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October 30, 2020

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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RE: Docket No. UM 2032 – In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities.

Attached are documents for Staff Response Testimony:

Exhibit 100, page 20 is confidential
Exhibit 101 to Exhibit 107
Exhibit 102 - page 4 to 5 are confidential

Confidential pages will be encrypted and emailed to parties who have signed Protective Order No: 20-301.

/s/ Kay Barnes

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CERTIFICATE OF SERVICE

UM 2032

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 30th day of October, 2020 at Salem, Oregon

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CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Response Testimony

October 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Caroline Moore. I am a Chief Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/101.

Q. What is the purpose of your testimony?

A. My testimony discusses Staff's positions on cost allocation practices for Network Upgrades for Oregon Qualifying Facilities (QFs). I address the two issues within the scope of this investigation:

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 (NRIS) or should QFs have the option to interconnect with Energy Resource Interconnection Service (ERIS) or an interconnection service similar to ERIS?

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Exhibits:

- Exhibit Staff/102, Idaho Power's Response to Staff Data Requests
- Exhibit Staff/103, PacifiCorp's Response to Staff Data Requests
- Exhibit Staff/104, Portland General Electric's Response to Staff Data Requests

- Exhibit Staff/105, Summary of the Network Upgrade Cost Landscape for QFs
- Exhibit Staff/106, Description of PacifiCorp's Transmission Network
- Exhibit Staff/107, Oregon Solar and Wind Potential Maps

Q. How is your testimony organized?

A. My testimony is organized as follows:

BACKGROUND

Q. Please provide background on the Investigation into Network Upgrade Costs for QFs.

A. This investigation concerns allocation of Network Upgrades, a specific class of interconnection costs for QFs in Oregon. The Commission established Oregon's Small Generator Interconnection Procedures (OR-SGIP) and Large Generator Interconnection Procedures (QF-LGIP) in 2009 and 2010, respectively.[1,2] These procedures dictate the interconnection process and policies for Qualifying Facilities (QFs) that sell their entire net output to the interconnecting utility.[3] The Commission's order adopting the QF-LGIP reflects that the Commission adopted the Federal Energy Regulatory Commission (FERC) pro forma Large Generator Interconnection Procedures (FERC LGIP)[4] with only a handful of modifications. For the OR-SGIP, the Commission adopted its own rules rather than simply adopting FERC's procedures.[5] These OR-SGIP rules generally follow the FERC procedures, although not as closely as the QF-LGIP follows the FERC LGIP. A key area where both the QF-LGIP

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[1] *See* Docket No. AR 521, Commission Order No. 09-196.
[2] *See* Docket No. UM 1401, Commission Order No. 10-132.
[3] *See* Docket No. UM 1401, Commission Order No. 10-132, Attachment A, Article 2.1. The SGIP also cover other Oregon-jurisdictional interconnections, which include interconnections to the utilities' distribution systems that are not otherwise addressed by rules related to net metering or other programs.
[4] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003 (FERC Order No. 2003), FERC Stats. & Regs. ¶ 31,146 (2003), order on reh'g, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, order on reh'g, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007).
[5] *See* Oregon Administrative Rules (OAR) Chapter 860, Division 082.

and OR-SGIP vary from FERC's pro-forma interconnection procedures is the treatment of Network Upgrade costs for QFs.

Between March and July of 2019, Commission Staff (Staff) worked with a broad group of stakeholders to identify issues related to the implementation of the Public Utilities Regulatory Policy Act (PURPA) for QFs in Oregon. Based on compelling arguments from stakeholders, Staff found that the treatment of Network Upgrades for QFs was an issue that could benefit from a more thorough development of a factual record rather than through a rulemaking.[6] The Commission adopted Staff's recommendation to open an investigation into Network Upgrades for QFs with Order No.19-254.

On May 22, 2020, the Administrative Law Judge adopted the following scope for the investigation into the treatment of Network Upgrades for QFs:

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 (NRIS) or should QFs have the option to interconnect with Energy Resource Interconnection Service (ERIS) or an interconnection service similar to ERIS?

Depending on the resolution of these two questions, a second phase of the docket may be necessary to address a third question:

3. If the answer to Issue No. 1 is that users and beneficiaries of Network Upgrades (which typically are primarily utility customers) should pay for the Network Upgrades necessary to interconnect the QF to the host utility, how should that policy be implemented? For example, should utility customers, and other beneficiaries and/or users, fund the cost of the Network Upgrades upfront, or should the QF provide the funding for the Network Upgrade subject to reimbursement from utility

[6] See Docket No. 2000, Commission Order No. 19-254, Appendix A, p. 3.

> customers? Should the QF, utility customers, and other beneficiaries and users, if any, share the costs of Network Upgrades? [7]

On August 24, 2020, Idaho Power, PacifiCorp, and Portland General Electric (Joint Utilities) filed opening testimony addressing the first two questions.

Q. Please summarize the Joint Utilities' Opening Testimony.

A. The Joint Utilities note their belief that this investigation only concerns interconnection of large generators, which are generators with a nameplate capacity of 20 MW and above.[8] The Joint Utilities state that it is their understanding that cost allocation for Network Upgrades for small generators, those 10 MW and below, will be addressed in the general investigation into Interconnection docketed as UM 2111.[9]

The Joint Utilities' testimony supports the current treatment of Network Upgrades for large QFs. The Joint Utilities argue that QFs should continue to pay for the full cost of Network Upgrades (without reimbursement) for two interrelated reasons: so that ratepayers remain indifferent to the cost of interconnecting QFs; and to encourage QFs to site their projects efficiently.[10]

The Joint Utilities also argue that QFs should continue to be required to interconnect under NRIS in Oregon.[11] The Joint Utilities believe that NRIS was designed for generators like QFs and are concerned that allowing QFs to

[7] See Docket No. UM 2032, ALJ Traci A. G. Kirkpatrick issues Ruling; disposition: issues list adopted.
[8] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/11.
[9] Id.
[10] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/23-28.
[11] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/29-36.

interconnect as ERIS would also shift costs to ratepayers and remove the incentive to cite projects efficiently.

Q. Please summarize Staff's position.

A. First, Staff disagrees that this investigation is limited to treatment of large QFs. Parties did not discuss or agree to limit the scope to large QFs during the scoping process for this investigation.[12] Staff's testimony addresses the cost allocation for all QFs in Oregon as well as the type of interconnection service all QFs in Oregon should be allowed to use.

Second, Staff finds that the Commission's existing policies for the treatment of Network Upgrades appropriately protect ratepayers and strike a reasonable balance between the interests of QFs and ratepayers. QF's should be responsible for Network Upgrade costs that exceed the utilities' avoided Network Upgrade costs. For the increment of Network Upgrades for which QFs are responsible, QFs should be compensated if the Network Upgrades provide a system benefit.

However, Staff is concerned that these 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. The remainder of this testimony explains these concerns and recommends additional actions to bring interconnection practices into alignment with the Commission's policies.

[12] See Docket No. UM 2032, ALJ Traci A. G. Kirkpatrick issues Ruling; disposition: issues list adopted.

NETWORK UPGRADE COST ALLOCATION FOR OREGON QFS

DEFINITION OF NETWORK UPGRADES

Q. What are Network Upgrades?

A. Network Upgrades are a type of interconnection upgrade classified by FERC. FERC requires all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce (Transmission Providers) to provide non-discriminatory, open access for generators to interconnect to their transmission and distribution systems.[13] When a generator requests interconnection, the Transmission Provider will identify the equipment or other upgrades required to accommodate the generator on their system. FERC breaks these interconnection upgrades into three categories:

- Interconnection Facilities: all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions, or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System.[14,15]
- Network Upgrades: 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

[13] FERC Order No. 888.
[14] FERC Pro Forma Large Generator Interconnection Procedures (FERC LGIP), p. 8.
[15] FERC Pro Forma Small Generator Interconnection Procedures (FERC SGIP), Attachment 1, p. 2.

interconnection of [Large and Small] Generators to the Transmission Provider's Transmission System.[16,17]

- Distribution Upgrades: additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.[18,19]

Q. Do either of Oregon's interconnection procedures include the same definitions?

A. Oregon's QF-LGIP uses these definitions,[20] but the OR-SGIP does not. The OR-SGIP only separates interconnection upgrades into Interconnection Facilities and System Upgrades. The definition of System Upgrades necessarily encompasses both Network Upgrades and Distribution Upgrades.[21]

Q. Does that mean that QFs following the OR-SGIP are not included in the scope of Staff's testimony?

[16] FERC LGIP, p. 5-6.
[17] FERC SGIP, Attachment 1, p. 2.
[18] FERC LGIP, p. 8.
[19] FERC SGIP, Attachment 1, p. 2.
[20] FERC LGIP, pp. 3, 5, 6, 8.
[21] OAR 860-082-0015(34) states that, ""System upgrade" means an addition or modification to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility."

A. No. When Staff discusses Network Upgrades in this testimony, Staff is including the OR-SGIP functional equivalent of Network Upgrades: System Upgrades on the transmission system, at or past the point of interconnection..

Q. Why does Staff include the OR-SGIP functional equivalent of Network Upgrades in its testimony?

A. QFs following the OR-SGIP that do not pass the fast-track screening process are treated the same as large QFs in terms of the identifying of Network Upgrades, cost allocation for Network Upgrades, and requirements for interconnection service. Specific recommendations related to cost allocation and interconnection service requirements for small generators may result from UM 1930[22] and UM 2111[23]. Staff's testimony in this investigation speaks generally about the appropriate treatment of Network Upgrades and their OR-SGIP functional equivalent for any Oregon QF selling its entire net output to the interconnecting utility.

Q. Are there any other definitions to consider?

A. Staff is not aware of any other definitions of Network Upgrade, but there is another set of definitions to consider. In 2020, PacifiCorp received approval to transition from a first in, first served serial interconnection queue process to a first ready, first served cluster study process.[24] PacifiCorp's new interconnection procedures distinguish two types of Network Upgrade:

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[22] See Docket No. UM 1930, Commission Order No. 20-038, which approved the implementation of a separate interconnection procedure for the Community Solar Program.
[23] See Docket No. UM 2111,
[24] See Docket No. UM 2108 PacifiCorp Queue Reform.

- Station upgrades include all Network Upgrades at the point of interconnection substation. These upgrades are designed and constructed on a per-termination basis, and are allocated per capita to generators within the cluster.
- All other Network Upgrades, including transmission lines, transformers, and distantly located breakers, are allocated based on proportional capacity of each individual generator in the cluster (per MW).[25]

In addition, the Joint Utilities' Opening Testimony describes the division between energy resource Network Upgrades, needed to safely and reliably physically interconnect the generating resource to the utility's transmission system, and deliverability-driven Network Upgrades, needed to ensure the aggregate of generation in the area where the generator proposes to interconnect can be reliably delivered to the aggregate of load on the transmission provider's system during peak load conditions.[26]

Q. Is there any other context related the Network Upgrades that may be helpful to understand?

A. It may be helpful to understand how relevant the discussion of Network Upgrades is to QFs seeking to interconnect with each utility. In general, Network Upgrades are most relevant to Oregon QFs seeking to interconnect with PacifiCorp and, somewhat, Idaho Power. PacifiCorp has identified over $500 million in Network Upgrade costs for Oregon QFs since 2014.[27] Idaho

[25] See Docket No. UM 2018, PacifiCorp's Queue Reform Filing, p. 30.
[26] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/8.
[27] Exhibit Staff/105, Moore/1-2.

Power has identified roughly $50 million.[28] But, PGE has typically not identified Network Upgrade costs to QFs.[29]

Q. Why is this issue more prevalent for PacifiCorp?

A. Every interconnection is unique and requires individual study to determine whether and why Network Upgrades are required. However, as the Joint Utilities note, high Network Upgrade costs are generally driven by the need to deliver generation to network load on a firm basis.[30] Staff is aware that PacifiCorp does not have a contiguous transmission network in Oregon.[31] Staff is also aware that some of the highest wind and solar generation potential in Oregon is found in more remote parts of the state, many of which overlap with remote parts of PacifiCorp's Oregon transmission system.[32] It makes sense that transmitting high volumes of power from remote areas to more densely populated areas of network load on a firm basis, over a non-contiguous system, would require transmission network expansion. In fact, this is a topic of much discussion in PacifiCorp's 2019 IRP and 2020 all source RFP.[33]

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[28] Id.
[29] Id.
[30] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/19-21.
[31] Exhibit Staff/106, Moore/1-10, PacifiCorp's Presentation for the January 17, 2019, OPUC Transmission Workshop 1 and Transmission System Model Topology excerpt from 2019 IRP.
[32] Exhibit Staff/107, Moore/1-2.
[33] For example, See LC 70, PacifiCorp 2019 Integrated Resource Plan, p. 79, which discusses transmission build-out plans and notes that, "[i]mportantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements."

CURRENT COST ALLOCATION POLICIES FOR NETWORK UPGRADES

Q. What is the function of classifying interconnection upgrades?

A. It is Staff's understanding that this allows FERC to set different cost allocation policies for different types of upgrades.[34]

Q. How does FERC allocate costs for the three types of interconnection upgrades?

A. FERC requires generators to pay the cost of Interconnection Facilities and Distribution Upgrades, but requires the Transmission System Owner to reimburse generators for cost of Network Upgrades.[35] This reimbursement can occur through credits on the generator's transmission service payments or direct payments. FERC explains that it adopted this policy because it:

- ensures that the generator will not pay twice for the upgrade, first through interconnection, second as a transmission customer;
- helps to ensure that the generator's interconnection is treated comparably to the interconnections that a non-independent Transmission Provider completes for its own Generating Facilities; and
- enhances competition in bulk power markets by promoting the construction of new generation, particularly in areas where entry

[34] FERC Order No. 2003, ¶ 22, states that, "the distinction between Interconnection Facilities and Network Upgrades is important because Interconnection Facilities will be paid for solely by the Interconnection Customer, and while Network Upgrades will be funded initially by the Interconnection Customer (unless the Transmission Provider elects to fund them), the Interconnection Customer would then be entitled to a cash equivalent refund (i.e., credit) equal to the total amount paid for the Network Upgrades, including any tax gross-up or other tax-related payments."
[35] FERC Order No. 2003, ¶ 21.

barriers due to unduly discriminatory transmission practices may still be significant.[36]

Q. Please elaborate on what it means for an interconnection customer to pay twice for the upgrade, first through interconnection, second as a transmission customer.

A. In addition to securing an Interconnection Agreement, a generator must secure the ability to transmit their power over the transmission system.[37] Transmission providers charge transmission service customers for their use of the transmission system at FERC approved transmission rates.[38] Network Upgrades are rolled into the provider's transmission rate base and paid for by all transmission system users.[39] It is Staff's understanding that paying twice for a Network Upgrade would occur if a generator paid the upfront cost to construct a Network Upgrade, then paid a share of that cost again as a transmission customer paying transmission rates.

Q. Please elaborate on what FERC said about ensuring non-independent transmission providers treat generators comparably to their own generating facilities.

A. FERC said that independent transmission providers could have more flexibility with the Network Upgrade cost allocation framework, but noted that:

> Most improvements to the Transmission System, including Network Upgrades, benefit all transmission customers, but the determination

[36] FERC Order No. 2003, ¶ 694.
[37] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/14.
[38] Exhibit Staff/102, Moore/7, Idaho Power Response to Staff Data Request 007, Exhibit Staff/103, Moore/14, PacifiCorp Response Staff Data Request No. 008.
[39] Id.

> of who benefits from such Network Upgrades is often made by a non-independent transmission provider, who is an interested party. In such cases, the Commission has found that it is just and reasonable for the Interconnection Customer to pay for Interconnection Facilities but not for Network Upgrades. Agreements between the Parties to classify Interconnection Facilities as Network Upgrades, or to otherwise directly assign the costs of Network Upgrades to the Interconnection Customer, have not been found to be just and reasonable and have been rejected by the Commission.[40]

Q. Do Oregon's current interconnection procedures include the same treatment of Network Upgrade costs as FERC?

A. The treatment of Network Upgrade costs and their OR-SGIP functional equivalent is one of the key areas of difference between Oregon and FERC's interconnection procedures. The QF-LGIP and OR-SGIP share similarities in how Network Upgrade costs or their equivalent are treated, but they are not exactly the same.

Q. Please summarize the current treatment of Network Upgrade costs under Oregon's current interconnection procedures.

A. First, the OR-SGIP requires Small Generators to, "pay the reasonable costs of any system upgrades."[41] Staff's understanding is that reasonable cost has not been defined, but the Commission provided some discussion when adopting the OR-SGIP:

> The proposed rules, however, include language that is meant to strictly limit a public utility's ability to require one small generator facility to pay for the cost of system upgrades that primarily benefit

[40] FERC Order No. 2003, ¶ 21.
[41] OAR 860-082-0035(4). Staff notes that this is mostly relevant for Tier 4 interconnection requests that did not pass screening criteria for generators with minimal system upgrades required.

> the utility or other small generator facilities, or that the public utility planned to make regardless of the small generator interconnection.[42]

Following this decision, the Commission similarly decided not to include FERC's reimbursement policy for Network Upgrades in the QF-LGIP. Instead, the Commission noted that transmission costs and Network Upgrades are included in the calculation of avoided cost rates and therefore:

> Interconnection Customers are responsible for all costs associated with network upgrades unless they can establish quantifiable system-wide benefits, at which point the Interconnection Customer would be eligible for direct payments from the Transmission Provider in the amount of the benefit**.**[43]

It is Staff's understanding that no party has developed a methodology or other process to (a) distinguish those system upgrade costs that primarily benefit the utility, other small generators, and/or were already planned, and (b) quantify the system benefits of a Network Upgrade. Staff discusses the utilities' current thinking on this in the following section of its testimony.

STAFF'S POSITION ON NETWORK UPGRADES FOR QFS

Q. Please Summarize the Joint Utilities position on the appropriate allocation of Network Upgrades to QFs?

A. The Joint Utilities argue that the cost of Network Upgrades caused by a QF's interconnection should be allocated to QFs. The Joint Utilities believe that this allocation practice is important both for conforming to PURPA and for protecting ratepayers from potentially significant costs. The Joint Utilities

[42] See Docket No. AR 521, Commission Order No. 09-196, pp. 4-5.
[43] See Docket No. 1401, Commission Order No. 10-132, p.3.

provide two main arguments for holding QFs responsible for Network Upgrade costs (without reimbursement):

1. This treatment holds ratepayers indifferent to whether the utility is purchasing power from the QF or another source.
2. This treatment provides a QF's financial incentive make economical siting decisions, which could intensify cost-shifting to ratepayers if it were removed.

Q. What are Staff's concerns about the Joint Utilities' position?

A. Staff agrees that ratepayers should be held indifferent and that QFs should be encouraged to make economical siting decisions. However, Staff is concerned that the Joint Utilities' proposal—which reflects their current treatment of QF Network Upgrades costs—is not doing this. Staff is concerned that the Joint Utilities are ignoring both avoided Network Upgrade costs and potential system benefits of Network Upgrades above the avoided cost.

Q. Please elaborate.

A. The Joint Utilities suggest that holding ratepayers indifferent requires QFs to pay for the full cost of interconnection upgrades caused by the QF, without recognizing the avoided interconnection costs of purchasing energy and capacity from some other source. First, the Joint Utilities state that ratepayers should,

> […]remain economically indifferent to the source of power the utility purchases by ensuring the cost to the utility associated with

> purchasing energy and capacity from a QF does not exceed the cost it would incur if it were purchasing from some other source.[44]

Then, the Joint Utilities argue that the avoided Network Upgrade costs should not be addressed through avoided cost rates,

> to maintain customer indifference to the purchase of QF power, the QF is paid for energy and capacity through a QF power purchase agreement with the purchasing utility, but the QF pays for its interconnection costs separately, as part of the interconnection agreement with the utility's transmission provider. Assessing QF interconnection costs separately through the interconnection process allows for site specific evaluation of interconnection costs and allows the transmission provider to give the QF detailed information about any cost barriers to development at that site.[45]

Following that, the Joint Utilities argue that the avoided Network Upgrade costs should not be considered when assessing QF's upgrades in the interconnection process, either,

> [T]he Commission's current policy requires QFs to interconnect with a level of interconnection service that accurately reflects their demands on the system, and to pay the costs caused by that interconnection. Under the Commission's current policy, a QF is required to pay the actual cost of its site-specific interconnection.[46]

The utilities do not acknowledge that the OR-SGIP only assigns *reasonable* interconnection costs to generators or the Commission's discussion of what reasonable should mean. The Joint Utilities do recognize that the QF-LGIP allows for compensation for quantifiable system benefits, but argue that QFs

[44] Joint Utilities/200, Wilding-Macfarlane-Williams/5.
[45] Id./6.
[46] Id.

cannot have system benefits because of the "but for" test under PURPA. I will discuss the "but for" test in more detail later in my testimony.

