows through Bulk Electric System elements must remain within their established normal operation thermal limits for no outage conditions.

Post-contingency power flows through Bulk Electric System elements must remain within their established emergency thermal limits.

Thermal limits for PGE elements are established in accordance with PGE's Facility Rating Methodology. Thermal limits set in the WECC Base Cases, from which the summer and winter Study Cases were derived, are used for non-PGE elements.

Thermal line loading increases, due to the Working Plan of Service, that are less than 2% over the Benchmark Case loadings are not considered significant impacts that need to be addressed.

ii) Bus Voltage Limits
Post-contingency bus voltages must remain within voltage limits posted in the WECC Base Cases from which the summer and winter Study Cases were derived.

iii) Bus Voltage Change Limits
The change between Base Case and post-contingency bus voltages must be less than:

- 5% for loss of a single system element
- 10% for simultaneous loss of two system elements.

Failure to meet the above performance requirements for any power flow simulation will require redesign or some other form of mitigation that results in acceptable performance.

C. Short Circuit Analysis

Short circuit studies are conducted to identify transmission equipment with rated fault capabilities that will be exceeded by the higher fault currents that result from adding the Working Plan of Service to PGE's Transmission System.

Modeling information for the Northwest transmission system is maintained through the collaborative efforts of the region's utilities. This modeling information provides the base data to which is added representations of equipment included in:

- The Working Plan of Service.
- Other significant additions to the Northwest transmission system.

Bus faults at substations in the vicinity of the Working Plan of Service are simulated using the Aspen OneLiner™ program. Increases in equipment fault duty, attributable to the Working Plan of Service, cannot result in fault duties that exceed equipment ratings. Any increases in fault duty of less than 1% are not considered significant impacts to the system and thus do not need to be addressed.

Failure to meet the above requirement, for any short circuit simulation, will necessitate redesign or some other form of mitigation that results in acceptable performance.

VII. Interconnection Feasibility Study Results

A. Maximum Flow Testing

The [redacted] Solar Project has a maximum rated output of 80 MW. The Working Plan of Service for this (NRIS) Request must therefore be capable of delivering the additional generation to PGE loads from the Point of Interconnection on the Pelton-Round Butte 230 kV generator lead line.

Because the Point of Interconnection is located outside PGE's service territory, there are no recognized transmission paths to PGE loads over which the output from the [redacted] Solar Project must flow. This means that there are no transmission paths to which we need to apply the Maximum Flow Test for the Working Plan of Service. However, the sole PGE-owned transmission line to PGE's load service territory from the Customer's point-of-interconnection is on the Bethel-Round Butte 230 kV line. This transmission line has no available transfer capability; therefore, for a NRIS interconnection, more transmission will need to be built to PGE's load service territory.

B. <u>Power Flow Analysis</u>

Power flow analysis was conducted on the Working Plan of Service incorporated into the summer-peak and winter-peak load Benchmark Cases using the list of contingencies in Appendix 1. Additional selected P6 (N-1-1) contingencies were also studied but were not listed since they are a combination of two P1 contingencies.

In the NRIS evaluation, the [redacted] solar interconnection does have an impact on the West of Cascades (WOCS) flow due to the rebuilding of the Bethel-Round Butte 230kV line to 500kV. When the interconnection is generating at its maximum output, the path's flow decreases by 942 MW in the heavy summer case and 1028 MW in the heavy winter case. PGE is not the path owner and is not the only Transmission Provider with facilities that are considered part of the path. These other Transmission Providers will be considered Affected Systems to this interconnection request. Affected Systems identified at this time include Bonneville Power Administration and PacifiCorp. Since the interconnection decreases the path flow, the Affected Systems may require facility upgrades on their systems to mitigate the decrease. In any scenario, a WECC path re-rating process will need to be completed with all Affected Systems, which process can take up to 2-3 years to complete. See WECC's document: *"Project Coordination, Path Rating and Progress Report Processes"* for more information on rerating a WECC major path.

In both the NRIS and ERIS evaluation, the heavy summer and heavy winter results show thermal overloads on 500kV lines in the area of the California-Oregon Intertie (COI), however, these overloads can be mitigated by the COI Remedial Action Scheme (RAS).

In the ERIS evaluation, the heavy summer results show thermal overloads on the Redmond BPA-Round Butte 230kV line for two P6 contingencies. While the [redacted] Solar project contributes to the overloads, these overloads exist in the base case, and are not attributed to the customer's project.

[redacted]

The Working Plan of Service is sufficient to satisfy the [redacted] Solar Project request for interconnection on PGE's Transmission System only. As described above, Affected Systems may have facility upgrade requirements on their Transmission System, especially as it impacts WOCS path flows.

Interconnection Feasibility Study for LGIP #17-068

C. Short Circuit Analysis

To determine the contribution of the [redacted] Solar Project interconnection request to fault duty, a short circuit analysis was performed that modeled the highest possible fault duty (worst case) for each of the Working Plans of Service. PGE's standard is to replace breakers when the interrupting capability increases beyond 85%. There are increases on the Pelton generator breaker interrupting capability from 84% to 87%, which necessitates the replacement of these three breakers.

In addition, the customer's proposed step-up transformer configuration will need to be changed from its proposed configuration to a 230 kV (wye) / 34.5 kV (delta) to reliably protect PGE's system.

VIII. Proposed Plan of Service

Study results show that PGET can provide a feasible Proposed Plan of Service that will satisfy the requirements for NRIS and ERIS requested by the Interconnection Customer.

The Proposed Plans of Service are the Preliminary Plans of Service with the addition of the PGE Transmission System upgrades and equipment replacements identified in Section V.

The Proposed Plan of Service for an ERIS interconnection is depicted in Figure 3:

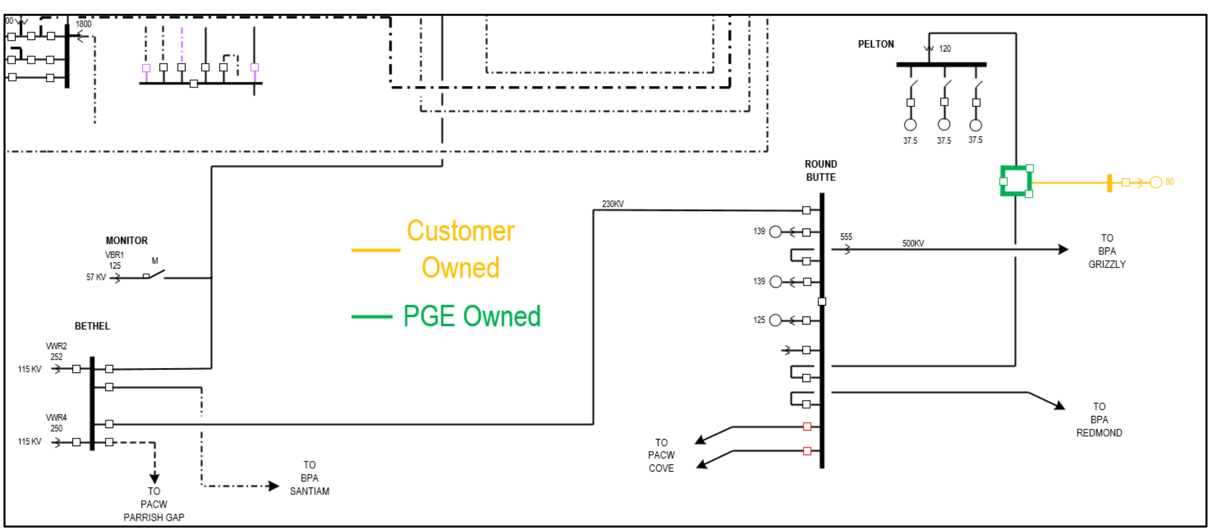

Figure 3: Solar Project ERIS Proposed Plan of Service

The Proposed Plan of Service for an NRIS interconnection is depicted in Figure 4:

[009931/350567/2]

Interconnection Feasibility Study for LGIP #17-068

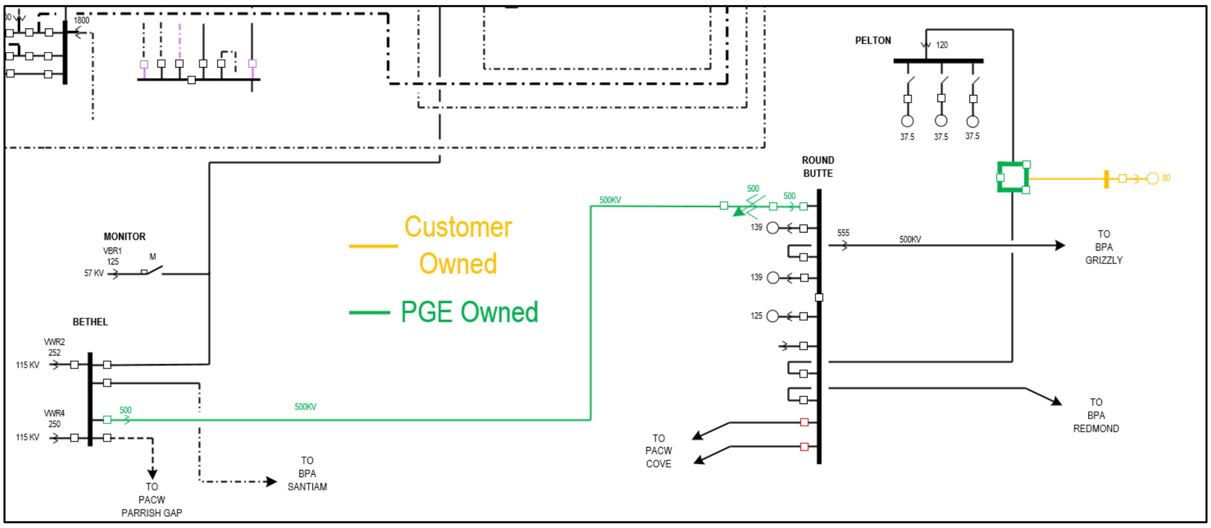

Figure 4: Solar Project NRIS Proposed Plan of Service

IX. Cost Estimate

The following financial assumptions were made in preparation of the cost estimate for the Proposed Plan of Service:

- Cost estimates are based on 2018 dollars.
- Some incremental costs, such as those for: land and right-of-way (ROW) acquisition, environmental studies, permitting, habitat mitigation cost, legal and other miscellaneous costs are not included in this estimate.

The cost estimate presented below is preliminary and is a non-binding good faith estimate. The target accuracy of this cost estimate is ± 50%:

Facilities Description	Cost Estimate
Proposed Plan of Service for ERIS Interconnection	
• **Pelton-Round Butte Tap Station:** Add a 230 kV three position ring bus with disconnect switches, relays, Transmission line work.	$ 2.6 M
• **Pelton Generator breakers:** Replace Pelton generator breakers.	$ 0.3 M
Total:	**$ 2.9 M**

Table 2: Cost Estimate for ERIS Proposed Plan of Service

[009931/350567/2]

The upgrades and equipment required to implement the ERIS Proposed Plan of Service will requires a 2.5-4 year timeline for design, permitting, and construction.

Facilities Description	Cost Estimate
Proposed Plan of Service for NRIS Interconnection	
• **Round Butte Substation:**	
Add a new 500 MVA 500/230 kV transformer with disconnect, switches, and relays.	$ 5.11 M
Add a 500 kV three position ring bus with disconnect switches, relays, transmission line work.	$ 5.2 M
Add a 500 MVA 500 kV phase-shifting transformer with a new circuit breaker, disconnect switches, relays.	$ 14.0 M
• **Bethel Substation:**	
Add a new 500 MVA 500/230 kV transformer with a new 230kV circuit breaker, disconnect switches, relays.	$ 6.2 M
• **Bethel-Round Butte Transmission Line:**	
Rebuild the existing 99 mile 230 kV line to a 500 kV line with new steel structures, disconnect switches, relays, Transmission line work.	$ 297.0 M
• **Pelton-Round Butte Tap Station:**	
Add a 230 kV three position ring bus with disconnect switches, relays, Transmission line work.	$ 2.6 M
• **Pelton Generator breakers:**	
Replace Pelton generator breakers.	$ 0.3 M
Total:	**$ 381.31 M**

Table 3: Cost Estimate for NRIS Proposed Plan of Service

The upgrades and equipment needed to implement the NRIS Proposed Plan of Service will require a 5-7 year timeline for design, permitting, and construction.

There are many factors outside of the Transmission Provider's control that could extend the time required for completing the Proposed Plan of Service outlined above for either service. These factors include, but are not limited to, the following: unexpected delays in the permitting process, extensions to the public process, challenges in acquiring easements/ROW, long lead times for obtaining electrical equipment, shortages of qualified workers, and inclement weather conditions.

X. Conclusions

This IFS concludes that the [redacted] Solar Project request for a Generation Interconnection can be met by proceeding with the Proposed Plan of Service as depicted in Section VIII of this Report, however, the requested in-service date of December 1, 2019 cannot be met. This conclusion in this IFS pertain only to Generation Interconnection to PGE's Transmission System. This IFS does not study, identify Affected System Impacts, or contain any conclusions related to any and all potential Affected Systems or Affected System Operators. The results of this IFS will be shared with the Affected Systems and separate study(s) may need to be conducted by the Affected Systems to identify Affected System Impacts and develop a plan for mitigation as needed.

The study results demonstrate that the Proposed Plan of Service for both ERIS and NRIS interconnection satisfies the requirements for the short circuit and power flow analysis except for negatively impacting the WOCS path rating. Since the WOCS is a major WECC path, a rerating study would be needed as outlined in WECC's document: "*Project Coordination, Path Rating and Progress Report Processes*". Beyond the rerating of WOCS, the Proposed Plan of Service is adequate for the requested NRIS and ERIS.

The estimated cost of the NRIS Proposed Plan of Service is approximately $381.31M and will take approximately 5-7 years to complete, while the ERIS Proposed Plan of Service costs $2.9M and will take approximately 2.5-4 years to complete.

The adequacy of the Proposed Plan of Service can only be confirmed by a more thorough System Impact Study which would include a transient stability analysis. This is needed to properly address the impact that the interconnection has on the area stability, which is currently managed by a Round Butte RAS that drops generation. The [redacted] Solar Project will need to be added to the existing RAS. The cost for adding [redacted] Solar to the RAS will be provided in the System Impact Study, when Stability Studies confirm the need.

The proposed plan of service includes potential upgrades identified and that are required for a higher-queued request, LGIP 17-065. If LGIP 17-065 does execute a Large Generator Interconnect Agreement plans to be energized on its requested in-service date in 2022, then the estimated costs of the [redacted] Solar project may be increased to covers certain costs associated with expediting the design and construction of Network Upgrades associated with LGIP 17-065 in order to timely accommodate interconnection service for this [redacted] Solar project.

Portland General Electric Company

Interconnection System Impact Re-Study

Interconnection request:

#17-068 (65 MW Photovoltaic Project)

Issued July 12, 2019

Prepared by Transmission Planning

Table of Contents

Introduction

This System Impact Study[1] (SIS) examines the feasibility of connecting the proposed 65 MW photovoltaic generation and Battery Energy Storage System project to the Portland General Electric (PGE) Transmission System with a requested in-service date of December 1, 2019. The Interconnection Customer has requested a Point of Interconnection (POI) on a generation lead line for the Pelton-Round Butte Hydroelectric Facility (PRB) in Central Oregon. PRB, including the generation lead line, is jointly owned by PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon (the Tribes).

The Interconnection Customer has requested generation interconnection service in conformance with the PGE Open Access Transmission Tariff (OATT). The Interconnection Customer has requested that the generation interconnection be studied for both Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).

Study Scope

This SIS will evaluate the system impact to PGE's Transmission System of the Interconnection Customer's proposed interconnection at the designated POI, and identify any required Contingent Facilities, Interconnection Facilities, and Network Upgrades necessary to accommodate such request. An SIS consists of a power flow analysis, short circuit analysis, transient stability analysis, and voltage stability analysis. This SIS also includes a Total Transfer Capability (TTC) analysis to quantify the utilization of PGE Transmission System and any congestion between the designated POI and PGE load. The following objectives will to be met in this SIS:

- Documentation of the assumptions used in the analyses;
- Documentation of any system impacts (i.e. thermal overloads or voltage limit violations) observed that are adverse to the reliability of the electric system as a result of the proposed interconnection;
- Documentation of other transmission providers' transmission systems that are impacted and identification of these transmission providers as Affected Systems;
- Documentation of fault interrupting equipment with short circuit capability limits that are exceeded as a result of the proposed interconnection;
- A list of Contingent Facilities;
- A non-binding, good faith estimate of the cost for constructing Transmission Provider's Interconnection Facilities and the Network Upgrades necessary to accommodate the requested interconnection service; and,
- A non-binding, good faith estimate of the time to construct the required Transmission Provider's Interconnection Facilities and Network Upgrades, and the estimated in-service completion times of the Contingent Facilities necessary to accommodate the requested interconnection service.

[1] With the exception of those terms that are defined herein, capitalized terms used throughout this document have the same meanings as such terms are defined in PGE's Open Access Transmission Tariff (OATT).

This SIS considered all transmission facilities and generation facilities that, on the date the study was commenced:

- Were directly interconnected to the PGE Transmission System;
- Were interconnected to other transmission providers' transmission systems and may have an impact on the requested interconnection service;
- Have a higher queued Interconnection Request[2] to interconnection to the PGE Transmission System; and
- Have no queue position but have executed a Large Generator Interconnection Agreement (LGIA) or requested that an unexecuted LGIA be filed with FERC[3].

Additionally, this SIS considered certain generator interconnection requests on other transmission providers' transmission systems that are expected to, based on engineering judgement, impact or be impacted by the Interconnection Customer's requested generation interconnection service request.

Study Assumptions

This SIS includes the following assumptions for all system conditions and seasons:

- The Interconnection Customer's requested in-service date is December 1, 2019;
- Higher queued generation interconnection requests are included and modeled at their requested maximum generation levels. Higher queued generation interconnection requests included in this SIS are:
    - Request# 16-061 – 100 MW Battery Energy Storage System at the Bethel substation;
    - Request# 17-065 – 400 MW Photovoltaic System at the Fort Rock substation;
    - Request# 17-066 – 200 MW Battery Energy Storage System at the Rivergate substation; and,
    - Request# 17-067 – 200 MW Battery Energy Storage System at the Harborton substation.
- No generator interconnection requests on other transmission providers' transmission systems were included in this SIS[4];
- Other than the higher queued projects identified above, there are no projects in PGE's annual progress report to WECC that are schedule to be on-line prior to the Customer's requested in-service date;
- This request for interconnection service is modeled at a maximum capability of 65 MW;

[2] With respect to both generation facilities and Contingent Facilities associated with any higher quested interconnection request.
[3] As of the date of this SIS was commenced, there were no Generating Facilities that lacked a queue position but had executed an LGIA or requested that an unexecuted LGIA be filed with FERC that would impact, or be impacted by, the proposed Plan of Service resulting from the studies conducted to-date for this generation interconnection request.
[4] Previous studies have shown that the current generator interconnection requests on other transmission providers' transmission systems have little or no impact on transfers from the Round Butte substation to PGE load.

- The POI is approximately 4.9 miles north of PGE's existing Round Butte Substation on the co-owned Pelton-Round Butte 230 kV generator lead line;
- The nominal voltage at the POI is 230 kV;
- The Interconnection Customer will design, permit, build, and maintain a 230 kV generator lead line from the Interconnection Customer's generation site to the POI; and,
- There is no available capacity from east to west between Round Butte and PGE's load due to existing, historical, internal transmission rights for PRB generation. In other words, the Available Transfer Capability (ATC) of the Round Butte to PGE load path in the east to west direction is 0 MW.

Study Case Development

This SIS utilizes WECC base cases as the starting point for studying the requested generator interconnection service. WECC base cases include models for the entire Western Interconnection including facility representation of voltage levels at the sub-transmission level. WECC collects the data for the Western Interconnection through its members who provide the representation and equivalent data for elements in their systems, including: the initial conditions for the study case, up-to-date line parameters, load information, generation unit parameters, and equivalent representation consistent with the time period being studied. The WECC base cases used in this SIS were modified for use in the PGE NERC TPL-001-4 Transmission Planning Assessment (TPL) as follows:

- The TPL 2020 summer peak case is based on the WECC 2018 Heavy Summer 4 OPS case;
- The TPL 2020-2021 winter peak case is based on the WECC 2018-19 Heavy Winter 3 OPS case; and,
- The TPL 2020 spring off-peak case is based on the WECC 2021 Light Spring 1 case.

The TPL cases were further modified to include the higher queued generator interconnection requests and associated Contingent Facilities listed in the Study Assumptions section of this SIS, and higher customer loads to reflect the 1-in-5 summer and winter peak forecasted for the PGE service territory. The resulting cases are referred to in this SIS as the "Benchmark Cases".

From the Benchmark Cases, a model of the Interconnection Customer's Generating Facility and generator lead line were inserted, and the resulting cases are hereafter referred to as the "Project Cases". The differences between the Benchmark Cases and the Project Cases form the basis for comparisons of the Transmission System's performance between the pre-and post-generator interconnection topology of the system.

SIS Methodology

This SIS includes powerflow, short circuit, transient stability, and voltage stability analyses in conformance with the PGE OATT. Each of these analyses may reveal unacceptable system performance that must be mitigated to integrate the proposed interconnection to the PGE Transmission System. The Benchmark Cases and the Project Cases are analyzed to determine if Network Upgrades (taking into consideration any applicable Contingent Facilities) are necessary to ensure that the Transmission System, with the addition of the Interconnection Customer's generator, demonstrates acceptable system performance. Each analysis is performed on a version of the Project Cases that include all Contingent Facilities required by higher queued interconnection requests.

Power Flow Analysis

The NERC TPL-001-4 reliability standard requires that all transmission system elements comprising the Bulk Electric System (BES) remain within their established thermal and voltage limits following the loss of a single BES element (N-1) or the loss of two or more BES elements (N-2 or N-1-1). This SIS includes the N-1, N-2, and N-1-1 contingencies for all BES elements in the PGE Transmission System and neighboring areas. The WECC System Performance Criteria, in addition, requires that the change in bus voltage percentage not exceed 8% for N-1 contingencies.

The analysis results for each contingency are assessed for compliance with the following NERC and WECC system performance Requirements:

Pre-Contingency:

- All BES elements shall be within their normal thermal limits
- All BES elements shall be within their normal voltage limits
- All BES elements shall be within their stability limits
- The BES shall demonstrate transient and voltage stability

Post-Contingency:

- All BES elements shall be within their emergency thermal limits
- All BES elements shall be within their emergency voltage limits
- Bus Voltage Change Limits:
    - The difference between pre and post-contingency load-serving bus voltages must be less than:
        - 8% for N-1 contingencies
        - 10% for N-2 and N-1-1 contingencies[5]
- The BES shall demonstrate transient and voltage stability
- Cascading or uncontrolled separation shall not occur
- Interruption of firm service (i.e. transmission curtailment) is allowed by modeling generation redispatch for applicable contingencies when acceptable, specified by the NERC TPL-001-4 Standard:

[5] The requirement load-serving bus voltages must be less than 10% for category P2-2 through category P7; this is a PGE performance requirement and is not documented in NERC and WECC standards.

- Allowed for category P2-2 through P2-4 contingencies below 300 kV, category P4-1 through P4-5 contingencies below 300 kV, category P4-6 contingencies, category P5 contingencies below 300 kV, and category P7 contingencies

Short Circuit Analysis

Short circuit analysis is performed to identify transmission equipment with rated fault capabilities that will be exceeded by the higher fault currents that result from adding the Interconnection Customer's Generating Facility to the PGE Transmission System. Short circuit modeling information for the Northwest area is maintained through the collaborative efforts of the region's utilities.

Faults at substations in the vicinity of the POI are simulated using the Aspen OneLiner program. Increases in equipment fault duty, attributable to the proposed Generating Facility, cannot result in fault duties that exceed equipment ratings. Fault duty increases of less than 1% are not considered significant impacts to the system and thus are not required to be mitigated by the Interconnection Customer.

Transient Stability Analysis

The transmission system must demonstrate post-contingency transient stability. Post-contingency transient stability is demonstrated when generator rotor angles, and bus voltages and frequencies show positive damping within the requirements of the WECC System Performance Criterion (TPL-001-WECC-CRT-3.1). The WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) establishes limits on the allowable size and duration of frequency and voltage swings during the transient period following a disturbance. The WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) performance requirements are:

Rotor Angle Stability

Generators must remain in synchronism with the PGE Transmission System and the rest of the transmission system in the Northwest area through the transient period. Rotor angle oscillations must exhibit positive damping for N-1 and N-2 contingencies.

Voltage Stability

Following the clearing of a fault, load-serving bus voltages shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all N-1 and N-2 events.

Following the recovery to 80% of pre-contingency voltage, a load-serving bus 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 all N-1 and N-2 events.

Following the opening of a transmission element without a fault, the voltage at a load-serving bus 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 all N-1 and N-2 events.

Frequency Stability

System frequency at any load-serving bus must not fall below 59.6 Hz for six cycles or more following an N-1 contingency, or 59.0 Hz for six cycles or more following an N-2 contingency.

Representative contingencies subject to transient stability simulations include contingencies affecting the PGE Transmission System and the neighboring transmission systems. The PowerWorld Simulator tool is used to perform transient system stability analysis.

Voltage Stability Analysis

The transmission system must demonstrate post-contingency voltage stability. Post-contingency voltage stability is demonstrated when the Reactive Margin at a bus is greater than or equal to the Reactive Power Margin Requirement (PMR).

The WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) requires that post-contingency PMR be demonstrated for stress levels of:

- A minimum of 105% for system normal conditions (N-0) and for N-1 contingencies; and
- A minimum of 102.5% for N-2 and N-1-1 contingencies

Representative contingencies used for the voltage stability analysis include contingencies affecting the PGE Transmission System and the neighboring transmission systems.

Both Reactive Margin and PMR are determined through the building of Q-V curves. The PowerWorld Simulator tool is used to build Q-V curves.

Total Transfer Capability Analysis

The concepts for determining transfer capability, described in NERC's 1995 *Transmission Transfer Capability* reference document, are still valid and do not change with the advent of open access transmission, or the need to determine TTCs.

The TTC analysis included the N-1 and N-2 contingencies of all BES facilities in the PGE transmission area and the neighboring areas. The analysis also included all credible and conditionally credible (as and when applicable) multiple contingencies for the study season, except for N-1-1 outages. N-1-1 outages, referred to as category P3 and P6 contingencies in the NERC TPL-001-4 standard, were excluded as the NERC standard allows for system adjustments, which can effectively mitigate issues resulting from a subsequent contingency. The TTC performance criteria are the same as the power flow and transient stability performance criteria documented above.

NRIS System Impact Study Analysis and Results

The PGE Transmission System in Central Oregon consists of PRB, the generation lead lines from PRB to the Round Butte substation, a 230 kV transmission line from the Round Butte substation to the Bethel substation in the Willamette Valley (Bethel-Round Butte 230 kV), a 230 kV transmission line from the Round Butte substation to the Redmond BPA substation (Redmond BPA-Round Butte 230 kV), a 500 kV transmission line from the Round Butte substation to the Grizzly BPA substation (Grizzly BPA-Round Butte 500 kV), and two 230 kV connections to PacifiCorp's Cove substation[6] located adjacent to the Round Butte Substation.

PGE does not have any load in Central Oregon. The Bethel-Round Butte 230 kV transmission line is the sole PGE Transmission System connection between PRB and the PGE service territory in the Willamette Valley. Currently, the output of PRB flows to PGE load via a combination of the Bethel-Round Butte 230 kV transmission line (utilizing the line's full capacity) and existing, historical transmission rights for PRB generation with the Bonneville Power Administration (BPA), all of which pre-date the OATT. There is no available capacity from east to west between Round Butte and PGE's load due to existing, historical, internal transmission rights for PRB generation. In other words, the Available Transfer Capability (ATC) of the Round Butte to PGE load path in the east to west direction is 0 MW. ATC is calculated in accordance with the NERC MOD-029-2a standard and can generally be represented as ATC = TTC - ETC, where TTC represents Total Transfer Capability and ETC represents Existing Transmission Commitments. Delivering the output of PRB to PGE load is an Existing Transmission Commitment that utilizes the full capacity of the Round Butte to PGE load path. Because the path ETC (PRB commitment) utilizes the full path TTC, the current ATC of the Round Butte to PGE load path is 0 MW. The existing TTC, and therefore the existing ETC, is determined in conformance with the NERC MOD-029-2a standard.

TTC for the Round Butte to PGE load path has not been calculated since there is currently no OASIS posted path. In order to provide generation interconnection service to PGE load, the TTC of the path must be calculated. Once the TTC of the Round Butte to PGE load path is determined, system modifications can be identified that will increase the TTC by 65 MW to facilitate the delivery of the output of the proposed interconnection.

Total Transfer Capability Analysis

NERC defines the TTC as the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time-frame. TTC, expressed in terms of MW, is the measure of the ability of interconnected electric systems to reliably move or "transfer" electric power from one area to another by all of the transmission lines (or Paths) between those areas under specified system conditions. In this context, "area" refers to the configuration of generating

[6] The PacifiCorp Cove substation serves PacifiCorp's load in the Madras area. The Cove substation is a load pocket that is only connected to the Bulk Electric System by the Round Butte facilities. The Cove substation, and the associated distribution system, does not connect back to the Bulk Electric System at any other point.

stations, switching stations, substations, and connecting transmission lines that define an individual electric system control area.

This SIS addresses TTC from the perspective of the PGE Transmission System's physical characteristics and limitations. The recommended approaches and practices for calculating TTC across particular paths or interfaces is defined in NERC's May 1995 *Transmission Transfer Capability* reference document. The PGE ATC paths are shown in **Figure 1**.

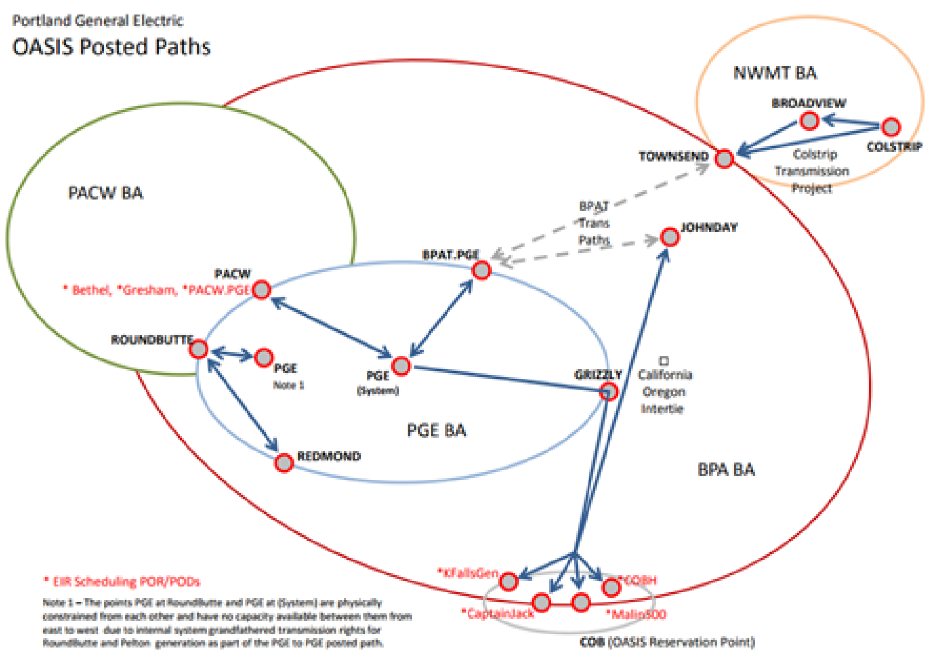

Figure 1: PGE ATC Path Diagram

Generation Dispatch

The PGE on-system generation and relevant generation in other areas were varied to achieve the maximum transfer across the Round Butte to PGE load path. The relevant external generation that was adjusted for this study includes the flowing, electrically similar generators:

- I-5 Corridor generation
- Upper Columbia generation
- Mid-Columbia generation
- Lower Columbia generation
- British Columbia generation
- California generation
- Other generation with material impacts identified using the PowerWorld Simulation software tools

Load

The PGE load levels, including PGE industrial loads but excluding station service loads, were scaled in the Benchmark Cases to 3861 MW summer peak and 3705 MW winter peak conditions. The PGE load and

PacifiCorp Portland area load were scaled together due to their geographical proximity. The PGE and PacifiCorp loads were not varied during the study. The maximum transfer across the path was achieved by varying generation and area exchange.

Remedial Action Schemes

Remedial Action Schemes (RAS) for which PGE is the Transmission Operator include the Round Butte RAS and the Grand Ronde RAS[7]. Additionally, all BPA RAS are considered during contingency analysis as defined by the applicable BPA Dispatcher Standing Orders.

Total Transfer Capability Results

A variety of generation patterns and load levels were studied in order to maximize transfers across the path. The path was studied to achieve maximum import in the direction of prevailing flow, which is from Round Butte to the PGE system. The final cases achieved maximum flow across the path of 199 MW in the summer and 260 MW in the winter. The changes in generation dispatch, path flows, and load from the starting Benchmark Cases to the stressed Benchmark Cases are summarized in the following tables:

Generation Group Name	Summer[8]		Winter[9]	
	Starting Case MW	Stressed Case MW	Starting Case MW	Stressed Case MW
I-5 Corridor Gen	4301	4128	5180	4117
Upper Columbia (Total) Gen	5429	4093	7806	7598
Mid-Columbia (Total) Gen	2588	2588	3043	3043
Lower Columbia (Total) Gen	4704	6135	4976	5082
PACW Lewis River Generation	125	30	386	326
Central Willamette Valley Generation	1145	896	1316	947
PGE On-System Generation	1524	529	2023	-85[10]

Table 1: NW Generation Dispatch Changes

[7] The Grand Ronde RAS is intended to alleviate under voltage concerns on local elements, and thus would not be triggered and has no impact to transfers on any ATC paths.
[8] The summer season is defined as starting on June 1st and ending on October 31st. However, the spring season—defined as starting April 1st and ending on May 31st—is included in the summer TTC season.
[9] The winter season is defined as starting on November 1st and ending on March 31st
[10] PGE On-System Generation includes 500 MW of Battery Energy Storage Devices. These batteries were modeled in charging mode to maximize the path transfers. Batteries in charging modes are displayed as negative generation.

Transfer Paths	Summer		Winter	
	Starting Case MW	Stressed Case MW	Starting Case MW	Stressed Case MW
BC Hydro-to-Northwest	2324	-1768	632	-2706
Montana-to-Northwest	577	741	1131	1189
Idaho-to-Northwest	-544	-244	-315	208
West of Cascades - North	3858	6651	7164	10363
West of Cascades - South	3591	5231	4245	6421
South of Allston	2112	1056	1546	222
North of John Day	4069	1188	3976	1993
California Oregon Intertie	3867	614	3741	-1096
Pacific DC Intertie (PDCI)	2800	2800	2301	2301
Midpoint-to-Summer Lake	219	-217	10	141

Table 2: Transfer Path Changes

Zone Name	Summer		Winter	
	Starting Case MW	Stressed Case MW	Starting Case MW	Stressed Case MW
PGE On System Load[11]	3861	3861	3705	3705
PAC: PTLD	446	446	480	480

Table 3: Load Changes

The loss of the Salem BPA 230/115 kV transformer sets the limitation of the Round Butte to PGE load path to 199 MW in the summer. The loss of the Ostrander BPA-Pearl BPA 500 kV transmission line sets the limitation of the Round Butte to PGE load path to 260 MW in the winter. The path was found to be thermally limited with no limiting voltage, reactive margin, or transient stability issues.

Summer				
Contingency Name	Limiting Element	Value	Limit	Percent
Salem BPA Transformer 230/115 kV	Chemawa BPA Transformer 230/115 kV	312.3 MVA	312.6 MVA	99.9%
Chemawa BPA-Salem BPA #1 230 kV	Chemawa BPA Transformer 230/115 kV	311.8 MVA	312.6 MVA	99.8%
Pearl BPA-Sherwood 230 kV	McLoughlin-Pearl BPA-Sherwood 230 kV	2623.8 A	2630.7 A	99.7%
Keeler BPA Transformer #2 500/230 kV	Murrayhill-St Marys 230 kV	1276.2 A	1315.4 A	97.0%

Table 4: Limiting Contingency – Summer

[11] PGE industrial loads were not scaled but are included in the PGE on-system load. PGE station service loads are not included in the listed PGE on-system load.

Winter				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Ostrander BPA-Pearl BPA 500kV	Troutdale PACW Transformer 230/115kV	299.7 MVA	300.0 MVA	99.9%

Table 5: Limiting Contingency – Winter

PRB, as a network resource, utilizes long-term network transmission to deliver its output to PGE load. Long-term network transmission is limited to the lowest transfer capability during the requested period. Because the Round Butte to PGE load path is limited by the summer TTC of 199 MW, the long-term ETC for PRB is set to 199 MW. Long-term ETC does not vary with the season. And because seasonal ATC is equal to seasonal TTC - ETC, the summer ATC is 0 MW and the winter ATC is 61 MW.

In order to provide NRIS for the proposed interconnection, 65 MW of long-term ATC to PGE load must be created. The existing long-term ATC is 0 MW in the summer and the ETC is 199 MW. Therefore, to create 65 MW of ATC, the TTC in summer must be increased by 65 MW to a total of 264 MW. The existing long-term ATC is 61 MW in the winter and the ETC is 199 MW. Therefore, to create 65 MW of long-term ATC, the TTC in winter must be increased by 4 MW to a total of 264 MW.

The addition of the 65 MW proposed interconnection increases the flow on the Round Butte to PGE load path by only 8 MW in both the summer and winter seasons. The path flow must be increased by 57 MW in addition to the 8 MW flow contribution of the proposed interconnection to obtain the necessary TTC value of 264 MW in the summer. The flow contribution is adequate to meet the necessary TTC value for the winter.

Several options exist to increase the TTC on the Round Butte to PGE load path by the required 57 MW:

- Reconductor the Bethel-Round Butte 230 kV transmission line to reduce the line impedance and increase flow on the line;
- Install a series capacitor on the Bethel-Round Butte 230 kV transmission line to reduce the line impedance and increase flow on the line; or,
- Install a phase shifting transformer on the Bethel-Round Butte 230 kV transmission line to manage the power angle and direct flow across the line.

The cost of reconductoring the Bethel-Round Butte 230 kV transmission line is expected to be significantly more expensive than the cost to install a series capacitor or a phase shifting transformer. A reconductor, therefore, is not further examined in this SIS. Project Cases were developed for the series capacitor option and the phase shifting transformer option. Both options resulted in increases on the Round Butte to PGE load path of the required 57 MW, and both options resulted in similar system performance. The summer and winter power flow results are shown below in **Table 6**, **Table 7**, **Table 8**, and **Table 9**. With the addition of the series capacitor or the phase shifting transformer, the path was found to be thermally limited with no limiting voltage, reactive margin, or transient stability issues[12].

[12] Study results and charts are available upon request.

The addition of either a series capacitor or a phase shifting transformer to the Bethel-Round Butte 230 kV transmission line sufficiently increases the Round Butte to PGE load path TTC and thereby the ATC.

Summer – Series Capacitor				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Pearl BPA-Sherwood 230 kV	McLoughlin-Pearl BPA-Sherwood 230 kV	2626.4 A	2630.7 A	99.8%
Salem BPA Transformer 230/115 kV	Chemawa BPA Transformer 230/115 kV	307.5 MVA	312.6 MVA	98.4%
Chemawa BPA-Salem BPA #1 230 kV	Chemawa BPA Transformer 230/115 kV	307.1 MVA	312.6 MVA	98.2%
Keeler BPA Transformer #2 500/230 kV	Murrayhill-St Marys 230 kV	1279.5 A	1315.4 A	97.3%

Table 6: Series Capacitor Option Limiting Contingency – Summer

Summer – Phase Shifting Transformer				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Pearl BPA-Sherwood 230 kV	McLoughlin-Pearl BPA-Sherwood 230 kV	2625.4 A	2630.7 A	99.8%
Salem BPA Transformer 230/115 kV	Chemawa BPA Transformer 230/115 kV	307.4 MVA	312.6 MVA	98.3%
Chemawa BPA-Salem BPA #1 230 kV	Chemawa BPA Transformer 230/115 kV	306.6 MVA	312.6 MVA	98.2%
Keeler BPA Transformer #2 500/230 kV	Murrayhill-St Marys 230 kV	1278.9 A	1315.4 A	97.2%

Table 7: Phase Shifting Transformer Option Limiting Contingency – Summer

Winter – Series Capacitor				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Ostrander BPA-Pearl BPA 500kV	Troutdale PACW Transformer 230/115kV	298.7 MVA	300.0 MVA	99.6%

Table 8: Series Capacitor Option Limiting Contingency – Winter

Winter – Phase Shifting Transformer				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Ostrander BPA-Pearl BPA 500kV	Troutdale PACW Transformer 230/115kV	299.2 MVA	300.0 MVA	99.7%

Table 9: Phase Shifting Transformer Option Limiting Contingency – Winter

NRIS Preliminary Plan of Service

A Preliminary Plan of Service is developed to meet the requirements for the Interconnection Customer's NRIS request. Based on the results of the TTC analysis, a series capacitor or a phase shifting transformer is required to deliver the output of the proposed Generating Facility to the PGE load. The preliminary estimates developed for the series capacitor and phase shifting transformer options indicate that a series capacitor's total installed cost is expected to be tens of millions of dollars less expensive than the total installed cost of the phase shifting transformer. For this reason, the Preliminary Plan of Service will consider only the series capacitor option, unless further analyses indicate that the series capacitor will not provide for acceptable system performance with the Interconnection Customer's Generating Facility in service.

The Interconnection Customer's proposed step-up transformer configuration must be changed from its proposed configuration to a 230 kV (wye) / 34.5 kV (delta) to reliably protect the PGE Transmission System.

There is a known stability issue at the Round Butte substation. Following the loss of two transmission lines connected to the Round Butte substation, generation connected to Round Butte must be immediately tripped so that no more than 200 MW of generation remains on-line. Any new Generating Facility connecting to Round Butte is required to participate in the Remedial Action Scheme that protects against this instability.

The Preliminary Plan of Service for NRIS, shown in **Figure 2** below, includes the following modifications to the PGE Transmission System:

- A new POI substation designed as a 3-position 230 kV ring bus that will sectionalize the Pelton-Round Butte 230 kV generation lead line and accept the Interconnection Customer's generation lead line;
- A new series capacitor on the Bethel-Round Butte 230 kV transmission line; and,
- The addition of the Interconnection Customer's Generating Facility and the new series capacitor to the existing Round Butte Remedial Action Scheme (RAS).

The Preliminary Plan of Service for NRIS will be added to the Benchmark Cases to develop the Project Cases for NRIS. The Benchmark Cases and the Project Cases are then analyzed for power flow, short circuit, transient stability, and voltage stability to confirm that the Preliminary Plan of Service provides for acceptable system performance. It is important to note that the Bethel-Round Butte 230 kV transmission line is part of the major WECC path known as West of Cascade South (WOCS). The addition of the series capacitor to the WOCS path will require review of the path rating through the WECC Path Rating Process. The WECC Path Rating Process is separate from this SIS, not controlled by PGE, and can take up to three years.

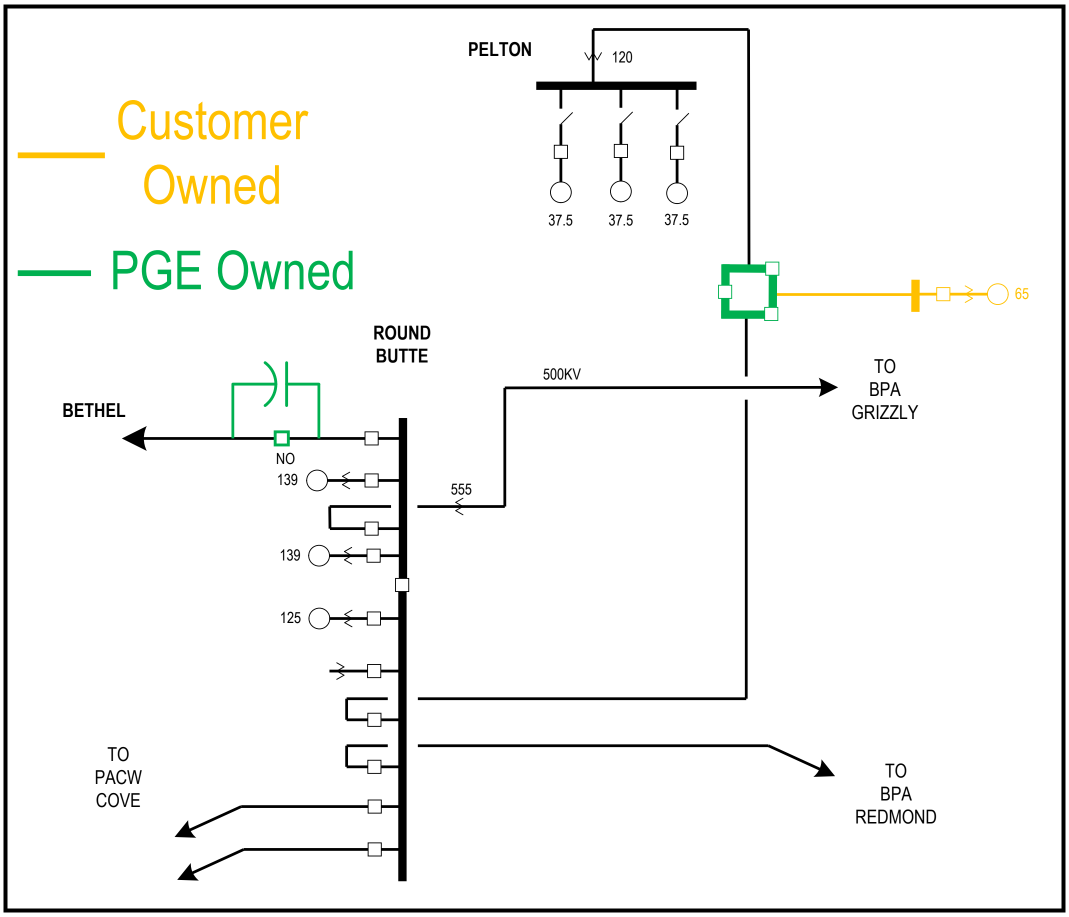

Figure 2: NRIS Preliminary Plan of Service

Power Flow Analysis

Power flow analysis was conducted on the Benchmark Cases and the Project Cases for peak summer and winter conditions, and off-peak spring conditions. The results of the power flow analysis for all seasons are nearly identical between the Benchmark Cases and the Project Cases. This is true for all categories of contingencies. Category N-1 contingencies that result in a system element loading to greater than 95% of its limit are shown below. The results of the power flow analysis for the winter season are shown below in **Table 10** and **Table 11**. The results of the N-1 analysis for summer and spring resulted in no system element loading greater than 95% of its limit and therefore are not represented in this report. The contingency results of the Benchmark Cases and the Project Cases are almost identical, resulting in no significant change attributed to the interconnection request.

Winter – Benchmark Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.8 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	401.3 MVA	420.0 MVA	95.5%

Table 10: Benchmark Case Power Flow Results - Winter

Winter – Project Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.2 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	400.8 MVA	420.0 MVA	95.8%

Table 11: Project Case Power Flow Results - Winter

Pending the results of the WECC Path Rating Process, no additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the power flow analysis.

Short Circuit Analysis

Short circuit analysis was conducted on the Benchmark Cases and the Project Cases to determine the change in fault duty attributable to adding the Preliminary Plan of Service to the PGE Transmission System. This proposed interconnection has no material impact on any existing circuit breaker rating.

No additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the short circuit analysis.

Transient Stability Analysis

Transient stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in system stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the transient stability analysis indicate that all generator rotor angles remain synchronized with the system, bus frequency remains above 59.6 Hz for all studied contingencies, and system voltages recover to 80% pre-contingency levels within 20 seconds.

No additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the transient stability analysis.

Voltage Stability Analysis

Voltage stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in voltage stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the voltage stability analysis indicate that that positive Reactive Margin and post-contingency PMR meet the WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) requirements.

No additional Network Upgrades have been identified as being necessary to satisfy the applicable NERC and WECC requirements as a result of the voltage stability analysis.

Proposed Plan of Service for NRIS

The results of the power flow analysis, short circuit analysis, transient stability analysis, and the voltage stability analysis show that the Preliminary Plan of Service for NRIS meets all NERC and WECC requirements. Because no additional Network Upgrades have been identified as being necessary, the Preliminary Plan of Service for NRIS is recommended as the Proposed Plan of Service for NRIS. A non-binding good-faith cost estimate of the Network Upgrades required for the Proposed Plan of Service for NRIS is shown below in **Table 12**, and the good-faith construction schedule is also discussed. The target accuracy of this cost estimate, in conformance with the PGE OATT, is ± 50%. The Interconnection Customer's generator lead line, located between the Generating Facility and the Point of Change of Ownership, is also not included in the estimate for the Proposed Plan of Service for NRIS since this is considered Interconnection Customer's Interconnection Facilities.

NRIS Proposed Plan of Service Cost Estimate[13]	
Network Upgrades	**Cost Estimate**
230 kV Series Capacitor at Round Butte substation, including: • Control Enclosure, Relay Racks, and Battery • Clear and grade land[14] and install fencing • 230 kV bus, structures, and disconnect switches	$10.8 M
Pelton Generator Lead Line Tap Station, including: • 230 kV three-position ring bus with circuit breakers, disconnect switches, and bus and structures • Control Enclosure, Relay Racks, and Battery • Clear and grade land[15] and install fencing • 230 kV bus, structures, and disconnect switches • Transmission Line Modification	$6.2 M
Include the POI Tap Station in the Existing Round Butte RAS, including: • Communication facilities to the POI Tap Station • Relay Racks	$10.0 M
Total	$27.0 M

Table 12: NRIS Proposed Plan of Service Cost Estimate

[13] The cost estimate for the POI substation increased in this restudy because the current estimate is more recent and more detailed. For example, the previous estimate did not include costs for land preparation, fencing, security, lighting, conduits, or engineering. This estimate also includes cost escalation to represent 2021 dollars.
[14] The costs of purchasing and permitting land adjacent to the Round Butte substation are not included in this estimate.
[15] The costs of purchasing and permitting land for the POI tap station are not included in this estimate.

The schedule required to implement the Proposed Plan of Service for NRIS requires a 3-5 year timeline for design, permitting, equipment acquisition, and construction.

There are many factors outside of the Transmission Provider's control that could extend the time required for completing the Proposed Plan of Service outlined above. These factors include, but are not limited to: unexpected delays in the permitting process, the WECC Path Rating Process, challenges in acquiring property adjacent to the Round Butte substation, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties, and inclement weather conditions. Much of the PRB generation complex, the Pelton-Round Butte 230 kV generation lead-line, and the Round Butte Substation exist within the boundaries of a federally protected natural area (Crooked River National Grassland), which could add complexity to permitting and land acquisition.

The Pelton-Round Butte 230 kV generator lead-line that the proposed POI is located on is part of the Pelton-Round Butte hydro generating facility which is not wholly owned by PGE. Consequently, the ability to interconnect to this line may be contingent upon a successful negotiation with the facility's other owner and successful separation of the line from the hydro facility, as such line is currently identified within the scope of the Hydro License issued by FERC.

ERIS System Impact Study Results

Preliminary Plan of Service for ERIS

A Preliminary Plan of Service is developed to meet the requirements for the Interconnection Customer's ERIS request.

There is a known stability issue at the Round Butte substation. Following the loss of two transmission lines connected to the Round Butte substation, generation connected to Round Butte must be immediately tripped so that no more than 200 MW of generation remains on-line. New generation facilities connecting to Round Butte are required to participate in the Remedial Action Scheme that protects against this instability.

The Preliminary Plan of Service for ERIS, shown in **Figure 3** below, includes the following modifications to the PGE Transmission System:

- A new POI substation designed as a 3-position 230 kV ring bus that will sectionalize the Pelton-Round Butte 230 kV generation lead line and accept the Interconnection Customer's generation lead line; and
- The addition of the Interconnection Customer's Generating Facility to the existing Round Butte Remedial Action Scheme (RAS).

