BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2274

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2023 All-Source Request for Proposals, Request for Partial Waiver of Competitive Bidding Rules	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION'S COMMENTS ON DRAFT RFP

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I. INTRODUCTION

The Northwest & Intermountain Power Producers Coalition ("NIPPC")[1] respectfully submits these Comments for consideration by the Oregon Public Utility Commission ("Commission") on Portland General Electric Company's ("PGE") 2023 Draft All-Source Request for Proposals ("Draft RFP"). NIPPC supports PGE moving forward with its RFP and proposes improvements to increase the number and quality of bids, and to ensure greater transparency and fairness.

There are several recommendations the Commission should require PGE to adopt before the RFP is approved. NIPPC notes that it has sought to limit the issues it has identified, and generally not relitigate its recommendations because the Commission recently approved a similar RFP. NIPPC's concerns are largely focused on new issues raised for the first time, PGE's decision to relitigate issues that it or other utilities have lost, and concerns that have become apparent from NIPPC's review of PGE's last RFP. NIPPC recommends the following changes to the RFP:

- Allow conditional firm system conditions transmission at a reduced capacity value;
- Remove the requirement for a completed facilities study for selection on the final shortlist;

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1 NIPPC is a membership-based advocacy group representing electricity market participants in the Pacific Northwest. NIPPC members include independent power producers ("IPPs"), electricity service suppliers, and transmission companies. NIPPC's current member list can be found at http://nippc.org/about/members/.

- Allow the bidder to provide a parental guarantee or post liquid security, not both, and clarify credit requirements to bid into the RFP and selection onto the final shortlist;

- Reduce the transferability discount for utility-owned bids to 50 percent;

- Ensure fair treatment between third-party bids and utility-owned bids;

- Assess a bid on the actual reserve rate a bid relies on from third-party balancing authorities instead of assuming Bonneville Power Administration (“BPA”) reserve rates for all bids;

- Require bidders to submit contract redlines aligned with the bid’s price score;

- Remove the imputed debt adder from the price score for Power Purchase Agreements (“PPAs”) and Storage Capacity Agreements (“SCAs”) because nearly twenty years of well-established policy and the Commission’s existing rules do not allow for artificial bid adders of imputed debt;

- Require PGE to provide a tool so that bidders can estimate the project’s effective load carrying capability (“ELCC”);

- Require PGE to disclose more details on the benchmark bids, and if PGE is not making the benchmark bids’ assets available to the public, then explain why;

- Prohibit the affiliate from bidding into this RFP or if the affiliate will be allowed to bid into this RFP, then treat it as a benchmark bid and make other changes, including to the affiliate PPA;

- Modify the form contracts to be more aligned with market terms consistent with the Independent Evaluator’s (“IE”) assessment from the 2021 RFP;

- Clarify the required Commercial Operation Dates (“COD”) for projects bidding into the RFP;

- Confirm a bidder can submit a permitting narrative to satisfy the minimum bid requirement related to permitting; and

- Modify the Non-Disclosure Agreement (“NDA”) to increase liability and extend term of the NDA.

NIPPC recommends that the Commission address each of these concerns and require PGE to update its RFP in accordance with NIPPC’s recommendations.

II. COMMENTS ON PGE'S DRAFT RFP

A. Minimum Bid Criteria

1. Transmission and Conditional Firm System Conditions

The Commission should direct PGE to allow a bidder to use conditional firm system conditions transmission service. Additionally, conditional firm system conditions should be given a capacity value in PGE's evaluation of bids. However, NIPPC recognizes that bids with conditional firm system conditions should not be credited with the same capacity value as other firm transmission, and a bidder should be allowed to propose a capacity value for a project that uses conditional firm system conditions that is subject to negotiations with PGE and review by the IE.

BPA offers its transmission customers two types of conditional curtailment options for two conditional firm service categories: "Number of Hours" and "System Condition".[2] While either option is, in practice, often effectively firm for most of the year, BPA retains the option to curtail conditional firm service when specific conditions are met. For the "Number of Hours" conditional curtailment option, BPA specifies (at the time it offers the customer a transmission service agreement) the number of hours per year that it may curtail the customer's service.[3] BPA can trigger curtailments of the customer's service up to the number of hours specified in the service agreement for any

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[2] BPA Transmission Business Practice, "Conditional Firm Service" Version 26 at Sec. A.3 (Jan. 13, 2022), available here: https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/conditional-firm-service-bp.pdf. These curtailment options apply to both the Bridge and Reassessment categories of conditional firm service.

[3] BPA Transmission Business Practice, "Conditional Firm Service" Version 26 at Sec. A.3.a and Sec. H.2.

reason. BPA's most recent awards of "Number of Hours" conditional firm service specified anywhere from 33 curtailment hours up to 247 hours of curtailment per year.[4]

For the "System Conditions" conditional curtailment option, BPA must identify in the service agreement the specific transmission grid conditions under which it may curtail the customer's service. An example of the type of system condition that would allow BPA to curtail conditional firm service would be when flows across specific paths approach the system operating limit.[5] Under "System Conditions", BPA can curtail customers' conditional firm service whenever "real-time analysis identifies curtailment [on specific paths] to mitigate transmission constraints".[6] System Condition conditional firm service requests that impact more than one path may be subject to curtailment when there is congestion on any of the paths specified in the service offer.[7]

BPA retains the right to reassess the characteristics of customers' conditional firm service every two years.[8] This allows BPA to either increase the number of hours of curtailment if the customers has selected the "Number of Hours" option; or when the customer has selected the "System Conditions" option, BPA can identify new system conditions that would allow it to trigger a curtailment of the customer's service.[9] When BPA reassesses customers' conditional firm service and increases the number of hours or

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4 BPA, 2022 Cluster Study Report at Sec. 5.2 (June 10, 2022) (Attachment A).

5 BPA Transmission Business Practice, "Conditional Firm Service" Version 26 at Sec. A.3.a and Sec. H.3.

6 Attachment A, BPA, 2022 Cluster Study Report at Sec. 5.2.

7 Attachment A, BPA, 2022 Cluster Study Report at Sec. 5.2.

8 BPA Transmission Business Practice, "Conditional Firm Service" Version 26 at Sec. D.3.

9 BPA Transmission Business Practice, "Conditional Firm Service" Version 26 at Sec. D.3.

increases the system conditions that apply to the conditional firm service, the customer has the option to terminate the service.[10]

Currently, BPA will no longer offer conditional firm service to transmission service requests into the Portland area on Number of Hours basis and only offer the service on a System Conditions basis.[11] BPA has noted that the Portland area sub-grid has become increasingly congested.[12] In order to manage congestion into the Portland sub-grid area, BPA has indicated it may need to identify additional ways to manage flows into Portland.[13] Because BPA has not yet identified these new paths, let alone calculated their transfer capability or developed data on the frequency of congestion, BPA will currently only offer conditional firm service into the Portland sub-grid on a System Conditions basis.[14] While BPA may offer the Number of Hours option into the Portland area in the future, it will do so only after identifying new paths capable of managing flows into the Portland area, calculating total transfer capability for those paths, and developing congestion frequency data over several years.

Only customers who secured transmission rights prior to the 2022 Cluster Study could now have the Number of Hours option for conditional firm transmission service into the Portland region. This means that PGE's prohibition on using conditional firm service into the Portland sub-grid on a System Conditions basis could have the practical

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[10] BPA Transmission Business Practice, "Conditional Firm Service" Version 26 at Sec. F.3.
[11] Attachment A, BPA, 2022 Cluster Study Report at Sec. 5.1.2.
[12] Attachment A, BPA, 2022 Cluster Study Report at Sec. 5.1.2.
[13] Attachment A, BPA, 2022 Cluster Study Report at Sec. 5.1.2.
[14] Attachment A, BPA, 2022 Cluster Study Report at Sec. 5.1.2.

effect of excluding a significant number of bids in this RFP, and the reductions in the bidder pool will get worse over time. Therefore, to ensure as many bids are eligible for the RFP as possible, especially in light of the later December 31, 2027 COD, the Commission should require PGE to accept bids that use conditional firm transmission service with the System Conditions curtailment option.

NIPPC understands that conditional firm transmission service with the System Conditions curtailment option is not as valuable as traditional firm transmission, but this service still would have significant energy value and some capacity value. Additionally, when a resource would be curtailed is highly dependent on the resource's generation characteristics and the system conditions BPA has placed on the transmission service. Thus, it would be unreasonable to assign no capacity value to resources that use conditional firm transmission service with the System Conditions curtailment option. The Commission should allow a bidder to obtain full energy value and to propose a capacity value for a project that uses conditional firm on a System Conditions basis, and the exact capacity value can be subject to negotiations with PGE and review by the IE to better ensure that PGEs does not unreasonably reduce the capacity value.

2. Interconnection Study Requirements

To qualify for the final shortlist, the RFP requires a bidder to have a completed facilities study.[15] The IE recommends removing this requirement for selection on the final shortlist as long as the bidder can still demonstrate it complies with COD

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[15] Draft RFP, Appendix N at 14 (May 19, 2023).

requirements.[16] The IE recommended this change due to delays in study queues.[17] NIPPC supports this recommendation and recommends the Commission require PGE to remove the requirement to have a completed facilities study for selection on the final shortlist if the project can demonstrate it meets COD requirements.

3. Credit Requirements

The Commission should direct PGE to allow the bidder to provide a parental guarantee or post liquid security, and not both. The contract forms and Appendix K appear to require the seller to post the liquid performance assurance even if the seller meets PGE's creditworthiness criteria or provides a parental guarantee.[18] The IE noted this duplicative security requirement as a problem in the 2021 RFP, explaining that it appeared to require bidders to use a parental guarantee *and* a letter of credit when bidders should have the option to provide just one or the other form of security.[19] NIPPC agrees that the Draft RFP appears to require *both* a liquid form of security (letter of credit or bond) *and* a parental guarantee, which is unnecessary.[20] It should be an either/or requirement, not both. The Commission should also direct PGE to accept non-United States banks as "qualified institutions" for purposes of credit requirements.[21] Thus, the

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16 IE's Assessment of PGE's Draft All Source RFP at 20 (May 31, 2023).
17 IE's Assessment of PGE's Draft All Source RFP at 20.
18 *See* Draft RFP, Appendix E at Article 9; *see also* Draft RFP, Appendix K at 2, 3-4.
19 *In re PGE 2021 All-Source Request for Proposals*, Docket No. UM 2166, Draft Independent Evaluator Report at 7-8 (Oct. 20, 2021).
20 *See* Draft RFP, Appendix E at Article 9; *see also* Draft RFP, Appendix K at 2, 3-4.
21 Draft RFP, Appendix K at 2.

Commission should direct PGE to require only a liquid form of security or a parental guarantee.

NIPPC also seeks clarification on the demonstration of credit requirements when bidding into the RFP and selection onto the final shortlist. From NIPPC's understanding, a bidder must only provide a "reasonable plan to obtain project financing" as a minimum bid requirement.[22] To make it onto the final shortlist, the bidder must meet PGE's credit eligibility thresholds.[23] However, Appendix K on credit requirements does not make this distinction. Thus, NIPPC requests that PGE clarify NIPPC's understanding on the credit requirements to bid into the RFP and selection on the final shortlist.

4. Transferability

The Commission should direct PGE to reduce the transferability discount to 50 percent for utility-owned bids. The Commission should also direct PGE to model sensitivities on the ranking of projects with various transferability percentages.

The RFP does not state the exact transferability discount percentage[24], but PGE states it is between 5 and 10 percent.[25] In NIPPC's view, the market for transferability is too new and uncertain still to use as the basis for supporting such a major investment for customers. It is NIPPC's understanding that many developers are not assuming transferability in their project economics. Including transferability of the tax credits for utility-owned bids would be an additional factor in the RFP that could bias the RFP

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22 Draft RFP, Appendix N at 2.
23 Draft RFP, Appendix N at 13-14.
24 Draft RFP, Appendix N at 9.
25 PGE's Presentation for the 5/26/23 Workshop at 18 (May 26, 2023).

against PPA resources in favor of utility-owned resources. Additionally, NIPPC submitted data requests to PGE to understand why it selected its proposed percentage and to ask for any information supporting PGE's selection, but PGE did not provide any substantive response or documentation to support its percentage.[26]

Once more is known about this market, there will be more information to decide the appropriate transferability discount that should be allowed to be used in PGE's next RFP. At this time, the Commission should direct PGE to reduce the transferability discount to 50 percent for utility-owned bids because the market is too unknown, PGE's lack of substantive response supporting its transferability discount, and 50 percent better accounts for the risks and uncertainties associated with this untested market.

Additionally, the Commission should direct PGE to model sensitivities on the ranking of projects with various transferability percentages so that stakeholders can better understand the effect transferability will have on project ranking. This information may be useful when developing PGE's next RFP.

5. Long-Term Service Agreements

The Draft RFP should contain additional clarity regarding the treatment of utility-owned bids to ensure fair treatment in this RFP where cost-based utility-owned bids will be compared to contract-based bids under PPA, BSA, and other hybrid PPA-plus-tolling proposals.

The Draft RFP provides little to no details as to how the performance and operational costs of utility-ownership bids will be handled. Those risks include lower

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[26] *See* PGE's Response to NIPPC Data Requests (Attachment B, DR 12)

capacity factor than forecast, lower round-trip efficiency on a battery than that required in the BSA applicable to tolling agreement bids, or lack of other performance guarantees and fixed prices for energy and capacity inherent in the PPA or tolling structure. The Draft RFP states generally that utility-owned bids must include quoted vendor costs for long-term service agreements ("LTSA") for a minimum of 5 years and any operation and maintenance agreements ("O&M Agreement") costs in the pricing of the utility-ownership bids, such as a benchmark or a BTA bid.[27] But the Draft RFP provides no description of the minimum protections it will require in such O&M Agreement, LTSA, or warranties, much less any assurance the protections therein will be equivalent to those in a PPA or BSA bids.