Whether it occurs through avoided costs, interconnection, or another method, holding ratepayers indifferent requires more consideration of the avoided Network Upgrade costs. In other words, Staff disagrees with the Joint Utilities understanding of ratepayer indifference. Staff believes the ratepayer indifference standard should take into account the costs of interconnection the utility is avoiding by purchasing from the QF and that QFs should pay no more for the Network Upgrade costs than what is incremental to the utility's avoided Network Upgrade costs.

Further, indifference would suggest that beneficiaries pay for the value of benefits received. There is not a sufficient process in place to identify any additional 'system-wide benefits' or upgrades that 'benefit the utility or other small generator facilities' above the utility's avoided cost.[47]

Q. Are avoided Network Upgrade costs included the utilities' avoided cost rates?

A. The Commission raised this when adopting the QF-LGIP policy on Network Upgrades. Specifically, the Commission stated that:

> As noted by the Utilities, transmission costs and network upgrades are included in the calculation of avoided cost rates. Consequently, QFs are currently compensated for these costs pursuant to the rates

[47] Staff is referring to language from the orders adopting the QF-LGIP and OR-SGIP referenced previously in its testimony.

established in their respective purchased power agreements with the utilities.[48]

A review of the utilities' avoided cost methodologies suggests that this is not the case:

- Idaho Power: Proxy resource capital costs are based on the National Renewable Energy Laboratory's Annual Technology Baseline, which includes a generic assumption about onsite electrical equipment, power electronics, and substation upgrades.[49]
- PacifiCorp: Proxy resource capital costs assume a 15-mile transmission line is constructed from the resource to the point of interconnection and additional direct assigned interconnection facilities are constructed before the point of interconnection. The specific costs are developed with a consultant.[50]
- Portland General Electric: PGE's assumes its proxy resources are located off-system, one leg of BPA transmission away from PGE's system. PGE includes an interconnection cost assumption based on an actual PGE plant, a Network Upgrade cost assumption, and an assumption that the third-party transmission provider is reimbursing PGE for Network Upgrade costs.[51]

[48] See Docket No. UM 1401, Commission Order No. 10-132, p. 3.
[49] Exhibit Staff/102, Moore/11-13, Idaho Power's Response to Staff Data Request Nos. 018 and 019.
[50] Exhibit Staff/103, Moore/26 and 28, PacifiCorp's Response to Staff Data Request Nos. 019 and 020.
[51] Exhibit Staff/104, Moore 12-15, Portland General Electric's Response to Staff Data Request Nos. 018 and 019.

None of these assumptions capture the cost to ratepayers of reimbursing non-QF generators for Network Upgrades.[52]

Q. How would you characterize the utilities' avoided Network Upgrade costs?

A. Network Upgrade reimbursement costs vary across generators and utilities. While Staff does not propose a specific avoided cost calculation at this time, the following historical data may provide helpful context.

Table 1. Network Upgrades Constructed 2010 – 2019 and in Current Rate Case

Company	Total Network Upgrade Costs for non-QFs	Approximate ratepayer share (%)	Approximate ratepayer share ($)	Total MW of non-QFs	Average ratepayer $/MW
Idaho Power[53]	**[begin confidential]** [redacted] **[end confidential]**	70%	**[begin confidential]** [redacted] **[end confidential]**	445	**[begin confidential]** [redacted] **[end confidential]**
PacifiCorp[54]	$143,915,425	81%	$116,571,494	2,711	$42,994
Portland General Electric[55]	None	87%	None	None	None

Additional context is provided in PacifiCorp's most recently filed general rate case. For example, the Company describes the Aeolus to Bridger/Anticline 500 kV Transmission Project as a $680 million transmission investment that was required to develop at least 1,150 MW of least cost, least

[52] The Joint Utilities explain that, "[o]ver 81 percent of PacifiCorp Transmission's annual transmission revenue comes from providing load service to PacifiCorp's retail customers. Similarly, PGE Merchant is the primary customer of PGE Transmission, holding approximately 87 percent of the long-term transmission rights. For Idaho Power, retail customer load service accounted for 70 percent of long-term transmission rights in 2018. Thus, any Network Upgrade costs that are not paid by QFs would be paid primarily by the utilities' retail customers." (Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/22.)
[53] Exhibit Staff/102, Moore/4 and 5, Idaho Power's Confidential Response to Staff Data Request No. 012 Attachment.
[54] Exhibit Staff/103, Moore/18-24,PacifiCorp's Response to Staff Data Request Nos. 013 and 014.
[55] Exhibit Staff/104, Moore/9, Portland General Electric's Response to Staff Data Request No. 012.

risk renewable generation.[56] PacifiCorp explains that this transmission project also includes 230 kV Network Upgrades associated with two specific generators:

- Q707 TB Flats 1: A $30.6 million Network Upgrade for a 250 MW wind facility, which is roughly $99,144 per MW for PacifiCorp ratepayers.
- Q712 Cedar Springs 1: A $61.7 million Network Upgrade for a 400 MW facility in Wyoming, which costs roughly $125,000 for PacifiCorp ratepayers.

Q. Is Staff advocating that the avoided cost rates be updated to reflect avoided Network Upgrade costs?

A. Not necessarily. This is one approach to improve the implementation of the Commission's existing policies, but it comes with trade-offs. The Joint Utilities' Opening Testimony points out that Network Upgrade costs are site-and queue-specific and vary dramatically depending on a rage of factors.[57] This approach ignores the benefits of increasing the capacity of the transmission system,

[56] See Docket No. UE 374, PAC/1000 Vail/ 7- 17, which describes this investment as critical to bring at least 1,150 MW of EV 2020 wind resources online. The remaining 3 out of 4 phases of the project cost, "$4.1 million in July 2018. The third sequence of work started in December 2019, for an estimated $11.1 million, is the installation of a Static Synchronous Compensator (STATCOM) voltage control device. To accommodate this equipment, the Latham Substation will be expanded with a new line termination bay. Finally, the last sequence of plant in-service is the two 500 kV substations and the transmission line for $663.9 million in December 2020."

[57] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/19 explains that, "The cost of a generator's interconnection can vary dramatically depending on siting, load, existing transmission system facilities, and existing generation. In some locations on a utility's transmission system, the cost of Network Upgrades needed to interconnect a generating facility can be relatively low; in other locations, the costs of Network Upgrades needed to interconnect can be significantly higher—tens of millions of dollars or more."

particularly between areas with high renewable resources and network customer load.

Q. Is there another process to identify the avoided Network Upgrade costs or otherwise quantify system-wide benefits of Network Upgrades for Oregon QFs?

A. Staff is not aware of another process. The Joint Utility testimony suggests that an additional process is not needed and argue that, regardless of system-wide benefits, PURPA prevents ratepayers from paying more than avoided costs for QFs. And, the avoided costs of Network Upgrades for QFs are zero because those upgrades would not occur 'but for' that QF's request for interconnection.[58]

Q. What are Staff's concerns about the "but for" test?

A. The "but for" test is not a perfect fit for allocating the costs and benefits of a QF's Network Upgrades. While a specific generator may trigger the *need* for an upgrade, it does not eliminate the *benefit* of avoiding the cost of another resource or increasing the transmission network for all users generator.[59] The "but for" test is also less straightforward when considering PacifiCorp's new cluster study approach, where a generator may be assigned a share of an upgrade that still would have been identified in the cluster but for its request.

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[58] Joint Utilities/200, Wilding-Macfarlane-Williams/11.
[59] Exhibit Staff/102, Moore/9-10, Idaho Power's response to Staff Data Request No. 017; Exhibit Staff/103, Moore/25, PacifiCorp response to Staff Data Request No. 018; and Exhibit Staff/104, Moore/10-11, PGE response to Staff Data Request No. 017.

Q. Does this mean that Staff supports FERCs Network Upgrade policy for Oregon QFs?

A. No. Staff can see some advantages to FERC's approach, but does not find the cost shifting under FERC's practice reasonable for Oregon ratepayers. Staff discusses these trade-offs below.

Benefits: A bright line policy is more practical to implement than developing a meaningful proxy Network Upgrade avoided cost methodology and/or evaluating the specific system-wide benefits on an individual generator basis. This was one of FERCs drivers for adopting the policy.[60] In addition, this policy would place QFs in a more equitable position with non-QFs, particularly within the same PacifiCorp cluster area. Finally, this policy is similar to PacifiCorp's line extension policy for Network Upgrades for lines over 230 kV.[61]

Costs: Staff does not support a policy that is likely to shift QF costs to ratepayers above avoided costs and additional benefits to the system. Staff agrees with the Joint Utilities that a bright line approach does not encourage efficient siting of QFs from a Network Upgrade perspective, which makes the risk of cost shifting more severe. The utilities' high-level analysis suggests that funding all Network Upgrade costs identified in Oregon QF interconnection requests between 2014 and 2019 would have the following impact on Oregon customers:

[60] FERC Order No. 2003, ¶ 66, states that, "We are removing references to beneficiaries from the definition, because our well-established precedent regarding what constitutes Network Upgrades does not require a case-specific determination that all users benefit from Network Upgrade; instead we look only as whether the upgrade is at or beyond the Point of Interconnection."
[61] See PacifiCorp's Oregon Rule 13, General Rules and Regulations Line Extensions.

- Idaho Power: Idaho Power identified $86.8 million of Network Upgrades assigned to the 215 MW of Oregon QF interconnection requests between 2014 and 2019. Using FERC's allocation approach to reimburse these upgrades would increase the transmission ratebase by roughly $79.4 million (approximately $55.6 million allocated to Idaho Power customers), which would increase transmission rates by roughly 6.9 percent.[62]
- PacifiCorp: PacifiCorp identified $1.3 billion in deliverability-driven Network Upgrades assigned to 550 MW of Oregon QF between 2014 and 2019. Using FERC's allocation approach to reimburse these upgrades would increase transmission ratebase by $160 million. This would shift $34 million to Oregon ratepayers (2.59 percent rate impact) under a multi-state allocation or $130 million (9.84 percent rate impact) if allocated situs.[63]
- Portland General Electric: PGE did not identify any on-system QFs with Network Upgrades that would be borne by PGE ratepayers as transmission customers.[64]

Q. Does PacifiCorp's transition to cluster studies affect these potential rate impacts?

[62] Exhibit Staff/102, Moore/1-3 and 6, Idaho Power Response to Staff Data Request No. 001 Attachment and No. 002.
[63] Exhibit Staff/103, Moore/1-10, PacifiCorp Response to Staff Data Request No. 002 and Attachment. When duplicate generators are removed from this calculation, the rate impact becomes $27 million to Oregon ratepayers (2.05 percent rate impact) or $103 million (7.80 percent rate impact) if allocated situs.
[64] Exhibit Staff/104, Moore/1-5, PGE Response to Staff Data Request No. 001 and Attachment.

A. Active Oregon interconnection requests of 80 MW and below in size represent 26 percent of total active Oregon interconnection requests on a per MW basis, and 74 percent on a per capita basis.[65] Therefore, it is reasonable to assume that the costs associated with QF-allocated Network Upgrades would be lower than the utility estimates above. However, the Network Upgrade costs assigned to non-QF's would increase proportionately. Meaning, ratepayers would face similar overall impacts regardless of the cluster study process.

Q. Are there any other approaches for allocating Network Upgrades?

A. Staff is aware of a couple of alternative approaches from other jurisdictions. A brief description of the other approaches and their trade-offs is provided below.

Idaho's fixed percentage approach: Jurisdictions have also employed a percentage-based cost allocation for Network Upgrades. One example is Idaho's 'Cassia Formula.' In 2007, the Idaho Commission adopted a stipulation that included QFs' agreement to curtail generation rather than pay for certain upgrades and that allocated the remaining interconnection Network Upgrade costs based on the following fixed percentages,

> Idaho Power will assume 100% of cost responsibility for phase one and will include this cost in its rate base. Phase one upgrades will likely have been required for native load in the near future.
>
> Remaining four phases:
>
> 25% of the costs will be provided by the project as a nonrefundable contribution in aid of construction (CIAC);
>
> 25% of the costs will be funded by Idaho Power and included in

[65] PacifiCorp OASIS, accessed October 10, 2020.

> Idaho Power's rate base;
>
> 50% of the costs will be funded by projects as an advance in aid of construction (AIAC) subject to refund. These costs will be rate based using standard regulatory accounting principles.[66]

The Idaho Commission is clear that these allocations were based on a compromise, not a rigorous study, and it recognized that:

> electric power transmission systems by their nature are joint use facilities and that many economic theories exist relating to cost allocation of joint use facilities.[67]

The Idaho Commission further indicated that this allocation approach may be reasonable for future QFs, but cannot be applied as a template without considering circumstances of future QF Network Upgrades. The Idaho Commission approved subsequent interconnection agreements in which the parties agreed to use Cassia Formula to allocate costs of Network Upgrades with no provision regarding redispatch, and in which the parties agreed to the Cassia Formula and a redispatch provision.[68,69]

Benefits: This policy is simple and reduces cost-shifting compared to FERC policy. It also balances the competing needs of efficient siting from a transmission capacity perspective with efficient siting from a renewable resource perspective.[70]

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[66] *Idaho Power/ Cassia Gulch Wind Park, LLC and Cassia Wind Farm, LLC,* Case No. IPC-E-06-21, Order No. 30414, p. 5.
[67] Id.
[68] *Idaho Power/Hotsprings*, Case No. IPC-E-06-34 and *Idaho Power/Bennett Creek*, IPC-E-06-35, Order No. 30453.
[69] Idaho Power/*Idaho Wind, LLC*, Case No. IPC-E-09-25, Order No. 32136.
[70] Staff does not believe the redispatch provision found in many of the Idaho agreements is a necessary predicate for this formula. The Cassia Formula allocated costs for Network Upgrades left after more expensive Network Upgrades had been removed from the discussion. The Cassia

Costs: Under this policy QFs would still shift 50 percent more Network Upgrade costs than the current cost allocation practice.

SPP capacity upgrade approach: As an independent transmission provider, FERC granted the Southwest Power Pool (SPP) flexibility to only reimburse Network Upgrades that "increase the power-flow capacity of a circuit on the Transmission System" in 2018.[71] SPP refers to these capacity upgrades as Creditable Upgrades. This distinction separates Network Upgrades along similar lines as PAC's cluster study distinction between Station Upgrades and other Network Upgrades.

Benefits: This policy is simple, while not ignoring project-specific benefits to the system. Drawing a line at power flow capacity is also in line with how utilities have discussed the benefits of upgrading the transmission system.[72] In addition, cost sharing balances the competing need to site efficiently from a transmission capacity perspective with the need to site efficiently from a renewable resource perspective.

Costs: Under this policy, QFs could still shift costs to ratepayers above the utilities' avoided costs at a level that is difficult to estimate prior to

Formula took into account the factors at issue here, such as the need for efficient siting and avoiding cost shifts.

[71] See SPP Open Access Transmission Tariff, Attachment Z2, p. 2509.

[72] For example, in its most recent general rate case, the Company explains that: "The benefits associated with these investments include increased load serving capability, enhanced reliability, conformance with NERC Reliability Standards, improved transfer capability within the existing system, relief of existing congestion, and interconnection and integration of new wind resources into PacifiCorp's transmission system." (UE 374 PAC/1000, Vail/12.)

PacifiCorp's transition to cluster studies. Further, this policy assumes that the benefit of an upgrade is equal to its cost.

Q. Does Staff recommend adopting one of the above approaches?

A. Not at this time. They all have trade-offs that can be explored further. Staff recommends the Commission order that a mechanism or process for reimbursement for system benefits be addressed in Phase II of this investigation.

INTERCONNECTION SERVICE FOR OREGON QFS

BACKGROUND ON INTERCONNECTION SERVICE

Q. What does 'interconnection' service mean in the context of Network Upgrades for QFs?

A. FERC specifies two types of interconnection service in its standard interconnection procedures. The type of interconnection service used can impact the Network Upgrades assigned to a generator during the interconnection process.

- Energy Resource Interconnection Service (ERIS): basic interconnection service which allows the generator to deliver its output to the Transmission Provider's system on an as-available basis. Does not consider the delivery of generation to an end point.[73]
- Network Resource Interconnection Service (NRIS): a more comprehensive interconnection service that allows the generator to deliver its output to load on a firm basis. Under NRIS, the System Operator is supposed to treat the generator in the same way that it integrates its own resources to serve its native load customers. An NRIS interconnection study considers ERIS and whether the aggregate of generation in the area where the interconnecting generator sited its project can be reliably delivered to the aggregate of load during peak conditions.[74]

[73] FERC LGIP, p. 14.
[74] FERC LGIP, pp.14-15.

The FERC LGIP allows the generator to choose either service, or to be studied as both.[75] The interconnection service in the OR-SGIP and FERC SGIP is not identified as NRIS or ERIS. However, FERC has stated that the interconnection service offered under its SGIP is akin to ERIS:

> The one interconnection service that the Commission proposed to make available to the Small Generating Facility is similar to the Energy Resource Interconnection Service that is offered under the LGIA.[76]

FERC does not allow a small generator to interconnect with NRIS under the SGIP. If a small generator wants to interconnect with NRIS, it must interconnect under the LGIP:

> Because Network Resource Interconnection Service entails high technical standards, we expect that an Interconnection Customer, particularly one interconnecting at a lower voltage, would rarely find this service to be efficient or practical. Nevertheless, we do not want to preclude it from choosing this option. If it wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it may do so. However, it must request interconnection under the LGIP and execute the LGIA.[77]

Q. What do the QF-LGIP and OR-SGIP say about interconnection service?

A. The QF-LGIP says that the "interconnection customer will be provided Network Resources interconnection service."[78] The OR-SGIP does not address interconnection service type.

Q. What does FERC say about the purpose of NRIS?

[75] See Docket No. UM 1401, Commission Order No. 10-132, Appendix A, p. 14.
[76] *Standardization of Small Generator Interconnection Agreements and Procedures* FERC Order No. 2006, ¶ 139 (May 22, 2005).
[77] Id., ¶ 140*.*
[78] See Docket No. UM 1401, Commission Order No. 10-132, Appendix B, p. 20.

A. FERC explained that:

> Network Resource Interconnection Service is intended to provide the Interconnection Customer with an interconnection of sufficient quality to allow the Generating Facility to qualify as a designated Network Resource on the Transmission Provider's system without additional Network Upgrades. This means that Network Resource Interconnection Service entitles the Generating Facility to be treated in the same manner as the Transmission Provider's own resources for purposes of assessing whether aggregate supply is sufficient to meet aggregate load within the Transmission Provider's Control Area, or other area customarily used for generation capacity planning. Thus, with Network Resource Interconnection Service, the Interconnection Customer would be eligible to obtain Network Service under the Transmission Provider's OATT, or network access service under the Tariff of an RTO or ISO, without the need for additional Network Upgrades.[79]

FERC explains that the NRIS is intended to identify Network Upgrades that are required for deliverability prior to the Transmission Service Request (TSR) process. FERC is also careful to explain that NRIS is not transmission service; NRIS generators would still need to secure transmission service, and it's possible that the (TSR) will identify additional Network Upgrades based on available transmission capacity at the time of the TSR.[80]

Q. How do QFs secure Transmission Service?

A. QFs secure transmission service differently than other generators. Once a QF has secured a Power Purchase Agreement (PPA), the utility's merchant function becomes the transmission service customer and is responsible for making the TSR.[81]

[79] FERC Order No. 2003, ¶ 768.
[80] Id.
[81] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/33.

STAFF'S RESPONSE TO THE JOINT UTILITIES

Q. Please summarize the Joint Utilities' position on interconnection service for QFs.

A. The Joint Utilities argue that QFs should be required to interconnect under NRIS for a couple reasons. First, the Joint Utilities argue that NRIS is intended for generators like QFs, because it aligns with PURPA's requirements for the delivery of QF output to network load on a firm basis. Second, allowing QFs to interconnect under ERIS would shift deliverability-driven Network Upgrade costs to ratepayers during the TSR process.[82]

Q. What is Staff's position on interconnection service for QFs?

A. NRIS is not the only way to deliver a generator's output to network load on a firm basis, but it is likely the most practical interconnection service for QFs.

Q. Why doesn't Staff think that NRIS is the only way to deliver a resource to network load on a firm basis?

A. NRIS is intended for generators that will be integrated in the same manner as the resources the utilities use to serve their native customer load on a firm basis. Practically speaking, this means that the utilities' designated network resources require the same firm delivery to load as QFs. However, the utilities' designated network resources do not interconnect under NRIS.[83]

[82] Id, 29.
[83] Exhibit Staff/102, Moore/7-8, Idaho Power Response to Staff Data Request 007; Exhibit Staff/103, Moore/13-14, PacifiCorp Response Staff Data Request No. 008; and Exhibit Staff/104, Moore/6-8, PGE Response to Staff Data Request No. 007.