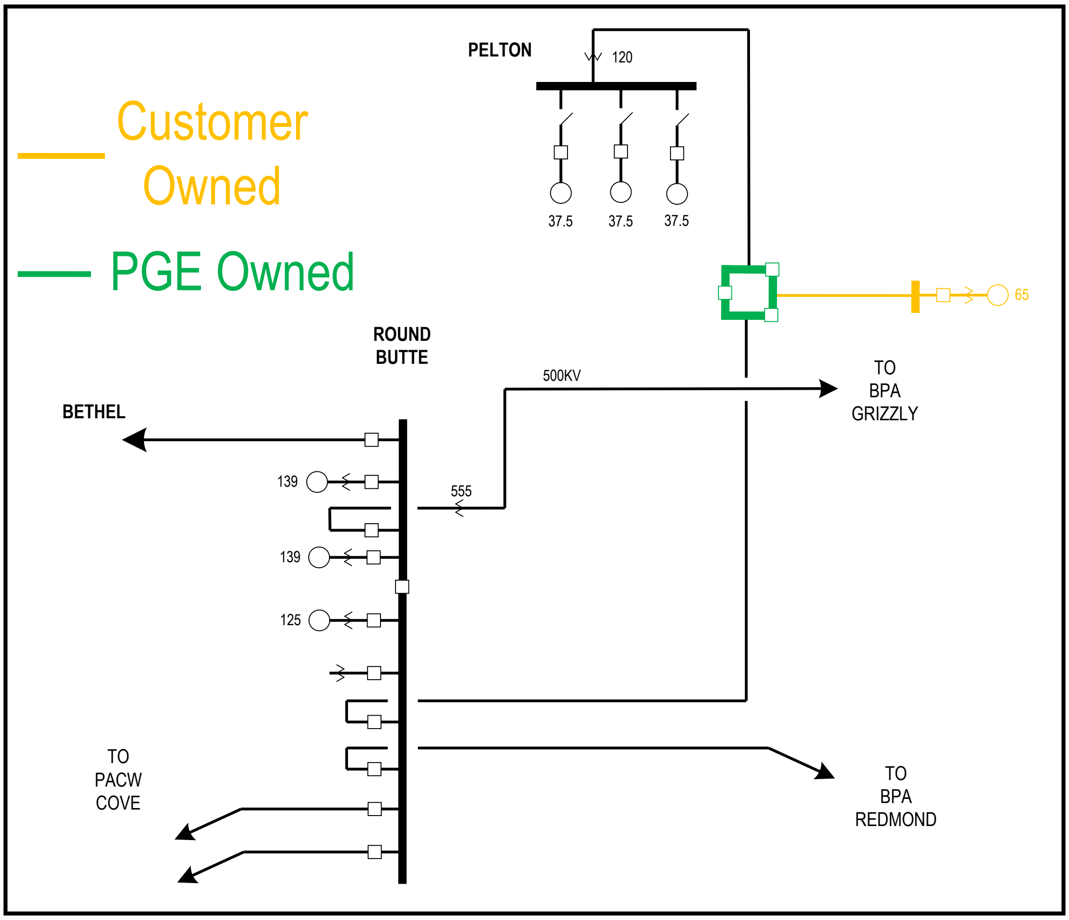

Figure 3: ERIS Preliminary Plan of Service

The Preliminary Plan of Service for ERIS will be added to the Benchmark Cases to develop the Project Cases for ERIS. The Benchmark Cases and the Project Cases are then analyzed for powerflow, short circuit, transient stability, and voltage stability to confirm that the Preliminary Plan of Service provides for acceptable system performance.

Power Flow Analysis

Power flow analysis was conducted on the Benchmark Cases and the Project Cases for peak summer and winter conditions, and off-peak spring conditions. The results of the power flow analysis for all seasons are nearly identical between the Benchmark Cases and the Project Cases. This is true for all categories of contingencies. Category N-1 contingencies that result in a system element loading to greater than 95% of its limit are shown below. The results of the power flow analysis for the winter season are shown below in **Table 13** and **Table 14**. The results of the N-1 analysis for summer and spring resulted in no system element loading greater than 95% of its limit and are therefore not represented in this report. The contingency results of the Benchmark Cases and the Project Cases are almost identical, resulting in no significant change attributed to the interconnection request.

Winter – Benchmark Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.8 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	401.3 MVA	420.0 MVA	95.5%

Table 13: Benchmark Case Power Flow Results - Winter

Winter – Project Case				
Contingency Name	**Limiting Element**	**Value**	**Limit**	**Percent**
Allston BPA-Clatsop BPA-Driscoll BPA 230kV	Allston BPA-Driscoll BPA #2 115 kV	735.5 MVA	740.0 MVA	99.4%
Allston BPA Transformer #3 230/115kV	Longview BPA Transformer 230/115 kV	400.8 MVA	420.0 MVA	95.4%

Table 14: Project Case Power Flow Results - Winter

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the power flow analysis.

Short Circuit Analysis

Short circuit analysis was conducted on the Benchmark Cases and the Project Cases to determine the change in fault duty attributable to adding the Preliminary Plan of Service to the PGE Transmission System. This proposed interconnection has no material impact on any existing circuit breaker rating.

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the short circuit analysis.

Transient Stability Analysis

Transient stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in system stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the transient stability analysis indicate that all generator rotor angles remain synchronized with the system, bus frequency remains above 59.6 Hz for all studied contingencies, and system voltages recover to 80% pre-contingency levels within 20 seconds.

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the transient stability analysis.

Voltage Stability Analysis

Voltage stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in voltage stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the voltage stability analysis indicate that Positive Reactive Margin and post-contingency PMR meet the WECC System Performance Criterion (TPL-001-WECC-CRT-3.1) requirements.

No additional Network Upgrades have been identified as necessary to satisfy the applicable NERC and WECC requirements as a result of the voltage stability analysis.

Proposed Plan of Service for ERIS

The results of the power flow analysis, short circuit analysis, transient stability analysis, and the voltage stability analysis show that the Preliminary Plan of Service for ERIS meets all NERC and WECC requirements. As no additional Network Upgrades have been identified as necessary, the Preliminary Plan of Service for ERIS is recommended as the Proposed Plan of Service for ERIS. A non-binding good-faith cost estimate of the Network Upgrades required for the Proposed Plan of Service for ERIS is shown below in **Table 15**, and the good-faith construction schedule is also discussed. The Interconnection Customer’s generator lead line, located between the Generating Facility and the Point of Change of Ownership, is not included in the estimate for the Proposed Plan of Service for ERIS since this is considered Interconnection Customer’s Interconnection Facilities. The target accuracy of this cost estimate, in conformance with the PGE OATT, is ± 50%.

ERIS Proposed Plan of Service Cost Estimate[16]	
Network Upgrades	**Cost Estimate**
Pelton Generator Lead Line Tap Station, including: • 230 kV three-position ring bus with circuit breakers, disconnect switches, and bus and structures • Control Enclosure, Relay Racks, and Battery • Clear and grade land[17] and install fencing • 230 kV bus, structures, and disconnect switches • Transmission Line Modification	$6.2 M
Include the POI Tap Station in the Existing Round Butte RAS, including: • Communication facilities to the POI Tap Station • Relay Racks	$10.0 M
Total	$16.2 M

Table 15: ERIS Proposed Plan of Service Cost Estimate

The Network Upgrades required to implement the Proposed Plan of Service for ERIS requires a 2-5 year timeline for design, permitting, equipment acquisition, and construction.

There are many factors outside of the Transmission Provider's control that could extend the time required for completing the ERIS Proposed Plan of Service outlined above. These factors include, but are not limited to: unexpected delays in the permitting process, challenges in acquiring property adjacent to the Round Butte substation, shortages of qualified workers, and inclement weather conditions.

The Pelton-Round Butte 230 kV generator lead-line that the proposed POI is located on is part of the Pelton-Round Butte hydro generating facility which is not wholly owned by PGE. Consequently, the ability to interconnect to this line may be contingent upon a successful negotiation with the facility's other owner and successful separation of the line from the hydro facility, as such line is currently identified within the scope of the Hydro License issued by FERC.

[16] The cost estimate for the POI substation increased in this restudy because the current estimate is more recent and more detailed. For example, the previous estimate did not include costs for land preparation, fencing, security, lighting, conduits, or engineering. This estimate also includes cost escalation to represent 2021 dollars.
[17] The costs of purchasing and permitting land for the POI tap station are not included in this estimate.

Conclusion

This SIS concludes that the Interconnection Customer's request for interconnection service can be met by proceeding with either the NRIS or the ERIS Proposed Plan of Service, but the Interconnection Customer's requested in-service date cannot be met. The in-service date, based on the Proposed Plan of Service for either ERIS and NRIS, is expected to be between 2021 and 2024, as discussed above.

The study results demonstrate that the Proposed Plan of Service for both NRIS and ERIS satisfy the requirements for power flow, short circuit, transient stability, and voltage stability analysis. Since the WOCS path is a major WECC path, a rerating study will be needed as outlined in WECC's document: "Project Coordination, Path Rating and Progress Report Processes". Beyond the rerating of the WOCS path, the Proposed Plan of Service is adequate for either the requested NRIS or ERIS.

The cost of the NRIS Proposed Plan of Service is approximately $27 M and will take approximately 3-5 years to complete, while the cost of the ERIS Proposed Plan of Service is approximately $16.2 M and will take approximately 2-5 years to complete.

No Contingent Facilities were identified in this SIS.

PGE cannot guarantee that future analysis (i.e. Transmission Service or Operational Studies) will not identify additional problems or system constraints that require mitigation or reduce operation. Neither ERIS nor NRIS conveys or implies any type of transmission service. If there is a material change in any aspect of the Generating Facility that is the subject of this study/report, a SIS restudy may be required.

Portland General Electric Company

Interconnection Feasibility Study

Interconnection request:

#19-081 (53 MW Photovoltaic Project)

Prepared by Transmission Planning

Table of Contents

Introduction

This Interconnection Feasibility Study[1] (IFS) examines the feasibility of connecting the proposed 53 MW Photovoltaic (PV) Project to the Portland General Electric (PGE) Transmission System with a requested in-service date of December 31, 2022. The Interconnection Customer has requested a Point of Interconnection (POI) on PGE's Redmond BPA-Round Butte 230 kV transmission line in central Oregon in the vicinity of Opal City, south of the Round Butte substation.

The Interconnection Customer has requested Network Resource Interconnection Service (NRIS) in conformance with the State Qualifying Facility-Large Generator Interconnection Procedures (QF-LGIP) in Oregon.

Study Scope

This IFS is a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to PGE's Transmission System at the designated POI. This IFS identifies any required Contingent Facilities, Interconnection Facilities, and Network Upgrades necessary to accommodate the proposed interconnection, as well as any Affected Systems. This IFS consists of a power flow analysis, a short circuit analysis, and a Total Transfer Capability (TTC) analysis. The following objectives are met in this IFS:

- Documentation of the assumptions used in the analyses;
- Documentation of any system impacts observed that are adverse to the reliability of the electric system as a result of the proposed interconnection;
- Documentation of TTC limitations and the Network Upgrades necessary to deliver the output of the Generating Facility to PGE load;
- Documentation of other transmission providers' transmission systems that are impacted and identification of these transmission providers as Affected Systems;
- Documentation of fault interrupting equipment with short circuit capability limits that are exceeded as a result of the proposed interconnection;
- A list of Contingent Facilities;
- A non-binding, good faith estimate of the cost for constructing Transmission Provider's Interconnection Facilities and the Network Upgrades necessary to accommodate the requested interconnection service; and,
- A non-binding, good faith estimate of the time to construct the required Transmission Provider's Interconnection Facilities and Network Upgrades, and the estimated in-service completion times of any Contingent Facilities necessary to accommodate the requested Interconnection Service.

[1] With the exception of those terms that are defined herein, capitalized terms used throughout this document have the same meanings as such terms defined in PGE's Open Access Transmission Tariff (OATT).

This IFS considers all transmission facilities and generation facilities that, on the date the study was commenced:

- Were directly interconnected to the PGE Transmission System;
- Were interconnected to other transmission providers' transmission systems and may have an impact on the requested Interconnection Service;
- Have a higher queued request to interconnect to the PGE Transmission System; and,
- Have no queue position but have executed a Large Generator Interconnection Agreement (LGIA) or requested that an unexecuted LGIA be filed with FERC.

Study Assumptions

This IFS includes the following assumptions for all system conditions and seasons:

- The Interconnection Customer's requested In-Service Date of December 31, 2022;
- Higher queued generator interconnection requests modeled at their requested maximum generation levels. The specific higher queued generator interconnection requests included in this IFS are:
  - Request #16-061 – 100 MW Battery Energy Storage System at the Bethel substation;
  - Request #17-065 – 400 MW Photovoltaic System near the Fort Rock substation;
  - Request #17-066 – 200 MW Battery Energy Storage System at the Rivergate substation;
  - Request #17-067 – 200 MW Battery Energy Storage System at the Harborton substation;
  - Request #17-068 – 65 MW Photovoltaic System near the Round Butte substation;
  - Request #18-071 – 600 MW Photovoltaic System near the Fort Rock substation;
  - Request #19-076 – 200 MW Photovoltaic System at the Blue Lake substation; and,
  - Request #19-080 – 80 MW Photovoltaic and Battery Energy Storage System near the Round Butte substation.
- All higher queued interconnection requests included in this IFS are modeled with the Generating Facility, Network Upgrades, and Contingent Facilities;
- Modeling of the Interconnection Request at a maximum capability of 53 MW;
- The interconnecting Generating Facility being offset by PGE on-system generation[2];
- The nominal voltage at the POI of 230 kV;
- The POI being on PGE's existing Redmond BPA-Round Butte 230 kV transmission line south of the Round Butte substation in the vicinity of Opal City;
- The Available Transfer Capability (ATC) of the Bethel-Round Butte 230 kV line being fully subscribed;

[2] There is insufficient on-system generation, outside of the local study area, in the off-peak spring case to offset 53 MW of new generation. Off-system generation was offset in the off-peak spring case.

- The TTC of the Bethel-Round Butte 230 kV transmission line at 344 MW[3] in the summer (limiting season) and dependent upon the construction of a series capacitor substation, including the series capacitor, adjacent to the Round Butte substation, all in connection with interconnection request #17-068 and upgraded by interconnection request #19-080;
- The Interconnection Customer designing, permitting, building, and maintaining a 230 kV generator lead line from the Interconnection Customer's generation site to the POI; and,
- The total plant output from the Generating Facility not exceeding 53 MW at the POI.

Study Case Development

This IFS utilizes WECC base cases as the starting point for studying the feasibility of the proposed interconnection to the Transmission System. WECC base cases include models for the entire Western Interconnection including facility representation of voltage levels at the sub-transmission level. WECC collects the data for the Western Interconnection through its members who provide the representation and equivalent data for elements in their systems, including: the initial conditions for the study case, up-to-date line parameters, load information, generation unit parameters, and equivalent representation consistent with the time period being studied. The WECC base cases used in this IFS were modified for use in the PGE NERC TPL-001-4 Transmission Planning Assessment (TPL) as follows:

- The TPL 2024 summer peak case is based on the WECC 2024 Heavy Summer 2 case;
- The TPL 2024-2025 winter peak case is based on the WECC 2023-24 Heavy Winter 2 case and,
- The TPL 2021 spring off-peak case is based on the WECC 2021 Light Spring 1 Scenario case.

The TPL cases include higher customer loads to reflect the 1-in-10 summer peak and winter peak forecasted for the PGE service territory. The TPL cases were further modified to include the higher queued generator interconnection requests[4] listed in the Study Assumptions section of this IFS. There are no planned PGE transmission projects in the area between 2021 and the Interconnection Customer's proposed In-Service Date. The 2021 spring off-peak TPL case was, therefore, considered sufficient for this IFS. The resulting cases are referred to in this IFS as the "Benchmark Cases".

From the Benchmark Cases, a model of the Interconnection Customer's Generating Facility and generator lead line were inserted, and the resulting cases are hereafter referred to as the "Project Cases". The differences between the Benchmark Cases and the Project Cases form the basis for comparisons of the Transmission System's performance between the pre- and post-generator interconnection topology of the system.

[3] The Bethel-Round Butte 230 kV line is not currently a posted path on the PGE OASIS website. The 344 MW TTC on the Bethel-Round Butte 230 kV line was determined in the Interconnection Feasibility Study for interconnection request #19-080.
[4] All higher queued interconnection requests included in this IFS are modeled with the Generating Facility, Network Upgrades, and Contingent Facilities.

IFS Methodology

This IFS includes powerflow and short circuit analyses in conformance with the Oregon QF-LGIP. This IFS also includes a TTC analysis to identify Network Upgrades necessary to ensure deliverability from the Interconnection Customer's Generating Facility to PGE load in the Willamette Valley. Each of these analyses may reveal unacceptable system performance that must be mitigated in order to safely and reliably interconnect the Generating Facility to the PGE Transmission System. The Benchmark Cases and the Project Cases are analyzed to determine if Network Upgrades (taking into consideration any applicable Contingent Facilities) are necessary to ensure that the Transmission System, with the addition of the Interconnection Customer's generator, demonstrates acceptable system performance. Each analysis is performed on a version of the Project Cases that include all Contingent Facilities associated with higher queued interconnection requests pending in PGE's generator interconnection queue.

Power Flow Analysis

The NERC TPL-001-4 reliability standard requires that all transmission system elements comprising the Bulk Electric System (BES) remain within their established thermal and voltage limits following the loss of a single BES element (N-1) or the loss of two or more BES elements (N-2 or N-1-1). This IFS includes the N-1, N-2, and N-1-1 contingencies for all BES elements in the PGE Transmission System and neighboring areas. In addition, the WECC System Performance Criteria requires that the change in bus voltage percentage not exceed 8% for N-1 contingencies. Thermal line loading increases, due to the Generating Facility, that are less than 2% over the Benchmark Case loadings are not considered significant impacts that need to be addressed.

The analysis results for each contingency are assessed for compliance with the following NERC and WECC system performance Requirements:

Pre-Contingency:

- All BES elements shall be within their normal thermal limits
- All BES elements shall be within their normal voltage limits

Post-Contingency:

- All BES elements shall be within their emergency thermal limits
- All BES elements shall be within their emergency voltage limits
- Bus Voltage Change Limits
    - The difference between pre and post-contingency load-serving bus voltages must be less than:
        - 8% for N-1 contingencies
        - 10% for N-2 and N-1-1 contingencies[5]

[5] The requirement is that load-serving bus voltages must be less than 10% for category P2-2 through category P7 contingencies; this is a PGE performance requirement and is not documented in NERC and WECC standards.

- Cascading or uncontrolled separation shall not occur
- Interruption of firm service (i.e. transmission curtailment) is allowed by modeling generation redispatch for applicable contingencies when acceptable, as specified by the NERC TPL-001-4 Standard:
    - Allowed for category P2-2 through P2-4 contingencies below 300 kV, category P4-1 through P4-5 contingencies below 300 kV, category P4-6 contingencies, category P5 contingencies below 300 kV, and category P7 contingencies

Short Circuit Analysis

A short circuit analysis is performed to identify transmission equipment with rated fault capabilities that will be exceeded by the higher fault currents that result from adding the Generating Facility to the PGE Transmission System. Short circuit modeling information for the Northwest area is maintained through the collaborative efforts of the region's utilities.

Faults at substations in the vicinity of the POI are simulated using the Aspen OneLiner program. Increases in equipment fault duty, attributable to the proposed Generating Facility, cannot result in fault duties that exceed equipment ratings. Fault duty increases of less than 1% are not considered significant impacts to the transmission system and thus are not required to be mitigated by the Interconnection Customer.

Total Transfer Capability Analysis

The TTC analysis was performed consistent with the requirements of the NERC MOD-029-2a reliability standard and included the N-1 and N-2 contingencies of all BES facilities in the Transmission System and the neighboring areas. The analysis also included all credible and conditionally credible (as and when applicable) multiple contingencies for the study season, except for N-1-1 outages. N-1-1 outages, referred to as category P3 and P6 contingencies in the NERC TPL-001-4 standard, were excluded as the NERC standard allows for system adjustments, which can effectively mitigate issues resulting from a subsequent contingency. The TTC performance criteria are the same as the power flow performance criteria documented above.

Analysis and Results

Preliminary Plan of Service

The Preliminary Plan of Service discussed in this section of the report was developed to meet the requirements for the Interconnection Customer's request.

The PGE Transmission System in Central Oregon consists of Pelton-Round Butte hydroelectric project (PRB), the generation lead lines from PRB to the Round Butte substation, a 230 kV transmission line from the Round Butte substation to the Bethel substation in the Willamette Valley (Bethel-Round Butte 230 kV), a 230 kV transmission line from the Round Butte substation to the Redmond BPA substation (Redmond BPA-Round Butte 230 kV), a 500 kV transmission line from the Round Butte substation to the Grizzly BPA substation (Grizzly BPA-Round Butte 500 kV), and two 230 kV connections to PacifiCorp's Cove substation[6] located adjacent to the Round Butte Substation. The requested POI is south of the Round Butte substation on the Redmond BPA-Round Butte 230 kV transmission line in the Opal City area.

A higher queued interconnection request #19-080 is expected to sectionalize the Redmond BPA-Round Butte 230 kV transmission line north of the POI for this Interconnection Request as shown in **Figure 1**. When #19-080 connects to the Transmission System it will create two line sections called Round Butte-19-080 230 kV and Redmond BPA-19-080 230 kV.

POI Substation

Connecting the Generating Facility to the Redmond BPA-Round Butte 230 kV transmission line requires the construction of a new 3-position ring bus substation that will sectionalize the Redmond BPA-19-080 230 kV transmission line and accept the Interconnection Customer's generation lead line. The new 3-position ring bus substation will create two new line segments from the existing transmission line. These line segments are the Redmond BPA-POI substation 230 kV line and the 19-080-POI substation 230 kV line. The 3-position ring bus substation, the Interconnection Customer's Generating Facility, and the PGE Transmission System in the Central Oregon area are shown in **Figure 1**.

Communications

Connecting the Generating Facility and the POI substation to the Transmission System requires redundant and path diverse communications between the POI substation and the PGE Control Center and between the POI substation and the Round Butte substation to support transfer-trip line protection, Remedial Action Scheme (RAS), SCADA, and metering applications. Interconnection request 19-080 will install redundant and path diverse ADSS fiber cable along the existing Redmond BPA-Round Butte 230 kV transmission line (from the Round Butte substation to the 19-080 substation and from the 19-080 substation to the Redmond BPA substation). The POI substation will connect to both of these ADSS fiber

[6] The PacifiCorp Cove substation serves PacifiCorp's load in the Madras area. The Cove substation is a load pocket that is only connected to the Bulk Electric System by the Round Butte facilities. The Cove substation, and the associated distribution system, does not connect back to the Bulk Electric System at any other point.

circuits. There is an existing PGE project to install fiber cable from Round Butte to the Grizzly BPA substation that will be utilized to complete the redundant and path diverse loop from Redmond BPA to Round Butte.

The Generating Facility will be integrated electronically into the PGE Balancing Authority Area (BAA) and will require interchange metering. Redundant and path diverse communications between the POI substation and the PGE Control Center are required for BAA integration and metering.

There is an existing RAS to protect against a known stability issue in the area of the Round Butte substation. Following the loss of two transmission lines connected to the Round Butte substation, generation connected to Round Butte must be immediately tripped so that no more than 200 MW of generation remains on-line. One of the two transmission lines, the loss of which will trigger the RAS, is the Redmond BPA-Round Butte 230 kV line. When the POI substation is constructed and the Redmond BPA-Round Butte 230 kV line is sectionalized, the loss of the Redmond BPA-POI substation 230 kV line will leave the Generating Facility connected to the Round Butte substation during potential system instability events. Thus, the Generating Facility is required to participate in the RAS that protects against the instability. For the Generating Facility to participate in the RAS, redundant and path diverse communications are required by NERC between the POI substation and the Round Butte substation. In addition to redundant communications paths, RAS racks will need to be installed in the POI substation and modifications will need to be made to the existing RAS equipment at the Round Butte substation, in order for this new Generating Facility to participate in the Round Butte RAS.

The ADSS fiber cable that is expected to be installed to accommodate interconnection request #19-080 is necessary for the operation of this Interconnection Request, and if delayed or not built, could cause a need for re-studies of this Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing, so those particular upgrades to the network have been identified as Contingent Facilities for the purposes of this Interconnection Request.

TTC Upgrades

PGE does not have any load in Central Oregon. The Bethel-Round Butte 230 kV transmission line is the sole PGE Transmission System connection between Central Oregon and PGE's service territory in the Willamette Valley. Currently, there is no Available Transfer Capability (ATC) from east to west between Round Butte and PGE's load. However, a higher queued interconnection request (#17-068) is expected to install a series capacitor on the Bethel-Round Butte 230 kV transmission line to increase the TTC, and create ATC, on that 230 kV line within the PGE Transmission System. Higher queued interconnection request #19-080 is expected to increase the size of the series capacitor and upgrade the Bethel-Round Butte 230 kV line to increase TTC and create additional ATC to deliver its output to PGE's load. Upgrading the Bethel-Round Butte 230 kV line requires the replacement of 48 structures.

The series capacitor size must be increased beyond what is required for #19-080 to provide the incremental TTC and ATC necessary to deliver the output of this additional Generating Facility to PGE's load.

The series capacitor substation associated with #17-068 must be constructed, and the series capacitor upgrade and the Bethel-Round Butte 230 kV 48 structure replacement associated with #19-080 must be completed before this Interconnection Request can operate. Consequently, the series capacitor substation, including the series capacitor and upgrade, and the Bethel-Round Butte 230 kV structure replacements expected to be installed for interconnection requests #17-068 and #19-080 are also considered Contingent Facilities for the purposes of this Interconnection Request.

The Preliminary Plan of Service is added to the Benchmark Cases to develop the Project Cases for NRIS. The Benchmark Cases and the Project Cases are then analyzed for power flow, short circuit, and TTC to confirm that the NRIS Preliminary Plan of Service provides for acceptable system performance.

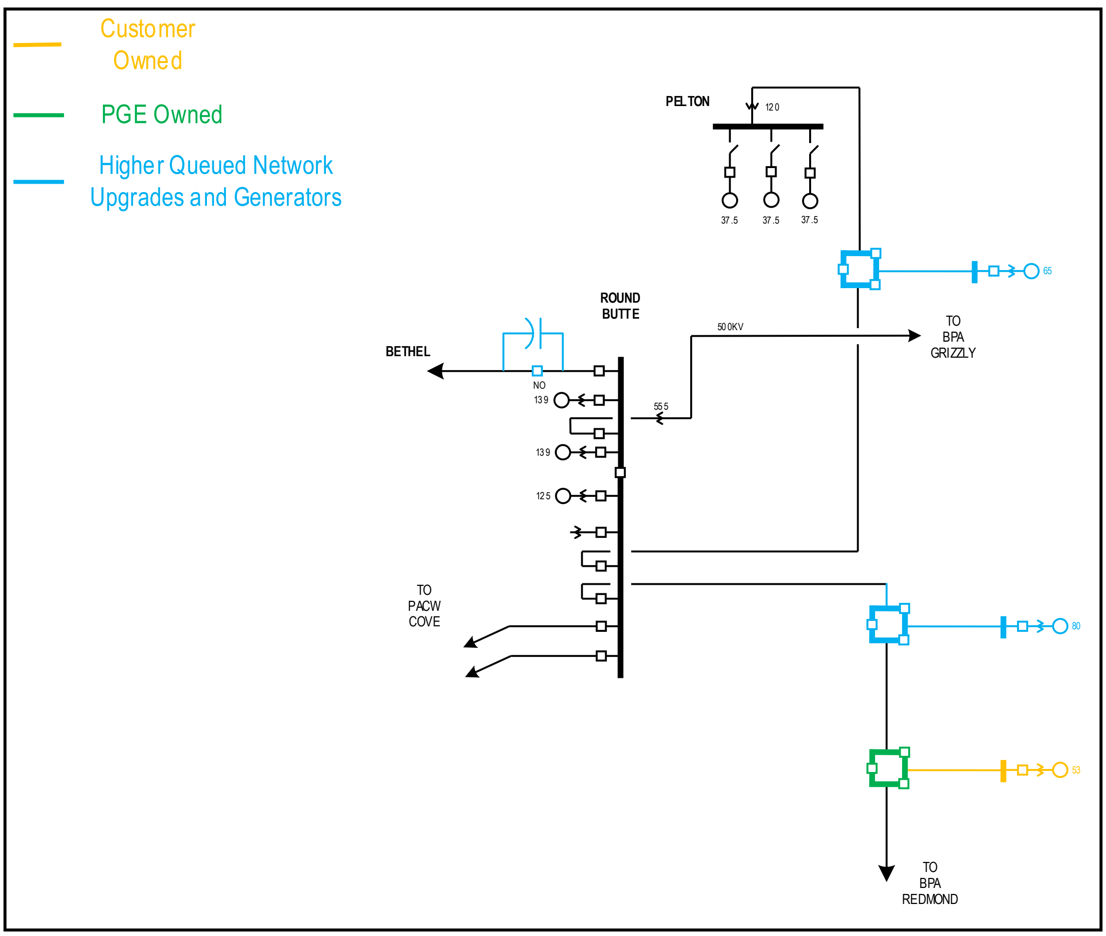

Figure 1: Preliminary Plan of Service

Results of Analysis

Total Transfer Capability Analysis

PGE does not have any load in Central Oregon. The Bethel-Round Butte 230 kV transmission line is the sole PGE Transmission System connection between Central Oregon and PGE's service territory in the Willamette Valley, approximately 100 miles away. The requested POI for this Interconnection Request is on the Redmond BPA-Round Butte 230 kV transmission line. The Redmond BPA-Round Butte 230 kV transmission line is a transmission path posted on the PGE OASIS site with a typical TTC of 282 MW in the summer and 334 MW in the winter in the north-to-south direction. In order to utilize the Bethel-Round Butte 230 kV transmission line to deliver to PGE's load in the Willamette Valley, the Redmond BPA-Round Butte 230 kV path must be utilized in the south-to-north direction. The Redmond BPA-Round Butte 230 kV path does not have a posted typical TTC in the south-to-north direction, but prior studies have identified that the TTC in the south-to-north direction will be set to the same value as the north-to-south direction. There is expected to be sufficient ATC in the south-to-north direction to allow for delivery of the output of this Generating Facility to the Round Butte substation.

Currently, there is no Available Transfer Capability (ATC) from east to west between Round Butte and PGE's load. ATC is calculated in accordance with the NERC MOD-029-2a standard and can generally be represented as ATC = TTC - ETC, where TTC represents Total Transfer Capability and ETC represents Existing Transmission Commitments. The TTC on the Bethel-Round Butte 230 kV transmission line is equal to the ETC. The TTC of the Bethel-Round Butte 230 kV transmission line is expected to be 344 MW in the summer and is dependent on Network Upgrades identified for the higher queued interconnection requests #17-068[7] and #19-080[8]. In order to deliver the full output of the Interconnection Customer's Generating Facility to PGE load, an additional 53 MW of new TTC on the Bethel-Round Butte 230 kV transmission line must be created.

The TTC on the Bethel-Round Butte 230 kV transmission line must be increased to at least 397 MW in the summer to deliver the output of the Generating Facility to PGE load. Preliminary studies indicate that the TTC can be increased to 397 MW. The TTC increase requires the series capacitor at the series capacitor substation, expected to be constructed for interconnection request #17-068 and upgraded by interconnection request #19-080, to be upgraded for this Interconnection Request as well. The TTC increase also requires the replacement of 78 structures on the Bethel-Round Butte 230 kV transmission line in addition to the 48 structures expected to be replaced by interconnection request #19-080. The replacement of structures is required to increase line clearances in order to achieve a higher thermal rating.

[7] Interconnection request #17-068 recently required the study of the TTC on the Bethel-Round Butte 230 kV line and informed the determination that the TTC on that line is expected to be 264 MW following the installation of a series capacitor on the Bethel-Round Butte 230 kV line to accommodate that interconnection.
[8] Interconnection request #19-080 required further study of the TTC on the Bethel-Round Butte 230 kV line and informed the determination that the TTC on that line is expected to be 344 MW following the upgrade of the series capacitor on the Bethel-Round Butte 230 kV line to accommodate that interconnection.

The TTC study cases for higher queued interconnection request #19-080 were utilized as a starting point for the TTC analysis for this IFS. A variety of generation patterns and load levels were studied in order to maximize the transfers across the path. Ultimately it was determined that increasing the TTC to 397 MW requires the series capacitor, installed as a Network Upgrade for interconnection request #17-068 and upgraded for interconnection request #19-080, to be upgraded further to compensate for approximately 60% of the reactance of the Bethel-Round Butte 230 kV transmission line. At that level of compensation, the Bethel-Round Butte 230 kV transmission line becomes the limiting element that sets the path rating to 397 MW in the summer. The Bethel-Round Butte 230 kV transmission line will overload for the N-1 loss of four different transmission lines or the N-2 failure of four different 500 kV circuit breakers at BPA's Marion substation. The limiting contingencies are shown in **Table 1**. The thermal rating of the Bethel-Round Butte 230 kV line must be increased to reduce the overload caused by the BPA breaker failure contingencies. The thermal rating of the line can be increased by replacing 78 structures with taller poles.

Category	Contingency Name	Limiting Element	Percent Loading
N-1	P1-2: Marion BPA-Santiam BPA 500kV	Bethel-Round Butte 230 kV	111.7%
	P1-2: Buckley BPA-Marion BPA 500kV	Bethel-Round Butte 230 kV	103.5%
	P1-2: Redmond BPA-POI Substation 230 kV	Bethel-Round Butte 230 kV	102.9%
	P1-2: Bethel-Santiam BPA 230kV	Bethel-Round Butte 230 kV	100.1%
N-2	P2-3: Marion 4386 BPA 500kV	Bethel-Round Butte 230 kV	120.6%
	P2-3: Marion 4383 BPA 500kV	Bethel-Round Butte 230 kV	111.4%
	P2-3: Marion 4389 BPA 500kV	Bethel-Round Butte 230 kV	103.5%
	P2-3: Marion 4368 BPA 500kV	Bethel-Round Butte 230 kV	100.3%

Table 1: TTC Limiting Contingency

Since series compensation of transmission lines is known to have negative effects on the system such as sub-synchronous resonance and other transient and voltage stability impacts, both voltage stability and transient stability analyses will be performed during the System Impact Study phase for this Interconnection Request. We expect such analysis to confirm our preliminary assessment that increasing the size of the series capacitor, at the series capacitor substation to be constructed for interconnection request #17-068 and upgraded for interconnection request #19-080, is a viable option for increasing the TTC of the Bethel-Round Butte 230 kV transmission line to 397 MW.

The Bethel-Round Butte 230 kV transmission line is part of the West of Cascades South major WECC path. Increasing the line rating and increasing the series compensation will require that such Network Upgrades be submitted to the WECC Path Rating Process. The WECC Path Rating Process can be conducted concurrently with design and construction of such Network Upgrades. It is possible that additional Network Upgrades could be identified during the WECC Path Rating Process that could impose additional cost and delay this Generating Facility's In-Service Date. The proposed upgrades will be submitted by PGE to WECC for study after the LGIA is signed for this Interconnection Request.

Power Flow Analysis

Power flow analysis was conducted on the Benchmark Cases and Project Cases for peak summer, peak winter, and off-peak spring conditions. No significant impacts attributable to the Generating Facility were identified for the off-peak spring conditions. The results of the peak summer and peak winter power flow analysis are discussed below.

Peak Summer and Peak Winter

The results of the power flow analysis for the summer season identify that two N-1-1 contingencies cause overloads on transmission elements in the area around the Round Butte substation. These contingencies, however, already exist for higher queued interconnection requests and can be mitigated by including the Generating Facility in the Round Butte RAS.

There are three transmission lines connected to the Round Butte substation: the Grizzly BPA-Round Butte 500 kV line, the Redmond BPA-Round Butte 230 kV line, and the Bethel-Round Butte 230 kV line. When the Generating Facility is interconnected to the Redmond BPA-Round Butte 230 kV line, the loss of the Grizzly BPA-Round Butte 500 kV line combined with the loss of either of the 230 kV lines will cause the remaining 230 kV transmission line connected to the Round Butte substation to overload.

The Bethel-Round Butte 230 kV line will overload in the event of the loss of both the Grizzly BPA-Round Butte 500 kV line and the Redmond BPA-POI Substation 230 kV transmission line, which will force all of the generation connected to the Round Butte substation and the Generating Facility into the Willamette Valley. This overload can be mitigated by including the Generating Facility in the existing Round Butte RAS and running back the Generating Facility for the combined outage of these two lines. Once the Generating Facility is added to the Round Butte RAS, the RAS should limit the flow on the Bethel-Round Butte 230 kV line for this N-1-1 outage. Additionally, the TTC analysis conducted in this IFS identified that the Bethel-Round Butte 230 kV transmission line thermal rating needs to be upgraded to deliver the output of the Generating Facility to PGE load. The thermal rating upgrade will also mitigate the overload to the Bethel-Round Butte 230 kV line for this N-1-1 outage.

The Redmond BPA-POI substation 230 kV line will overload in the event of the loss of both the Grizzly BPA-Round Butte 500 kV line and the Bethel-Round Butte 230 kV transmission line, which will force all of the generation connected to the Round Butte substation and the Generating Facility into the Central Oregon area. This overload can be mitigated by including the Generating Facility in the existing Round Butte RAS and running back the Generating Facility for the combined outage of these two lines. Once the Generating Facility is added to the Round Butte RAS, the RAS should limit the flow on the Redmond BPA-POI Substation 230 kV line.

The power flow results are shown in **Table 2** and **Table 3** below.

Summer Power Flow Results				
Contingency Name	**Limiting Element**	**Benchmark Case Percent Loading**	**Project Case Percent Loading**	**Difference**
N-1-1 Bethel-Round Butte 230 kV & Grizzly BPA-Round Butte 230 kV	Redmond BPA-POI Substation 230kV	106.0%	119.0%	13.0%
N-1-1 Grizzly BPA-Round Butte 230 kV & Redmond BPA-POI Substation 230 kV	Bethel-Round Butte 230 kV	105.2%	118.6%	13.4%

Table 2: Power Flow Results – Summer

Winter Power Flow Results				
Contingency Name	**Limiting Element**	**Benchmark Case Percent Loading**	**Project Case Percent Loading**	**Difference**
N-1-1 Grizzly BPA-Round Butte 230 kV & Redmond BPA-POI Substation 230 kV	Bethel-Round Butte 230 kV	94.6%	106.0%	11.4%

Table 3: Power Flow Results – Winter

Short Circuit Analysis

A short circuit analysis was conducted for the Round Butte area to determine the change in fault duty attributable to adding the Preliminary Plan of Service to the PGE Transmission System. This proposed Interconnection Request has no material impact on any existing circuit breaker rating.

As a result, no additional Network Upgrades or Contingent Facilities have been identified as being necessary to satisfy the applicable NERC and WECC requirements.

Proposed Plan of Service[9]

The results of the power flow analysis show that the Preliminary Plan of Service does not meet all NERC and WECC requirements and the Preliminary Plan of Service does not allow for the delivery of the Generating Facility's output to PGE load in the Willamette Valley. The Preliminary Plan of Service causes two transmission lines in the Round Butte area to overload for N-1-1 contingencies. The Proposed Plan of Service, therefore, includes the Preliminary Plan of Service, increased thermal rating of the Bethel-Round Butte 230 kV transmission line, increased series compensation of the Bethel-Round Butte 230 kV transmission line, and modifications to the existing Round Butte RAS to mitigate N-1-1 contingencies. This IFS has previously identified Contingent Facilities that are necessary to deliver the output of the Generating Facility to PGE load. Those Contingent Facilities will be listed again, below.

A non-binding good-faith cost estimate of the Network Upgrades required for the Proposed Plan of Service is shown below in **Table 4, Table 5, Table 6**, **Table 7,** and **Table 8** and the good-faith construction schedule is also discussed. The Interconnection Customer's Interconnection Facilities, including the generator lead line, located between the Generating Facility and the Point of Change of Ownership, are not included in the estimate for the Proposed Plan of Service. The target accuracy of this cost estimate is ± 50%.

The cost estimate to increase the series compensation of the Bethel-Round Butte 230 kV line to 60% and replace 78 structures on the Bethel-Round Butte 230 kV line for purposes of increasing the line rating is shown in **Table 4**. The estimated cost to increase the series capacitor size is dependent upon timing, and whether or not a Large Generator Interconnection Agreement (LGIA) is in place to accommodate this Interconnection Request by the time PGE specifies and orders the series capacitor for interconnection #17-068 and interconnection #19-080. If the order for the series capacitor (for interconnection requests #17-068 and #19-080) has already been placed by the time an LGIA is executed and PGE has been authorized to proceed with this Interconnection Request, then it will be necessary to pursue a change order or other steps necessary to obtain a larger sized series capacitor, and the Interconnection Customer will be responsible for any additional charges associated with change orders, modifications, replacement, etc. that are incurred by PGE to obtain the larger series capacitor needed to accommodate this Interconnection Request.

[9] Upgrades to protection, communications, and/or other equipment at Round Butte, Bethel, Redmond BPA, and other substations will be required. The scope of work at these substations is expected to be minimal and will be identified during the Facility Study.

TTC Upgrades Cost Estimate	
Series Capacitor Substation	
Increase Series Capacitor Size	$1,000,000
Replace 78 Transmission Structures	
Contractor Labor	$1,899,400
Purchased Material	$2,528,900
Contractor and Outside Services	$478,700
Engineering, Permitting and Equipment	$1,759,400
Total	**$7,666,400**

Table 4: TTC Upgrade Cost Estimate

The cost estimate to construct the 3-position ring bus POI substation is shown in **Table 5**. The estimated costs do not include property costs.

Point of Interconnection Substation Cost Estimate		
Purchased Material Including Labor		
3- Circuit Breaker, 230kV, SF6, 3000A, 50kA		$805,800
9 - Disconnect Switch, 230kV, 3000A		$362,300
9 - CCVT, 230kV		$245,400
3 - Metering CTs, 230kV		$268,100
9 - Surge Arrestors, 230kV		$148,500
1 - Control Enclosure, 50' x 16' with floors and two battery rooms		$661,400
8 - Relay Racks		$866,300
Structures, 230 kV - with Foundations		$2,222,000
	Sub Total	**$5,579,800**
Contractor and Outside Services		
Contract Construction - General Costs Mob, Demob, Site Services, Management, Bond, etc.		$550,000
Site Prep, Fence, Conduit and Vaults, 230 kV Bus, Security Systems, etc.		$2,268,800
Engineering, Geotech, Survey, Permitting, etc.		$1,306,300
	Sub Total	**$4,125,100**
	Total	**$9,704,900**

Table 5: POI Substation Cost Estimate

The cost estimate to modify RAS equipment at the Round Butte substation is shown in **Table 6**.

RAS Modification Cost Estimate	
Hardware, Programming, and Testing	$250,000

Table 6: RAS Modification at Round Butte Substation Cost Estimate

The cost estimate to sectionalize the Redmond BPA-Round Butte 230 kV transmission line is shown in **Table 7**. The estimated costs do not include environmental mitigations or acquiring new easements and rights of way.

Transmission Estimate	
Redmond BPA-Round Butte 230 kV Modifications	
Contractor Labor	$521,900
Purchased Material	$473,700
Contractor and Outside Services	$1,034,400
Engineering, Permitting and Equipment	$571,300
Total	**$2,601,300**

Table 7: Transmission Cost Estimate

The total project cost estimate (i.e., the sum of the costs outlined in **Table 4** through **Table 7**) to construct a 3-position ring bus substation, sectionalize the Redmond BPA-Round Butte 230 kV transmission line, modify the Round Butte RAS, and increase the series compensation and thermal rating of the Bethel-Round Butte 230 kV line is shown in **Table 8**.

Total Project Cost Estimate	
TTC Upgrade Cost Estimate	$7,666,400
Point of Interconnection Substation Cost Estimate	$9,704,900
Round Butte RAS Modification Cost Estimate	$250,000
Transmission Estimate	$2,601,300
Total	**$20,222,600**

Table 8: Total Project Cost Estimate

The schedule to implement the Proposed Plan of Service requires a 2-2.5 year timeline for design, permitting, material procurement, and construction. This schedule does not meet the Interconnection Customer’s requested In-Service Date of 12/31/2022.

BPA and PacifiCorp operate transmission systems in the area of the POI and BPA’s transmission lines and BPA breaker failure contingencies are identified as limiting the TTC for the Bethel-Round Butte 230 kV transmission line at 397 MW. For these reasons, BPA and PacifiCorp have been identified as Affected Systems.

There are many factors outside of the Transmission Provider’s control that could extend the time required for completing the Proposed Plan of Service outlined above. These factors include but are not limited to: unexpected delays in the permitting process, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties, the duration of and any additional upgrades identified during the WECC Path Rating Process, and inclement weather conditions.

Conclusion

The conclusions drawn from performing this IFS are that the Interconnection Customer's request for Interconnection Service can be met by proceeding with the Proposed Plan of Service as outlined above.

The study results demonstrate that the Preliminary Plan of Service 1) does not meet all NERC and WECC requirements; 2) does not allow for the delivery of the Generating Facilities output to PGE load in the Willamette Valley; and 3) causes the Bethel-Round Butte 230 kV line and the Redmond BPA-POI substation 230 kV line to overload for N-1-1 contingencies. The NRIS Proposed Plan of Service, therefore, requires:

- Construction of a POI substation;
- Modification of the Redmond BPA-Round Butte 230 kV transmission line;
- Replacement of 78 structures on Bethel-Round Butte 230 kV transmission line;
- Increased series compensation of the Bethel-Round Butte 230 kV transmission line; and,
- Modifications to the existing Round Butte RAS to mitigate N-1-1 contingencies.

The series capacitor substation associated with #17-068 must be constructed, and the series capacitor upgrade and the Bethel-Round Butte 230 kV 48 structure replacements associated with #19-080 must be completed before this Interconnection Request can operate. Consequently, the series capacitor substation, including the series capacitor and upgrade, and the Bethel-Round Butte 230 kV structure replacements expected to be installed for higher-queued interconnection requests #17-068 and #19-080 are considered Contingent Facilities for purposes of this Interconnection Request.

The ADSS fiber cable that is expected to be installed to accommodate interconnection request #19-080 is necessary for the operation of this Interconnection Request, and if delayed or not built, could cause a need for re-studies of this Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing, so those Network upgrades have also been identified as Contingent Facilities for the purposes of this Interconnection Request.

The schedule to implement the Proposed Plan of Service requires a 2-2.5 year timeline for design, permitting, material procurement, and construction. This schedule does not meet the Interconnection Customer's requested In-Service Date of 12/31/2022.

BPA and PacifiCorp operate transmission systems in the area of the POI and BPA's transmission lines and BPA breaker failure contingencies are identified as limiting the TTC for the Bethel-Round Butte 230 kV transmission line at 397 MW. For these reasons, BPA and PacifiCorp have been identified as Affected Systems.

There are many factors outside of the Transmission Provider's control that could extend the time required for completing the Proposed Plan of Service outlined above. These factors include but are not limited to: unexpected delays in the permitting process, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties, the duration of and any additional upgrades identified during the WECC Path Rating Process, and inclement weather conditions.

PGE cannot guarantee that future analysis (i.e. Requests for Transmission Service or Operational Studies) will not identify additional problems or system constraints that require mitigation or reduced operation. Interconnection service neither conveys nor implies any type of transmission service. If there is a material change in any aspect of the Generating Facility or to a higher-queued interconnection request, a re-study may be required.

Portland General Electric Company

System Impact Re-Study

Interconnection Request:

#19-081 (53 MW Photovoltaic Project)
Issued May 3, 2021

Prepared by Transmission Planning

Table of Contents

Introduction

This System Impact Study[1] (SIS) further examines the feasibility of connecting the proposed 53 MW Photovoltaic (PV) Project to the Portland General Electric (PGE) Transmission System with a requested in-service date of June 30, 2023. The Interconnection Customer has requested a Point of Interconnection (POI) on a PGE transmission line from the Round Butte substation to the Bonneville Power Administration's (BPA) Redmond substation. The requested POI is in Central Oregon in the vicinity of Opal City, south of the Round Butte substation.

The Interconnection Customer has requested Network Resource Interconnection Service (NRIS) in conformance with the State Qualifying Facility-Large Generator Interconnection Procedures (QF-LGIP) in Oregon.

Study Scope

This SIS is an evaluation of the system impact and cost of interconnecting the Generating Facility to PGE's Transmission System at the designated POI. This SIS identifies any required Contingent Facilities[2], Interconnection Facilities, and Network Upgrades necessary to accommodate the proposed interconnection, as well as any Affected Systems. This SIS consists of a power flow analysis, short circuit analysis, transient stability analysis, voltage stability analysis, and Total Transfer Capability (TTC) analysis. The following objectives are met in this SIS:

- Documentation of the assumptions used in the analyses;
- Documentation of any system impacts observed that are adverse to the reliability of the electric system as a result of the proposed interconnection;
- Documentation of TTC limitations and the Network Upgrades necessary to deliver the output of the Generating Facility to PGE load;
- Documentation of other transmission providers' transmission systems that are impacted and identification of these transmission providers as Affected Systems;
- Documentation of fault interrupting equipment with short circuit capability limits that are exceeded as a result of the proposed interconnection;
- A list of Contingent Facilities;
- A non-binding, good faith estimate of the cost for constructing Transmission Provider's Interconnection Facilities and the Network Upgrades necessary to accommodate the requested Interconnection Service; and,

[1] With the exception of those terms that are defined herein, capitalized terms used throughout this document have the same meanings as such terms are defined in the QF LGIP adopted by the Public Utility Commission of Oregon ("OPUC") in Order 10-132.
[2] Contingent Facilities are defined as unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection 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.

- A non-binding, good faith estimate of the time to construct the required Transmission Provider's Interconnection Facilities and Network Upgrades, and the estimated in-service completion times of the Contingent Facilities necessary to accommodate the requested Interconnection Service.

This SIS considered all transmission facilities and generation facilities that, on the date the study was commenced:

- Were directly interconnected to the PGE Transmission System;
- Were interconnected to other transmission providers' transmission systems and may have an impact on the requested Interconnection Service;
- Have a higher queued interconnection request[3] to interconnect to the PGE Transmission System; and,
- Have no queue position but have executed a Large Generator Interconnection Agreement (LGIA) or requested that an unexecuted LGIA be filed with FERC.

Study Assumptions

This SIS includes the following assumptions for all system conditions and seasons:

- The Interconnection Customer's requested in-service date is June 30, 2023;
- Higher queued generator interconnection requests modeled at their requested maximum generation levels. The specific higher queued generation interconnection requests included in this SIS are:
    - Request #17-065 – 400 MW Photovoltaic System near the Fort Rock substation;
    - Request #17-066 – 200 MW Battery Energy Storage System at the Rivergate substation;
    - Request #17-067 – 200 MW Battery Energy Storage System at the Harborton substation;
    - Request #17-068 – 65 MW Photovoltaic System and Battery Energy Storage System on the Pelton-Round Butte 230kV line; and,
    - Request #19-076 (NRIS) – 200 MW Battery Energy Storage System at the Blue Lake substation.
- All higher queued interconnection requests included in this SIS are modeled with those requests' generating facility, network upgrades, and contingent facilities;
- Modeling of this Interconnection Request at a maximum capability of 53 MW;
- No generator interconnection requests on other transmission providers' transmission systems were included in this SIS;
- Projects scheduled to be on-line around the Customer's requested in-service date are reflected in the 2022 Spring, 2022 Summer and 2022-2023 Winter benchmark cases.
    - No transmission projects are expected to have an impact on the results of this SIS.

[3] With respect to both generation facilities and Contingent Facilities associated with any higher quested interconnection request.

- The Generating Facility output is offset by PGE on-system generation decrements in the Project Cases[4];
- The POI being on PGE's existing Redmond BPA-Round Butte 230 kV transmission line south of the Round Butte substation in the vicinity of Opal City;
- The nominal voltage at the POI of 230 kV;
- The Interconnection Customer being responsible for designing, permitting, building, and maintaining a 230 kV generator lead line from the Interconnection Customer's generation site to the POI;
- The TTC of the Redmond BPA-Round Butte 230 kV line in the S>N direction being the same as the TTC in the N>S direction;
- The ATC of the Bethel-Round Butte 230 kV line being fully subscribed;
- The TTC of the Bethel-Round Butte 230 kV transmission line at 264 MW[5] in the summer (limiting season) and dependent upon the construction of a series capacitor substation, including the series capacitor, adjacent to the Round Butte substation, all in connection with the higher-queued interconnection request #17-068; and,
- The total plant output from the Generating Facility not exceeding 53 MW at the POI.

