BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2032

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities	NEWSUN'S PREHEARING BRIEF

I. INTRODUCTION

NewSun Energy LLC ("NewSun") hereby submits this Prehearing Brief in Docket No. UM 2032 regarding the two issues presented for resolution in this Phase I of the docket. Those issues are:

> 1. Who should be required to pay for Network Upgrades necessary to interconnect the [qualifying facility (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?[1]

Depending on the resolution of Phase I, the question for Phase II is:

> 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 customers? Should the QF, utility

[1] Ruling at 1-2 (May 22, 2020).

> customers, and other beneficiaries and users, if any, share the costs of Network Upgrades?[2]

The Oregon Public Utility Commission (the "Commission") should resolve question one by adopting the framework set forth by the Federal Energy Regulatory Commission ("FERC"). FERC's approach is easy to implement, aligns the costs and benefits, and puts this one small subset of QFs on equal footing with all other QFs and generators. Notably, FERC determined that in most cases, network upgrades benefit the integrated system as a whole and therefore all users of the system. As a result, FERC established a framework where the interconnection customer initially funds network upgrades but receives reimbursement. NewSun further recommends that the Commission adopt a refund methodology which mirrors other interconnection authorities by allowing refunds of 100% upon the upgrade reaching commercial operation or over 5 years as is done by the California Independent System Operator ("CAISO"). If the Commission adopts this framework, it could eliminate the need to move into a Phase II. Or the Commission could at least adopt this framework as an immediate interim approach pending the outcome of Phase II.

Further, as to question two, allowing a QF to interconnect with ERIS will enable creative solutions to addressing transmission constraints, also puts QFs on equal footing with other generators, and contrary to the Joint Utilities' assertions, there are no factual reasons why a QF cannot be interconnected with ERIS.

NewSun further recommends that in the interim before there is a full resolution of the issues in this docket, the Commission:

1. Confirm that network upgrades are wholly refundable, and that the refund should occur not later than would normally be done under FERC's process; and

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[2] Ruling at 3 (May 22, 2020).

2. Allow all QFs to be studied as both ERIS and NRIS through Cluster Study or System Impact Study phase. This is consistent with FERC's *pro forma* process and PacifiCorp's FERC jurisdictional study process.[3] This will make ER study results available should the Commission decide to allow ERIS for QFs or even if the Commission continues to require NRIS for QFs, allowing QFs to be *studied* for both will improve overall interconnection processing should QFs decide to switch to a FERC-jurisdictional interconnection and go with ER service.

II. NETWORK UPGRADES

The Commission should resolve question one by adopting FERC's framework for allocating the cost of network upgrades. FERC's framework is the best approach because it is easy to implement, it aligns with the practical reality that "Network upgrades . . . are those assets that benefit all customers using the transmission system,"[4] and it places QFs on the same footing as other generators. For example, at a high level and as further discussed below and in testimony, a simple disconnect switch added to a transmission line enables broad system benefits by enabling the transmission owner to isolate or break up a portion of that line to mitigate for wildfire risk and/or keep power to some customers when outages need to occur. Those benefits

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3 FERC *pro forma* Large Generator Interconnection Procedures at §3.2; PacifiCorp, Open Access Transmission Tariff FERC Electric Tariff Volume No. 11 at §38.2 (updated April 15, 2022) ("any Interconnection Customer requesting Network Resource Interconnection Service may also request that it be concurrently studied for Energy Resource Interconnection Service, up to the point of five (5) Business Days after the initial Cluster Study Report Meeting held under Section 42.4(c). Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed.")

4 *In re PacifiCorp Request for a General Rate Revision*, Docket No. UE 399, PAC/600, Vail/9 (Mar. 1, 2022).

exist whether the disconnect switch was funded by a QF, other generator, or the transmission owner. As such, there is no reason to treat the QF less favorably than other generators.