Q. Why does Staff believe that NRIS is the most practical interconnection service for QFs?

A. It is the cleanest way to manage the cost allocation of deliverability-driven Network Upgrades for QFs.

Q. Please elaborate.

A. When the utility merchant function makes a TSR for the QF, the TSR will consider whether the transmission service (delivery of the QF's output) requires Network Upgrades in addition to those identified and constructed during the interconnection process. Given that NRIS requires deliverability to load, it is less likely that the TSR for a QF interconnecting with NRIS will trigger additional Network Upgrade. If a QF interconnects with ERIS, it is more likely a TSR for the QF's output will trigger Network Upgrades.

PURPA does not include a provision that authorizes the Commission to directly allocate costs associated with transmission service to a QF after that QF has signed a fixed-price Power Purchase Agreement (PPA). Accordingly, allowing a QF to interconnect with ERIS, and leaving the identification of Network Upgrades to the TSR, which typically is not submitted until after the QF's PPA is executed, will not allow the costs of any Network Upgrades identified to be allocated to QFs.

In addition, the Commission establishes avoid cost rates and may take into account when determining avoided cost rates that a purchase from a QF may not allow a utility to avoid transmission-related costs. However, the Commission's process for establishing standard avoided cost prices does not offer opportunity to take into account the location of each QF that interconnects, meaning that QF-specific TSR costs cannot be easily captured in avoided cost rates.

Q. Is it certain that allowing QFs to interconnect with ERIS will result in a large share of deliverability-driven upgrades identified at the time of the Transmission Service Request?

A. Not necessarily. The study parameters for interconnection service and transmission service are not the same. For example, in interconnection studies the utility must determine whether it has sufficient capacity to interconnect generator's nameplate capacity without regard to the utility's ability to dispatch resources. For transmission service requests, the utility is allowed to consider the dispatch of resources to determine whether it has sufficient capacity for the transmission customer.[84] Accordingly, an interconnection study may identify Network Upgrades that are necessary to interconnect a QF with NRIS but not ERIS. However, if that QF choses ERIS, the TSR may not necessarily identify the same additional Network Upgrades that would have been identified in an NRIS interconnection request. The Community Solar Program (CSP) interconnection process is expected to provide data and insights into this by allowing generators to interconnect as ERIS and addressing Network Upgrades if they arise in the TSR process.[85]

[84] Exhibit Staff/103, Moore/16, PacifiCorp Response to Staff Data Request No. 009.
[85] Exhibit Staff/103, Moore/13, PacifiCorp Response to Staff Data Request No. 008.

CONCLUSION AND STAFF RECOMMENDATIONS

Q. Please summarize your testimony.

A. QFs should pay for Network Upgrade costs above the utilities' avoided Network Upgrade costs plus any additional system benefits. While the Commission's PURPA, OR-SGIP, and QF-LGIP policies appropriately strike this balance, the current cost allocation practices do not. This is because utilities generally do not include a realistic estimate of avoided interconnection costs in the avoided cost rate, and also have not implemented a mechanism by which to reimburse QFs for system benefits of Network Upgrades paid for by QFs.

Staff generally agrees with the Joint Utilities that NRIS is the most appropriate interconnection service for QFs. Allowing QFs to interconnect without taking NRIS is possible, but requiring NRIS it is likely the most straightforward and certain policy approach in terms of the treatment of Network Upgrades for QFs. Staff, however, remains open to exploring how allowing ERIS service could impact Network Upgrade costs if compelling data becomes available in UM 1930.

Q. What is Staff's recommendation for Phase I of this docket?

Staff recommends that the Commission investigate the calculation of avoided interconnection costs in the investigation in the avoided cost methodology in Docket No. UM 2000. With respect to the reimbursement for system benefits of QF Network Upgrades, Staff recommends the Commission order that a mechanism or process for reimbursement for system benefits be addressed in Phase II of this investigation.

Q. Does this conclude your testimony?

A. Yes.

CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statements

October 30, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	Caroline F. Moore
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TITLE:	Chief Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
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CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Response Testimony

<u>Public Version</u>
October 30, 2020

TOPIC OR KEYWORD: NETWORK UPGRADE COSTS

STAFF'S DATA REQUEST NO. 1:

In an electronic, Excel format with formulae intact, please identify the cost of deliverability driven network upgrades identified in the system impact study for each Oregon-sited interconnection applicant between the period of January 1, 2014 to present that received a system impact study:

a. Queue #
b. Date of interconnection request
c. Interconnection request status
d. Service type (NR/ER)
e. Generator type (state or federal, large or small)
f. Nameplate capacity in MW
g. County location (in OR)
h. Generator technology type
i. Point of interconnection
j. Network Upgrade costs assigned to generator ($)
k. Network Upgrade costs assigned to higher queued generators identified in the system impact study ($)
l. Whether the network upgrade was constructed or is under construction.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 1:

Please see the attached Excel spreadsheet containing the requested information. The Company presumes that Staff's use of the phrase "deliverability driven network upgrades" refers to network upgrades that would have been identified in a Network Resource Interconnection Service ("NRIS") interconnection study but that would not have been identified in an Energy Resource Interconnection Service ("ERIS") interconnection study. Idaho Power can only identify such costs if the interconnection customer was specifically studied for both NRIS and ERIS. Because that did not occur for most interconnection studies, the Company has provided responsive information related to all network upgrades identified in the relevant studies but cannot specifically break out "deliverability driven" network upgrades.

Additional information about the data is provided below:

Column J – represents the total direct costs identified in the System Impact Study ("SIS"), but does not include contingency or overhead adders that are used to calculate the total of the system impact study, which range from 30-45 percent of the total excluding such costs.

Column K - the actual costs assigned to higher-queued generators are not available. In cases where costs would be allocable to higher-queued generators, those generators have been identified.

Columns M-P – the Company's system impact studies (SIS) identify four cost categories: network upgrades, distribution upgrades, substation upgrades, and substations plus interconnections. The Company has inserted additional columns to provide the breakdown of the SIS costs, as follows:

Column M – reflects the Network Upgrade costs. Oregon's Qualifying Facility Large Generator Interconnection Procedures ("QF-LGIP"), adopted by the Commission in Order No. 10-132, define "Network Upgrades" as "the 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.”

Column N – reflects the Distribution Upgrade costs. The QF-LGIP defines “Distribution Upgrades” as the “additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility. Distribution Upgrades do not include Interconnection Facilities.”

Column O – The Company’s SISs separately present system upgrades related to substations, but do not delineate whether the substation upgrades are related to transmission or distribution. The Company has determined that the majority of the substation costs are transmission system-related network upgrades.

Column P – One project requested interconnection at a substation. Some substation costs were combined with the Interconnection Facilities in the SIS, and therefore it was not possible to provide the dollar amount of each component.

Queue #	Date of Interconnection Request	Interconnection request status	Service type (NR/ER)	Jurisdictional/ Size	Nameplate Capacity	County	Generator Tech Type	Point of Interconnection	Total Costs To Queue Position	Network Upgrade Costs Assigned To Sr. Queue Position	Were Network Upgrades Constructed Or Are They Currently Under Construction	Network Upgrades Cost	Distribution Upgrades Cost	Substation Upgrade Cost	Substation and Interconnection Facility Upgrades Cost
424	01/22/14	In Service	NR	OPUC	10.00	Malheur	Solar	12.5 kV	$ 955,800		Yes	$ -	$ 352,800	$ 603,000	$ -
425	01/22/14	In Service	NR	OPUC	4.50	Malheur	Solar	12.5 kV	$ 1,720,800	#412, #413, #414, #419,#424	Yes	$ -	$ 1,454,400	$ 266,400	$ -
472	03/16/15	Withdrawn	NR	OPUC	5.00	Malheur	Solar	34.5	$ 21,500,000		No	$ 18,420,000	$ 330,000	$ 2,750,000	$ -
473	03/25/15	Withdrawn	NR	OPUC	5.00	Malheur	Solar	34.5	$ 19,830,000	#472	No	$ 17,010,000	$ 80,000	$ 2,740,000	$ -
474	03/26/15	Withdrawn	NR	OPUC	5.00	Malheur	Solar	12.5	$ 4,130,000	#472, #473	No	$ 3,930,000	$ 185,000	$ 15,000	$ -
475	03/26/15	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 2,610,000	#472, #473	No	$ 1,140,000	$ 1,460,000	$ 10,000	$ -
476	03/26/15	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 350,000	#475	No	$ -	$ 340,000	$ 10,000	$ -
477	03/31/15	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 4,050,000	#475	No	$ 1,500,000	$ 230,000	$ 2,320,000	$ -
479	03/31/15	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 1,300,000	#475, #476	No	$ -	$ -	$ 1,300,000	$ -
480	04/03/15	Withdrawn	NR	OPUC	5.00	Malheur	Solar	34.5	$ 5,105,000	#475, #476	No	$ 5,105,000	$ -	$ -	$ -
486	04/10/15	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 1,470,000	#475, #476	No	$ -	$ 470,000	$ 1,000,000	$ -
491	04/22/15	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 3,250,000	#475, #476	No	$ 1,245,000	$ 525,000	$ 1,480,000	$ -
493	05/05/15	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 510,000	#475, #476	No	$ -	$ 460,000	$ 50,000	$ -
495	05/15/15	Withdrawn	NR	OPUC	10.00	Baker	Solar	69	$ 522,000	#493	No	$ -	$ -	$ -	$ 522,000
510	01/22/16	In-Service	NR	OPUC	3.00	Malheur	Solar	12.5	$ -		No	$ -	$ -	$ -	$ -
511	01/29/16	In-Service	NR	OPUC	3.00	Malheur	Solar	12.5	$ -		No	$ -	$ -	$ -	$ -
512	01/29/16	In-Service	NR	OPUC	2.75	Malheur	Solar	12.5	$ -		No	$ -	$ -	$ -	$ -
519	10/18/16	In-Service	NR	OPUC	15.00	Baker	Solar	34.5	$ 1,820,400		Yes	$ 133,400	$ -	$ 1,687,000	$ -
525	08/04/17	In-Service	NR	OPUC	3.00	Malheur	Solar	12.5	$ 469,800		No	$ -	$ 464,000	$ 5,800	$ -
532	05/03/18	GIA	ER/NR	OPUC	2.95	Malheur	Solar	12.5	$ 58,000		No	$ -	$ 58,000	$ -	$ -
536	06/25/18	Withdrawn	ER/NR	FERC	23.00	Malheur	Solar	69	$ 12,626,600		No	$ 12,533,800	$ -	$ 92,800	$ -
541	10/29/18	Withdrawn	NR	OPUC	10.00	Malheur	Solar	12.5	$ 1,299,741	#541	No	$ -	$ 29,000	$ 1,270,741	$ -
546	12/03/18	Active	NR	OPUC	3.00	Baker	Solar	12.5	$ 759,800		Yes	$ -	$ -	$ 759,800	$ -
556	05/06/19	Active	NR	OPUC	30.00	Grant	Solar	138	$ 2,056,200		N/A	$ 237,800	$ -	$ 1,818,400	$ -
562	08/05/19	Active	NR	OPUC	42.00	Malheur	Solar	~~138~~	Still in SIS Phase		N/A	$ -	$ -	$ -	$ -
566	08/30/19	Active	NR	OPUC	5.00	Malheur	Solar	12.47	$ 375,000		Yes	$ -	$ 375,000	$ -	$ -

MW not included in 215 MW figure in Staff's testimony because Network Upgrade costs are not available

Staff/102 pages 4 and 5 are confidential

TOPIC OR KEYWORD: Network Upgrade Costs

STAFF'S DATA REQUEST NO. 2:

For each generator identified in #1 with a network upgrade cost assigned to that generator in the system impact study, please calculate the ratepayer impact for cost of service customers if the network upgrade costs were allocated to current transmission customers. Please report this information as a dollar amount and as a percentage increase. Please provide all work papers in electronic excel format with formulae intact.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 2:

All of the generators identified in the response to Data Request No. 1 are qualifying facilities ("QF"), cogeneration facilities or small power production facilities that meet the Public Utility Regulatory Policies Act of 1978 ("PURPA") criteria. Therefore, under the Company's retail tariff in both Oregon (Rate Schedule 85) and Idaho (Rate Schedule 72), the QF's are required to pay all network upgrade costs associated with their project. Idaho Power's investment in 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.

If the Company's retail tariff in either Oregon or Idaho was modified such that the QF was not required to pay all network upgrade costs, those costs would be recorded in Account 101 with no offset. Transmission-related Account 101 balances are a component of Idaho Power's transmission formula rate under the Company's Open Access Transmission Tariff ("OATT"), therefore the inclusion of the network upgrade costs would increase rates to transmission customers. However, it is important to note that under the Federal Energy Regulatory Commission ("FERC") authorized transmission formula rate methodology, Idaho Power would not be permitted to assign 100 percent of the costs to transmission customers. Rather, transmission customers would pay their load ratio share of the network upgrade investments and the rest of the costs would be passed on to Idaho Power's retail customers in the jurisdiction(s) where it was authorized.

Using the transmission formula rate spreadsheet currently in effect, included as an attachment to this response, as a high-level estimate an increase of $79,433,941 in transmission-related Account 101 balances (the total of all network upgrade costs included in column M and the total of all substation upgrade costs included in column O of the attachment provided in the Company's Response to Staff's Request No. 1), would result in an increase in transmission rates of 6.9 percent. This estimate assumes no incremental accumulated depreciation, incremental depreciation expense or incremental transmission operations and maintenance expense. Additionally, as further discussed in the Company's Response to Staff's Request No. 3, a portion of the costs associated with these upgrades would be borne by the Company's retail customers. Given these adverse rate impacts, Idaho Power does not agree that allocation of network upgrade costs to transmission customers is reasonable or complies with PURPA.

TOPIC/KEYWORD: Network Resource Interconnection Service Requirement

STAFF'S INFORMATION REQUEST NO. 7:

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 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 DNR in part a are recovered, including whether the costs are paid by transmission customers and ratepayers.**

d. **Please explain why these the DNRs identified in part a were not required to interconnect under Network Upgrade Interconnection Service.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 7:

(a) All of the DNRs that Idaho Power itself has developed and interconnected to its system have interconnected using NRIS under generator interconnection agreements[1] or were interconnected prior to FERC's definition of NRIS in Order 2003 (issued July 24, 2003).

Idaho Power has three non-QF DNRs that were not developed by Idaho Power. These three DNRs interconnected to Idaho Power's system using a FERC-jurisdictional Small Generator Interconnection Agreement (SGIA) or Large Generator Interconnection Agreement (LGIA) These projects were not required to obtain NRIS because they were developed by third parties and could choose which FERC-jurisdictional generator interconnection service they would use. The table below lists whether the customer had an SGIA or LGIA, and if LGIA, which type of interconnection service it chose.

DNR	Generator Size (MW)	Location (OR/ID)	Resource Type	Commercial Operation Date[2]	Generator Interconnection Agreement
Arrowrock hydroelectric power project	18	ID	Hydro	December 2009	SGIA
Elkhorn Wind Project	101	OR	Wind	November 2007	LGIA (66 MW NRIS; 35 MW ERIS)
Neal Hot Springs	36	OR	Geothermal	March 2011	LGIA (NRIS)

[1] The Bennett Mountain, Langley Gulch, and Evander Andrews/Danskin (2 newer units) gas plants, as well as an upgrade to the Shoshone Falls hydroelectric plant.
[2] Commercial Operation Date as listed in the facility's generator interconnection agreement.

(b) The facilities listed in part (a) are designated Network Resources which, like all designated Network Resources, are delivered to load on a firm basis using Network Integration Transmission Service. With respect to Elkhorn, the amount of available Network Integration Transmission Service varies based on seasonal forecasts. In order to avoid paying for the network upgrades necessary to deliver its entire output to Idaho Power under Network Integration Transmission Service, Elkhorn chose to accept contractual provisions that would limit its ability to sell power to Idaho Power during the times that there is no Network Integration Transmission Service available. Therefore, the amount of generation from the project that exceeds the Network Integration Transmission Service available is delivered to load using firm Point-to-Point Transmission Service, if it is available, and using non-firm Point-to-Point Transmission Service to the extent firm is not available.

(c) As a general matter, and as was the case for the DNRs listed in the table in part (a), under FERC's *pro forma* SGIA and LGIA, any Network Upgrades would be initially funded by the interconnection customer but would be reimbursed via transmission credits. Thus, the costs of such Network Upgrades, once reimbursed, would ultimately be included in the rates for transmission service under the Open Access Transmission Tariff, which are charged to all transmission customers, including Idaho Power on behalf of its retail customers. Thus, both transmission and retail customers ultimately pay for the costs of Network Upgrades through their rates. (Any Interconnection Facilities or Distribution Upgrades, as defined in the LGIA, would be funded by the interconnection customer without reimbursement.)

When transmission service is requested with respect to the generating facilities, the transmission service study process may identify additional Network Upgrades required to deliver the generation to load (if delivery to load was not studied in the interconnection process under NRIS). Under FERC's *pro forma* Open Access Transmission Tariff, the Transmission Provider funds the costs of these transmission service (that is, deliverability)-related Network Upgrades. The costs of such Network Upgrades is included in the rates for transmission service under the Open Access Transmission Tariff, which are charged to all transmission customers, including Idaho Power on behalf of its retail customers. Thus, both transmission and retail customers ultimately pay for the costs of Network Upgrades through their rates. For the three DNRs listed in the table in part (a), no additional transmission-service-related Network Upgrades were necessary for the transmission service that Idaho Power currently provides.

(d) The DNRs listed in part (a) are not Qualifying Facilities under PURPA, and as such Idaho Power was not statutorily required to purchase their output, while maintaining customer indifference. The entities who requested interconnection of those facilities did so following the FERC-jurisdictional interconnection processes. Under that process, an interconnection customer may choose ERIS or NRIS. In any event, resources listed in (a) are all designated Network Resources being delivered to load using Network Integration Transmission Service. This means that they were ultimately studied for deliverability to load, either in the interconnection process or the transmission service process.

TOPIC/KEYWORD: Customer Indifference

STAFF'S INFORMATION REQUEST NO. 17:

Please explain whether and how the Company ensures that only a generator that triggers a Network Upgrade will utilize or otherwise be the sole beneficiary from the construction of that upgrade.

a. If the Company does not or cannot ensure that only a generator that triggers a Network Upgrade will utilize or otherwise be the sole beneficiary from the construction of that upgrade, please list and describe the other parties that would utilize a Network Upgrade (e.g., new transmission line), how they would secure those rights, and which entities would receive revenues or other benefits from the use of that transmission line.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 17:

In the interconnected transmission system, specific components are not isolated for use by a single user and the uses of any component change over time. The rights to use available capacity on the transmission system are secured through the transmission service process.

The Company does not ensure that only a generator that triggers a Network Upgrade can utilize it. Per FERC Order Nos. 888 and 890, the Company has an Open Access Transmission Tariff (OATT). Under FERC rules, all transmission capacity, including transmission capacity originally funded by Idaho Power and transmission capacity added due to Network Upgrades, is available to all transmission or interconnection customers on a first-come first-serve basis.

Any transmission or interconnection customer may secure unutilized transmission or interconnection capacity through a transmission or interconnection service request under the standard process detailed in the Company's OATT. It is possible that an interconnection customer could fund the costs of Network Upgrades from which later interconnection or transmission customers might also be able to use capacity. The later customers would obtain rights to such capacity by submitting an interconnection or transmission service request, which, if approved, would grant them such rights.

With respect to FERC-jurisdictional interconnections, if an interconnection customer funds Network Upgrades which are later also used by another customer, the original interconnection customer continues to receive transmission credits from the transmission provider until it is fully reimbursed for the costs it had funded, as discussed in the response to Staff's Information Request No. 16. This results in all the transmission provider's transmission customers paying the costs of the Network Upgrades, due to FERC's policy determination under the Federal Power Act that all customers benefit from such facilities. Any use of existing transmission capacity by transmission customers, and the associated revenues, are included in the transmission formula rate and, all else being equal, would reduce the rate for all customers. There is no separate or additional reimbursement to the original customer from the later customer's usage.

With respect to state-jurisdictional interconnections in Oregon, there is no reimbursement to an original customer if a later customer also uses the capacity created by upgrades funded by the original customer.

State-jurisdictional interconnections in Idaho are governed by Idaho Power's Rate Schedule 72, which does not use the term "Network Upgrades." Instead, it defines upgrades to the transmission system as "Upgrades" and "Special Facilities," both of which are included in the umbrella term "Interconnection Facilities." If an interconnection customer funds Interconnection Facilities which are later also used by another customer within five years of Idaho Power completing construction of the facilities, the original customer is entitled to partial reimbursement of the amounts it had paid for the facilities (this time-limited right is known as a "Vested Interest"). The new customer is required to pay a portion of the costs of the facilities that it uses that were initially funded by the original customer, and the original customer is entitled to receive the amounts paid by the new customer.

TOPIC/KEYWORD: Customer Indifference

STAFF'S INFORMATION REQUEST NO. 18:

Please explain in detail whether and how interconnection costs are considered in the Company's Oregon QF avoided cost rates.

a. Please provide citations.

b. Please provide any relevant work papers in the form of electronic Excel workbooks with formulae intact.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 18:

Interconnection costs are considered in the Company's Oregon QF avoided cost rates, both Standard Avoided Costs as well as negotiated avoided costs.