Study Case Development

This SIS utilizes WECC base cases as the starting point for studying the impact of the proposed interconnection to the Transmission System. WECC base cases include models for the entire Western Interconnection including facility representation of voltage levels at the sub-transmission level. WECC collects the data for the Western Interconnection through its members who provide the representation and equivalent data for elements in their systems, including: the initial conditions for the study case, up-to-date line parameters, load information, generation unit parameters, and equivalent representations consistent with the time period being studied. The WECC base cases used in this SIS were modified for use in the PGE NERC TPL 001-4 Transmission Planning Assessment (TPL) as follows:

- The TPL 2022 summer peak case is based on the WECC 2020 Heavy Summer 3 case;
- The TPL 2022-2023 winter peak case is based on the WECC 2020-21 Heavy Winter 2 case; and,
- The TPL 2022 spring off-peak case is based on the WECC 2020 Light Spring 1 Scenario case.

The TPL cases include higher customer loads to reflect the 1-in-10 summer peak and winter peak forecasted for the PGE service territory. The TPL cases were further modified to include the higher queued generator interconnection requests listed in the Study Assumptions section of this SIS. There are

[4] There is insufficient PGE generation in the off-peak spring case to offset the 53 MW of new generation. Non-PGE generation remote to the PGE System was offset in the off-peak spring case to represent a decrease in market purchases.
[5] The Bethel-Round Butte 230 kV line is not currently a posted path on the PGE OASIS website. The 264 MW TTC on the Bethel-Round Butte 230 kV line was determined in the System Impact Study for Interconnection Request #17-068.

no planned transmission projects in the Round Butte area between 2022 and the Interconnection Customer's proposed in-service date. The 2022 TPL cases are, therefore, considered sufficient for this SIS. The resulting cases are referred to in this SIS as the "Benchmark Cases".

From the Benchmark Cases, a model of the Interconnection Customer's Generating Facility and generator lead line were inserted, and the resulting cases are hereafter referred to as the "Project Cases". The differences between the Benchmark Cases and the Project Cases form the basis for comparisons of the Transmission System's performance between the pre-and post-generator interconnection topology of the system.

SIS Methodology

This SIS includes powerflow, short circuit, transient stability, and voltage stability studies in conformance with the QF-LGIP adopted by the OPUC. This SIS also includes a TTC analysis to identify Network Upgrades necessary to ensure deliverability of the aggregate of generation in the local area, including the Interconnection Customer's Generating Facility, to the aggregate of load on PGE's Transmission System in the Willamette Valley, as is necessary for the Generating Facility to receive NRIS. Each of these analyses may reveal unacceptable system performance that must be mitigated in order to safely and reliably interconnect the Generating Facility to the PGE Transmission System. The Benchmark Cases and the Project Cases are analyzed to determine if Network Upgrades (taking into consideration any applicable Contingent Facilities) are necessary to ensure that the Transmission System, with the addition of the Interconnection Customer's generator, demonstrates acceptable system performance. Each analysis is performed on a version of the Project Cases that include all Contingent Facilities required by higher queued interconnection requests pending in PGE's generator interconnection queue.

Power Flow Analysis

The NERC TPL-001-4 reliability standard requires that all transmission system elements comprising the Bulk Electric System (BES) remain within their established thermal and voltage limits following the loss of a single BES element (N-1) or the loss of two or more BES elements (N-2 or N-1-1). This SIS includes the N-1, N-2, and N-1-1 contingencies for all BES elements in the PGE Transmission System and neighboring areas. In addition, the WECC System Performance Criteria [6] requires that the change in bus voltage percentage not exceed 8% for N-1 contingencies. Thermal line loading increases, due to the Generating Facility, that are less than 2% over the Benchmark Case loadings are not considered significant impacts that need to be addressed.

The analysis results for each contingency are assessed for compliance with the following NERC and WECC system performance requirements:

Pre-Contingency:

- All BES elements shall be within their normal thermal limits.
- All BES elements shall be within their normal voltage limits.

Post-Contingency:

- All BES elements shall be within their emergency thermal limits.
- All BES elements shall be within their emergency voltage limits.
- Bus Voltage Change Limits:
  - The difference between pre and post-contingency load-serving bus voltages must be less than:
    - 8% for N-1 contingencies.

[6] WECC Criterion – TPL-001-WECC-CRT-3.2

        - 10% for N-2 and N-1-1 contingencies[7].
- Cascading or uncontrolled separation shall not occur.
- Interruption of firm service (i.e. transmission curtailment) is allowed by modeling generation redispatch for applicable contingencies when acceptable, specified by the NERC TPL-001-4 Standard:
    - Allowed for category P2-2 through P2-4 contingencies below 300 kV, category P4-1 through P4-5 contingencies below 300 kV, category P4-6 contingencies, category P5 contingencies below 300 kV, and category P7 contingencies.

Short Circuit Analysis

Short circuit analysis is performed to identify transmission equipment with rated fault capabilities that will be exceeded by the higher fault currents that result from adding the Generating Facility to the PGE Transmission System. Short circuit modeling information for the Northwest area is maintained through the collaborative efforts of the region's utilities.

Faults at substations in the vicinity of the POI are simulated using the Aspen OneLiner program. Increases in equipment fault duty, attributable to the proposed Generating Facility, cannot result in fault duties that exceed equipment ratings. Fault duty increases of less than 1% are not considered significant impacts to the transmission system and thus are not required to be mitigated by the Interconnection Customer.

Transient Stability Analysis

The transmission system must demonstrate post-contingency transient stability. Post-contingency transient stability is demonstrated when generator rotor angles, and bus voltages and frequencies show positive damping within the requirements of the WECC System Performance Criteria. The WECC System Performance Criteria establishes limits on the allowable size and duration of frequency and voltage swings during the transient period following a disturbance. The WECC System Performance Criteria performance requirements are:

Rotor Angle Stability

Generators must remain in synchronism with the PGE Transmission System and the rest of the transmission system in the Northwest area through the transient period. Rotor angle oscillations must exhibit positive damping for single and multiple contingencies.

[7] The requirement is that load-serving bus voltages must be less than 10% for category P2-2 through category P7 contingencies; this is a PGE performance requirement and is not documented in NERC and WECC standards.

Voltage Stability

Following the clearing of a fault, load-serving bus voltages shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all single and multiple contingency events.

Following the recovery to 80% of pre-contingency voltage, a load-serving bus 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 all single and multiple contingency events.

Following the opening of a transmission element without a fault, the voltage at a load-serving bus 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 all single and multiple contingency events.

Frequency Stability

System frequency at any load-serving bus must not fall below 59.6 Hz for six cycles or more following a single contingency, or 59.0 Hz for six cycles or more following a multiple contingency.

Representative contingencies subject to transient stability simulations include contingencies affecting the PGE Transmission System and the neighboring transmission systems. The PowerWorld Simulator tool is used to perform transient system stability analysis.

Voltage Stability Analysis

The Transmission System must demonstrate voltage stability. Voltage stability is demonstrated when forecasted load does not exceed the maximum load or transfer limit obtained and the Reactive Margin is greater than or equal to the Reactive Power Margin Requirement (PMR).

The WECC System Performance Criteria established the maximum load or transfer limit as the lower of the following:

- 5% below the load (for load areas) or path flow (for transfer paths) at the collapse point on the P-V curve for system normal conditions (N-0);
- 5% below the pre-contingency flow or load corresponding to the collapse point on the P-V curve for N-1 contingencies; and,
- 2.5% below the pre-contingency flow or load corresponding to the collapse point on the P-V curve for N-2 and N-1-1 contingencies.

The PowerWorld Simulator tool is used to build P-V curves.

The WECC System Performance Criteria requires that post-contingency PMR be demonstrated for stress levels of:

- A minimum of 105% for system normal conditions (N-0) and for N-1 contingencies; and,
- A minimum of 102.5% for N-2 and N-1-1 contingencies.

Representative contingencies used for the voltage stability analysis include contingencies affecting the PGE Transmission System and the neighboring transmission systems.

Both Reactive Margin and PMR are determined through the building of Q-V curves. The PowerWorld Simulator tool is used to build Q-V curves.

<u>Total Transfer Capability Analysis</u>

The TTC analysis consists of power flow, transient stability, and voltage stability analyses. The power flow analysis includes all N-1 and N-2 contingencies for the BES facilities in the PGE transmission area and the neighboring areas. The analysis also includes all credible and conditionally credible (as and when applicable) multiple contingencies for the study season, except for N-1-1 outages. N-1-1 outages, referred to as category P3 and P6 contingencies in the NERC TPL-001-4 standard, are excluded as the NERC standard allows for system adjustments, which can effectively mitigate issues resulting from a subsequent contingency. The TTC performance criteria are the same as the power flow performance criteria documented above.

Preliminary Plan of Service

The Preliminary Plan of Service discussed in this section of the report was developed to meet the requirements for the Interconnection Customer's request.

The PGE Transmission System in Central Oregon consists of the following lines and connections: 1) a 230 kV transmission line from the Round Butte substation to the Bethel substation in the Willamette Valley (Bethel-Round Butte 230 kV), 2) a 230 kV transmission line from the Round Butte substation to the Redmond BPA substation (Redmond BPA-Round Butte 230 kV), 3) a 500 kV transmission line from the Round Butte substation to the Grizzly BPA substation (Grizzly BPA-Round Butte 500 kV), and 4) two 230 kV connections to PacifiCorp's (PACW) Cove substation[8] located adjacent to the Round Butte Substation. The requested POI is south of the Round Butte substation on the Redmond BPA-Round Butte 230 kV transmission line in the Opal City area.

POI Substation

Connecting the Generating Facility to the Redmond BPA-Round Butte 230 kV transmission line requires the construction of a new 3-position ring bus substation that will sectionalize the Redmond BPA-Round Butte 230 kV transmission line and accept the Interconnection Customer's generation lead line. The new 3-position ring bus substation will create two new line segments from the existing transmission line. These line segments are the Round Butte-19-081 230 kV line and the Redmond BPA-19-081 230 kV line. The 3-position ring bus substation, the Interconnection Customer's Generating Facility, and the PGE Transmission System in the Central Oregon area are shown in **Figure 1**.

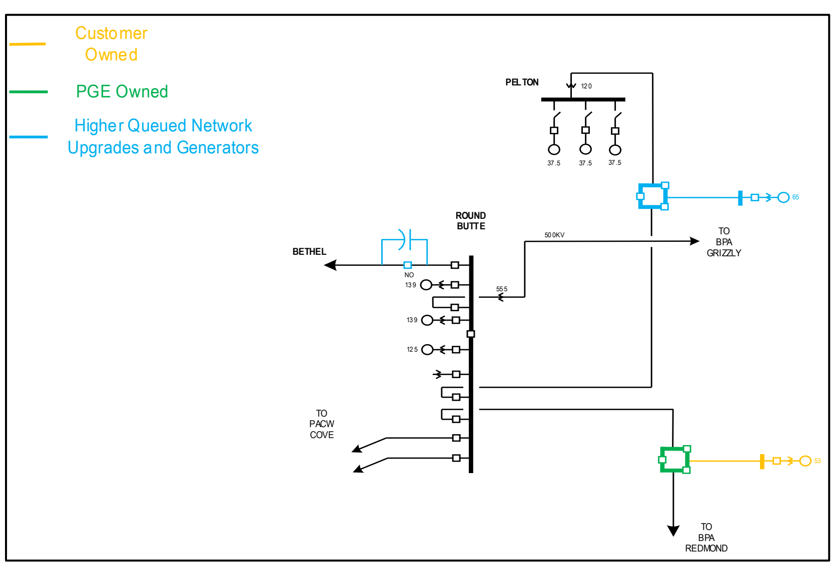

Figure 1: Preliminary Plan of Service

[8] The PacifiCorp Cove substation serves PacifiCorp's load in the Madras area. The Cove substation is a load pocket that is only connected to the Bulk Electric System by the Round Butte facilities. The Cove substation, and the associated distribution system, does not connect back to the Bulk Electric System at any other point.

Communications

Connecting the Generating Facility and the POI substation to the Transmission System requires redundant and path diverse communications between the POI substation and the PGE System Control Center, and between the POI substation and the Round Butte substation, to support transfer trip line protection, Remedial Action Scheme (RAS), SCADA, and metering applications. Redundant and path diverse communications will be achieved by installing ADSS fiber cable along the existing Redmond BPA-Round Butte 230 kV transmission line (from the Round Butte substation to the POI substation and from the POI substation to the Redmond BPA substation). The installation of the ADSS fiber cable will require the replacement of some of the Redmond BPA-Round Butte 230 kV line structures to support the additional load of the cable. The existing fiber cable from Round Butte to the Grizzly BPA substation will be utilized to complete the redundant and path diverse loop from Redmond BPA to Round Butte.

The Generating Facility will be integrated electronically into the PGE Balancing Authority Area (BAA) and will require interchange metering. Redundant communications between the POI substation and the PGE Control Center are required for BAA integration and metering.

The Redmond BPA-Round Butte 230 kV existing line protection scheme utilizes power line carrier (PLC) technology to provide transfer trip between the Round Butte and Redmond BPA substations. The ADSS fiber cable will be utilized for transfer trip between the Round Butte substation and the POI substation, and between the POI substation and the Redmond BPA substation. The PLC equipment at the Round Butte and Redmond BPA substations will be retired.

There is an existing RAS to protect against a known stability issue in the area of the Round Butte substation. Following the loss of two transmission lines connected to the Round Butte substation, generation connected to Round Butte must be immediately tripped so that no more than 200 MW of generation remains on-line. One of these two transmission lines is the Redmond BPA-Round Butte 230 kV line. When the POI substation is constructed and the Redmond BPA-Round Butte 230 kV line is sectionalized, the loss of the Redmond BPA-19-081 230 kV line will leave the Generating Facility connected to the Round Butte substation during potential system instability events. Thus, the Generating Facility is required to participate in the RAS that protects against the instability. For the Generating Facility to participate in the RAS, redundant and path diverse communications are required by NERC between the POI substation and the Round Butte substation. In addition to redundant communications paths, RAS racks will need to be installed in the POI substation and modifications will need to be made to the existing RAS equipment at the Round Butte substation, in order for this new Generating Facility to participate in the Round Butte RAS.

TTC Upgrades

PGE does not have any load in Central Oregon. The Bethel-Round Butte 230 kV transmission line is the sole PGE Transmission System connection between Central Oregon and PGE’s service territory, in the Willamette Valley. Currently, there is no Available Transfer Capability (ATC) from east to west between Round Butte and PGE’s load. However, a higher-queued interconnection request (#17-068) is expected to install a series capacitor on the Bethel-Round Butte 230 kV transmission line to increase the TTC, and create ATC, on that 230 kV line within the PGE Transmission System. That series capacitor size must be increased beyond what is required for #17-068 to provide the incremental TTC and ATC necessary to deliver the output of this additional Generating Facility to PGE's load. The series capacitor substation associated with #17-068 must first be constructed before this Generating Facility can operate. Consequently, the series capacitor substation, including the series capacitor, expected to be installed for interconnection request #17-068 is considered a Contingent Facility for the purposes of this Interconnection Request.

The Preliminary Plan of Service is added to the Benchmark Cases to develop the Project Cases. The Benchmark Cases and the Project Cases are then analyzed for power flow, short circuit, and TTC to confirm that the Preliminary Plan of Service provides for acceptable system performance.

Analysis and Results

Total Transfer Capability Analysis

PGE does not have any load in Central Oregon. The Bethel-Round Butte 230 kV transmission line is the sole PGE Transmission System connection between Central Oregon and PGE's service territory in the Willamette Valley, approximately 100 miles away. The requested POI for this Interconnection Request is on the Redmond BPA-Round Butte 230 kV transmission line. The Redmond BPA-Round Butte 230 kV transmission line is a transmission path posted on the PGE OASIS site with a typical TTC of 282 MW in the summer and 334 MW in the winter in the north-to-south direction. In order to utilize the Bethel-Round Butte 230 kV transmission line to deliver to PGE's load in the Willamette Valley, the Redmond BPA-Round Butte 230 kV line must have a path established in the south-to-north direction. Because it is not yet a recognized path, the Redmond BPA-Round Butte 230 kV path does not have a posted typical TTC in the south-to-north direction. However, prior studies have identified that the TTC for a new path in the south-to-north direction could be set to the same value as the existing path in the north-to-south direction. Accordingly, there is expected to be sufficient ATC in the south-to-north direction to allow for delivery of the output of this Generating Facility to the Round Butte substation.

Currently, there is no Available Transfer Capability (ATC) from east to west between Round Butte and PGE's load. ATC can generally be represented as ATC = TTC - ETC, where TTC represents Total Transfer Capability and ETC represents Existing Transmission Commitments. The TTC on the Bethel-Round Butte 230 kV transmission line is equal to the ETC. The TTC of the Bethel-Round Butte 230 kV transmission line is expected to be 264 MW in the summer and is dependent on Network Upgrades identified for the higher queued interconnection request #17-068[9]. In order to deliver the full output of the Interconnection Customer's Generating Facility to PGE load, an additional 53 MW of new TTC on the Bethel-Round Butte 230 kV transmission line must be created.

The TTC on the Bethel-Round Butte 230 kV transmission line must be increased to 317 MW in the summer to deliver the output of the Generating Facility to PGE load. Studies confirm that the TTC can be increased to 317 MW with the installation of a larger series capacitor at the series capacitor substation expected to be constructed for Interconnection Request #17-068.

The Benchmark Cases were utilized as a starting point for the TTC analysis for this SIS. A variety of generation patterns and load levels were studied in order to maximize the transfers across the path. Ultimately it was determined that increasing the TTC to 317 MW requires the series capacitor, installed as a Network Upgrade for interconnection request #17-068, to be upgraded to compensate for approximately 42% of the reactance of the Bethel-Round Butte 230 kV transmission line.

Series compensation of transmission lines is known to have negative effects on the system such as sub-synchronous resonance and other transient and voltage stability impacts. After consulting with

[9] Interconnection request #17-068 recently required the study of the TTC on the Bethel-Round Butte 230 kV line and informed the determination that the TTC on that line is expected to be 264 MW following the installation of a series capacitor on the Bethel-Round Butte 230 kV line to accommodate that interconnection.

neighboring transmission providers and regional partners, it was determined that risk of sub-synchronous resonance is expected to be minimal and a study was therefore not performed. Both voltage stability and transient stability analyses were performed for this Interconnection Request. These analyses did not identify any adverse impacts of increasing the size of the series capacitor constructed for interconnection request #17-068. Increasing the capacitor size is a viable option for increasing the TTC of the Bethel-Round Butte 230 kV transmission line to 317 MW.

The Bethel-Round Butte 230 kV transmission line is part of the West of Cascades South major WECC path. Increasing the line rating and increasing the series compensation will require that such Network Upgrades be submitted to the WECC Path Rating Process. The WECC Path Rating Process can be conducted concurrently with design and construction of such Network Upgrades. It is possible that additional Network Upgrades could be identified during the WECC Path Rating Process that could impose additional costs, and could delay this Generating Facility’s In-Service Date. The proposal for upgrades to the West of Cascades South path will be submitted by PGE after the LGIA is signed for this Interconnection Request.

Power Flow Analysis

Power flow analysis was conducted on the Benchmark Cases and Project Cases for peak summer, peak winter, and off-peak spring conditions. No significant impacts attributable to the Generating Facility were identified for all seasons.

No additional Network Upgrades have been identified as being necessary for the interconnection of the Generating Facility, to satisfy the applicable NERC and WECC requirements as a result of the power flow analysis.

Short Circuit Analysis

A short circuit analysis was conducted for the Round Butte area to determine the change in fault duty attributable to adding the Preliminary Plan of Service to the PGE Transmission System. This proposed Interconnection Request has no material impact on any existing circuit breaker rating.

As a result, no additional Network Upgrades or Contingent Facilities have been identified as being necessary to satisfy the applicable NERC and WECC requirements.

Transient Stability Analysis

Transient stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in system stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the transient stability analysis indicate that all generator rotor angles remain synchronized with the system and exhibit positive damping, and bus frequency remains above 59.6 Hz for six cycles for all studied contingencies. Also, all system bus voltages are not in violation of the WECC System Performance Criteria.

Thus, no additional Network Upgrades have been identified as being necessary for the interconnection of the Generating Facility to satisfy the applicable NERC and WECC requirements as a result of the transient stability analysis.

Voltage Stability Analysis

Voltage stability analysis was conducted on the Benchmark Cases and the Project Cases to determine if there is a change in voltage stability attributable to adding the Preliminary Plan of Service to the PGE Transmission System. Results of the voltage stability analysis indicate that the Reactive Margin is greater than or equal to the Reactive Power Margin Requirement (PMR) per the WECC System Performance Criteria requirements.

Thus, no additional Network Upgrades have been identified as being necessary for the interconnection of the Generating Facility to satisfy the applicable NERC and WECC requirements as a result of the voltage stability analysis.

Proposed Plan of Service[10]

The results of the power flow analysis show that the Preliminary Plan of Service meets all NERC and WECC requirements, and allows for the delivery of the Generating Facility's output to PGE load in the Willamette Valley, which is necessary for the Generating Facility to receive NRIS. Therefore, the Proposed Plan of Service is the Preliminary Plan of Service.

A non-binding good-faith cost estimate of the Network Upgrades required for the Proposed Plan of Service is shown below in **Table 1, Table 2, Table 3**, **Table 4,** and **Table 5** and the good-faith construction schedule is also discussed. The Interconnection Customer's Interconnection Facilities, including the generator lead line located between the Generating Facility and the Point of Change of Ownership, are not included in the estimate for the Proposed Plan of Service. The target accuracy of this cost estimate is ± 50%.

The cost estimate to increase the series compensation of the Bethel-Round Butte 230 kV line to 42% is shown in **Table 1**. The estimated cost to increase the series capacitor size is dependent upon timing, and whether or not a Large Generator Interconnection Agreement (LGIA) is in place to accommodate this Interconnection Request by the time PGE specifies and orders the series capacitor for interconnection request #17-068. If the order for the series capacitor (for interconnection request #17-068) has already been placed by the time an LGIA is executed and PGE has been authorized to proceed with this Interconnection Request, then it will be necessary to pursue a change order or other steps necessary to obtain a larger sized series capacitor, and the Interconnection Customer will be responsible for any additional charges associated with change orders, modifications, etc. that are incurred by PGE to obtain the larger series capacitor needed to accommodate this Interconnection Request.

TTC Upgrades Cost Estimate	
Series Capacitor Substation	
Increase Series Capacitor Size	$100,000
Total	**$100,000**

Table 1: TTC Upgrade Cost Estimate

[10] Upgrades to protection, communications, and/or other equipment at Round Butte, Bethel, Redmond BPA, and other substations will be required. The scope of work at these substations is expected to be minimal and will be identified during the Facilities Study.

The cost estimate to construct the 3-position ring bus POI substation is shown in **Table 2**. The estimated costs do not include costs to purchase property or acquire easements.

Point of Interconnection Substation Cost Estimate		
Purchased Material Including Labor		
3- Circuit Breaker, 230kV, SF6, 3000A, 50kA		$805,800
9 - Disconnect Switch, 230kV, 3000A		$362,300
9 - CCVT, 230kV		$245,400
3 - Metering CTs, 230kV		$268,100
9 - Surge Arrestors, 230kV		$148,500
1 - Control Enclosure, 50' x 16' with floors and two battery rooms		$661,400
8 - Relay Racks		$866,300
Structures, 230 kV - with Foundations		$2,222,000
	Sub Total	**$5,579,800**
Contractor and Outside Services		
Contract Construction - General Costs Mob, Demob, Site Services, Management, Bond, etc.		$550,000
Site Prep, Fence, Conduit and Vaults, 230 kV Bus, Security Systems, etc.		$2,268,800
Engineering, Geotech, Survey, Permitting, etc.		$1,306,300
	Sub Total	**$4,125,100**
	Total	**$9,704,900**

Table 2: POI Substation Cost Estimate

The cost estimate to modify RAS equipment at the Round Butte substation is shown in **Table 3**.

RAS Modification Cost Estimate	
Hardware, Programming, and Testing	$250,000

Table 3: RAS Modification at Round Butte Substation Cost Estimate

The cost estimate to sectionalize the Redmond BPA-Round Butte 230 kV transmission line and install fiber cable between Round Butte, Redmond BPA, and the POI substation is shown in **Table 4**. The estimate assumes that 20% of the Redmond BPA-Round Butte 230 kV structures will need to be replaced to accommodate the additional loading of the ADSS fiber cable. The estimated costs do not include environmental mitigation or acquiring new easements and right of way.

Transmission Estimate	
Redmond BPA-Round Butte 230 kV Modifications	
Contractor Labor	$2,237,100
Purchased Material	$1,861,400
Contractor and Outside Services	$1,406,600
Engineering, Permitting and Equipment	$1,704,400
Total	**$7,209,500**

Table 4: Transmission and Comm Cost Estimate

The total project cost estimate (i.e. the sum of the costs outlined in **Table 1** through **Table 4**) to increase the series compensation of the Bethel-Round Butte 230 kV line, construct a 3-position ring bus substation, sectionalize the Redmond BPA-Round Butte 230 kV transmission line, modify the Round Butte RAS, and construct fiber cable between Round Butte, Redmond BPA, and the POI substation is shown in **Table 5**.

Total Project Cost Estimate	
TTC Upgrade Cost Estimate	$100,000
Point of Interconnection Substation Cost Estimate	$9,704,900
Round Butte RAS Modification Cost Estimate	$250,000
Transmission Estimate	$7,209,500
Total	**$17,264,400**

Table 5: Total Project Cost Estimate

The estimated period of time required to implement the Proposed Plan of Service is 2-2.5 year for design, permitting, material procurement, and construction. This may align with the Interconnection Customer's proposed In-Service date of 6/30/2023.

The series capacitor substation that is expected to be installed to accommodate interconnection request #17-068 is necessary for the operation of this Interconnection Request, and if delayed or not built, could cause a need for re-studies of this Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. So, those Network Upgrades have been identified as Contingent Facilities for the purposes of this Interconnection Request.

BPA and PacifiCorp operate transmission systems adjacent to the PGE transmission lines connected to the Round Butte substation. For this reason, BPA and PacifiCorp have been identified as Affected Systems.

There are many factors outside of the Transmission Provider's control that could extend the time required for completing the Proposed Plan of Service outlined above. These factors include but are not limited to: unexpected delays in the permitting process, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties, the duration of and any additional upgrades identified during the WECC Path Rating Process, inclement weather conditions, and COVID-19 or other pandemic related conditions.

Conclusion

The conclusions drawn from performing this SIS are that the Interconnection Customer's request for Interconnection Service can be met by proceeding with the Proposed Plan of Service.

The study results demonstrate that the Preliminary Plan of Service meets all NERC and WECC requirements and allows for the delivery of the Generating Facilities output to PGE load in the Willamette Valley. The Preliminary Plan of Service is therefore recommended as the Proposed Plan of Service. The Proposed Plan of Service requires:

- Increased series compensation of the Bethel-Round Butte 230 kV transmission line;
- Construction of the POI substation;
- Modification of the Redmond BPA-Round Butte 230 kV transmission line; and,
- Installation of fiber cable along the Redmond BPA-Round Butte 230 kV transmission line.

The series capacitor substation, including the series capacitor that is expected to be installed to accommodate interconnection request #17-068 is necessary for the operation of this Interconnection Request. If any of these facilities are delayed or not built, it could cause a need for re-studies of this Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing, so those particular Network Upgrades have been identified as Contingent Facilities for purposes of this Interconnection Request.

The estimated period of time required to implement the Proposed Plan of Service is 2-2.5 year for design, permitting, material procurement, and construction. This may align with the Interconnection Customer's proposed In-Service date of 6/30/2023.

BPA and PacifiCorp operate transmission systems in the area of the POI and BPA's breaker failure contingency sets the TTC for the Bethel-Round Butte 230 kV transmission line at 317 MW. For these reasons, BPA and PacifiCorp have been identified as Affected Systems.

There are many factors outside of the Transmission Provider's control that could extend the time required for completing the Proposed Plan of Service outlined above. These factors include but are not limited to: unexpected delays in the permitting process, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties, the duration of and any additional upgrades identified during the WECC Path Rating Process, inclement weather conditions, and COVID-19 or other pandemic related conditions.

PGE cannot guarantee that future analysis (i.e. Requests for Transmission Service or Operational Studies) will not identify additional problems or system constraints that require mitigation or reduced operation. NRIS does not convey or imply any type of transmission service. If there is a material change in any aspect of the Generating Facility or to a higher-queued interconnection request, a re-study may be required.

September 18, 2020

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NIPPC Data Request No. 004
Dated September 1, 2020

Request:

For each Federal Energy Regulatory Commission ("FERC")-jurisdictional qualifying facility interconnection (e.g., a QF interconnecting to PGE but selling their net output to a different utility), please provide or identify a publicly available location for the feasibility study, system impact study, facilities study, interconnection study, the final accounting with actual interconnection costs, and identify all network upgrades.

Response:

PGE lacks the information needed to respond to this data request. If a transmission provider receives an interconnection request from a QF generator that does *not* intend to sell 100 percent of its net output to the interconnecting utility under PURPA, from the perspective of the transmission provider, that interconnection customer is simply seeking a FERC-jurisdictional interconnection and is processed accordingly. Under that scenario, the transmission provider has no visibility into the commercial plans of the interconnecting generator, including whether the generator has an off-taker, who the generator's off-taker is, or whether the generator plans to sell its power to the off-taker under PURPA.

September 18, 2020

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NIPPC Data Request No. 007
Dated September 1, 2020

Request:

For each QF that has interconnected to PGE's system and achieved commercial operation in the past 30 years to sell 100 percent of the net output to PGE and is thus a state-jurisdictional interconnection, provide the following information:

a. Capacity of the facility (as measured by interconnection capacity);

b. Type of generation resource (e.g., wind, solar, hydropower);

c. Cost of Interconnection Facilities (using the definition in FERC's Order No. 2003, which is facilities up to the point of interconnection), including both costs in the final Facilities Study and the actual costs after construction was complete;

d. Cost of Network Upgrades (using the definition in FERC's Order No. 2003, which is facilities at or beyond the point of interconnection) including both costs in the final Facilities Study and the actual costs after construction was complete;

e. If the amounts for any facilities in (c) and (d) for the final Facilities Study and the actual costs after construction differ, explain the reason for the difference.

f. For the Network Upgrades identified in subpart D for each facility, please explain whether PGE agrees that any of the facilities are used by other users of the system or PGE and identify facilities not used solely by the QF.

Response:

Based on conversations with counsel for NIPPC, PGE understands that this request encompasses only interconnections for which Network Upgrades were identified. Please see PGE's response to NIPPC Data Request No. 3. Although PGE has some QFs whose interconnection studies identified

Network Upgrades that are still in the interconnection process, PGE does not have any QFs whose interconnection studies identified Network Upgrades that have achieved commercial operation.

September 18, 2020

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NIPPC Data Request No. 008
Dated September 1, 2020

Request:

For each generator that has interconnected to PGE's system and achieved commercial operation in the past 30 years under a FERC-jurisdictional interconnection, provide the following information:

a. Capacity of the facility (as measured by interconnection capacity);

b. Type of generation resource (e.g., wind, solar, hydropower);

c. Whether the generator is owned by PGE or a third party;

d. Cost of Interconnection Facilities (using the definition in FERC's Order No. 2003, which is facilities up to the point of interconnection), including both costs in the final Facilities Study and the actual costs after construction was complete;

e. Cost of Network Upgrades (using the definition in FERC's Order No. 2003, which is facilities at or beyond the point of interconnection) including both costs in the final Facilities Study and the actual costs after construction was complete;

f. If the amounts for any facilities in (d) and (e) for the final Facilities Study and the actual costs after construction differ, explain the reason for the difference.

g. For the Network Upgrades identified in subpart D for each facility, please explain whether PGE agrees that any of the facilities are used by other users of the system or PGE and identify facilities not used solely by the QF.

Response:

PGE objects that this request for 30 years of data is overly broad, unduly burdensome, and seeks information that is not relevant to this case nor reasonably calculated to lead to the discovery of admissible evidence. In particular, interconnections that occurred before FERC's Order 2003 took effect did not include the concepts of NRIS, ERIS, Network Upgrades, or Interconnection Facilities.

Notwithstanding and without waiving these objections, PGE responds as follows:

a. 225 MW
b. Natural gas
c. PGE
d. none
e. none
f. n/a
g. PGE objects that this request is vague and ambiguous in that it references "QFs" but requests data regarding FERC-jurisdictional interconnections. Notwithstanding and without waiving this objection, PGE responds as follows: PGE has not had any FERC-jurisdictional interconnections that resulted in Network Upgrades. Generally speaking, the need for a particular Network Upgrade can be triggered by a specific generator, but specific components of the transmission system are not isolated for use by a single user and the uses of any component change over time.

December 9, 2020

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NIPPC Data Request No. 031
Dated December 1, 2020

Request:

Please refer to PGE Response to NIPPC Data Request No. 001, which states that "PGE has designated most QFs as network resources," and Supplemental Attachment 001A, which indicates PGE has designated 44 of 180 QFs as network resources.

a. Does PGE agree that Supplemental Attachment 001 indicates PGE has designated 44 QFs as network resources and has not designated 136 QFs as network resources? If not, what number of QFs, out of the 180 indicated, does PGE agree that it has designated as network resources?

b. What is PGE's position on the percentage of QFs that PGE has designated as network resources?

Response:

PGE objects that this request misinterprets PGE's Response to NIPPC Data Request No. 001. In that response, PGE wrote, "All of PGE's QFs that have achieved commercial operation are being delivered via firm transmission service. While PGE has designated most QFs as network resources for delivery, it has elected to deliver some QFs' output using firm point-to-point transmission service." When read in context, the statement referenced in NIPPC Data Request No. 031 conveys that PGE has designated most QFs *that have achieved commercial operation* as network resources for delivery. PGE will issue a revised response to NIPPC Data Request No. 001 to avoid any confusion.

a. Because not all QFs that enter power purchase agreements (PPAs) with PGE achieve commercial operation, PGE currently typically does not designate a QF as a network resource until the QF has achieved commercial operation. All of the QFs with whom PGE has entered PPAs and that have subsequently achieved commercial operation have either been designated as network resources for delivery or are being delivered using firm point-to-point transmission service. Supplemental Attachment 001A lists all of the QFs that have entered PPAs with PGE—not just those that have achieved commercial operation—which is why many of the QFs listed in the attachment have not yet been designated as network resources. PGE confirms that the Attachment reflects that PGE has designated 44 QFs as network resources out of the 180 QFs listed in the Attachment with whom PGE has entered PPAs.

b. Please see PGE's response to part (a). 44 QFs designated / 180 QFs that have executed PPAs = 24%. However, PGE reiterates that stating PGE has only designated 24% of QFs as network resources would be misleading because many of the QFs that have executed PPAs have not yet achieved commercial operation. Of those QFs that have achieved commercial operation, PGE has designated all but two as network resources, and those two QFs are being delivered via firm point-to-point transmission service. Please see PGE's Response to NIPPC Data Request No. 1.

December 9, 2020

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NIPPC Data Request No. 032
Dated December 1, 2020

Request:

Please refer to NIPPC Data Request No. 002, PGE Response to NIPPC Data Request No. 002, and PGE Response to NIPPC Data Request No. 001 Supplemental Attachment 001A. NIPPC Data Request No. 002 asked PGE to "indicate whether PGE interconnected each state jurisdictional qualifying facility interconnection as an energy or network resource." PGE responded in relevant part "To the best of PGE's knowledge…PGE has interconnected all QFs using NRIS."

a. Is it PGE's position that indicating a QF was interconnected using NRIS answers the question of whether the QF was interconnected "as an energy or network resource"? If not, please explain PGE Response to NIPPC Data Request No. 002.

b. Is it PGE's position that indicating a QF was interconnected using NRIS means the QF was interconnected as a network resource? If not, please explain PGE Response to NIPPC Data Request No. 002.

c. If it is PGE's position that stating "PGE has interconnected all QFs using NRIS" means that PGE has "interconnected each [QF] as" a network resource, please explain why, according to PGE Response to NIPPC Data Request No. 001 Supplemental Attachment 001A, PGE has not designated 136 QFs as network resources?

Response:

PGE objects that the phrasing throughout this request regarding "interconnecting [a generator] as an energy or network resource" is vague, ambiguous, and undefined. PGE believes this phrasing reflects confusion regarding the concepts of interconnection and transmission service and will attempt to clarify in its response below.

a. Because NIPPC Data Request No. 002 inquired about how PGE had "interconnected" QFs, PGE understood that request to be asking whether PGE had interconnected QFs using Energy Resource Interconnection Service (ERIS) or Network Resource Interconnection Service (NRIS), and PGE responded based on that understanding. PGE will revise its response to NIPPC Data Request No. 002 to avoid any confusion. PGE's position is that *interconnecting* a QF using NRIS or ERIS is not the equivalent of designating a QF as a network resource for purposes of delivering the QF's output (i.e., for transmission service). Designating a generator as an "energy resource" is not a concept under the OATT.

b. It is PGE's position that *interconnecting* a QF using NRIS is *not* the same as *designating* a QF as a network resource, if that is what this request is asking. Please see PGE's response to part (a) above for an explanation regarding PGE's Response to NIPPC Data Request No. 002.

c. Interconnecting a QF using NRIS is not the equivalent of designating a QF as a network resource. NRIS is an *interconnection* service,[1] whereas designating a generator as a network resources allows it to obtain *transmission* service. Designating a QF as a network resource means that the QF output can be transmitted via network integration transmission service to PGE's load. Thus, PGE's Response to NIPPC Data Request No. 002 that it has interconnected all QFs with NRIS is not inconsistent with its Response to NIPPC Data Request No. 001 regarding the designation of QFs as network resources. Although NRIS is typically used for generators that need firm transmission service for delivery, and such delivery is often achieved by designating the generator as a network resource, not all generators that receive NRIS become designated network resources, and conversely, not all designated network resources receive NRIS. However, if a generator receives ERIS and later seeks firm transmission to load (including by being designated as a network resource), the upgrades required to provide the transmission service would be identified in a study conducted after the request to designate the generator (the transmission service request) is received—not in the interconnection study process.

[1] *See* QF-LGIP Definition of "Network Resource Interconnection Service" ("Network Resource Interconnection Service in and of itself does not convey transmission service.").

January 14, 2021

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition ("NIPPC")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NIPPC Data Request No. 033
Dated December 31, 2020

Request:

Please refer to Joint Utilities/300, Wilding-Macfarlane-Williams/37:16 ("Nevertheless, utilities regularly enter into PPAs with non-QF generators."). Please identify all PPAs that PGE has entered into with non-QF generators in Oregon or otherwise for the purpose of serving PGE's Oregon customers. Please indicate the date upon which PGE entered into the PPA, the counter parties, and amount of electricity purchased.

Response:

PGE objects that this request is overly broad and unduly burdensome in that it contains no temporal limitation. PGE also objects that the relevance of the requested information is unclear. Notwithstanding and without waiving these objections, PGE responds as follows:

Please see Confidential Attachment 33A. The attachment includes only long-term PPAs, not those entered into for market purchases under an enabling agreement such as WSPP. The attachment includes those PPAs under which PGE received deliveries in 2020 and PPAs for resources that are not yet online. Some of the PPAs are call/capacity contracts so the MWH provided does not represent the full ability of the resource. Finally, the MWH purchased under each PPA may vary from year-to-year, particularly for those PPAs that are for variable energy resources.

REDACTED

UM 2032
PGE to NIPPC DR 033 Attach

Resource/Contract Name	Counterparty	2020 MWH	Effective Date	Notes
Bakeoven Solar 1 & 2	Avangrid	***Redacted***	10/12/2018	Not Yet Online
Bellevue Solar	Bellevue Solar, LLC	***Redacted***	8/18/2010	
BPA Capacity Contracts	BPA	***Redacted***	1/9/2018	1/1/2021 start date
Covanta	Covanta Marion, Inc.	***Redacted***	5/31/2014	
Douglas 2020 PPA	Douglas County PUD	***Redacted***	5/8/2020	1/1/2021 start date
Wells 2018 Agreement	Douglas County PUD	***Redacted***	3/29/2017	
Summer/Winter Peaking Capacity	Avangrid	***Redacted***	1/9/2018	
Klondike Wind	Avangrid	***Redacted***	1/1/2015	
Montague Solar	Avangrid	***Redacted***	11/26/2019	Not Yet Online
Outback Solar	Outback Solar, LLC	***Redacted***	5/9/2012	
Pelton & Round Butte	Confederated Tribes of Warm Springs	***Redacted***	3/21/2014	
Pelton Re-Regulation Dam	Confederated Tribes of Warm Springs	***Redacted***	3/21/2014	
Portland Hydro	City of Portland	***Redacted***	9/1/2017	
Priest Rapids Project	Grant County PUD	***Redacted***	11/2/2004	
Vansycle Wind	NextEra	***Redacted***	11/27/1996	
Wheatridge Wind	NextEra	***Redacted***	9/11/2020	Partial Year - COD in Nov
Wheatridge Solar & Storage	NextEra	***Redacted***	2/11/2019	Not Yet Online
Yamhill Solar	Yamhill Solar, LLC	***Redacted***	8/18/2010	

October 2, 2020

TO: Caroline Moore
Public Utility Commission of Oregon

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to OPUC Data Request No. 005
Dated September 10, 2020

Request:

5. Please indicate the date on which the Company began requiring Oregon QFs to interconnect using Network Resource Interconnection Service.

   a. Please provide any announcements, business practices, or other supporting documentation.

Response:

Network Resource Interconnection Service (NRIS) came into existence at the time the Federal Energy Regulatory Commission's Order No. 2003 became effective in 2004. To the best of PGE's knowledge, the Company did not study any QF requests to interconnect between 2004 and 2010. Similarly, PGE knows that it did not execute any QF PPAs during that time period. PGE has been interconnecting QFs with NRIS since 2010.

October 2, 2020

TO: Caroline Moore
Public Utility Commission of Oregon

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to OPUC Data Request No. 008
Dated September 10, 2020

Request:

8. Please list all QFs that the Company has interconnected under Energy Resource Interconnection Service.

    a. Please include generator size (MW), Location (state), resource type, Commercial Operations Date.
    b. Please explain how each QF in part a is delivered to load, including whether it is on a firm basis.
    c. Please explain how the Network Upgrade and any other deliverability costs for each QF in part a are recovered, including whether costs are paid by transmission customers and ratepayers.
    d. Please explain why the QFs identified in part a were interconnected under Energy Resource Interconnection Service.

Response:

PGE has not interconnected any QFs selling directly to PGE with ERIS.

January 20, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Response to NewSun Data Request No. 007
Dated January 6, 2020

Request:

For each qualifying facility that has requested a power purchase agreement (PPA) with PGE from January 1, 2014 until present please provide the following:

a. Project name,
b. Date of PPA request,
c. Nameplate capacity,
d. Project location (county and state),
e. Generation technology type (wind, solar, etc),
f. Interconnecting utility,
g. The power purchase agreement, if one was executed,
h. The developer or developers that requested or negotiated the power purchase agreement,
i. The in-service date, if operating, or scheduled commercial operation date if not,

Response:

PGE objects that this request is overly broad and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

Notwithstanding and without waiving these objections: Please see PGE's Response to NIPPC Data Request No. 1, docket RE 143, and Attachment 7A.

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	Developer	Technology	County (all in Oregon)	Nameplate Capacity	Scheduled Commercial Operation Date
Abert Rim Solar	Juwi Americas	Solar	Lake	10	12/31/2019
Airport Solar	Obsidian Renewables	Solar	Lake	47.25	11/1/2019
Alfalfa Solar	NewSun Energy	Solar	Crook	10	6/26/2019
Alkali	Southern Current	Solar	Lake	10	7/31/2019
AM - West Silverton	Enerparc	Solar	Marion	2.97	12/2/2019
Amity Solar	Pacific Northwest Solar	Solar	Yamhill	4	12/31/2019
Arklow Solar	Sulus Solar	Solar	Clackamas	2.97	7/2/2021
Ash Creek Solar	GreenKey Solar	Solar	Information not provided to PGE	2	Information not provided to PGE
Ashcroft Solar	Cypress Creek Renewables	Solar	Polk	2.25	9/30/2019
Ashfield Solar	Sulus Solar	Solar	Marion	3	12/2/2019
Ashfield Solar (2)	Sulus Solar	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
Ashfield Solar (3)	Sulus Solar	Solar	Marion	1.98	2/2/2023
Auburn Solar	Sulus Solar	Solar	Clackamas	1.26	7/2/2021
Auburn Solar (2)	Sulus Solar	Solar	Clackamas	1.26	11/2/2022
Avangrid Generic Solar	Avangrid	Solar	Information not provided to PGE	80	Information not provided to PGE

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	**Developer**	**Technology**	**County (all in Oregon)**	**Nameplate Capacity**	**Scheduled Commercial Operation Date**
Avangrid Generic Wind	Avangrid	Wind	Information not provided to PGE	80	Information not provided to PGE
Ballston Solar	BNRG Renewables	Solar	Yamhill	2.2	8/31/2018
Basin Creek Solar	Cypress Creek Renewables	Solar	Clackamas	19.99	Information not provided to PGE
Bear Creek Butte	R-Squared	Wind	Crook	10	10/15/2015
Beaver Creek Solar	TLS Capital	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
Belvedere Solar	Renewable Properties	Solar	Marion	2.97	11/2/2021
Belvedere Solar (2)	Smart Power Innovation	Solar	Marion	2.97	5/2/2022
BH - South Wilamina	Sulus Solar	Solar	Yamhill	3	12/2/2019
Big Horn	PineGate Renewables	Solar	Marion	2.2	5/1/2020
BioGreen	Wellons	Biomass	Descutes	28	8/1/2020
Black Forest Solar	Sulus Solar	Solar	Yamhill	1.26	12/2/2019
Blue Hill Solar	Sulus Solar	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
Blue Marmot IX	EDP Renewables	Solar	Lake	10	3/31/2020
Blue Marmot V	EDP Renewables	Solar	Lake	10	11/30/2019
Blue Marmot VI	EDP Renewables	Solar	Lake	10	11/30/2019

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	**Developer**	**Technology**	**County (all in Oregon)**	**Nameplate Capacity**	**Scheduled Commercial Operation Date**
Blue Marmot VII	EDP Renewables	Solar	Lake	10	3/31/2020
Blue Marmot VIII	EDP Renewables	Solar	Lake	10	3/31/2020
Boring Solar	BNRG Renewables	Solar	Clackamas	2.2	1/31/2019
Bottlenose Solar	Cypress Creek Renewables	Solar	Clackamas	2.2	5/1/2020
Bridgeport Solar	Pacific Northwest Solar	Solar	Polk	7	12/31/2019
Brightwood Solar	Cypress Creek Renewables	Solar	Clackamas	10	11/30/2021
Bristol Solar	Enerparc	Solar	Marion	3	12/2/2019
Brompton Solar	Sulus Solar	Solar	Washington	2.97	7/2/2021
Brownseed Solar	Sulus Solar	Solar	Information not provided to PGE	2.97	Information not provided to PGE
Brush College Solar	TLS Capital	Solar	Polk	2	12/1/2019
Brush Creek Solar	Birch Creek Development	Solar	Marion	2.2	4/5/2019
Buckner Creek Solar	Conifer Energy Partners	Solar	Clackamas	2.5	12/1/2020
Butler Solar	Pacific Northwest Solar	Solar	Yamhill	4	5/29/2020
Butler Solar Addition	Pacific Northwest Solar	Solar	Information not provided to PGE	6	Information not provided to PGE
Carlow Solar	Sulus Solar	Solar	Clackamas	2.565	7/2/2021

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	**Developer**	**Technology**	**County (all in Oregon)**	**Nameplate Capacity**	**Scheduled Commercial Operation Date**
Carnes Creek Solar	Conifer Energy Partners	Solar	Marion	2.5	11/1/2020
Carus Solar	Pacific Northwest Solar	Solar	Clackamas	2.2	12/1/2020
Case Creek Solar	BNRG Renewables	Solar	Marion	2.2	5/5/2019
Castleknock Solar	Brendan Judge	Solar	Washington	2.97	12/12/2021
Cavan Solar	Renewable Properties	Solar	Washington	1.8	11/2/2021
Cavan Solar (2)	Sulus Solar	Solar	Washington	1.8	5/2/2022
CC - Sandy Cherryville	Sulus Solar	Solar	Clackamas	3	1/2/2019
Chewaucan Solar	Juwi Americas	Solar	Lake	10	12/31/2019
Christmas Valley	Sustainable Energy Group	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
City of Cove	Oregon Energy Green	Hydro	Information not provided to PGE	0.8	Information not provided to PGE
Clackamas Solar	3 phases renewables	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
Clapham Solar	Brendan Judge	Solar	Yamhill	2.97	12/12/2021
Clayfield Solar	Smart Power Innovation	Solar	Clackamas	2.565	7/2/2021
Cockerham Creek Solar	GreenKey Solar	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
Conifer Grove Solar	Cypress Creek Renewables	Solar	Yamhill	19.99	Information not provided to PGE

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	**Developer**	**Technology**	**County (all in Oregon)**	**Nameplate Capacity**	**Scheduled Commercial Operation Date**
Connley Solar	Obsidian Renewables	Solar	Lake	10	12/1/2021
Coolmine Solar	Sulus Solar	Solar	Clackamas	1.98	2/2/2023
Corduff Solar	Sulus Solar	Solar	Polk	1.8	12/2/2021
Cork Solar	Renewable Properties	Solar	Clackamas	1.26	11/2/2021
Cork Solar (2)	Sulus Solar	Solar	Clackamas	1.26	5/2/2022
Corn Field Solar	TLS Capital	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
Cosper Creek Solar	Conifer Energy Partners	Solar	Polk	2.5	12/1/2019
Cottontail Solar	Sabal Solar Development	Solar	Marion	2.2	5/1/2020
Covanta Marion	Covanta	Biomass	Marion	13.1	10/1/2019
Cow Creek Solar	Conifer Energy Partners	Solar	Polk	1.75	2/1/2020
Craycroft Solar	Sulus Solar	Solar	Information not provided to PGE	Information not provided to PGE	Information not provided to PGE
Crooked River Solar	Ecoplexus Inc.	Solar	Jefferson	80	Information not provided to PGE
Cusack Solar	Sulus Solar	Solar	Clackamas	2.565	11/2/2022
CY - Clear Water	Sulus Solar	Solar	Yamhill	2.5	1/2/2019
Daisy Solar 1	OneEnergy Renewables	Solar	Morrow	10	4/6/2020

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	Developer	Technology	County (all in Oregon)	Nameplate Capacity	Scheduled Commercial Operation Date
Daisy Solar 2	OneEnergy Renewables	Solar	Morrow	10	4/6/2020
Daisy Solar 3	OneEnergy Renewables	Solar	Morrow	10	4/6/2020
Daisy Solar 4	OneEnergy Renewables	Solar	Morrow	10	4/6/2020
Daisy Solar 5	OneEnergy Renewables	Solar	Morrow	10	4/6/2020
Dalreed Solar II	Energy of Utah LLC	Solar	Morrow	80	Information not provided to PGE
Dawson Solar	Sulus Solar	Solar	Information not provided to PGE	1.98	Information not provided to PGE
Day Hill Solar	BNRG Renewables	Solar	Clackamas	2.2	9/15/2020
Dayton Solar I	NewSun Energy	Solar	Yamhill	10	1/25/2019
DB - Bull Run	Enerparc	Solar	Clackamas	2.565	12/2/2019
DC - Donald (Sulus25)	Enerparc	Solar	Marion	2.16	12/2/2019
DD - Molalla	Sulus Solar	Solar	Clackamas	3	12/2/2019
DE - Clear Water	Sulus Solar	Solar	Yamhill	2.5	1/2/2019
Delaney Solar	Heelstone Energy	Solar	Marion	2.5	10/31/2020
Deschutes Valley Water District	Deschutes Valley Water District	Hydro	Jefferson	4.8	1/1/2021
DF - West Eagle Creek	Enerparc	Solar	Clackamas	2.79	12/2/2019

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	**Developer**	**Technology**	**County (all in Oregon)**	**Nameplate Capacity**	**Scheduled Commercial Operation Date**
DH - West Scott Mills	Sulus Solar	Solar	Marion	2.5	1/2/2019
Dover Solar	Renewable Properties	Solar	Clackamas	1.98	11/2/2021
Dover Solar (2)	Smart Power Innovation	Solar	Clackamas	1.98	5/2/2022
Drift Creek	Birch Creek Development	Solar	Marion	2.2	4/1/2019
Dryland Solar	Conifer Energy Partners	Solar	Clackamas	2.5	12/1/2019
Dublin Solar	Sulus Solar	Solar	Clackamas	2.97	2/2/2023
Dunn Rd Solar	Conifer Energy Partners	Solar	Clackamas	1.85	10/31/2019
Duus Solar	Pacific Northwest Solar	Solar	Clackamas	10	12/31/2019
Eagle Creek Solar	Heelstone Energy	Solar	Clackamas	5	10/31/2020
Earth By Design Global Solar	Earth By Design	Solar	Information not provided to PGE	50	Information not provided to PGE
Energy Partners II	Energy Partners	Biomass	Lake	10	6/1/2019
Energy Partners I	Energy Partners	Biomass	Tillamook	10	6/1/2019
Eola Solar	BNRG Renewables	Solar	Yamhill	2.2	1/31/2020
Evensol 3.2	Evensol	Biogas	Information not provided to PGE	3.2	Information not provided to PGE
Evensol 4.8	Evensol	Biogas	Information not provided to PGE	4.8	Information not provided to PGE

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

UM 2032
PGE to NewSun DR 007 Attach A

Project Name	**Developer**	**Technology**	**County (all in Oregon)**	**Nameplate Capacity**	**Scheduled Commercial Operation Date**
Evergreen BioPower	Freres Lumber	Biomass	Linn	10	1/1/2018

March 5, 2021

TO: Marie Barlow
NewSun Energy, LLC ("NewSun")

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 2032
PGE Supplemental Response to NewSun Data Request No. 019
Dated January 6, 2020

Request:

Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

a. Queue Number,
b. Project name,
c. Date of transmission service request,
d. Transmission service request status,
e. Nameplate capacity,
f. Project location (county and state),
g. Generation technology type (wind, solar, etc),
h. Type of transmission service,
i. Point of receipt and point of delivery,
j. Any transmission service request studies not publicly available online,
k. The transmission service agreement, if one was executed,
l. The in-service date, if operating, or scheduled commercial operation date if not,
m. Whether the output from the generator is delivered to PGE's retail load,
n. Whether the generator is a qualifying facility,
o. Whether the generator is on-system or off system,
p. Whether the generator is interconnected using ERIS or NRIS,
q. Regarding network upgrade costs:
    1. Estimated network upgrade costs in any transmission service studies,
    2. Final network upgrade costs assigned to the request,
    3. Whether the network upgrades were ultimately constructed or are under construction,

Supplemental Response:

After conferral with NewSun, PGE understands that the intent of these data requests was to allow NewSun to trace specific generators through the interconnection and transmission-service-request processes to evaluate the Joint Utilities' testimony that Network Upgrades can be shifted from the interconnection process to the transmission-service-request process when a generator interconnects with ERIS instead of NRIS. PGE notes that the potential for upgrade-shifting that NewSun seeks to confirm is a straightforward application of the OATT and related FERC orders. In addition, as noted in PGE's initial responses, the additional information NewSun requests is voluminous and would be extremely burdensome to compile, if it were even available. However, PGE provides this supplemental response in an effort to respond directly to the narrower question that PGE now understands NewSun is asking. PGE understands that NewSun is not interested in reviewing every transmission and interconnection study, and PGE believes that this supplemental response more efficiently and directly responds to NewSun's question than providing information about numerous interconnection and transmission service requests.