First, FERC's framework is easy to implement. FERC adopted a bright-line approach in which interconnection customers initially fund but then receive a 100% reimbursement for the costs of network upgrades.[5] Should the interconnection customer's facility never reach commercial operation, then it does not receive reimbursement for the network upgrade.[6] In implementing a refund methodology, other interconnection authorities allow refunds of 100% upon the upgrade reaching commercial operation or over 5 years as is done in CAISO.[7] Some interconnection authorities, like PacifiCorp's affiliate NV Energy, do not even require initial funding by the generator, but instead require a letter of credit as a backstop in the event the project fails (and the letter of credit is terminated once the network upgrades are complete).[8] NewSun recommends this Commission adopt a simple-bright line refund approach that mirror's FERCs framework and allows a 100% refund upon reaching commercial operation or refunds over 5 years.[9]

This bright-line approach is simple and will not create a burdensome process in which either the QF or the host utility will need to bring a contested case before the Commission to prove who "benefits" from a particular upgrade. While Staff ultimately recommends against it,

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5 *Standardization of Generator Interconnection Agreements and Procedures*, FERC Order No. 2003, 104 FERC ¶ 61,103 at P. 696 (July 24, 2003) *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

6 FERC Pro Forma Large Generator Interconnection Agreement § 11.4.

7 NewSun/100, Rahman/12.

8 *Id.*

9 At a minimum, the refund should be made not later than the date the utility seeks to recover the cost of the upgrade in its rate case.

Staff recognizes that there may be benefits to this bright-line approach.[10] Further, the Joint Utilities, who routinely testify before the Commission in rate cases about the costs and benefits of various transmission system investments,[11] state in this case that they believe "it is unclear how any party would quantify a specific financial benefit of a Network Upgrade or allocate financial benefits from a specific Network Upgrade to specific parties."[12] If the Joint Utilities, who have full access to their system information,[13] cannot prove who benefits from a particular upgrade, then a bright-line approach makes the most sense. At a minimum, the QF should not bear that burden. FERC's approach has the benefit of creating a bright-line rule so that neither party will have to embark on the burdensome process of proving who benefits, and it will save Commission resources in litigating such disputes.

Second, FERC's approach also has the benefit of aligning the costs and benefits, at least in most cases. Network upgrades provide a variety of benefits that extend to the system as a whole and users beyond the interconnecting generator.[14] For example, new taps and disconnects installed by QFs on the Bonneville Power Administration's ("BPA") 115 KV "Harney Line" have enabled BPA to take down only part of the line for maintenance activities or wildfire risk prevention whereas without the QF-funded disconnect BPA would have needed to take down the entire line.[15] This benefited the rest of the system by enabling part of the line to remain in service and has therefore benefited BPA's load customers.[16] Further, new communications and monitoring equipment at those sites benefit the transmission operator by giving BPA near real-

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10 Staff/100, Moore/23.
11 NewSun/400, Andrus/10-12.
12 Joint Utilities/500, Vail-Bremer-Foster-Olennikov-Ellsworth/8.
13 Interconnection Customer Coalition/100, Lowe/19.
14 NewSun/100, Rahman/11; *See Also* NewSun/500.
15 NewSun/500, Boissevain/5-7.
16 *Id.*

time monitoring of voltage, current and power, thus giving them more insight into the transmission operation and health of the line.[17]

More broadly speaking, network upgrades benefit the system by "increasing overall system capacity and in general the robustness of the interconnected system."[18] Larger line sizes, for example, can be used to "move more power as well as allow the system to operate farther from its peak capacity and mitigate associated stresses and failure points under peak system conditions or unplanned outages."[19] Further, general types of transmission system upgrades include new transmission lines or upgrades to lines, substations or upgrades to substations, conductors, protection and control upgrades, breakers, poles, reclosers, supervisory control and indication equipment, which are the same types of upgrades that a QF may be required to fund in the interconnection process.[20] And according to the Joint Utilities' own witness, these types of upgrades provide greater system benefits including to add or enhance operational function, resolve overloading issues, decrease the risks of equipment failures, improve clearing times for protective relaying schemes, and to comply with reliability requirements, among others.[21] In short, network upgrades provide a whole host of benefits to the greater transmission system and other users of that system, including retail customers.