Per the approved methodology for Oregon Standard Avoided Costs, the avoided capacity cost is based on the full fixed cost of a proxy combined cycle combustion turbine ("CCCT"), less capitalized energy costs. The cost of the proxy CCCT includes plant capital and interconnection-related capital investments in Idaho Power's transmission system.

For QF projects that are not eligible for Standard Avoided Costs, the Incremental Cost Integrated Resource Plan ("ICIRP") avoided cost methodology is used to determine avoided energy and capacity costs that are specific to a QF's own hourly generation profile. The ICIRP avoided capacity cost is based on the cost of a proxy simple cycle combustion turbine ("SCCT"). The cost of the proxy SCCT includes plant capital and interconnection-related capital investments in Idaho Power's transmission system.

a. The plant capital and transmission system interconnection capital costs used in Idaho Power's current Oregon Standard Avoided Costs were sourced from Idaho Power's 2019 Integrated Resource Plan ("IRP"). [1] The plant capital and transmission system interconnection capital costs currently used in negotiated avoided costs are sourced from Idaho Power's 2017 IRP.[2]

   The plant capital cost assumptions used in the 2017 IRP and 2019 IRP are sourced from the National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline ("ATB"). The plant capital costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction. NREL refers to these costs as the "overnight cost of capital", which they describe as the cost of constructing a plant, including onsite electrical equipment (e.g., switchyard), a nominal-distance spur line, and necessary upgrades at a transmission substation.[3]

[1] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2019/2019_IRP_Tech_AppendixUpdated.pdf Page 23.

[2] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/AppendixC_Tech.pdf Page 76. Note, the column labeled "Cost of Capital" is reflective of both plant capital costs and transmission system interconnection capital costs. In addition, while the table labels the costs "Transmission," as described in this response, the facilities that make up the costs are those that would be required for interconnection and are therefore more accurately described as interconnection costs for purposes of this response.

[3] https://atb.nrel.gov/

In summary, NREL's "overnight cost of capital" is reflective of plant capital costs, including interconnection costs. The transmission system capital costs used in the 2017 IRP and 2019 IRP are reflective of transmission system improvements needed to interconnect the generation resource. These cost assumptions, used in Idaho Power's IRP, are ultimately sourced in Oregon QF avoided cost rates.

b. Please see the attached Excel file, which includes the workpapers to support Idaho Power's current Standard Avoided Costs, as approved in Commission Order No. 20-192. Within the Excel File, the tab labeled "Table 8" includes the input values for plant capital and transmission system interconnection capital costs, which feed into the determination of Standard Avoided Costs.

TOPIC/KEYWORD: Customer Indifference

STAFF'S INFORMATION REQUEST NO. 19:

19. Please explain in detail whether and how transmission costs are considered in the Company's Oregon QF avoided cost rates.

a. Please provide citations.

b. Please provide any relevant work papers in the form of electronic Excel workbooks with formulae intact.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 19:

Interconnection-related capital investments in Idaho Power's transmission system are considered in the Company's Oregon QF avoided cost rates, both Standard Avoided Costs as well as negotiated avoided costs. Please refer to Idaho Power's response to Staff's Information Request No. 18.

CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Response Testimony

October 30, 2020

PacifiCorp
UM 2032 Data Response
$ - Thousands
Company Response to Data Request OPUC 2 & 3

Line No.									Annual Revenue Requirement to Retail Customers ($ '000)									
		TOTAL	**Q#544**	**Q#594**	**Q#603**	**Q#607**	**Q#621**	**Q#629**	**Q#650**	**Q#726**	**Q#728**	**Q#731 (1)**	**Q#731 (2)**	**Q#734 (1)**	**Q#734 (2)**	**Q#738**	**Q#747**	**Q#893**
	100% Retail Customers																	
1	*100% Situs OR*	160,328	7,616	2,173	5,018	16,427	2,238	2,509	11,947	15,910	4,779	15,910	16,606	16,606	16,606	17,920	4,779	3,285
2	*Percentage Impact*	12.15%	0.58%	0.16%	0.38%	1.24%	0.17%	0.19%	0.91%	1.21%	0.36%	1.21%	1.26%	1.26%	1.26%	1.36%	0.36%	0.25%
3	*System-Allocated OR*	42,199	2,004	572	1,321	4,324	589	660	3,144	4,187	1,258	4,187	4,371	4,371	4,371	4,717	1,258	865
4	*Percentage Impact*	3.20%	0.15%	0.04%	0.10%	0.33%	0.04%	0.05%	0.24%	0.32%	0.10%	0.32%	0.33%	0.33%	0.33%	0.36%	0.10%	0.07%
5	19% Transmission; 81% Retail Customers																	
6	*100% Situs OR*	129,866	6,169	1,760	4,064	13,306	1,813	2,032	9,677	12,887	3,871	12,887	13,451	13,451	13,451	14,516	3,871	2,661
7	*Percentage Impact*	9.84%	0.47%	0.13%	0.31%	1.01%	0.14%	0.15%	0.73%	0.98%	0.29%	0.98%	1.02%	1.02%	1.02%	1.10%	0.29%	0.20%
8	*System-Allocated OR*	34,181	1,624	463	1,070	3,502	477	535	2,547	3,392	1,019	3,392	3,540	3,540	3,540	3,820	1,019	700
9	*Percentage Impact*	2.59%	0.12%	0.04%	0.08%	0.27%	0.04%	0.04%	0.19%	0.26%	0.08%	0.26%	0.27%	0.27%	0.27%	0.29%	0.08%	0.05%

PacifiCorp
UM 2032 Data Response
$-Thousands
Network Upgrade Costs for QFs

Line No.	Total Company	Q#544	Q#594	Q#603	Q#607	Q#621	Q#629	Q#650	Q#726	Q#728	Q#731 (1)	Q#731 (2)	Q#734 (1)	Q#734 (2)	Q#738	Q#747	Q#893
		TOTAL COMPANY															
1	Capital Investment	63,745	18,191	42,000	137,500	18,731	21,000	100,000	133,170	40,000	133,170	139,000	139,000	139,000	150,000	40,000	27,500
2	Depreciation Reserve	(604)	(172)	(398)	(1,303)	(178)	(199)	(948)	(1,262)	(379)	(1,262)	(1,318)	(1,318)	(1,318)	(1,422)	(379)	(261)
3	Accumulated DIT Balance	(911)	(260)	(600)	(1,965)	(268)	(300)	(1,429)	(1,903)	(572)	(1,903)	(1,986)	(1,986)	(1,986)	(2,143)	(572)	(393)
4	Net Rate Base	62,230	17,759	41,002	134,232	18,285	20,501	97,623	130,005	39,049	130,005	135,696	135,696	135,696	146,435	39,049	26,846
5	Pre-Tax Rate of Return	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%
6	Pre-Tax Return on Rate Base	5,695	1,625	3,752	12,284	1,673	1,876	8,934	11,897	3,574	11,897	12,418	12,418	12,418	13,401	3,574	2,457
7	Operation & Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Depreciation	1,116	318	735	2,406	328	368	1,750	2,331	700	2,331	2,433	2,433	2,433	2,625	700	481
9	Property Taxes	561	160	370	1,210	165	185	880	1,172	352	1,172	1,223	1,223	1,223	1,320	352	242
10	**Rev. Reqt. Before Revenue Gross-up**	**7,372**	**2,104**	**4,857**	**15,901**	**2,166**	**2,428**	**11,564**	**15,400**	**4,626**	**15,400**	**16,074**	**16,074**	**16,074**	**17,346**	**4,626**	**3,180**
11	Franchise Taxes	179	51	118	386	53	59	281	374	112	374	390	390	390	421	112	77
12	Bad Debt Expense	29	8	19	62	8	9	45	60	18	60	63	63	63	68	18	12
13	Resource Supplier Tax	10	3	6	21	3	3	15	20	6	20	21	21	21	23	6	4
14	PUC Fee	27	8	18	57	8	9	42	56	17	56	58	58	58	63	17	11
15	**Total Revenue Requirement**	**7,616**	**2,173**	**5,018**	**16,427**	**2,238**	**2,509**	**11,947**	**15,910**	**4,779**	**15,910**	**16,606**	**16,606**	**16,606**	**17,920**	**4,779**	**3,285**

Line No.	Oregon-Allocated	Q#544	Q#594	Q#603	Q#607	Q#621	Q#629	Q#650	Q#726	Q#728	Q#731 (1)	Q#731 (2)	Q#734 (1)	Q#734 (2)	Q#738	Q#747	Q#893
		OREGON-ALLOCATED															
1	Capital Investment	16,778	4,788	11,054	36,190	4,930	5,527	26,320	35,050	10,528	35,050	36,585	36,585	36,585	39,480	10,528	7,238
2	Depreciation Reserve	(159)	(45)	(105)	(343)	(47)	(52)	(250)	(332)	(100)	(332)	(347)	(347)	(347)	(374)	(100)	(69)
3	Accumulated DIT Balance	(240)	(68)	(158)	(517)	(71)	(79)	(376)	(501)	(151)	(501)	(523)	(523)	(523)	(564)	(151)	(103)
4	Net Rate Base	16,379	4,674	10,792	35,330	4,813	5,396	25,694	34,217	10,278	34,217	35,715	35,715	35,715	38,542	10,278	7,066
5	Pre-Tax Rate of Return	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%	9.151%
6	Pre-Tax Return on Rate Base	1,499	428	988	3,233	440	494	2,351	3,131	941	3,131	3,268	3,268	3,268	3,527	941	647
7	Operation & Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Depreciation	294	84	193	633	86	97	461	613	184	613	640	640	640	691	184	127
9	Property Taxes	148	42	97	319	43	49	232	308	93	308	322	322	322	347	93	64
10	**Rev. Reqt. Before Revenue Gross-up**	**1,940**	**554**	**1,278**	**4,185**	**570**	**639**	**3,044**	**4,053**	**1,217**	**4,053**	**4,231**	**4,231**	**4,231**	**4,566**	**1,217**	**837**
11	Franchise Taxes	47	13	31	102	14	16	74	98	30	98	103	103	103	111	30	20
12	Bad Debt Expense	8	2	5	16	2	2	12	16	5	16	17	17	17	18	5	3
13	Resource Supplier Tax	3	1	2	5	1	1	4	5	2	5	5	5	5	6	2	1
14	PUC Fee	7	2	5	15	2	2	11	15	4	15	15	15	15	17	4	3
15	**Total Revenue Requirement**	**2,004**	**572**	**1,321**	**4,324**	**589**	**660**	**3,144**	**4,187**	**1,258**	**4,187**	**4,371**	**4,371**	**4,371**	**4,717**	**1,258**	**865**

PacifiCorp
UM 2032 Data Response
$-Thousands

Line No.	Total Company	Q#544	Q#594	Q#603	Q#607	Q#621	Q#629	Q#650	Q#726	Q#728	Q#731 (1)	Q#731 (2)	Q#734 (1)	Q#734 (2)	Q#738	Q#747	Q#893
1	Capital Investment	63,745	18,191	42,000	137,500	18,731	21,000	100,000	133,170	40,000	133,170	139,000	139,000	139,000	150,000	40,000	27,500
2	Depreciation Reserve	(604)	(172)	(398)	(1,303)	(178)	(199)	(948)	(1,262)	(379)	(1,262)	(1,318)	(1,318)	(1,318)	(1,422)	(379)	(261)
3	Accumulated DIT Balance	(911)	(260)	(600)	(1,965)	(268)	(300)	(1,429)	(1,903)	(572)	(1,903)	(1,986)	(1,986)	(1,986)	(2,143)	(572)	(393)
4	Net Rate Base	62,230	17,759	41,002	134,232	18,285	20,501	97,623	130,005	39,049	130,005	135,696	135,696	135,696	146,435	39,049	26,846
5	Operation & Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Depreciation	1,116	318	735	2,406	328	368	1,750	2,331	700	2,331	2,433	2,433	2,433	2,625	700	481
7	Property Taxes	561	160	370	1,210	165	185	880	1,172	352	1,172	1,223	1,223	1,223	1,320	352	242
9	Property Tax Rate	0.89%															

Line No.	Oregon-Allocated	Q#544	Q#594	Q#603	Q#607	Q#621	Q#629	Q#650	Q#726	Q#728	Q#731 (1)	Q#731 (2)	Q#734 (1)	Q#734 (2)	Q#738	Q#747	Q#893
1	Capital Investment	16,778	4,788	11,054	36,190	4,930	5,527	26,320	35,050	10,528	35,050	36,585	36,585	36,585	39,480	10,528	7,238
2	Depreciation Reserve	(159)	(45)	(105)	(343)	(47)	(52)	(250)	(332)	(100)	(332)	(347)	(347)	(347)	(374)	(100)	(69)
3	Accumulated DIT Balance	(240)	(68)	(158)	(517)	(71)	(79)	(376)	(501)	(151)	(501)	(523)	(523)	(523)	(564)	(151)	(103)
4	Net Rate Base	16,379	4,674	10,792	35,330	4,813	5,396	25,694	34,217	10,278	34,217	35,715	35,715	35,715	38,542	10,278	7,066
5	Operation & Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Depreciation	294	84	193	633	86	97	461	613	184	613	640	640	640	691	184	127
7	Property Taxes	148	42	97	319	43	49	232	308	93	308	322	322	322	347	93	64
9	Property Tax Rate	0.89%															

Annual Revenue Requirement to Retail Customers ($ '000)
$ - Thousands

	Aggregate Upgrades
100% Retail Customers	
100% Situs OR	210,107
Percentage Impact	15.92%
System-Allocated OR	55,300
Percentage Impact	4.19%
19% Transmission; 81% Retail Customers	
100% Situs OR	170,187
Percentage Impact	12.89%
System-Allocated OR	44,793
Percentage Impact	3.39%

PacifiCorp
UM 2032 Data Response
$-Thousands
Network Upgrade Costs for QFs

Line No.	Total Company	TOTAL COMPANY Aggregate Upgrades
1	Capital Investment	1,758,672
2	Depreciation Reserve	(16,672)
3	Accumulated DIT Balance	(25,129)
4	Net Rate Base	1,716,872
5	Pre-Tax Rate of Return	9.151%
6	Pre-Tax Return on Rate Base	157,118
7	Operation & Maintenance	-
8	Depreciation	30,779
9	Property Taxes	15,479
10	**Rev. Reqt. Before Revenue Gross-up**	**203,375**
11	Franchise Taxes	4,937.52
12	Bad Debt Expense	794.71
13	Resource Supplier Tax	264.25
14	PUC Fee	735.37
15	**Total Revenue Requirement**	**210,107**

Line No.	Oregon-Allocated	OREGON-ALLOCATED Aggregate Upgrades
1	Capital Investment	462,884
2	Depreciation Reserve	(4,388)
3	Accumulated DIT Balance	(6,614)
4	Net Rate Base	451,882
5	Pre-Tax Rate of Return	9.151%
6	Pre-Tax Return on Rate Base	41,353
7	Operation & Maintenance	-
8	Depreciation	8,101
9	Property Taxes	4,074
10	**Rev. Reqt. Before Revenue Gross-up**	**53,529**
11	Franchise Taxes	1,299.56
12	Bad Debt Expense	209.17
13	Resource Supplier Tax	69.55
14	PUC Fee	193.55

15	**Total Revenue Requirement**	**55,300**

PacifiCorp
UM 2032 Data Response
$-Thousands

Line No.	Total Company	Aggregate Upgrades
1	Capital Investment	1,758,672
2	Depreciation Reserve	(16,672)
3	Accumulated DIT Balance	(25,129)
4	Net Rate Base	1,716,872
5	Operation & Maintenance	-
6	Depreciation	30,779
7	Property Taxes	15,479
9	Property Tax Rate	0.89%

Line No.	Oregon-Allocated	Aggregate Upgrades
1	Capital Investment	462,884
2	Depreciation Reserve	(4,388)
3	Accumulated DIT Balance	(6,614)
4	Net Rate Base	451,882
5	Operation & Maintenance	-
6	Depreciation	8,101
7	Property Taxes	4,074
9	Property Tax Rate	0.89%

PacifiCorp
December 2019 Results of Operations
Variables

Line no.	Capital Structure	Capital Structure	Capital Cost	Weighted Cost	Tax Gross-up	Pre-Tax Cost
1	Debt	48.360%	5.049%	2.442%		2.442%
2	Preferred	0.020%	6.753%	0.001%	1.326	0.002%
3	Common	51.620%	9.800%	5.059%	1.326	6.708%
4			**TOTAL**	**7.502%**		**9.151%**
5	Consolidated Tax Rate		24.587%			
6	Tax Gross-up factor = (1/(1 - tax rate))		1.3260			
	Property Tax Calculation as filed					
7	Total Company (Forecast for 12 ME Dec 2020)					153,852,032
8	Oregon GPS Factor [2]					27.5427%
9	Oregon Property Taxes					42,375,017
10	Oregon Gross EPIS					8,046,254,352
11	Oregon Accum. Depr.					(3,095,065,798)
12	Oregon Accum. Amort.					(182,355,936)
13	Oregon Net EPIS					4,768,832,618
14	Estimated Oregon Property Tax Rate					0.889%
15	SG Factor [1]					26.3201%
16	GPS Factor [2]					27.5427%

Line no.	Franchise Tax and Bad Debt Percentage [3]	Percentage of Revenue	w/ Tax Gross-up
17	Franchise Tax	2.350%	2.428%
18	Bad Debt Percentage	0.378%	0.391%
19	Resource Suppliers Tax	0.126%	0.130%
20	PUC Fee	0.350%	0.362%

Footnotes:

1 SG Factor from December 2019 Results of Operations filed April 2020
2 GPS Factor from December 2019 Results of Operations filed April 2020
3 From December 2019 Results of Operations filed April 2020

OPUC Information Request 2

Network Upgrade Costs
For each generator identified in #1 with a network upgrade cost assigned to that generator in the system impact study, please calculate the ratepayer impact for cost of service customers if the network upgrade costs were allocated to current transmission customers. Please report this information as a dollar amount and as a percentage increase. Please provide all work papers in electronic excel format with formulae intact.

Response to OPUC Information Request 2

The Company's current transmission formula rate (included in PacifiCorp's Open Access Transmission Tariff) was approved by the Federal Energy Regulatory Commission (FERC) in Docket ER11-3643. The Company's transmission formula rate is updated annually with the annual transmission revenue requirement (ATRR) that represents the annual total cost of providing firm transmission service over the test year. The ATRR calculation incorporates all transmission system investments by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments. Transmission assets, including new transmission capital and transmission network upgrades, are included in the ATRR, weighted by months in service. The ATRR is converted into a rate by dividing the ATRR by firm transmission demand. All third-party revenues for transmission service (along with third-party revenues for ancillary services) are included as revenue credits in the calculation of rates in each of the Company's state retail jurisdictions. Most recently, the current transmission formula rate approved by FERC has been updated to also include the return of excess deferred income taxes as a result of the Tax Cuts and Jobs Act of 2017.

In accordance with PacifiCorp's 2020 annual transmission formula update, in calendar year 2019, 81 percent of the load is attributable to Energy Supply Management while 19 percent is attributable to third party load. Retail customers pay for 100 percent of transmission costs, but then get a credit for the third-party wholesale transmission revenue in the calculation of the retail/state revenue requirement.

Please refer to Attachment OPUC 2, lines 5 through 9 on the "Summary" tab, for the customer impact to cost of service customers if the deliverability-driven (Network Resource Interconnection Service (NR)) network upgrade costs identified in a generator's system impact study were allocated to current transmission customers assuming 81 percent of the load is attributable to cost of service customers as stated above. The Company has calculated the impact to customers under both the assumption that the costs are 100 percent assigned to Oregon customers, and the assumption that the costs are allocated under the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol to Oregon customers as transmission function costs. In accordance with the Company's December 2019 results of operations, Oregon customers are allocated approximately 26.32 percent of Transmission costs. Although PacifiCorp understands Staff to be asking about deliverability-driven network upgrade costs in OPUC Information Request 1, PacifiCorp has also calculated the aggregate impact of both deliverability (NR) and non-deliverability (Energy Resource Interconnection Service (ER)) driven network upgrade costs on cost of service customers. This additional calculation is found on lines 10-14 of the tab labeled “Summary – Additional.”

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.

[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 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.

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. PAC confirmed that this value should be $5.12 million and will update their response	~~$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 a 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.

OPUC Information Request 18

Customer Indifference
Please explain whether and how the Company ensures that only a generator that triggers a Network Upgrade will utilize or otherwise be the sole beneficiary from the construction of that upgrade.

(a) If the Company does not or cannot ensure that only a generator that triggers a Network Upgrade will utilize or otherwise be the sole beneficiary from the construction of that upgrade, please list and describe the other parties that would utilize a Network Upgrade (e.g., new transmission line), how they would secure those rights, and which entities would receive revenues or other benefits from the use of that transmission line.