As PGE has explained in testimony and in response to other data requests, all of PGE's on-system QFs interconnected with NRIS. Of the on-system, non-QF resources that PGE owns or purchases power from, only one generator originally interconnected with ERIS.[3] As PGE previously indicated in response to NewSun Data Request No. 20, "PGE's Port Westward 2 generating facility interconnected with ERIS. No network upgrades were required to designate Port Westward 2 as a network resource because sufficient transmission capacity existed on PGE's system to deliver the output to PGE's network load." Port Westward 2 is located near PGE's Port Westward 1 and Beaver facilities. When developing and interconnecting Port Westward 2, PGE's Merchant Function knew that it already possessed sufficient transmission capacity to deliver Port Westward 2's output to PGE's load and therefore decided to interconnect the facility using ERIS.

To the extent NewSun is interested in identifying the magnitude of Network Upgrades that *could* be shifted if a generator interconnected with ERIS, Attachment 001A to PGE's response to Staff Data Request No. 1 shows the deliverability-driven Network Upgrades PGE has identified in system impact studies for two large generators, one of which is a QF with more than $10 million in deliverability-driven Network Upgrades.

Note this response applies to NewSun Data Request Nos. 6, 8, 19 and 20.

<u>Response:</u>

PGE objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence.

Notwithstanding and without waiving these objections:

A point-to-point transmission service request is not associated with a specific generator. Therefore, PGE cannot respond to subparts (b), (e), (f), (g), (l), (m), (n), (o), or (p) for each transmission service request. To the extent this request is asking about network integration transmission service, a list of designated network resources is available on OASIS and in PGE's Response to NIPPC Data Request No. 1. All QFs directly interconnected to PGE received NRIS. PGE has not constructed any Network Upgrades on its system associated with requests for transmission service from PGE. Please see Confidential Attachment 19A for information regarding the confirmed, currently active, yearly, point-to-point transmission service requests.

[3] Many of PGE's on-system resource interconnected well before FERC issued Order 2003, which adopted the NRIS and ERIS concepts, and took effect on January 20, 2004. *See* Order 2003-A at ¶ 40.

Reservation Summary
Provider: PGE
Increment: YEARLY
Type: POINT_TO_POINT
Status: Confirmed
Req Type: ORIGINAL
Use DST: true
Show NITS: true
Time : Active Before Today (01/01/1900 - 01/12/2021)

Status	Assign Ref	TP	Seller	Customer	MW Req	MW Grant	POR	POD	Service	Increment	Type	Source	Sink	Preconfirmed	Sale Ref	Start Time	Stop Time	Queued Time	Last Updated	Class	Subclass
CONFIRMED	79875117	PGE	PGE	PGEM	250	250	COB	JOHNDAY	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2015-01-01 00:00:00 PS	2020-01-01 00:00:00 PS	2014-06-23 07:48:42 PD	2014-06-25 15:49:53 PD	FIRM	
CONFIRMED	81087171	PGE	PGE	PGEM	200	200	PACW	PGE	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2021-01-01 00:00:00 PS	2015-04-17 12:04:18 PD	2019-12-30 09:28:18 PS	FIRM	
CONFIRMED	81087178	PGE	PGE	PGEM	200	200	PGE	PACW	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2021-01-01 00:00:00 PS	2015-04-17 12:07:06 PD	2019-12-30 12:37:48 PS	FIRM	
CONFIRMED	81182934	PGE	PGE	PGEM	100	100	PACW	PGE	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2021-01-01 00:00:00 PS	2015-05-14 10:02:47 PD	2019-12-30 09:28:18 PS	FIRM	
CONFIRMED	81182959	PGE	PGE	PGEM	100	100	PGE	PACW	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2021-01-01 00:00:00 PS	2015-05-14 10:04:40 PD	2019-12-30 12:37:48 PS	FIRM	
CONFIRMED	81348249	PGE	PGE	PGEM	148	148	PGE	PACW	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2021-01-01 00:00:00 PS	2015-06-25 09:35:57 PD	2019-12-30 12:37:48 PS	FIRM	
CONFIRMED	81348278	PGE	PGE	PGEM	118	118	PACW	PGE	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2021-01-01 00:00:00 PS	2015-06-25 09:42:13 PD	2016-01-07 10:48:37 PS	FIRM	
CONFIRMED	81712548	PGE	PGE	PGEM	177	177	COB	JOHNDAY	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2021-01-01 00:00:00 PS	2015-09-25 08:21:28 PD	2015-10-21 13:46:20 PD	FIRM	
CONFIRMED	315999	PGE	PGE	AVST	200	200	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT	SPECULATIVE	SPECULATIVE	NO		2002-01-01 00:00:00 PS	2022-01-01 00:00:00 PS	2000-09-27 15:15:46 PD	2008-02-04 14:38:49 PS	FIRM	
CONFIRMED	432190	PGE	PGE	PGEM	200	200	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2002-01-01 00:00:00 PS	2022-01-01 00:00:00 PS	2002-01-11 08:16:18 PS	2020-02-14 06:55:59 PS	FIRM	
CONFIRMED	82107491	PGE	PGE	PGEM	200	200	COB	JOHNDAY	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2017-01-01 00:00:00 PS	2022-01-01 00:00:00 PS	2016-01-11 13:03:43 PS	2016-02-02 14:23:00 PS	FIRM	
CONFIRMED	83164604	PGE	PGE	PAC	2	2	ROUNDBUTTE	REDMOND	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2017-04-01 00:00:00 PD	2022-04-01 00:00:00 PD	2016-07-27 09:54:47 PD	2018-02-07 12:17:00 PS	FIRM	
CONFIRMED	83164629	PGE	PGE	PAC	10	10	ROUNDBUTTE	REDMOND	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2017-04-01 00:00:00 PD	2022-04-01 00:00:00 PD	2016-07-27 09:57:19 PD	2016-07-27 10:18:09 PD	FIRM	
CONFIRMED	73065442	PGE	PGE	PGEM	27	27	COLSTRIP	BROADVIEW	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2009-06-01 00:00:00 PD	2022-07-01 00:00:00 PD	2009-05-07 06:47:53 PD	2011-09-23 09:40:54 PD	FIRM	
CONFIRMED	73068563	PGE	PGE	PGEM	280	280	COLSTRIP	GARRISON	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2009-06-01 00:00:00 PD	2022-07-01 00:00:00 PD	2009-05-08 09:08:57 PD	2011-09-23 09:37:49 PD	FIRM	
CONFIRMED	76059414	PGE	PGE	PGEM	307	307	COLSTRIP	TOWNSEND	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2011-10-01 00:00:00 PD	2022-07-01 00:00:00 PD	2011-08-16 10:02:25 PD	2020-12-29 15:23:30 PS	FIRM	
CONFIRMED	84996127	PGE	PGE	PGEM	19	19	PACW	PGE	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2017-07-01 00:00:00 PD	2022-07-01 00:00:00 PD	2017-06-13 17:50:51 PD	2020-12-08 09:12:43 PS	FIRM	
CONFIRMED	84999325	PGE	PGE	PGEM	15	15	PGE	PACW	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2017-07-01 00:00:00 PD	2022-07-01 00:00:00 PD	2017-06-14 07:42:28 PD	2020-12-08 15:38:35 PS	FIRM	
CONFIRMED	82941662	PGE	PGE	PWX	100	100	COB	JOHNDAY	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2018-01-01 00:00:00 PS	2023-01-01 00:00:00 PS	2016-06-17 10:08:41 PD	2018-06-02 17:43:03 PD	FIRM	
CONFIRMED	85905952	PGE	PGE	PGEM	15	15	PACW	PGE	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2018-12-01 00:00:00 PS	2023-12-01 00:00:00 PS	2017-11-21 07:07:28 PS	2020-12-08 09:12:43 PS	FIRM	
CONFIRMED	80833317	PGE	PGE	PGEM	25	25	ROUNDBUTTE	PGE	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES		2016-01-01 00:00:00 PS	2025-01-01 00:00:00 PS	2015-02-16 08:12:09 PS	2021-01-11 08:59:29 PS	FIRM	
CONFIRMED	89006855	PGE	PGE	PGEM	5	5	PACW	PGE	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2020-01-01 00:00:00 PS	2025-01-01 00:00:00 PS	2019-04-25 07:17:06 PD	2020-12-08 09:12:44 PS	FIRM	
CONFIRMED	89006960	PGE	PGE	PGEM	5	5	PGE	PACW	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2020-01-01 00:00:00 PS	2025-01-01 00:00:00 PS	2019-04-25 07:25:46 PD	2020-12-08 15:38:35 PS	FIRM	
CONFIRMED	92809269	PGE	PGE	PGEM	5	5	PGE	PACW	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO		2021-01-01 00:00:00 PS	2026-01-01 00:00:00 PS	2020-12-14 13:01:21 PS	2020-12-28 15:37:48 PS	FIRM	
CONFIRMED	79072075	PGE	PGE	PWX	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO	PTP-36	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-13 09:38:33 PS	2019-11-06 06:34:34 PS	FIRM	
CONFIRMED	79082732	PGE	PGE	PGEM	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES	PTP-34	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-16 07:11:40 PS	2017-06-19 09:58:49 PD	FIRM	
CONFIRMED	79084421	PGE	PGE	EXGN	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES	PTP-35	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-16 14:02:55 PS	2019-03-01 11:08:27 PS	FIRM	

CONFIRMED	79091330	PGE	PGE	REMC	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES	PTP-38	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-18 08:59:25 PS	2014-09-24 09:44:56 PD	FIRM	
CONFIRMED	79091530	PGE	PGE	MSCG	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES	PTP-39	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-18 09:18:16 PS	2014-07-24 08:20:29 PD	FIRM	
CONFIRMED	79091653	PGE	PGE	KPUD	11	11	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO	PTP-37	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-18 09:43:55 PS	2020-12-27 17:44:51 PS	FIRM	
CONFIRMED	79091680	PGE	PGE	TEA	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO	PTP-40	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-18 09:49:45 PS	2020-12-27 17:47:58 PS	FIRM	
CONFIRMED	79092316	PGE	PGE	LEWI	11	11	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			YES	PTP-41	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-18 11:53:17 PS	2020-12-27 17:44:00 PS	FIRM	
CONFIRMED	79092388	PGE	PGE	FCPD	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO	PTP-42	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-18 12:10:48 PS	2020-12-27 17:42:31 PS	FIRM	
CONFIRMED	79092678	PGE	PGE	COWL	10	10	JOHNDAY	COB	YEARLY FIRM	YEARLY	POINT_TO_POINT			NO	PTP-43	2014-01-01 00:00:00 PS	2034-01-01 00:00:00 PS	2013-12-18 13:39:12 PS	2017-09-29 14:03:54 PD	FIRM	

Total: 34 Record(s)
01/13/2021 05:02:37 PM PST

Date: November 24, 2020

TO:

LISA RACKNER	JORDAN SCHOONOVER
MCDOWELLO RACKNER GIBSON PC	MCDOWELLO RACKNER GIBSON PC
ATTORNEYS FOR PGE	ATTORNEYS FOR PGE
lisa@mrg-law.com	jordan@mrg-law.com

FROM: Caroline Moore
Chief Analyst
Energy Resources and Planning Division

OREGON PUBLIC UTILITY COMMISSION

Docket No. UM 2032- PGE 1st Set Data Request filed November 10, 2020

PGE Data Request No 05:

5. Does Staff agree that the Commission has never defined the term "system benefits" as it applies to Network Upgrades incurred to interconnect QFs? If the response is anything other than an unconditional "agree," please explain fully including providing citations to Commission decisions.

OPUC Response No 05:

5. Agree

OPUC Docket No. UM 2032
November 20, 2020
NewSun's Response to PGE's First Set of Data Requests

Request:

32. Refer to the Response Testimony of Brian S. Rahman (NewSun/100), page 13, lines 21-23, where Mr. Rahman testifies that the "decision to go with ERIS as opposed to NRIS is generally a decision left to the generator based on many factors including: cost of the network upgrade, risk of curtailment, power purchase agreement provision . . ." What is Mr. Rahman's understanding of a utility's ability to curtail QF generation? Please provide a detailed explanation for Mr. Rahman's understanding, including citations to all applicable regulatory requirements that allow curtailment of QF generation.

Response:

NewSun objects to the extent that production of the data requested would be unduly burdensome and that the request is overly broad and calls for legal conclusions. NewSun further objects to this request to the extent that it requires a non-lawyer to state a legal opinion regarding regulatory requirements. It would be unduly burdensome for NewSun to provide Portland General Electric Company (PGE) with specific citations to each regulatory requirement where those documents are publicly available, and PGE can perform its own legal research.

Notwithstanding the foregoing, Mr. Rahman states that, based on his experience in the industry, he understands the purchasing utility is permitted to curtail the QF's output only in limited circumstances and cannot curtail QF output before it curtails output from its own resources.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 2032

Joint Utilities' Response to NewSun Energy

LLC's Motion to Compel Discovery

Attachment C

UM 2032 PacifiCorp Discovery

June 28, 2021

Attachment C: List of Included UM 2032 PacifiCorp Discovery

"System Benefits" Information

- UM 2032 PAC Response to NewSun DR 1.10
- UM 2032 PAC Supp Response to NewSun DR 1.10
- UM 2032 PAC to NewSun Attach 1.10-1 (redacted)
- UM 2032 PAC Response to NewSun DR 1.19
- UM 2032 PAC Supp Response to NewSun DR 1.19
- UM 2032 PAC Response to NewSun DR 1.20
- UM 2032 PAC Supp Response to NewSun DR 1.20
- UM 2032 PAC Response to NewSun DR 1.21
- UM 2032 PAC Supp Response to NewSun DR 1.21
- UM 2032 PAC Response to NewSun DR 1.11
- UM 2032 PAC Supp Response to NewSun DR 1.11
- UM 2032 PAC Response to OPUC DR 013
- UM 2032 PAC to OPUC DR 013 Attach
- UM 2032 PAC 1st Supp Response to OPUC DR 013
- UM 2032 PAC to OPUC DR 013 1st Supp Attach
- UM 2032 PAC 2nd Supp Response to OPUC DR 013
- UM 2032 PAC to OPUC DR 013 2nd Supp Attach
- UM 2032 PAC Response to OPUC DR 014
- UM 2032 PAC Response to NIPPC DR 003
- UM 2032 PAC Supp Response to NIPPC DR 003
  - PacifiCorp's response to NIPPC DR 003 also included a number of attachments, including copies of over 100 PacifiCorp interconnection agreements. In order to

avoid unnecessarily burdening this filing, PacifiCorp has not attached these documents to its filing, but would be happy to provide copies upon request.

- UM 2032 PAC Response to NIPPC DR 008
- UM 2032 PAC to NIPPC DR 008 Attach
- UM 2032 PAC Response to NIPPC DR 016
- UM 2032 PAC Response to NIPPC DR 027
- UM 2032 PAC Response to NIPPC DR 034

"Validation of Differences" DRs

- UM 2032 PAC Response to NewSun DR 1.6
- UM 2032 PAC to NewSun DR 1.6 Attach
- UM 2032 PAC Supp Response to NewSun DR 1.6
- UM 2032 PAC to NewSun DR 1.6 Supp Attach
- UM 2032 PAC Response to NewSun DR 1.8
- UM 2032 PAC Supp Response to NewSun DR 1.8
    - PacifiCorp's response to NewSun DR 1.8 also included copies of 64 interconnection studies that were superseded and thus, unlike others, are not publicly available on OASIS (Attach 1.8-1), and copies of 50 interconnection agreements and amendments in response to the DR (1.8-2). In order to avoid unnecessarily burdening this filing, PacifiCorp has not attached these documents to its filing, but would be happy to provide copies upon request.
- UM 2032 PAC Response to NewSun DR 1.24
- UM 2032 PAC 1st Supp Response to NewSun DR 1.24
- UM 2032 PAC 2nd Supp Response to NewSun DR 1.24
- UM 2032 PAC Response to NewSun DR 1.26
- UM 2032 PAC Response to OPUC DR 007

    - PacifiCorp's response to OPUC 7 also included multiple attachments, including various PacifiCorp legal filings described in the DR response. In order to avoid unnecessarily burdening this filing, PacifiCorp has not attached all of these documents to its filing, but would be happy to provide copies upon request.
- UM 2032 PAC Response to OPUC DR 008
    - PacifiCorp's response to OPUC 8 also included multiple attachments, described in the DR response. In order to avoid unnecessarily burdening this filing, PacifiCorp has not attached all of these documents to its filing, but would be happy to provide copies upon request.
- UM 2032 PAC Response to OPUC DR 009
- UM 2032 PAC Response to OPUC DR 017 (redacted)
    - PacifiCorp has not included its attachment to OPUC 17 because it is confidential.
- UM 2032 PAC Response to NIPPC DR 007
- UM 2032 PAC to NIPPC DR 007 Attach
- UM 2032 PAC Response to NIPPC DR 025

NewSun Information Request 1.10

For each network upgrade constructed since January 1, 2014, please provide:

(a) The cost of the network upgrade,

(b) Where PacifiCorp first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),

(c) How the network upgrade was funded (e.g., utility funded, queue number funded, other),

(d) Whether the network upgrade was included in rate base or whether PacifiCorp intends to include it in rate base,

(e) If the network upgrade was included in rate base, the rate of return earned on the network upgrade,

(f) The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others), and

(g) The net increase or decrease in transmission customer rates that resulted from the network upgrade,

Response to NewSun Information Request 1.10

PacifiCorp objects to this data request on the grounds that certain information requested is overly broad and unduly burdensome, including subparts (b), (f) and (g). Moreover, subpart (f) is vague and ambiguous and subpart (b), to the extent it goes beyond generator interconnection-driven network upgrades, is not reasonably calculated to lead to the discovery of admissible evidence in this case. It is not clear what "incremental transmission operations resulting from the network upgrade" refers to. Subject to and without waiving these objections, PacifiCorp responds as follows:

PacifiCorp understands the term "Network Upgrades" to refer to generator interconnection-driven Network Upgrades as defined by PacifiCorp's Open Access Transmission Tariff (OATT), a definition Public Utility Commission of Oregon (OPUC) staff and the Joint Utilities have used throughout the course of this docket. With that understanding, information regarding Network Upgrades identified in interconnection studies is publicly available on PacifiCorp's Open Access Same-Time Information System (OASIS), and also in PacifiCorp's responses to OPUC data requests propounded in this docket, including OPUC Information Request 13. In addition:

(a) Please refer to PacifiCorp's responses to OPUC Information Request 13.

(b) PacifiCorp's responses to OPUC Information Request 13.

(c) PacifiCorp's responses to OPUC Information Request 13.

(d) PacifiCorp's responses to OPUC Information Request Nos. 13 and 14. Network upgrades constructed and placed in-service from January 1, 2014, through December 31, 2020, as identified in the response to this data request, are included in Oregon rate base, but not included in Oregon customer rates until January 1, 2021.

(e) The approved rate of return in Oregon on rate base is 7.137 percent, effective January 1, 2021.

NewSun Information Request 1.10

For each network upgrade constructed since January 1, 2014, please provide:

(a) The cost of the network upgrade,

(b) Where PacifiCorp first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),

(c) How the network upgrade was funded (e.g., utility funded, queue number funded, other),

(d) Whether the network upgrade was included in rate base or whether PacifiCorp intends to include it in rate base,

(e) If the network upgrade was included in rate base, the rate of return earned on the network upgrade,

(f) The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others), and

(g) The net increase or decrease in transmission customer rates that resulted from the network upgrade,

1st Supplemental Response to NewSun Information Request 1.10

In further support of the Company's response to NewSun Information Request 1.10 dated January 21, 2021, the Company responds further as follows:

After conferral with NewSun, PacifiCorp understands that a number of NewSun Data Requests, including 1.10, 1.19, 1.20, 1.21, and 1.22 were seeking information on upgrades to the transmission system more broadly, not just Network Upgrades associated with interconnection service, as that term has been defined by the Federal Energy Regulatory Commission (FERC) and used by the Public Utility Commission of Oregon (OPUC) and parties to this proceeding.

Specifically, PacifiCorp understands that NewSun seeks information regarding various types of major transmission system upgrades PacifiCorp has completed, the cost of the upgrade, and the reason for the upgrade. As specific examples of the types of projects that NewSun is interested in, NewSun mentioned constructing a new transmission line, reconductoring a transmission line, constructing a new substation, and adding breakers, disconnects, or communications equipment.

Because NewSun's data requests used the term "network upgrades," a term that is defined in the Open Access Transmission Tariff (OATT), and a term that all parties have used in testimony consistently with the OATT's definition, PacifiCorp maintains that its original data request responses were complete and adequate. Based on PacifiCorp's new understanding that NewSun's requests were intended to encompass upgrades to the transmission system more broadly, PacifiCorp reiterates its objections that the requests are overly broad and unduly burdensome. Moreover, the data requests relate to issues outside the scope of Phase 1 of this proceeding, and that may be addressed in Phase 2. Notwithstanding and without waiving these objections or its original objections, PacifiCorp responds as follows:

Please refer to the testimony of Richard A. Vail in docket UE 374, PacifiCorp's most recent general rate case. Mr. Vail's testimony details major transmission investments made by PacifiCorp from 2013 through 2020, and the rationale for PacifiCorp's request that these investments be included in Oregon rates. See, e.g., docket UE 374; PacifiCorp/1000, PacifiCorp/2800, and PacifiCorp/4200, and associated exhibits. In addition, please refer to Confidential Attachment NewSun 1.10, detailing recent, smaller additions to PacifiCorp's transmission system and the high-level rationale for their construction and inclusion in customer rates.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

REDACTED
Docket No. UE 374
Exhibit PAC/4202
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Surrebuttal Testimony of Richard A. Vail

Description of Pro Forma Transmission Plant Additions Over $500,000
(Total-Company)

August 2020

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Vantage Pomona Heights 230kV Line	May-20	[redacted]		Addressed in Vail Direct (PAC/1000, Vail/35) and Surrebuttal (PAC/4200) Testimony.
PP Trans New Connect	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer requested new interconnections in California, Oregon, and Washington. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system.
Goshen-Sugarmill-Rigby 161kV Transm Line	Nov-20	[redacted]		Addressed in Vail Direct (PAC/1000, Vail/38) and Surrebuttal (PAC/4200) Testimony.
TMP Generation Interconnection Projects East	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system per the Open Access Transmission Tariff. This category pertains only to projects Idaho, Utah. and Wyoming with in-service dates planned in 2020. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2020 used to determine costs.
Transmission Blankets	Various	[redacted]	OPUC 226-1	These 2019 projects provide functional upgrades and asset replacements to transmission substations and lines in Utah, Wyoming, and Idaho. These projects will add or enhance an existing operational function and replace assets that have failed or deteriorated and are deemed a risk to public safety and/or reliability.
Goshen #3 345/161 kV 700 MVA Trfrmr Inst	Nov-20	[redacted]	OPUC 226-1	This project involves the installation of a third 345/161 kV transformer at the Goshen substation located in southeast Idaho. This project is needed in order to resolve a potential overloading issue at the existing Goshen 345/161 kV transformers. Load in the Goshen area has continued to increase and as the load continues to grow, the risk of overloading the two existing Goshen 345/161 kV transformers increases. The 2016 Goshen area studies indicated that by 2021, loss of either one of the Goshen 345/161 kV transformers can overload the remaining Goshen 345/161 kV transformer above its emergency rating. Cost estimate included in rate case is for the installation of the third transformer being placed in-service in 2020. A replacement spare transformer is being ordered but will be received outside the dates of this rate case.
Wildfire Mitigation - Trans	Various	[redacted]	OPUC 226-1	These blanket projects will fund projects to decrease risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Jordanelle - Midway Construct 138 kV Line - Trans	2021	[redacted]	OPUC 226-1	This project has experienced major delays in obtaining a conditional use permit and is now projected to be placed in service sometime mid-2021. There will be $0.00 placed in service prior to 2021. This project will construct 9 miles of 138 kV transmission line with 795 ACSR conductor between Midway and Jordanelle substations. It will also construct a 138 kV three breaker ring bus at Midway substation, fiber optic communications between Silver Creek and Midway substations, and protection and control upgrades at all affected substations. Multiple outage scenarios on the 138 kV and 46 kV lines in the Summit and Wasatch County areas, and the outage of the Midway 75 MVA 138-46 kV transformer causes low voltage or voltage collapse conditions on the 138 kV and 46 kV systems in the area, which may result in load shedding. A 138 kV tie between Midway and Jordanelle substations mitigates this issue. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400)
Oregon New Large Load Network Upgrades	Dec-20		OPUC 226-1	This category of projects represents system upgrades required to reliably serve customer requested new large load interconnections in Oregon. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. The specific projects that make up this category are Network Upgrade needed to serve a 60 MW Load Addition project. The customer intends to add an additional 220 MW of load between 2020 and 2022 that the proposed improvements will also be able to service.
Q0542 Pryor Mountain	Dec-20		OPUC 226-1	Addressed in Vail Surrebuttal (PAC/4200) Testimony. This project is to interconnect 240 megawatts of new wind generation to PacifiCorp's Frannie - Yellowtail 230 kilovolt transmission line approximately 14.2 miles north of the Frannie substation located in Carbon County, Montana.
PP Trans	Various		OPUC 226-1; OPUC 745-2 2nd Supp CONF	These blanket projects will fund functional upgrades and asset replacements to transmission substations and lines in Oregon, Washington, and Idaho. These projects replace assets that have deteriorated, or add efficiency improvements and/or enhance productivity functions of an asset. An example of this activity is as follows: A breaker is in excellent working condition, however, the required fault interrupting capability is not high enough. You replace the breaker with one that meets the requirements and because you are enhancing the required functions of the breaker the “Modernize and Upgrade” activity would be used.
TMP Trans Main Grid East	Various		OPUC 226-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Utah, Wyoming, or Idaho to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All project that fits description with estimated in-service in 2020 but are under $10m are rolled into this category. See tab 2 for projects included in this cost category.

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Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Wildfire Mitigation Plan - CA T	Various	[redacted]	OPUC 226-1	This blanket project provides the means of allocating capital funds to mitigate operational risk within geographic regions that present the greatest risk of catastrophic wildfires. These investments are implemented consistent with the Company's 2020 Wildfire Mitigation Plan, including of 38 line miles of covered conductor, installation and commissioning of 31 system automation programs, replacement of 3 line miles of small diameter Cu conductor with aluminum stranded conductor, replacement of 189 in-service wooden poles with fiberglass for enhanced structural resilience, as well as evaluation of various pilot project results and continued implementation of enhanced inspection and correction programs.
TMP Gateway Projects	Various	[redacted]	OPUC 226-1	This 2019 blanket project provides the means of allocating capital funds for condemnation activities required on the Populus-Terminal 345 kV line placed in service in 2015. The settlement included the relocation of the line from customer's property to the adjacent Forest Service property.
TMP Transmission Major Projects - PP	Various	[redacted]	OPUC 226-1	This 2020 blanket project provides the means of allocating capital funds for improvements and reinforcements needed to support general load growth on transmission facilities located in Oregon, Washington, or California that arepart of the sub-transmission system. See tab 2 for the projects with in-service dates planned in 2020 included in this cost category.
TMP Trans Main Grid West	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Oregon, Washington, or California to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All projects that fit the above description with estimated in-service in 2020, but are under $10M, are rolled into this category. See tab 2 for projects included in this cost category.
TMP Trans Customer Generated East	Various	[redacted]	OPUC 226-1	This category of projects represents system upgrades required in Utah, Wyoming, or Idaho to reliably serve transmission network customer requested loads as specified by the network customers in their OATT required load and resource submittals. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2020 used to determine costs.
Replace Substation Switchgear, Breakers, Reclosers - UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Utah when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Replace - Storm & Casualty - UT Trans	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace damaged transmission equipment in Utah due to a storm or external event (like a car hit pole).
TMP Trans Customer Generated East	Various	[redacted]	OPUC 220-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Oregon, Washington, or California to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects with in-service dates planned in 2019 used to determine costs.

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Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Oregon - Rplc-OH Trans-Pole	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Oregon that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
TMP Generation Interconnections West	Various	[redacted]	OPUC 220-1	This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system in Oregon, Washington and California. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system. See tab 2 for the projects used to determine costs.
U2 2-2 GSU Replacement	Oct-19	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining the Huntington power plant by providing efficient and reliable electrical power. The replacement of the existing (40+) year old 2-2 GSUT with a new transformer will result in a reduced risk of an unscheduled outage at Huntington Plant. The project reduces the risk of failure of the existing 2-2 GSUT if it were replaced with a new one. The transformer is over 41 years old and the rate of failure in a transformer increases with age.
BIA - Fort Hall Grace - Goshen	Jun-20	[redacted]	OPUC 220-1	This project will renew the tribal authority permit for a portion of the Grace-Goshen transmission line. This permit is required in order to continue the operation of this line.
Replace Overhead Transmission Poles - UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace transmission poles in Utah that have deteriorated and are deemed a risk to public safety and/or system reliability.
U0 Spare GSU Transformer	Dec-20	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining the Huntington power plant by providing efficient and reliable electrical power. Having a new universal spare will benefit PacifiCorp by reducing installation time (due to not having to manufacture bussing to tie into) in case of a GSUT failure. If the current spare GSUT is installed in an emergency, it will eventually need to be replaced, thus creating lost generation, restricted loads and unnecessary costs to perform the equipment change twice.
TMP Transmission Major Projects - PP	Various	[redacted]	OPUC 220-1	This 2019 blanket project provides the means of allocating capital funds for improvements and reinforcements needed to support general load growth on transmission facilities located in Oregon, Washington, or California that are part of the sub-transmission system. All project that fits description with estimated in-service in 2019 but are under $10m are rolled into this category. See tab 2 for projects behind cost estimate.
Replace Overhead Transmission Lines - Other - UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Utah that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
TMP Gateway Projects	Various	[redacted]	OPUC 220-1	This 2020 blanket project provides the means of allocating capital funds for the final condemnation activities required on the Populus-Terminal 345 kV line placed in service in 2015. This The case involves a property owner who has contested valuation based on potential future mining and quarry activities and perceived profit potential from the area occupied by the project, and is still proceeding through the court. The Company anticipates resolution during the calendar year 2021.

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Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Wildfire Mitigation - Trans	Various	[redacted]	OPUC 220-1	These 2019 projects will result in decreased risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.
Oregon - Transmission Improvements	Various		OPUC 220-1	The linescope reliability projects are being performed to enhance system visibility on the transmission system in strategic locations, enabling rapid response to faulted lines, ultimately enabling accurate fault location and quicker sectionalizing and restoration of customers.
Reroute JB Goshen 345kV line for Slide: IPC Shared	2021		OPUC 220-1	This project will not be placed in service until 2021 or later. There will be $0.00 placed in service prior to 2021. This project will relocate 2.5 miles of the Jim Bridger - Goshen 345kV transmission line out of a land slide area. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400).
Pavant - Improve Transformer Protection	Dec-20		OPUC 220-1	This project will allow for maintenance to be performed on either transformer without requiring an outage to the entire Pavant 46 kV system. This will increase reliability for customers served from the Pavant substation.
Replace Transmission Conductor / Armor Rod - ID	Various		OPUC 220-1	These projects are needed to maintain reliability of existing facilities by replacing deteriorated transmission line conductor and/or reinforcing existing conductor with armor rod. Damage has occurred mainly from Aeolian vibration so vibration dampeners are also installed.
Grid Resiliency Phase 1 - 230/69kV Xfmr Purchase	Dec-20		OPUC 220-1	A spare transformer analysis identified a spare transformer deficiency (or gap) in the Delta-Wye portion of the installed 230-69 kV transformer fleet. A new 230-69 kV, Delta-Wye, 150-MVA spare transformer is being purchased to serve as a ready-to-use spare backing up the six (6) three-phase Delta-Wye transformers in-service. The spare will provide timely customer service restoration should failure occur.
Idaho Power - Borah - Midpoint #1 replace wood w/ steel	Various		OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) This project will fund the PacifiCorp portion of the replacement of wood structures with steel structures on the Idaho Power operated Borah to Midpoint #1 line. This will reduce the need for future priority 2 replacements as well as improve the durability of the line by improving its resistance to fires and severe weather conditions.
Replace Substation Transformers - UT	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation transformers in Utah when equipment has failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Calif - Rplc- Trans Strm&Cas	Various		OPUC 220-1	This blanket project provides the means of allocating capital funds to replace damaged equipment due to a storm or external event (like a car hit pole).
Replace Substation Bushings, Glass & Other - ID	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Idaho that have failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Oregon - Rplc-OH Trans-Othr	Various		OPUC 220-1	This blanket project provides the means of allocating capital funds to replace transmission line items other than poles that have deteriorated. Deteriorated Transmission cross arms, insulators, water passage culverts, easement access gates, are all examples of "other" items that fall into this category and are reported during annual field inspections.

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Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
302 Spare GSU Replacement	Oct-19	[redacted]	OPUC 220-1	(Uncontested per Staff Response to PAC DR 73) The project will benefit our customers by maintaining reliability and ensure Hunter Plant can continue to provide efficient electrical power at full unit rating. The purchase of a new spare GSU will result in a lower risk of an extended load restriction in the event of a failure of one of the in-service transformers. If a spare GSU transformer is onsite, the estimated time frame to remove a failed transformer from service and install the spare is 10–14 days. The best case scenario to purchase a GSU replacement is 18 months. The project reduces the risk of an extended half load restriction due to a GSU failure of an in-service transformer.
BIA Camp Williams 4 Corners: BIA ROW Renewal - Ute Mtn Tribal	Apr-20		OPUC 220-1	This project will renew the tribal authority permit for a portion of the Camp Williams-Four Corners transmission line. This permit is critical to continued operation of the line and the ability to meet firm transmission obligations from Four Corners into Utah. This line is part of the WECC rated TOT 2B1 transmission path.
State Prison at Salt Lake City - 8 MW Load	Sep-20		OPUC 220-1	This project will provide the customer a 138 kV connection in order to serve their requested load. This will also provide property for a future Rocky Mountain Power owned distribution substation to serve other projected load growth in the area.
Sams Valley 500-230kV New Substation	Nov-20		OPUC 220-1	The Sams Valley 500-230kV project is being placed in service in separate sequences. This is for upgrades at Grants Pass substation to reinforce the 230kV transmission system and resolve NERC reliability standard issues.
BLM Camp Williams 4 Corners: ROW Renewal PL#99001	Feb-20		OPUC 220-1	This project will renew the BLM permit for a portion of the Camp Williams-Four Corners transmission line. This permit is critical to continued operation of the line and the ability to meet firm transmission obligations from Four Corners into Utah. This line is part of the WECC rated TOT 2B1 transmission path.
Replace Substation Bushings, Glass & Other - UT	Various		OPUC 220-1	This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Utah that has failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
TMP Trans Main Grid East	Various		OPUC 220-1	This category of projects represents system upgrades required on main grid transmission (115 kV and above) facilities located in Utah, Wyoming, or Idaho to reliably serve existing customers, including general load growth. Upgrades in this category are identified in accordance with NERC Reliability Standards, including MOD, PRC and TPL-001-4 categories, to maintain compliance with system performance requirements of the interconnected transmission system. All project that fits description with estimated in-service in 2019 but are under $10m are rolled into this category. See tab 2 for projects included in this cost estimate.
Replace - Storm & Casualty - ID Trans	Various		OPUC 220-1	This 2020 blanket project will replace damaged transmission equipment in Idaho due to a storm or external event (like a car hit pole). The pro forma amount is based on historical performance for this cost category.
Purchase One (1) 230-69kV 150 MVA 3 Phase Wye-Delta XFMR	Dec-20		OPUC 220-1	This is a second phase to Grid Resiliency Phase 1 - 230/69kV Xfmr Purchase project discussed above.
Replace Overhead Transmission Poles - ID	Various		OPUC 220-1	This 2020 blanket project will replace transmission poles in Idaho that have deteriorated and are deemed a risk to public safety and/or system reliability.
Replace Overhead Transmission Lines - Other - ID	Various		OPUC 220-1	This 2020 blanket project will replace transmission line assets other than poles in Idaho that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.

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Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Upgrade Trans CB and Relays UT	Various	[redacted]	OPUC 220-1	This 2020 blanket project will fund functional upgrades to transmission substations in Utah. An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
Purchase One (1) 115-69 kV Wye-Delta 100 MVA 3 Phase XFMR Dedicated for Columbia	Dec-20		OPUC 220-1	A spare transformer analysis identified an aging spare transformer concern in the Delta-Wye portion of the installed 115-69 kV transformer fleet. A new 115-69 kV, Delta-Wye, 150-MVA spare transformer is being purchased to serve as a ready-to-use spare backing up the two (2) three-phase Delta-Wye transformers in-service. The spare will provide timely customer service restoration should failure occur.
Naples 138-12.5 kV New Substation TPL	Aug-2020			Transmission portion of new substation construction to address compliance with NERC Reliability Standards related to unacceptable voltage deviation and low voltage issues.
Parowan Valley Reg Replacement	Dec-20			This project was mis-classified as a transmission level project. This is a distribution level project in the state of Utah and should be removed from this filing. This project will replace the existing regulators at Parowan Valley substation that are projected to overload due to area load growth. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400).
Oregon Trans- Rplc Sub-Swgr,Brk,Rec	various			This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Oregon when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
BLM - Antelope Bannock Pass Anaconda -	May-20			This project will renew the BLM permit for a portion of the Antelope-Amps-Peterson Flat 230 kV transmission line. This permit is required in order to continue the operation of this line.
Replace Overhead Transmission Poles - WY	Various			This 2020 blanket project will replace transmission poles in Wyoming that have deteriorated and are deemed a risk to public safety and/or system reliability.
Oregon Trans - Repl Sub - Mtrs &	various			This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Oregon when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Oregon - Rplc- Trans Strm&Cas	various			This 2020 blanket project will replace damaged transmission equipment in Oregon due to a storm or external event (like a car hit pole).
Asset Removal - UT	Various			This 2020 blanket project will remove transmission utility assets in Utah that have been abandoned for some length of time.
Wildfire Mitigation Plan - OR T	various			This 2020 blanket project provides the means of allocating capital funds to mitigate operational risk in Oregon that present the greatest risk of catastrophic wildfires.
Upgrade Trans CB and Relays WY	Various			This 2020 blanket project will fund functional upgrades to transmission substations in Wyoming. An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
Replace Substation Switchgear, Breakers, Reclosers - WY	Various			This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Wyoming when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Block 216 Tower Service Request	Oct-2020	[redacted]		This project was mis-classified as a transmission level project. This is a distribution level project in the state of Oregon and should be 100 percent assigned to Oregon from this filing. This project provides distribution service to a mixed use new customer load addition. Please refer to the surrebuttal testimony of Ms. Shelley E. McCoy (PAC/4400)
Replace Substation Meters and Relays - UT	Various			This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Utah when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Lassen Sub-New 69x115 kV sub to replace Mt Shasta Sub(Net 12.5 MVA) T	Jun-2020			Addressed in Vail Surrebuttal (PAC/4200) Testimony.
Targeted reliability Improvement, Trans - UT	Various			This 2020 blanket project will rebuild or replace existing transmission facilities, or install additional transmission facilities or functionality in Utah in order to improve customer reliability within a targeted area.
Replace Overhead Transmission Lines - Other - WY	Various			This 2020 blanket project will replace transmission line assets other than poles in Wyoming that have failed or deteriorated and are deemed a risk to public safety and/or system reliability.
Upgrade Trans CB and Relays ID	Various			This 2020 blanket project will fund functional upgrades to transmission substations in Idaho An upgrade would be the addition or enhancement to an existing operational function. For example, adding supervisory control and indication (SCADA) to an existing substation to allow remote operation and monitoring would be considered a functional upgrade.
TMP Generation Interconnections West	Various			This category of projects represents system upgrades required to reliably serve customer generation interconnection requests on the PacifiCorp transmission system per the Open Access Transmission Tariff. This category pertains only to projects Oregon, Washington, and California with in-service dates planned in 2020. Upgrades in this category are identified in accordance with NERC Reliability Standards, including FAC-002 and TPL-001-4, to maintain compliance with system performance requirements of the interconnected transmission system.
Replace - Storm & Casualty - WY Trans	Various			This 2020 blanket project will replace damaged transmission equipment in Wyoming due to a storm or external event (like a car hit pole).
Wash - Rplc-OH Trans-Pole	various			This 2020 blanket project provides the means of allocating capital funds to replace transmission poles in Washington that have deteriorated.
SF6 - Replace Naughton CB 235	5/1/2020			This project will replace the 1971 vintage, 230 kV circuit breaker at Naughton substation due to the ongoing failure of individual components and high rate of leaking SF6 gas. This will reduce SF6 emissions as well as reduce the risk of breaker failure that would result in added reliability risk.
SF6 - Replace Antelope CB 201 - shared IPC	10/1/2020			This project will replace the 1969 vintage, 230 kV circuit breaker at Antelope substation due to the ongoing failure of individual components and high rate of leaking SF6 gas. This will reduce SF6 emissions as well as reduce the risk of breaker failure that would result in added reliability risk.
Calif - Transmission Improvements	various			This 2020 blanket project will rebuild or replace existing transmission facilities, or install additional transmission facilities or functionality in California in order to improve customer reliability within a targeted area.

REDACTED

Pro Forma Projects $500k and Over

Project Name	In-Service Date	Cost Estimate	Previously Addressed in DR	Project Description including explanation of system benefit and any cost overruns
Replace Substation Meters and Relays - ID	Various	[redacted]		This 2020 blanket project will rebuild or replace existing transmission level substation meters and relays in Idaho when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
Replace Substation Switchgear, Breakers, Reclosers - ID	Various			This 2020 blanket project will rebuild or replace existing transmission level substation switchgear, breakers, and reclosers in Idaho when equipment has failed, deteriorated, or become obsolete in order to ensure properly functioning equipment.
System Reinforcement - Local Transmission Projects	Various			This 2020 blanket project will fund transmission level system reinforcement projects in Utah in order to maintain acceptable reliability for the growing load. These projects typically consist of capacity increase projects such as replacing substation class transformers with larger ones.
Replace Substation Bushings, Glass & Other - WY	Various			This 2020 blanket project will rebuild or replace transmission level substation bushings, brown glass and other equipment in Wyoming that have failed, deteriorated, or become obsolete and is deemed a risk to public safety and/or system reliability.
Projects Less Than $500 Thousand	Various			Of the 110 line items that make up the list of projects under $500k, 98 are program level funding which is based on historical experience. The Company forecasts a level of capital associated with unexpected events and smaller maintenance that requires capital replacement. The remaining line items are individual small projects or close-out costs on projects that enter service prior to the test period covered in this rate case.
Transmission Five Year Average Removals				

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Projects By Budget Category

Category	Project Name	Planned Cost ($million)	Project Description
TMP Gen Interconnection East		$ 21.4	
	Q589 Sigurd Solar, LLC	[redacted]	This project interconnects 80 MW of new generation to PacifiCorp's Sigurd 230 kV substation located in Sevier County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes adding a new breaker, dead-end, switches, and other protection and control equipment at Sigurd substation. As well as updating communications at Salt Lake Control Center.
	Q0631 Milford Solar 1, LLC - Interconnection		This project interconnects 99 MW of new generation to PacifiCorp's Hickory 345 kV substation located in Beaver County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes expanding Hickory substation and adding a new 345 kV position and related communication/relay equipment.
	Q737 Cove Mountain Solar 2, LLC		This project interconnects 122 MW of new generation to PacifiCorp's Enterprise Valley substation 138 kV bus located in Washington County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes new relaying and communications equipment at the Enterprise Valley substation. Communications and relaying to be installed at the Richfield service center and Holt, West Cedar, Clover, and Sigurd substations to support a Remedial Action Scheme (RAS).
	Q754 Steel Solar		The project interconnects 80 MW of new generation to PacifiCorp's 138 kV line east of Washakie substation located in Box Elder County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The Network upgrade work for this project includes installation of a new three breaker ring bus substation for the Point of Interconnection (POI), including all appurtenant metering and communication equipment and the loop in/out of the Wheelon-Nucor 138 kV transmission line at the new POI substation.
	Q764 Graphite Solar		The project interconnect 80 MW of new generation to PacifiCorp's Mathington 138 kV substation located in Carbon County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes: new RAS panel at Carbon substation; a new bay and RAS master at Mathington substation; and a new reactor and RAS panel at Spanish Fork substation.
	Q0781 Elektron Solar		This project interconnects 80 MW of new generation to PacifiCorp's Craner Flat 138 kV substation located in Tooele County, Utah. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes: a new circuit breaker at Craner Flat substation to tap to Homestead Knoll – Horseshoe transmission line; and modification of communications equipment and settings at Homestead and Horseshoe substations.
	Program level funding		
TMP Transmission Major Projects - PP		$ 7.7	

REDACTED

	Corvallis 115kV Loop - Reconductor 1 mile Fry - Circle Blvd	[redacted]	This project will reconductor a 1.1 mile section of the Fry – Circle Boulevard 115 kV line and replace the getaway conductor at Circle Boulevard substation. This project is needed to increase capacity on the Fry to Circle end of the 115 kV Corvallis loop and eliminates the need to shed up to 13 MW of load for an outage of the Hazelwood – Circle Tap 115 kV line during heavy summer loading.
	Dry Gulch Substation - Replace 115/69kV Transformer	[redacted]	This project replaces the existing 115/69 kV, 20 megavolt ampere (MVA) transformer, T-2210, with new 115/69 kV, 50 MVA transformer with on-load tap changer (LTC) at Dry Gulch substation located in Eastern Washington near Clarkston. Installation of a new 115/69 kV transformer at Dry Gulch with the ability to automatically control voltage on the 69 kV system will allow the 69 kV line to operate in a normal open configuration, with a sectionalizing point in the middle of the line. This will resolve a North American Electric Reliability Corporation (NERC) transmission planning (TPL) deficiency for a bus fault at the substation that results in low voltages. It will mitigate overloads for outages of heavily loaded parallel main grid lines. Also, by sectionalizing the line, customer outage exposure will be reduced.
	Yreka Sub 115/69 kV Tx addition - Install	[redacted]	This project will install a new 115/69 kV, 30/40/50 MVA LTC transformer at Yreka substation, relocate existing circuit breaker 3G85 to 69 kV breaker bay, and reroute Line 47 within Yreka substation so that 69 kV wire bus does not pass above new transformer bay. Transmission voltage in the Scott Valley is projected to fall below the 0.90 per unit guideline limit at summer peak during normal system operation, beyond the range of distribution substation regulators to maintain customer voltage within American National Standards Institute (ANSI) limits. The addition of an LTC transformer at Yreka will improve control of the 69 kV system voltage and will allow the use of load drop compensation feature to further improve the Scott Valley transmission voltage profile over the long term.
TMP Trans Main Grid East		**$ 12.2**	
	Siphon Tap - Pingree Junction 138 kV Reconductor	[redacted]	This project reconductored the 8.9-mile-long Siphon Tap to Pingree 138 kV line section of Idaho Power Company's (IPC) Don to Pingree to Blackfoot line, located in eastern Idaho. A construction agreement was signed with IPC outlining that all of the work for this project will be performed by IPC. IPC will own the completed project and all associated equipment. PacifiCorp will fund 100 percent of the actual project costs as agreed in the construction agreement. Results of the NERC TPL-001-4 Assessment, identified that the loss of the Goshen 345 kV source can cause the Don – Pingree 138 kV line to load up to 220 MVA. Thus, in order to eliminate the overload, preemptive load shedding of up to 150 MW would have been required in the Goshen area. By reconductoring the Don – Pingree line the rating will increase to at least 191.2 MVA continuous and emergency, and will reduce the preemptive load shedding requirement up to 65 MW.
	Spanish Fork 345/138 Transformer Upgrade TPL	[redacted]	This project upgrades the existing Spanish Fork substation transformer #3, installs backup bus differential relays, and replaces jumpers on the Spanish Fork – Tanner 138 kV line.. The project, based on the NERC TPL-001-4 and the Utah Valley 10-year study, will resolve thermal overload issues, eliminate voltage issues, and eliminate risk of load shedding or generation curtailment identified as NERC TPL-001-4 Category P1, P2, P3 and P6 issues impacting the system.
	TPL Backup Bus Differential Relays	[redacted]	Program level funding to mitigate NERC TPL-001-4 Category P5-5 contingency events for a failure of the relay to clear a bus fault. The backup bus differential relays monitors for bus faults and initiate tripping of circuit breakers thereby providing backup protection for the failure of the primary bus differential relays to operate. The failure of a bus differential relay during system peak load conditions could result in NERC TPL-001-4 performance violations resulting from thermal overloads or low voltage issues in the surrounding network.