In establishing its current framework, FERC found that in most instances network upgrades from a new interconnection customer will generally result in a lower transmission rate for remaining customers. Network upgrade costs, once paid by the transmission utility, are

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17 *Id*. at 8
18 NewSun/100, Rahman/11.
19 *Id.*
20 NewSun/400, Andrus/11-14.
21 *Id.* (quoting Witness Vail's rate case testimony).

added to transmission rate base.[22] Rates are ultimately a function of both the amount of power moved through the transmission system and the rate base.[23] Under FERC's policies, the transmission rate a particular FERC-jurisdictional interconnection customer pays is generally the higher of an incremental rate or an embedded average cost rate. FERC has observed:

> Our experience indicates that the incremental rate associated with network upgrades required to interconnect a new generator (dividing the costs of any necessary network upgrades by the projected transmission usage by the new generator) will generally be less than the embedded average cost rate (including the costs of the new facilities in the numerator and the additional usage of the system in the denominator). In other words, *in most instances, the additional usage of the transmission system by a new Interconnection Customer will generally cause the average embedded cost transmission rate to decline for all remaining customers*.[24]

As applied here, this would mean that in most instances, a QF funding network upgrades without reimbursement simply pays the full cost of the upgrade while the remaining users of the system enjoy a transmission rate decrease.

Current Commission policy and what the Joint Utilities recommend here, therefore, errs on the side that is least likely to occur. In other words, by making the QF bear the burden of paying for network upgrades without reimbursement, the Commission assumes that the overall transmission rate for remaining customers will increase with each network upgrade. This is the opposite of what FERC found to occur "in most instances." Therefore, adopting the FERC approach in Oregon has the added benefit of erring on the side that is most likely to occur.

Third and finally, adopting the FERC approach here places "on-system" QFs on an equal footing with other generators and other QFs. As just discussed, the FERC approach would avoid the discriminatory outcome where a QF ends up funding network upgrades that result in an

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22 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, 106 FERC ¶ 61,220, at P. 657 (Mar. 5, 2004).

23 *Id.*

24 Order No. 2003-A, 106 FERC ¶ 61,220 at P. 581 (emphasis added).

overall transmission rate decrease for transmission customers (which the QF is not). It also would treat QFs the same as FERC-jurisdictional generators. But even more so than that, adopting the FERC approach also puts QFs subject to the Commission's rule on an equal footing with other QFs. Several types of QFs in Oregon are not subject to the Commission's rule but instead interconnect under FERC jurisdictional interconnections. These include:

1. QFs that are "off-system," i.e., that sell to a utility other than their interconnecting utility;
2. QFs that sell less than 100% of their output to the interconnecting utility; and
3. Generators that are certified as a QF (most likely to take advantage of exemptions from the Federal Power Act and the Public Utility Holding Company Act), but that persuade the utility to execute a bi-lateral non-PURPA power purchase agreement (i.e., that do not invoke PURPA's must-purchase obligation).[25]

For example, the Neal Hot Springs project has a QF self-certification on file at FERC, but it entered into a non-PURPA agreement with Idaho Power at prices higher than Idaho Power's PURPA rates in Idaho at the time.[26] That project was interconnected under the FERC OATT process and required some system upgrades.[27]

Further, projects can switch between being a QF and not being a QF. For example, PacifiCorp's Pryor Mountain Wind project was initially a QF but later changed its QF status and was acquired by PacifiCorp.[28] That can enable the project to interconnect under the OATT process and take advantage of the preferential treatment entitled to customers in that process.

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25 *See* NewSun/400, Andrus/15.
26 NewSun/400, Andrus/16.
27 *Id*; NewSun/402, Andrus/7.
28 NewSun/400, Andrus/16-17.

FERC-jurisdictional generators and other QFs can all interconnect under FERC's rules which allow the generator to receive full reimbursement for their network upgrades. Therefore, it makes no practical sense to single out those QFs that sell 100% of their output to their interconnecting utility under a PURPA must-take agreement for differential treatment. Rather, the most practical, and non-discriminatory approach is to put those QFs on equal footing with other generators and simply adopt FERC's framework. As discussed above, FERC's approach also has the added benefit of defaulting to the situation that is most likely to occur, wherein the transmission rates decrease for the remaining customers in response to a new interconnection, and it is a simple and bright-line solution.

At a minimum, all parties to this docket appear to agree that in at least some instances, it is appropriate for other users and beneficiaries to pay for network upgrades triggered by an Oregon jurisdictional interconnection.[29] Therefore, should the Commission decide not to adopt FERC's framework in this Phase I, it can at a minimum resolve question one in the affirmative and move this docket into Phase II to decide how that policy should be implemented. If the Commission does so, NewSun recommends that it adopt the FERC framework as an immediate interim approach pending the outcome of Phase II.