Response to OPUC Information Request 18

No transmission provider can ensure that only a generator that triggers a network upgrade will utilize or otherwise be the sole beneficiary of the construction of that upgrade, as electrons cannot be color-coded. Other parties may use a network upgrade by requesting and contracting for generator interconnection service or transmission service in accordance with federal or state processes. *See* PacifiCorp's response to OPUC Information Request 15 for a detailed discussion of network upgrade costs and benefits, including revenue credits.

OPUC Information Request 19

Customer Indifference
Please explain in detail whether and how interconnection costs are considered in the Company's Oregon QF avoided cost rates.

(a) Please provide citations.

(b) Please provide any relevant work papers in the form of electronic Excel workbooks with formulae intact.

Confidential Response to OPUC Information Request 19

(a) Current Oregon qualifying facility avoided costs are based on resource costs reported in PacifiCorp's 2019 Integrated Resource Plan (IRP) supply-side table, specifically those for combined cycle combustion turbine and simple cycle combustion turbine natural gas generating facilities, and wind resources. Generic interconnection costs were included in the capital costs for these resources in the 2019 IRP, so they are captured in avoided costs.

The 2018 Renewable Resources Assessment provides details on the interconnection costs for renewable resources in the 2019 IRP. This report was included in Appendix P of Volume II of the 2019 IRP. Interconnection costs are identified in the summary tables starting on pdf page 256:

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_M-R.pdf

Generic interconnection costs for natural gas generating facilities included in the 2019 IRP are shown below. Costs shown are in mid-2018 dollars (2018$).

i. Combined Cycle, Greenfield: 345 kilovolt (kV) single circuit line, **[Confidential Begins]** [redacted] **[Confidential Ends]**.

ii. Combined Cycle, Brownfield: 345 kV single circuit line without right of way (ROW) and permitting, **[Confidential Begins]** [redacted] **[Confidential Ends]**.

iii. Simple Cycle: 161 kV single circuit line, **[Confidential Begins]** [redacted] **[Confidential Ends]**.

Direct Assigned Costs: **[Confidential Begins]** [redacted] **[Confidential Ends]**.

(b) No work papers were produced for any of the electrical interconnection costs.

Confidential information is provided subject to General Protective Order No. 20-301.

OPUC Information Request 20

Customer Indifference
Please explain in detail whether and how transmission costs are considered in the Company's Oregon QF avoided cost rates.

(a) Please provide citations.

(b) Please provide any relevant work papers in the form of electronic Excel workbooks with formulae intact.

Response to OPUC Information Request 20

(a) Beyond the costs identified in the Company's response to OPUC Information Request 19, the proxy resource costs used in the calculation of the current Oregon qualifying facility avoided cost rates do not include costs related to transmission.

(b) Please refer to the Company's response to subpart (a) above.

CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Response Testimony

October 30, 2020

August 7, 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. 001
Dated July 7, 2020

Request:

In an electronic, Excel format with formulae intact, please identify the cost of deliverability driven network upgrades identified in the system impact study for each Oregon-sited interconnection applicant between the period of January 1, 2014 to present that received a system impact study:

a. Queue #
b. Date of interconnection request
c. Interconnection request status
d. Service type (NR/ER)
e. Generator type (state or federal, large or small)
f. Nameplate capacity in MW
g. County location (in OR)
h. Generator technology type
i. Point of interconnection
j. Network Upgrade costs assigned to generator ($)
k. Network Upgrade costs assigned to higher queued generators identified in the system impact study ($)
l. Whether the network upgrade was constructed or is under construction.

Response:

Please see Attachment 001A. Rows 2-8 contain information regarding PGE's large generator interconnection requests that have received a System Impact Study (SIS). "Deliverability driven" is not defined and could be subject to multiple interpretations, but PGE interprets this phrase to refer to upgrades that were identified in an Network Resource Interconnection Service (NRIS) study that were not, or would not have been, identified in an Energy Resource Interconnection Service (ERIS) study. Using this interpretation, PGE has only two large generator interconnection requests (highlighted in green) that have received SISs that identify deliverability driven Network Upgrades (shown in Column O). In addition, PGE interpreted item K in the Request, “Network Upgrade costs assigned to higher queued generators,” to be inquiring about Contingent Facilities, as that term is defined in the OATT. However, Contingent Facilities are not always associated with higher-queued interconnection requests, and PGE has been clear about the source of the Contingent Facilities in Column Q.

Rows 9-161 contain information about PGE’s small generator interconnection requests. None of PGE’s small generator interconnection requests to-date have received SISs identifying the functional equivalent of Network Upgrades, as that term is defined in the OATT and the QF-LGIP, but PGE is providing information about the system upgrades identified for its small generator interconnection requests to ensure Staff has complete information. To be clear, all of the system upgrades identified in Column P are upgrades to the distribution system—not the transmission system—and PGE’s understanding is that upgrades to the distribution system are not within the scope of this docket. Because small generator interconnection studies do not separately identify Contingent Facilities, PGE is not providing information in Column Q for Rows 9-161. Finally, please note that for a few of the older small generator interconnection requests, PGE was unable to locate the SIS and so instead provided information from the Facilities Study or the Interconnection Agreement, as reflected in the Key.

Queue No.	Application Date	Status	ER/NR	State or Federal	Large or Small	System Impact Study (Y/N)	Nameplate (MW)	County	Generation Type	Longitude	Latitude	Point of Interconnection	All Network Upgrades (as defined in QF-LGIP & PGE's OATT)	Deliverability Driven Network Upgrades	System Upgrades (as defined in OAR 860-082-0015(34))	Contingent Facilities (as defined in PGE's OATT)	Built or Under Construction
16-061	9/16/2016	LGIA signed	Both	Federal	Large Generation	Yes	100	Marion	BESS	not available	not available	Bethel 230kV	$1,368,452.00	$0.00	$0.00	N/A	Neither (customer requested to extend COD)
17-065	3/28/2017	Affected System Study (PGE studies complete)	Both	Federal	Large Generation	Yes	400	Lake	Solar PV	not available	not available	500kV near Fort Rock	$663,000,000.00	$623,276,070.00	$0.00	N/A	Neither
17-066	9/1/2017	Affected System Study (PGE studies complete)	Both	Federal	Large Generation	Yes	200	Multnomah	BESS	not available	not available	Rivergate 230kV	$840,000.00	$0.00	$0.00	Yes, but not associated with higher-queued projects. There are planned upgrades on other TPs' systems that must be completed before this project can go online. PGE has no cost information for those projects.	Neither
17-067	9/1/2017	Affected System Study (PGE studies complete)	Both	Federal	Large Generation	Yes	200	Multnomah	BESS	not available	not available	Harborgate 230kV	$910,000.00	$0.00	$0.00	Yes, but not associated with higher-queued projects. There are planned upgrades on other TPs' systems that must be completed before this project can go online. PGE has no cost information for those projects.	Neither
17-068	10/5/2017	OPUC Litigation	NR	State	Large Generation	Yes	65	Jefferson	Solar + Storage	not available	not available	Pelton 230kV Gen Lead Line	$27,000,000.00	$10,800,000.00	$0.00	N/A	Neither
18-071	7/11/2018	Affected System Study (PGE studies complete)	ER	Federal	Large Generation	Yes	600	Lake	Solar	not available	not available	500kV near Fort Rock	$14,020,000.00	$0.00	$0.00	$27,650,000 (higher-queued request is 17-065)	Neither
19-076	5/7/2019	Affected System Study, PGE Facilities Study in progress	Both	Federal	Large Generation	Yes	200	Multnomah	BESS	not available	not available	Blue Lake 230kV	$5,510,000.00	$0.00	$0.00	N/A	Neither
SPQ0002	6/5/2015	Completed	NR	State	Small Generation	No	2.2	Polk	Solar	-123.60761	45.054641	Grand Ronde-Fort Hill 13kV	$0.00	$0.00	$215,800.00	N/A	Built
SPQ0003	7/21/2015	Completed	NR	State	Small Generation	No	2.2	Marion	Solar	-122.897501	45.130436	Waconda-Waconda 13kV	$0.00	$0.00	$52,000.00	N/A	Built
SPQ0004	7/26/2015	Completed	NR	State	Small Generation	No	2.2	Polk	Solar	-123.423169	45.086083	Sheridan-Kadell 13kV	$0.00	$0.00	$138,659.00	N/A	Built
SPQ0005	8/29/2015	Completed	NR	State	Small Generation	No	2.2	Marion	Solar	-122.807194	45.013911	Silverton-North 13kV	$0.00	$0.00	$0.00	N/A	Built
SPQ0006	8/31/2015	Completed	NR	State	Small Generation	No	2.2	Marion	Solar	-122.9488	44.825657	Turner-Cascade 13kV	$0.00	$0.00	$113,659.00	N/A	Built
SPQ0007	1/25/2016	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.805034	44.969687	Silverton-West 13kV	$0.00	$0.00	$286,560.00	N/A	Built
SPQ0008	3/12/2016	Completed	NR	State	Small Generation	Yes	2.203	Marion	Solar	-122.813127	44.984216	Silverton-West 13kV	$0.00	$0.00	$480,000.00	N/A	Built
SPQ0010	4/20/2016	Completed	NR	State	Small Generation	Yes	3.027	Clackamas	Solar	-122.2843	45.430825	Dunns Corner-Dunns Corner 13kV	$0.00	$0.00	$50,000.00	N/A	Built
SPQ0011	4/20/2016	Completed	NR	State	Small Generation	Yes	2.2	Polk	Solar	-123.394694	45.076888	Sheridan-East 13kV	$0.00	$0.00	$50,000.00	N/A	Built
SPQ0012	4/28/2016	Under Construction	NR	State	Small Generation	Yes	10	Yamhill	Solar	-123.409807	45.101408	Sheridan-Kadell 13kV	$0.00	$0.00	$574,741.00	N/A	Under Construction
SPQ0013	4/29/2016	Completed	NR	State	Small Generation	Yes	10	Clackamas	Solar	-122.227602	45.38055	Sandy-Sandy 13kV	$0.00	$0.00	$429,057.00	N/A	Built
SPQ0014	4/29/2016	Completed	NR	State	Small Generation	Yes	10	Clackamas	Solar	-122.33103	45.31781	Estacada-Estacada 13kV	$0.00	$0.00	$483,500.00	N/A	Built
SPQ0015	4/29/2016	Withdrawn	NR	State	Small Generation	Yes	2.19	Yamhill	Solar	-122.94488	45.34916	Springbrook-Zimri 13kV	$0.00	$0.00	$246,000.00	N/A	Neither
SPQ0016	4/29/2016	Withdrawn	NR	State	Small Generation	Yes	6	Yamhill	Solar	-123.19631	45.12079	Amity-Amity 13kV	$0.00	$0.00	$610,000.00	N/A	Neither
SPQ0017	4/30/2016	Completed	NR	State	Small Generation	Yes	2.2	Washington	Solar	-123.140222	45.471861	Scoggins-Laurelwood 13kV	$0.00	$0.00	$50,000.00	N/A	Built
SPQ0018	4/30/2016	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.936055	45.119944	St Louis-West 13kV	$0.00	$0.00	$519,409.00	N/A	Built
SPQ0019	7/23/2015	Completed	NR	State	Small Generation	Yes	2.2	Yamhill	Solar	-123.134422	45.169833	Dayton-S&W 13kV	$0.00	$0.00	$111,876.00	N/A	Built
SPQ0020	4/30/2016	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-123.008305	44.860194	Barnes-Battle Creek 13kV	$0.00	$0.00	$375,000.00	N/A	Built
SPQ0021	6/16/2016	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.993472	45.0235	Indian-North 13kV	$0.00	$0.00	$0.00	N/A	Built
SPQ0022	6/17/2016	Under Construction	NR	State	Small Generation	Yes	2.2	Yamhill	Solar	-123.499502	45.053694	Willamina-Buell 13kV	$0.00	$0.00	$245,500.00	N/A	Under Construction
SPQ0022A	6/17/2016	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.912249	45.172305	St Louis-North 13kV	$0.00	$0.00	$303,000.00	N/A	Built
SPQ0023	7/23/2015	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.473477	45.170375	Colton-Dhoogie 13kV	$0.00	$0.00	$255,067.00	N/A	Built
SPQ0024	7/23/2015	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-123.09393	45.03333	Wallace-Wallace 13kV	$0.00	$0.00	$104,550.00	N/A	Built
SPQ0025	4/30/2016	Under Construction	NR	State	Small Generation	Yes	2.2	Yamhill	Solar	-123.103694	45.184333	Dayton-S&W 13kV	$0.00	$0.00	$288,129.00	N/A	Under Construction
SPQ0026	7/23/2015	Withdrawn	NR	State	Small Generation	Yes	2.2	Clackamas	Solar	-122.377166	45.367691	Eagle Creek-River Mill 13kV	$0.00	$0.00	$0.00	N/A	Neither
SPQ0027	8/17/2016	Under Construction	NR	State	Small Generation	Yes	2.2	Clackamas	Solar	-122.329166	45.268833	Estacada-North Fork 13kV	$0.00	$0.00	$45,000.00	N/A	Under Construction
SPQ0028	8/17/2016	Completed	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.904527	45.083472	Waconda-Waconda 13kV	$0.00	$0.00	$74,000.00	N/A	Built
SPQ0029	8/26/2016	Under Construction	NR	State	Small Generation	Yes	10	Clackamas	Solar	-122.080061	45.385494	Brightwood-North Bank 13kV	$0.00	$0.00	$1,236,000.00	N/A	Under Construction
SPQ0030	9/7/2016	Completed	NR	State	Small Generation	Yes	2.2	Clackamas	Solar	-122.264833	45.374055	Sandy-Wildcat 13kV	$0.00	$0.00	$0.00	N/A	Built
SPQ0031	10/18/2016	Withdrawn	NR	State	Small Generation	Yes	2.2	Clackamas	Solar	-122.4144305	45.172261	Colton-Greys Hill 13kV	$0.00	$0.00	$570,600.00	N/A	Neither
SPQ0032	10/18/2016	Under Construction	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.7703277	45.088891	Mt Angel-West 13kV	$0.00	$0.00	$214,000.00	N/A	Under Construction
SPQ0033	10/18/2016	Withdrawn	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.9336583	45.13813	St Louis-West 13kV	$0.00	$0.00	$167,100.00	N/A	Neither
SPQ0034	10/18/2016	Withdrawn	NR	State	Small Generation	Yes	2.2	Yamhill	Solar	-123.2058194	45.128861	Amity-Amity 13kV	$0.00	$0.00	$375,500.00	N/A	Neither
SPQ0035	10/27/2016	Under Construction	NR	State	Small Generation	Yes	2.2	Clackamas	Solar	-122.620027	45.171719	Liberal-Liberal 13kV	$0.00	$0.00	$55,000.00	N/A	Under Construction
SPQ0036	10/27/2016	Under Construction	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.959272	44.967386	Middle Grove-Cordon 13kV	$0.00	$0.00	$60,000.00	N/A	Under Construction
SPQ0037	10/27/2016	Withdrawn	NR	State	Small Generation	Yes	2.2	Marion	Solar	-122.7126861	45.071163	Scotts Mills-Scotts Mills 13kV	$0.00	$0.00	$334,000.00	N/A	Neither
SPQ0038	11/9/2016	Completed	NR	State	Small Generation	Yes	2.204	Clackamas	Solar	-122.618638	45.131083	Molalla-Marquam 13kV	$0.00	$0.00	$84,175.00	N/A	Built
SPQ0039	11/9/2016	Withdrawn	NR	State	Small Generation	Yes	2.2	Yamhill	Solar	-123.151388	45.155916	Dayton-S&W 13kV	$0.00	$0.00	$392,400.00	N/A	Neither