REDACTED

Projects By Budget Category

	TPL Overdutied Circuit Breaker Replacements	[redacted]	Program level funding to replace overdutied circuit breakers with higher interrupt capability breakers. The failure of overdutied breakers during system peak load conditions could result in NERC TPL-001-4 deficiencies resulting from thermal overloads or low voltage issues in the surrounding area.
TMP Trans Main Grid West		**$ 7.1**	
	Hazelwood Sub- Expand Yard & Install Ring Bus	[redacted]	Treasureton 138 kV Sub Cap Bank Backup Protection ($0.1 million) - This project installs backup relays for two 49.5-MVAr capacitor banks providing backup protection for the failure of the primary relays at Treasureton 138 kV substation located in Preston, Idaho. The projects, based on the TPL-001-4 Category P5-4 analysis, which is a delayed fault clearing due to the failure of a non-redundant relay, will mitigate the issues impacting the system. Operating procedures cannot be implemented to mitigate the risk of P5-4 contingency events from occurring.
	Lone Pine Circuit Breaker Replacement	[redacted]	This project replaces four 115 kV circuit breakers with non-oil-filled units rated for 40,000 Amp RMS fault current capability to withstand and interrupt fault current at Lone Pine substation in Medford, Oregon. This project will resolve NERC Standard TPL-001-4 requirements that short circuit current interrupting ratings of circuit breakers be adequate to interrupt the available short circuit current. The momentary and interrupting capabilities of the existing 115 kV circuit breakers are not adequate to withstand the available fault current since the energization of Whetstone 230-115 kV substation.
	Meridian RAS Expansion	[redacted]	This project expands the existing Meridian RAS to cover three additional N-1-1 contingencies on the southern Oregon 500 kV system and trip additional load. The proposed RAS expansion will ensure compliance with the NERC PRC-014 Reliability Standard, Western Electricity Coordinating Council (WECC) PRC-(012-014)-WECC-CRT-2 Regional Criterion and NERC TPL-001-4 Reliability Standard. In addition, expanding the RAS will avoid relying on the Southern Oregon under Voltage Load Shedding scheme as the primary mitigation for double contingencies on the 500 kV system.
TMP Trans Customer Generated East- 2020		**$ 6.9**	
	Q2469 PacifiCorp ESM	[redacted]	This project is due to a PacifiCorp's energy supply management (ESM) request on PacifiCorp's Open Access, Same-time Information System (OASIS) for Designated Network Resource (DNR) status. The Construction Agreement was executed between PacifiCorp, on behalf of its merchant function (ESM), and PacifiCorp, on behalf of its transmission function on December 20, 2018. The project is associated with Generation Interconnection queue request Q0631. The network upgrade work includes: development and installation of new relay settings for the Spanish Fork – Timp transmission line at Spanish Fork substation, installation of new fiber and the decommissioning of the Spanish Fork – Lake Mountain microwave link; installation of a new 138 kV circuit breaker (and associated switches) at Timp substation; reconductoring of approximately 5.23 miles of the Spanish Fork- Timp transmission line; and installation of fiber in the shield wire position from Timp to Spanish Fork substation. Under the OATT, PacifiCorp is required to plan, construct, operate and maintain its transmission system in order to provide its network customers service over the transmission provider's transmission system.

REDACTED

	Q155 UAMPS	[redacted]	This project is in response to a transmission service request from UAMPS pursuant to its Transmission Service and Operating Agreement for a new point of delivery. The scope consists of constructing a new 138 kV substation with four circuit breakers, switches, etc., looping the Jordanelle – Midway 138 kV line in and out of the substation and two 138 kV delivery connections to UAMPS customer. Under the OATT, PacifiCorp is required to plan, construct, operate and maintain its transmission system in order to provide its network customers service over the transmission provider's transmission system.
TMP Trans Customer Generated East- 2019		**$ 4.3**	
	Bull River to Carter Substation 138 kV Conv - Trans	[redacted]	This project was required for increased load service for a UAMPS network customer. The project is to re-build 2.3 miles of the Lehi Bull River tap to Saratoga tap 46 kV line to 138 kV line.
	Program level funding	[redacted]	The close-out of several projects placed into service late 2018 and early 2019.
TMP Generation Interconnections West		[redacted]	
	Q729 Airport Solar, LLC - Airport Solar	[redacted]	This project interconnects a total of 47.25 MW of new generation to PacifiCorp's Chiloquin-Alturas 115 kV line at 42.178563°N, 120.357580°W located in Lake County, Oregon. The project is a FERC-jurisdictional interconnection and per the OATT PacifiCorp must accommodate the customer request. The Network upgrade work for this project includes: construction of a new 115 kV three-breaker ring bus substation.
TMP Transmission Major Projects - PP		**$ 2.6**	
	NE Portland Trans Upgrade	[redacted]	This project addressed electrical network deficiencies required to improve reliability within Northeast Portland. This project is a systemic solution to the operational and contingency related network issues in the Portland transmission and substation system. The dollars in 2019 were for the last phase of the project which was the installation of a second transformer at Albina substation.
	Program level funding	[redacted]	The close-out of several projects placed into service late 2018 and early 2019.
TMP Trans Main Grid East		[redacted]	
	90th South Bus Tie Breaker	[redacted]	The project, based on the 2017 TPL Assessment, identified that a fault on the 90th South 138 kV bus tie breaker results in a loss of the entire 90th South 138 kV substation. Once the project is completed, loss of the entire 90th South 138 kV substation will be prevented. Thermal overloads on the following 138 kV line segments will be resolved: Lone Peak – Lone Peak Tap, Travers Mtn. – South Mtn. South Tap, and South Mtn. South Tap – South Mountain. Low voltages on the 106th South, 108th South, Quarry, Dimple Dell and Dumas substations will not occur, and overloading of the Camp Williams transformer as seen in the 2022 TPL case will be prevented.

NewSun Information Request 1.19

Regarding PacifiCorp's Ochoco to Corral transmission line and associated upgrades to PacifiCorp's system and substations, and PacifiCorp's load service in the Prineville area, please provide:

(a) Where PacifiCorp identified the need for the upgrades (e.g., load growth, interconnection request, transmission request, or other),

(b) How the upgrades were funded (e.g., utility funded, queue number funded, other),

(c) The existing load and forecast load upon which PacifiCorp relied in justifying the upgrade, including the MVa rating of the loads that triggered the upgrades, including the dates of the associated load interconnection requests, the load initial and current projected on-line dates, and the status of each load service,

(d) The cost of the upgrades,

(e) How the upgrades were funded (e.g., utility funded, queue number funded, other),

(f) Whether the upgrade were included in rate base or whether PacifiCorp intends to include it in rate base,

(g) If the upgrades were included in rate base, the rate of return earned on the upgrades,

(h) Describe how PacifiCorp serves its load in the Prineville area, including to what extent PacifiCorp relies on contiguous transmission from other areas of the PacifiCorp system,

(i) Confirm whether the Prineville service area and Bend and Redmond service areas are electrically contiguous for PacifiCorp, and what the transfer capacity is within PacifiCorp's system in the area, as well as what the transfer capacity and monthly average and peak energy service from BPA at each point of service from BPA in the area, including Pilot Butte and Ponderosa substation,

(j) Describe what long term rights PacifiCorp has on the California-Oregon Intertie (aka the COI aka the AC Intertie) and how PacifiCorp uses these rights and other short term procurement via the COI to serve Prineville area load,

(k) Provide a comparison for the Prineville area between when interconnections and loads were requested, including comparative timing, along with the available avoided cost rates at the time of each request,

(l) Provide a summary of the power contract rates for facilities constructed or contracted to be constructed in the Prineville area, whether those facilities were ER or NR, what the likely network upgrades would have been for any ER facility that was (or is being) constructed if it had been required to be NR instead. Compare the PPA prices for these facilities at the time of contracting with the avoided cost rates available to the QFs which sought interconnections and PPAs in this area,

(m) Please provide PacifiCorp's analysis based on the information in (k) and (l) as to whether the prospective QFs in its interconnection queue and/or otherwise seeking PPAs from PacifiCorp would have likely been economically viable based on these numbers were such facilities allowed ER interconnections and been allowed refundability of network upgrades. How does this compare to the number of actual facilities for which interconnection was requested in the Prineville area system (i.e. on lines directly connected to Ponderosa substation)? Please provide a total of all calculated revenues which would have been associated with any facilities which would have reasonably been likely to be economically viable per prior question; please make such calculations based on estimated facility energy production that would have resulted during the term of the resultant PPA using avoided cost pricing that would have been available at the time, and

(n) Provide copies of all correspondence, load service studies, upgrades requested, and upgrades implemented, including associated cost estimates and who paid for those upgrades, associated with PacifiCorp's service of the Prineville actual and prospective loads, particularly at Ponderosa substation, including a summary of all related lobbying efforts, contacts with BPA executive management, and contact with other elected officials, including the governor's office, Senator Merkely, Senator Widen, and Congressman Walden, and any related requests made for support or action by these officials related to load service in the Prineville area and the justifications for these requests. Please summarize the comparative timing of these upgrades relative to the PacifiCorp load queue requests and loads in service, associated capacities, and a comparison of any differences in how generation interconnection studies for the area treated load requests with respect to power flow studies and justification of network upgrades related to service of these load requests, whether such upgrades where performed by PacifiCorp or BPA.

Response to NewSun Information Request 1.19

PacifiCorp objects to this data request because the information sought is not reasonably calculated to lead to the discovery of admissible evidence in this docket, overly broad and unduly burdensome.

NewSun Information Request 1.19

Regarding PacifiCorp's Ochoco to Corral transmission line and associated upgrades to PacifiCorp's system and substations, and PacifiCorp's load service in the Prineville area, please provide:

(a) Where PacifiCorp identified the need for the upgrades (e.g., load growth, interconnection request, transmission request, or other),

(b) How the upgrades were funded (e.g., utility funded, queue number funded, other),

(c) The existing load and forecast load upon which PacifiCorp relied in justifying the upgrade, including the MVa rating of the loads that triggered the upgrades, including the dates of the associated load interconnection requests, the load initial and current projected on-line dates, and the status of each load service,

(d) The cost of the upgrades,

(e) How the upgrades were funded (e.g., utility funded, queue number funded, other),

(f) Whether the upgrade were included in rate base or whether PacifiCorp intends to include it in rate base,

(g) If the upgrades were included in rate base, the rate of return earned on the upgrades,

(h) Describe how PacifiCorp serves its load in the Prineville area, including to what extent PacifiCorp relies on contiguous transmission from other areas of the PacifiCorp system,

(i) Confirm whether the Prineville service area and Bend and Redmond service areas are electrically contiguous for PacifiCorp, and what the transfer capacity is within PacifiCorp's system in the area, as well as what the transfer capacity and monthly average and peak energy service from BPA at each point of service from BPA in the area, including Pilot Butte and Ponderosa substation,

(j) Describe what long term rights PacifiCorp has on the California-Oregon Intertie (aka the COI aka the AC Intertie) and how PacifiCorp uses these rights and other short term procurement via the COI to serve Prineville area load,

(k) Provide a comparison for the Prineville area between when interconnections and loads were requested, including comparative timing, along with the available avoided cost rates at the time of each request,

(l) Provide a summary of the power contract rates for facilities constructed or contracted to be constructed in the Prineville area, whether those facilities were ER or NR, what the likely network upgrades would have been for any ER facility that was (or is being) constructed if it had been required to be NR instead. Compare the PPA prices for these facilities at the time of contracting with the avoided cost rates available to the QFs which sought interconnections and PPAs in this area,

(m) Please provide PacifiCorp's analysis based on the information in (k) and (l) as to whether the prospective QFs in its interconnection queue and/or otherwise seeking PPAs from PacifiCorp would have likely been economically viable based on these numbers were such facilities allowed ER interconnections and been allowed refundability of network upgrades. How does this compare to the number of actual facilities for which interconnection was requested in the Prineville area system (i.e. on lines directly connected to Ponderosa substation)? Please provide a total of all calculated revenues which would have been associated with any facilities which would have reasonably been likely to be economically viable per prior question; please make such calculations based on estimated facility energy production that would have resulted during the term of the resultant PPA using avoided cost pricing that would have been available at the time, and

(n) Provide copies of all correspondence, load service studies, upgrades requested, and upgrades implemented, including associated cost estimates and who paid for those upgrades, associated with PacifiCorp's service of the Prineville actual and prospective loads, particularly at Ponderosa substation, including a summary of all related lobbying efforts, contacts with BPA executive management, and contact with other elected officials, including the governor's office, Senator Merkely, Senator Widen, and Congressman Walden, and any related requests made for support or action by these officials related to load service in the Prineville area and the justifications for these requests. Please summarize the comparative timing of these upgrades relative to the PacifiCorp load queue requests and loads in service, associated capacities, and a comparison of any differences in how generation interconnection studies for the area treated load requests with respect to power flow studies and justification of network upgrades related to service of these load requests, whether such upgrades where performed by PacifiCorp or BPA.

1st Supplemental Response to NewSun Information Request 1.19

In further support of the Company's response to NewSun Information Request 1.19 dated January 20, 2021, the Company responds further as follows:

PacifiCorp reiterates its objections to this request. To the extent NewSun has identified this as a request seeking to understand the types of transmission system upgrades constructed by utilities and the rationale for such construction, notwithstanding and without waiving its objections, the Company responds as follows:

UM 2032 / PacifiCorp
March 5, 2021
NewSun Information Request 1.19 – 1st Supplemental

Please refer to the Company's 1st Supplemental response to NewSun Information Request 1.10.

UM 2032 / PacifiCorp
January 21, 2021
NewSun Information Request 1.20

NewSun Information Request 1.20

In its December 24, 2014, filing in FERC Docket Nos. ER15-741-000 & -001, the docket referenced in PacifiCorp's response to OPUC Information Request No. 6, PacifiCorp states that: "on the one hand, PURPA requires a utility to purchase QF power and make firm transmission arrangements (e.g., DNR status) to deliver it, even if the QF has chosen to site in a constrained area. On the other hand, Commission open access policy and precedent do not appear to support the granting of new DNRs until sufficient ATC is available to meet the request. . . this appears to put the utility in the position of having to construct network upgrades in order to accommodate the PURPA-required QF firm transmission service, even if the utility would not have otherwise constructed those upgrades – certainly not for load service, reliability or because they were cost-justified."

Identify all instances in which PacifiCorp constructed network upgrades in Oregon to accommodate PURPA-required QF firm transmission service that the utility would not have otherwise constructed for load service, reliability, or because the network upgrades were not cost-justified or would not have provided benefits to the transmission system. Identify all instances in which PacifiCorp would have constructed such upgrades but for the OPUC policy of requiring QFs to pay for all network upgrades with no transmission credits or other recovery of costs.

Response to NewSun Information Request 1.20

PacifiCorp objects to this data request because the request is overly broad and unduly burdensome. The request also requires speculation about what PacifiCorp would have constructed under a different state regulatory policy construct. Moreover, the phrase "benefits to the transmission system" is vague and unclear. Subject to and without waiving these objections, PacifiCorp responds as follows:

PacifiCorp has not performed such an analysis.

NewSun Information Request 1.20

In its December 24, 2014, filing in FERC Docket Nos. ER15-741-000 & -001, the docket referenced in PacifiCorp's response to OPUC Information Request No. 6, PacifiCorp states that: "on the one hand, PURPA requires a utility to purchase QF power and make firm transmission arrangements (e.g., DNR status) to deliver it, even if the QF has chosen to site in a constrained area. On the other hand, Commission open access policy and precedent do not appear to support the granting of new DNRs until sufficient ATC is available to meet the request. . . this appears to put the utility in the position of having to construct network upgrades in order to accommodate the PURPA-required QF firm transmission service, even if the utility would not have otherwise constructed those upgrades – certainly not for load service, reliability or because they were cost-justified."

Identify all instances in which PacifiCorp constructed network upgrades in Oregon to accommodate PURPA-required QF firm transmission service that the utility would not have otherwise constructed for load service, reliability, or because the network upgrades were not cost-justified or would not have provided benefits to the transmission system. Identify all instances in which PacifiCorp would have constructed such upgrades but for the OPUC policy of requiring QFs to pay for all network upgrades with no transmission credits or other recovery of costs.

1st Supplemental Response to NewSun Information Request 1.20

In further support of the Company's response to NewSun Information Request 1.20 dated January 21, 2021, the Company responds further as follows:

PacifiCorp reiterates its objections to this request. Notwithstanding and without waiving its objections, PacifiCorp responds as follows:

Please refer to the Company's 1st Supplemental response to NewSun Information Request 1.6, specifically Attachment NewSun 1.6 1st Supplemental. The attachment lists the power purchase agreements (PPA), including qualifying facility (QF) PPAs, under which PacifiCorp currently purchases power and the transmission service request (TSR) queue number for each PPA. The attachment links the interconnection queue numbers and TSR queue numbers for all PPAs in Oregon under which PacifiCorp purchases power (to the extent that such information exists, as some facilities predate Federal Energy Regulatory Commission's practice of assigning queue numbers to such requests). The TSR queue number associated with each QF generator in the list allows NewSun to access the QF generator's TSR information on the Open Access Same-Time Information System (OASIS), including the requesting party, the type of transmission service requested, and studies identifying any upgrades needed to grant the TSR request associated with the QF's output, to the extent the need for such upgrades existed.

UM 2032 / PacifiCorp
March 5, 2021
NewSun Information Request 1.20 – 1st Supplemental

To the extent NewSun has identified this as a request seeking to understand the types of transmission system upgrades constructed by utilities and the rationale for such construction, notwithstanding and without waiving its objections, the Company responds as follows:

Please refer to the Company's 1st Supplemental response to NewSun Information Request 1.10.

NewSun Information Request 1.21

Please provide an itemized summary table of all network upgrades constructed by PacifiCorp since 2010 in Oregon and planned for construction in Oregon (or cost allocation to Oregon ratepayers), including the upgrades' associated costs (initial estimate and final actual cost), whether currently rate-based (or planned for future rate-basing approval), project justification(s), nominal capacity, amount of associated load and generation directly supported by the specific incremental upgrade (total and $/MW), ratio of maximum service capacity to directly supported actual, in-service generation or load, and the average cost per MW of capacity per ratepayer. Identify explicitly where excess capacity was built in anticipation of future use (not immediate direct use), itemizing comparatively for those justified by loads, by generators, and by QFs.

Response to NewSun Information Request 1.21

PacifiCorp objects that this request is overly broad and unduly burdensome; that the phrases "planned for construction in Oregon," "project justifications," "amount of associated load and generation directly supported," "ratio of maximum service capacity to directly supported actual, in-service generation or load," and "itemizing comparatively for those justified by loads, by generators, and by QFs" are all vague and ambiguous; and that the request seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. PacifiCorp also objects that this request asks PacifiCorp to develop information and prepare analysis that would be unduly burdensome and does not have a high degree of relevance to the case. Notwithstanding and without waiving these objections, please see PacifiCorp's responses to OPUC Information Request Nos. 13 and 14.

NewSun Information Request 1.21

Please provide an itemized summary table of all network upgrades constructed by PacifiCorp since 2010 in Oregon and planned for construction in Oregon (or cost allocation to Oregon ratepayers), including the upgrades' associated costs (initial estimate and final actual cost), whether currently rate-based (or planned for future rate-basing approval), project justification(s), nominal capacity, amount of associated load and generation directly supported by the specific incremental upgrade (total and $/MW), ratio of maximum service capacity to directly supported actual, in-service generation or load, and the average cost per MW of capacity per ratepayer. Identify explicitly where excess capacity was built in anticipation of future use (not immediate direct use), itemizing comparatively for those justified by loads, by generators, and by QFs.

1st Supplemental Response to NewSun Information Request 1.21

In further support of the Company's response to NewSun Information Request 1.21 dated January 20, 2021, the Company responds further as follows:

PacifiCorp reiterates its objections to this request. Moreover, the data request relates to issues outside the scope of Phase 1 of this proceeding, and that may be addressed in Phase 2. Notwithstanding and without waiving its objections, the Company responds as follows:

Please refer to the Company's 1st Supplemental response to NewSun Information Request 1.10.

NewSun Information Request 1.11

Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?

Response to NewSun Information Request 1.11

PacifiCorp objects to this data request because the request is overly broad and unduly burdensome to the extent it asks PacifiCorp to analyze all qualifying facility (QF) funded Network Upgrades going back to 2005. Moreover, the phrase “any benefits to the transmission system” is vague and ambiguous. The term “benefits” is vague and has not been defined. Please refer to Joint Utilities/300, Wilding-Macfarlane-Williams/18-19. Please also refer to the Public Utility Commission of Oregon (OPUC) staff’s response to PGE Data Request 05 (The Commission has never defined the term system-wide “benefits” as it applies to Network Upgrades incurred to interconnect QFs.).

NewSun Information Request 1.11

Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?

1st Supplemental Response to NewSun Information Request 1.11

In further support of the Company's response to NewSun Information Request 1.11 dated January 20, 2021, the Company responds further as follows:

PacifiCorp reiterates its objections to this request. Moreover, the data request relates to issues outside the scope of Phase 1 of this proceeding, and that may be addressed in Phase 2. Notwithstanding and without waiving its objections, the Company responds as follows:

Any qualifying facility (QF) funded network upgrade would be driven solely by a QF's interconnection and designed only as needed and necessary to interconnect the QF.

OPUC Information Request 13

Customer Indifference
Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of Network Upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please list all Network Upgrades that the Company has constructed since 2010. Please also include Network Upgrades that would match this definition if not for the reference to large generating facility. Please include the following information for each year since the upgrade was in service through 2019 inclusive:

(a) Interconnection queue number of the generator(s) that triggered the upgrade.

(b) Whether the generator(s) are owned by the Company.

(c) Cost of the upgrade borne by the generator(s).

(d) Cost of the upgrade borne by ratepayers.

(e) Cost of the upgrade borne by other transmission customers.

(f) Transmission revenues generated by the upgrade.

In conversations with Staff, Staff has clarified that PacifiCorp should provide the following information to this response:

- All network upgrades put in service since 2010 - 2019 by generator
- Queue number
- Location of generator (state)
- Ownership of generator, including whether the ownership changed during the course of the interconnection process
- Jurisdiction over interconnection
- Total cost of the network upgrades constructed for that queue number

For each customer's network upgrades identified in Phase one between 2010 - 2019, provide

- The total cost of the network upgrades
- The portion of the total cost provided by interconnection customer, including whether the portion was provided by interconnection customer upfront or in some other way.

- Whether the interconnection customer was or is being reimbursed for their contribution to network upgrades and by whom.
- If the interconnection customer did not provide all upfront capital for network upgrades, identify who also contributed to upfront capital (i.e., PAC merchant function), and specify what portion they provided and whether this entity(s) is being reimbursed (i.e., from PAC transmission revenues).

Response to OPUC Information Request 13

Please see Attachment OPUC 13.

PacifiCorp is still completing its response to part (f) of this data request and will provide it as soon as possible, but no later than October 8, 2020.

OR UM 2032
OPUC 13

Attachment OPUC 13

Q#	Ownership	QF?	Jurisdiction	Size (MW)	ST	Voltage (kV)	Type	Actual Interconnection Network Upgrade Costs	Description of Network Upgrades	Costs Borne by Generator	Cost Borne by Ratepayers	Cost Borne by Transmission Customers	Did IC Upfront All Capital?	Was/Is IC Being Reimbursed?
102-106 145-147	Third Party	QF	State	64.55	OR	69	Wind	$3,500,000	**Substation expansion, protection and communications equipment upgrades, transmission line rebuild.	$3,500,000	$0	$0	Yes	No
117-118*	PacifiCorp	NO	Federal	118.5	WY	230	Wind	$8,213,183	New point of interconnection substation, protection and communications equipment upgrades.	$0	$8,213,183	$8,213,183	Yes	Yes
119	PacifiCorp	NO	Federal	127.5	WY	230	Wind	$1,462,379	Substation expansion, protection and communications equipment upgrades.	$0	$1,462,379	$1,462,379	Yes	Yes
122	Third Party	NO	Federal	10.8	WA	230	Wind	$70,347	Communications and protection equipment upgrades.	$0	$70,347	$70,347	Yes	Yes
126	PacifiCorp	NO	Federal	239	WY	230	Wind	$16,518,007	New point of interconnection substation, protection and communications equipment upgrades.	$0	$16,518,007	$16,518,007	Yes	Yes
129	Third Party	NO	Federal	4.8	UT	46	Biogas	$497,883	Communications and protection equipment upgrades.	$0	$497,883	$497,883	Yes	Yes
153	Third Party	NO	Federal	200.5	WY	230	Wind	$1,819,811	Substation expansion, protection and communications equipment upgrades.	$0	$1,819,811	$1,819,811	Yes	Yes
171	Third Party	QF	State	16.5	WY	69	Wind	$650,000	**Substation expansion, protection and communications equipment upgrades.	$650,000	$0	$0	Yes	No
203	PacifiCorp	NO	Federal	123	WY	230	Wind	$10,499,932	New point of interconnection substation, protection and communications equipment upgrades.	$0	$10,499,932	$10,499,932	Yes	Yes
220	Third Party	NO	Federal	99	WY	230	Wind	$5,120,466	New point of interconnection substation, protection and communications equipment upgrades.	$0	$949,852	$949,852	Yes	Yes
248	Third Party	QF	State	5	OR	69	Hydro	$500,000	**New point of interconnection substation, protection and communications equipment upgrades.	$500,000	$0	$0	Yes	No
301	PacifiCorp	NO	Federal	625	UT	345	Natural Gas	$13,323,330	New point of interconnection substation, protection and communications equipment upgrades.	$0	$13,323,330	$13,323,330	Yes	Yes
306	Third Party	QF	State	40	WY	230	Wind	$7,500,000	***New point of interconnection substation, protection and communications equipment upgrades.	$7,500,000	$0	$0	Yes	No
313	Third Party	NO	Federal	25	UT	138	Geothermal	$5,285,015	New point of interconnection substation, protection and communications equipment upgrades.	$0	$5,285,015	$5,285,015	Yes	Yes
323	Third Party	QF	State	43.2	ID	230	Wind	$8,500,000	***New point of interconnection substation, protection and communications equipment upgrades.	$8,500,000	$0	$0	Yes	No
324	Third Party	QF	State	80	UT	138	Solar	$875,000	**Substation expansion, protection and communications equipment upgrades.	$875,000	$0	$0	Yes	No
384	Third Party	QF	State	60	UT	138	Wind	$1,500,000	**Substation expansion, protection and communications equipment upgrades.	$1,500,000	$0	$0	Yes	No
442	Third Party	QF	State	5.6	ID	69	Natural Gas	$150,000	**Communications and protection equipment upgrades.	$150,000	$0	$0	Yes	No
450	Third Party	QF	State	50	UT	46	Solar	$1,400,000	**Substation expansion, protection and communications equipment upgrades.	$1,400,000	$0	$0	Yes	No
513	Third Party	QF	State	80	UT	138	Solar	$2,100,000	**Substation expansion, protection and communications equipment upgrades.	$2,100,000	$0	$0	Yes	No
514	Third Party	QF	State	80	UT	138	Solar	$4,000,000	**New point of interconnection substation, protection and communications equipment upgrades.	$4,000,000	$0	$0	Yes	No
515	Third Party	QF	State	80	UT	345	Solar	$8,500,000	**New point of interconnection substation, protection and communications equipment upgrades.	$8,500,000	$0	$0	Yes	No
539	Third Party	QF	State	130.4	UT	138	Solar	$5,000,000	***New point of interconnection substation, protection and communications equipment upgrades.	$5,000,000	$0	$0	Yes	No
564	Third Party	QF	State	80	UT	138	Solar	$850,000	**Substation expansion, protection and communications equipment upgrades.	$850,000	$0	$0	Yes	No
566	Third Party	QF	State	8.5	OR	69	Solar	$1,500,000	**Substation expansion, protection and communications equipment upgrades.	$1,500,000	$0	$0	Yes	No
594	Third Party	NO	Federal	56	OR	115	Solar	$1,561,839	Substation expansion, protection and communications equipment upgrades.	$0	$1,561,839	$1,561,839	Yes	Yes
684	Third Party	NO	Federal	20	UT	46	Solar	$1,171,128	Substation expansion.	$0	$1,171,128	$1,171,128	Yes	Yes
729 & 780	Third Party	NO	Federal	47.25	OR	115	Solar	$5,272,105	New point of interconnection substation, protection and communications equipment upgrades.	$0	$5,272,105	$5,272,105	Yes	Yes
795	Third Party	QF	State	20	WY	69	Solar	$4,575,747	**Substation expansion, protection and communications equipment upgrades.	$4,575,747	$0	$0	Yes	No
796	Third Party	QF	State	20	WY	69	Solar	$6,000,000	**New substation transformer, substation expansion	$6,000,000	$0	$0	Yes	No

*Indicates interconnection request that was submitted by a third party originally but rights were purchased by PacifiCorp at later stage in process.
** Indicates that the actual cost of these network upgrades are an estimate because interconnection facilities costs and network upgrades costs were not accounted for separately.
*** Indicates that the actual cost of these network upgrades are an estimate because interconnection facilities costs and network upgrades costs were not accounted for separately. Additionally some of the network upgrades were constructed by the interconnection customer so those actual costs are also estimated.

UM 2032 / PacifiCorp
October 9, 2020
OPUC Information Request 13 – 1st Supplemental

OPUC Information Request 13

Customer Indifference
Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of Network Upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please list all Network Upgrades that the Company has constructed since 2010. Please also include Network Upgrades that would match this definition if not for the reference to large generating facility. Please include the following information for each year since the upgrade was in service through 2019 inclusive:

(a) Interconnection queue number of the generator(s) that triggered the upgrade.

(b) Whether the generator(s) are owned by the Company.

(c) Cost of the upgrade borne by the generator(s).

(d) Cost of the upgrade borne by ratepayers.

(e) Cost of the upgrade borne by other transmission customers.

(f) Transmission revenues generated by the upgrade.

In conversations with Staff, Staff has clarified that PacifiCorp should provide the following information to this response:

- All network upgrades put in service since 2010 - 2019 by generator
- Queue number
- Location of generator (state)
- Ownership of generator, including whether the ownership changed during the course of the interconnection process
- Jurisdiction over interconnection
- Total cost of the network upgrades constructed for that queue number

For each customer's network upgrades identified in Phase one between 2010 - 2019, provide

- The total cost of the network upgrades
- The portion of the total cost provided by interconnection customer, including whether the portion was provided by interconnection customer upfront or in some other way.

- Whether the interconnection customer was or is being reimbursed for their contribution to network upgrades and by whom.
- If the interconnection customer did not provide all upfront capital for network upgrades, identify who also contributed to upfront capital (i.e., PAC merchant function), and specify what portion they provided and whether this entity(s) is being reimbursed (i.e., from PAC transmission revenues).

1st Supplemental Response to OPUC Information Request 13

(c) As additional information on PacifiCorp's prior response to subsection (c), the costs of Interconnection Facilities and Network Upgrades are assigned to interconnecting qualifying facilities (QFs). Consequently, PacifiCorp does not track these two types of costs separately. The "Costs Borne by Generator" column of the attachment therefore provides round-number estimates of QF interconnection costs attributable to each QF's Network Upgrades.

(d) Please refer to Attachment OPUC 13-1 1st Supplemental. In PacifiCorp's previous version of this attachment, FERC-jurisdictional network upgrade costs were not appropriately allocated between ratepayers and third-party transmission customers. This has been corrected in the current attachment.

In addition, Column I shows the in-service date of projects for the non-QF network upgrades. Network upgrades that were in service by December 31, 2013, were included in the rate base used to set Oregon rates in the Company's last general rate case (GRC), UE 263, effective January 1, 2014. Network upgrades shown in the attachment that have gone into service between January 1, 2014, and December 31, 2019, are not currently in Oregon rates, but have been included in the rate base in the Company's pending GRC, UE 374. Accumulated depreciation as of the rate effective date reduces the rate base amount included in revenue requirement. Depreciation expense on these assets began once they were in service, however, annual depreciation expense is not included in customer rates until the assets are included in a GRC.

The total cost of the network upgrade paid by PacifiCorp (Column M) is included in rate base for the revenue requirement calculation in GRCs for its retail customers and in the calculation of the Company's Open Access Transmission Tariff (OATT) charged to transmission customers. Transmission revenues received from transmission customers' usage of PacifiCorp's transmission system are reflected as a reduction in the calculation of revenue requirement used in setting retail rates in a GRC.

Transmission assets are long-lived assets, with the annual depreciation expense being included in the revenue requirement when setting retail rates in a GRC or the annual update to the OATT. Transmission customers begin paying for these assets once they go into service, whereas retail customers only begin paying for the assets once they are included in retail rates. Columns N and P show the amount that transmission and Oregon retail customers, respectively, would pay for these assets over their entire life, based on the following assumptions.

- Both groups of customers begin paying for the assets once they are in service, with no regulatory lag.
- Transmission customers' usage of PacifiCorp's system remains at 19 percent.
- Oregon's allocation of transmission costs remains at 26 percent.

(e) Please see the response to subpart (d).

(f) The Company objects to this request as unduly burdensome and as requesting information not maintained during the ordinary course of business or preparation of a special study. Without waiving these objections, the Company responds as follows:

Please refer to Confidential Attachment OPUC 13-2 1st Supplemental. PacifiCorp does not in its normal course of business track transmission revenues as generated by a particular network upgrade, so it cannot provide a definitive revenue amount attributable to the network upgrades identified in response to Attachment OPUC 13-1 1st Supplemental (or any other specific network upgrades). For purposes of responding to this information request, PacifiCorp roughly estimated the annual revenues associated with eight generation projects placed into service between 2010 and 2019, but did so with two important clarifications. First, the source of the assumed revenues associated with these particular generator interconnection network upgrades is the payment of PacifiCorp's transmission service rate by the entity who arranged for transmission service to deliver the interconnected generator's power. In some cases, that transmission rate is paid by a third-party transmission customer, and in other cases it is paid by PacifiCorp's merchant function (for service to retail customers), as indicated in Tab 1, Column F. This distinction would be an important factor to consider in evaluating the overall rate impact of the revenue stream estimates. Second, the transmission customer that arranges transmission service to deliver a qualifying facility's power on PacifiCorp's system is PacifiCorp's merchant function.

In addition to those clarifications, PacifiCorp offers additional detail about the source of the inputs and assumptions for Confidential Attachment OPUC 13-2 1st Supplement. With respect to the transmission rates, the eight generation projects are delivered on either network integration transmission service or point-to-point transmission service, and the PacifiCorp OATT rate associated the relevant transmission service types was used for the estimated calculation. These rates are updated annually on May 15th and effective June 1st. On May 15th, PacifiCorp arrives at a "projected rate," which is billed for the next rate year (June 1st through May 31st), but also a "true-up rate" for the prior calendar year. The true-up rate results in a refund or surcharge issued to long-term, firm point-to-point and network transmission service customers. The annual update is publicly available on PacifiCorp's Open Access Same-Time Information System (OASIS) website. The annual revenue estimates for each project date back to 2012, which was the effective date of PacifiCorp's FERC formula rate. The billing determinant/divisor in the transmission formula is 12 coincident peak (CP). The 12CP monthly peak is the average of the 12 monthly system peaks calculated as the network customers monthly network load (Section 34.2 of the Open Access Transmission Tariff) plus the reserve capacity of all LTF PTP customers. The true-up rate utilizes the actual 12CP demand.

PacifiCorp calculated a high-level impact of each generation project by year, starting in 2012, by identifying the percentage of the generation project's network upgrade in relationship to the total amount of transmission plant utilized in the formula rate. This percentage was then multiplied by the annual revenue requirements utilized in the formula rate true-up calculation for each calendar year. The resulting revenue requirement was then multiplied by the ratio of 3rd party billing determinants compared to the total billing determinants to calculate a rough revenue estimate recognized as a result of the network upgrade asset. This process is not precise, but a reasonable approach to roughly estimating the value the amount of revenue impact the asset has in the formula. This high-level process did not factor in changes items such as depreciation, which lowers the revenue impact per year.

Confidential information is provided subject to General Protective Order No. 20-301.

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Attachment OPUC 13-1 1st Supplemental

Q#	Ownership	QF?	Jurisdiction	Size (MW)	ST	Voltage (kV)	Type	In-Service Date	Actual Interconnection Network Upgrade Costs	Description of Network Upgrades	Costs Borne by Generator	Costs Borne by Ratepayers/ Transmission Customers	19% Allocation to Transmission Customers	81% Allocation to Retail Customers	Approximate 26% Allocation in Oregon Retail Customers	Did IC Upfront All Capital?	Was/Is IC Being Reimbursed?
102-106 145-147	Third Party	QF	State	64.55	OR	69	Wind		$3,500,000	**Substation expansion, protection and communications equipment upgrades, transmission line rebuild.	$3,500,000	$0	$0	$0	$0	Yes	No
117-118*	PacifiCorp	NO	Federal	118.5	WY	230	Wind	1/3/2009	$8,213,183	New point of interconnection substation, protection and communications equipment upgrades.	$0	$8,213,183	$1,560,505	$6,652,678	$1,729,696	Yes	Yes
119	PacifiCorp	NO	Federal	127.5	WY	230	Wind	9/30/2009	$1,462,379	Substation expansion, protection and communications equipment upgrades.	$0	$1,462,379	$277,852	$1,184,527	$307,977	Yes	Yes
122	Third Party	NO	Federal	10.8	WA	230	Wind	6/27/2008	$70,347	Communications and protection equipment upgrades.	$0	$70,347	$13,366	$56,981	$14,815	Yes	Yes
126	PacifiCorp	NO	Federal	239	WY	230	Wind	1/2/2009	$16,518,007	New point of interconnection substation, protection and communications equipment upgrades.	$0	$16,518,007	$3,138,421	$13,379,586	$3,478,692	Yes	Yes
129	Third Party	NO	Federal	4.8	UT	46	Biogas	4/1/2009	$497,883	Communications and protection equipment upgrades.	$0	$497,883	$94,598	$403,285	$104,854	Yes	Yes
153	Third Party	NO	Federal	200.5	WY	230	Wind	10/28/2010	$1,819,811	Substation expansion, protection and communications equipment upgrades.	$0	$1,819,811	$345,764	$1,474,047	$383,252	Yes	Yes
171	Third Party	QF	State	16.5	WY	69	Wind		$650,000	**Substation expansion, protection and communications equipment upgrades.	$650,000	$0	$0	$0	$0	Yes	No
203	PacifiCorp	NO	Federal	123	WY	230	Wind	9/30/2010	$10,499,932	New point of interconnection substation, protection and communications equipment upgrades.	$0	$10,499,932	$1,994,987	$8,504,945	$2,211,286	Yes	Yes
220	Third Party	NO	Federal	99	WY	230	Wind	12/1/2009	$5,120,466	New point of interconnection substation, protection and communications equipment upgrades.	$0	$949,852	$180,472	$769,380	$200,039	Yes	Yes
248	Third Party	QF	State	5	OR	69	Hydro		$500,000	**New point of interconnection substation, protection and communications equipment upgrades.	$500,000	$0	$0	$0	$0	Yes	No
301	PacifiCorp	NO	Federal	625	UT	345	Natural Gas	5/8/2014	$13,323,330	New point of interconnection substation, protection and communications equipment upgrades.	$0	$13,323,330	$2,531,433	$10,791,897	$2,805,893	Yes	Yes
306	Third Party	QF	State	40	WY	230	Wind		$7,500,000	***New point of interconnection substation, protection and communications equipment upgrades.	$7,500,000	$0	$0	$0	$0	Yes	No
313	Third Party	NO	Federal	25	UT	138	Geothermal	12/11/2013	$5,285,015	New point of interconnection substation, protection and communications equipment upgrades.	$0	$5,285,015	$1,004,153	$4,280,862	$1,113,024	Yes	Yes
323	Third Party	QF	State	43.2	ID	230	Wind		$8,500,000	***New point of interconnection substation, protection and communications equipment upgrades.	$8,500,000	$0	$0	$0	$0	Yes	No
324	Third Party	QF	State	80	UT	138	Solar		$875,000	**Substation expansion, protection and communications equipment upgrades.	$875,000	$0	$0	$0	$0	Yes	No
384	Third Party	QF	State	60	UT	138	Wind		$1,500,000	**Substation expansion, protection and communications equipment upgrades.	$1,500,000	$0	$0	$0	$0	Yes	No
442	Third Party	QF	State	5.6	ID	69	Natural Gas		$150,000	**Communications and protection equipment upgrades.	$150,000	$0	$0	$0	$0	Yes	No
450	Third Party	QF	State	50	UT	46	Solar		$1,400,000	**Substation expansion, protection and communications equipment upgrades.	$1,400,000	$0	$0	$0	$0	Yes	No
513	Third Party	QF	State	80	UT	138	Solar		$2,100,000	**Substation expansion, protection and communications equipment upgrades.	$2,100,000	$0	$0	$0	$0	Yes	No
514	Third Party	QF	State	80	UT	138	Solar		$4,000,000	**New point of interconnection substation, protection and communications equipment upgrades.	$4,000,000	$0	$0	$0	$0	Yes	No
515	Third Party	QF	State	80	UT	345	Solar		$8,500,000	**New point of interconnection substation, protection and communications equipment upgrades.	$8,500,000	$0	$0	$0	$0	Yes	No
539	Third Party	QF	State	130.4	UT	138	Solar		$5,000,000	***New point of interconnection substation, protection and communications equipment upgrades.	$5,000,000	$0	$0	$0	$0	Yes	No
564	Third Party	QF	State	80	UT	138	Solar		$850,000	**Substation expansion, protection and communications equipment upgrades.	$850,000	$0	$0	$0	$0	Yes	No
566	Third Party	QF	State	8.5	OR	69	Solar		$1,500,000	**Substation expansion, protection and communications equipment upgrades.	$1,500,000	$0	$0	$0	$0	Yes	No
594	Third Party	NO	Federal	56	OR	115	Solar	10/31/2017	$1,561,839	Substation expansion, protection and communications equipment upgrades.	$0	$1,561,839	$296,749	$1,265,090	$328,923	Yes	Yes
684	Third Party	NO	Federal	20	UT	46	Solar	12/23/2016	$1,171,128	Substation expansion.	$0	$1,171,128	$222,514	$948,614	$246,640	Yes	Yes
729 & 780	Third Party	NO	Federal	47.25	OR	115	Solar	12/23/2019	$5,272,105	New point of interconnection substation, protection and communications equipment upgrades.	$0	$5,272,105	$1,001,700	$4,270,405	$1,110,305	Yes	Yes
795	Third Party	QF	State	20	WY	69	Solar		$4,575,747	**Substation expansion, protection and communications equipment upgrades.	$4,575,747	$0	$0	$0	$0	Yes	No
796	Third Party	QF	State	20	WY	69	Solar		$6,000,000	**New substation transformer, substation expansion	$6,000,000	$0	$0	$0	$0	Yes	No

*Indicates interconnection request that was submitted by a third party originally but rights were purchased by PacifiCorp at later stage in process.
** Indicates that the actual cost of these network upgrades are an estimate because interconnection facilities costs and network upgrades costs were not accounted for separately.
*** Indicates that the actual cost of these network upgrades are an estimate because interconnection facilities costs and network upgrades costs were not accounted for separately. Additionally some of the network upgrades were constructed by the interconnection customer so those actual costs are also estimated.

OPUC Information Request 13

Customer Indifference
Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of Network Upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please list all Network Upgrades that the Company has constructed since 2010. Please also include Network Upgrades that would match this definition if not for the reference to large generating facility. Please include the following information for each year since the upgrade was in service through 2019 inclusive:

(a) Interconnection queue number of the generator(s) that triggered the upgrade.

(b) Whether the generator(s) are owned by the Company.

(c) Cost of the upgrade borne by the generator(s).

(d) Cost of the upgrade borne by ratepayers.

(e) Cost of the upgrade borne by other transmission customers.

(f) Transmission revenues generated by the upgrade.

In conversations with Staff, Staff has clarified that PacifiCorp should provide the following information to this response:

- All network upgrades put in service since 2010 - 2019 by generator
- Queue number
- Location of generator (state)
- Ownership of generator, including whether the ownership changed during the course of the interconnection process
- Jurisdiction over interconnection
- Total cost of the network upgrades constructed for that queue number

For each customer's network upgrades identified in Phase one between 2010 - 2019, provide

- The total cost of the network upgrades
- The portion of the total cost provided by interconnection customer, including whether the portion was provided by interconnection customer upfront or in some other way.

- Whether the interconnection customer was or is being reimbursed for their contribution to network upgrades and by whom.
- If the interconnection customer did not provide all upfront capital for network upgrades, identify who also contributed to upfront capital (i.e., PAC merchant function), and specify what portion they provided and whether this entity(s) is being reimbursed (i.e., from PAC transmission revenues).

2nd Supplemental Response to OPUC Information Request 13

In further support of the Company's 1st Supplemental Response to OPUC Information Request 13, dated October 9, 2020, the Company has become aware of a minor error in Attachment OPUC 13-1 1st Supplemental. Specifically, the dollar amount included in cell M11 was incorrect. A corrected attachment is provided as Attachment OPUC 13-1 2nd Supplemental. This attachment replaces the original in its entirety. There are no changes to the narrative response or to Confidential Attachment OPUC 13-2 1st Supplemental.

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OPUC 13

Attachment OPUC 13-1 2nd Supplemental

Q#	Ownership	QF?	Jurisdiction	Size (MW)	ST	Voltage (kV)	Type	In-Service Date	Actual Interconnection Network Upgrade Costs	Description of Network Upgrades	Costs Borne by Generator	Costs Borne by Ratepayers/ Transmission Customers	19% Allocation to Transmission Customers	81% Allocation to Retail Customers	Approximate 26% Allocation in Oregon Retail Customers	Did IC Upfront All Capital?	Was/Is IC Being Reimbursed?
102-106 145-147	Third Party	QF	State	64.55	OR	69	Wind		$3,500,000	**Substation expansion, protection and communications equipment upgrades, transmission line rebuild.	$3,500,000	$0	$0	$0	$0	Yes	No
117-118*	PacifiCorp	NO	Federal	118.5	WY	230	Wind	1/3/2009	$8,213,183	New point of interconnection substation, protection and communications equipment upgrades.	$0	$8,213,183	$1,560,505	$6,652,678	$1,729,696	Yes	Yes
119	PacifiCorp	NO	Federal	127.5	WY	230	Wind	9/30/2009	$1,462,379	Substation expansion, protection and communications equipment upgrades.	$0	$1,462,379	$277,852	$1,184,527	$307,977	Yes	Yes
122	Third Party	NO	Federal	10.8	WA	230	Wind	6/27/2008	$70,347	Communications and protection equipment upgrades.	$0	$70,347	$13,366	$56,981	$14,815	Yes	Yes
126	PacifiCorp	NO	Federal	239	WY	230	Wind	1/2/2009	$16,518,007	New point of interconnection substation, protection and communications equipment upgrades.	$0	$16,518,007	$3,138,421	$13,379,586	$3,478,692	Yes	Yes
129	Third Party	NO	Federal	4.8	UT	46	Biogas	4/1/2009	$497,883	Communications and protection equipment upgrades.	$0	$497,883	$94,598	$403,285	$104,854	Yes	Yes
153	Third Party	NO	Federal	200.5	WY	230	Wind	10/28/2010	$1,819,811	Substation expansion, protection and communications equipment upgrades.	$0	$1,819,811	$345,764	$1,474,047	$383,252	Yes	Yes
171	Third Party	QF	State	16.5	WY	69	Wind		$650,000	**Substation expansion, protection and communications equipment upgrades.	$650,000	$0	$0	$0	$0	Yes	No
203	PacifiCorp	NO	Federal	123	WY	230	Wind	9/30/2010	$10,499,932	New point of interconnection substation, protection and communications equipment upgrades.	$0	$10,499,932	$1,994,987	$8,504,945	$2,211,286	Yes	Yes
220	Third Party	NO	Federal	99	WY	230	Wind	12/1/2009	$5,120,466	New point of interconnection substation, protection and communications equipment upgrades.	$0	$5,120,466	$972,889	$4,147,577	$1,078,370	Yes	Yes
248	Third Party	QF	State	5	OR	69	Hydro		$500,000	**New point of interconnection substation, protection and communications equipment upgrades.	$500,000	$0	$0	$0	$0	Yes	No
301	PacifiCorp	NO	Federal	625	UT	345	Natural Gas	5/8/2014	$13,323,330	New point of interconnection substation, protection and communications equipment upgrades.	$0	$13,323,330	$2,531,433	$10,791,897	$2,805,893	Yes	Yes
306	Third Party	QF	State	40	WY	230	Wind		$7,500,000	***New point of interconnection substation, protection and communications equipment upgrades.	$7,500,000	$0	$0	$0	$0	Yes	No
313	Third Party	NO	Federal	25	UT	138	Geothermal	12/11/2013	$5,285,015	New point of interconnection substation, protection and communications equipment upgrades.	$0	$5,285,015	$1,004,153	$4,280,862	$1,113,024	Yes	Yes
323	Third Party	QF	State	43.2	ID	230	Wind		$8,500,000	***New point of interconnection substation, protection and communications equipment upgrades.	$8,500,000	$0	$0	$0	$0	Yes	No
324	Third Party	QF	State	80	UT	138	Solar		$875,000	**Substation expansion, protection and communications equipment upgrades.	$875,000	$0	$0	$0	$0	Yes	No
384	Third Party	QF	State	60	UT	138	Wind		$1,500,000	**Substation expansion, protection and communications equipment upgrades.	$1,500,000	$0	$0	$0	$0	Yes	No
442	Third Party	QF	State	5.6	ID	69	Natural Gas		$150,000	**Communications and protection equipment upgrades.	$150,000	$0	$0	$0	$0	Yes	No
450	Third Party	QF	State	50	UT	46	Solar		$1,400,000	**Substation expansion, protection and communications equipment upgrades.	$1,400,000	$0	$0	$0	$0	Yes	No
513	Third Party	QF	State	80	UT	138	Solar		$2,100,000	**Substation expansion, protection and communications equipment upgrades.	$2,100,000	$0	$0	$0	$0	Yes	No
514	Third Party	QF	State	80	UT	138	Solar		$4,000,000	**New point of interconnection substation, protection and communications equipment upgrades.	$4,000,000	$0	$0	$0	$0	Yes	No
515	Third Party	QF	State	80	UT	345	Solar		$8,500,000	**New point of interconnection substation, protection and communications equipment upgrades.	$8,500,000	$0	$0	$0	$0	Yes	No
539	Third Party	QF	State	130.4	UT	138	Solar		$5,000,000	***New point of interconnection substation, protection and communications equipment upgrades.	$5,000,000	$0	$0	$0	$0	Yes	No
564	Third Party	QF	State	80	UT	138	Solar		$850,000	**Substation expansion, protection and communications equipment upgrades.	$850,000	$0	$0	$0	$0	Yes	No
566	Third Party	QF	State	8.5	OR	69	Solar		$1,500,000	**Substation expansion, protection and communications equipment upgrades.	$1,500,000	$0	$0	$0	$0	Yes	No
594	Third Party	NO	Federal	56	OR	115	Solar	10/31/2017	$1,561,839	Substation expansion, protection and communications equipment upgrades.	$0	$1,561,839	$296,749	$1,265,090	$328,923	Yes	Yes
684	Third Party	NO	Federal	20	UT	46	Solar	12/23/2016	$1,171,128	Substation expansion.	$0	$1,171,128	$222,514	$948,614	$246,640	Yes	Yes
729 & 780	Third Party	NO	Federal	47.25	OR	115	Solar	12/23/2019	$5,272,105	New point of interconnection substation, protection and communications equipment upgrades.	$0	$5,272,105	$1,001,700	$4,270,405	$1,110,305	Yes	Yes
795	Third Party	QF	State	20	WY	69	Solar		$4,575,747	**Substation expansion, protection and communications equipment upgrades.	$4,575,747	$0	$0	$0	$0	Yes	No
796	Third Party	QF	State	20	WY	69	Solar		$6,000,000	**New substation transformer, substation expansion	$6,000,000	$0	$0	$0	$0	Yes	No

*Indicates interconnection request that was submitted by a third party originally but rights were purchased by PacifiCorp at later stage in process.
** Indicates that the actual cost of these network upgrades are an estimate because interconnection facilities costs and network upgrades costs were not accounted for separately.
*** Indicates that the actual cost of these network upgrades are an estimate because interconnection facilities costs and network upgrades costs were not accounted for separately. Additionally some of the network upgrades were constructed by the interconnection customer so those actual costs are also estimated.

OPUC Information Request 14

Customer Indifference
Please refer to Vail-Bremer-Foster-Larson-Ellsworth/7 of the Joint Utility Opening Testimony, which provides the FERC definition of network upgrades, " [T]he additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System." Please identify all Network Upgrades matching this definition that the Company included or seeks to include in rate base in the Company's most recently filed General Rate Case. Please also include Network Upgrades that would match this definition if not for the reference to large generating facility. For all Network Upgrades identified, please indicate the following:

(a) Description of upgrade, including location, equipment, size or rating, and cost.