The Commission's rules expressly require the IE to independently score and evaluate the risk of utility ownership for *all* utility ownership bids.[28] The Commission's rules state that the IE must evaluate the unique risks and advantages of utility-owned bids, including the risk of cost overruns, risk of performance assumptions, and operation and maintenance costs.[29] In NIPPC's view, this should require development of reasonable contingency cost adders for utility-ownership bids (i.e., the benchmarks and BTA bids) whenever those bids do not provide contractual guarantees and damages provisions with protections analogous to the requirements of PPA and tolling agreement bids. Thus, the RFP should contain strict LTSA and warranty requirements for the utility

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27 Draft RFP, Appendix N at 8, 9.
28 OAR 860-089-0450(5).
29 OAR 860-089-0450(6).

ownership structures and develop reasonable contingency price adders for those bids that do not provide such contractual protections.

In sum, NIPPC recommends that the RFP specify minimum requirements for LTSAs and/or warranties for all utility ownership bids that will make those bids subject to the same type of contractual protections as the PPA and BSA bids. To the extent the RFP does not require LTSAs and equipment warranties for the life of the project or include those costs for the life of the project, the IE should develop appropriate operating and maintenance costs and appropriate contingency price bid adders, or performance contingency risk adjustments, for the added risk of the utility ownership bids.

6. Integration

The Commission should direct PGE to assess a bid on the actual reserve rate a bid relies on from third-party balancing authorities. Currently, PGE is proposing to assess all bids on the BPA reserves rate.[30] While this might be the most simplistic approach, it does not accurately capture all costs of a project. Further, PGE is seeking pricing that reflects all the cost to deliver the resource, which will not be accurate if PGE only assesses bids on the BPA reserve rates.

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[30] Draft RFP, Appendix N at 9. In PGE's Scoring and Modeling Methodology in their RFP, they state that: "To evaluate bids containing different resource characteristics on a comparable basis, prices submitted by the Bidder may be subject to adjustments, and adjustments may also be required throughout the evaluation process. For consistency, PGE intends to assess all bids the BPA reserves rate. Renewable resources will be assessed BPA's variable energy resource balancing services, and dispatchable resources will be assessed dispatchable energy resource balancing services."

An example can illustrate this concern. PGE is evaluating wind resources in various locations including Wyoming and Montana.[31] Thus, a bidder may propose a project in this area that would need to consider costs to deliver the energy from NorthWestern Energy's system to PGE. For projects that are exporting to another balancing area, NorthWestern Energy charges several fees including system control and dispatch (Schedule 1), regulation and frequency response (Schedule 3A), and a flex reserve service (Schedule 11, unique to wind).[32] If PGE is not including these types of costs to a bid, then it can drastically affect prices as NorthWestern Energy's flex reserve service charge can add significant costs to a wind project. These costs will be different from BPA's reserve rate. The standard reserve rates for spinning and non-spinning reserves are almost the same for BPA and NorthWestern Energy, but there are additional reserve costs when wheeling across territories that should be captured in a bid's price.

The Commission should direct PGE to assess a bid on the actual reserve rate a bid relies on from third-party balancing authorities instead of assuming BPA reserve rates for all bids. The bidders, who end up ultimately bearing these delivery costs, can provide these costs in their bids, which would be subject to review by PGE and the IE.

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[31] *In re PGE 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, 2023 Clean Energy Plan and Integrated Resource Plan at 20 (Mar. 31, 2023).

[32] All schedules available on NorthWestern Energy's OASIS website under "Tariffs / FERC Filings" then "Current NWE MT OATT" tabs, available here: http://www.oasis.oati.com/NWMT/index.html.

In addition, PGE should also assess full delivery costs based on the control area system for ownership bids. For example, it is equally inappropriate for an ownership bid to assume lower (or higher) delivery costs than what it is actually expected to incur.

B. Scoring

1. Bidders Should Be Required to Provide Contract Redlines or Term Sheet Redlines Aligned with the Bidder's Price

The Commission should direct PGE to require bidders to provide redlines to the contract forms and/or term sheets that are aligned with the bidder's price score. PGE has eliminated the non-price score from the RFP, which NIPPC generally supports. However, this approach raises concerns about how PPA bidders will be evaluated against each other during selection of the final shortlist and during negotiations. For example, Bidder A could provide a lower price score aligned with more beneficial contract provisions than those provided in PGE's form contract/term sheet (i.e., a lower price and revisions to reflect normal market contract provisions) while Bidder B could provide a higher price score aligned with PGE's form contract/term sheet (i.e., a higher price necessary to account for PGE's non-market contract provisions). Potentially Bidder B is more likely to be successful in contract negotiations with PGE, but it is not clear how Bidder B would be evaluated for contract negotiations because it has a higher price score.

Thus, bidders should be required to provide contract redlines and/or term sheet redlines that align with the project's bid price. The bidder should not be penalized for contract/term sheet redlines, but providing contract/term sheet redlines aligned with the score can increase transparency during the contract negotiation process and allow the IE more insight into PGE's decision-making process.

2. Imputed Debt Adder

NIPPC strongly recommends deleting the Draft RFP's price adder for imputed debt. The Draft RFP states PGE will increase all PPA and BSA bids for alleged costs of imputed debt.[33] This price adder will, of course, not apply to any utility-ownership bids, including the benchmarks or the BTA bids. Notably, as discussed below, the IE's Report agrees with NIPPC that imputed debt should not be included in the RFP. NIPPC will also be filing a report from Michael Gorman, one of the nation's leading cost of capital experts, that responds to PGE's specific proposal and provides the technical grounds for its rejection.

Use of imputed debt bid adders is bad policy, barred by the Commission's historic policies, orders and rules, and rejected by the Commission in Idaho Power's RFP less than a month ago. Given this overwhelming precedent, NIPPC is surprised that PGE has not simply withdrawn the penalty.

The Commission has a long history of disallowing the use of imputed debt for use in selection of the initial shortlist at least since the Commission's 2006 bidding guidelines, which allowed consideration of imputed debt only for development of a final shortlist and reserved the possibility of requiring a rating agency opinion to substantiate the utility's decision to use imputed debt at all.[34] Subsequently, in 2011, the Commission disallowed the use of imputed debt whatsoever in RFPs and directed utilities to raise the issue solely in a rate case where the utility's overall cost of capital could be fully

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[33] Draft RFP, Appendix N at 9; *see* PGE's June 5, 2023 Workshop Presentation at 8.

[34] *In re Investigation Regarding Competitive Bidding*, Docket No. UM 1182, Order No. 06-446 at 10-12 (Aug. 10, 2006) (discussing Guideline 9(c)).

analyzed in context.[35] Only a few months after the Commission decision, PGE ignored the Commission's precedent and proposed use of imputed debt to penalize PPA and tolling agreement bids, the Commission rejected the proposal, citing its 2011 decision.[36] Furthermore, just recently the Commission rejected Idaho Power's proposed use of an imputed debt adder for PPA and SCA bids in its 2026 RFP.[37] Consistent with that authority, the Commission's current rules require that price scores "*must* be based on the prices submitted by bidders and calculated using units that are appropriate for the product sought and technologies anticipated to be employed in responsive bids using real-levelized or annuity methods."[38]

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35 *In re the Pub. Util. Comm'n of Ore.; An Investigation Regarding Performance-Based Ratemaking Mechanisms to Address Potential Build-vs.-Buy Bias*, Docket No. UM 1276, Order No. 11-001 at 6 (Jan. 3, 2011) (stating: "we allow the utilities to raise the impact on this practice on credit ratings and earnings in individual rate proceedings. We believe that this issue is more appropriately addressed in the context of an overall examination of a utility's cost of capital").

36 *See In re PGE's Request for Proposals for Capacity Resources*, Docket No. UM 1535, Order No. 11-371 at 7 (Sept. 27, 2011) (rejecting PGE's proposed use of imputed debt in an RFP and stating: "We agree with CUB that, although PGE's position is consistent with our Competitive Bidding Guidelines, it conflicts with Order No. 11-001. We take this opportunity to clarify that this more recent order supersedes the guidelines and directs the parties to deal with debt imputation issues in rate cases.").

37 *See In re Idaho Power Company Application for Approval of 2026 All-Source Request for Proposals to Meet 2026 Capacity Resource Need*, Docket No. UM 2255, Staff Report for the June 7, 2023 Special Public Meeting (June 1, 2023); *see also* Docket No. UM 2255, Staff Report for the May 16, 2023 Public Meeting (May 3, 2023). Staff Reports were adopted at June 7, 2023 Special Public Meeting (*see* Minutes here: https://oregonpuc.granicus.com/DocumentViewer.php?file=oregonpuc_702b017965f3e340ebd1ac7e210283f3.pdf&view=1) and May 16, 2023 Public Meeting (*see* Minutes here: https://oregonpuc.granicus.com/DocumentViewer.php?file=oregonpuc_38a79a655b017840a5c47abde688ee13.pdf&view=1).

38 OAR 860-089-0400(2)(a) (emphasis added).

Aside from violating the Commission's longstanding policy, PGE's proposal runs counter to the central policies of good RFP design because it is lacking in transparency and justification. The IE notes, it is "concerned that [imputed debt] is a theoretical cost that could serve to bias the selection of bids."[39] Additionally, the IE notes it has "seen no additional evidence from S&P or other parties that this risk has increased in the past few years."[40] The IE states it sees no reason to depart from past precedent unless there is evidence that "S&P is becoming more aggressive in assessing these costs and that PGE has actually incurred increased costs as a result of debt imputation."[41]

This all goes to show that—as the Commission has repeatedly determined—it is unlikely that a single PPA emerging from an Oregon RFP would ultimately lead to imputed debt and even more unlikely that the impact of such imputed debt would actually flow through as a perceptible cost to ratepayers when considering all of the other factors that affect a utility's cost of capital and its impact on rates. PGE did not provide any reasonable basis to assume that any rating agency would impute debt to a prevailing PPA or tolling agreement in this RFP given PGE's circumstances, much less explain how such imputed debt (if it were to be applied by a ratings agency) would ultimately result in a lower overall credit rating for PGE or ultimately have a perceptible impact on rates PGE would request to charge its customers. Nor has PGE properly sought to waive the Commission's longstanding proscription against use of imputed debt in Oregon RFPs at

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[39] IE's Assessment of PGE's Draft All Source RFP at 19.
[40] IE's Assessment of PGE's Draft All Source RFP at 19.
[41] IE's Assessment of PGE's Draft All Source RFP at 19.

the time it filed its request for approval of its RFP.[42] Thus, the Commission should direct PGE to remove its imputed debt adder for PPA and SCA bids.

3. ELCC

The Commission should require PGE to provide a tool so that bidders can estimate the project's effective load carrying capability ("ELCC") that PGE will use in the project's capacity determination. PGE is not providing a tool for estimating ELCC like it did in its 2021 RFP. In PGE's last RFP, the Commission adopted Staff's recommendation to require PGE to provide a calculator tool so that a bidder could estimate its ELCC.[43] PGE has not explained why it is departing from this recent Commission precedent.

C. Benchmark

The RFP states PGE plans to submit benchmark bids, but it does not contain much detail about those benchmarks, as is typically included and is also required by the Commission rules and policy.[44] PGE states it is currently evaluating wind, solar, hybrid, and stand-alone storage resources.[45] PGE states that the only utility-controlled assets for the benchmark bids or affiliate is land in northeast Oregon.[46]

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42 *See* OAR 860-089-0010(2) (request to waive RFP rules must be supported by good cause shown "prior to or concurrent with the initiation of a resource acquisition").

43 *See In re PGE 2021 All-Source Request for Proposals* Docket No. UM 2166, Staff Report at 10 (Nov. 19, 2021); *see also* Docket No. UM 2166, Order No. 21-460 at 2-4 (Dec. 10, 2021).

44 Draft RFP, Appendix P.

45 Draft RFP, Appendix P.

46 Draft RFP, Appendix P.

The Commission has long required transparency regarding the benchmark bids in RFPs. The Commission's IRP Guidelines even require discussion of the utility's planned benchmark bids in the IRP.[47] PGE has not included this information in its IRP. While NIPPC is not proposing disallowance, PGE's failure to comply with the IRP guidelines could be grounds for concluding that the RFP cannot be aligned with the IRP and disallowing the benchmark bids.

The Commission's bidding rules further require identification of the benchmark for the purpose of disclosing and alerting the Commission, the IE, stakeholders, and bidders as to whether any benchmark assets, such as its site or interconnection and transmission rights, will be shared with bidders to utilize.[48] In adopting that rule, the Commission explained that "the use of utility owned resources by third parties to develop additional or better, more efficient bids will help facilitate the objective of more and better proposal options."[49] Although utilities are not required to make their assets available in all cases, the rules do require "a filed analysis of the decision be provided to the Commission at the time of RFP development, as well in a subsequent prudence determination"[50] and, the failure to make certain ratepayer-backed assets available to other bidders should be a consideration in the Commission's decision to acknowledge the final shortlist.

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47 *In re Pub. Util. Comm'n of Or*., *Investigation into Integrated Resource Planning*, Docket No. 1056, Order No. 07-002 at 22-24 (Jan. 8, 2007) (discussing Guideline 13).

48 OAR 860-089-0450(6)(c); OAR 860-089-0300(2)-(3).

49 *In re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324 at 10 (Aug. 30, 2018).

50 *Id*. at 11.

Identification of the benchmark bids and why PGE is apparently deciding not to share any potentially useful assets fundamentally impacts whether this RFP can be fair and competitive. Such assets are often ultimately supported by ratepayer-backed resources (utility funds and employee time) and making such assets available to obtain the best product for ratepayers is entirely logical. Without identification of the benchmark information, it is not possible for the IE, Staff, or stakeholders to understand whether and how ratepayer assets could be biasing the RFP toward more expensive and less reliable assets.