Key	Cost Source
	Interconnection Agreement
	System Impact Study
	Facility Study

SPQ0041	11/29/2016	Withdrawn	NR	State	Small Generation	No	2.5	Marion	Solar	-122.905417	44.821972	Turner-Turner 13kV	$0.00	$0.00	$1,230,287.15	N/A	Neither
SPQ0042	12/15/2016	Withdrawn	NR	State	Small Generation	Yes	2.29	Yamhill	Solar	-123.16006	45.52091	Dilley-Dilley 13kV	$0.00	$0.00	$371,659.00	N/A	Neither
SPQ0043	12/20/2016	Withdrawn	NR	State	Small Generation	Yes	10	Clackamas	Solar	-122.080061	45.385494	Brightwood-Rhododendron 13kV	$0.00	$0.00	$512,000.00	N/A	Neither
SPQ0044	1/27/2017	Withdrawn	NR	State	Small Generation	Yes	2.2	Yamhill	Solar	-123.170447	45.359981	Yamhill-Yamhill 13kV	$0.00	$0.00	$0.00	N/A	Neither
SPQ0045	1/27/2017	Completed	NR	State	Small Generation	Yes	0.75	Marion	Solar	-122.990409	45.02565	Indian-North 13kV	$0.00	$0.00	$0.00	N/A	Built
SPQ0046	2/14/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Marion	Solar	-122.707707	45.080397	Scotts Mills-Scotts Mills 13kV	$0.00	$0.00	$1,213,755.00	N/A	Neither
SPQ0047	2/14/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.424307	45.16988	Colton-Greys Hill 13kV	$0.00	$0.00	$190,000.00	N/A	Neither
SPQ0048	2/14/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Marion	Solar	-122.939467	45.062974	Waconda-Waconda 13kV	$0.00	$0.00	$754,500.00	N/A	Neither
SPQ0049	3/24/2017	Under Construction	NR	State	Small Generation	Yes	4	Clackamas	Solar	-122.33305	45.419923	Boring-City 13kV	$0.00	$0.00	$140,000.00	N/A	Under Construction
SPQ0051	10/20/2017	Withdrawn	NR	State	Small Generation	Yes	2	Clackamas	Solar	-122.293298	45.448667	Dunns Corner-Dunns Corner 13kV	$0.00	$0.00	$603,500.00	N/A	Neither
SPQ0052	3/24/2017	Withdrawn	NR	State	Small Generation	Yes	2	Clackamas	Solar	-122.596019	45.193009	Liberal-Liberal 13kV	$0.00	$0.00	$310,000.00	N/A	Neither
SPQ0055	3/24/2017	Withdrawn	NR	State	Small Generation	Yes	4	Marion	Solar	-122.80392	45.060507	Mt Angel-West 13kV	$0.00	$0.00	$227,500.00	N/A	Neither
SPQ0058	4/3/2017	Under Construction	NR	State	Small Generation	Yes	2.2	Yamhill	Solar	-123.417361	45.087388	Sheridan-Kadell 13kV	$0.00	$0.00	$243,000.00	N/A	Under Construction
SPQ0066	4/13/2017	Under Construction	NR	State	Small Generation	Yes	2	Marion	Solar	-122.937421	44.982318	Middle Grove-Cordon 13kV	$0.00	$0.00	$140,000.00	N/A	Under Construction
SPQ0067	4/24/2017	Under Construction	NR	State	Small Generation	Yes	2.552	Clackamas	Solar	-122.276776	45.418364	Dunns Corner-Kelso 13kV	$0.00	$0.00	$100,000.00	N/A	Under Construction
SPQ0068	4/24/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Yamhill	Solar	-123.106004	45.218121	Dayton-Lafayette 13kV	$0.00	$0.00	$234,500.00	N/A	Neither
SPQ0069	5/9/2017	Under Construction	NR	State	Small Generation	Yes	2	Clackamas	Solar	-122.660963	45.100046	Molalla-Marquam 13kV	$0.00	$0.00	$627,500.00	N/A	Under Construction
SPQ0070	5/23/2017	Under Construction	NR	State	Small Generation	Yes	2.331	Clackamas	Solar	-122.286638	45.430749	Dunns Corner-Dunns Corner 13kV	$0.00	$0.00	$170,000.00	N/A	Under Construction
SPQ0071	5/23/2017	Under Construction	NR	State	Small Generation	Yes	1.85	Clackamas	Solar	-122.295388	45.430638	Dunns Corner-Dunns Corner 13kV	$0.00	$0.00	$150,000.00	N/A	Under Construction
SPQ0072	6/12/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.551014	45.11436	Molalla-Marquam 13kV	$0.00	$0.00	$942,700.00	N/A	Neither
SPQ0073	6/12/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Marion	Solar	-122.67006	45.027181	Scotts Mills-Scotts Mills 13kV	$0.00	$0.00	$828,964.00	N/A	Neither
SPQ0074	6/12/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Marion	Solar	-122.712766	45.071294	Scotts Mills-Scotts Mills 13kV	$0.00	$0.00	$726,888.00	N/A	Neither
SPQ0075	5/9/2017	Under Construction	NR	State	Small Generation	Yes	2	Marion	Solar	-122.792269	45.115146	Woodburn-East 13kV	$0.00	$0.00	$68,000.00	N/A	Under Construction
SPQ0079	6/15/2017	Withdrawn	NR	State	Small Generation	Yes	2	Clackamas	Solar	-122.735565	45.259515	Canby-Butteville 13kV	$0.00	$0.00	$611,000.00	N/A	Neither
SPQ0080	10/20/2017	Withdrawn	NR	State	Small Generation	Yes	4	Yamhill	Solar	-123.146549	45.31108	Yamhill-Carlton 13kV	$0.00	$0.00	$1,025,500.00	N/A	Neither
SPQ0082	6/21/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.606457	45.118001	Molalla-Marquam 13kV	$0.00	$0.00	$213,900.00	N/A	Neither
SPQ0083	6/21/2017	Withdrawn	NR	State	Small Generation	Yes	3	Clackamas	Solar	-122.677959	45.209716	Canby-Zimmerman 13kV	$0.00	$0.00	$720,000.00	N/A	Neither
SPQ0084	7/17/2017	Completed	NR	State	Small Generation	Yes	3	Washington	Diesel			Shute 35kV	$0.00	$0.00	$70,000.00	N/A	Built
SPQ0085	7/10/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.553602	45.140119	Molalla-Forest 13kV	$0.00	$0.00	$153,000.00	N/A	Neither
SPQ0085a	7/14/2017	Withdrawn	NR	State	Small Generation	Yes	10	Clackamas	Solar	-122.611375	45.197382	Liberal-Liberal 13kV	$0.00	$0.00	$2,707,500.00	N/A	Neither
SPQ0085b	7/14/2017	Withdrawn	NR	State	Small Generation	Yes	5	Clackamas	Solar	-122.372446	45.35448	Eagle Creek-River Mill 13kV	$0.00	$0.00	$1,963,200.00	N/A	Neither
SPQ0085c	7/14/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Marion	Solar	-122.964947	44.845741	Turner-Cascade 13kV	$0.00	$0.00	$612,600.00	N/A	Neither
SPQ0086	7/17/2017	Under Construction	NR	State	Small Generation	Yes	2	Clackamas	Solar	-122.590595	45.181705	Liberal-Liberal 13kV	$0.00	$0.00	$111,100.00	N/A	Under Construction
SPQ0087	7/17/2017	Withdrawn	NR	State	Small Generation	Yes	2	Marion	Solar	-122.808491	45.053112	Mt Angel-West 13kV	$0.00	$0.00	$431,000.00	N/A	Neither
SPQ0088	7/20/2017	Withdrawn	NR	State	Small Generation	Yes	1.26	Yamhill	Solar	-123.113167	45.118867	Unionvale-Unionvale 13kV	$0.00	$0.00	$60,000.00	N/A	Neither
SPQ0089	7/20/2017	Withdrawn	NR	State	Small Generation	Yes	3	Yamhill	Solar	-123.08703	45.028492	Unionvale-Unionvale 13kV	$0.00	$0.00	$180,000.00	N/A	Neither
SPQ0090	7/20/2017	Under Construction	NR	State	Small Generation	Yes	2.79	Clackamas	Solar	-122.430014	45.347891	Redland-Redland 13kV	$0.00	$0.00	$180,000.00	N/A	Under Construction
SPQ0091	7/20/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.575633	45.302198	Leland-Beavercreek 13kV	$0.00	$0.00	$130,000.00	N/A	Neither
SPQ0093	7/21/2017	Facility Study	NR	State	Small Generation	Yes	2	Clackamas	Solar	-122.672222	45.08308	Scotts Mills-Scotts Mills 13kV	$0.00	$0.00	$1,065,053.00	N/A	Neither
SPQ0094	7/21/2017	Under Construction	NR	State	Small Generation	Yes	2	Clackamas	Solar	-122.610078	45.143518	Molalla-Marquam 13kV	$0.00	$0.00	$70,000.00	N/A	Under Construction
SPQ0095	8/8/2017	Under Construction	NR	State	Small Generation	Yes	2.97	Marion	Solar	-122.759935	44.977092	Silverton-West 13kV	$0.00	$0.00	$343,500.00	N/A	Under Construction
SPQ0096	8/8/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Yamhill	Solar	-123.465074	45.039439	Willamina-Buell 13kV	$0.00	$0.00	$310,500.00	N/A	Neither
SPQ0097	8/8/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.178714	45.349709	Sandy-Sandy 13kV	$0.00	$0.00	$771,500.00	N/A	Neither
SPQ0098	8/8/2017	Under Construction	NR	State	Small Generation	Yes	2.16	Marion	Solar	-122.819553	45.277584	Wilsonville-Charbonneau 13kV	$0.00	$0.00	$300,000.00	N/A	Under Construction
SPQ0100	8/8/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.371617	45.368168	Eagle Creek-River Mill 13kV	$0.00	$0.00	$94,500.00	N/A	Neither
SPQ0101	8/8/2017	Under Construction	NR	State	Small Generation	Yes	2.97	Polk	Solar	-123.510915	45.107537	Willamina-Bridge 13kV	$0.00	$0.00	$274,000.00	N/A	Under Construction
SPQ0102	8/17/2017	Under Construction	NR	State	Small Generation	Yes	2.565	Clackamas	Solar	-122.287778	45.454225	Dunns Corner-Dunns Corner 13kV	$0.00	$0.00	$193,500.00	N/A	Under Construction
SPQ0103	8/17/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Marion	Solar	-122.993321	45.04204	Indian-North 13kV	$0.00	$0.00	$120,000.00	N/A	Neither
SPQ0104	8/17/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.469073	45.413883	Carver-Carver 13kV	$0.00	$0.00	$0.00	N/A	Neither
SPQ0105	8/17/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Washington	Solar	-123.086911	45.559371	Cornelius-Verboort 13kV	$0.00	$0.00	$140,000.00	N/A	Neither
SPQ0106	8/17/2017	Under Construction	NR	State	Small Generation	Yes	3	Yamhill	Solar	-123.395752	45.081021	Sheridan-East 13kV	$0.00	$0.00	$345,000.00	N/A	Under Construction
SPQ0107	8/30/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Washington	Solar	-122.93045	45.370347	Six Corners-Borchers 13kV	$0.00	$0.00	$260,000.00	N/A	Neither
SPQ0108	8/30/2017	Under Construction	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.650708	45.141103	Molalla-Yoder 13kV	$0.00	$0.00	$320,000.00	N/A	Under Construction
SPQ0109	8/30/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.248114	45.331311	Sandy-Wildcat 13kV	$0.00	$0.00	$520,000.00	N/A	Neither
SPQ0111	11/3/2017	Withdrawn	NR	State	Small Generation	Yes	2.2	Clackamas	Solar	-122.627364	45.118638	Molalla-Marquam 13kV	$0.00	$0.00	$775,600.00	N/A	Neither
SPQ0113	11/10/2017	Withdrawn	NR	State	Small Generation	Yes	3	Marion	Solar	-122.80536	44.866833	Silverton-West 13kV	$0.00	$0.00	$1,442,300.00	N/A	Neither
SPQ0114	11/10/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.567591	45.128824	Molalla-Forest 13kV	$0.00	$0.00	$895,900.00	N/A	Neither
SPQ0121	12/4/2017	Withdrawn	NR	State	Small Generation	Yes	2.16	Yamhill	Solar	-123.461399	45.037607	Willamina-Buell 13kV	$0.00	$0.00	$833,700.00	N/A	Neither

SPQ0122	12/13/2017	Withdrawn	NR	State	Small Generation	Yes	2	Polk	Solar	-123.101395	44.991433	Wallace-Wallace 13kV	$0.00	$0.00	$649,500.00	N/A	Neither
SPQ0123	12/13/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.512472	45.295346	Leland-Beavercreek 13kV	$0.00	$0.00	$410,000.00	N/A	Neither
SPQ0124	12/13/2017	Under Construction	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.620103	45.127527	Molalla-Marquam 13kV	$0.00	$0.00	$70,800.00	N/A	Under Construction
SPQ0125	12/13/2017	Under Construction	NR	State	Small Generation	Yes	2	Marion	Solar	-122.829069	45.129527	Woodburn-East 13kV	$0.00	$0.00	$262,000.00	N/A	Under Construction
SPQ0127	12/14/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Yamhill	Solar	-123.48982	45.054232	Willamina-Buell 13kV	$0.00	$0.00	$2,706,100.00	N/A	Neither
SPQ0129	12/14/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Yamhill	Solar	-123.096029	45.021064	Wallace-Wallace 13kV	$0.00	$0.00	$509,600.00	N/A	Neither
SPQ0131	12/18/2017	Withdrawn	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.632738	45.114309	Molalla-Marquam 13kV	$0.00	$0.00	$337,350.00	N/A	Neither
SPQ0132	12/29/2017	Under Construction	NR	State	Small Generation	Yes	2.97	Washington	Solar	-123.073356	45.560545	Cornelius-Verboort 13kV	$0.00	$0.00	$159,500.00	N/A	Under Construction
SPQ0135	12/29/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.34294	45.392839	Boring-City 13kV	$0.00	$0.00	$1,051,800.00	N/A	Neither
SPQ0137	12/29/2017	Withdrawn	NR	State	Small Generation	Yes	2.97	Washington	Solar	-123.041045	45.607345	North Plains-North Plains 13kV	$0.00	$0.00	$160,500.00	N/A	Neither
SPQ0138	1/2/2018	Withdrawn	NR	State	Small Generation	Yes	2	Polk	Solar	-123.605563	45.072689	Grand Ronde-Agency 13kV	$0.00	$0.00	$441,700.00	N/A	Neither
SPQ0139	1/2/2018	Withdrawn	NR	State	Small Generation	Yes	2.97	Marion	Solar	-122.789624	45.147255	Woodburn-Tomlin 13kV	$0.00	$0.00	$60,000.00	N/A	Neither
SPQ0140	1/2/2018	Withdrawn	NR	State	Small Generation	Yes	3	Marion	Solar	-123.087016	45.027381	Wallace-Wallace 13kV	$0.00	$0.00	$604,803.00	N/A	Neither
SPQ0142	1/2/2018	Withdrawn	NR	State	Small Generation	Yes	3	Marion	Solar	-122.949462	45.096001	Waconda-River 13kV	$0.00	$0.00	$1,154,000.00	N/A	Neither
SPQ0143	1/2/2018	Withdrawn	NR	State	Small Generation	No	2.97	Clackamas	Solar	-122.677544	45.210567	Canby-Zimmerman 13kV	$0.00	$0.00	$1,157,900.00	N/A	Neither
SPQ0148	1/2/2018	Withdrawn	NR	State	Small Generation	Yes	2.97	Clackamas	Solar	-122.355996	45.332536	Estacada-Estacada 13kV	$0.00	$0.00	$885,400.00	N/A	Neither
SPQ0149	1/2/2018	Withdrawn	NR	State	Small Generation	Yes	2.97	Yamhill	Solar	-123.40785	45.092994	Sheridan-Kadell 13kV	$0.00	$0.00	$1,297,000.00	N/A	Neither
SPQ0150	1/2/2018	Withdrawn	NR	State	Small Generation	Yes	0.99	Washington	Solar	-122.985544	45.64325	North Plains-Mason Hill 13kV	$0.00	$0.00	$786,300.00	N/A	Neither
SPQ0151	1/2/2018	Under Construction	NR	State	Small Generation	Yes	1.26	Marion	Solar	-122.936511	44.879319	Mill Creek-Eastland 13kV	$0.00	$0.00	$120,000.00	N/A	Under Construction
SPQ0152	1/2/2018	Under Construction	NR	State	Small Generation	Yes	2.5	Polk	Solar	-123.498182	45.056776	Willamina-Buell 13kV	$0.00	$0.00	$268,600.00	N/A	Under Construction
SPQ0153	1/5/2018	Withdrawn	NR	State	Small Generation	Yes	2.97	Washington	Solar	-123.029612	45.62197	North Plains-North Plains 13kV	$0.00	$0.00	$440,100.00	N/A	Neither
SPQ0154	1/5/2018	Withdrawn	NR	State	Small Generation	Yes	2.97	Marion	Solar	-122.708908	44.891426	Silverton-West 13kV	$0.00	$0.00	$3,485,300.00	N/A	Neither
SPQ0156	1/16/2018	Withdrawn	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.672393	45.083116	Scotts Mills-Scotts Mills 13kV	$0.00	$0.00	$2,470,600.00	N/A	Neither
SPQ0157	1/29/2018	Under Construction	NR	State	Small Generation	Yes	2.5	Yamhill	Solar	-123.021046	45.266736	Newberg-Dundee 13kV	$0.00	$0.00	$120,000.00	N/A	Under Construction
SPQ0158	1/29/2018	Interconnection Agreement	NR	State	Small Generation	Yes	2.5	Marion	Solar	-122.927126	45.075646	Waconda-Waconda 13kV	$0.00	$0.00	$738,900.00	N/A	Neither
SPQ0159	1/29/2018	Withdrawn	NR	State	Small Generation	Yes	2.5	Marion	Solar	-123.092142	45.018393	Wallace-Wallace 13kV	$0.00	$0.00	$209,500.00	N/A	Neither
SPQ0161	1/29/2018	Withdrawn	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.502289	45.324272	Redland-Henrici 13kV	$0.00	$0.00	$160,000.00	N/A	Neither
SPQ0162	1/29/2018	Withdrawn	NR	State	Small Generation	Yes	2.5	Yamhill	Solar	-123.448012	45.078033	Willamina-Buell 13kV	$0.00	$0.00	$191,100.00	N/A	Neither
SPQ0163	2/7/2018	Interconnection Agreement	NR	State	Small Generation	Yes	2.5	Marion	Solar	-123.096697	45.017705	Wallace-Wallace 13kV	$0.00	$0.00	$294,312.00	N/A	Neither
SPQ0164	2/5/2018	Under Construction	NR	State	Small Generation	Yes	1.75	Marion	Solar	-122.935747	44.927711	Bethel-Geer 13kV	$0.00	$0.00	$0.00	N/A	Under Construction
SPQ0165	2/12/2018	Withdrawn	NR	State	Small Generation	Yes	2.5	Marion	Solar	-123.093589	45.018197	Wallace-Wallace 13kV	$0.00	$0.00	$154,850.00	N/A	Neither
SPQ0166	2/12/2018	Under Construction	NR	State	Small Generation	Yes	2.5	Marion	Solar	-122.807131	45.13654	Woodburn-East 13kV	$0.00	$0.00	$295,350.00	N/A	Under Construction
SPQ0168	3/12/2018	Withdrawn	NR	State	Small Generation	Yes	1.75	Polk	Solar	-123.6194	45.05466	Grand Ronde-Fort Hill 13kV	$0.00	$0.00	$194,450.00	N/A	Neither
SPQ0171	3/19/2018	Withdrawn	NR	State	Small Generation	Yes	3	Clackamas	Solar	-122.552169	45.114345	Molalla-Marquam 13kV	$0.00	$0.00	$1,006,200.00	N/A	Neither
SPQ0172	3/23/2018	Facility Study	NR	State	Small Generation	Yes	2.25	Marion	Solar	-122.913603	45.072629	Waconda-Waconda 13kV	$0.00	$0.00	$977,456.00	N/A	Neither
SPQ0179	6/25/2018	Under Construction	NR	State	Small Generation	Yes	2.565	Polk	Solar	-123.555579	45.062023	Grand Ronde-Fort Hill 13kV	$0.00	$0.00	$278,900.00	N/A	Under Construction
SPQ0180	6/27/2018	Under Construction	NR	State	Small Generation	Yes	2.565	Clackamas	Solar	-122.352752	45.267308	Estacada-Estacada 13kV	$0.00	$0.00	$457,950.00	N/A	Under Construction
SPQ0181	7/19/2018	Under Construction	NR	State	Small Generation	Yes	2.5	Yamhill	Solar	-123.175601	45.321445	Yamhill-Yamhill 13kV	$0.00	$0.00	$257,600.00	N/A	Under Construction
SPQ0182	7/11/2018	Withdrawn	NR	State	Small Generation	Yes	2.22	Yamhill	Solar	-123.05296	45.22291	Dayton-East 13kV	$0.00	$0.00	$240,500.00	N/A	Neither
SPQ0189	8/13/2018	Withdrawn	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.449759	45.403145	Carver-Carver 13kV	$0.00	$0.00	$154,700.00	N/A	Neither
SPQ0190	8/8/2018	Withdrawn	NR	State	Small Generation	Yes	1.8	Washington	Solar	-123.041045	45.607345	North Plains-North Plains 13kV	$0.00	$0.00	$500.00	N/A	Neither
SPQ0191	8/21/2018	Under Construction	NR	State	Small Generation	Yes	2.5	Clackamas	Solar	-122.558017	45.258955	Leland-Carus 13kV	$0.00	$0.00	$5,000.00	N/A	Under Construction
SPQ0192	9/17/2018	Withdrawn	NR	State	Small Generation	Yes	1.5	Clackamas	Solar	-122.591298	45.175861	Liberal-Liberal 13kV	$0.00	$0.00	$92,206.00	N/A	Neither
SPQ0193	10/9/2018	Under Construction	NR	State	Small Generation	Yes	1.98	Clackamas	Solar	-122.677544	45.210567	Canby-Zimmerman 13kV	$0.00	$0.00	$185,000.00	N/A	Under Construction
SPQ0211	12/6/2018	Withdrawn	NR	State	Small Generation	Yes	2.99	Marion	Solar	-122.789624	45.147255	Woodburn-Tomlin 13kV	$0.00	$0.00	$413,100.00	N/A	Neither
SPQ0212	1/9/2019	Completed	NR	State	Small Generation	Yes	0.001	Multnomah	Other	-122.648055	45.495366	Harrison-Harrison 13kV	$0.00	$0.00	$0.00	N/A	Built
SPQ0217	3/7/2019	Under Construction	NR	State	Small Generation	Yes	2.988	Marion	Solar	-122.789638	45.147332	Woodburn-Tomlin 13kV	$0.00	$0.00	$60,000.00	N/A	Under Construction
SPQ0220	4/12/2019	Under Construction	NR	State	Small Generation	Yes	1.256	Clackamas	Solar	-122.556878	45.127437	Molalla-Forest 13kV	$0.00	$0.00	$197,000.00	N/A	Under Construction
SPQ0223	7/1/2019	Withdrawn	NR	State	Small Generation	Yes	1.98	Marion	Solar	-122.945	45.093	Waconda-River 13kV	$0.00	$0.00	$641,949.00	N/A	Neither
SPQ0229	8/30/2019	Withdrawn	NR	State	Small Generation	Yes	1.26	Clackamas	Solar	-122.344	45.391	Boring-City 13kV	$0.00	$0.00	$393,307.00	N/A	Neither
SPQ0230	9/10/2019	Withdrawn	NR	State	Small Generation	Yes	1.531	Polk	Solar	-123.542253	45.057591	Grand Ronde-Fort Hill 13kV	$0.00	$0.00	$97,445.00	N/A	Neither
SPQ0233	10/16/2019	Facility Study	NR	State	Small Generation	Yes	2.565	Polk	Solar	-123.636312	45.057363	Grand Ronde-Fort Hill 13kV	$0.00	$0.00	$451,151.00	N/A	Neither
SPQ0236	10/16/2019	Facility Study	NR	State	Small Generation	Yes	2.565	Clackamas	Solar	-122.213	45.377	Sandy-Sandy 13kV	$0.00	$0.00	$152,469.00	N/A	Neither
SPQ0238	11/14/2019	Facility Study	NR	State	Small Generation	Yes	1.98	Clackamas	Solar	-122.236	45.383	Sandy-Sandy 13kV	$0.00	$0.00	$311,961.00	N/A	Neither
SPQ0241	1/17/2020	Under Construction	NR	State	Small Generation	Yes	0.287	Washington	Solar	-122.829822	45.513056	Tektronix-Ducks 13kV	$0.00	$0.00	$0.00	N/A	Under Construction
SPQ0246	2/14/2020	Facility Study	NR	State	Small Generation	Yes	2.971	Clackamas	Solar	-122.612517	45.132157	Molalla-Marquam 13kV	$0.00	$0.00	$629,041.25	N/A	Neither
SPQ0248	3/9/2020	Completed	NR	State	Small Generation	Yes	0.234	Washington	Solar	-122.826698	45.510868	Tektronix-Ducks 13kV	$0.00	$0.00	$0.00	N/A	Built

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. 007
Dated September 10, 2020

Request:

7. 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 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 DNR in part a are recovered, including whether the costs are paid by transmission customers and ratepayers.
   d. Please explain why these the DNRs identified in part a were not required to interconnect under Network Upgrade Interconnection Service.