(b) How that investment was identified.

(c) How the costs were allocated to Oregon and includable in state revenue requirements, as well as each state where PacifiCorp serves retail load.

Response to OPUC Information Request 14

(a) The generation interconnections projects with network upgrades included in the most recent general rate case are described below. Costs and description are for the network upgrade portion of the projects.

East Side

- **Q0641 Cove Mountain Solar ($8 million)** - The project interconnects 58 megawatts (MW) of new generation to PacifiCorp's 138 kilovolts (kV) bus at Enterprise Valley substation located in Washington County, Utah. The project is not considered a qualifying facility (QF) and per the Open Access Transmission Tariff (OATT) PacifiCorp must accommodate the customer request. The network upgrade work includes adding a 138 kV four breaker ring bus and new control house at the Enterprise Valley substation; looping in 138 kV lines to Red Butte and West Cedar substations; developing new relay settings at Red Butte substation; adding protection and controls equipment and settings at Holt substation; and modifying communications equipment at the control centers.

- **Q754 Steel Solar ($2.5 million)** - The project interconnects 80 MW of new generation to PacifiCorp's 138 kV line east of Washakie substation located in Box Elder County, Utah. The project is not considered a QF and per the OATT

PacifiCorp must accommodate the customer request. The Network upgrade work for this project includes installation of a new three breaker ring bus substation for the Point of Interconnection (POI), including all appurtenant metering and communication equipment and the loop in/out of the Wheelon-Nucor 138 kV transmission line at the new POI substation.

- **Q737 Cove Mountain Solar 2, LLC ($8.6 million)** - The project interconnects 122 MW of new generation to PacifiCorp's Enterprise Valley substation 138 kV bus located in Washington County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes new relaying and communications equipment at the Enterprise Valley substation. Communications and relaying to be installed at the Richfield service center and Holt, West Cedar, Clover, and Sigurd substations to support a Remedial Action Scheme (RAS).

- **Q589 Sigurd Solar, LLC ($2.2 million)** - The project interconnects 80 MW of new generation to PacifiCorp's Sigurd 230 kV substation located in Sevier County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes adding a new breaker, dead-end, switches, and other protection and control equipment at Sigurd substation. As well as updating communications at Salt Lake Control Center.

- **Q0766 Hunter Solar, LLC ($13.2 million)** - The project interconnects 100 MW of new generation to PacifiCorp's Emery 138 kV substation located in Emery County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes construction of a new communications site, conversion and build-out of the Emery substation bus, and the reconductor of approximately 3.1 miles of the Black Hawk – Ferron 69 kV line.

- **Q764 Graphite Solar ($4.2 million)** - The project interconnect 80 MW of new generation to PacifiCorp's Mathington 138 kV substation located in Carbon County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes: new RAS panel at Carbon substation; a new bay and RAS master at Mathington substation; and a new reactor and RAS panel at Spanish Fork substation.

- **Q0781 Elektron Solar ($1.4 million)** - This project interconnects 80 MW of new generation to PacifiCorp's Craner Flat 138 kV substation located in Tooele County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes: a new circuit breaker at Craner Flat substation to tap to Homestead Knoll – Horseshoe transmission line; and modification of communications equipment and settings at Homestead and Horseshoe substations.

- **Q0763 Appaloosa Solar I, LLC Interconnection ($20.3 million)** - This project interconnects 200.25 MW of new generation to PacifiCorp's Three Peaks 345 kV substation located in Iron County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes: installation of line loss panels at Red Butte substation and Sigurd substation; a new bay, breaker and switch at Three Peaks substation; and the rebuild of 45 miles of the Sigurd-Tushar transmission line.

- **Q0631 Milford Solar 1, LLC - Interconnection ($3.3 million)** - This project interconnects 99 MW of new generation to PacifiCorp's Hickory 345 kV substation located in Beaver County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. Network upgrade work includes expanding Hickory substation and adding a new 345 kV position and related communication/relay equipment.

- **Q0786 Echo Divide Wind ($8.2 million)** - This project interconnects 100 MW of new generation to PacifiCorp's Evanston-Anschutz 138 kV line located in Summit County, Utah. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes: a new 138 kV three (3) breaker ring bus at the POI substation; the loop in and out of the transmission line; reconductoring the Croydon-Railroad line; replacing jumpers at Canyon Compression and Carter Creek substation; new communications and protections and controls equipment at Evanston and Railroad substations; new communications equipment at Medicine Butte substation; and new fiber from POI to Evanston and Railroad substations.

West Side

- **Q0621 Prineville Solar Energy, LLC ($1.1 million)** - The project is to interconnect 55 MW of new generation to PacifiCorp's Baldwin Road substation located in Crook County, Oregon. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes the expansion of Baldwin substation, installation of a new breaker and bay, rerouting the transmission line, and installation of switches, voltage transformers and communications equipment. As well as, installation of communication upgrades at Bend PDO, Houston Lake substation, and Portland Control Center.

- **Q0850 Invenergy - Millican Solar ($8.3 million)** - The project is to interconnect 60.75 MW of new generation to PacifiCorp's Ponderosa – Houston Lake 115 kV transmission line located in Crook County, Oregon. The project is not considered a QF and per the OATT PacifiCorp must accommodate the customer request. The network upgrade work includes: a new three-breaker ring bus substation; a transmission line loop-in/out at the POI substation; installation of fiber optic cable to both Ponderosa and Houston Lake substations; and reconductor of the Powell Butte-Redmond transmission line.

(b) Network upgrades that went into service by June 30, 2019, are included in the actual Base Period accounting data in PacifiCorp's pending general rate case (GRC), UE 374. The cost of these projects are included in the Transmission Plant balances in the "Unadjusted Results" columns on pages McCoy/31 – 32 of Exhibit PAC/1302 in UE 374. Network upgrades with an in-service date of July 1, 2019, through December 30, 2020, are included on page McCoy/16 of Confidential Exhibit PAC/1309.

(c) All transmission costs are allocated to Oregon and PacifiCorp's other state jurisdictions per the approved allocation methodologies. In the pending Oregon GRC, the 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol) was utilized to allocate transmission rate base and expenses on the System Generation (SG) factor. The 2020 Protocol was approved by the Public Utility Commission of Oregon with Order 20-024 on January 23, 2020. Previously approved allocation methodologies also allocated transmission costs utilizing the SG factor. PacifiCorp's other five state commissions have either approved or approval is pending to allocate transmission costs using the SG factor. Each state's revenue requirement calculation includes its allocation of transmission rate base and expenses.

NIPPC Data Request 3

For each state jurisdictional qualifying facility interconnection, please provide (or identify a publicly available location for accessing) the feasibility study, system impact study, facilities study, interconnection study, the final accounting with actual interconnection costs, and identify all network upgrades.

Response to NIPPC Data Request 3

Based on conversations with counsel for the Northwest and Intermountain Power Producers Coalition (NIPPC), PacifiCorp understands "interconnection study" means "interconnection agreement." In addition, PacifiCorp understands that this request encompasses only interconnections for which Network Upgrades were identified. Based on the foregoing understanding, the Company responds as follows:

All studies are available on PacifiCorp's Open Access Same-Time Information System (OASIS) webpage, which can be accessed using the following website link:

http://www.oasis.oati.com/ppw/index.html

Please refer to Attachment NIPPC 3-1 for actual costs. Please refer to Confidential Attachment NIPPC 3-2 for copies of the interconnection agreements.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UM 2032 / PacifiCorp
May 27, 2021
NIPPC Data Request 3 – 1st Supplemental

NIPPC Data Request 3

For each state jurisdictional qualifying facility interconnection, please provide (or identify a publicly available location for accessing) the feasibility study, system impact study, facilities study, interconnection study, the final accounting with actual interconnection costs, and identify all network upgrades.

1st Supplemental Response to NIPPC Data Request 3

In further support of PacifiCorp's September 25, 2020 response, the Company provides the following supplemental response:

Please refer to Attachment NIPPC 3-1 1st Supplemental for additional interconnection agreements responsive to this request.

In addition, the interconnection agreements provided with the Company's original response were incorrectly designated as confidential. Interconnection agreements are not confidential. A replacement attachment, which includes the same agreements provided September 25, 2020, but without the confidential designation, is provided here as Attachment NIPPC 3-2 1st Revised.

NIPPC Data Request 8

For each generator that has interconnected to PacifiCorp's system and achieved commercial operation in the past 30 years under a FERC-jurisdictional interconnection, provide the following information:

(a) Capacity of the facility (as measured by interconnection capacity).

(b) Type of generation resource (e.g., wind, solar, hydropower).

(c) Whether the generator is owned by PacifiCorp or a third party.

(d) Cost of Interconnection Facilities (using the definition in FERC's Order No. 2003, which is facilities up to the point of interconnection), including both costs in the final Facilities Study and the actual costs after construction was complete.

(e) Cost of Network Upgrades (using the definition in FERC's Order No. 2003, which is facilities at or beyond the point of interconnection) including both costs in the final Facilities Study and the actual costs after construction was complete.

(f) If the amounts for any facilities in (d) and (e) for the final Facilities Study and the actual costs after construction differ, explain the reason for the difference.

(g) For the Network Upgrades identified in subpart D for each facility, please explain whether PacifiCorp agrees that any of the facilities are used by other users of the system or PacifiCorp and identify facilities not used solely by the QF.

Response to NIPPC Data Request 8

PacifiCorp objects that this request for 30 years of data is overly broad, unduly burdensome, and seeks information that is not relevant to this case nor reasonably calculated to lead to the discovery of relevant evidence. In particular, interconnections that occurred before the Federal Energy Regulatory Commission's (FERC) Order 2003 took effect did not include the defined terms of network resource interconnection service (NRIS), energy resource interconnection service (ERIS), Network Upgrades, or interconnection facilities. Notwithstanding and without waiving these objections, PacifiCorp responds as follows:

a-f. Please refer to Attachment NIPPC 8.

g. PacifiCorp objects that this request is vague and ambiguous in that it references "QFs" but requests data regarding FERC-jurisdictional interconnections. Notwithstanding and without waiving this objection, PacifiCorp responds as follows:

The need for a particular Network Upgrade can be triggered by a specific generator, but the usage of specific components of the transmission system are not isolated for use by a single user and change over time.

OR - Um 20332
NIPPC 8

Attachment NIPPC 8

Q#	QF?	Size (MW)	ST	Voltage (kV)	Type	Estimated Interconnection Facilities Costs from Facilities Study	Estimated Interconnection Network Upgrade Costs from Facilities Study
117-118	NO	118.5	WY	230	Wind	$736,546	$472,522
119	NO	127.5	WY	230	Wind	$1,160,901	$1,535,683
122	NO	10.8	WA	230	Wind	$18,758	$0
126	NO	239	WY	230	Wind	$1,348,474	$11,763,946
129	NO	4.8	UT	46	Biogas	$124,643	$374,964
153	NO	200.5	WY	230	Wind	$1,767,153	$2,202,630
203	NO	123	WY	230	Wind	$870,000	$9,913,000
220	NO	99	WY	230	Wind	$159,400	$1,445,600
284	NO	6	OR	115	Hydro	$166,419	$80,616
301	NO	625	UT	345	Natural Gas	$3,061,000	$20,475,000
313	NO	25	UT	138	Geothermal	$2,500,000	$6,153,000
549	NO	3.6	UT	138	Other	$26,200	$0
594	NO	56	OR	115	Solar	$1,052,000	$1,243,000
639	NO	2	UT	46	Solar	$27,000	$0
684	NO	20	UT	46	Solar	$941,000	$1,608,000
729 & 780	NO	47.25	OR	115	Solar	$96,000	$6,061,000
852	NO	1	UT	46	Battery	$12,000	$0

OR - Um 20332
NIPPC 8

Attachment NIPPC 8

Actual Interconnection Facility Costs	Actual Interconnection Network Upgrade Costs
$1,414,534	$8,213,183
$685,930	$1,462,379
$192,756	$70,347
$601,383	$16,518,007
$299,792	$497,883
$394,379	$1,819,811
$171,653	$10,499,932
$452,393	$949,852
$74,581	$0
$964,897	$13,323,330
$460,615	$5,285,015
$42,965	$0
$888,911	$1,561,839
$2,277	$0
$683,435	$1,171,128
$455,113	$5,272,105
$10,930	$0

Explaination of cost variance

Study assumed interconnection customer would construct stand alone network upgrades but Transmission Provider did the construction increasing the Transmission Provider's costs.

Within estimate accuracy

No records could be found with the data requested due to the age of the project.

No records could be found with the data requested due to the age of the project.

Additional work identified as necessary during detailed design.

Portions of direct assign scope were performed by interconnection customer which led to lower costs for the Transmission Provider.

Within estimate accuracy

Within estimate accuracy

Lower than anticipated design and construction costs. Costs listed as network upgrades in study were misclassified as all costs for this request were direct assigned.

Lower than anticipated design and construction costs.

Interconnection customer did not construct the entire output that was studied therefore work associated with phase 2 were cancelled lower costs. There were also lower than expected costs for the work that was completed.

Design change by interconnection customer required rework by Transmission Provider which led to increased costs.

Additional work required due to a delay of a higher priority interconnection request assumed to be in service.

Lower than anticipated labor support costs.

Design and construction efficiencies due to parallel work on Q0532 led to lower costs.

Within estimate accuracy

Within estimate accuracy

UM 2032 / PacifiCorp
September 18, 2020
NIPPC Data Request 16

NIPPC Data Request 16

Please refer to Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/8-9. Please identify all instances in which a FERC jurisdictional interconnection network upgrade resulted in quantified system-wide benefits to PacifiCorp's transmission or distribution system. For each instance, please identify the specific upgrade, dollar amount, any interconnection studies or agreements, and whether the generation facility was owned by PacifiCorp.

Response to NIPPC Data Request 16

The Federal Energy Regulatory Commission (FERC) has determined as a matter of policy, rather than as a matter of fact, that Network Upgrades provide presumptive benefits to transmission and interconnection customers in connection with the development of competitive wholesale markets under the Federal Power Act (FPA). FERC does not quantify the actual costs or benefits that the construction of specific transmission system facilities may have on the wider system, nor does it require others to do so. Consequently, PacifiCorp lacks the information to respond to this request. To the extent the question asks about the "distribution system", PacifiCorp is unaware of any theory under which a FERC-jurisdictional "network upgrade" would result in upgrades to the "distribution system" that might conceivably provide "system-wide benefits".

NIPPC Data Request 27

Please refer to Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/24 lines 2-5. Please identify any FERC jurisdictional Network Upgrades that did not result in system benefits to other interconnection customers.

Response to NIPPC Data Request 27

PacifiCorp assumes the Northwest and Intermountain Power Producers Coalition (NIPPC) is referring in this data request to the Federal Energy Regulatory Commission's (FERC) definition of "system benefits" under the Federal Power Act (FPA); that is, the benefits FERC presumes accrue to all transmission and interconnection customers under the FPA (rather than "system benefits" that may accrue to retail electric customers under state regulatory policy, state law, or PURPA). It is not possible to identify whether specific FERC-jurisdictional Network Upgrades resulted in *actual* "system benefits" under the FPA. FERC has determined as a matter of policy, rather than as a matter of fact, that Network Upgrades provide presumptive benefits to transmission and interconnection customers in connection with the development of competitive wholesale markets under the FPA. FERC does not quantify the actual costs or benefits that the construction of specific transmission system facilities may have on the wider system, nor does it require others to do so. Consequently, PacifiCorp lacks the information to respond to this request.

NIPPC Data Request 34

Please refer to Joint Utilities/400, Vail/Bremer/Foster/Larson/Ellsworth/2:5-7 ("Transmission planners engage in comprehensive transmission system planning precisely because not all transmission system upgrades have equivalent value and not all benefit retail customers")
Is it the position of PacifiCorp that every Network Upgrade that benefits customers is identified in comprehensive transmission system planning? If so, please provide support for PacifiCorp's conclusion.

Response to NIPPC Data Request 34

PacifiCorp's position, as stated in the Joint Utilities' testimony, is that the Public Utility Commission of Oregon does not deem all transmission upgrades appropriate for inclusion in retail rates, even if a particular upgrade may provide some unspecified or hypothetical benefit. Utilities are required to engage in transmission system planning and least-cost, least-risk analysis to identify where transmission upgrades may be justified for cost or reliability purposes.

NewSun Information Request 1.6

Please list all power purchase agreements under which PacifiCorp purchases power including:

(a) Project name,

(b) Nameplate capacity,

(c) Term of power purchases,

(d) Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,

(e) Whether the facility is certified as a qualifying facility under PURPA,

(f) Under what interconnection rules/process the facility was interconnected,

(g) Whether the facility interconnected as ERIS or NRIS,

(h) The cost of network upgrades funded under the interconnection agreement,

(i) Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,

(j) The type of transmission service,

(k) The entity that submitted the transmission service request, and

(l) The cost of network upgrades funded under the transmission service request.

Response to NewSun Information Request 1.6

PacifiCorp objects to this data request to the extent it is overly broad, unduly burdensome, and seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding and without waiving this objection, PacifiCorp responds as follows:

Please refer to Attachment NewSun 1.6 and to the Company’s responses to the following NewSun Information Requests: NewSun Information Request 1.8 and supportive documentation, NewSun Information Request 1.10, NewSun Information Request 1 .24, and NewSun Information Request 1.26.

OR UM 2032
NewSun 1.6

Attachment NewSun 1.6

(a) Name	State	(b) MW	(c) Term (Years)[1]	(d) Agreement Source	(e) Qualifying Facility (QF)
Adams Solar Center, LLC	OR	10.00	20	PURPA	QF
Appaloosa Solar I, LLC	UT	120.00	20	RFP	Non-QF
Appaloosa Solar I, LLC	UT	80.00	20	RFP	Non-QF
BC Solar, LLC	OR	8.00	20	PURPA	QF
Bear Creek Solar Center, LLC	OR	10.00	20	PURPA	QF
Bell Mountain Hydro LLC (Ted Sorenson)	ID	0.28	20	PURPA	QF
Bell Mountain Power (Jake Amy)	ID	0.45	35	PURPA	QF
Beryl Solar, LLC	UT	3.00	20	PURPA	QF
Big Top LLC	OR	1.65	20	PURPA	QF
Biomass One, L.P.	OR	32.50	15	PURPA	QF
Birch Creek Hydro	ID	2.65	35	PURPA	QF
Birch Creek Hydro	ID	2.65	20	PURPA	QF
Black Cap Solar	OR	2.00	16	RFP	Non-QF
Bly Solar Center, LLC	OR	8.50	20	PURPA	QF
Bogus Creek	CA	0.16	50	PURPA	QF
Brigham Young University Idaho	ID	5.60	20	PURPA	QF
Buckhorn Solar, LLC	UT	3.00	20	PURPA	QF
Bureau of Land Management - Rawlins Office	WY	0.10	10	PURPA	QF
Butter Creek Power LLC	OR	4.95	20	PURPA	QF
C Drop Hydro, LLC	OR	1.10	15	PURPA	QF
Captain Jack Solar	OR	2.70	20	PURPA	QF
Cargill, Q3 (Kettle Butte Dairy)	ID	1.70	10	PURPA	QF
Castle Solar, LLC	UT	20.00	25	RFP	Non-QF
CDM Hydro	ID	7.45	20	PURPA	QF
Cedar Springs Wind III, LLC	WY	133.30	20	RFP	Non-QF
Cedar Springs Wind, LLC	WY	199.40	20	RFP	Non-QF
Cedar Valley Solar, LLC	UT	3.00	20	PURPA	QF
Central Oregon Irrigation District (COID) (Juniper Ridge)	OR	5.00	20	PURPA	QF
Central Oregon Irrigation District (COID) (Siphon)	OR	6.00	35	PURPA	QF
Chiloquin Solar, LLC	OR	9.90	20	PURPA	QF
Chopin Wind, LLC	OR	10.00	20	PURPA	QF
City of Albany, Department of Public Works	OR	0.50	15	PURPA	QF
City of Astoria	OR	0.03	15	PURPA	QF
City of Buffalo	WY	0.20	5	PURPA	QF
City of Portland, Portland Water Bureau	OR	0.03	15	PURPA	QF

OR UM 2032
NewSun 1.6

Attachment NewSun 1.6

Combine Hills I, LLC	OR	41.00	20	RFP	Non-QF
Commercial Energy Management	ID	0.90	30	PURPA	QF
Consolidated Irrigation Company	ID	0.48	20	PURPA	QF
Cottonwood Hydro Lower	UT	0.85	10	PURPA	QF
Cottonwood Hydro Upper	UT	0.26	10	PURPA	QF
Cove Mountain Solar 2, LLC	UT	122.00	25	RFP	Non-QF
Cove Mountain Solar, LLC	UT	58.00	25	RFP	Non-QF
Deschutes Valley Water District (Opal Springs)	OR	5.93	15	PURPA	QF
Deseret Generation & Transmission	UT	100.00	20	Bilateral	Non-QF
Dorena Hydro, LLC	OR	6.10	20	PURPA	QF
Douglas County Forest Products	OR	6.25	10	PURPA	QF
Draper Irrigation Company	UT	0.51	20	PURPA	QF
Dry Creek (Birch Power)	ID	4.00	35	PURPA	QF
Eagle Point Irrigation District (Nichols Gap)	OR	0.72	35	PURPA	QF
eBay	UT	0.52	10	PURPA	QF
EBD Hydro, LLC (45 Mile Hydro)	OR	2.99	15	PURPA	QF
Elbe Solar Center, LLC	OR	10.00	20	PURPA	QF
Elektron Solar	UT	10.24	20	RFP	Non-QF
Elektron Solar	UT	69.76	25	RFP	Non-QF
Enterprise Solar LLC	UT	80.00	20	PURPA	QF
Escalante Solar I LLC	UT	80.00	20	PURPA	QF
Escalante Solar II LLC	UT	80.00	20	PURPA	QF
Escalante Solar III LLC	UT	80.00	20	PURPA	QF
ExxonMobile Production Company (Shute Creek)	WY	107.40	3	PURPA	QF
Farm Power Misty Meadow, LLC	OR	0.75	15	PURPA	QF
Farmers Irrigation District	OR	4.80	15	PURPA	QF
Finley Bioenergy, LLC	OR	4.80	15	PURPA	QF
Four Corners Windfarm LLC	OR	10.00	20	PURPA	QF
Four Mile Canyon Windfarm LLC	OR	10.00	20	PURPA	QF
Galesville Dam (Douglas County)	OR	1.80	35	PURPA	QF
Georgetown Power	ID	0.33	30	PURPA	QF
Granite Mountain - East	UT	80.00	20	PURPA	QF
Granite Mountain - Wet	UT	50.40	20	PURPA	QF
Granite Peak Solar, LLC	UT	3.00	20	PURPA	QF
Graphite Solar I, LLC	UT	80.00	15	RFP	Non-QF
Greenville Solar, LLC	UT	2.19	20	PURPA	QF
Hayward Paul Luckey	CA	0.05	2	PURPA	QF
Hill Air Force Base	UT	2.46	20	PURPA	QF

OR UM 2032
NewSun 1.6

Attachment NewSun 1.6

Horseshoe Solar, LLC	UT	75.00	25	RFP	Non-QF
Hunter Solar, LLC	UT	100.00	25	RFP	Non-QF
Iron Springs	UT	80.00	20	PURPA	QF
J Bar 9 Ranch	WY	0.10	7	PURPA	QF
Kennecott Utah Copper, LLC (Refinery)	UT	7.54	2	PURPA	QF
Kennecott Utah Copper, LLC (Smelter)	UT	31.80	2	PURPA	QF
Klamath Falls Solar 1, LLC	OR	0.83	20	PURPA	QF
Klamath Falls Solar 2, LLC	OR	2.90	20	PURPA	QF
Lacomb Irrigation Limited Partnership	OR	0.96	35	PURPA	QF
Laho Solar, LLC	UT	3.00	20	PURPA	QF
Lake Siskiyou (Box Canyon)	CA	5.00	35	PURPA	QF
Latigo Wind	UT	60.00	20	PURPA	QF
Loyd Fery	OR	0.07	3	PURPA	QF
Marsh Valley Hydro & Electric Company	ID	1.70	40	PURPA	QF
Meadow Creek Project Company - Five Pine	ID	39.90	20	PURPA	QF
Meadow Creek Project Company - North Point	ID	79.80	20	PURPA	QF
Mid-Columbia Hydro	-	170.00	35	Bilateral	Non-QF
Middle Fork Irrigation District	OR	3.70	15	PURPA	QF
Milford Flat Solar, LLC	UT	3.00	20	PURPA	QF
Milford Solar I, LLC	UT	99.00	25	RFP	Non-QF
Millican Solar Energy, LLC	OR	60.00	20	RFP	Non-QF
Mink Creek Hydro (Robert Fackrell)	ID	2.70	35	PURPA	QF
Monroe Hydro, LLC	OR	0.30	15	PURPA	QF
Mountain Energy, Inc	OR	0.05	15	PURPA	QF
Mountain Wind 1	WY	60.90	25	PURPA	QF
Mountain Wind 2	WY	79.80	25	PURPA	QF
Nicholson Sunnybar Ranch	ID	0.35	35	PURPA	QF
Norwest Energy 2 LLC (Neff)	OR	9.90	15	PURPA	QF
Norwest Energy 4 LLC (Bonanza)	OR	4.80	15	PURPA	QF
Norwest Energy 7 LLC (Eagle Point)	OR	9.90	15	PURPA	QF
Norwest Energy 9 LLC (Pendleton)	OR	6.00	15	PURPA	QF
O.J. Power Company	ID	0.26	35	PURPA	QF
Old Mill Solar	OR	5.00	25	RFP	Non-QF
OR Solar 2, LLC	OR	10.00	20	PURPA	QF
OR Solar 3, LLC	OR	10.00	20	PURPA	QF
OR Solar 5, LLC	OR	8.00	20	PURPA	QF
OR Solar 6, LLC	OR	10.00	20	PURPA	QF
OR Solar 8, LLC	OR	10.00	20	PURPA	QF

Orchard Wind Farm 1, LLC	OR	10.00	20	PURPA	QF
Orchard Wind Farm 2, LLC	OR	10.00	20	PURPA	QF
Orchard Wind Farm 3, LLC	OR	10.00	20	PURPA	QF
Orchard Wind Farm 4, LLC	OR	10.00	20	PURPA	QF
Oregon Environmental Industries, LLC	OR	3.20	15	PURPA	QF
Oregon Institute of Technology (OIT)	OR	0.28	20	PURPA	QF
Oregon Solar Land Holdings (OSLH, LLC)	OR	9.90	15	PURPA	QF
Oregon State University	OR	6.50	10	PURPA	QF
Oregon Trail Windfarm LLC	OR	9.90	20	PURPA	QF
Pacific Canyon Windfarm LLC	OR	8.25	15	PURPA	QF
Pavant Solar LLC	UT	50.00	20	PURPA	QF
Pavant Solar II LLC	UT	50.00	20	PURPA	QF
Pavant Solar III LLC	UT	20.00	20	RFP	Non-QF
Pioneer Wind Park I LLC	WY	80.00	20	PURPA	QF
Portland General Electric	Not Applicable	3.00		Bilateral	Non-QF
Power County Wind Park North	ID	22.50	20	PURPA	QF
Power County Wind Park South	ID	22.50	20	PURPA	QF
Preston City Hydro	ID	0.40	20	PURPA	QF
Prineville Solar Energy, LLC	OR	40.00	20	RFP	Non-QF
Quichapa Solar 1	UT	3.00	20	PURPA	QF
Quichapa Solar 2	UT	3.00	20	PURPA	QF
Quichapa Solar 3	UT	3.00	20	PURPA	QF
RES Ag - Oak Lea, LLC	OR	0.17	15	PURPA	QF
Rock River I	WY	49.00	20	Bilateral	Non-QF
Rocket Solar, LLC	UT	80.00	25	RFP	Non-QF
Roseburg Forest Products - Weed	CA	10.00	10	PURPA	QF
Roseburg Forest Products Company - Dillard	OR	20.00	10	PURPA	QF
Roseburg Landfill Gas Energy, LLC	OR	1.60	20	PURPA	QF
Sage Solar I, LLC	UT / WY	20.00	20	PURPA	QF
Sage Solar II, LLC	UT / WY	20.00	20	PURPA	QF
Sage Solar III, LLC	UT / WY	17.60	20	PURPA	QF
Sand Ranch Windfarm LLC	OR	9.90	20	PURPA	QF
Shiloh Warm Springs Ranch	ID	0.95	35	PURPA	QF
Sigurd Solar, LLC	UT	80.00	25	RFP	Non-QF
Simplot Phosphates	WY	13.00	4	PURPA	QF
Skysol, LLC	OR	55.00	20	PURPA	QF
Slate Creek	CA	4.20	15	PURPA	QF
Soda Lake Geothermal	NV	20.00	25	RFP	Non-QF

Spanish Fork Wind Park 2	UT	18.90	20	PURPA	QF
Sprague Hydro (North Fork Sprague)	OR	0.75	35	PURPA	QF
St. Anthony Hydro	ID	0.50	20	PURPA	QF
Stahlbush Island Farms, Inc	OR	1.60	4	PURPA	QF
SunEdison DB 18 LLC - South Milford Solar	UT	2.97	20	PURPA	QF
SunEdison DB24 LLC	UT	2.97	20	PURPA	QF
SunEdison Solar XVII Project 1 LLC	UT	3.00	20	PURPA	QF
SunEdison Solar XVII Project 2 LLC	UT	3.00	20	PURPA	QF
SunEdison Solar XVII Project 3 LLC	UT	3.00	20	PURPA	QF
Sunnyside Cogeneration Associates	UT	53.00	35	PURPA	QF
Swalley Irrigation District	OR	0.75	20	PURPA	QF
Sweetwater Solar, LLC	WY	80.00	23	PURPA	QF
Swift 2	WA	51.80		Bilateral	Non-QF
Tata Chemicals	WY	30.00	2	PURPA	QF
Tesoro Refining and Marketing Company	UT	25.00	2	PURPA	QF
Thayn Ranch Hydro	UT	0.58	15	PURPA	QF
Three Buttes Windpower / Campbell Hill	WY	99.00	20	RFP	Non-QF
Three Peaks Power LLC	UT	80.00	20	PURPA	QF
Three Sisters Irrigation District (Watson Hydro) (700 kW)	OR	0.70	15	PURPA	QF
Three Sisters Irrigation District (Watson Hydro) (200 kW)	OR	0.20	20	PURPA	QF
Threemile Canyon Wind I LLC	OR	9.90	20	PURPA	QF
TMF Biofuels	OR	4.80	10	PURPA	QF
Tooele Army Depot (Wind 1)	UT	1.50	10	PURPA	QF
Tooele Army Depot (Wind 2)	UT	1.70	10	PURPA	QF
Top of the World Wind LLC	WY	200.20	20	RFP	Non-QF
Tumbleweed Solar, LLC	OR	9.90	20	PURPA	QF
Utah Red Hills Renewable Park	UT	80.00	20	PURPA	QF
Wagon Trail LLC	OR	3.30	20	PURPA	QF
Ward Butte Windfarm LLC	OR	6.60	20	PURPA	QF
Weber County, State of Utah	UT	0.95	20	PURPA	QF
Wolverine Creek	ID	64.50	20	RFP	Non-QF
Woodline Solar LLC	OR	8.00	20	PURPA	QF
Yakima Tieton (Cowiche)	WA	1.47	10	PURPA	QF
Yakima Tieton (Orchards)	WA	1.44	10	PURPA	QF

Notes:

1. Term is for current transaction as a number of the QFs are PPA renewals.

NewSun Information Request 1.6

Please list all power purchase agreements under which PacifiCorp purchases power including:

(a) Project name,

(b) Nameplate capacity,

(c) Term of power purchases,

(d) Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,

(e) Whether the facility is certified as a qualifying facility under PURPA,

(f) Under what interconnection rules/process the facility was interconnected,

(g) Whether the facility interconnected as ERIS or NRIS,

(h) The cost of network upgrades funded under the interconnection agreement,

(i) Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,

(j) The type of transmission service,

(k) The entity that submitted the transmission service request, and

(l) The cost of network upgrades funded under the transmission service request.

1st Supplemental Response to NewSun Information Request 1.6

In further support of the Company's response to NewSun Information Request 1.6 dated January 21, 2021, the Company responds further as follows:

During discovery conferences with NewSun, PacifiCorp learned that many of NewSun's requests and their multiple subparts, including this request, were also intended to elicit information that would allow NewSun to trace specific generators through the interconnection and transmission service request (TSR) processes. As PacifiCorp explained, PacifiCorp does not compile information or keep records in this manner in the normal course of business. The additional information is voluminous and would be extremely burdensome to compile for all power purchase agreements (PPA), in the event it is even available. Even making the bare linkages from the interconnection queue to the TSR queue for all PPAs would require time-consuming investigation by PacifiCorp personnel and must be done one generator at a time. Thus, to the extent NewSun is asking PacifiCorp to "link up" generators associated with all PPAs from the interconnection process through the TSR process, the data request is overly broad and unduly burdensome. To the extent NewSun further asks PacifiCorp to perform various types of analyses on each generator to generate data for NewSun about such linkages, the data request is likewise overly broad and unduly burdensome.

Nevertheless, and without waiving its objections to this request, PacifiCorp responds as follows:

Please refer to Attachment NewSun 1.6 1st Supplemental. Note: this attachment supplements the attachment provided with PacifiCorp's original response to NewSun Information Request 1.6 (Attachment NewSun 1.6) by "linking up" the interconnection queue numbers and TSR queue numbers for all PPAs in Oregon under which PacifiCorp purchases power, to the extent that information exists.

The interconnection queue number allows NewSun to access the generator's interconnection studies on the Open Access Same-Time Information System (OASIS), including detailed information about the generator, the generator's interconnection service request (including interconnection service type), and upgrades and upgrade costs identified by those studies. The associated TSR queue number allows NewSun to access the same generator's transmission service request on OASIS, including the requesting party, the type of transmission service requested, any upgrades needed to effectuate the transmission service, and the upgrade costs.

OR UM 2032
NewSun 1.6

Attachment NewSun 1.6 1st Supplemental

(a)		(b)	(c)	(d)	(e)	Supplemental Information		
Name	State	MW	Term (Years)[1]	Agreement Source	Qualifying Facility (QF)	Interconnection Queue Number[2]	TSR Queue Number	AREF
Adams Solar Center, LLC	OR	10.00	20	PURPA	QF	556	2074	82489720
BC Solar, LLC	OR	8.00	20	PURPA	QF	585	1893	80039313
Bear Creek Solar Center, LLC	OR	10.00	20	PURPA	QF	580	1891	80035471
Big Top LLC	OR	1.65	20	PURPA	QF	145	1637	77877455
Biomass One, L.P.	OR	32.50	15	PURPA	QF	151	1638	77877558
Black Cap Solar	OR	2.00	16	RFP	Non-QF	392	1506	796780
Bly Solar Center, LLC	OR	8.50	20	PURPA	QF	566	1897	80103182
Butter Creek Power LLC	OR	4.95	20	PURPA	QF	145-B	1687	77979419
C Drop Hydro, LLC	OR	1.10	15	PURPA	QF	299	1640	77879485
Captain Jack Solar	OR	2.70	20	PURPA	QF	971	2845	92200965
Central Oregon Irrigation District (COID) (Juniper Ridge)	OR	5.00	20	PURPA	QF	248	1642	77879661
Central Oregon Irrigation District (COID) (Siphon)	OR	6.00	35	PURPA	QF	Legacy	2553	88223254
Chiloquin Solar, LLC	OR	9.90	20	PURPA	QF	612	2018	81774198
Chopin Wind, LLC	OR	10.00	20	PURPA	QF	547	1866	79672901
City of Albany, Department of Public Works	OR	0.50	15	PURPA	QF	Legacy	1647	77888579
City of Astoria	OR	0.03	15	PURPA	QF	352	1949	80781778
City of Portland, Portland Water Bureau	OR	0.03	15	PURPA	QF	296	1643	77880688
Combine Hills I, LLC	OR	41.00	20	RFP	Non-QF	17	1699	78002619
Deschutes Valley Water District (Opal Springs)	OR	5.93	15	PURPA	QF	1012	2453	86943452
Dorena Hydro, LLC	OR	6.10	20	PURPA	QF	364	1708	78040128
Douglas County Forest Products	OR	6.25	10	PURPA	QF	53	2838	91806183
Eagle Point Irrigation District (Nichols Gap)	OR	0.72	35	PURPA	QF	Legacy	1464	780644
EBD Hydro, LLC (45 Mile Hydro)	OR	2.99	15	PURPA	QF	372	1649	77888834
Elbe Solar Center, LLC	OR	10.00	20	PURPA	QF	556	2075	82489752
Farm Power Misty Meadow, LLC	OR	0.75	15	PURPA	QF	Off System	1695	77979576
Farmers Irrigation District	OR	4.80	15	PURPA	QF	643	1651	77888858
Finley Bioenergy, LLC	OR	4.80	15	PURPA	QF	Off System	1661	77888964
Four Corners Windfarm LLC	OR	10.00	20	PURPA	QF	104	1652	77888996
Four Mile Canyon Windfarm LLC	OR	10.00	20	PURPA	QF	106	1653	77889056
Galesville Dam (Douglas County)	OR	1.80	35	PURPA	QF	Legacy	1659	77913519
Klamath Falls Solar 1, LLC	OR	0.83	20	PURPA	QF	581	1965	80959436
Klamath Falls Solar 2, LLC	OR	2.90	20	PURPA	QF	624	1984	81235960
Lacomb Irrigation Limited Partnership	OR	0.96	35	PURPA	QF	Legacy	1724	78194569
Loyd Fery	OR	0.07	3	PURPA	QF	169	2829	91643352
Middle Fork Irrigation District	OR	3.70	15	PURPA	QF	Off System	1665	77913704
Millican Solar Energy, LLC	OR	60.00	20	RFP	Non-QF	850	2892	92863803
Monroe Hydro, LLC	OR	0.30	15	PURPA	QF	413	1707	78040097
Mountain Energy, Inc	OR	0.05	15	PURPA	QF	355	1681	77972311
Norwest Energy 2 LLC (Neff)	OR	9.90	15	PURPA	QF	571	1995	81269090
Norwest Energy 4 LLC (Bonanza)	OR	4.80	15	PURPA	QF	577	2002	81460501

OR UM 2032
NewSun 1.6

Attachment NewSun 1.6 1st Supplemental

(a)		(b)	(c)	(d)	(e)	Supplemental Information		
Name	State	MW	Term (Years)[1]	Agreement Source	Qualifying Facility (QF)	Interconnection Queue Number[2]	TSR Queue Number	AREF
Norwest Energy 7 LLC (Eagle Point)	OR	9.90	15	PURPA	QF	578	1982	81269111
Norwest Energy 9 LLC (Pendleton)	OR	6.00	15	PURPA	QF	588	1998	81369319
Old Mill Solar	OR	5.00	25	RFP	Non-QF	573	1974	81074553
OR Solar 2, LLC	OR	10.00	20	PURPA	QF	660	1986	81288775
OR Solar 3, LLC	OR	10.00	20	PURPA	QF	661	1987	81288790
OR Solar 5, LLC	OR	8.00	20	PURPA	QF	670	1992	81316143
OR Solar 6, LLC	OR	10.00	20	PURPA	QF	672	1991	81316106
OR Solar 8, LLC	OR	10.00	20	PURPA	QF	671	1989	81315991
Orchard Wind Farm 1, LLC	OR	10.00	20	PURPA	QF	650	2144	83693097
Orchard Wind Farm 2, LLC	OR	10.00	20	PURPA	QF	651	2145	83693107
Orchard Wind Farm 3, LLC	OR	10.00	20	PURPA	QF	652	2146	83693112
Orchard Wind Farm 4, LLC	OR	10.00	20	PURPA	QF	653	2147	83693115
Oregon Environmental Industries, LLC	OR	3.20	15	PURPA	QF	Legacy	1670	77921043
Oregon Institute of Technology (OIT)	OR	0.28	20	PURPA	QF	251	1671	77921092
Oregon Solar Land Holdings (OSLH, LLC)	OR	9.90	15	PURPA	QF	572	1997	81369264
Oregon State University	OR	6.50	10	PURPA	QF	174	2830	91643443
Oregon Trail Windfarm LLC	OR	9.90	20	PURPA	QF	102	1673	77921139
Pacific Canyon Windfarm LLC	OR	8.25	15	PURPA	QF	145-A	1674	77921166
Prineville Solar Energy, LLC	OR	40.00	20	RFP	Non-QF	621/731	2891	92863796
RES Ag - Oak Lea, LLC	OR	0.17	15	PURPA	QF	303	1667	77913784
Roseburg Forest Products Company - Dillard	OR	20.00	10	PURPA	QF	5	2603	88868661
Roseburg Landfill Gas Energy, LLC	OR	1.60	20	PURPA	QF	366	1677	77971685
Sand Ranch Windfarm LLC	OR	9.90	20	PURPA	QF	105	1678	77971814
Skysol, LLC	OR	55.00	20	PURPA	QF	721	2804	91223004
Sprague Hydro (North Fork Sprague)	OR	0.75	35	PURPA	QF	Legacy	1665	77913704
Stahlbush Island Farms, Inc	OR	1.60	4	PURPA	QF	176	2626	89079189
Swalley Irrigation District	OR	0.75	20	PURPA	QF	141	1683	77972520
Three Sisters Irrigation District (Watson Hydro) (700 kW)	OR	0.70	15	PURPA	QF	Off System	1788	79026180
Three Sisters Irrigation District (Watson Hydro) (200 kW)	OR	0.20	20	PURPA	QF	Off System	2456	86939977
Threemile Canyon Wind I LLC	OR	9.90	20	PURPA	QF	71	1932	80179624
TMF Biofuels	OR	4.80	10	PURPA	QF	360	1691	77973101
Tumbleweed Solar, LLC	OR	9.90	20	PURPA	QF	613	2017	81774191
Wagon Trail LLC	OR	3.30	20	PURPA	QF	147	1693	77973304
Ward Butte Windfarm LLC	OR	6.60	20	PURPA	QF	103	1684	77973341
Woodline Solar LLC	OR	8.00	20	PURPA	QF	609	1983	81235956

Notes:
1. Term is for current transaction as a number of the QFs are PPA renewals.
2. Legacy means prior to interconnection serial queue numbering system established by FERC

NewSun Information Request 1.8

For each generator that has submitted an interconnection application to PacifiCorp from January 1, 2014 until present please provide the following:

(a) Queue Number,

(b) Project name,

(c) Date of interconnection request,

(d) Interconnection request status,

(e) Nameplate capacity,

(f) Project location (county and state),

(g) Generation technology type (wind, solar, etc),

(h) Whether the project requested interconnection as a QF selling 100% of its net output to PacifiCorp (at initial application or at any point during the interconnection process) and whether it switched from this QF status to non-QF status, and the date it switched (or vice-versa, if it first requested interconnection as a non-QF and later switched to QF),

(i) Any interconnection studies not publicly available online, including any prior studies which have been superseded by the studies that are posted on the website,

(j) The interconnection agreement, if one was executed,

(k) The developer or developers that submitted the interconnection application,

(l) The in-service date, if operating, or scheduled commercial operation date if not,

(m) Regarding NR and ER interconnection service:
1. Which service type was requested at initial application,
2. Which service type was studied in each of the Feasibility, System Impact, and Facilities studies,
3. Which service type the project ultimately interconnected under,

(n) Regarding network upgrade costs (identified in ER or NR or both):
1. Estimated network upgrade costs in each of the Feasibility, System Impact, and Facilities studies,
2. Final network upgrade costs assigned to the generator,

3. Whether the network upgrades were ultimately constructed or are under construction,

(o) Provide a comparative table for all interconnection requests showing the key features of ER/NR (initial and final), interconnection and network upgrade costs (initial and final), withdrawal status, GIA execution, operational status, and QF status, and

(p) Summarize the comparative outcomes of ER interconnection vs NR interconnection applications as relates interconnection and generator outcomes for projects in the following GIR size ranges: 0-10, 11-20, 21-40, 41-60, 61-80. Indicate withdrawal rates and summary numbers, interconnection agreements signed, and average final interconnection costs including network upgrades.

Response to NewSun Information Request 1.8

(a) to (g) Please refer to PacifiCorp's Open Access Same-Time Information System (OASIS) webpage: http://www.oasis.oati.com/ppw/index.html.

(h) The information requested can be obtained by reviewing the documents provided with the Company's responses to subparts (i), (j), (k) below, or by reviewing the studies posted on PacifiCorp's OASIS webpage.

(i) Please refer to Attachment NewSun 1.8-1 which provides copies of studies superseded by follow on restudies.

(j) Please refer to Attachment NewSun 1.8-2 which provides copies of interconnection agreements and amendments.

(k) PacifiCorp objects to this subsection (k) because developer names are neither relevant or reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding that objection, PacifiCorp states as follows: Developer names for those that have signed interconnection agreements are available on PacifiCorp's OASIS webpage. PacifiCorp cannot release the names of those that have not or did not sign an interconnection agreement as that is considered non-public information under the FERC interconnection procedures (*see* Section 38.5) and Oregon interconnection procedures (*see* Section 3.4).

(l) Please refer to Attachment NewSun 1.8-3 which provides the in-service dates for those that have achieved commercial operation. Commercial operation dates (COD) for those that have not gone into service is available on

PacifiCorp’s OASIS webpage.

(m) The information requested can be obtained by reviewing the documents provided with the Company’s responses to subparts (i) and (j) or by reviewing the studies posted on PacifiCorp’s OASIS webpage.

(n) and (o) The information requested can be obtained by reviewing the documents provided with the Company’s responses to subparts (i) and (j) or by reviewing the information posted on PacifiCorp’s OASIS webpage.

(p) The information requested can be obtained by reviewing the information posted on PacifiCorp’s OASIS webpage.

NewSun Information Request 1.8

For each generator that has submitted an interconnection application to PacifiCorp from January 1, 2014 until present please provide the following:

(a) Queue Number,

(b) Project name,

(c) Date of interconnection request,

(d) Interconnection request status,

(e) Nameplate capacity,

(f) Project location (county and state),

(g) Generation technology type (wind, solar, etc),

(h) Whether the project requested interconnection as a QF selling 100% of its net output to PacifiCorp (at initial application or at any point during the interconnection process) and whether it switched from this QF status to non-QF status, and the date it switched (or vice-versa, if it first requested interconnection as a non-QF and later switched to QF),

(i) Any interconnection studies not publicly available online, including any prior studies which have been superseded by the studies that are posted on the website,

(j) The interconnection agreement, if one was executed,

(k) The developer or developers that submitted the interconnection application,

(l) The in-service date, if operating, or scheduled commercial operation date if not,

(m) Regarding NR and ER interconnection service:
1. Which service type was requested at initial application,
2. Which service type was studied in each of the Feasibility, System Impact, and Facilities studies,
3. Which service type the project ultimately interconnected under,

(n) Regarding network upgrade costs (identified in ER or NR or both):
1. Estimated network upgrade costs in each of the Feasibility, System Impact, and Facilities studies,
2. Final network upgrade costs assigned to the generator,

3. Whether the network upgrades were ultimately constructed or are under construction,

(o) Provide a comparative table for all interconnection requests showing the key features of ER/NR (initial and final), interconnection and network upgrade costs (initial and final), withdrawal status, GIA execution, operational status, and QF status, and

(p) Summarize the comparative outcomes of ER interconnection vs NR interconnection applications as relates interconnection and generator outcomes for projects in the following GIR size ranges: 0-10, 11-20, 21-40, 41-60, 61-80. Indicate withdrawal rates and summary numbers, interconnection agreements signed, and average final interconnection costs including network upgrades.

1st Supplemental Response to NewSun Information Request 1.8

In further support of the Company's response to NewSun Information Request 1.8 dated January 21, 2021, the Company responds further as follows:

During discovery conferences with NewSun, PacifiCorp learned that many of NewSun's requests and their multiple subparts, including this request, were also intended to elicit information that would allow NewSun to trace specific generators through the interconnection and transmission service request (TSR) processes. As PacifiCorp explained, PacifiCorp does not compile information or keep records in this manner in the normal course of business. The additional information is voluminous and would be extremely burdensome to compile, in the event it is even available. Even making the bare linkages from the interconnection queue to the TSR queue for all interconnection requests would require time-consuming investigation by PacifiCorp personnel and must be done one generator at a time. Thus, to the extent NewSun is asking PacifiCorp to "link up" all generator interconnection requests from the interconnection process through the TSR process, the data request is overly broad and unduly burdensome. To the extent NewSun further asks PacifiCorp to perform various types of analyses on each generator to generate data for NewSun or the content of publicly available studies to which NewSun has access, the data request is likewise overly broad and unduly burdensome. Nevertheless, and without waiving its objections to this request, PacifiCorp responds as follows:

Please refer to the Company's 1st Supplemental response to NewSun Information Request 1.6.

NewSun Information Request 1.24

Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

(a) Queue Number,

(b) Project name,

(c) Date of transmission service request,

(d) Transmission service request status,

(e) Nameplate capacity,

(f) Project location (county and state),

(g) Generation technology type (wind, solar, etc),

(h) Type of transmission service,

(i) Point of receipt and point of delivery,

(j) Any transmission service request studies not publicly available online,

(k) The transmission service agreement, if one was executed,

(l) The in-service date, if operating, or scheduled commercial operation date if not,

(m) Whether the output from the generator is delivered to PacifiCorp's retail load,

(n) Whether the generator is a qualifying facility,

(o) Whether the generator is on-system or off system,

(p) Whether the generator is interconnected using ERIS or NRIS, and

(q) Regarding network upgrade costs:
1. Estimated network upgrade costs in any transmission service studies,

2. Final network upgrade costs assigned to the request,

3. Whether the network upgrades were ultimately constructed or are under construction.

Response to NewSun Information Request 1.24

PacifiCorp objects to this data request because the request is overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving these objections, PacifiCorp responds as follows:

The vast majority of the information requested is available on PacifiCorp's OASIS, including under the following tabs: Generation Interconnection, Network, and TSR Queue. In addition, please refer to the Company's response to NewSun Information Request 1.8 and supportive documentation.

NewSun Information Request 1.24

Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

(a) Queue Number,

(b) Project name,

(c) Date of transmission service request,

(d) Transmission service request status,

(e) Nameplate capacity,

(f) Project location (county and state),

(g) Generation technology type (wind, solar, etc),

(h) Type of transmission service,

(i) Point of receipt and point of delivery,

(j) Any transmission service request studies not publicly available online,

(k) The transmission service agreement, if one was executed,

(l) The in-service date, if operating, or scheduled commercial operation date if not,

(m) Whether the output from the generator is delivered to PacifiCorp's retail load,

(n) Whether the generator is a qualifying facility,

(o) Whether the generator is on-system or off system,

(p) Whether the generator is interconnected using ERIS or NRIS, and

(q) Regarding network upgrade costs:
1. Estimated network upgrade costs in any transmission service studies,

2. Final network upgrade costs assigned to the request,

3. Whether the network upgrades were ultimately constructed or are under construction.

1st Supplemental Response to NewSun Information Request 1.24

PacifiCorp reiterates its objections to this data request. Subject to and without waiving those objections, PacifiCorp responds as follows:

Based on NewSun's description of the information it is seeking during the February 19, 2021, phone call, PacifiCorp stated that NewSun may find the OASIS list of designated network resources (DNR) most helpful, and PacifiCorp offered to provide additional specifics on that OASIS tab, as well as the other OASIS tabs it referenced in its original response. First, with respect to the list of DNRs, it can be found by clicking on the "Network" folder, then on the spreadsheet entitled "Designated Network Resources." While the Designated Network Resources spreadsheet shows the DNRs for all PacifiCorp transmission's network customers, PacifiCorp's impression is that NewSun is most interested in focusing on the list of DNRs for only one of those network customers, PacifiCorp's merchant function, which start on row 66 of the spreadsheet. With respect to NewSun's list of requested information about that subset of DNRs, it is available in that spreadsheet or other publicly available sources as follows:

(1) item (b) is shown in column C that lists the network resource name;
(2) for item (d), all resources listed in this spreadsheet have "confirmed" status because they are DNRs;
(3) item (e) is shown in column F that lists total installed capacity;
(4) item (f) is shown in columns D and E containing geographical and electrical locations;
(5) item (g) is shown in column B that lists resource type and QF status;
(6) for item (h), all resources in the spreadsheet secured network transmission, or DNR status;
(7) for item (k), all network transmission service agreements between PacifiCorp transmission and its network customers are on file with FERC, and the network transmission service agreement most relevant to the DNRs on which NewSun is focused (i.e., between PacifiCorp's transmission function and PacifiCorp's merchant function) was last filed with FERC in Docket No. ER14-929;
(8) for item (l), all resources in the spreadsheet are operating;
(9) for item (m), all resources in the spreadsheet are used for load service consistent with the definition of network transmission service;
(10) item (n) is shown in column B that lists resource type and QF status.
(11) To access queue numbers (a), transmission service request dates (c), points of receipt and delivery (i), copies of transmission service studies (j), commercial operation dates (l), any network upgrades identified in studies (q, subpart 1), and whether network upgrades were ultimately constructed (q, subpart 3) for all transmission service requests, including those corresponding to the DNRs listed in

the above-referenced spreadsheet, click on the "TSR Queue" folder and then on the "TSR Queue" spreadsheet. With respect to the studies (q, subpart 1), links to all transmission service study reports are available in that same spreadsheet. With respect to whether construction is completed (q, subpart 3), the spreadsheet shows "OASIS status" in column H. As noted above, if a resource is listed as a DNR, then any construction contingencies have been completed because service has been granted.