Indeed, NIPPC believes it would be per se imprudent not to do so where the assets are ratepayer-funded in any manner. Such assets can also be uniquely available to the utility due to its status as the incumbent monopoly in its balancing authority area that can build off of its legacy rights and retiring facilities to perpetuate its position by outcompeting competitive bidders lacking access to such resources, such as advantageous interconnection or transmission rights tied to a retiring coal facility.

Without clarity in the RFP as to the details of the benchmark, it is not possible to comment further on this important subject. The Commission should require complete disclosure of the benchmark resource(s). At minimum, PGE should be required to provide the following information for each benchmark bid similar to what PacifiCorp and Idaho Power Company have provided in their respective RFPs: size (in MW), location, technology type, interconnection status, expected life, expected efficiency, target COD, status (new build vs. existing facility), and product type (resource-based or market purchase).[51] The Commission should also require complete disclosure of PGE's decision not to share assets supporting such bid(s). NIPPC reserves the right to comment further on PGE's decision to make benchmark assets available to competitive bids once that information is made public.

D. Affiliate

An affiliate of PGE should not be allowed to bid into this RFP. NIPPC is not opining on PGE's affiliate application in Docket No. UI 489 in this docket, but if the Commission were to approve the affiliate in the other docket, then the affiliate should not be allowed to bid into this specific RFP and instead be allowed to bid into the next RFP (subject to any appropriate conditions). The Commission's RFP rules were designed for affiliates with different structures than PGE's proposed affiliate, and there needs to be a more robust review of the necessary RFP changes that would result in a fair, objective, and transparent process. There is sufficient time, no urgency to approve the affiliate in this expedited RFP, nor any harm to limit affiliate participation to future RFPs because PGE's requirements in HB 2021, including continual progress toward meeting the requirements of HB 2021, will result in more resource needs and frequent RFPs in the future.

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[51] *See In re Idaho Power Company Application for Approval of 2026 All-Source Request for Proposals to Meet 2026 Capacity Resource Need*, Docket No. UM 2255, Staff Report at 2 (June 1, 2023) (Staff recommending Supplemental RFP Condition 1); *see also In re PacifiCorp Application for Approval of 2022 All-Source Request for Proposals*, Docket No. UM 2193, PacifiCorp's Final Draft 2022AS RFP, Appendix O (Jan. 14, 2022).

1. The Affiliate Is Not Appropriate for this Expedited Schedule

There are several procedural concerns to allowing the affiliate to bid into this RFP. If PGE had wanted an affiliate considered in this RFP, then PGE should have sought and obtained Commission-approval prior to filing the RFP. In addition, it would be more appropriate to consider how to allow an affiliate bid without harming ratepayers and the wholesale power market in a regular rather than expedited RFP. There is not enough time to fully review the affiliate application because of the expedited nature of this RFP and PGE's decision not to file its affiliate application earlier.

PGE sought an expedited schedule to approve this RFP and sought waiver of three competitive bidding rules due to its near-term capacity needs.[52] PGE emphasized it wanted to "streamline the RFP process" due to its near-term capacity needs.[53] NIPPC did not object to these requests to streamline the process, but recommended further review from the IE.[54] However, an affiliate should not be allowed to be rushed through into this expedited RFP without the proper time to review and ensure proper protections against anti-competitive practices or effects.

PGE could have filed its applications months earlier and given parties more time to review instead of filing it around the same time as the RFP. PGE states that it seeks to use an affiliate due to normalization issues with the Investment Tax Credit that were not

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52 Request for Partial Waiver of Competitive Bidding Rules (Jan. 31, 2023). PGE sought waiver so that PGE could "continue working with the IE used for the 2021 RFP, to have the scoring and modeling methodology review occur in parallel with review of the draft RFP, and to have the 2023 RFP review process run in parallel with the 2023 IRP and CEP docket." *Id.* at 2.

53 Request for Partial Waiver of Competitive Bidding Rules at 1-3.

54 *See* NIPPC's Comments regarding PGE's Waiver Request (Apr. 13, 2023).

fully resolved with the passage of the Inflation Reduction Act ("IRA").[55] The IRA was passed in August 2022, but PGE waited until May 2023 to file its affiliate application, which was after PGE filed its draft RFP.[56] PGE also did not revise its RFP to reflect that it would be the first Oregon RFP to ever allow an affiliate to bid.

There is not time to review the RFP, especially the form PPA, with an affiliate transaction in mind because we do not know, if the affiliate was approved, what conditions would be placed on the affiliate. Any conditions on the affiliate would affect review of the terms and conditions of the PPA and minimum bidding requirements. If the Commission approves the affiliate, then stakeholders need more time to carefully review and deliberate on many aspects of the RFP. Additionally, it is unclear if the IE has reviewed the PPA with an affiliate in mind.[57] PGE has not provided any basic information on its affiliate similar to what would be required to be provided for a benchmark bid.[58] Since PGE refused to answer basic questions, the Commission should

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55 *In re PGE Application for Affiliated Interest Transaction with Portland Renewable Resource Company, LLC*, Docket No. UI 489, Initial Application at 2, 4-6 (May 22, 2023).

56 PGE filed its draft RFP on May 19, 2023 and filed its affiliate application on May 22, 2023.

57 *See* IE's Assessment of PGE's Draft All Source RFP at 21 (only three boilerplate references to the word affiliate). NIPPC is not criticizing the IE for not reviewing the impact of PGE's proposed affiliate because it is not reasonable to assume that the IE would have had an opportunity to review, or it is worth the expenditure of ratepayer resources on the IE review, until it is clear that an affiliate will be allowed and, if so, under what conditions.

58 *See* PGE Objection to NIPPC Data Request (Attachment B, DR 24) (PGE refused to answer what site the affiliate resource will use, provide an analysis explaining why the site for the affiliate resource will not be made available to other bidders, clarify what transmission rights the affiliate resource will use, or explain why the transmission rights for the affiliate resource will not be made available to other bidders.).

assume that PGE will be using ratepayer resources to benefit its affiliate. The Commission and stakeholders deserve a thorough review by the IE of the risks associated with any Commission-approved affiliate prior to submission of comments and approval of any RFP.

2. The Commission Should Require Special Protections and Revise the RFP Design, Including an Affiliate PPA, in Any RFP that Includes an Affiliate

An RFP that includes a "non-independent" affiliate should be subject to special provisions to ensure fairness, transparency, and competition compared to an RFP with a real affiliate. RFPs can be biased in favor of utility owned resources not just because of generic provisions or biases that penalize or preclude non-ownership options, or generally support utility ownership, but an RFP can be specifically designed in favor of specific utility ownership options. For example, a utility can require certain interconnection, transmission, permitting, integration, delivery points, site control, and other conditions that the utility preferred resource meets, but exclude large numbers or potentially all non-ownership bids. There has been no time, and there is no sufficient remaining time in the schedule for this RFP, to understand the affiliate bid, and whether this RFP is designed in a manner that, for practical purposes, results in the affiliate bid "winning."

If an affiliate is allowed to bid into the RFP, then NIPPC is concerned that affiliate bids will have a large advantage over other PPA bids because the PPA form has not been revised to address the unusual circumstance of a non-independent affiliate backed with ratepayer resources. PGE has not even provided an affiliate PPA to review.

PGE claims it will enforce the PPA,[59] but it is difficult to imagine PGE strictly enforcing PPA provisions, much less bringing legal action to do so, against its affiliate. For example, will PGE's legal counsel bring a claim against PGE's affiliate, which may have the same lawyers? How will PGE's management evaluate whether PGE should effectively decide to sue itself?

There are several PPA provisions that should be revised for an affiliate PPA and would need Commission consideration. These include delay damages, performance guarantees and damages, legal disputes, security requirements, and more.

There are other provisions that should be subject to more specificity regarding what PGE's management preferences are, which will be reflected in any affiliate bid. For example, the contract term length under the PPA should be a 15-year minimum and a 30-year maximum. Fifteen years is the minimum fixed price term minimally necessary to ensure most independent power producers can be financed.[60] It is important for independent power producers to have this 15-30 year range because there are numerous different financing and business models which may support the bidder selecting one term or another. PGE's management's preferred PPA length could be reflected in whatever PGE's affiliate's proposed PPA term will be. The Commission and bidding community, however, should know exactly what PPA length(s) the affiliate is proposing, so that they can understand PGE's preferences when preparing their own bid.

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59 *See* PGE's Response to NIPPC Data Requests (Attachment B, DR 17). *See also* Docket No. UI 489, Initial Application, Attachment 2.

60 *See In re Comm'n Staff's Investigation Relating to Elec.. Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order 05-584 at 19 (May 13, 2005).

3. If Allowed in Any RFP, then PGE's Affiliate Should Be Treated as a Benchmark Bid

Whether in this RFP or the next RFP, PGE's affiliate bid should be treated as a benchmark bid subject to the provisions of the Commission rules because the rules did not envision a bidding non-independent affiliate, PGE's affiliate has not yet been approved by the Commission, and the affiliate that PGE has proposed is not sufficiently independent from PGE to be treated the same as an actual independent power producer. The affiliate should be subject to the requirement to explain why its assets are not being made available to third party bids, to be scored first and filed with the Commission before the third-party bidding process begins, and to separate employees who participated in the development of the RFP from employees who developed the affiliate bid. PGE should also clarify that the affiliate PPA will be a fixed-price PPA instead of cost-based PPA, and there should be additional opportunity to comment on how the RFP, especially the affiliate PPA, should be revised to reflect the final affiliate approved by the Commission.

In the rulemaking docket that adopted the benchmark and affiliate rules, the Commission discussed "affiliates" and the more relaxed treatment of them than benchmark bids and explained:

> we clarify that separate utility affiliates need not offer any resource elements to their other bidders nor explain their decision not to offer such elements. A separate affiliate, like a private third party bidding on an RFP, operates in a higher-risk highly competitive environment and it should not be obligated to provide access to its proprietary assets to other competitive entities.[61]

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[61] Docket No. AR 600, Order No. 18-324 at 11.

This demonstrates the Commission envisioned an affiliate for the RFP process to be a separate entity from the utility which has similar risks and costs to those of other independent third-party bidders.

Here, PGE's affiliate is not the type of affiliate contemplated in the RFP rules as it is not a separate entity. From the information PGE has shared in Docket No. UI 489, PGE's affiliate will share employees with PGE, PGE will provide office support to the affiliate, and PGE will provide various services to the facilitate such as "business analysis, finance and treasury support, human resources, investor relations, legal services, construction and engineering, purchasing, consulting/training services, and other services[.]"[62] It does not appear the "affiliate" here even has its own employees separate from PGE. Additionally, PGE is the likely source of credit support for this affiliate. Further, the Commission has yet to approve the bare minimum affiliated interest transactions for office support for the affiliate by PGE.[63]

PGE's affiliate bid should be subject to all benchmark bid requirements outlined in Commission rules. One requirement for benchmark bids is that if elements of a benchmark bid secured by the utility are not made available to all bidders, the utility must provide an explanation when seeking RFP acknowledgement and recovery of costs in rates.[64] Some examples of these elements include interconnection, land, and transmission rights. PGE's affiliate bid should be subject to these same requirements because it should be treated as a benchmark bid.

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62 Docket No. UI 489, Initial Application at 18.
63 *See generally*, Docket No. UI 489.
64 OAR 860-089-0300(3).

A second requirement for benchmark bids is that benchmark bids must be scored first and filed with the Commission before the third-party bidding process begins.[65] The IE Report explains that PGE properly states in its RFP that it will score the benchmark bids before the rest of the bids.[66] However, in this RFP, PGE's affiliate bid should also be submitted beforehand with the benchmark. Thus, the Commission should require PGE to submit its affiliate bid early for scoring with the other benchmark bids.

A third requirement for benchmark and affiliate bids is that "[a]ny individual who participates in the development of the RFP or the evaluation or scoring of bids on behalf of the electric company may not participate in the preparation of an electric company or affiliate bid and must be screened from that process."[67] PGE states that it separated the RFP development team from the benchmark and affiliate teams.[68] The IE acknowledges that PGE stated it has complied with this requirement but states it "presume[s] that PGE will provide a list of names to us specifying who is on which side of this divide."[69] Additionally, affiliate bids need to reflect all personnel and development costs. For example, if PGE spent three years scouting potential sites and analyzing transmission, then those costs should be assigned to the affiliate and not to PGE's customers. Thus, it will be important to know if employees have participated on multiple teams.

The Commission should adopt the IE's recommendation that PGE provide a list of names who worked on preparing the RFP, who will evaluate and score the RFP bids,

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65 OAR 860-089-350(1).
66 IE's Assessment of PGE's Draft All Source RFP at 22.
67 OAR 860-089-0300(1)(b).
68 Draft RFP at 6.
69 IE's Assessment of PGE's Draft All Source RFP at 21.

and who will be involved with the benchmark and affiliate bids. Additionally, the Commission should require PGE confirm: 1) that everyone on the benchmark and affiliate teams was not involved in the Integrated Resource Planning ("IRP") process because the IRP leads to the RFP since the RFP relies on IRP modeling; and 2) that everyone on the benchmark and affiliate teams has never and will not have access to any data, analysis, or other resources used by the team working on the RFP to the same extent as non-affiliate bidders. This should include but not be limited to anyone that provides business analysis, finance and treasury support, human resources, investor relations, legal services, construction and engineering, purchasing, consulting/training services, and other services. Both recommendations are the bare minimum level of transparency in the RFP process.

Fourth, if the affiliate is allowed to bid into this RFP, then PGE should clarify that the affiliate PPA will be a fixed price PPA similar to any other third-party PPA bid. PGE's affiliate application references a cost-based price PPA.[70] It is unclear what this means or how cost-based ratepayer funded resources may be providing an advantage to the affiliate. The affiliate PPA price should be the same as any other third-party PPA price at a fixed rate. Additional PPA provisions should be required to resolve this ambiguity and lack of transparency to ensure that the "cost-based" PPA does not provide PGE with an unfair advantage.