Response:

Pursuant to the terms of its Open Access Transmission Tariff (OATT), PGE does not require all DNRs to interconnect with NRIS. An on-system generator that receives ERIS from PGE or an off-system generator that is delivered from another transmission provider's system can also be designated as a DNR. When a load-serving entity requests to designate a network resource, it provides the transmission provider with the information required for the Transmission Provider to assess whether there is sufficient capacity available on the transmission system to deliver the requested network resource to the requesting entity's network load—including the network resource, network load to be served, point of delivery, and point of receipt. If there is not sufficient capacity available, then the request is placed into study and the transmission provider conducts engineering studies to determine the upgrades necessary to allow the requested DNR to serve the requested network load on a firm basis. Because the principal purpose of NRIS is to allow a new generator's power to be capable of delivery to the purchasing utility's load using firm network service on the transmission provider's transmission system (i.e., to be designated as a network resource), a generator that received NRIS can likely be designated without additional upgrades. However, if a generator did not interconnect to the transmission provider with NRIS, then any upgrades required for deliverability would be identified in the transmission studies when the load-serving entity requests to designate the generator as a network resource.

a. All of the DNRs (both QFs and PGE-owned) that interconnected with PGE (i.e., on-system resources) after the effective date of FERC Order 2003, which adopted the concept of NRIS, were studied by PGE for NRIS. PGE has a number of QF DNRs that deliver from off-system and therefore were not studied by PGE for NRIS, as they did not obtain interconnection service from PGE. To the best of PGE's knowledge, PGE was not required to interconnect PGE-owned off-system resources to other transmission providers using NRIS. When PGE acquires a new resource via a Request for Proposals, PGE requires that the bidder have firm transmission to get the resource's output to PGE's system if the resource is off-system. It is up to the bidder to determine the form of interconnection service it receives so long as it obtains firm transmission to PGE—the bidder would be responsible for any necessary upgrades in this scenario whether the upgrades are identified in the interconnection or the transmission process.

b. By definition, an on-system DNR is delivered to load on firm network transmission service. PGE OATT Sec. 1.59 (defining Network Resource in relevant part to include only resources that are not committed for sale to third parties "or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis . . . ."). Off-system DNRs are required to attest that they can be delivered to the transmission provider's system on a firm basis as part of the designation process. PGE OATT Sec. 30.2.

c. As a foundational matter, PGE objects to the premise of this question that all Network Upgrades are related to deliverability, which is incorrect. An ERIS interconnection, which does not assess deliverability, can also trigger Network Upgrades. If a generator did not interconnect with NRIS, then all of the deliverability costs would be identified in the transmission service context. For PGE DNRs, PGE Merchant (PGEM) is the entity requesting transmission service and the entity that would be responsible to pay for Network Upgrades identified in the transmission service context. PGEM would receive refunds as it takes transmission service, and the amounts would be placed in transmission rates—which would be 87% paid for by PGE's utility customers, with the remaining 13% paid for by other transmission customers. The Commission's decision in the Blue Marmot case, Docket UM 1829, Order No. 19-322, makes clear that for QFs delivering from off-system, PGE may communicate that a particular delivery point is unavailable if PGE determines that accepting QF output at the delivery point would require transmission-related upgrade costs that are not accounted for in the avoided cost rate.

d. PGE assumes that "Network Upgrade Interconnection Service" is intended to refer to "NRIS." Subject to this assumption, off-system QFs are not required to interconnect with NRIS because their interconnections are FERC-jurisdictional and are not subject to the Oregon Commission's QF interconnection policies. Off-system PGE-owned resources are not required to interconnect with NRIS because these resources are not serving network load on the system to which they are interconnecting, so they would not typically be studied for NRIS. In order to qualify as DNRs serving network load in PGE's system, off-system resources need to attest that they have firm transmission rights on any third-party system to reach PGE's system, and then any upgrades required to effectuate delivery to the network load on PGE's system would be picked up in PGE's request to designate the resource as a network resource.

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. 017
Dated September 10, 2020

Request:

17. Please explain whether and how the Company ensures that only a generator that triggers a Network Upgrade will utilize or otherwise be the sole beneficiary from the construction of that upgrade.

    a. If the Company does not or cannot ensure that only a generator that triggers a Network Upgrade will utilize or otherwise be the sole beneficiary from the construction of that upgrade, please list and describe the other parties that would utilize a Network Upgrade (e.g., new transmission line), how they would secure those rights, and which entities would receive revenues or other benefits from the use of that transmission line.

Response:

PGE objects that this request is vague and ambiguous in that it is not clear what it meant by the terms "utilize" or "sole beneficiary." PGE also objects to the premise of this question that it could or should ensure that only a specific generator uses a Network Upgrade. Notwithstanding and without waiving these objections, PGE responds as follows:

In the interconnected transmission system, specific components are not isolated for use by a single user and the uses of any component change over time. Generally, utilities cannot and do not direct the flow of electrons over particular facilities. Transmission facilities are designed and constructed to accommodate the flow of power necessary to maintain the reliability of the Bulk Electric System in the given area of the facility, with specific design criteria determined by the resources and loads in the area, voltage and stability requirements, etc. A change to any of these inputs—for example, the addition of a new generator—requires studying the transmission system to determine the upgrades necessary to maintain reliability and stability. While those upgrades become part of the Bulk Electric System and are not dedicated to serve any particular facility, the need that triggered the upgrades can be tied to a particular event (in this case, the addition of the generator). In such cases, the upgrade might not have been required, but-for the addition of the generator. Other users of the transmission system do not benefit from the new upgrade because the transmission system accommodated their output reliably prior to the upgrade.

The rights to use available capacity on the transmission system are secured through the transmission service reservation process.

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. 018
Dated September 10, 2020

Request:

18. Please explain in detail whether and how interconnection costs are considered in the Company's Oregon QF avoided cost rates.

    a. Please provide citations.
    b. Please provide any relevant work papers in the form of electronic Excel workbooks with formulae intact.

Response:

PGE's Oregon Schedule 201 PURPA Qualifying Facility avoided cost rates include interconnection costs for the proxy resources. The current rates (effective August 4, 2020) are based on rates from PGE's May 2020 compliance filing. Citations and workpapers for the interconnection costs for the current rates are provided below.

a. Attachment 018-A provides PGE's UM 1728 compliance filing from May 19, 2020. The interconnection costs (interconnection facilities and network upgrade costs) for the three proxy resources are shown on page 1 of Attachment C (note that Attachment 018-A includes multiple attachments from the original compliance filing). There are associated network upgrade credits from the transmission provider, which are discussed below.

b. Attachment 018-B provides the non-confidential version of the Avoided Cost workbook filed in Docket No. UM 1728 for the current rates. The location of interconnection costs and associated network upgrade credits for each proxy resource are described below.

   Simple-Cycle Combustion Turbine

   - The interconnection costs are provided on the "Plant Cap Cost" worksheet in rows 23-24. These costs are included in the resource cost calculations on the "Rev Req SCCT" worksheet in cell V70.

- The associated network upgrade credits are calculated on the “Wheeling & fuel” worksheet in columns K-R. These credits are included in the resource Wheeling cost calculations on the “Rev Req SCCT” worksheet in cells N22:N59.

Combined-Cycle Combustion Turbine

- The interconnection costs are provided on the “Plant Cap Cost” worksheet in rows 43-44. These costs are included in the resource cost calculations on the “Rev Req CCCT” worksheet in cell W70.

- The associated network upgrade credits are calculated on the “Wheeling & fuel” worksheet in columns T-AA. These credits are included in the resource Wheeling cost calculations on the “Rev Req CCCT” worksheet in cells O22:O59.

Gorge Wind

- The interconnection costs are provided on the “Plant Cap Cost” worksheet in rows 67-68. These costs are included in the resource cost calculations on the “Rev Req Wind” worksheet in cell U61.

- The associated network upgrade credits are calculated on the “Wheeling & fuel” worksheet in columns AC-AJ. These credits are included in the resource Wheeling cost calculations on the “Rev Req Wind” worksheet in cells M22:M51.

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. 019
Dated September 10, 2020

Request:

19. Please explain in detail whether and how transmission costs are considered in the Company's Oregon QF avoided cost rates.

    a. Please provide citations.
    b. Please provide any relevant work papers in the form of electronic Excel workbooks with formulae intact.

Response:

PGE's proxy resources for its Schedule 201 PURPA Qualifying Facility avoided cost rates are all assumed to be located off-system, one leg of BPA transmission away from PGE's system, and for market prices, the market is assumed to be Mid-C, which is also one leg of BPA transmission away from PGE's system. Therefore, PGE's standard avoided cost rates include transmission costs for the proxy resources during the deficiency period and for wholesale market energy during the sufficiency period, as well as adjustments to account for BPA line losses associated with transmission. PGE's avoided cost rates do not include the cost of transmission on PGE's system.

The current Schedule 201 rates (effective August 4, 2020) are based on rates from PGE's May 2020 compliance filing. Citations and workpapers for the transmission costs for the current rates are provided below.

a. Please refer to Attachment 018-B provided in PGE's response to OPUC Data Request No. 018. Attachment 018-B provides the non-confidential version of the Avoided Cost workbook filed in Docket No. UM 1728 for the current rates. The location of the BPA wheeling rates, the transmission costs associated with the proxy resources and market purchases, and the line loss adjustments in Attachment 018-B are described below.

<u>BPA Wheeling Rates</u>

- The forecast of BPA Point-to-Point (PTP) and Scheduling, System Control, and Dispatch (SCD) rates are provided on the "Wheeling & fuel" worksheet in column B in dollars per kW per month.

<u>Simple-Cycle Combustion Turbine</u>

- The annual BPA transmission costs are calculated on the "Rev Req SCCT" worksheet in the resource Wheeling cost in cells N22:N59. Note that the values are net of any applicable Network Upgrade credits, as discussed in PGE's response to OPUC Data Request No. 018.

<u>Combined-Cycle Combustion Turbine</u>

- The annual BPA transmission costs are calculated on the "Rev Req CCCT" worksheet in the resource Wheeling cost in cells O22:O59. Note that the values are net of any applicable Network Upgrade credits, as discussed in PGE's response to OPUC Data Request No. 018.

<u>Gorge Wind</u>

- The annual BPA transmission costs are calculated on the "Rev Req Wind" worksheet in the resource Wheeling cost in cells M22:M51. Note that the values are net of any applicable Network Upgrade credits, as discussed in PGE's response to OPUC Data Request No. 018.

<u>Wholesale Market Electricity Prices</u>

- The market prices are adjusted for BPA transmission costs on the "Electricity prices" worksheet in columns G-H.

<u>BPA Line Losses</u>

- The BPA line loss rate is provided on the "Plant Oper" worksheet in cell B58.

- The loss rate is accounted for in the Avoided cost Study table calculations on the "energy", "capacity", "energy renewable", and "capacity renewable" worksheets.

b. Please refer to the response to Part A above.

CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Response Testimony

October 30, 2020

Exhibit 105 - Network Upgrades Identified for Oregon Interconnection Requests

The following tables summarize the Network Upgrade costs assigned to each individual Oregon generator that requested interconnection between 2014 and 2019. This data was provided in each utilities' response to Staff DR Nos. 001 and 002 which can be found in Exhibits 102, 103, and 104.

PACIFICORP					
Year/Generator	**# Requests**	**Total cost of Network Upgrades**	**Straight Average Cost of Network Upgrade**	**Min. Network Upgrade**	**Max. Network Upgrade**
QFs					
2014	28	$266,253,300	$9,509,046	$0	$137,500,000
2015	20	$139,297,000	$6,964,850	$0	$104,059,000
2016	9	$103,856,000	$11,539,556	$0	$40,000,000
2017	9	$78,597,000	$8,733,000	$0	$27,500,000
2018	5	$4,223,000	$844,600	$0	$4,223,000
2019	1	$0	$0	$0	$0
QF Total	**72**	**$592,226,300**	**$8,225,365**		
Non-QFs					
2014	4	$44,761,000	$11,190,250	$0	$19,846,000
2015	3	$1,193,540,000	$397,846,667	$49,414,000	$900,573,000
2016	31	$981,085,000	$31,647,903	$0	$150,000,000
2017	27	$183,337,000	$6,790,259	$0	$44,578,000
2018	4	$839,586,000	$209,896,500	$0	$839,586,000
2019	1	$0	$0	$0	$0
Non-QF Total	**70**	**$3,242,309,000**	**$45,666,324**		
All Gen. Total	**142**	**$3,834,535,300**	**$26,814,932**		

IDAHO POWER					
Year/Generator	**# Requests**	**Total cost of Network Upgrades**	**Straight Average Cost of Network Upgrade**	**Min. Network Upgrade**	**Max. Network Upgrade**
QF					
2014	2	$0	$0	$0	$0
2015	12	$48,350,000	$4,029,167	$0	$18,420,000
2016	4	$133,400	$33,350	$0	$133,400
2017	1	$0	$0	$0	$0
2018	3	$0	$0	$0	$0
2019	3	$237,800	$79,267	$0	$237,800
QF TOTAL	**25**	**$48,721,200**	**$1,948,848**		
Non-QF					
2018	1	$12,533,800	$12,533,800	$12,533,800	$12,533,800
Non-QF Total	**1**	**$12,533,800**	**$12,533,800**		
Grand Total	**26**	**$61,255,000**	**$2,355,962**		

Portland General Electric					
Year/Generator	# Requests	Total cost of Network Upgrades	Straight Average Cost of Network Upgrade	Min. Network Upgrade	Max. Network Upgrade
QF					
2015	9	$0	$0	$0	$0
2016	32	$0	$0	$0	$0
2017	66	$27,000,000*	$409,091*	$0	$27,000,000*
2018	35	$0	$0	$0	$0
2019	9	$0	$0	$0	$0
2020	3	$0	$0	$0	$0
QF TOTAL	**154**	**$27,000,000***	**$175,325***		
Non-QF					
2016	1	$1,368,452	$1,368,452	$1,368,452	$1,368,452
2017	3	$664,750,000	$221,583,333	$840,000	$663,000,000
2018	1	$14,020,000	$14,020,000	$14,020,000	$14,020,000
2019	1	$5,510,000	$5,510,000	$5,510,000	$5,510,000
Non-QF Total	**6**	**$685,648,452**	**$114,274,742**		
Grand Total	**160**	**$712,648,452**	**$4,454,053**		

*This cost is associated with a single off-system generator, interconnecting with PacifiCorp.

CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

Exhibits in Support
Of Response Testimony

October 30, 2020

PacifiCorp Overview





PACIFICORP

POWERING YOUR GREATNESS

PacifiCorp

Pacific Power and Rocky Mt. Power

- Serve approx. 1.9 million customers in OR WA CA ID UT &WY
- Service area covers 141,000 square miles
- Own 10,887 MW of generation
- Own 2,198 MW of non carbon generation
- Own and operate approx. 16,500 miles of transmission lines in 10 states
- Own and operate approx. 64,000 miles of distribution lines

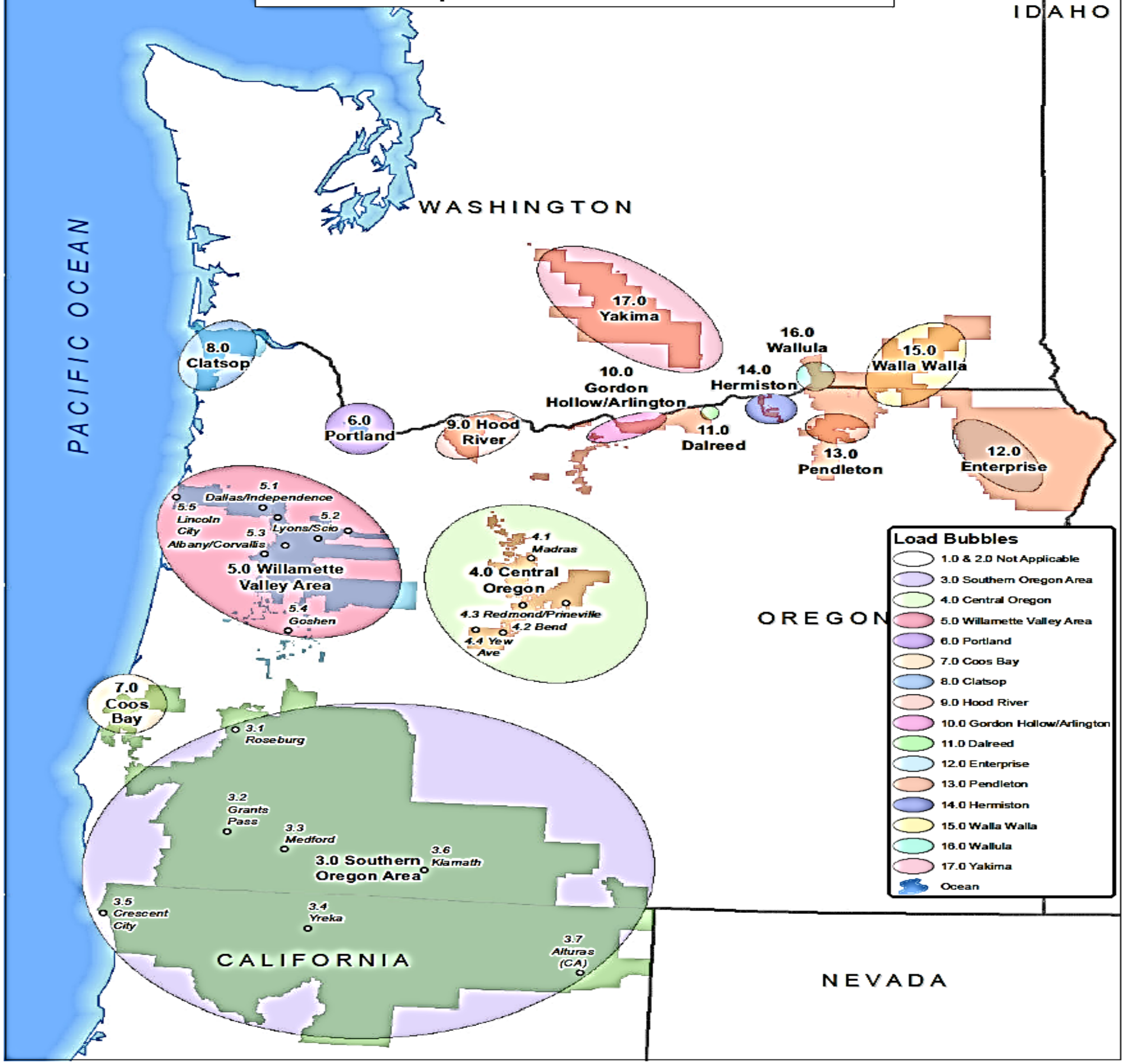
PACW System

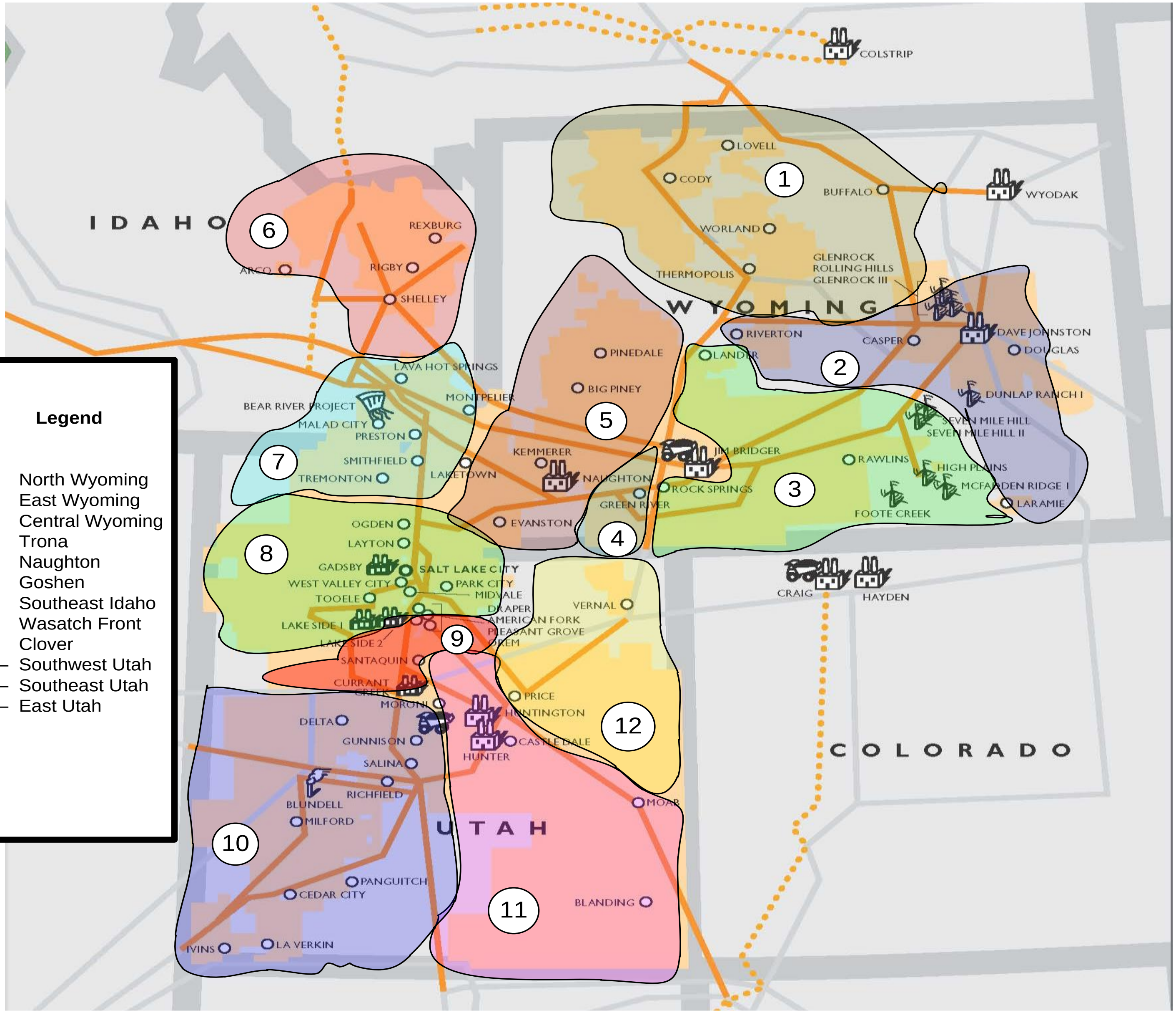
- California, Oregon and Washington
- Transmission voltages: 500 kV, 230 kV, 115 kV, 69 kV, 57 kV
- 15 primary area load bubbles in the PACW system
  - Most are interconnected by Bonneville Power Administration (BPA) main grid transmission
- 4,354 MW record peak demand
- Over 750,000 customers across three states
- Over 4,300 circuit-miles of transmission lines