(12) With respect to (p), to access the selection of energy resource interconnection service or network resource interconnection service for all generator interconnection requests, including those corresponding to the DNRs listed in the above-referenced spreadsheet, click on the "Generator Interconnection" folder and examine either the "Serial Queue" folder (which houses information about pre-queue reform requests) or the "Cluster Queue" folder (which houses information about queue reform transition and prospective cluster studies).

(13) With respect to (q) subpart (2), final network upgrade costs are not assigned to the requesting entity, but rather rolled into PacifiCorp's transmission rate base per FERC policy.

During conversations with NewSun during the discovery conferral process, PacifiCorp also learned that many of NewSun's requests and their multiple subparts, including this request, were also intended to elicit information that would allow NewSun to trace specific generators through the interconnection and transmission service request processes. As PacifiCorp explained, PacifiCorp does not compile information or keep records in this manner in the normal course of business. The additional information is voluminous and would be extremely burdensome to compile, in the event it is even available. Even making the bare linkages from the interconnection queue to the transmission service queue for all requests from 2014 to present would require time-consuming investigation by PacifiCorp personnel and must be done one generator at a time, to the extent PacifiCorp even has the ability to make such linkages. Thus, to the extent NewSun is asking PacifiCorp to "link up" generators from interconnection process through the transmission service process, the request is overly broad and unduly burdensome. To the extent NewSun further asks PacifiCorp to perform various type of analyses on each generator to generate data for NewSun about such linkages, the request is likewise overly broad and unduly burdensome. Nevertheless, PacifiCorp continues to evaluate its ability to respond to this element of NewSun's request, and without waiving its objections, intends to provide an additional supplement to this response.

NewSun Information Request 1.24

Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

(a) Queue Number,

(b) Project name,

(c) Date of transmission service request,

(d) Transmission service request status,

(e) Nameplate capacity,

(f) Project location (county and state),

(g) Generation technology type (wind, solar, etc),

(h) Type of transmission service,

(i) Point of receipt and point of delivery,

(j) Any transmission service request studies not publicly available online,

(k) The transmission service agreement, if one was executed,

(l) The in-service date, if operating, or scheduled commercial operation date if not,

(m) Whether the output from the generator is delivered to PacifiCorp's retail load,

(n) Whether the generator is a qualifying facility,

(o) Whether the generator is on-system or off system,

(p) Whether the generator is interconnected using ERIS or NRIS, and

(q) Regarding network upgrade costs:
1. Estimated network upgrade costs in any transmission service studies,

2. Final network upgrade costs assigned to the request,

3. Whether the network upgrades were ultimately constructed or are under construction.

2nd Supplemental Response to NewSun Information Request 1.24

In further support of the Company's prior responses to NewSun Information Request 1.24, the Company responds further as follows:

PacifiCorp reiterates its prior objections to this request. Nevertheless, and without waiving its objections to this request, PacifiCorp provides the following supplemental response:

Please refer to the Company's 1st Supplemental response to NewSun Information Request 1.6. Note: the referenced attachment (Attachment NewSun 1.6 1st Supplemental) identifies whether each generator is on-system or off-system, which was information requested in subpart (o) of NewSun Information Request 1.24, and the only subpart that PacifiCorp did not address in its 1st Supplemental response to NewSun Information Request 1.24.

NewSun Information Request 1.26

For each State in which PacifiCorp operates, please:

(a) Describe which set of procedures PacifiCorp uses to interconnect qualifying facilities that propose to sell 100% of their net output to PacifiCorp,

(b) Describe which set of procedures PacifiCorp uses to interconnect qualifying facilities that propose to sell less than 100% of their net output to PacifiCorp,

(c) Indicate for (a) and (b) whether QFs have the option to select ERIS or NRIS,

(d) Indicate for (a) and (b) whether QFs receive refunds for the cost of network upgrades,

(e) Describe the cost allocation and refund policy for network upgrades; compare these policies based on whether the QF interconnected as a FERC or state-jurisdictional interconnection, and

(f) How would these answers differ if a prospective otherwise equivalent generator proposed interconnection but it did not seek to sell 100% of its output under a mandatory purchase contract to PacifiCorp? For example, in each situation, if the potential QF were a 40 MW solar-only facility that was eligible for certification as a QF.

Response to NewSun Information Request 1.26

(a) Please refer to PacifiCorp's response to OPUC Information Request 7.

(b) PacifiCorp's Open Acess Transmission Tariff approved by the Federal Energy Regulatory Commission (FERC).

(c) For (a), no. For (b), yes.

(d) For (a), yes. For (b), nos.

(e) PacifiCorp follows the FERC cost-allocation policies with respect to Network Upgrades for FERC-jurisdictional interconnection customers. For a description of how PacifiCorp reimburses a generator under FERC policy, please refer to the Company's response to OPUC Information Request 17. State-jurisdictional qualifying facilities (QF) are not reimbursed for Network Upgrades, as noted in the Company's response to subpart (d) above.

(f) The Public Utility Regulatory Policies Act of 1978 (PURPA) gives state authorities jurisdiction over QF interconnections if the QF is selling 100 percent of its output to the directly interconnected utility. In such a case, the state's PURPA interconnection policies apply. Otherwise, FERC's general interconnection policies apply.

UM 2032 / PacifiCorp
October 2, 2020
OPUC Information Request 7

OPUC Information Request 7

Network Resource Interconnection Service Requirement
For each state outside of Oregon in which the Company interconnects QFs, please indicate:

(a) The required interconnection service type(s) for QFs, including documentation for this requirement, including the date in which the requirement was put in place.

(b) How QF Network Upgrade costs are allocated, including between transmission customers and between ratepayers in different states, including documentation for this practice.

Response to OPUC Information Request 7

(a) Aside from Utah and Oregon, no state in PacifiCorp’s service territory has explicitly ordered specific treatment of a QF’s deliverability-driven Network Upgrades; all have recognized PURPA’s customer indifference mandate. Please refer to PacifiCorp’s response to OPUC Information Request 6. PacifiCorp successfully defended the network resource (NR) interconnection service requirement for qualifying facility (QF) interconnection customers before the Public Service Commission of Utah, which resulted in the order provided as Attachment OPUC 7-1. PacifiCorp has also provided detailed descriptions of its QF NR interconnection requirements to the Federal Energy Regulatory Commission (FERC), such as in its December 7, 2018, and January 11, 2019 comments filed in the Blue Marmots proceeding, FERC Docket No. EL19-13-000. Copies of these comments are provided as Attachment OPUC 7-2.

(b) QFs are responsible for the cost of network upgrades required to grant their generator interconnection service requests, so unlike network upgrades triggered by FERC-jurisdictional generator interconnection requests, PacifiCorp does not provide a QF refunds for the cost of upfront funded network upgrades or roll those refunded amounts into PacifiCorp’s transmission rate base. Therefore, PacifiCorp does not allocate QF network upgrade costs among any customer classes, as they are never included in its transmission or retail rate base.

PacifiCorp requested and received FERC approval to discontinue paying a small generator its monthly interconnection service network upgrade refund credits after the generator switched from a FERC-jurisdictional interconnection agreement to state-jurisdictional QF interconnection agreement to maintain customer indifference. Included as Attachment OPUC 7-3 are PacifiCorp’s FERC filing and FERC’s order approving PacifiCorp’s agreement, which stated, in relevant part:

> On July 10, 2012, PacifiCorp filed an Agreement for Reduction of Network Upgrade Credit Repayment (Repayment Agreement) with

> Roseburg Forest Products Company (Roseburg). PacifiCorp states that, on or about October 2011, it learned that Roseburg had been exclusively selling the output of its generating facility to PacifiCorp's Commercial and Trading function as a qualifying facility (QF). Prior to this time, PacifiCorp believed Roseburg was receiving interconnection service as a FERC-jurisdictional small generator pursuant to the terms of a pro forma Small Generator Interconnection Agreement (SGIA). However, this issue has been resolved and the parties have now executed a QFSGIA. **<u>PacifiCorp calculated a network upgrade balance of $115,572.17 for Roseburg's facility; this amount should have been directly assigned to Roseburg under the terms of the QFSGIA. The Repayment Agreement is intended to memorialize the mechanism for a reduced repayment of network upgrade costs under the pro forma SGIA during the period that the QFSGIA properly governs the interconnection of Roseburg's facility as a QF</u>**. PacifiCorp's proposed Repayment Agreement is accepted for filing, effective June 28, 2012, as requested. (emphasis added)

OPUC Information Request 8

Network Resource Interconnection Service Requirement
Please explain whether the Company requires all designated network resources (DNRs) to interconnect under Network Resource Interconnection Service.

(a) Please list any of the Company's DNRs that were not required to interconnect under Network Resource Interconnection Service. Please include generator size (MW), Location (state), resource type, Commercial Operations Date.

(b) Please explain how each DNR in subpart a is delivered to load, including whether it is on a firm basis.

(c) Please explain how the Network Upgrade and any other deliverability costs for each DNR in subpart a are recovered, including whether the costs are paid by transmission customers and ratepayers.

(d) Please explain why these the DNRs identified in subpart a were not required to interconnect under Network Upgrade Interconnection Service.

Response to OPUC Information Request 8

PacifiCorp transmission requires qualifying facilities (QF) to secure network resource (NR) interconnection when it evaluates a QF's generator interconnection request. PacifiCorp transmission does not, however, require its network customers, including PacifiCorp's merchant function, to verify that a generator (QF or non-QF) secured NR interconnection as a pre-requisite to PacifiCorp transmission performing a network transmission service study in response to a request for network transmission service (which is the same as a request to designate a generator as a network resource or DNR).

The interconnection service type nevertheless has a direct relationship to the transmission service study evaluation. In particular, PacifiCorp's transmission function uses any network upgrades previously identified in the interconnection study as required for the generator's interconnection service as a baseline starting point for its evaluation of what is required to provide the requested network transmission service (i.e., what is required to make the generator a DNR). This coordination between interconnection study requirements and transmission service study requirements prevents the transmission service study from identifying overlapping requirements. This is particularly true if the generator secured network resource interconnection service and, therefore, certain "aggregate-level" deliverability issues have already been evaluated and addressed in the interconnection study. If the generator has only secured the lower-level energy resource (ER) interconnection service, it is less likely there would be overlap between the ER interconnection study and the network transmission service, or DNR, study. Under that scenario, if the generator is seeking state-jurisdictional interconnection service, the opportunity to evaluate any deliverability-related network upgrades in the state interconnection study process has passed, and the only study remaining is a Federal Energy Regulatory Commission (FERC) jurisdictional transmission service study subject to FERC's open access policies and cost allocation requirements.

As explained in more detail in the Company's response to OPUC Information Request 7, after FERC's *Pioneer Wind* order rejected PacifiCorp's QF power purchase agreement (PPA) curtailment provision, PacifiCorp has aimed to evaluate deliverability issues early on in the QF contracting process by requiring QFs to secure NR interconnection service and by evaluating the QF's interconnection study during the QF PPA negotiation. This early identification and evaluation of deliverability issues is also consistent with the FERC's admonition in *Blue Marmot* that a utility should take steps early in the contracting process to identify deliverability issues associated with a QF's chosen location. *See, e.g.*, *Blue Marmot V-IV, LLC v. Portland General Electric Company*, Order No. 19-322 at page 16 (Sept. 30, 2019) (In discussing the transmission service-related requirements associated with the QF at issue in the case, the Commission stated that "[a] utility should review significant proposed QF delivery terms as early as possible, and ideally well before providing a final draft executable contract."). Please refer to Attachment OPUC 8-1.

This early evaluation is not always possible in non-QF PPA negotiation scenarios, particularly if a FERC-jurisdictional interconnection customer has only requested an ER interconnection study—a choice a FERC-jurisdictional generator has under the Open Access Transmission Tariff (OATT). That does not, however, mean that PacifiCorp ignores the possibility of deliverability in the non-QF contracting process. Rather, PacifiCorp evaluates a potential non-QF PPA counterparty's generator interconnection study network upgrade costs and timing as part of the standard due diligence performed for potential incremental resource acquisitions. The Commission-approved structure of PacifiCorp's ongoing 2020 all source request for proposals (2020AS RFP) is a prime example of this, as PacifiCorp has developed a specific step in the bid evaluation process for reviewing each bid's interconnection information (i.e., interconnection studies or the executed interconnection agreement, if the generator has one). Indeed, in recognition of the importance of evaluating the cost and timing requirements associated with a generator's interconnection service, PacifiCorp specifically designed its RFP schedule so the interconnection review could occur after all bidders had received an interconnection study, i.e., after the issuance of PacifiCorp's transition cluster study report.

In addition to reviewing interconnection information during the non-QF PPA negotiation process, PacifiCorp has in recent years begun to include provisions in non-QF PPAs that limit the amount of network upgrades that can be triggered by the future (i.e., post-PPA execution) transmission service study without contractual ramifications. If the transmission service study triggers more network upgrades that the PPA-specified threshold, then potential contractual ramifications could include, for example, price adjustment, term adjustment, generator curtailment (which is not an option for QF PPAs, per FERC's *Pioneer* order), or PPA termination. Please refer to Confidential Attachment

OPUC 8-2 for an example of a non-QF PPA that includes a provision like this in Section 11.4.

The Commission approved the use of a similar provision in the Community Solar context, but the contractual ramification is non-specific. Instead, if the transmission service study identifies network upgrades that must be constructed to arrange transmission service to deliver a community solar project, then the parties to the agreement must seek assistance from the Commission.[1] Please refer to Attachment OPUC 8-3. The provision, which was often referred to in the community solar docket as the "Conditional DNR" language, offered a "safety valve" to the overall contracting process if other deliverability risk mitigating tools did not prevent the transmission service study from identifying the need to construct network upgrades. In particular, when the community solar generator is studied for interconnection service earlier in the process, it is required to limit the size of its project in accordance with a methodology designed to reduce (although not eliminate) the likelihood of deliverability network upgrades.

(a) As described above, PacifiCorp's transmission function only requires state-jurisdictional QF interconnection customers to secure NR interconnection service, so all FERC-jurisdictional interconnection customers whose generators were later designated as network resources had a choice between ER and NR interconnection service in the OATT interconnection study process. All of the resources that have been designated as network resources, or DNRs, on the network integration transmission service agreement (NITSA) between PacifiCorp's transmission function and PacifiCorp's merchant function are listed on the Open Access Same-Time Information System (OASIS) and can be retrieved as follows:

1. Go to PacifiCorp's OASIS page at http://www.oasis.oati.com/ppw/index.html.
2. On the left-hand side of the screen, click on the folder that says "Network".
3. Click on the first spreadsheet listed, "Designated Network Resources".
4. The spreadsheet shows a list of *all* designated network resources, or DNRs, for the various NITSAs between PacifiCorp transmission and its network

[1] The provision as described in the Commission's order (using PGE's PPA version instead of PacifiCorp's) states as follows: "If PGE is notified in writing by the Transmission Provider that designation of the Facility as a network resource requires the construction of transmission system network upgrades or otherwise requires potential re-dispatch of other network resources of PGE (a "Conditional DNR Notice"), PGE and Project Manager will promptly meet to determine how such conditions to the Facility's network resource designation will be addressed in this Agreement. If, within sixty (60) days following the date of PGE's receipt of the Conditional DNR Notice, PGE and Project Manager are unable to reach agreement regarding how to designate the Facility as a network resource in light of the Conditional DNR Notice, PGE will submit the matter to the Commission for a determination on whether, as a result of the Conditional DNR Notice, this Agreement should be terminated or amended."

transmission customers. To see PacifiCorp's merchant function's DNRs in particular, scroll down to where you see the counterparty listed in column B says "PacifiCorp Merchant." The spreadsheet indicates whether a DNR is a QF.

(b) If a resource is a DNR, then that is essentially shorthand for saying that the resource has secured network transmission service. Therefore, all of the DNRs identified in subpart (a) are, by definition, delivered using firm network transmission service. If a PacifiCorp DNR needs to be transmitted across a third-party transmission system to get to network load, then PacifiCorp's merchant function requests firm, point-to-point (PTP) transmission service over that third-party system. In that case, the DNRs identified in subpart (a) would be delivered using a combination of network transmission service (on PacifiCorp's system) and PTP transmission service (on the third-party system).

(c) This question seems to suggest that all Network Upgrades are deliverability related. This is incorrect; only some Network Upgrades are deliverability related. Subject to this clarification, PacifiCorp responds as follows: If granting a FERC-jurisdictional transmission service request triggers the need to construct network upgrades, then:

1. From a federal rates perspective, the cost of those network upgrades are rolled into PacifiCorp's FERC-filed transmission rate base and paid for by all transmission system users consistent with FERC's long-standing transmission pricing policy. This is consistent with FERC's *policy* (not *factual*) determination that sharing the cost of transmission service-triggered network upgrades among all users of the system would facilitate wholesale competition under the Federal Power Act (FPA) - a policy determination that FERC did not have to reconcile with a second statutory construct, Public Utility Regulatory Policies Act of 1978 (PURPA), containing a customer indifference requirement.[2]

2. From a state rates perspective, FERC's pricing policy does not speak to whether and how a multi-state utility's state allocation methodology may reflect state policies that trigger transmission-level network upgrades. Transmission-level network upgrades funded by the Company are included in retail rates. For PacifiCorp, the costs are allocated among PacifiCorp's six state jurisdictions consistent with the 2020 Interjurisdictional Cost Allocation Methodology. In addition, revenues collected from PacifiCorp's wholesale transmission customers are included as a revenue credit in PacifiCorp's retail rates, which credits retail customers for third-party use of PacifiCorp's transmission system.

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[2] FERC did consider how to reconcile the twin statutory goals of facilitating wholesale competition under the FPA and maintaining customer indifference under PURPA when PacifiCorp filed and FERC approved a novel, PURPA-related exemption from the OATT's longstanding obligation to construct the network upgrades necessary for a transmission provider to grant FERC-jurisdictional transmission service requests. See PacifiCorp's response to OPUC Information Request 6 and attachments to that response for more detail on that exemption.

(d) Please refer to the Company's responses above as well as OPUC Information Request 6 and OPUC Information Request 7.

Confidential information is provided subject to General Protective Order No. 20-301.

OPUC Information Request 9

Network Resource Interconnection Service Requirement
Please list all QFs that the Company has interconnected under Energy Resource Interconnection Service.

(a) Please include generator size (MW), Location (state), resource type, Commercial Operations Date.

(b) Please explain how each QF in subpart a is delivered to load, including whether it is on a firm basis.

(c) Please explain how the Network Upgrade and any other deliverability costs for each QF in subpart a are recovered, including whether costs are paid by transmission customers and ratepayers.

(d) Please explain why the QFs identified in subpart a were interconnected under Energy Resource Interconnection Service.

Response to OPUC Information Request 9

(a) Refer to the Company's response to NIPPC Data Request 2, specifically Attachment NIPPC 2.

(b) Qualifying facility (QF) designated network resources (DNR), like non-QF DNRs, are delivered on firm network transmission service as described in detail in the Company's response to OPUC Information Request 8 subpart (b), with one important exception: QF DNRs cannot be economically dispatched per Federal Energy Regulatory Commission's (FERC) holding in *Pioneer Wind*, discussed in detail in the Company's response to OPUC Information Request 6. In particular, the Open Access Transmission Tariff (OATT) - FERC's pro-forma OATT and PacifiCorp's OATT - states that "Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load." At a high level, this means that PacifiCorp's merchant function, as a network customer of PacifiCorp transmission, has the flexibility to dispatch the combination and megawatt (MW) amount of DNRs that allow it to serve its network load firm in the most economical way possible. This includes the flexibility to both run a DNR and to curtail a DNR in order to follow network load levels in the most economical manner in real time. The exception, as noted above, is that PacifiCorp's merchant function does not have that same flexibility with respect to QF DNRs that, absent a system emergency, must be dispatched to their full nameplate capacity and cannot be curtailed. *See, e.g.*, *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 27 (2013) ("We will accept PacifiCorp's proposed amendment to the Network Operating Agreement (NOA), to be effective

February 22, 2015, as requested. We find that PacifiCorp's proposed amendment is consistent with Public Utility Regulatory Policies Act of 1978 (PURPA). As PacifiCorp acknowledges, [Federal Energy Regulatory Commission] precedent requires electric utilities, such as PacifiCorp, **to deliver a QF's power on a firm basis and prohibits the curtailment of QF resources except under two very narrow circumstances**: (1) system emergencies; and (2) extreme light loading conditions.[1] PacifiCorp's proposed amendment complies with these requirements because it would obligate PacifiCorp Energy to **curtail the schedules of non-QFs before the schedules of any QFs during normal operating conditions.**") (emphasis added).

(c) Please refer to PacifiCorp's response to OPUC Information Request 8 subpart (c). For clarity, the Company's responses to this subpart (c) and the Company's response to OPUC Information request 8 subpart (c) are the same because they both pertain to FERC-jurisdictional transmission service arrangements, regardless of whether the generator being transmitted is a QF or a non-QF.

(d) Please refer to PacifiCorp's response to OPUC Information Request 6.

[1] The light loading exception to the curtailment prohibition does not apply to long-term QF PPAs, so long-term QF PPAs can only be curtailed in system emergencies.

OPUC Information Request 17

Customer Indifference
Please refer to Vail-Bremer-Foster-Larson-Ellsworth/23 of the Joint Utilities Opening Testimony, which states, "Specifically, Section 11.4.1 of FERC's pro forma LGIA states that once a generating facility is operational, the utility will reimburse the generator for the cost of its Network Upgrades, ordinarily through receipt of transmission credits".

(a) Please explain in detail how the transmission credits are calculated and returned to generators. Please provide an example.

(b) Please explain whether and how the Company reimburses FERC jurisdictional generators for Network Upgrades in instances where the generator is not reimbursed through transmission credits. Please provide an example.

[redacted] **Response to OPUC Information Request 17**

The key to the difference between (a) and (b) in this request is whether or not the interconnection customer is the same entity as the transmission customer.

(a) Transmission providers use transmission invoice credits to reimburse generators for the cost of upfront funded network upgrades ***if*** the interconnection customer is the same entity as the transmission customer. Tab 2 of Confidential Attachment OPUC 17 provides an example of this type of situation. In particular, the owner of the generator requested both (1) generator interconnection service and (2) 52 megawatts of point-to-point transmission service from PacifiCorp transmission. The spreadsheet shows that the transmission customer owed $140,607.46 for one month of transmission service, but that PacifiCorp transmission applied a transmission invoice credit for that same amount, which zeroed out the transmission charges. In addition, PacifiCorp transmission paid interest to the transmission customer, calculated at the Open Access Transmission Tariff (OATT) interest rate,[1] in the amount of $14,655.27. PacifiCorp transmission will continue to apply network upgrade refund credits and interest to this point-to-point transmission customer's transmission service invoice in this manner each month until the total upfront funded network upgrades have been fully refunded.

(b) Transmission providers do not use transmission invoice credits to reimburse generators for the cost of upfront funded network upgrades if the interconnection customer is not ***also*** a transmission service customer. The reason for this is simple – there is no transmission invoice on which the transmission provider can apply a refund credit. Instead, the transmission provider issues a monthly refund check to the generator, calculated based on the generator's usage of the transmission system

[1] The OATT refers to a FERC regulation, 18 C.F.R. § 35.19a(a)(2)(iii), for calculation of the interest rate.

relative to other generators. Tab 1 of Confidential Attachment OPUC 17 provides an example of this type of situation. The generator interconnection customer is **[Begin Confidential]** [redacted] **[End Confidential]**

Confidential information is provided subject to General Protective Order No. 20-301.

NIPPC Data Request 7

For each QF that has interconnected to PacifiCorp's system and achieved commercial operation in the past 30 years to sell 100 percent of the net output to PacifiCorp and is thus a state-jurisdictional interconnection, provide the following information:

(a) Capacity of the facility (as measured by interconnection capacity).

(b) Type of generation resource (e.g., wind, solar, hydropower).

(c) Cost of Interconnection Facilities (using the definition in FERC's Order No. 2003, which is facilities up to the point of interconnection), including both costs in the final Facilities Study and the actual costs after construction was complete.

(d) Cost of Network Upgrades (using the definition in FERC's Order No. 2003, which is facilities at or beyond the point of interconnection) including both costs in the final Facilities Study and the actual costs after construction was complete.

(e) If the amounts for any facilities in (c) and (d) for the final Facilities Study and the actual costs after construction differ, explain the reason for the difference.

(f) For the Network Upgrades identified in subpart D for each facility, please explain whether PacifiCorp agrees that any of the facilities are used by other users of the system or PacifiCorp and identify facilities not used solely by the QF.

Response to NIPPC Data Request 7

Based on conversations with counsel for the Northwest and Intermountain Power Producers Coalition (NIPPC), PacifiCorp understands that this request encompasses only interconnections at the transmission level for which Network Upgrades were identified. PacifiCorp objects that this request for 30 years of data is overly broad, unduly burdensome, and seeks information that is not relevant to this case nor reasonably calculated to lead to the discovery of relevant evidence. In particular, interconnections that occurred before the Federal Energy Regulatory Commission's (FERC) Order 2003 took effect did not include the defined terms of network resource interconnection service (NRIS), energy resource interconnection service (ERIS), Network Upgrades, or interconnection facilities.

Notwithstanding and without waiving these objections, PacifiCorp responds as follows:

a-e. Please refer to Attachment NIPPC 7. Per discussion with NIPPC's counsel, PacifiCorp has not separated out the costs requested in NIPPC Data Request 7(c) and (d).

f. The need for a particular Network Upgrade can be triggered by a specific generator, but the usage of specific components of the transmission system are not isolated for use by a single user and change over time.

OR - UM 2032
NIPPC 7

Attachment NIIPC 7

Q#	QF?	Size (MW)	ST	Voltage (kV)	Type	Estimate Costs Facilities Study	Actual Costs
102-106 145-147	QF	64.55	OR	69	Wind	$2,132,306	$4,675,916
171	QF	16.5	WY	69	Wind	$2,193,700	$777,314
248	QF	5	OR	69	Hydro	$590,200	$603,988
306	QF	40	WY	230	Wind	$1,732,000	$2,459,910
323	QF	43.2	ID	230	Wind	$10,796,000	$3,024,254
324	QF	80	UT	138	Solar	$1,293,000	$1,262,062
335	QF	40	WY	230	Wind	$217,000	$252,121
341	QF	120	ID	161	Wind	$327,000	$78,406
384	QF	60	UT	138	Wind	$2,982,000	$1,937,623
432	QF	6.3	UT	138	Other	$324,000	$443,072
442	QF	5.6	ID	69	Natural Gas	$604,700	$725,360
450	QF	50	UT	46	Solar	$1,590,000	$1,959,635
513	QF	80	UT	138	Solar	$5,000,000	$2,731,061
514	QF	80	UT	138	Solar	$7,520,000	$4,805,453
515	QF	80	UT	345	Solar	$12,895,000	$9,541,554
516	QF	80	UT	345	Solar	$290,000	$275,332
532	QF	50	UT	46	Solar	$1,020,000	$786,491
539	QF	130.4	UT	138	Solar	$8,480,000	$1,894,764
551	QF	80	UT	345	Solar	$1,500,000	$464,833
564	QF	80	UT	138	Solar	$2,413,000	$1,162,095
566	QF	8.5	OR	69	Solar	$1,514,000	$2,921,805
638	QF	1.715	UT	46	Wind	$92,000	$26,084
795	QF	20	WY	69	Solar	$3,602,000	$4,575,747
796	QF	20	WY	69	Solar	$6,198,000	$7,311,236
809	QF	20	WY	69	Solar	$150,000	$100,618

Explaination of cost variance

Additional scope had to be added to Transmission Provider work due to interconnection customer changes and upon clarification of scope responsibility during design.
Lower than anticipated design and construction costs.
Within estimate accuracy
Interconnection customer delayed project for several years after the completion of the studies which led to increased costs.
Interconnection customer elected option to construct the new substation required for the interconnection request which resulted in lower costs by Transmission Provider from what was assumed in the study.
Within estimate accuracy
Within estimate accuracy
Lower than anticipated design and construction costs.
Lower than anticipated design and construction costs.
Higher than anticipated design and construction costs.
Within estimate accuracy
Determined during detailed design that the Transmission Provider needed to own the tie line to the generating facility therefore that scope was shifted to the Transmission Provider which led to increased costs for the Transmission Provider.
No records could be found with the data requested
Lower than anticipated design and construction costs.
Lower than anticipated design and construction costs.
Within estimate accuracy

Design and construction efficiencies due to parallel work on Q0450 led to lower costs.
Interconnection customer elected option to construct the new substation required for the interconnection request which resulted in lower costs by Transmission Provider from what was assumed in the study.
Design and construction efficiencies due to parallel work on Q0515 and Q0516 led to lower costs.
No records could be found with the data requested
Customer delays required amendment of interconnection agreement milestones five separate times which led to inefficiences of design and project management increasing costs. Additional infrastructure at customer site was deemed necessary during detailed design.
Interconnection customer performed some work assumed to be done by Transmission Provider therefore lowering Transmission Provider project costs.
Assumptions about existing space in substation were not accurate leading to additional substation upgrades.
Within estimate accuracy
Design and construction efficiencies due to parallel work on Q0795 and Q0796 led to lower costs.

UM 2032 / PacifiCorp
September 18, 2020
NIPPC Data Request 25

NIPPC Data Request 25

Please refer to Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/21, which states:

"Q. If QFs were not required to pay for the Network Upgrades necessitated by their interconnection, what impact would that have on QFs' siting decisions?

A. If the Commission were to relieve QFs of the obligation to pay for interconnection-driven Network Upgrades, QFs would have no financial incentive to site in a location where Network Upgrade costs are minimized. As a result, we would likely see more QFs seeking to site and develop projects in areas that require significant Network Upgrades to safely physically interconnect the new generator, or to deliver QF power from areas that may be significantly constrained. Removing QFs' incentives to make economical siting decisions would likely increase—perhaps dramatically—the overall cost of transmission system upgrades needed to interconnect and deliver QF power, and also would shift the cost of such upgrades from QFs to other utility customers, with significant impacts to retail customers."

(a) Do FERC jurisdictional interconnection customers initially fund, but are then paid back, the Network Upgrade costs necessitated by their interconnection?

(b) Do FERC jurisdictional interconnection customers have any financial incentives to site in a location where Network Upgrade costs are minimized?

(c) Do FERC jurisdictional interconnection customers seek to site and develop projects in areas that require significant Network Upgrades to physically interconnect safely to the new generator, or to deliver power from areas that may be significantly constrained?

(d) Has removing FERC jurisdictional interconnection customers' incentives to make economical siting decisions increased the overall cost of transmission system upgrades needed to interconnect and deliver their power?

(e) Has removing FERC jurisdictional interconnection customers' incentives to make economical siting decisions shifted the cost of such upgrades from the interconnection customers to other utility customers, with significant impacts to retail customers?

Response to NIPPC Data Request 25

The Federal Energy Regulatory Commission's (FERC) interconnection policy determinations are made within a different (i.e., non- Public Utility Regulatory Policies Act (PURPA)) legal and regulatory framework, with different policy drivers, and without the constraint of PURPA's customer indifference mandate, so it is unclear what relevance this has to state PURPA policy determinations.

(a) Yes, after the generator achieves commercial operation.

(b) Yes. Unlike state-jurisdictional qualifying facilities (QF), competitive independent power producer (IPP) generators must compete for an off-taker. To be competitive, the overall costs of and timing associated with a project (including interconnection and transmission network upgrade costs and the timing associated with constructing those network upgrades) must be attractive and workable to the off-taker. These factors are addressed in a number of ways in competitive negotiations and incentivize competitive IPPs to site projects where Network Upgrades are minimized. Moreover, competitive IPPs, unlike QFs, do not have a guaranteed buyer, so they face significant risks when providing up-front funding for construction of Network Upgrades, as those funds will only be paid back in the event the project finds an off-taker and achieves commercial operation.

To the extent a utility is the off-taker, or it develops its own generation projects, the utility will not receive cost recovery for the project unless it demonstrates that the project is both prudent and used and useful for customers. These requirements create an incentive to site a project in a location where the need for Network Upgrades—with their associated cost and timing issues—are minimized.

(c) FERC-jurisdictional interconnection customers may site and develop projects in areas that require significant Network Upgrades if the terms of their commercial arrangement can accommodate the cost and timing issues associated with the need to build Network Upgrades.

(d) As noted previously, unlike QF generators, *non-QF generators* do have incentives to make economical siting decisions even under FERC's pricing policies. But it is not possible to quantify the overall cost of network upgrades under FERC's pricing policies vs. the cost of network upgrades that would be built absent FERC's pricing policies.

(e) Please refer to the Company's response to subpart (d) above.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 2032

Joint Utilities' Response to NewSun Energy

LLC's Motion to Compel Discovery

Attachment D

UM 2032 NewSun Energy LLC's Data Requests to Joint Utilities

June 28, 2021

NewSun Energy LLC
390 SW Columbia, Suite 120
Bend, OR 97702

January 7, 2021

Via Electronic Mail

Adam Lowney
McDowell, Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
dockets@mcd-law.com
adam@mrg-law.com

Donovan E. Walker
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
dokets@idahopower.com

Re: In the Matter of PULBIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities
Docket No. UM 2032

Dear Adam, Donovan:

Please find NewSun Energy LLC's ("NewSun") Corrected first set of data requests to Idaho Power Company ("Idaho Power") in this proceeding. Idaho Power has fourteen days to response to these data requests, or by January 20, 2021.

Please do not hesitate to contact me with any questions.

Sincerely,

NewSun Energy LLC

/s/ Marie Barlow

Marie Barlow
In-House Counsel, Policy & Regulatory Affairs

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2032

In the matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities	**NEWSUN ENERGY LLC'S AMENDED FIRST SET OF DATA REQUESTS TO IDAHO POWER**

Dated: January 6, 2021

I. <u>DEFINITIONS</u>:

1. "Documents" refers to all writings and records of every type in your possession, control, or custody, whether or not claimed to be privileged or otherwise excludable from discovery, including but not limited to: testimony and exhibits, memoranda, papers, correspondence, letters, reports (including drafts, preliminary, intermediate, and final reports), surveys, analyses, studies (including economic and market studies), summaries, comparisons, tabulations, bills, invoices, statements of services rendered, charts, books, pamphlets, photographs, maps, bulletins, corporate or other minutes, notes, diaries, log sheets, ledgers, transcripts, microfilm, microfiche, computer data (including E-mail), computer files, computer tapes, computer inputs, computer outputs and printouts, vouchers, accounting statements, budgets, workpapers, engineering diagrams (including "one-line" diagrams), mechanical and electrical recordings, telephone and telegraphic communications, speeches, and all other records, written, electrical, mechanical, or otherwise, and drafts of any of the above.

   "Documents" include copies of documents, where the originals are not in your possession, custody, or control.

   "Documents" include every copy of a document, which contains handwritten or other notations, or which otherwise does not duplicate the original or any other copy.

   "Documents" also include any attachments or appendices to any document.

2. "Identification" and "identify" mean:

   When used with respect to a document, stating the nature of the document (<u>e.g.</u>, letter, memorandum, corporate minutes); the date, if any, appearing thereon; the date, if known, on which the document was prepared; the title of the document; the general subject matter of the document; the number of pages comprising the document; the identity of each person who wrote, dictated, or otherwise participated in the preparation of the document; the identity of each person who signed or initiated the document; the identity of each person to whom the document was addressed; the identity of each person who received the document or reviewed it; the location of the document; and the identity of each person having possession, custody, or control of the document.

When used with respect to a person, stating his or her full name; his or her most recently known home and business addresses and telephone numbers; his or her present title and position; and his or her present and prior connections or associations with any participant or party to this proceeding.

3. “Idaho Power” refers to Idaho Power Company or any officer, director, or employee of Idaho Power Company, or any affiliated company.

4. “Person” refers to, without limiting the generality of its meaning, every natural person, corporation, partnership, association (whether formally organized or ad hoc), joint venture, unit operation, cooperative, municipality, commission, governmental body or agency, or any other group or organization.

5. “Studies” or “study” includes, without limitation, reports, reviews, analyses, and audits.

6. The terms “and” and “or” shall be construed either disjunctively or conjunctively whenever appropriate to bring within the scope of this discovery any information or documents that might otherwise be considered beyond their scope.

7. The singular form of a word shall be interpreted as plural, and the plural form of a word shall be interpreted as singular whenever appropriate to bring within the scope of this discovery request any information or documents that might otherwise be considered beyond their scope.

II. INSTRUCTIONS:

1. These requests call for all information, which includes information contained in documents relating to the subject matter of the Data Request, and information known or available to you.

2. Where a Data Request has several separate subdivisions or related parts or portions, a complete response is required to each such subdivision, part, or portion. Any objection to a Data Request should clearly indicate which subdivision, part, or portion of the Data Request it directly relates to.

3. The time period encompassed by these Data Requests is from 2005 to the present unless otherwise specified.

4. Each response should be furnished on a separate page. In addition to hard copy, electronic versions of the document, including studies and analyses, must also be furnished if available.

5. If you cannot answer a Data Request in full after exercising due diligence to secure the information necessary to do so, state the answer to the extent possible, why you cannot answer the Data Request in full, and what information or knowledge you have concerning the unanswered portions.

6. If, in answering any of these Data Requests, you feel that any Data Request or definition or instruction applicable thereto is ambiguous, set forth the language you feel is ambiguous and the interpretation you are using in responding to the Data Request.

7. If a document requested is unavailable, identify the document, describe in detail the reasons the document is unavailable, state where the document can be obtained, and specify the number of pages it contains.

8. If you assert that any document has been destroyed, state when and why it was destroyed and identify the person who directed its destruction. If the document was destroyed pursuant to your document destruction program, identify and produce a copy of the guideline, policy, or company manual describing your document destruction program.

9. If you refuse to respond to any Data Request by reason of a claim of privilege, confidentiality, or for any other reason, state in writing the type of privilege claimed and the facts and circumstances you rely upon to support the claim of privilege or the reason for refusing to respond. With respect to requests for documents to which you refuse to respond, identify each such document, and specify the number of pages it contains. Please provide: (a) a brief description of the document; (b) date of document; (c) name of each author or preparer; (d) name of each person who received the document; and (e) the reason for withholding it and a statement of facts constituting the justification and basis for withholding it.

10. Identify the person from whom the information and documents supplied in response to each Data Request were obtained, the person who prepared each response, the person who reviewed each response, and the person who will bear ultimate responsibility for the truth of each response.

11. If no document is responsive to a Data Request that calls for a document, then so state.

12. These requests for documents and responses are continuing in character so as to require you to file supplemental answers as soon as possible if you obtain further or different information. Any supplemental answer should refer to the date and use the number of the original request or subpart thereof.

13. Whenever these Data Requests specifically request an answer rather than the identification of documents, the answer is required and the production of documents in lieu thereof will not substitute for an answer.

14. To the extent that the Company believes it is burdensome to produce specific information requested, please contact NewSun to discuss the problem and determine if the request can be modified to pose less difficulty in responding before filing an answer objecting to the specific information requested.

15. To the extent the Company objects to any of these requests, please contact NewSun to determine if the request can be modified to produce a less objectionable request.

III. FIRST SET OF DATA REQUESTS:

1. Please provide Jared Ellsworth's resume or CV.

    a. Please list all cases in which Jared Ellsworth appeared as a witness in the last 10 years.
    b. Please provide copies of all testimony prepared by Jared Ellsworth in the last 10 years.

2. Please provide Allison Williams's resume or CV.

    a. Please list all cases in which Allison Williams appeared as a witness in the last 10 years.
    b. Please provide copies of all testimony prepared by Allison Williams in the last 10 years.

3. Please list all Idaho Power employees that at any point prior to becoming employed by Idaho Power have been employed by the Oregon Public Utility Commission. For each employee listed, please:

    a. Provide the employee's resume or CV,
    b. Indicate the employee's job responsibilities while employed by the Oregon Public Utility Commission,
    c. List each docket in which that employee took an active part on behalf of the Oregon Public Utility Commission,
    d. Indicate the employee's job responsibilities while employed by Idaho Power,
    e. List each docket in which that employee took an active part on behalf Idaho Power,
    f. Provide copies of all testimony prepared by that employee while employed by Idaho Power.

4. Please list all consultants, independent contractors, or other non-Idaho Power employees that have been retained by Idaho Power in any capacity and that at any point prior to being retained by Idaho Power have been employed by the Oregon Public Utility Commission. For each individual listed, please:

a. Provide the individual's resume or CV,
b. Indicate the individual's job responsibilities while employed by the Oregon Public Utility Commission,
c. List each docket in which that individual took an active part on behalf of the Oregon Public Utility Commission,
d. Indicate the individual's responsibilities while retained by Idaho Power,
e. List each docket in which that individual took an active part on behalf Idaho Power,
f. Provide copies of all testimony prepared by that individual while retained by Idaho Power.

5. Please list all power purchase agreements under which Idaho Power purchases power including:

   a. Project name,
   b. Nameplate capacity,
   c. Term of power purchases,
   d. Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,
   e. Whether the facility is certified as a qualifying facility under PURPA,
   f. Under what interconnection rules/process the facility was interconnected,
   g. Whether the facility interconnected as ERIS or NRIS,
   h. The cost of network upgrades funded under the interconnection agreement,
   i. Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,
   j. The type of transmission service,
   k. The entity that submitted the transmission service request,
   l. The cost of network upgrades funded under the transmission service request.

6. For each qualifying facility that has requested a power purchase agreement (PPA) with Idaho Power from January 1, 2014 until present please provide the following:

   a. Project name,
   b. Date of PPA request,
   c. Nameplate capacity,
   d. Project location (county and state),
   e. Generation technology type (wind, solar, etc),
   f. Interconnecting utility,
   g. The power purchase agreement, if one was executed,
   h. The developer or developers that requested or negotiated the power purchase agreement,
   i. The in-service date, if operating, or scheduled commercial operation date if not,

7. For each generator that has submitted an interconnection application to Idaho Power from January 1, 2014 until present please provide the following:

    a. Queue Number,
    b. Project name,
    c. Date of interconnection request,
    d. Interconnection request status,
    e. Nameplate capacity,
    f. Project location (county and state),
    g. Generation technology type (wind, solar, etc),
    h. Whether the project requested interconnection as a QF selling 100% of its net output to Idaho Power (at initial application or at any point during the interconnection process) and whether it switched from this QF status to non-QF status, and the date it switched (or vice-versa, if it first requested interconnection as a non-QF and later switched to QF),
    i. Any interconnection studies not publicly available online, including any prior studies which have been superseded by the studies that are posted on the website,
    j. The interconnection agreement, if one was executed,
    k. The developer or developers that submitted the interconnection application,
    l. The in-service date, if operating, or scheduled commercial operation date if not,
    m. Regarding NR and ER interconnection service:
        1. Which service type was requested at initial application,
        2. Which service type was studied in each of the Feasibility, System Impact, and Facilities studies,
        3. Which service type the project ultimately interconnected under,
    n. Regarding network upgrade costs (identified in ER or NR or both):
        1. Estimated network upgrade costs in each of the Feasibility, System Impact, and Facilities studies,
        2. Final network upgrade costs assigned to the generator,
        3. Whether the network upgrades were ultimately constructed or are under construction,
    o. Provide a comparative table for all interconnection requests showing the key features of ER/NR (initial and final), interconnection and network upgrade costs (initial and final), withdrawal status, GIA execution, operational status, and QF status.
    p. Summarize the comparative outcomes of ER interconnection vs NR interconnection applications as relates interconnection and generator outcomes for projects in the following GIR size ranges: 0-10, 11-20, 21-40, 41-60, 61-80. Indicate withdrawal rates and summary numbers, interconnection agreements signed, and average final interconnection costs including network upgrades.

8. For each network upgrade constructed since January 1, 2014, please provide:

    a. The cost of the network upgrade,
    b. Where Idaho Power first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),
    c. How the network upgrade was funded (e.g., utility funded, queue number funded, other),
    d. Whether the network upgrade was included in rate base or whether Idaho Power intends to include it in rate base,
    e. If the network upgrade was included in rate base, the rate of return earned on the network upgrade,
    f. The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others),
    g. The net increase or decrease in transmission customer rates that resulted from the network upgrade,

9. Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?

10. Please list all QF interconnections that resulted in lower transmission rates from Bonneville Power Administration (BPA) for Network Integration Transmission (NT) Service by reducing network load on the hour of the BPA Monthly Transmission System Peak Load?

11. Does Idaho Power add to rate base the costs of network upgrades paid for by qualifying facilities? Does Idaho Power add to rate base the costs of network upgrades paid for or financed by non-QF generators who interconnect to Idaho Power's system?

12. Referring to Joint Utilities/200 (Wilding-Macfarlane-Williams) at 11, please identify all upgrades on the utility's system in Oregon that were required solely to provide adequate transmission capacity for the interconnecting QF.

13. In its response to NIPPC Information Request No. 30, Idaho Power states that imposing Network Upgrade costs on QFs is necessary to prevent the total cost of the QF, including energy, capacity, and interconnection costs, from exceeding the utility's avoided costs. Identify all examples in which an interconnecting QF would have been paid more than the utility's avoided costs if had not been required to pay for Network Upgrades.

14. Please provide all evidentiary support for the premise that upgrades to the transmission network caused by qualifying facility interconnections provide no system benefits.

15. Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 8-9, identify the engineering or modeling methodologies the utility would deem acceptable to demonstrate that a QF-funded Network Upgrade results in quantifiable system-wide benefits to the utility's transmission system and/or distribution network.

16. How does Idaho Power account for forecast new loads and/or load growth when conducting interconnection studies for new generation? Is the treatment the same for ERIS as for NRIS studies?

17. Please provide an itemized summary table of all network upgrades constructed by Idaho Power since 2010 in Oregon and planned for construction in Oregon (or cost allocation to Oregon ratepayers), including the upgrades' associated costs (initial estimate and final actual cost), whether currently rate-based (or planned for future rate-basing approval), project justification(s), nominal capacity, amount of associated load and generation directly supported by the specific incremental upgrade (total and $/MW), ratio of maximum service capacity to directly supported actual, in-service generation or load, and the average cost per MW of capacity per ratepayer. Identify explicitly where excess capacity was built in anticipation of future use (not immediate direct use), itemizing comparatively for those justified by loads, by generators, and by QFs.

18. Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

    a. Queue Number,
    b. Project name,
    c. Date of transmission service request,
    d. Transmission service request status,
    e. Nameplate capacity,
    f. Project location (county and state),
    g. Generation technology type (wind, solar, etc),
    h. Type of transmission service,
    i. Point of receipt and point of delivery,
    j. Any transmission service request studies not publicly available online,
    k. The transmission service agreement, if one was executed,
    l. The in-service date, if operating, or scheduled commercial operation date if not,
    m. Whether the output from the generator is delivered to Idaho Power's retail load,
    n. Whether the generator is a qualifying facility,
    o. Whether the generator is on-system or off system,

p. Whether the generator is interconnected using ERIS or NRIS,
q. Regarding network upgrade costs:
    1. Estimated network upgrade costs in any transmission service studies,
    2. Final network upgrade costs assigned to the request,
    3. Whether the network upgrades were ultimately constructed or are under construction,

19. Identify all instances in which Idaho Power provides firm transmission service, including either Network Interconnection Transmission Service or Point-to-Point Transmission service, to generators interconnected using ERIS.

20. For each State in which Idaho Power operates, please:

    a. Describe which set of procedures Idaho Power uses to interconnect qualifying facilities that propose to sell 100% of their net output to Idaho Power,

    b. Describe which set of procedures Idaho Power uses to interconnect qualifying facilities that propose to sell less than 100% of their net output to Idaho Power,

    c. Indicate for (a) and (b) whether QFs have the option to select ERIS or NRIS,

    d. Indicate for (a) and (b) whether QFs receive refunds for the cost of network upgrades,

    e. Describe the cost allocation and refund policy for network upgrades; compare these policies based on whether the QF interconnected as a FERC or state-jurisdictional interconnection?

    f. How would these answers differ if a prospective otherwise equivalent generator proposed interconnection but it did not seek to sell 100% of its output under a mandatory purchase contract to Idaho Power? For example, in each situation, if the potential QF were a 40 MW solar-only facility that was eligible for certification as a QF.

21. Indicate whether Idaho Power believes it is obligated to purchase power from a QF in the following circumstances:

    g. If it is interconnected via a FERC jurisdictional interconnection? If such interconnection is ER? If NR?

    h. Is that answer different if the QF was off-system or on-system?

    i. If the QF only proposes to sell one hour per year to the QF?

j. If the QF proposes to sell all of its output except 1 day per year?

k. If the QF proposes solely to sell Idaho Power power seasonally?

l. If the QF sells some of its other output to another utility?

22. What interconnection rules, tariff or policies does Idaho Power use to process an interconnection request from a QF that intends to sell its power to Idaho Power as delivered—i.e., not pursuant to a contract or other legally enforceable obligation to sell over a specified term—including in the case where the QF might deliver some output to a different buyer?

23. Is it Idaho Power's position that the current system of siting non-QF renewable generation on Idaho Power's transmission and distribution system is efficient for interconnection customers and potential customers in the market?

24. Is it Idaho Power's position that the utility has no obligation to provide for an efficient process for identifying lower-cost sites for renewable generators on Idaho Power's transmission and distribution system?

25. Has Idaho Power constructed any network upgrades that provided capacity beyond that which was required to serve network load? How were the costs of those upgrades recovered?

26. How does Idaho Power determine whether a network upgrade provides quantifiable system-wide benefits? Has Idaho Power constructed any network upgrades recovered via retail rates that did not provide system-wide benefits?

27. Are there any constrained paths on Idaho Power's network that would benefit from locating additional generation?

28. Can Idaho Power explain how the standard for recovery of network upgrade costs from retail customers for Idaho Power planned and constructed network upgrades is the same as the standard Idaho Power would wish to impose on QFs requesting interconnection and reimbursement for network upgrades?

29. Are there any areas of Idaho Power's system where additional generation would provide benefits to Idaho Power wholesale or retail customers?

30. Please describe network upgrades Idaho Power constructed during the period of years 2000-2010. How were the costs of those network upgrades recovered? How were the benefits of those network upgrades determined? Were those "deliverability-driven" network upgrades? How was the deliverability analysis performed?

31. Is there capacity created by Idaho Power network upgrades included in retail rates that is not being fully utilized? Is this a result of the nature of lumped network capacity upgrades?

32. Has Idaho Power constructed any network upgrades that were driven by the need to provide deliverability to California or Canada? How were those upgrades paid for? How were the costs of those upgrades recovered? Are there any areas where additional generation could have been sited that would have offset or eliminated the need for those network upgrades?

33. Will the Northwest Energy Imbalance Market (EIM) change the way Idaho Power's transmission system is utilized? Will additional benefits accrue to Idaho Power retail customers as a result of the EIM? Should the existence of this market influence the cost recovery mechanisms for future network upgrades?

34. How do siting decisions for Idaho Power-owned generation resources address cost recovery for associated network upgrades and how does that differ from what the Joint Utilities are advocating for QFs? How does Idaho Power conclude that one approach promotes efficient siting decisions while the other does not?