Finally, the Commission should allow parties an additional opportunity to comment on what changes should be made to the scoring methodology, evaluation of

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70 Docket No. UI 489, Initial Application at 13

energy and capacity value, and, most importantly, the affiliate PPA terms prior to when PGE evaluates any bids.

In summary, if the Commission approves the affiliate in Docket No. UI 489, then the Commission should not allow the affiliate to bid into this RFP due to the expedited nature of this RFP and lack of time to fully review an affiliate PPA in relation to the conditions placed on the affiliate. If the Commission allows the affiliate to bid into this RFP, then the affiliate should be treated the same as a benchmark bid and be subject to the same competitive bidding rules, and PGE should be required to submit an affiliate PPA for review by the IE and parties.

E. Form Contracts and Term Sheets

The Commission should direct PGE to provide form contracts for a renewable + storage bid, BTA bid, and the minimum terms for the LTSA and O&M Agreement for utility-owned bids. The IE also suggested PGE provide a renewable + storage PPA form contract.[71] PGE appears to have agreed to provide a hybrid PPA form contract, but not the others NIPPC believes are necessary.[72] Additionally, the Commission should direct PGE to provide term sheets for the various bid types. Term sheets are useful to bidders to summarize the main provisions on the form contracts. Currently, PGE has provided no term sheets, but should be required to do so. Thus, the Commission should direct PGE to provide all the form contracts for any type of bid into the RFP and the accompanying term sheets.

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[71] IE's Assessment of PGE's Draft All Source RFP at 13.
[72] *See* PGE's Response to NIPPC's Data Request (Attachment B, DR 16).

F. The Draft RFP's Form Contracts for PPA and SCA Bids Contain Commercially Unreasonable Terms that Should Be Revised to Reduce Bias

The Commission should review and reject contract provisions that are out of market, which means that PGE would be prohibited from including those in any non-affiliate PPA bids. There have been no pure solar or wind PPAs that were not linked to a utility-owned option in the last couple RFPs. This indicates the current form contracts do not match the actual market, which the IE also referenced in its summary of the contract negotiations from the 2021 RFP.[73] In addition, because there is no non-price score related to commercial performance, all contract provisions should not be left until contract negotiations otherwise PGE would have too much discretion. Essentially, PGE's non-market PPA may be contributing to or a major factor in solar and wind PPA bids being unable to win PGE's recent RFPs. Thus, the Commission should direct PGE to make the following changes to its draft contracts to be more aligned with market conditions.

1. Guaranteed COD

The Commission should direct PGE to change the Guaranteed COD to 180 days after the Scheduled COD. Currently, PGE defines Guaranteed COD as 120 days after the Scheduled COD.[74] However, the IE noted that many bidders pushed out this date typically to 180 days.[75] This change would be more aligned with the market for large

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73 IE's Assessment of PGE's Draft All Source RFP at 5-7.
74 Draft RFP, Appendices E & F at "Guaranteed Commercial Operation Date" definition.
75 IE's Assessment of PGE's Draft All Source RFP at 5.

developers. Thus, the Commission should direct PGE to modify the definition of Guaranteed COD to 180 days after the Scheduled COD.

2. Delay Damages

The Commission should direct PGE to make changes to the amount and timing of Delay Damages. Currently, the PPA definition of delay damages is $150/MW from the first day after the Scheduled COD through the 30th day after the Scheduled COD, $250/MW from the 31st day after the Scheduled COD through the 60th day after the Scheduled COD, and $350/MW from the 61st day after the Scheduled COD through either the Guaranteed COD or actual COD.[76] The PPA and SCA term sheets and form contracts have very high delay damages penalties that are not contained in the Engineering, Procurement, and Construction ("EPC") terms sheet, even though the EPC/BTA bidder must also ensure it brings the facility online timely. There is no apparent basis for the lenient provisions in the EPC contract.[77]

The excessive delay liquidated damages provisions on the PPA and SCA contract forms should be deleted, and damages should be determined based on actual damages at the time of a default, as appears to be the proposal for the EPC/BTA bids. In the alternative, the delay damage amounts should be reduced, and the timing should be extended for each level of damages by 30 days (i.e., the tier of damages should be from the first day after the Scheduled COD through the 60th day after the Scheduled COD).

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[76] Draft RFP, Appendix E at "Delay Damages" definition.
[77] Draft RFP, Appendix I at § 3.7.

This is more aligned with the changes the bidders in the 2021 RFP made as summarized by the IE.[78]

3. Output Guarantee

The Commission should direct PGE to revise the PPA form contract to clarify there is an annual output guarantee instead of a monthly output guarantee. While unclear, it appears PGE may still be requiring a monthly output guarantee.[79] In PGE's 2021 RFP, PGE proposed a monthly output guarantee of 90 percent of the expected facility output. The IE noted that most bidders in the 2021 RFP rejected the monthly guarantee and offered annuals guarantees in the range of 80 percent of the expected output.[80] An annual output is more aligned with market. Thus, the Commission should direct PGE to revise its PPA form contract to clarify that it is requesting an annual output of 80 percent.

4. Mechanical Availability

The Commission should direct PGE to reduce its Mechanical Availability Percentage. The PPA form contract contains a commercially unreasonable availability guarantee. Currently, the PPA requires a Mechanical Availability of 97 percent for any two out of three contract years and failure to meet this requirement is an event of default.[81] A 97-percent availability requirement is unreasonably high. The IE noted

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[78] IE's Assessment of PGE's Draft All Source RFP at 5.

[79] *See* Draft RFP, Appendix E at § 6.1 (discussing Seller's failure to delivery energy and refers to damages on a monthly basis); *see also* Draft RFP, Appendix E at "Specified Amounts" definition ("the amount of Facility Output generated by the Facility that Seller is expected to deliver to PGE at the Delivery Point for each monthly period during the Delivery Period.").

[80] IE's Assessment of PGE's Draft All Source RFP at 6.

[81] Draft RFP, Appendix E at § 5.1.9.

many bidders in the 2021 RFP "thought this was too aggressive, offering a range of alternatives from around 80% to 95%."[82] Notably, nothing in the RFP requires the utility-ownership bids to contain anything close to this availability guarantee.[83] Thus, the Commission should direct PGE to reduce its Mechanical Availability Percentage to 80%.

5. BESS Availability

The Commission should direct PGE to reduce its Guaranteed Availability percentage. The SCA form contract contains an annual Guaranteed Availability of 98%.[84] A 98% availability requirement is unreasonably high. The IE noted that bidders in the 2021 RFP "offered annual availability guarantees anywhere from 85% to 97%."[85] Notably, nothing in the RFP requires the utility-ownership bids to contain anything close to this availability guarantee.[86] Thus, the Commission should direct PGE to reduce its Guaranteed Availability percentage to 85%.

6. Test Energy

The Commission should direct PGE to pay for test energy. Currently, a bidder would not receive any payment for test energy and could even owe expenses to PGE.[87] This is an unreasonable contract provision. The IE noted that most bidders in the 2021

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82 IE's Assessment of PGE's Draft All Source RFP at 6.
83 *See generally*, Draft RFP, Appendix I.
84 Draft RFP, Appendix F at "Guaranteed Availability" definition and § 5.10(b).
85 IE's Assessment of PGE's Draft All Source RFP at 6.
86 *See generally*, Draft RFP, Appendix I.
87 Draft RFP, Appendix E at § 2.2 ("The price for such Test Energy received by PGE shall be zero dollars ($0.00) and Seller shall pay any costs or additional expenses that are required for PGE to receive the Test Energy, including but not limited to reimbursement for negative pricing and procurement of any necessary capacity costs or reserves."); *see also* Draft RFP, Appendix F at § 5.9(a)(iii).

RFP would not agree to this provision and proposed "anywhere from 50% or more of the contract price for such [test] energy."[88] Thus, the Commission should direct PGE to compensate bidders for test energy at the lower of 85 percent of Index Rate or 85 percent of Contract Price.[89]

7. Curtailment

The Commission should direct PGE to remove the uncompensated curtailment provision in the PPA form contract. The PPA contract form contains a requirement that the bidder agree to 400 hours (or 4.5 percent) of the hours per year of *uncompensated* curtailment by PGE in the PPA.[90] Because the PPA seller would only be paid for delivered power and not provided a flat capacity payment, the ratepayers would pay nothing for the curtailment right, and the PPA bidders would need to increase their bid price for a volumetric contract price based on the assumption they will be subject to this extensive uncompensated curtailment. In contrast, ratepayers will pay PGE for each hour of curtailment for whatever reason with at utility-owned EPC/APA or benchmark bid because the resource remains in rate base and its operating and maintenance expense remains in base rates without any adjustment to account for such curtailments. Additionally, the IE noted that this provision was "soundly rejected" by bidders in the

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88 IE's Assessment of PGE's Draft All Source RFP at 6.

89 The Commission recently concluded that these test energy payments were reasonable for qualifying facilities. *In re Rulemaking to Address Procedures, Terms, and Conditions Associated with Qualifying Facilities (QF) Standard Contracts*, Docket No. AR 631, Order No. 23-152, Appendix B at 26 (Apr. 25, 2023).

90 Draft RFP, Appendix E at § 3.8.9.

2021 RFP.[91] Thus, the Commission should require PGE to remove the uncompensated curtailment provision because it is unreasonable, biases the RFP against PPA bids, and not market.

8. Performance Assurance/Security

The Commission should direct PGE to reduce the security amounts. The PPA form contract requires a bidder to pay pre-COD security in the amount of $200/kW and delivery security in the amount of $100/kW.[92] These amounts are excessive and unreasonable. Further, these performance assurance levels are not comparably applied across resource types. EPC/APA bids are only required to post pre-COD security of $100/kW and post a performance bond, payment bond, and warranty bond.[93]

In any event, there is no reason provided for why the harm would be greater in the case of a delay default with a PPA as opposed to utility ownership. Indeed, given that the utility may own the underlying site and could not just terminate the contract and walk away from a project with an EPC structure, it would appear the utility's damages exposure could be even higher with an EPC. Additionally, PGE does not explain why it will not accept a bond as a form of security for PPA bids, which should be allowed if it is allowed for utility-ownership bids.

The IE explained that bidders in the 2021 RFP reduced the security amounts to around $100/kW.[94] The amounts proposed by PGE are excessive, unreasonable, and not

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91 IE's Assessment of PGE's Draft All Source RFP at 7.
92 Draft RFP, Appendix E at §§ 9.1 and 9.2.
93 Draft RFP, Appendix I at § 7.10; Draft RFP, Appendix K at 3.
94 IE's Assessment of PGE's Draft All Source RFP at 7.

market. Thus, the Commission should direct PGE to reduce the security amounts to around $100/kW to be more aligned with the market.

9. Labor Requirements

The Commission should direct PGE to clarify its labor requirements. Currently, the PPA and SCA form contracts contain requirements that the project comply with the labor requirements from Oregon House Bill ("HB") 2021.[95] Not all projects may be built in Oregon, so this requirement should be clarified with respect to apply to projects that will be built in Oregon.

While the PPA and SCA form contracts do not appear to require a Project Labor Agreement ("PLA"), the minimum bid requirements require a PLA.[96] The Commission should require PGE to clarify that a project can comply with the HB 2021 labor requirements, and similar IRA requirements for full tax credit eligibility, through a PLA or meeting other requirements. HB 2021 includes requirements that renewable energy projects over 10 megawatts in Oregon must comply with prevailing wage rates and benefits, participate in apprenticeship programs, and establish and execute a plan for outreach, recruitment, and retention of workers of women, minorities, veterans, and people with disabilities, and those requirements include one compliance pathway of relying on PLAs.[97] HB 2021 makes a PLA a compliance option, but not a requirement, for developers of renewable energy projects.

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95 Draft RFP, Appendix E at § 3.1.2 and Appendix F at § 4.1(j).
96 Draft RFP, Appendix N at 7.
97 HB 2021, Sec. 26(2), (3), 81st Or. Leg. Assembly, 2021 Reg. Sess. (codified at 2021 Or. Laws ch. 508).

Additionally, the Commission directed PGE to remove the PLA requirement in the 2021 RFP.[98] NIPPC notes this prior directive for the record in this proceeding. The Commission should direct PGE to clarify that a project can comply with the important state and federal labor requirements in the various applicable ways under those laws.

10. Carbon Emissions on Imbalance Energy

The Commission should direct PGE to remove the portion of the PPA provision that requires the bidder to pay PGE for carbon emission associated with the imbalance energy for its delivery. In the alternative, if this provision will not be deleted, then the Commission should require PGE add this cost to any utility-owned resource. Currently, the PPA requires the bidder to pay for any costs from carbon emissions related to the delivered imbalance energy.[99] This is an unreasonable cost to add to a third-party PPA bid because this cost would not be included in a utility-ownership bid. Thus, the Commission should direct PGE to remove this carbon emissions cost on imbalance energy from the PPA form contract or require PGE to add this cost to any utility-owned bids.

11. Transmission

The Commission should direct PGE to revise the PPA and SCA form contracts to match the minimum bid criteria that conditional firm transmission is allowed and include

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98 Docket No. UM 2166, Order No. 21-460 at 8-9.