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29 Joint Utilities/500, Vail-Bremer-Foster-Olennikov-Ellsworth/1 (recommending the Commission retain current policy and move to Phase II to decide how to determine system-wide benefits); Staff/300, Moore/3 (recommending that QFs and other users share in the costs of network upgrades proportionally to the benefits); Interconnection Customer Coalition/300, Lowe/3 (recommending that the Commission retain the principle that beneficiaries pay for benefits but adopt a presumption that network upgrades provide benefits and allow the utility to rebut that presumption).

III. ENERGY RESOURCE INTERCONNECTION SERVICE

The Commission should allow for ERIS because it would enable creative solutions to transmission constraints, also puts QFs on equal footing with other generators, and there is no practical reason that prevents it.

First, ERIS would enable creative solutions to transmission constraints. In a constrained transmission system, the costs for full deliverable status significantly increase such that most generators will select ERIS if it is available.[30] For example, in PacifiCorp's current Cluster Study #2 queue, only 8 projects out of 212 have opted to be studied for NRIS-only. An additional 23 are Oregon-jurisdictional QFs. The remaining 181 projects are being studied for ER only or both ER and NR including 31 PacifiCorp-owned projects which amount to approximately 9,400 MW.[31] Depending on the business objectives of the generator, NRIS may be unnecessary and a QF could agree to terms and conditions in their power purchase agreement that would make NRIS unnecessary.[32] For example, from a practical perspective, a QF could decide to only deliver within a time frame during which the system is not constrained[33] or could agree to voluntary curtailments.[34]

Second, like in the cost allocation discussion above, there are a number of generators and other QFs that are permitted to interconnect under FERC's rules that allow a generator to select ERIS. By allowing ERIS for the small subset of Oregon jurisdictional QFs, the Commission places those QFs on equal footing with those other generators and QFs. The current practice in

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30 NewSun/100, Rahman/17.

31 *See* PacifiCorp Generation Interconnection Requests Cluster Study 2 (as of May 23, 2022) Available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpcliaq2.htm.

32 NewSun/100, Rahman/13-14.

33 NewSun/500, Andrus/4.

34 Interconnection Customer Coalition/100, Lowe/25.

Oregon requiring NRIS for Oregon "on-system" QFs, has resulted in confusion and irreparable harm for developers and investors in Oregon which ultimately proved to be a substantial barrier to solar development in the state, especially on PacifiCorp's system.[35] As the Commission is well aware, PacifiCorp's system in Oregon is plagued by the concept PacifiCorp calls "load pockets" where there is insufficient load in a service area to absorb additional generation.[36] PacifiCorp's NRIS studies therefore often result in "multi-hundred million dollar network upgrades for massive new transmission projects" where nearby projects being studied for ERIS might have much smaller interconnection costs.[37]

The practice requiring NRIS in Oregon, therefore has ultimately been a "fatal barrier" to some QF development, particularly in PacifiCorp's Prineville area load pocket.[38] And this is a barrier does not exist for comparable nearby facilities that are QF-sized or that could have potentially been QFs.[39] Notably even an additional million dollars of cost would be discriminatory. For example, if a new 40 MW solar facility costs \$50 million to construct, a non-refundable \$5 million network upgrade for a substation would comprise a 10% increase in cost. This is further amplified because interconnection costs (including network upgrades) are not eligible to receive the Investment Tax Credit ("ITC").[40]

Even where firm transmission is desired or needed, one possible alternative to NRIS would be to allow ERIS but use third-party point-to-point transmission service to move the

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35 NewSun/300, Bunge/3-4.
36 Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/30.
37 NewSun/300, Bunge/3-4.
38 *Id.* at 2-4.
39 *Id.*
40 *See* 26 C.F.R. § 1.48-9; Riley Sullivan, Solar ITC Table: Eligible and Ineligible Costs, Zenergy (Jan. 13, 2017), https://zenergyfin.com/solar-itc-table-eligible-and-ineligible-costs/.

power to load.[41] Therefore, by allowing ERIS, the Commission could put on-system QFs on an equal footing with other generators and other QFs and open up other solutions to transmission constraints.