35. Can Idaho Power explain how network upgrades associated with Idaho Power's remote generation facilities only benefit Idaho Power customers and provide no quantifiable benefit to other transmission customers or support for the reliability of the transmission grid as a whole?

36. Commission Staff have expressed a concern that avoided interconnection costs may not be adequately captured in utilities' current avoided cost calculations. Please explain how system-wide benefits of non- Idaho Power owned generation to the transmission network are included in Idaho Power 's current avoided costs.

37. The Joint Utilities argue there is no factual basis for presuming that system upgrades benefit all users of the system. Is Idaho Power's position that there should be a presumption that system upgrades only benefit a single user of the system? Doesn't this run counter to the presumption that the Western Interconnection operates as a single synchronized grid that provides reliability and resiliency benefits for all users?

38. Grid resilience is the ability to avoid or withstand grid stress events without suffering operational compromise or to adapt to and compensate for the resultant strains so as to minimize compromise via graceful degradation. It is in large part about what does not happen to the grid or electricity

39. Idaho Power is a member of Northern Grid which is a transmission planning association formed to facilitate regional transmission planning across the Pacific Northwest and Intermountain West and provide the region with a forum to discuss common planning assumptions, identify regional upgrade projects, eliminate duplicative administrative processes, and facilitate compliance with FERC cost allocation requirements. Please explain how Idaho Power perceives common interests and shared benefits derived from coordination with other NW transmission entities and also holds the view that upgrades to that transmission

network as a result of distributed resource additions only benefit the owner of the generation resource.

40. Please explain how Idaho Power 's avoided costs rates would change if the proxy resource used for calculating the avoided costs were located in an area outside of BPA's balancing authority area and outside of Idaho Power's balancing authority area.

NewSun Energy LLC
390 SW Columbia, Suite 120
Bend, OR 97702

January 6, 2021

Via Electronic Mail

Donald Light
Portland General Electric Company
121 SW Salmon St, 1WTC1301
Portland OR 97204
Donald.light@pgn.com

Lisa Rackner and Jordan Schoonover
McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
dockets@mrg-law.com

Re: In the Matter of PULBIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities
Docket No. UM 2032

Dear Donald, Lisa and Jordan:

Please find NewSun Energy LLC's ("NewSun") first set of data requests to Portland General Electric ("PGE") in this proceeding. PGE has fourteen days to response to these data requests, or by January 20, 2021.

Please do not hesitate to contact me with any questions.

Sincerely,

NewSun Energy LLC

/s/ Marie Barlow

Marie Barlow
In-House Counsel, Policy & Regulatory Affairs

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2032

In the matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities	**NEWSUN ENERGY LLC'S FIRST SET OF DATA REQUESTS TO PGE**

Dated: January 6, 2021

I. DEFINITIONS:

1. "Documents" refers to all writings and records of every type in your possession, control, or custody, whether or not claimed to be privileged or otherwise excludable from discovery, including but not limited to: testimony and exhibits, memoranda, papers, correspondence, letters, reports (including drafts, preliminary, intermediate, and final reports), surveys, analyses, studies (including economic and market studies), summaries, comparisons, tabulations, bills, invoices, statements of services rendered, charts, books, pamphlets, photographs, maps, bulletins, corporate or other minutes, notes, diaries, log sheets, ledgers, transcripts, microfilm, microfiche, computer data (including E-mail), computer files, computer tapes, computer inputs, computer outputs and printouts, vouchers, accounting statements, budgets, workpapers, engineering diagrams (including "one-line" diagrams), mechanical and electrical recordings, telephone and telegraphic communications, speeches, and all other records, written, electrical, mechanical, or otherwise, and drafts of any of the above.

   "Documents" include copies of documents, where the originals are not in your possession, custody, or control.

   "Documents" include every copy of a document, which contains handwritten or other notations, or which otherwise does not duplicate the original or any other copy.

   "Documents" also include any attachments or appendices to any document.

2. "Identification" and "identify" mean:

When used with respect to a document, stating the nature of the document (e.g., letter, memorandum, corporate minutes); the date, if any, appearing thereon; the date, if known, on which the document was prepared; the title of the document; the general subject matter of the document; the number of pages comprising the document; the identity of each person who wrote, dictated, or otherwise participated in the preparation of the document; the identity of each person who signed or initiated the document; the identity of each person to whom the document was addressed; the identity of each person who received the document or reviewed it; the location of the document; and the identity of each person having possession, custody, or control of the document.

When used with respect to a person, stating his or her full name; his or her most recently known home and business addresses and telephone numbers; his or her present title and position; and his or her present and prior connections or associations with any participant or party to this proceeding.

3. "PGE" refers to Portland General Electric Company or any officer, director, or employee of Portland General Electric Company, or any affiliated company.

4. "Person" refers to, without limiting the generality of its meaning, every natural person, corporation, partnership, association (whether formally organized or ad hoc), joint venture, unit operation, cooperative, municipality, commission, governmental body or agency, or any other group or organization.

5. "Studies" or "study" includes, without limitation, reports, reviews, analyses, and audits.

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10. Identify the person from whom the information and documents supplied in response to each Data Request were obtained, the person who prepared each response, the person who reviewed each response, and the person who will bear ultimate responsibility for the truth of each response.

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14. To the extent that the Company believes it is burdensome to produce specific information requested, please contact NewSun to discuss the problem and determine if the request can be modified to pose less difficulty in responding before filing an answer objecting to the specific information requested.

15. To the extent the Company objects to any of these requests, please contact NewSun to determine if the request can be modified to produce a less objectionable request.

III. <u>FIRST SET OF DATA REQUESTS:</u>

1. Please provide Shaun Foster's resume or CV.

    a. Please list all cases in which Shaun Foster appeared as a witness in the last 10 years.
    b. Please provide copies of all testimony prepared by Shaun Foster in the last 10 years.

2. Please provide Sean Larsen's resume or CV.

    a. Please list all cases in which Sean Larsen appeared as a witness in the last 10 years.
    b. Please provide copies of all testimony prepared by Sean Larsen in the last 10 years.

3. Please provide Robert Macfarlane's resume or CV.

    a. Refer to Joint Utilities/200, Wilding-Macfarlane-Williams/2, lines 10-12. Please provide copies of all testimony prepared by Robert Macfarlane in the referenced proceedings.

4. Please list all PGE employees that at any point prior to becoming employed by PGE have been employed by the Oregon Public Utility Commission. For each employee listed, please:

    a. Provide the employee's resume or CV,
    b. Indicate the employee's job responsibilities while employed by the Oregon Public Utility Commission,

c. List each docket in which that employee took an active part on behalf of the Oregon Public Utility Commission,
d. Indicate the employee's job responsibilities while employed by PGE,
e. List each docket in which that employee took an active part on behalf PGE,
f. Provide copies of all testimony prepared by that employee while employed by PGE.

5. Please list all consultants, independent contractors, or other non- PGE employees that have been retained by PGE in any capacity and that at any point prior to being retained by PGE have been employed by the Oregon Public Utility Commission. For each individual listed, please:

    a. Provide the individual's resume or CV,
    b. Indicate the individual's job responsibilities while employed by the Oregon Public Utility Commission,
    c. List each docket in which that individual took an active part on behalf of the Oregon Public Utility Commission,
    d. Indicate the individual's responsibilities while retained by PGE,
    e. List each docket in which that individual took an active part on behalf PGE,
    f. Provide copies of all testimony prepared by that individual while retained by PGE.

6. Please list all power purchase agreements under which PGE purchases power including:

    a. Project name,
    b. Nameplate capacity,
    c. Term of power purchases,
    d. Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,
    e. Whether the facility is certified as a qualifying facility under PURPA,
    f. Under what interconnection rules/process the facility was interconnected,
    g. Whether the facility interconnected as ERIS or NRIS,
    h. The cost of network upgrades funded under the interconnection agreement,
    i. Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,
    j. The type of transmission service,
    k. The entity that submitted the transmission service request,
    l. The cost of network upgrades funded under the transmission service request.

7. For each qualifying facility that has requested a power purchase agreement (PPA) with PGE from January 1, 2014 until present please provide the following:

a. Project name,
b. Date of PPA request,
c. Nameplate capacity,
d. Project location (county and state),
e. Generation technology type (wind, solar, etc),
f. Interconnecting utility,
g. The power purchase agreement, if one was executed,
h. The developer or developers that requested or negotiated the power purchase agreement,
i. The in-service date, if operating, or scheduled commercial operation date if not,

8. For each generator that has submitted an interconnection application to PGE from January 1, 2014 until present please provide the following:

a. Queue Number,
b. Project name,
c. Date of interconnection request,
d. Interconnection request status,
e. Nameplate capacity,
f. Project location (county and state),
g. Generation technology type (wind, solar, etc),
h. Whether the project requested interconnection as a QF selling 100% of its net output to PGE (at initial application or at any point during the interconnection process) and whether it switched from this QF status to non-QF status, and the date it switched (or vice-versa, if it first requested interconnection as a non-QF and later switched to QF),
i. Any interconnection studies not publicly available online, including any prior studies which have been superseded by the studies that are posted on the website,
j. The interconnection agreement, if one was executed,
k. The developer or developers that submitted the interconnection application,
l. The in-service date, if operating, or scheduled commercial operation date if not,
m. Regarding NR and ER interconnection service:
    1. Which service type was requested at initial application,
    2. Which service type was studied in each of the Feasibility, System Impact, and Facilities studies,
    3. Which service type the project ultimately interconnected under,
n. Regarding network upgrade costs (identified in ER or NR or both):
    1. Estimated network upgrade costs in each of the Feasibility, System Impact, and Facilities studies,
    2. Final network upgrade costs assigned to the generator,

3. Whether the network upgrades were ultimately constructed or are under construction,

o. Provide a comparative table for all interconnection requests showing the key features of ER/NR (initial and final), interconnection and network upgrade costs (initial and final), withdrawal status, GIA execution, operational status, and QF status.

p. Summarize the comparative outcomes of ER interconnection vs NR interconnection applications as relates interconnection and generator outcomes for projects in the following GIR size ranges: 0-10, 11-20, 21-40, 41-60, 61-80. Indicate withdrawal rates and summary numbers, interconnection agreements signed, and average final interconnection costs including network upgrades.

9. For each network upgrade constructed since January 1, 2014, please provide:

a. The cost of the network upgrade,
b. Where PGE first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),
c. How the network upgrade was funded (e.g., utility funded, queue number funded, other),
d. Whether the network upgrade was included in rate base or whether PGE intends to include it in rate base,
e. If the network upgrade was included in rate base, the rate of return earned on the network upgrade,
f. The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others),
g. The net increase or decrease in transmission customer rates that resulted from the network upgrade,

10. Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?

11. Please list all QF interconnections that resulted in lower transmission rates from Bonneville Power Administration (BPA) for Network Integration Transmission (NT) Service by reducing network load on the hour of the BPA Monthly Transmission System Peak Load?

12. Does PGE add to rate base the costs of network upgrades paid for by qualifying facilities? Does PGE add to rate base the costs of network

upgrades paid for or financed by non-QF generators who interconnect to PGE's system?

13. Referring to Joint Utilities/200 (Wilding-Macfarlane-Williams) at 11, please identify all upgrades on the utility's system in Oregon that were required solely to provide adequate transmission capacity for the interconnecting QF.

14. In its response to NIPPC Information Request No. 30, PGE states that imposing Network Upgrade costs on QFs is necessary to prevent the total cost of the QF, including energy, capacity, and interconnection costs, from exceeding the utility's avoided costs. Identify all examples in which an interconnecting QF would have been paid more than the utility's avoided costs if had not been required to pay for Network Upgrades.

15. Please provide all evidentiary support for the premise that upgrades to the transmission network caused by qualifying facility interconnections provide no system benefits.

16. Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 8-9, identify the engineering or modeling methodologies the utility would deem acceptable to demonstrate that a QF-funded Network Upgrade results in quantifiable system-wide benefits to the utility's transmission system and/or distribution network.

17. How does PGE account for forecast new loads and/or load growth when conducting interconnection studies for new generation? Is the treatment the same for ERIS as for NRIS studies?

18. Please provide an itemized summary table of all network upgrades constructed by PGE since 2010 in Oregon and planned for construction in Oregon (or cost allocation to Oregon ratepayers), including the upgrades' associated costs (initial estimate and final actual cost), whether currently rate-based (or planned for future rate-basing approval), project justification(s), nominal capacity, amount of associated load and generation directly supported by the specific incremental upgrade (total and $/MW), ratio of maximum service capacity to directly supported actual, in-service generation or load, and the average cost per MW of capacity per ratepayer. Identify explicitly where excess capacity was built in anticipation of future use (not immediate direct use), itemizing comparatively for those justified by loads, by generators, and by QFs.

19. Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

   a. Queue Number,

b. Project name,
c. Date of transmission service request,
d. Transmission service request status,
e. Nameplate capacity,
f. Project location (county and state),
g. Generation technology type (wind, solar, etc),
h. Type of transmission service,
i. Point of receipt and point of delivery,
j. Any transmission service request studies not publicly available online,
k. The transmission service agreement, if one was executed,
l. The in-service date, if operating, or scheduled commercial operation date if not,
m. Whether the output from the generator is delivered to PGE's retail load,
n. Whether the generator is a qualifying facility,
o. Whether the generator is on-system or off system,
p. Whether the generator is interconnected using ERIS or NRIS,
q. Regarding network upgrade costs:
    1. Estimated network upgrade costs in any transmission service studies,
    2. Final network upgrade costs assigned to the request,
    3. Whether the network upgrades were ultimately constructed or are under construction,

20. Identify all instances in which PGE provides firm transmission service, including either Network Interconnection Transmission Service or Point-to-Point Transmission service, to generators interconnected using ERIS.

21. For each State in which PGE operates, please:

a. Describe which set of procedures PGE uses to interconnect qualifying facilities that propose to sell 100% of their net output to PGE,

b. Describe which set of procedures PGE uses to interconnect qualifying facilities that propose to sell less than 100% of their net output to PGE,

c. Indicate for (a) and (b) whether QFs have the option to select ERIS or NRIS,

d. Indicate for (a) and (b) whether QFs receive refunds for the cost of network upgrades,

e. Describe the cost allocation and refund policy for network upgrades; compare these policies based on whether the QF interconnected as a FERC or state-jurisdictional interconnection?

f. How would these answers differ if a prospective otherwise equivalent generator proposed interconnection but it did not seek to sell 100% of its output under a mandatory purchase contract to PGE? For example, in each situation, if the potential QF were a 40 MW solar-only facility that was eligible for certification as a QF.

22. Indicate whether PGE believes it is obligated to purchase power from a QF in the following circumstances:

g. If it is interconnected via a FERC jurisdictional interconnection? If such interconnection is ER? If NR?

h. Is that answer different if the QF was off-system or on-system?

i. If the QF only proposes to sell one hour per year to the QF?

j. If the QF proposes to sell all of its output except 1 day per year?

k. If the QF proposes solely to sell PGE power seasonally?

l. If the QF sells some of its other output to another utility?

23. What interconnection rules, tariff or policies does PGE use to process an interconnection request from a QF that intends to sell its power to PGE as delivered—i.e., not pursuant to a contract or other legally enforceable obligation to sell over a specified term—including in the case where the QF might deliver some output to a different buyer?

24. Is it PGE's position that the current system of siting non-QF renewable generation on PGE's transmission and distribution system is efficient for interconnection customers and potential customers in the market?

25. Is it PGE's position that the utility has no obligation to provide for an efficient process for identifying lower-cost sites for renewable generators on PGE's transmission and distribution system?

26. Has PGE constructed any network upgrades that provided capacity beyond that which was required to serve network load? How were the costs of those upgrades recovered?

27. How does PGE determine whether a network upgrade provides quantifiable system-wide benefits? Has PGE constructed any network upgrades recovered via retail rates that did not provide system-wide benefits?

28. Did construction of additional generating resources at Port Westward avoid any network upgrade costs associated with a constrained transmission path? Did construction of additional generating resources at

Port Westward create the need for any network upgrades on PGE’s system?

29. Did the interconnection of Carty create the need for network upgrades? What upgrades were required? Who paid for those upgrades? How does the cost of Carty including the cost of any necessary network upgrades compare to PGE’s avoided cost?

30. Did the interconnection of Wheatridge create the need for network upgrades? What upgrades were required? Who paid for those upgrades? How does the cost of Carty including the cost of any necessary network upgrades compare to PGE’s avoided cost?

31. Are there any constrained paths on PGE’s network that would benefit from locating additional generation?

32. Can PGE explain how the standard for recovery of network upgrade costs from retail customers for PGE planned and constructed network upgrades is the same as the standard PGE would wish to impose on QFs requesting interconnection and reimbursement for network upgrades?

33. Are there any areas of PGE’s system where additional generation would provide benefits to PGE wholesale or retail customers?

34. Please describe network upgrades PGE constructed during the period of years 2000-2010. How were the costs of those network upgrades recovered? How were the benefits of those network upgrades determined? Were those “deliverability-driven” network upgrades? How was the deliverability analysis performed?

35. Is there capacity created by PGE network upgrades included in retail rates that is not being fully utilized? Is this a result of the nature of lumped network capacity upgrades?

36. Has PGE constructed any network upgrades that were driven by the need to provide deliverability to California or Canada? How were those upgrades paid for? How were the costs of those upgrades recovered? Are there any areas where additional generation could have been sited that would have offset or eliminated the need for those network upgrades?

37. Will the Northwest Energy Imbalance Market (EIM) change the way PGE’s transmission system is utilized? Will additional benefits accrue to PGE retail customers as a result of the EIM? Should the existence of this

market influence the cost recovery mechanisms for future network upgrades?

38. Please describe the deliverability analysis that was performed for Carty and Wheatridge. Was it assumed that the full output of those generating resources would be delivered to PGE load during all hours of operation?

39. How do siting decisions for PGE-owned generation resources address cost recovery for associated network upgrades and how does that differ from what the Joint Utilities are advocating for QFs? How does PGE conclude that one approach promotes efficient siting decisions while the other does not?

40. Can PGE explain how network upgrades associated with PGE's remote generation facilities only benefit PGE customers and provide no quantifiable benefit to other transmission customers or support for the reliability of the transmission grid as a whole?

41. Commission Staff have expressed a concern that avoided interconnection costs may not be adequately captured in utilities' current avoided cost calculations. Please explain how system-wide benefits of non-PGE owned generation to the transmission network are included in PGE's current avoided costs.

42. The Joint Utilities argue there is no factual basis for presuming that system upgrades benefit all users of the system. Is PGE's position that there should be a presumption that system upgrades only benefit a single user of the system? Doesn't this run counter to the presumption that the Western Interconnection operates as a single synchronized grid that provides reliability and resiliency benefits for all users?

43. Grid resilience is the ability to avoid or withstand grid stress events without suffering operational compromise or to adapt to and compensate for the resultant strains so as to minimize compromise via graceful degradation. It is in large part about what does not happen to the grid or electricity

44. PGE is a member of Northern Grid which is a transmission planning association formed to facilitate regional transmission planning across the Pacific Northwest and Intermountain West and provide the region with a forum to discuss common planning assumptions, identify regional upgrade projects, eliminate duplicative administrative processes, and facilitate compliance with FERC cost allocation requirements. Please explain how

PGE perceives common interests and shared benefits derived from coordination with other NW transmission entities and also holds the view that upgrades to that transmission network as a result of distributed resource additions only benefit the owner of the generation resource.

45. Please explain how PGE's avoided costs rates would change if the proxy resource used for calculating the avoided costs were located in an area outside of BPA's balancing authority area and outside of PGE's balancing authority area.

46. PGE has noted a QF interconnected directly to a PGE-owned transmission line in Central Oregon. Please explain how the investment for this line is being recovered and why the cost recovery mechanism for the original transmission line should differ from the recovery mechanism for subsequent upgrades. Please explain how the beneficiaries of the original transmission line would not realize any benefit from subsequent upgrades to that line.

NewSun Energy LLC
390 SW Columbia, Suite 120
Bend, OR 97702

January 6, 2021

Via Electronic Mail

Karen Kruse
Pacific Power
825 NE Multnomah St., Ste. 2000
Portland, OR 97232
Karen.kruse@pacificorp.com

Carla Scarsella
Pacific Power
825 NE Multnomah St., Ste. 2000
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Carla.scarsella@pacificorp.com

Re: In the Matter of PULBIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities
Docket No. UM 2032

Dear Karen, Carla:

Please find NewSun Energy LLC's ("NewSun") first set of data requests to PacifiCorp in this proceeding. PacifiCorp has fourteen days to response to these data requests, or by January 20, 2021.

Please do not hesitate to contact me with any questions.

Sincerely,

NewSun Energy LLC

/s/ Marie Barlow

Marie Barlow
In-House Counsel, Policy & Regulatory Affairs

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2032

In the matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities	**NEWSUN ENERGY LLC'S FIRST SET OF DATA REQUESTS TO PACIFICORP**

Dated: January 6, 2021

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When used with respect to a person, stating his or her full name; his or her most recently known home and business addresses and telephone numbers; his or her present title and position; and his or her present and prior connections or associations with any participant or party to this proceeding.

3. “PacifiCorp” refers to PacifiCorp, Pacific Power, Rocky Mountain Power or any officer, director, or employee of PacifiCorp, Pacific Power, Rocky Mountain Power, or any affiliated company.

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12. These requests for documents and responses are continuing in character so as to require you to file supplemental answers as soon as possible if you obtain further or different information. Any supplemental answer should refer to the date and use the number of the original request or subpart thereof.

13. Whenever these Data Requests specifically request an answer rather than the identification of documents, the answer is required and the production of documents in lieu thereof will not substitute for an answer.

14. To the extent that the Company believes it is burdensome to produce specific information requested, please contact NewSun to discuss the problem and determine if the request can be modified to pose less difficulty in responding before filing an answer objecting to the specific information requested.

15. To the extent the Company objects to any of these requests, please contact NewSun to determine if the request can be modified to produce a less objectionable request.

III. FIRST SET OF DATA REQUESTS:

1. Please provide Richard A. Vail's resume or CV.

   a. Please list all cases in which Richard A. Vail appeared as a witness in the last 10 years.
   b. Please provide copies of all testimony prepared by Richard A. Vail in the last 10 years.

2. Please provide Kris Bremer's resume or CV.

   a. Please list all cases in which Kris Bremer appeared as a witness in the last 10 years.
   b. Please provide copies of all testimony prepared by Kris Bremer in the last 10 years.

3. Please provide Michael G. Wilding's resume or CV.

   a. Refer to Joint Utilities/200, Wilding-Macfarlane-Williams/1, lines 19-21. Please list all cases in which Michael G. Wilding appeared as a witness in the last 10 years.
   b. Refer to Joint Utilities/200, Wilding-Macfarlane-Williams/1, lines 19-21. Please provide copies of all testimony prepared by Michael G. Wilding in the last 10 years.

4. Please list all PacifiCorp employees that at any point prior to becoming employed by PacifiCorp have been employed by the Oregon Public Utility Commission. For each employee listed, please:

   a. Provide the employee's resume or CV,

b. Indicate the employee's job responsibilities while employed by the Oregon Public Utility Commission,
c. List each docket in which that employee took an active part on behalf of the Oregon Public Utility Commission,
d. Indicate the employee's job responsibilities while employed by PacifiCorp,
e. List each docket in which that employee took an active part on behalf PacifiCorp,
f. Provide copies of all testimony prepared by that employee while employed by PacifiCorp.

5. Please list all consultants, independent contractors, or other non-PacifiCorp employees that have been retained by PacifiCorp in any capacity and that at any point prior to being retained by PacifiCorp have been employed by the Oregon Public Utility Commission. For each individual listed, please:

    a. Provide the individual's resume or CV,
    b. Indicate the individual's job responsibilities while employed by the Oregon Public Utility Commission,
    c. List each docket in which that individual took an active part on behalf of the Oregon Public Utility Commission,
    d. Indicate the individual's responsibilities while retained by PacifiCorp,
    e. List each docket in which that individual took an active part on behalf PacifiCorp,
    f. Provide copies of all testimony prepared by that individual while retained by PacifiCorp.

6. Please list all power purchase agreements under which PacifiCorp purchases power including:

    a. Project name,
    b. Nameplate capacity,
    c. Term of power purchases,
    d. Whether the purchase agreement was entered into pursuant to PURPA, an RFP, a bi-lateral agreement, or other,
    e. Whether the facility is certified as a qualifying facility under PURPA,
    f. Under what interconnection rules/process the facility was interconnected,
    g. Whether the facility interconnected as ERIS or NRIS,
    h. The cost of network upgrades funded under the interconnection agreement,
    i. Whether the generator is eligible to receive refunds for its network upgrades funded under the interconnection agreement,
    j. The type of transmission service,
    k. The entity that submitted the transmission service request,
    l. The cost of network upgrades funded under the transmission service request.

7. For each qualifying facility that has requested a power purchase agreement (PPA) with PacifiCorp from January 1, 2014 until present please provide the following:

   a. Project name,
   b. Date of PPA request,
   c. Nameplate capacity,
   d. Project location (county and state),
   e. Generation technology type (wind, solar, etc),
   f. Interconnecting utility,
   g. The power purchase agreement, if one was executed,
   h. The developer or developers that requested or negotiated the power purchase agreement,
   i. The in-service date, if operating, or scheduled commercial operation date if not,
   j.

8. For each generator that has submitted an interconnection application to PacifiCorp from January 1, 2014 until present please provide the following:

   a. Queue Number,
   b. Project name,
   c. Date of interconnection request,
   d. Interconnection request status,
   e. Nameplate capacity,
   f. Project location (county and state),
   g. Generation technology type (wind, solar, etc),
   h. Whether the project requested interconnection as a QF selling 100% of its net output to PacifiCorp (at initial application or at any point during the interconnection process) and whether it switched from this QF status to non-QF status, and the date it switched (or vice-versa, if it first requested interconnection as a non-QF and later switched to QF),
   i. Any interconnection studies not publicly available online, including any prior studies which have been superseded by the studies that are posted on the website,
   j. The interconnection agreement, if one was executed,
   k. The developer or developers that submitted the interconnection application,
   l. The in-service date, if operating, or scheduled commercial operation date if not,
   m. Regarding NR and ER interconnection service:
      1. Which service type was requested at initial application,
      2. Which service type was studied in each of the Feasibility, System Impact, and Facilities studies,
      3. Which service type the project ultimately interconnected under,
   n. Regarding network upgrade costs (identified in ER or NR or both):
      1. Estimated network upgrade costs in each of the Feasibility, System Impact, and Facilities studies,

2. Final network upgrade costs assigned to the generator,
3. Whether the network upgrades were ultimately constructed or are under construction,

o. Provide a comparative table for all interconnection requests showing the key features of ER/NR (initial and final), interconnection and network upgrade costs (initial and final), withdrawal status, GIA execution, operational status, and QF status.

p. Summarize the comparative outcomes of ER interconnection vs NR interconnection applications as relates interconnection and generator outcomes for projects in the following GIR size ranges: 0-10, 11-20, 21-40, 41-60, 61-80. Indicate withdrawal rates and summary numbers, interconnection agreements signed, and average final interconnection costs including network upgrades.

9. Please review PacifiCorp's OASIS Interconnection Generation Queue for the Withdrawn projects, queue number 629. Under the column titled "Request Status Explanation," this queue number states: "original IA signed 7/6/16, new IA signed 5/12/17, terminated 4/22/20," yet no studies are publicly posted on OASIS for this project. Please provide all studies performed for this project including any that may have been withdrawn or overridden by subsequent studies.

10. For each network upgrade constructed since January 1, 2014, please provide:

    a. The cost of the network upgrade,
    b. Where PacifiCorp first identified the need for the network upgrade (e.g., load growth, interconnection request, transmission request, integrated resource plan, or other),
    c. How the network upgrade was funded (e.g., utility funded, queue number funded, other),
    d. Whether the network upgrade was included in rate base or whether PacifiCorp intends to include it in rate base,
    e. If the network upgrade was included in rate base, the rate of return earned on the network upgrade,
    f. The incremental transmission operations resulting from the network upgrade (e.g., increased throughput, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, relief of existing congestion on the transmission system, or others),
    g. The net increase or decrease in transmission customer rates that resulted from the network upgrade,

11. Please list all QF-funded network upgrades that did not result in any benefit to the transmission system, such benefits to include, but not be limited to, increased load serving capability, enhanced reliability, improved transfer capability within the existing system, or relief of existing congestion on the transmission system?

12. Please list all QF interconnections that resulted in lower transmission rates from Bonneville Power Administration (BPA) for Network Integration Transmission (NT) Service by reducing network load on the hour of the BPA Monthly Transmission System Peak Load?

13. Does PacifiCorp add to rate base the costs of network upgrades paid for by qualifying facilities? Does PacifiCorp add to rate base the costs of network upgrades paid for or financed by non-QF generators who interconnect to PacifiCorp's system?

14. Referring to Joint Utilities/200 (Wilding-Macfarlane-Williams) at 11, please identify all upgrades on the utility's system in Oregon that were required solely to provide adequate transmission capacity for the interconnecting QF.

15. In its response to NIPPC Information Request No. 30, PacifiCorp states that imposing Network Upgrade costs on QFs is necessary to prevent the total cost of the QF, including energy, capacity, and interconnection costs, from exceeding the utility's avoided costs. Identify all examples in which an interconnecting QF would have been paid more than the utility's avoided costs if had not been required to pay for Network Upgrades.

16. Please provide all evidentiary support for the premise that upgrades to the transmission network caused by qualifying facility interconnections provide no system benefits.

17. Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 8-9, identify the engineering or modeling methodologies the utility would deem acceptable to demonstrate that a QF-funded Network Upgrade results in quantifiable system-wide benefits to the utility's transmission system and/or distribution network.

18. How does PacifiCorp account for forecast new loads and/or load growth when conducting interconnection studies for new generation? Is the treatment the same for ERIS as for NRIS studies?

19. Regarding PacifiCorp's Ochoco to Corral transmission line and associated upgrades to PacifiCorp's system and substations, and Pacificorp's load service in the Prineville area, please provide:

    a. Where PacifiCorp identified the need for the upgrades (e.g., load growth, interconnection request, transmission request, or other),
    b. How the upgrades were funded (e.g., utility funded, queue number funded, other),
    c. The existing load and forecast load upon which PacifiCorp relied in justifying the upgrade, including the MVa rating of the loads that triggered the upgrades, including the dates of the associated load interconnection

requests, the load initial and current projected on-line dates, and the status of each load service,

d. The cost of the upgrades,
e. How the upgrades were funded (e.g., utility funded, queue number funded, other),
f. Whether the upgrade were included in rate base or whether PacifiCorp intends to include it in rate base,
g. If the upgrades were included in rate base, the rate of return earned on the upgrades,
h. Describe how Pacificorp serves its load in the Prineville area, including to what extent Pacificorp relies on contiguous transmission from other areas of the Pacificorp system.
i. Confirm whether the Prineville service area and Bend and Redmond service areas are electrically contiguous for Pacificorp, and what the transfer capacity is within Pacifcorp's system in the area, as well as what the transfer capacity and monthly average and peak energy service from BPA at each point of service from BPA in the area, including Pilot Butte and Ponderosa substation.
j. Describe what long term rights Pacificorp has on the California-Oregon Intertie (aka the COI aka the AC Intertie) and how Pacificorp uses these rights and other short term procurement via the COI to serve Prineville area load.
k. Provide a comparison for the Prineville area between when interconnections and loads were requested, including comparative timing, along with the available avoided cost rates at the time of each request.
l. Provide a summary of the power contract rates for facilities constructed or contracted to be constructed in the Prineville area, whether those facilities were ER or NR, what the likely network upgrades would have been for any ER facility that was (or is being) constructed if it had been required to be NR instead. Compare the PPA prices for these facilities at the time of contracting with the avoided cost rates available to the QFs which sought interconnections and PPAs in this area.
m. Please provide Pacificorp's analysis based on the information in (k) and (l) as to whether the prospective QFs in its interconnection queue and/or otherwise seeking PPAs from Pacificorp would have likely been economically viable based on these numbers were such facilities allowed ER interconnections and been allowed refundability of network upgrades. How does this compare to the number of actual facilities for which interconnection was requested in the Prineville area system (i.e. on lines directly connected to Ponderosa substation)? Please provide a total of all calculated revenues which would have been associated with any facilities which would have reasonably been likely to be economically viable per prior question; please make such calculations based on estimated facility energy production that would have resulted during the term of the resultant PPA using avoided cost pricing that would have been available at the time.

n. Provide copies of all correspondence, load service studies, upgrades requested, and upgrades implemented, including associated cost estimates and who paid for those upgrades, associated with Pacificorp's service of the Prineville actual and prospective loads, particularly at Ponderosa substation, including a summary of all related lobbying efforts, contacts with BPA executive management, and contact with other elected officials, including the governor's office, Senator Merkely, Senator Widen, and Congressman Walden, and any related requests made for support or action by these officials related to load service in the Prineville area and the justifications for these requests. Please summarize the comparative timing of these upgrades relative to the Pacificorp load queue requests and loads in service, associated capacities, and a comparison of any differences in how generation interconnection studies for the area treated load requests with respect to power flow studies and justification of network upgrades related to service of these load requests, whether such upgrades where performed by Pacificorp or BPA.

20. In its December 24, 2014, filing in FERC Docket Nos. ER15-741-000 & -001, the docket referenced in PacifiCorp's response to OPUC Information Request No. 6, PacifiCorp states that: "on the one hand, PURPA requires a utility to purchase QF power and make firm transmission arrangements (e.g., DNR status) to deliver it, even if the QF has chosen to site in a constrained area. On the other hand, Commission open access policy and precedent do not appear to support the granting of new DNRs until sufficient ATC is available to meet the request. . . this appears to put the utility in the position of having to construct network upgrades in order to accommodate the PURPA-required QF firm transmission service, even if the utility would not have otherwise constructed those upgrades – certainly not for load service, reliability or because they were cost-justified."

    Identify all instances in which PacifiCorp constructed network upgrades in Oregon to accommodate PURPA-required QF firm transmission service that the utility would not have otherwise constructed for load service, reliability, or because the network upgrades were not cost-justified or would not have provided benefits to the transmission system. Identify all instances in which PacifiCorp would have constructed such upgrades but for the OPUC policy of requiring QFs to pay for all network upgrades with no transmission credits or other recovery of costs.

21. Please provide an itemized summary table of all network upgrades constructed by Pacificorp since 2010 in Oregon and planned for construction in Oregon (or cost allocation to Oregon ratepayers), including the upgrades' associated costs (initial estimate and final actual cost), whether currently rate-based (or planned for future rate-basing approval), project justification(s), nominal capacity, amount of associated load and generation directly supported by the specific incremental upgrade (total and $/MW), ratio of maximum service capacity to directly supported actual, in-service generation or load, and the average cost per MW of

capacity per ratepayer. Identify explicitly where excess capacity was built in anticipation of future use (not immediate direct use), itemizing comparatively for those justified by loads, by generators, and by QFs.

22. In its December 24, 2014, filing in FERC Docket Nos. ER15-741-000 & -001, the docket referenced in PacifiCorp's response to OPUC Information Request No. 6, PacifiCorp states that: "on the one hand, PURPA requires a utility to purchase QF power and make firm transmission arrangements (e.g., DNR status) to deliver it, even if the QF has chosen to site in a constrained area. On the other hand, Commission open access policy and precedent do not appear to support the granting of new DNRs until sufficient ATC is available to meet the request. . . this appears to put the utility in the position of having to construct network upgrades in order to accommodate the PURPA-required QF firm transmission service, even if the utility would not have otherwise constructed those upgrades – certainly not for load service, reliability or because they were cost-justified."

    Identify all constrained portions of the PacifiCorp transmission system in Oregon in which PacifiCorp would be required to construct network upgrades to accommodate a QF interconnection and for which such network upgrades would not otherwise be constructed by PacifiCorp to accommodate load growth, to improve system reliability, or to meet planned transmission expansions.

23. Referring to PacifiCorp's response to OPUC Data Request No. 6, identify all instances in which a QF's network upgrade costs were rolled into PacifiCorp's transmission rate base causing a "violation of [PURPA's] customer indifference requirements." Identify all instances in which rolled-in network upgrade costs would have caused such a violation of PURPA's customer indifference requirements but for PacifiCorp's requirement that the QF obtain NR interconnection service.

24. Referring to Joint Utilities/100 (Vail-Bremer-Foster-Larson-Ellsworth) at 30-31, please provide the following for each transmission service request received from January 1, 2014 until present:

    a. Queue Number,
    b. Project name,
    c. Date of transmission service request,
    d. Transmission service request status,
    e. Nameplate capacity,
    f. Project location (county and state),
    g. Generation technology type (wind, solar, etc),
    h. Type of transmission service,
    i. Point of receipt and point of delivery,
    j. Any transmission service request studies not publicly available online,
    k. The transmission service agreement, if one was executed,
    l. The in-service date, if operating, or scheduled commercial operation date if not,

m. Whether the output from the generator is delivered to PacifiCorp's retail load,
n. Whether the generator is a qualifying facility,
o. Whether the generator is on-system or off system,
p. Whether the generator is interconnected using ERIS or NRIS,
q. Regarding network upgrade costs:
    1. Estimated network upgrade costs in any transmission service studies,
    2. Final network upgrade costs assigned to the request,
    3. Whether the network upgrades were ultimately constructed or are under construction,

25. Identify all instances in which PacifiCorp provides firm transmission service, including either Network Interconnection Transmission Service or Point-to-Point Transmission service, to generators interconnected using ERIS.

26. For each State in which PacifiCorp operates, please:

    a. Describe which set of procedures PacifiCorp uses to interconnect qualifying facilities that propose to sell 100% of their net output to PacifiCorp,

    b. Describe which set of procedures PacifiCorp uses to interconnect qualifying facilities that propose to sell less than 100% of their net output to PacifiCorp,

    c. Indicate for (a) and (b) whether QFs have the option to select ERIS or NRIS,

    d. Indicate for (a) and (b) whether QFs receive refunds for the cost of network upgrades,

    e. Describe the cost allocation and refund policy for network upgrades; compare these policies based on whether the QF interconnected as a FERC or state-jurisdictional interconnection?

    f. How would these answers differ if a prospective otherwise equivalent generator proposed interconnection but it did not seek to sell 100% of its output under a mandatory purchase contract to Pacificorp? For example, in each situation, if the potential QF were a 40 MW solar-only facility that was eligible for certification as a QF.

27. Indicate whether Pacificorp believes it is obligated to purchase power from a QF in the following circumstances:

    a. If it is interconnected via a FERC jurisdictional interconnection? If such interconnection is ER? If NR?

b. Is that answer different if the QF was off-system or on-system?

c. If the QF only proposes to sell one hour per year to the QF?

d. If the QF proposes to sell all of its output except 1 day per year?

e. If the QF proposes solely to sell Pacificorp power seasonally?

f. If the QF sells some of its other output to another utility?

28. What interconnection rules, tariff or policies does PacifiCorp use to process an interconnection request from a QF that intends to sell its power to PacifiCorp as delivered—i.e., not pursuant to a contract or other legally enforceable obligation to sell over a specified term—including in the case where the QF might deliver some output to a different buyer?

29. Is it PacifiCorp's position that the current system of siting non-QF renewable generation on PacifiCorp's transmission and distribution system is efficient for interconnection customers and potential customers in the market?

30. Is it PacifiCorp's position that the utility has no obligation to provide for an efficient process for identifying lower-cost sites for renewable generators on PacifiCorp's transmission and distribution system?

31. PacifiCorp's 2020 RFP does not consider the cost of Network Upgrades in scoring proposed projects for selecting winners of the RFP

a. How does PacifiCorp's 2020 RFP ensure efficient siting of generation if network upgrades are not considered?

b. Does Pacificorp expect that ratepayers will bear the cost of all the network upgrades associated with those selections?

c. Are Pacificorp's ratepayers able to receive tax credit benefits for the interconnection and network upgrade costs associated with the RFP shortlist and (if finally selected and constructed) winners?

d. How does the average cost, after tax benefits are accounted for, to ratepayers compare for a dollar of interconnection or network upgrade cost, as compared to a non-interconnection (i.e. tax credit eligible) construction cost of a wind facility? For a solar facility?

e. What is the total projected interconnection and network upgrade costs that Pacificorp anticipates ratepayers will ultimately pay for its RFP initial short list, final short list, and final RFP winners? Please provide per project and summarized estimates. To the extent precise numbers are not known, please provide best available estimate, likely range, and maximum and minimum values.

f. Please also provide these network upgrades and interconnection costs converted to cents per kWh across (a) the applicable PPA power purchase term and (b) across a 15 year power purchase term (as is available in Oregon to a QF).

g. How will these interconnection and network upgrades be financed, including the timing of any direct payments by Pacificorp and when Pacificorp's ratepayers will begin bearing associated costs.

h. Will Pacificorp or the applicable generation own or have the benefit of any surplus interconnection or transmission capacity not directly and immediately used by the RFP projects should the generation facility be constructed? How much capacity? What is the actual and proportional cost of that excess capacity relative the direct need of the applicable generator. Will the ratepayer pay for that additional capacity; if so, when?

32. Has PacifiCorp constructed any network upgrades that provided capacity beyond that which was required to serve network load? How were the costs of those upgrades recovered?

33. How does PacifiCorp determine whether a network upgrade provides quantifiable system-wide benefits? Has PacifiCorp constructed any network upgrades recovered via retail rates that did not provide system-wide benefits?

34. Are there any constrained paths on PacifiCorp's network that would benefit from locating additional generation?

35. Can PacifiCorp explain how the standard for recovery of network upgrade costs from retail customers for PacifiCorp planned and constructed network upgrades is the same as the standard PacifiCorp would wish to impose on QFs requesting interconnection and reimbursement for network upgrades?

36. Are there any areas of PacifiCorp's system where additional generation would provide benefits to PacifiCorp wholesale or retail customers?

37. Please describe network upgrades PacifiCorp constructed during the period of years 2000-2010. How were the costs of those network upgrades recovered? How were the benefits of those network upgrades determined? Were those "deliverability-driven" network upgrades? How was the deliverability analysis performed?

38. Is there capacity created by PacifiCorp network upgrades included in retail rates that is not being fully utilized? Is this a result of the nature of lumped network capacity upgrades?

39. Has PacifiCorp constructed any network upgrades that were driven by the need to provide deliverability to California or Canada? How were those upgrades paid for? How were the costs of those upgrades recovered? Are there any areas where

additional generation could have been sited that would have offset or eliminated the need for those network upgrades?

40. Will the Northwest Energy Imbalance Market (EIM) change the way PacifiCorp's transmission system is utilized? Will additional benefits accrue to PacifiCorp retail customers as a result of the EIM? Should the existence of this market influence the cost recovery mechanisms for future network upgrades?

41. How do siting decisions for PacifiCorp-owned generation resources address cost recovery for associated network upgrades and how does that differ from what the Joint Utilities are advocating for QFs? How does PacifiCorp conclude that one approach promotes efficient siting decisions while the other does not?

42. Can PacifiCorp explain how network upgrades associated with PacifiCorp's remote generation facilities only benefit PacifiCorp customers and provide no quantifiable benefit to other transmission customers or support for the reliability of the transmission grid as a whole?

43. Commission Staff have expressed a concern that avoided interconnection costs may not be adequately captured in utilities' current avoided cost calculations. Please explain how system-wide benefits of non- PacifiCorp owned generation to the transmission network are included in PacifiCorp 's current avoided costs.

44. The Joint Utilities argue there is no factual basis for presuming that system upgrades benefit all users of the system. Is PacifiCorp's position that there should be a presumption that system upgrades only benefit a single user of the system? Doesn't this run counter to the presumption that the Western Interconnection operates as a single synchronized grid that provides reliability and resiliency benefits for all users?

45. Grid resilience is the ability to avoid or withstand grid stress events without suffering operational compromise or to adapt to and compensate for the resultant strains so as to minimize compromise via graceful degradation. It is in large part about what does not happen to the grid or electricity

46. PacifiCorp is a member of Northern Grid which is a transmission planning association formed to facilitate regional transmission planning across the Pacific Northwest and Intermountain West and provide the region with a forum to discuss common planning assumptions, identify regional upgrade projects, eliminate duplicative administrative processes, and facilitate compliance with FERC cost allocation requirements. Please explain how PacifiCorp perceives common interests and shared benefits derived from coordination with other NW transmission entities and also holds the view that upgrades to that transmission network as a result of distributed resource additions only benefit the owner of the generation resource.

47. Please explain how PacifiCorp 's avoided costs rates would change if the proxy resource used for calculating the avoided costs were located in an area outside of BPA's balancing authority area and outside of PacifiCorp's balancing authority area.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2032

Joint Utilities' Response to NewSun Energy

LLC's Motion to Compel Discovery

Attachment E

UM 2032 PacifiCorp Summary of Key Discovery

June 28, 2021

Summary of key discovery requests on NewSun's issues.

PacifiCorp has responded to numerous data requests (DRs) seeking information on the issues in this docket. (The DRs PacifiCorp has received are representative of the DRs that the other Joint Utilities have received in discovery, as well.)

The following examples are intended to give the ALJ an indication of the types of discovery the Joint Utilities have responded to on the issues NewSun raises. This is not intended to be a comprehensive summary of PacifiCorp's responses to discovery, nor to serve as a substitute for PacifiCorp's responses, which speak for themselves.

Examples of information available to NewSun regarding the treatment of "Network Upgrades" for purposes of assessing potential system benefits.

PacifiCorp has responded to numerous DRs seeking information on how Network Upgrades are studied and assessed from a regulatory perspective. The responses include, but are not limited to, the following:

- NewSun DR 1.10 (providing detail about PacifiCorp's Network Upgrades and information about a wide array of transmission system upgrades).
- OPUC DR 1 (providing significant amounts of data about various interconnection driven Network Upgrades on PacifiCorp's system).
- OPUC DRs 2 and 3 (calculating the ratepayer impact if QF-driven Network Upgrades had been assigned to ratepayers, rather than QFs; explaining how PacifiCorp's transmission rate formula works; and providing an Excel spreadsheet that allows parties to plug in real or hypothetical costs for Network Upgrades and obtain an estimated ratepayer impact).
- OPUC DR 21 (explaining the potential costs related to QF siting choices, among other things).
- OPUC DRs 13 and 14 (providing detail about PacifiCorp's Network Upgrades, including a description of the Network Upgrades and information on their location, upgrade costs, cost allocation information, ownership information, and more).
- NewSun DR 1.8 (identifying for NewSun where it could find all of the interconnection studies performed by PacifiCorp, providing NewSun with additional (non-posted) copies of studies that were superseded; and providing NewSun with (non-public) copies of interconnection agreements and amendments, among other things).
- NewSun DR 1.17 (responding to a system benefits question: "[a]s the Joint Utilities have explained in their testimony, it is unclear how any party would quantify a specific financial benefit of a Network Upgrade or allocate specific financial benefits from most upgrades to specific parties. Utilities do not decide where and when to make transmission system investments in this manner.").
- NewSun DR 1.38 (explaining how excess capacity as the result of Network Upgrades is allocated (to the extent any exists).
- NewSun DR 1.40 (explaining why EIM is not relevant to the cost recovery issues in this docket).

- NewSun DR 1.46 (describing benefits of regional transmission planning, which selects the best resources to achieve specific regional reliability and load-service goals in the context of regional coordination).
- OPUC DR 15 (providing explanation for how a utility's Network Upgrades are identified, how they are paid for, and how costs and benefits are determined from a regulatory or policy perspective).
- NIPPC DR 3 (providing detailed information on PacifiCorp's state jurisdictional interconnections, including information on feasibility studies, system impact studies, facilities studies, interconnection studies, accounting treatment, and cost allocation of Network Upgrades, as well as copies of interconnection agreements).
- NIPPC DR 5 (explaining that " . . . FERC does not quantify the actual costs or benefits that the construction of specific transmission system facilities may have on the wider system, nor does it require others to do so. To the extent FERC defines "system benefits" as the broad build-out of the transmission system in support of competitive wholesale markets under the FPA, PacifiCorp does not take issue with FERC's view of its obligations under the FPA or its implementation of that federal policy.").
- NIPPC DR 6 (explaining the differences between FERC and state interconnection policy based on law and legal presumptions, rather than a factual analysis of specific benefits).
- NIPPC DRs 7 and 8 (providing information on state- and FERC-jurisdictional interconnections (comparatively), including information about the generators, the resource type, ownership, cost, and more).
- NIPPC DR 16 (responding to question about FERC-jurisdictional interconnection-driven Network Upgrades and whether they resulted in "quantified system-wide benefits" for PacifiCorp's transmission or distribution system. "FERC does not quantify the actual costs or benefits that the construction of specific transmission system facilities may have on the wider system, nor does it require others to do so.").
- NIPPC DR 27 (confirming, among other things, that PacifiCorp does not validate or contradict FERC's presumption that interconnection-driven Network Upgrades of competitive generators benefit—or do not benefit—all users of the transmission system).
- NIPPC DRs 28-30 (describing the Joint Utilities' interpretation of elements of the Commission's "quantifiable system-wide benefits" test, as outlined in the Joint Utilities' testimony in this docket).
- NIPPC DR 34 (explaining that "PacifiCorp's position, as stated in the Joint Utilities' testimony, is that the Public Utility Commission of Oregon does not deem all transmission upgrades appropriate for inclusion in retail rates, even if a particular upgrade may provide some unspecified or hypothetical benefit. Utilities are required to engage in transmission system planning and least-cost, least-risk analysis to identify where transmission upgrades may be justified for cost or reliability purposes.").
- NIPPC DR 35 (explaining that, "PacifiCorp is unaware of any methodology that exists in Oregon, or any other jurisdiction, that would allow utilities to quantify and allocate the benefits of a specific Network Upgrade to retail customers. . . .").

Information available to NewSun regarding the treatment of QFs and non-QFs.

The information provided in discovery on this issue includes the data responses above. It also includes, but is not limited to, the following:

- NewSun DR 1.6 (providing "linkages" allowing NewSun to understand the relationship between interconnection and transmission service studies).
- NewSun DR 1.7 (providing a confidential chart providing detailed information on QFs that have requested PPA pricing with PacifiCorp since 2014, including their date, size, and location.).
- NewSun DR 1.13 (providing a narrative explanation for how QF Network Upgrades are treated for accounting purposes).
- NewSun DR 1.14 (providing a description of how NewSun can use the information in NewSun 1.6 to determine what transmission service studies were conducted as the result of QF PPAs and non-QF DNRs for every PacifiCorp DNR, thus allowing NewSun to review how the studies were conducted, any practical differences between them, and what upgrades, if any, were necessary to accommodate the generators).
- NewSun DR 1.24 (providing NewSun with a step-by-step explanation for how NewSun could find detailed information sought by NewSun about PacifiCorp transmission service requests; noting in PacifiCorp's Second Supplemental Response that Supplemental NewSun DR 1.6 would allow NewSun to understand the "linkages" between interconnection and TSR studies that NewSun was seeking).
- DR 1.26 (describing how QFs are treated in each of PacifiCorp's states for purposes of interconnection (ERIS vs NRIS) and how cost allocation is addressed, and referring NewSun to other relevant responses, among other things).
- NewSun DR 1.29 (explaining how FERC's interconnection policies, though different from the OPUC's, encourage efficient siting of projects).
    - The response references PacifiCorp's response to NIPPC DR 25 (explaining the difference between qualifying facilities (QF) and competitive independent power producers (IPP), including differences in their incentives).
- NewSun DR 1.31 (explaining how, for competitive generators (i.e. non-QFs), the company will evaluate Network Upgrades associated with that generation to determine the lowest-cost, lowest-risk resource, inclusive of Network Upgrade costs, when deciding what generation to purchase on behalf of customers, and providing a detailed response to NewSun's questions on treatment regarding the same).
- NewSun DR 1.41 (describing how the RFP process (non-QFs) incentivizes the most cost-effective and efficient sites for development, where the siting decision is the competitive bidder's risk, whereas QFs do not face the same competitive risks; and noting that PacifiCorp's responses to discovery from OPUC Staff and NIPPC have addressed the same issues).
- NewSun DR 1.43 (explaining how avoided interconnection costs are currently captured under the OPUC's avoided cost methodology).

- OPUC DRs 7 and 8 (explaining QF interconnection cost allocation for all of PacifiCorp's states).
- OPUC DR 9 (explaining issues re dispatchability and deliverability unique to QFs).
- NIPPC DR 25 (providing a detailed explanation of cost allocation treatment and incentives for FERC-jurisdictional interconnection customers (in contrast to QF interconnections)).