99 Draft RFP, Appendix E at § 3.6 ("Additionally, Seller is responsible for and shall pay for all costs, if any, whether incurred by Seller or PGE, resulting from any carbon emissions generated by or associated with the Imbalance Energy delivered to the Delivery Point. Seller may provide PGE with carbon emissions offsets that are reasonably satisfactory to PGE in lieu of a monetary settlement.").

provisions necessary for off-system delivery. Currently, the PPA form contract only lists long-term firm point-to-point transmission service as permissible and does not reference conditional firm transmission service.[100] Also, the SCA form contract has no provisions for off-system delivery.[101] As conditional firm transmission is allowed, the PPA should be revised accordingly. Also, the SCA form contract should be revised to include provisions necessary for an off-system project. A bidder will not know what PGE's assumed provisions are for an on-system storage project and cannot accurately price the project. Thus, the Commission should direct PGE to revise the PPA form contract to note that conditional firm transmission service is allowed and revise the SCA form contract to include provisions necessary for an off-system project.

12. Force Majeure

The Commission should require PGE to revise its force majeure provisions. PGE's force majeure provision related to the unavailability of energy or bundled renewable energy certificates excludes "changes in climactic conditions" and "environmental obstructions caused by events or circumstances that may impact the Facility's generation output but without causing a Facility outage (e.g., forest fire or volcanic eruption located outside of the Facility site)".[102] These provisions are unreasonable and should be removed.

The SCA form contract also includes an exclusion from force majeure of certain "loss events" which are defined as property loss, casualty, or a condemnation event

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[100] Draft RFP, Appendix E at § 3.8.2.
[101] Draft RFP, Appendix F at Recitals.
[102] Draft RFP, Appendix E at § 4.1 and Appendix F at § 10.2.

causing the facility lose storage capacity.[103] If a loss event occurs, the bidder must pay PGE to "buy down" the list storage capacity even if it caused by a force majeure event.[104] This exclusion from force majeure is unreasonable and should be removed.

13. Step-In Rights

The Commission should direct PGE to remove the step-in rights provision in the PPA form contract. Currently, the PPA form contract includes step-in rights if PGE terminates the contract.[105] This right is unreasonable and unnecessary as PGE already has provisions in the PPA form contract for performance guarantees, liquidated damages if performance guarantees are not met, and termination damages. Thus, the Commission should direct PGE to remove the step-in rights provision.

G. Non-Disclosure Agreement

The Commission should direct PGE, at minimum, to increase the liability cap in the NDA to $2 million and increase the term of the NDA to five years, which is consistent with what the Commission ordered in PGE's 2021 RFP. To participate in the RFP, bidders will need to execute PGE's proposed NDA.[106] PGE has proposed in this RFP to lower the liability cap to $500,000 and a term of two years.[107]

In PGE's 2021 RFP, NIPPC recommended removing the cap on liability and indefinitely extending the term of the NDA.[108] NIPPC still believes these changes are

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[103] Draft RFP, Appendix F at §§ 9.1, 10.3, and "Loss Event" definition.
[104] Draft RFP, Appendix F at §§ 9.1 and 10.3.
[105] Draft RFP, Appendix E at § 9.4.
[106] Draft RFP, Appendix L.
[107] Draft RFP, Appendix L at §§ 7, 11(b).
[108] Docket No. UM 2166, NIPPC's Comments on PGE's Final Draft RFP at 27-29 (Nov. 1, 2021).

reasonable, but out of deference to the Commission, NIPPC is not seeking to relitigate its original position. Respectfully, NIPPC believes that this should not be an issue that parties need to continue to litigate. The Commission directed PGE to increase the liability cap to $2 million and extend the term of the NDA to five years.[109] In NIPPC's view, PGE should have incorporated those changes into this NDA as well. Thus, the Commission should direct PGE to increase the liability cap in the NDA to $2 million and extend the term of the NDA to five years.

H. Clarification Issues

1. NIPPC Seeks Clarification of the Required CODs

NIPPC requests PGE clarify the required COD for projects bidding into PGE's RFP. The RFP states projects must have a COD of December 31, 2025 to meet PGE's near-term 2026 capacity need, but it would accept multi-phase projects as long as all phases come online by December 31, 2026, the first phase is online by December 31, 2025, and the phases after December 31, 2025 would not count towards PGE's near-term 2026 capacity need.[110] The RFP also notes it would extend the COD for long-lead time resources.[111]

Many stakeholders had questions about the COD requirements and how the projects would be scored at the bidder workshops on May 26, 2023 and June 5, 2023. PGE provided clarification at the June 5 workshop.[112] From NIPPC's understanding,

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[109] Docket No. UM 2166, Order No. 21-460 at 6-7.
[110] Draft RFP, Appendix N at 2-3 (May 19, 2023).
[111] Draft RFP, Appendix N at 2.
[112] *See* PGE's June 5, 2023 Workshop Presentation at 3-5 (June 5, 2023).

PGE will accept any CODs prior to December 31, 2027, with the exception of long lead time resources which may select a COD of December 31, 2028. Only projects that meet the December 31, 2025 COD will be considered for PGE's near-term 2026 capacity need. Other projects with CODs from January 1, 2026 to December 31, 2027 will be considered for PGE's yearly anticipated energy needs of approximately 181 megawatts average ("MWa"). Further, all bids will be scored the same, but a project's COD will depend on which of PGE's needs the project can meet, near-term 2026 capacity or yearly energy. For scoring, a bid's price would be its cost. All bids will also receive an energy value, capacity value, and a flexibility value (batteries) that will be used to determine a bid's value. These two components make up the bid's value-to-cost evaluation, which is then scaled on a 1,000-point scale to receive a bid's price score. Bids that perform well on the price score will be placed on the initial shortlist. For final shortlist selection, PGE will use its modeling methodologies to generate optimal portfolios based on cost and risk for customers. NIPPC requests PGE please confirm this understanding is correct and update the RFP to match this understanding.

2. Permitting Requirements

At the May 26 workshop, a stakeholder asked if PGE would consider allowing a bidder to submit a permitting narrative explanation if the bidder is unable to meet the permitting requirements timeline. PGE responded it was open to this suggestion. From NIPPC's understanding, a permitting narrative explanation is already allowed.[113] NIPPC seeks confirmation from PGE that a bidder will be allowed to submit a permitting

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[113] Draft RFP, Appendix N at 3, n.4.

narrative explanation. If not, then the Commission should require PGE to accept a permitting narrative explanation if the bidder is unable to meet the permitting requirements timeline.

Allowing a narrative explanation is particularly important with the extension of the COD until December 31, 2027. It is not reasonable to require a project that is planning on delivering power in more than four years to have obtained the necessary permits.

III. CONCLUSION

NIPPC appreciates the effort that PGE has put into the preparation of its RFP and urges PGE to make revisions and provide the clarifications requested in these comments. If necessary, the Commission should direct PGE to make all changes and clarifications identified in these comments.

Dated this 16th day of June 2023.

Respectfully submitted,

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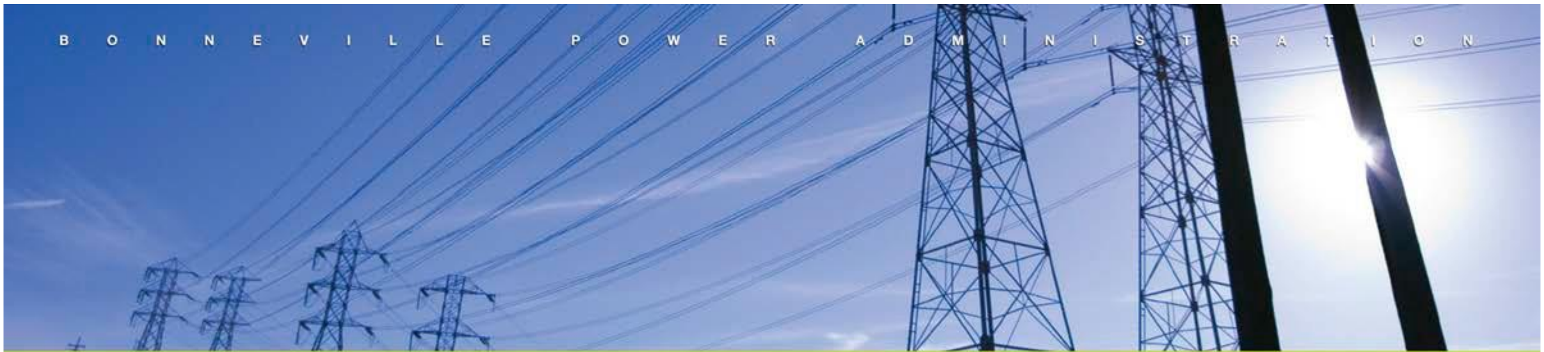
Attachment A

Bonneville Power Administration

2022 Cluster Study Report

BONNEVILLE POWER ADMINISTRATION



TRANSMISSION PLANNING

Transmission Service Request Study and Expansion Process

2022 CLUSTER STUDY REPORT

June 10, 2022

Executive Summary

On June 17, 2021, Bonneville Power Administration initiated the 2022 Transmission Service Request Study and Expansion Process (TSEP) Cluster Study (CS). BPA received 144 Transmission Service Requests (TSR) that met the eligibility requirements with an associated demand of 11,118 MW. Customers also requested a Conditional Firm Service (CFS) study for 142 TSRs totaling 10,553 MW. The CS to define the required plans of service commenced on January 3, 2022.

Using scenario-based powerflow modeling to evaluate the requests for service, BPA identified the following paths which required further examination to determine what reinforcements, if any, were needed in response:

- South of Custer;
- North of Echo Lake;
- Raver-Paul;
- South of Allston;
- Cross Cascades North;
- Cross Cascades South;
- West of Garrison.

BPA also identified the following sub-grid areas for further study to assess the need for required reinforcements in the 2022 TSEP CS:

- Mid-Columbia Area;
- Northwest Washington Area
- Portland Area;
- Central Planning Area;
- South Planning Area;
- South Oregon Coast Area.

As a result of the 2022 TSEP CS, BPA concluded:

1. Eleven (11) TSRs, totaling 1,046 MW were awardable without transmission upgrades beyond requirements identified in Small or Large Generator Interconnection Procedure studies.
2. Fifty-nine (59) TSRs, totaling 3,161 MW, could be awarded assuming that required TSEP projects and other reliability-based projects are completed as planned, and were not identified to have impacts to third-party Transmission Providers.
3. Seventy-four (74) TSRs, totaling 6,911 MW, could be awarded assuming that required BPA projects and other reliability-based projects, plus impacts to identified third-party Transmission Providers are also mitigated.
4. Ninety-six (96) TSRs were determined to be eligible for Conditional Firm Service (CFS) for a total of 5,947 MW.
5. Six (6) TSRs for a total of 461 MW do not qualify for right of first refusal (ROFR) given the length of requested service duration, and system expansion could not be accomplished prior to the requested TSR termination dates. Therefore, these requests were studied only for CFS. The study found that CFS could be offered to all of these requests, and is included in the CFS total above.

A number of requestors in the 2022 TSEP CS submitted TSRs with associated demand that, cumulatively, exceeded the total generating facility capability cited for those TSRs in the Data Exhibits. Those customers subsequently indicated to BPA that they would not pursue transmission in excess of the cited generating facility capability. As a result, upon completion of the study, customers with cumulative TSR demand in excess of the cited generation capability cannot pursue transmission service in amounts in excess of the cited generation capability (including accepted offers of CFS). Based on the information provided by customers, a total of 9,851 MW of incremental Long-Term Firm (LTF) transmission service in the 2022 TSEP CS is requested.

The analysis and findings in this report do not represent a determination to classify facilities discussed herein as network transmission facilities, interconnection facilities, or other types of facilities. BPA has determined that no direct assignment of any facilities discussed herein is required. Classifications of facilities and allocation of costs are separate determinations that are outside the scope of this report. In addition, this report provides results for the provision of transmission service only. Requirements related to the interconnection of new generating facilities are identified separately through the Large or Small Generator Interconnection Procedures. Customers may be required to complete interconnection upgrades in addition to any transmission upgrades identified in this report.

Finally, nothing in this report represents a decision by BPA to move forward with any projects at rolled-in rates or to construct any of the projects identified herein. Final decisions regarding whether to construct TSEP projects referenced herein are made outside of the CS process in subsequent phases of TSEP. Any decision to build would be made only after BPA completes required environmental review for any proposed facilities.

The following tables summarize the participants in the 2022 TSEP CS. Table 1 lists total requested demand by customer, Table 2 lists total requests by Points of Receipt (POR), and Table 3 lists total requests by Points of Delivery (POD).