PACE System

- Idaho, Utah and Wyoming
- Transmission voltages: 500 kV, 345 kV, 230 kV, 161 kV, 138 kV, 115 kV, 69 kV, 46 kV
- 12 primary area load bubbles in the PACE system; 5 sub-bubbles in Wasatch Front
- 9,142 MW record peak demand
- Over 1,100,000 customers across three states
- Over 12,000 circuit-miles of transmission lines

PacifiCorp - PACW Load Bubbles





Legend

1 – North Wyoming
2 – East Wyoming
3 – Central Wyoming
4 – Trona
5 – Naughton
6 – Goshen
7 – Southeast Idaho
8 – Wasatch Front
9 – Clover
10 – Southwest Utah
11 – Southeast Utah
12 – East Utah

PacifiCorp Interconnections

PACE BAA

- Arizona Public Service
- NV Energy
- Los Angeles Water & Power
- NorthWestern Energy
- WALC-Phoenix
- Idaho Power
- WACM-Loveland
- WAPA
- Black Hills Power
- Utah Area Municipal Power Systems
- Utah Municipal Power Agency
- Deseret
- Basin Electric Co-Op
- Inter Mountain Power Producers
- TriState Generation & Transmission
- Public Service of New Mexico

PACW BAA

- Bonneville Power Administration
- Portland General Electric
- Avista
- Grant County PUD
- Idaho Power
- California ISO
- Pacific Gas and Electric
- Clark County PUD
- Cowlitz PUD
- Benton County PUD
- Klickitat PUD
- Columbia Power REA
- Tillamook PUD
- Western Oregon electric Co-Op
- Central Electric Co-Op
- Surprise Valley Electric Co-Op

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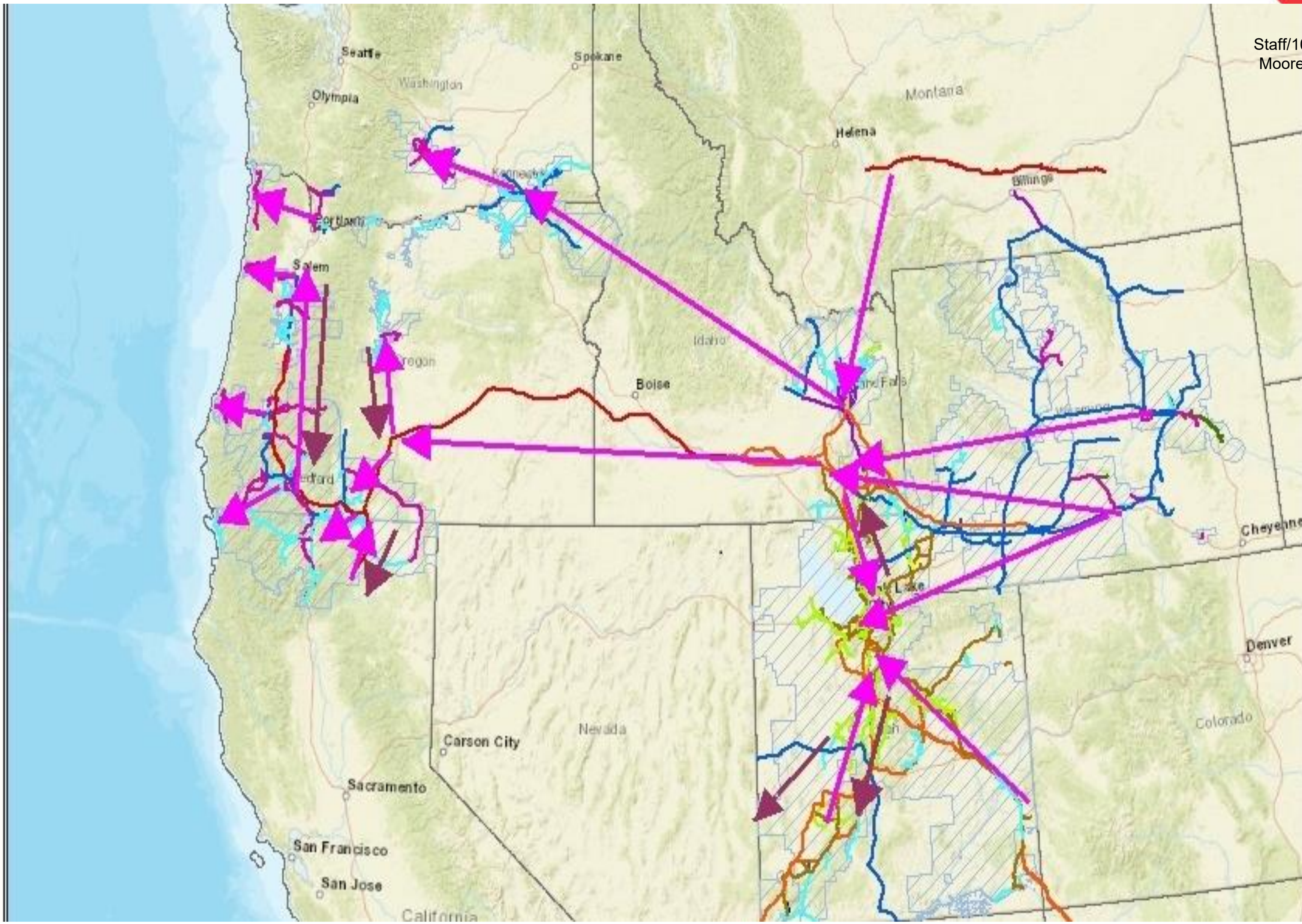
Moore/7



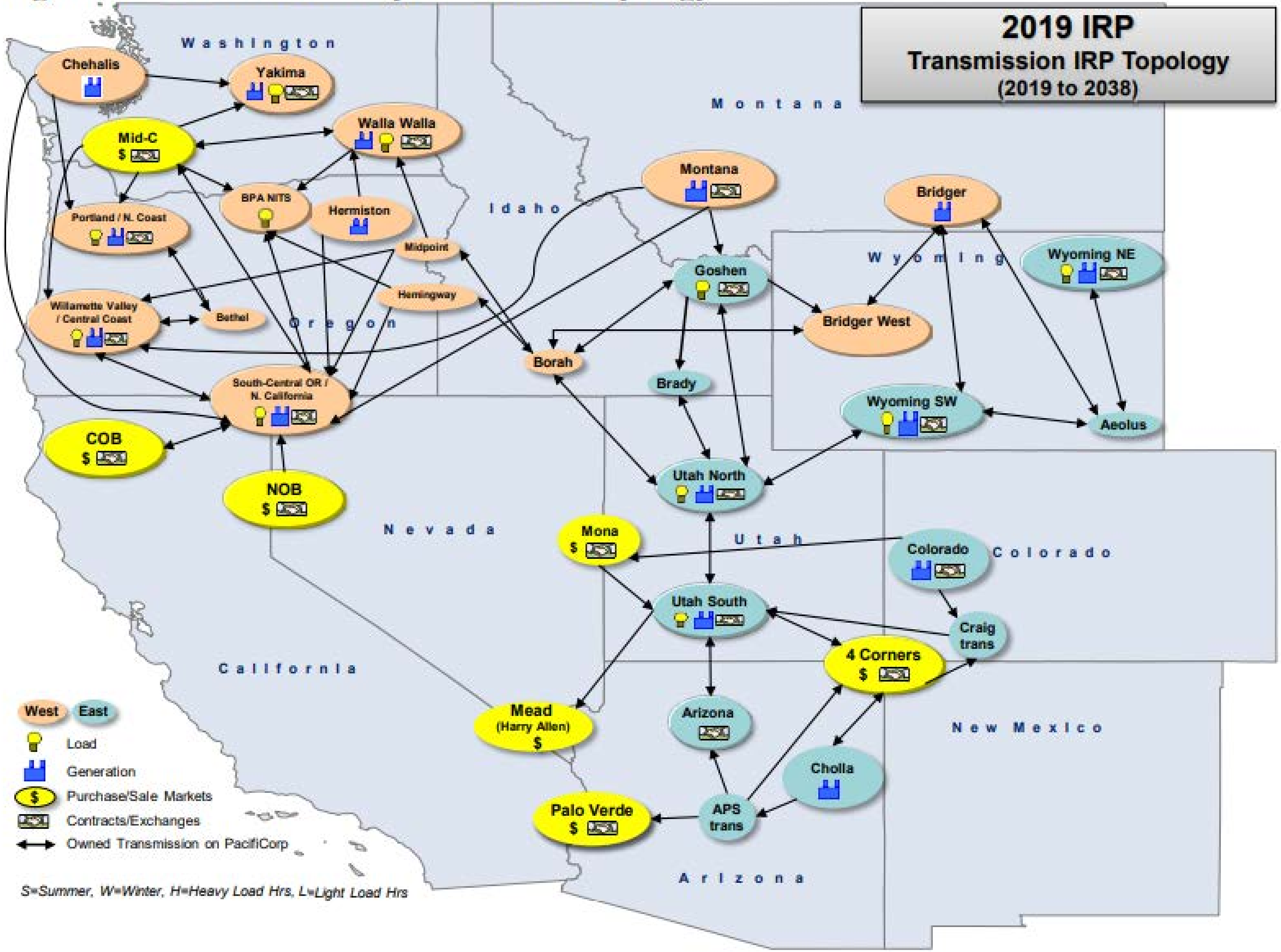
System Planning

- Annual load and resource plan – 10 year horizon
- Yearly reliability compliance studies – 1, 5 and 10 year horizons
- Bi-annual regional plan – 10 year horizon
- Bi-annual integrated resource plan – 20 year horizon
- Local load area studies – 5-10 year horizon, areas updated on 2-5 year cycle

Questions

Staff/106
Moore/10

Figure 7.2 – Transmission System Model Topology



CASE: UM 2032
WITNESS: CAROLINE MOORE

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 107

Exhibits in Support
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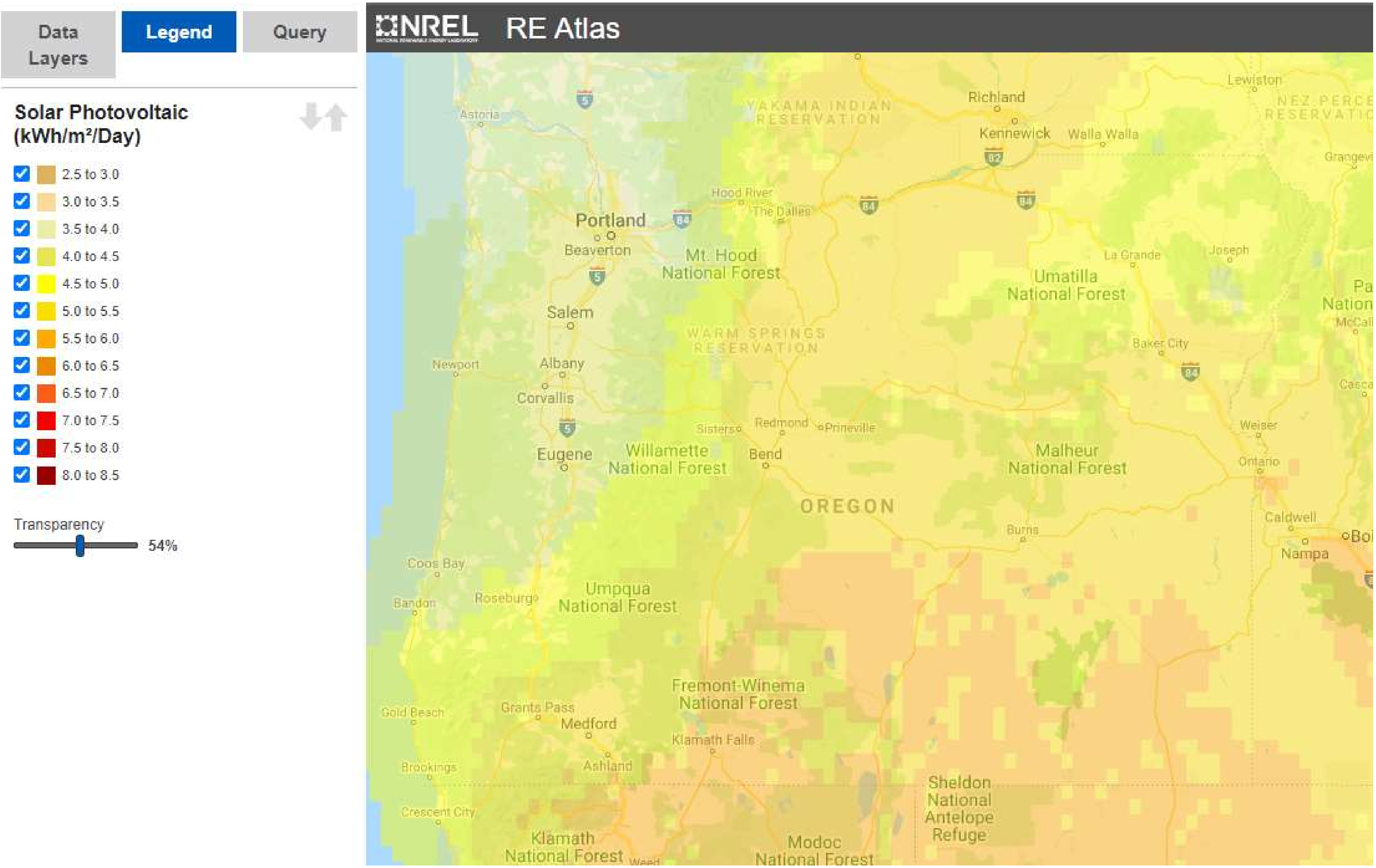
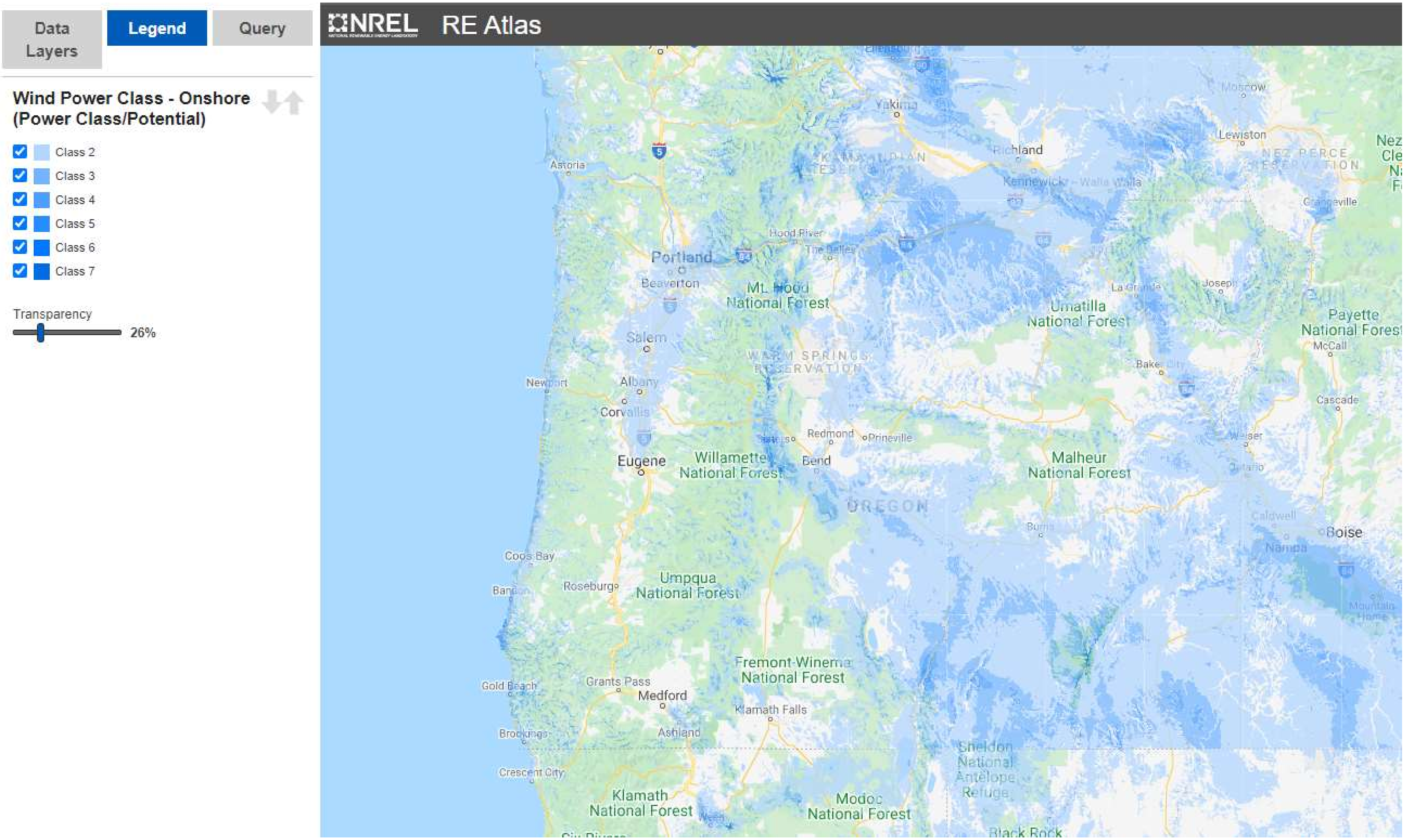

Data Layers
Legend
Query
Solar Photovoltaic (kWh/m²/Day)
2.5 to 3.0
3.0 to 3.5
3.5 to 4.0
4.0 to 4.5
4.5 to 5.0
5.0 to 5.5
5.5 to 6.0
6.0 to 6.5
6.5 to 7.0
7.0 to 7.5
7.5 to 8.0
8.0 to 8.5
Transparency
54%
NREL
RE Atlas
Astoria
YAKAMA INDIAN RESERVATION
Richland
Kennewick
Walla Walla
Lewiston
Hood River
The Dalles
Portland
Beaverton
Mt. Hood National Forest
La Grande
Joseph
Umatilla National Forest
Salem
WARM SPRINGS RESERVATION
Baker City
Newport
Albany
Corvallis
Sisters
Redmond
Prineville
Weiser
Eugene
Willamette National Forest
Bend
Malheur National Forest
Ontario
OREGON
Burns
Caldwell
Nampa
Coos Bay
Bandon
Roseburg
Umpqua National Forest
Fremont-Winema National Forest
Gold Beach
Grants Pass
Medford
Klamath Falls
Brookings
Ashland
Sheldon National Antelope Refuge
Crescent City
Klamath National Forest
Modoc National Forest


Data Layers
Legend
Query
Wind Power Class - Onshore (Power Class/Potential)
Class 2
Class 3
Class 4
Class 5
Class 6
Class 7
Transparency
26%
NREL
RE Atlas
Yakima
Richland
Kennewick
Lewiston
Astoria
Hood River
Portland
Beaverton
Mt. Hood National Forest
Umatilla National Forest
La Grande
Joseph
Payette National Forest
McCall
Salem
WARM SPRINGS RESERVATION
Baker City
Newport
Albany
Corvallis
Cascade
Redmond
Prineville
Eugene
Willamette National Forest
Bend
Malheur National Forest
Weiser
OREGON
Burns
Boise
Nampa
Coos Bay
Roseburg
Umpqua National Forest
Fremont-Winema National Forest
Grants Pass
Medford
Gold Beach
Klamath Falls
Ashland
Brookings
Crescent City
Klamath National Forest
Modoc National Forest
Sheldon National Antelope Refuge
Black Rock