Finally, the practical reasons Joint Utilities cite as justifications for treating on-system QFs differently from other generators do not hold up in practice. First, even if firm transmission is required, NRIS is not a "prerequisite" to achieving such firm transmission.[42] In fact, many projects have secured ERIS and taken firm transmission including PGE's Port Westward 2 generating facility and Idaho Power's Big Sky Dairy Digester (2 MW), Rock Creek Dairy Digester (2 MW), Lucky Peak (101 MW), Jackpot Solar (120 MW), and Elkhorn Wind (101 MW).[43]

Second, there are many non-QF interconnection customers that are not also the same entity that is seeking transmission service, i.e., the "unity of identity," as the Joint Utilities refer to it, does not exist. The primary user of each utility's transmission system is their respective merchant or load service functions.[44] It is the utility that arranges for transmission for its own load. Indeed, managing the energy balance is a fundamental core responsibility of the utility. For example, on PacifiCorp's system, the following on-system generators in Oregon sell to PacifiCorp under non-PURPA agreements but have been submitted by PacifiCorp's Merchant Function to the Transmission Function under the transmission service request process: Black Cap Solar (2 MW), Combine Hills I, LLC (41 MW), Millican Solar Energy, LLC (60 MW), Old Mill

41 Interconnection Customer Coalition/300, Lowe/15-16.
42 *Compare* Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/17 *with* Joint Utilities/400, Vail-Bremer-Foster-Larson-Ellsworth/27.
43 NewSun/400, Andrus/3.
44 Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/21 (PacifiCorp 81%, PGE 87% and Idaho Power 70%).

Solar (5 MW), and Prineville Solar Energy, LLC (40 MW).[45] Further, "Idaho Power holds network transmission capacity on behalf of all PURPA [QFs] and Non-PURPA facilities under contract to deliver their generation to Idaho Power," and it is "Idaho Power's Supply business unit that submits the transmission service request for facilities under contract to deliver their generation to the Company."[46] The non-PURPA generators Idaho Power lists include Elkhorn Wind (100.65 MW), Neal Hot Springs Unit #1 (22 MW), Raft River Unit #1 (13 MW), and Jackpot Holdings, LLC (120 MW).[47]

Therefore, if each of the Joint Utilities' merchant or load service functions are the transmission customer for each non-QF generator they are using to serve load, then there is no practical reason to treat QFs differently and there is clearly a method for addressing deliverability issues even if firm transmission is required. In addition, while Staff ultimately does not recommend ERIS, it does not take the position that it is infeasible or that otherwise not permitted.[48] As such, the Commission should allow for ERIS because there is no practical reason not to, it places Oregon jurisdictional QFs on equal footing with other generators and has the added benefit of enabling parties to develop creative solutions to transmission constraints.

IV. FEDERAL AND OREGON POLICY

Adopting these recommendations will facilitate meeting federal and Oregon state policy goals and statutory requirements. The standard under the Public Utility Regulatory Policies Act is to "encourage" the development of QFs.[49] In addition, rates shall not discriminate against

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45 NewSun/400, Andrus/7 (note that this DR only covered Oregon-sited projects).
46 *Id.* (quoting NewSun/402, Andrus/4-5 (Idaho Power's response to NewSun DR 5)).
47 *Id.*
48 Staff/300, Moore/3 ("Staff also believes that NRIS is the most practical interconnection service for QFs.")
49 16 USC § 824a-3(a).

QFs.[50] In Oregon, it is a statutory goal to "[p]romote the development of a diverse array of permanently sustainable energy resources using the public and private sectors to the highest degree possible" and the policy of the state to "[i]ncrease the marketability of electric energy produced by qualifying facilities located throughout the state for the benefit of Oregon's citizens."[51] Further, Oregon most recently established mandatory targets for putting the utilities on a pathway towards 100% clean electricity.[52]

The recommendations in this brief will help the Commission comply with these statutory objectives and policy goals and are essential to meeting PURPA's requirements to encourage QF development and ensure that QFs are not discriminated against.

V. CONCLUSION

In conclusion, the Commission should resolve both questions one and two by adopting FERC's approach to cost allocation and giving Oregon-jurisdictional generators the option to interconnect with ERIS.

Dated this 3rd day of June 2022.

Respectfully submitted,

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50 16 USC § 824a-3(c).
51 ORS 758.515.
52 ORS 469A.410.