Table 1: Participants in the 2022 TSEP Cluster Study

Customer	Demand (MWs)	TSR Count
Avangrid Renewables, LLC	941	17
Avista Corporation	50	1
BrightNights LLC	600	12
Cypress Creek Renewables Transmission LLC	240	5
Energy of Utah LLC	360	5
Franklin County PUD	40	1
Fremont Solar LLC	400	3
Gallatin Power Partners, LLC	440	6
Harney Solar I LLC	800	8
Innergex Renewables USA LLC	1,350	27
Invenergy Energy Management LLC	76	1
NextEra Energy Marketing LLC	664	7
Parasol Renewable Energy Holdings	300	2
Powerex Corp.	720	8
Scout Clean Energy LLC	1,270	16

Customer	Demand (MWs)	TSR Count
Seattle City Light	2	2
Shell Energy North America	100	1
TX NW I LLC	2,200	20
Umatilla Electric Cooperative	475	1
Clark Public Utilities	90	1
Total	**11,118**	**144**

Table 2: 2022 TSEP CS TSRs by Point of Receipt

Source (Evaluated Source for Newpoint)	Demand (MW)	TSR Count
BOARDMAN115GEN	166	6
BOXCNYN115	90	1
COLMBIA230CHPD	515	2
COYTSPRGS2_500	50	1
KNIGHT500	160	4
MIDWAY230MIDCR	200	4
NEWPOINT (Maupin 230)	200	4
NEWPOINT (Boardman 115)	85	2
NEWPOINT (Buckley 500)	300	2
NEWPOINT (COLUMBIAGEN500)	570	9
NEWPOINT (Coyote Springs 500)	440	6
NEWPOINT (FORT_RK_31_500)	400	3
NEWPOINT (Franklin 230)	700	7
NEWPOINT (GOLDBEACH115)	2200	20
NEWPOINT (LaPine 230)	164	2
NEWPOINT (Midway 230)	200	2
NEWPOINT (Moxee 115)	80	1
NEWPOINT (Pot Holes-Grand Coulee 230 kV)	300	3
NEWPOINT (Sickler 230)	200	2
NEWPOINT (Stateline Wind Project)	200	2
NEWPOINT (WAUTOMA 500)	1750	35
NWMRKTHUB(NWH)	1	1
PONDEROSA500	800	8
SLATT230AVRN	41	1
SLATT500	240	3
SLATT500PGE	120	2
SNOHMSH230SCLM	1	1
SPRNCRK230AVRN	125	1
USCNDNBDRCNTGS	720	8
VANTAGE230	100	1
Total	**11,118**	**144**

Table 3: 2022 TSEP CS TSRs by Points of Delivery

Sink (Evaluated Sink for Newpoint)	Demand (MW)	TSR Count
BENTONINTRCON	50	1
CLARKNTDP	90	1
CNTRLFRRY230	150	3
COVNGTN230PSEI	1,725	18
FRANKLINCNTGS	40	1
GARRISON230	820	9
MCLOUGHLIN230	80	1
MIDWAY230MIDCR	740	15
MIDWAY230PAC	520	10
NWMRKTHUB(NWH)	1	1
PEARL230	350	4
PGE_CNTGS	3,965	42
PSEI_CENTCNTGS	531	14
PSEI_STHCNTGS	200	2
REDMOND115PACW	80	1
RIVERGATE230	120	2
SEATTLECNTGSB	401	7
TOUTDL230PAC	80	1
UMATILANTDP	475	1
VANTAGE230MIDC	300	2
WHITERIVER230	400	8
Total	**11,118**	**144**

Table of Contents

1. Introduction

1.1 Purpose

Bonneville Power Administration (BPA) – Transmission Services (BPA) initiated the 2022 Transmission Service Request (TSR) Study and Expansion Process (TSEP) Cluster Study (CS) as a means of processing and offering service to customers with requests for Long-Term Firm (LTF) transmission service over the BPA Network. As part of TSEP, BPA performed a CS to determine what transmission system expansion, if any, is required to accommodate the requested service, as well as whether Conditional Firm Service (CFS) could be reliably offered to requesting customers. This report describes the results of the 2022 TSEP CS.

The technical assessments in this document are for Long-Term Firm (LTF) transmission service requests. This document does not address generation interconnection capacity or generator balancing services. The studies summarized in this report were conducted using the best available information at the time of study. Findings and recommendations are based on assumptions, which could change. BPA reserves the right to modify any content in this report as necessary.

1.2 Background

On June 17, 2021, BPA initiated the 2022 TSEP CS. BPA conducted its CS pursuant to section 19.10 and 32.6 of BPA's OATT for all eligible TSRs and forecast TSRs in the long-term firm pending queue.

The 2022 TSEP CS includes the following steps:

- BPA validated all Data Exhibit submittals that identified the location of the resource supplying the energy and capacity and the ultimate load that will receive the transmitted energy and capacity.
- During the Data Exhibit validation process, BPA worked with the customer to clarify the maximum generating facility capability that should be included in the CS assumptions. In such cases, the customer's abilities to pursue LTF transmission service are limited to the identified generating facility capability.
- BPA then offered CS Agreements (CSA) for all eligible TSRs. The CSA obligates the customer to pay for its pro-rata share of the CS.
- BPA next processed the transmission queue by removing TSRs for which customers failed to return executed CSAs. BPA then determined whether it was able to make offers of service based on existing ATC to any of the TSRs that remained in the queue.
- BPA performed a Needs Assessment to determine whether each defined path had sufficient capacity for the requests and further, if path capacity was insufficient, to determine which TSRs required additional path capacity and how much additional path capacity would be needed to enable the requested service.
- BPA then performed a CS to define what transmission expansion projects, if any, are required to accommodate service to TSRs for which there is insufficient ATC or for which sub-grid constraints exist.
- BPA also performed a CFS study of TSRs consistent with the type(s) of CFS requested by customers.
- BPA then prepared a Cluster Study Report (this document) describing the results of the CS.

2. 2022 TSEP Cluster Study Methodology for LTF Transmission Service

2.1 Introduction

BPA studied 144 new TSRs for 11,118 MW. The 2022 TSEP CS includes five fundamental elements:

1. Determine which requests could be awarded on the existing system.
2. Determine which requests could be reliably awarded Conditional Firm Service (CFS) on the existing system and the associated conditions.
3. Determine which requests require system reinforcement and on what part(s) of the transmission system, as well as which requests can be offered CFS consistent with type(s) requested by the customer.
4. Develop plans of service for requests that require system reinforcement.
5. Demonstrate that the interconnected transmission system, together with the identified reinforcements, is able to accommodate the requested service amounts for which customers indicated they wanted to have the option to execute transmission service.

2.2 Scenario-Based Needs Determination and Sub-Grid Assessment

BPA utilized scenario-based powerflow cases to determine the paths requiring additional study and possible reinforcement. The objective of the scenario-based Needs Assessment is to study a range of scenarios that adequately capture anticipated firm Network path utilization. Currently, most of the TSRs that have not been through a previous CS are comprised of variable energy resources (VER), particularly wind and solar. Wind and solar outputs have enough independence that multiple scenarios are necessary to capture the potential range of impacts due to geographic location. This section provides a high-level description of the methodology and initial scenarios that BPA used to identify paths needing plans of service for additional capacity within the 2022 TSEP CS.

Scenarios were developed based on groupings of TSRs in the long-term transmission pending queue with similarly-situated POR location and/or expected resource type, and by considering which market and weather conditions may induce the greatest firm transmission utilization from these requests on Network paths.

Analysis started with the LTF ATC powerflow base cases used in the 2021 LT ATC Base Case Update for spring, summer, and winter seasons. The scenarios were run on cases representing projected loads for up to five years in the future. New confirmed reservations granted since the 2021 LT ATC Base Case Update were also modeled.

Resource displacement was established for each scenario to maintain load/resource balance and varied between some scenarios. For thermal units in the Pacific Northwest, an approximate economic merit order dispatch was implemented using analysis of historical yearly capacity factors and Production Cost Model yearly average capacity factors to determine the frequency of thermal generation contributing to the grid. The thermal heat rates and costs of running the plants were then used to further group the generation. High cost resources are assumed to be displaced prior to low cost resources. For FCRPS hydro merit order estimation, resource displacement categorized “flexible hydro” resources based on deployment trends and existing minimum generation requirements.

Based on the BPA LTF ATC Methodology, a set of seasonal scenarios were developed to identify paths on which additional ATC would be needed to enable the requests for service in the 2022 TSEP CS. The scenarios were designed to stress all of the BPA paths with consideration of participating TSRs, as well as existing obligations.

In summary, the scenarios considered in the Needs Assessment were:

1. Summer Sunset hour, 80% of peak load, wind off, solar off
2. Summer Sunset hour, 80% of peak load, wind on, solar off
3. Summer Off-peak hour, 60% of peak load, wind on, solar off
4. Summer Peak hour, wind off, solar on
5. Summer Peak hour, wind on, solar on
6. Light Spring Night hour w/ run-off, MT wind on, NW wind and solar off
7. Winter Mid-day hour, 90% of peak load, wind on, solar on
8. Winter Peak hour, wind on, solar off

These scenarios were used to determine which BPA paths may require increased capacity. The following paths were identified in the 2022 TSEP CS Needs Assessment, with the corresponding scenario found to be most limiting:

Limiting Path Name	Limiting Scenario
South of Custer (N>S)	Summer (3)
Raver-Paul (N>S)	Summer (2)
South of Allston - BPA (N>S)	Summer (1)
Cross Cascades North (E>W)	Winter (8)
Cross Cascades South (E>W)	Summer (4)
North of Echo Lake (S>N)	Winter (7)
West of Garrison (W>E)	All Seasons

Paths not listed in this table had no capacity needs beyond plans of service currently on the path to energization, based on the conducted scenario analysis.

2.2.1 Scenario Descriptions

The following is a brief description of each scenario studied as part of the Needs Assessment, and the particular paths that the scenarios were intended to stress.

Summer Sunset Hour with No Wind

This scenario reflects an hour near sunset (around 7:00 pm) with high north-to-south flows across the BPA Network. When the sun is going down and wind is not generating, the gas fleet and flexible hydro chase high spot power prices. This aligns with an observed pattern from recent summers where the peak South of Allston flow has shifted to a later hour in the day, due to increasing solar buildout in California. Pacific Northwest load in this scenario was adjusted to 80% of the original peak value, scaling only non-fixed loads. This freed up enough spare resources to export to California, but also reduced counter flow from serving Puget Sound area loads. The magnitude of the CA solar ramp is projected to get steeper each year for the foreseeable future. Lower Snake and Lower Columbia hydro typically have less flexibility than Upper Columbia hydro due to non-power constraints. The California Oregon Intertie

(COI) and Pacific Direct Current Intertie (PDCI) could be modeled up to their full north-to-south path capacities as resource levels allowed, and higher flows on North of Hanford would be expected due to this.

The 20% reduction in Pacific Northwest loads also affected NT load values and the obligation to serve them from the FCRPS. A pro-rata reduction in the Big 10 generation equal to the decrease in NT load forecasts was performed and balanced through decreased flows to California.

This would potentially stress West of Slatt, North of Hanford, and the I-5 corridor paths.

Summer Sunset Hour with Wind
This scenario also reflects an hour near sunset (around 7:00 pm) at 80% of peak load, but with north-to-south exports to California potentially driven higher by Northwest wind generation at full contract rights. Historical analysis points to a regular occurrence of summer sunset conditions with wind generation operating over a wide range of outputs.

This would potentially stress West of Slatt, West of McNary, West of John Day, and the I-5 corridor paths, particularly Raver-Paul.

Summer Off-Peak Hour with Extra Light Load and No Renewables
This scenario represents an evening hour in early summer with no/low renewable generation online. The Northwest is buying considerable power from BC Hydro rather than using thermal generation, and is storing water when able. Exports to California are low to moderate. This scenario was built to use low loads and imports on the BC intertie as a N>S stressor and was identified using Production Cost Model analysis of peak flow hours on South of Custer.

This would potentially stress the South of Custer and Raver-Paul paths.

Summer Peak Hour with No Wind
This scenario represents a traditional peak summer afternoon when Northwest end-use demand peaks, but additional solar generation coming online serves local load and surplus power is sent to California. Solar and dispatchable resources should both be high because of peak loading and the time of day. Exports to California are more moderate. This scenario was traditionally the most limiting on the I-5 corridor prior to the recent solar buildout, where peak flow hours occurred in the afternoon rather than sunset hours.

This would potentially stress West of Slatt, West of McNary, West of John Day paths, and the I-5 corridor paths.

Summer Peak Hour with High Renewable Availability
This scenario assumes availability of both wind and solar generation during peak summer hours, offsetting the use of dispatchable resources. This would represent aggressive carbon policies and/or renewable portfolio standard requirements. Exports to California would be at moderate or high levels, as California power prices can get extremely high during peak demand.
This would potentially stress West of Slatt, West of McNary, West of John Day, and the I-5 corridor paths.

Spring Night Hour with Runoff and NW Wind OFF and MT Wind ON

In this scenario, the Northwest has surplus energy and very low spot market prices, which leads to high exports on the Northern and Southern Interties. The sun may have gone down but the Northwest has hydro oversupply and high wind generation imports from Montana. The Northwest is sending power to British Columbia on the Western interconnection of the Northern Intertie so they can store additional water, and sending low or zero cost power to California so they can capitalize on the Northwest runoff instead of utilizing thermals after sunset.

This would potentially stress the North of Hanford, West of Hatwai, West of Garrison, North of Echo Lake, West of Lower Monumental, and West of Slatt paths.

Winter Mid-Day Hour with High Renewable Availability

This scenario reflects a sunny mid-day hour during a cold snap (around 11:00 am) with exports to British Columbia Hydro. This scenario assumes British Columbia will be even colder than the Northwest and also experiencing near-peak loads. High availability of renewable resources within the Northwest provides British Columbia with the opportunity to save water for later peak hours. Pacific Northwest load in this scenario was adjusted to 90% of the original peak value. Montana is assumed to be consuming the available power from its local resources, as their winter weather is often more extreme. Imports from California are modeled until an oversupply within the Northwest occurs. This scenario aligns with peak North of Echo Lake south-to-north flows in Production Cost Model analysis.

The 10% reduction in Pacific Northwest loads also affected NT load values and the obligation to serve them from the FCRPS. A pro-rata reduction in the Big 10 generation equal to the decrease in NT load forecasts was performed and balanced through increased production at lowest-cost thermal resources.

This would potentially stress the North of Echo Lake, Cross Cascades North, and Cross Cascades South paths.

Winter Peak Hour with Wind (No Solar)

This is a high Northwest and Montana wind scenario with peak winter loads. Northwest generation is serving load centers west of the Cascades. Dispatchable resources are running high, and solar is not available.

This would potentially stress the Cross Cascades South, Cross Cascades North, West of Lower Monumental and North of Echo Lake paths.

2.2.2 Sensitivity Descriptions

The following is a brief description of sensitivities analyzed as additional stressors in the powerflow scenarios. These are modeled as additions on top of the base scenarios.

Requests from Montana

Additional sensitivity analysis cases were created for each “wind on” scenario to isolate the flow impacts on Network paths from proposed wind generation resources in Montana and North Idaho. The sensitivities include Point-to-Point (PTP) requests for Montana wind projects with a POR at Garrison that have previously been identified as needing a major reinforcement across West of Garrison, such as the Montana to Washington (M2W) project or a new 500 kV transmission line. This amounted to 500 MW of total additional imports from Montana, modeled in addition to the M2W project. Generation was displaced according to the merit order for each scenario.

Battery Discharge
In scenarios where resources with co-located energy storage are considered to be offline due to lack of wind or sunlight, a sensitivity was run to consider the impact of the batteries at a full discharge output. The battery capacity is less than the total plant output.

Boardman-Hemingway (B2H) Project
A 500 MW LTF request from the Mid-Columbia area to a Newpoint of Longhorn 500 kV substation was submitted as part of the 2021 TSEP Cluster Study. Since the Boardman-Hemingway (B2H) project would be a new 500 kV line that terminates into the proposed Longhorn substation, enabling delivery of power to the requesting customer's native load, the 500 MW TSR was included in all sensitivities where the B2H project was modeled. Sensitivities were performed for the spring and summer seasons.

Columbia Generating Station (CGS) Off
This sensitivity simulates the 1,182 MW generation at CGS being offline, due to refueling outages which occur every other year in the spring and typically last for several weeks. This sensitivity was therefore run in the spring scenario.

Intalco Load
In the extra light load off-peak summer case, the Intalco load with firm transmission service was turned offline to consider the impacts of this potential future on the South of Custer N>S path. The 403 MW of load directly interconnecting to Custer substation was disconnected and offset using the scenario's merit order resource stack.

2.2.3 Cumulative Demand Limits

To determine the amount of cumulative demand for the 2022 TSEP CS TSRs in the Needs Assessment, BPA analyzed the instances in which customers indicated a maximum TSR demand during the Data Exhibit validation process. In cases where the customer requested a cumulative TSR demand that exceeded the cited generating facility capability, BPA modeled the maximum generating facility capability at each applicable POR. The table below lists the PORs for which BPA modeled the maximum generating facility capability, despite a cumulative TSR demand that exceeded this amount.

POR Location of NEWPOINT POR – BPA Study Assumption POR	Cumulative TSR POR Demand	Determination of Maximum Generating Capability
Maupin 230 kV	400 MW	300 MW
Wautoma 500 kV	1350 MW	600 MW
Knight 500 kV	450 MW	381 MW
Ashe-Marion 500 kV line	570 MW	500 MW
McNary-Franklin 230 kV line	700 MW	350 MW

2.2.4 Determination of Cluster Study Areas

Starting with the Needs Assessment results, each path and sub-grid area was assessed individually, leveraging existing reliability studies and limits. A comparison between existing system limits, derived from existing reliability studies, and the requested capacity was then performed for each path and each sub-grid POR/POD. Where existing system capability was not adequate to accommodate the requested service, BPA identified system reinforcements, or projects, that would allow BPA to accommodate the incremental requests for service. In the instances where a new transmission project was identified, reliability studies were performed to ensure the project met the reliability needs of the system and the applicable TSRs. In addition, preliminary scope, cost estimates, and potential energization dates for new projects were also identified.

3. Cluster Study Results

The list below summarizes the TSRs in the 2022 TSEP CS according to five categories:

- Eleven (11) TSRs, totaling 1,046 MW were awardable without transmission upgrades beyond requirements identified in Small or Large Generator Interconnection Procedure studies.
- Fifty-nine (59) TSRs, totaling 3,161 MW, could be awarded assuming that required TSEP projects and other reliability-based projects are completed as planned, and were not identified to have impacts to third-party Transmission Providers.
- Seventy-four (74) TSRs, totaling 6,911 MW, could be awarded assuming that required BPA projects and other reliability-based projects, plus impacts to identified third-party Transmission Providers are also mitigated.
- Ninety-six (96) TSRs were determined to be eligible for Conditional Firm Service (CFS) for a total of 5,947 MW.
- Six (6) TSRs for a total of 461 MW do not qualify for right of first refusal (ROFR) given the length of requested service duration, and system expansion could not be accomplished prior to the requested TSR termination dates. Therefore, these requests were studied only for CFS. The study found that CFS could be offered to all of these requests, and is included in the CFS total above.

3.1 Northern Intertie & South of Custer

Background

The Northern Intertie (NI) path is the interchange between BPA and BC Hydro. The NI is further defined to delineate the western tie (NI-W) and the eastern tie (NI-E). The South of Custer (SOC) path is located in Northwest Washington. SOC is a north-to-south path that protects the northern Puget Sound Area (PSA). Major customers in the PSA include Puget Sound Energy (PSE), Seattle City Light (SCL), Snohomish PUD (SNPD), and Tacoma Power (TPU).

The Northern Intertie path is defined as:

Line	kV	Owner	Meter Point
Custer-Ingledow #1 (NI-W)	500	BPA/BCH	Custer
Custer-Ingledow #2 (NI-W)	500	BPA/BCH	Custer
Boundary-Nelway #1 (NI-E)	230	BPA/BCH	Boundary
Boundary-Waneta #1 (NI-E) , normally open	230	BPA/BCH	Boundary

The current Path Long Term (LT) TTC for NI-W is 2,530 MW in the north to south direction. According to the BPA 2022 TSEP CS Needs Assessment, existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase flows across NI-W to an expected flow of 2,850 MW.

The SOC path is defined as:

Line	kV	Owner	Meter Point
Monroe-Custer #1	500	BPA	Custer
Monroe-Custer #2	500	BPA	Custer
Bellingham-Custer #1	230	BPA	Custer
Murray-Custer #1	230	BPA	Custer

The current path LT TTC for SOC is 900 MW. According to the BPA 2022 TSEP CS Needs Assessment, existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase BPA's flows across SOC to an expected flow of 2,266 MW. Reinforcements required for earlier queued TSRs associated with prior TSEP cycles are also required for TSRs associated with this 2022 TSEP that have a non-*de minimis* impact on NI-W or SOC paths.

Assumptions

A heavy summer power flow case was used for this study, reflecting the most limiting season for the NI-W and SOC paths.

The NI and SOC paths are sensitive to the PSA generation. Local generation in the Whatcom County are particularly impactful.

A Whatcom County generation level of 220 MW is assumed for assessing limiters and requiring projects. This is a conservative assumption consistent with BPA's reliability planning assumptions. This generation assumption corresponds to either just the large Ferndale plant running (240 MW) or if that plant is not available then the two smaller Enserch and Sumas plants (220 MW total). Most of the time during moderate to high load, all three of these plants are running. High north to south flow is expected to correlate with times of high market demand, when all three of these plants would also be expected to run. Therefore, the 220 MW assumption is conservative. Lower levels of Whatcom County generation output are plausible and can cause increased stress on limiting elements, but are less likely to occur during peak transfers or peak load.

Existing Performance

The existing summer north-to-south reliability limit for SOC is 1,725 MW and 1,925 MW for NI-W due to thermal limitations which are highly sensitive to Whatcom County load and generation. Requested service cannot be met with the existing system.

Proposed Plan of Service

The proposed plan of service on the BPA transmission system is as follows:

- Expand the existing WS-RAS by adding line loss logic at Custer 230 kV, Murray 230 kV, and Bellingham 230 kV to trigger BC Hydro generation drop (up to 1,850 MW) for the limiting contingency.
- PSE 3rd Party Affected System impact notices (impacts on elements at PSE Portal Way substation). The impacts to PSE's network from these 2022 TSRs occur during extremely low Whatcom County generation output levels coinciding with high Whatcom County load levels. These impacts require resolution with PSE before service can be granted, and may require PSE affected system studies or PSE mitigations.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrated that the NI and SOC path system performance with the proposed plan of service is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

3.2 North of Echo Lake

Background
The North of Echo Lake (NOEL) path is located in Northwest Washington and is in series with the Northern Intertie (NI) path, which connects British Columbia to north Seattle. NOEL path is a south-to-north path that protects the central Puget Sound Area (PSA). Major customers in the PSA include Puget Sound Energy (PSE), Seattle City Light (SCL), Snohomish PUD (SNPD), and Tacoma Power (TPU).The Northwest Washington load service area includes the cities of Seattle and Tacoma, Washington, which include high concentrations of industrial, commercial, and residential load.

The highest flow across the NOEL path occurs during peak winter load conditions combined with high east-to-west flows on West of Cascades North (WOCN) path and high south-to-north transfers from the Pacific Northwest to the PSA and Canada.

The NOEL path is defined as:

Line	kV	Owner	Meter Point
Echo Lake-Maple Valley	500	BPA	Echo Lake
Echo Lake-Snoking-Monroe	500	BPA	Echo Lake
Covington-Maple Valley	230	BPA	Covington

The current LT TTC for NOEL is 2,800 MW. According to the BPA 2022 TSEP CS Needs Assessment, existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase BPA's flows across NOEL to an expected flow of 3,029 MW. Reinforcements required for earlier queued TSRs associated with 2021 TSEP are also required for TSRs associated with this 2022 TSEP that have a non-*de minimis* impact on NOEL path.

Assumptions
A heavy winter power flow case was used for this study, reflecting the highest utilization of the NOEL path. The NOEL path limit is sensitive to local area generation. The 2022 TSEP CS assumed a conservative PSA generation level consistent with BPA's reliability planning assumptions that would tend to stress the NOEL path.

Existing Performance
Several Puget Sound Area/Northern Intertie (PSANI) reinforcements were developed jointly between Seattle City Light, Puget Sound Energy and BPA in 2011 as a result of the Columbia Grid Puget Sound Area Study Team (PSAST). The reinforcements include:

1. BPA's 500/230 kV transformer at Raver and associated 230 kV line to Covington substation
2. Puget Sound Energy's Energize Eastside project
3. Joint BPA-Seattle City Light (SCL) Bothell-Snoking #1 and #2 230 kV transmission line upgrade
4. SCL's Broad Street 115 kV and Denny 115 kV series inductors

Since these reinforcements were required for the earlier queued TSRs associated with the 2021 TSEP, the same reinforcement is required for later queued 2022 TSEP CS TSRs that have a non-*de minimis* impact on NOEL.

Proposed Plan of Service

The requested service can be accommodated after all PSANI projects are energized. This assumes a conservative PSA generation level consistent with BPA's reliability planning assumptions.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the NOEL Path system performance, with the planned reinforcements identified by the regional Puget Sound Area Study Team in service, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

3.3 Raver-Paul

Background
The Raver-Paul (R-P) path is located in Western Washington spanning from Raver substation east of Kent, WA to Paul substation near Centralia, WA. The R-P path is inventoried in the north-to-south direction as the predominant direction of flow corresponding to the reliability limit.
The R-P path reaches maximum north-to-south flow during late spring and early summer light to moderate load hours. During this season, large quantities of hydro and wind generation can be online in the Pacific Northwest and Canada with moderate to low loads in the Pacific Northwest. Simultaneously, I-5 corridor thermal generation may be offline due to maintenance schedules or economic reasons. In the future, following the expected retirement of Centralia power plant and continued increase of renewable generation, R-P flows may reach high levels even during peak load conditions.

The R-P path is defined as:

Line	kV	Owner	Meter Point
Raver-Paul #1	500	BPA	Raver

The current R-P Path LT TTC is 1,450 MW. According to the BPA LT ATC methodology and 2022 TSEP CS Needs Assessment, existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase R-P path flow to an expected flow of 1,638 MW. Reinforcements required for earlier queued TSRs associated with 2021 TSEP are also required for TSRs associated with this 2022 TSEP that have a non-*de minimis* impact on R-P path.

Assumptions
A heavy summer power flow case with wind generation online was used for this study, reflecting the highest utilization of the R-P path.

Local generation, including the Cowlitz River generation, Grays Harbor generation, and Centralia generation can impact both the path ATC and TTC.

For purposes of the 2022 TSEP CS, the planned BPA Schultz-Wautoma 500 kV series compensation project is assumed in-service. BPA anticipates energization of this project in spring 2024.

Existing Performance
The generation pattern with the most limiting ATC consists of low output for the Cowlitz River (Mayfield and Mossy Rock) generation with Centralia thermal generation and Grays Harbor thermal generation off. Although R-P path TTC is lower with Grays Harbor and Centralia generation on, the corresponding path flow is lower to a greater degree. Therefore the most limiting ATC scenario assumes Grays Harbor and Centralia off. Based on this generation pattern requested service cannot be met with the existing system.

Reinforcements required for the earlier queued TSRs associated with the 2021 TSEP are required for later queued 2022 TSEP CS TSRs that have a non-de minimis impact on R-P. These previously identified R-P reinforcements that are not yet energized include:

- Schultz-Wautoma 500 kV Series Compensation. The projected energization date for this plan of service is spring 2024. This is a contingent project to accommodate 2020, 2021 and 2022 TSEP CS TSRs impacting the Raver-Paul path.

Proposed Plan of Service

The proposed plan of service on the BPA transmission system to rebuild approximately 53 miles of the Covington-Chehalis #1 230 kV line. The project will replace the conductor and will rebuild towers as-needed to accommodate a larger conductor.

BPA's good faith cost estimate and project schedule can be found in summary of projects in section 6.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrated that the R-P Path system performance with the proposed plan of service is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

3.4 South of Allston

Background
The South of Allston (SOA) path is located along the I-5 Corridor west of the Cascade Mountains and spans from near Alston, Oregon to Sherwood, Oregon. The main grid facilities located in this area are the Allston-Keeler and Keeler-Pearl 500 kV lines; and the Allston, Keeler, and Pearl substations. The Southwest Washington and Northwest Oregon load service areas include the cities of Portland, Oregon and Vancouver, Washington, which include high concentrations of industrial, commercial, and residential load.

The highest flow across the SOA path occurs during peak summer load conditions combined with high north-to-south transfers from Canada and high Upper Columbia hydro generation through the Northwest to the Puget Sound, Portland, and California load areas. The high north-to-south flows tend to occur due to inter-regional transfers between Canada, the Northwest, and California, or during periods of high energy demands in the Willamette Valley and California. The SOA path capacity is jointly owned by BPA, Portland General Electric (PGE) and PacifiCorp (PAC).
The path is defined as:

Line	kV	Owner	Meter Point
Keeler-Allston	500	BPA	Allston
Trojan-St. Mary's	230	PGE	Trojan
Trojan-Rivergate	230	PGE	Trojan
Ross-Lexington	230	BPA	Ross
St. Helens-Allston	115	BPA	Allston
Merwin-St. Johns	115	PACW	Merwin
Seaside-Astoria	115	PACW	Astoria
Clatsop 230/115 kV transformer	230	BPA	Clatsop

According to the BPA 2022 TSEP CS Needs Assessment, existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase BPA's share of flows across SOA in the north-to-south direction to an expected flow of 2,395 MW (Total SOA expected flow 3,256 MW). This assumes the Schultz-Wautoma 500 kV series compensation project in service. This project was identified as a requirement in the 2019 TSEP CS, and has a projected in service date of 2024. Reinforcements required for earlier queued TSRs associated with 2021 TSEP are also required for TSRs associated with this 2022 TSEP that have a non-*de minimis* impact on SOA path.

Assumptions
The 2022 TSEP CS leverages results from the past cluster studies as well as BPA's 2022 System Assessment (SA) results. For the 2022 TSEP CS, there were no significant topology changes, including new or retired generation or load interconnections for the SOA studies.

The 2022 TSEP CS verified a need for the Schultz-Wautoma 500 kV series compensation project. The project was assumed in-service for prior TSEP studies. BPA anticipates energization of the project in spring 2024.

Existing Performance
With the Schultz-Wautoma 500 kV series capacitor in-service the existing transmission commitment (ETC) across SOA is reduced by 150 MW, while the BPA share of SOA LT TTC remains at 2,115 MW. The identified BPA need is 2,395 MW, therefore the Schultz-Wautoma 500 kV series compensation project is not adequate to accommodate the 2022 TSEP CS TSRs.

Reinforcements required for the earlier queued TSRs associated with the 2021 TSEP are required for later queued 2022 TSEP CS TSRs that have a non-*de minimis* impact on SOA. These previously identified SOA reinforcements that are not yet energized include:

- Schultz-Wautoma 500 kV Series Compensation. The projected energization date for this plan of service is spring 2024. This is a contingent project to accommodate 2020, 2021 and 2022 TSEP CS TSRs impacting the SOA path.

Proposed Plan of Service
The proposed plan of service on the BPA transmission system is as follows:

- BPA will increase SOA LT TTC to 3,200 MW based on 2020 and 2021 reliability study results. This will increase BPA's allocation from 2,115 MW to 2,208 MW.
- Rebuild Ross-Rivergate #1 230 kV line to increase SOA LT TTC beyond 3,200 MW. This increase is enough to grant all 2022 TSRs across SOA.
- PGE will be an impacted 3rd Party for the Ross-Rivergate #1 230kV project, since the span and terminal equipment at Rivergate substation is owned by PGE.

BPA's good faith cost estimate and project schedule can be found in summary of projects in section 6.

System Performance with Proposed Plans of Service
The 2022 TSEP CS demonstrates that the SOA Path system performance (including the planned Schultz-Wautoma series capacitor project) is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

3.5 Cross Cascades North

Background

The West of Cascades North (WOCN) Path spans the northern Cascades Mountain range in Washington State. It connects generation hubs on the Columbia River in Eastern Washington to load centers in Puget Sound and Western Washington. It is comprised of system elements owned by BPA and Puget Sound Energy (PSE), and only primarily flows in the east-to-west direction. The Cross Cascades North (CCN) path is defined as BPA's share of WOCN. The WOCN path consists of the following transmission lines:

Line	kV	Owner	Meter Point
Chief Joseph-Monroe	500	BPA	Chief Joe
Schultz-Raver #1	500	BPA	Schultz
Schultz-Raver #3	500	BPA	Schultz
Schultz-Raver #4	500	BPA	Schultz
Schultz-Echo Lake	500	BPA	Schultz
Chief Joseph-Snohomish #3	345	BPA	Chief Joe
Chief Joseph-Snohomish #4	345	BPA	Chief Joe
Rocky Reach-Maple Valley	345	BPA	Rocky Reach
Grand Coulee-Olympia	287	BPA	Grand Coulee
Bettas Road-Covington	230	BPA	Bettas Road
Rocky Reach-Cascade	230	PSE	Rocky Reach

The winter LT TTC for CCN is currently 10,250 MW. According to the BPA 2022 TSEP CS Needs Assessment, existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase flows on CCN to an expected flow of 11,320 MW in winter. Reinforcements required for earlier queued TSRs associated with 2021 TSEP are also required for TSRs associated with this 2022 TSEP that have a non-*de minimis* impact on CCN.

Assumptions

A heavy winter power flow base case was used for this study, reflecting the highest utilization of the WOCN path. Northwest Washington area thermal generation was displaced by generation on the east side of the Cascades, using the minimum, operationally-credible generation pattern in the Puget Sound Area.

Existing Performance

The 2022 TSEP Needs Assessment indicates that not all of the TSRs can be accommodated without exceeding the CCN LT TTC. The current CCN LT TTC of 10,250 was verified by the 2022 System Assessment studies, driven by a common tower outage in a 2027 heavy winter scenario base case. The TTC is a voltage stability limit, during peak winter condition combined with low Puget Sound area generation.

Reinforcements required for the earlier queued TSRs associated with the 2021 TSEP are required for later queued 2022 TSEP CS TSRs that have a non-*de minimis* impact on CCN. These previously identified CCN reinforcements that are not yet energized include:

- Schultz-Raver #3 500 kV series capacitor addition
- Schultz-Raver #4 500 kV series capacitor addition (phase 1)

Proposed Plan of Service

BPA has identified the following project to increase capacity on CCN as part of 2022 TSEP CS:

- Schultz-Raver #3 500 kV reconductor
- Schultz-Raver #4 500 kV reconductor
- Schultz-Raver #4 500 kV series capacitor increase (phase 2)
- Olympia 230 kV SVC addition
- Paul 500 kV shunt capacitor addition
- Schultz 500 kV shunt reactor addition

BPA's good faith cost estimate and project schedule can be found in summary of projects in section 6.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrated that the CCN Path system performance with the proposed plan of service is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

3.6 Cross Cascades South

Background

Cross Cascades South (CCS) is the BPA share of the West of Cascades South (WOCS) path. WOCS capacity is jointly owned by BPA and PGE. The CCS path is an east-to-west path that transfers power from east of the Cascade Mountains to Southwest Washington, the Willamette Valley and the Oregon coast west of the Cascades Mountains. CCS path flow is primarily winter peaking when Southwest Washington and Willamette Valley loads are highest. During spring and early summer conditions, high flows on the CCS path can occur when there is surplus hydro and wind generation east of the Cascades and thermal generation in Southwest Washington and Northwest Oregon is off-line for maintenance, market conditions and other reasons.

The WOCS path consists of the following lines:

Line	kV	Owner	Meter Point
Knight-Ostrander	500	BPA	Knight
Big Eddy-Ostrander	500	BPA	Big Eddy
Ashe-Marion	230	BPA	Ashe
John Day-Marion	230	BPA	John Day
Buckley-Marion	230	BPA	Buckley
McNary-Ross	345	BPA	McNary
Big Eddy-McLoughlin	230	BPA	Big Eddy
Big Eddy-Chemawa	230	BPA	Big Eddy
Big Eddy-Troutdale	230	BPA	Big Eddy
North Bonneville-Midway	230	BPA	N. Bonneville
Jones Canyon-Santiam	230	BPA	Jones Canyon
Round Butte-Bethel	230	PGE	Round Butte

The CCS path limit can be reached if generation in Southwest Washington and Northwest Oregon (mainly along the I-5 corridor) is displaced by generation east of the Cascades. Winter is considered a critical season as the Westside load areas served by CCS are typically winter peaking. However for the purpose of this assessment, the summer was identified as a limiting seasons due to south-to-north flow patterns in the I-5 corridor.

The WOCS (CCS path plus PGE‘s Bethel – Round Butte 230 kV) path LT TTC for summer is 5,780 MW. According to BPA LT ATC methodology and the 2022 TSEP Needs Assessment, existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase WOCS flows in the east-to-west direction to an expected flow of 7,001 MW in the summer. The 2022 TSEP Needs Assessment did not show a winter limitation for CCS. Reinforcements required for earlier queued TSRs associated with 2021 TSEP are also required for TSRs associated with this 2022 TSEP that have a non-*de minimis* impact on CCS path.

Assumptions

The 2022 TSEP CS cases for CCS and Portland were based on BPA's 2022 System Assessment (SA) cases for the Willamette and SW Washington (WILSWA) region (includes Portland, Vancouver, South of Allston, and WOCS). 2022 SA cases were based on WECC-approved 2027 and 2031 heavy summer (27HS) and (31HS) base cases modified with updated topology and load forecasts. The 2022 SA cases represent best-available modeling information for planned transmission projects and load forecasts.

The TSEP CS cases were further modified to reflect existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs. Per BPA's LT ATC methodology, no additional loads were modeled beyond the forecasts provided for 2022 SA within critical load serving areas (Clark PUD, BPA, PAC or PGE). Instead, existing resources adjacent to the loads were displaced with resources associated with the new 2022 TSRs. To account for PGE's capacity on WOCS, plants at Pelton and Round Butte are dispatched at full output in the TSEP cases.

Additional CCS base case details can be found in the Portland Area sub-grid section 4.2.2.

Other resources that were reduced and offset with resources east of the Cascades, to reflect simultaneous use of TSRs across CCS and into the Portland area included:

- Clark PUD: River Road
- PAC: Merwin, Yale and Swift hydro, and Chehalis
- PSE: Mint Farm, Fredrickson
- Grays Harbor
- Centralia is retired for 2022 studies

Significant BPA transmission projects assumed in service:

- Schultz-Wautoma 500 kV series capacitor (expected energization 2024)
- Longview second 230/115 kV transformer (ISD 2021)
- Keeler 230 kV bus sectionalizing project (expected ISD 2026)
- Pearl 230 kV series bus section breaker addition (expected ISD 2027)
- Keeler 230 kV series bus section breaker addition (expected ISD 2027)
- Keeler 500 kV breaker and half bus configuration expansion (expected ISD 2027)
- Keeler 500/230 2nd transformer bank (expected ISD 2027-2029)
- Pearl-Sherwood 230 kV Reconfiguration (need date 2027), scope includes:
  - Split & retermination of Pearl-Sherwood #1 & #2 230 kV
  - PGE/BPA upgrade of Pearl-Sherwood-McLoughlin 230 kV (at least 2000 A @ 40C MOT)
  - Split & retermination of Pearl-Sherwood-McLoughlin 230, creation of new Pearl-Sherwood #3 230 kV
  - Upgrade all Pearl 230 kV terminal equipment to 3000 A @ 40 C (including CTs)

Existing Performance

The existing summer reliability limit of 5,780 MW is due to thermal limitations on the 230 kV system between BPA's Pearl substation and PGE's Sherwood substation. Existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs will increase CCS flows in the east-to-west direction to an expected flow of 7,001 MW in the summer. Requested service cannot be met with the existing system.

Many 2022 TSEP CS TSRs with impact to CCS contribute to through flow in the Portland area and as a result have multiple Portland sub-grid requirements (see Portland sub-grid section 4.2.2).

Proposed Plan of Service
The 2022 TSEP CCS plan of service will reconfigure the existing BPA Big Eddy-Chemawa 230 kV line by looping into nearby Pearl and Ostrander substations to create the following new circuits:

- Pearl-Chemawa 230 kV line, 25 miles and utilize existing conductor
- Ostrander-Pearl #2 500 kV line, rebuild 20 miles to 500 kV
- Big Eddy-Ostrander #2 500 kV line, rebuild 71 miles to 500 kV

BPA's good faith cost estimate and project schedule can be found in summary of projects in section 6.

BPA and PGE had previously identified a project to reinforce the 230 kV system between Pearl and Sherwood substations, the Pearl-Sherwood-Mcloughlin Reinforcement project, to meet load service reliability needs beyond the long term planning horizon. The need for this project is accelerated by requests for firm service in the east-to-west direction on the CCS path.

Prior TSEP studies for CCS included impacts to Pearl-Keeler. These impacts can now be found in the Portland sub-grid section 4.2.2. Additionally, 2022 TSEP CS TSRs with impact on CCS contribute to through flow in the Portland area and as a result require other upgrades (see Portland sub-grid section 4.2.2). These projects are separate from the Pearl-Sherwood-Mcloughlin reinforcement.

System Performance with Proposed Plans of Service
The 2022 TSEP CS demonstrated that the CCS Path system performance is sufficient to meet existing obligations and anticipated uses studied based on the 2022 TSEP CS TSRs.

3.7 West of Garrison (West to East)

Background

The West of Garrison (WOG) west-to-east (W>E) path consists of the lines that form the interconnection between NorthWestern Energy (NWE) in the east and lines owned by Avista and BPA in the west. The WOG path closely mirrors WECC Path 8 (Montana to the Northwest), but, consists of facilities on the west side of the path; BPA treats West of Garrison with the same rating as Path 8. The WOG W>E path capacity is allocated between Avista and BPA. BPA's currently posted LT TTC (as of May 2022) is 931 MW which corresponds to a WOG W>E capacity of 1,313 MW for the full WOG path. The West of Garrison path consists of the following lines:

Line	kV	Owner	Meter Point
Broadview - Garrison #1	500	BPA	Garrison
Broadview - Garrison #2	500	BPA	Garrison
Mill Creek - Garrison #1	230	NWE	Garrison
Mill Creek - Anaconda #1	230	BPA	Anaconda
Ovando - Garrison #1	230	NWE	Garrison
Placid Lake - Hot Springs	230	BPA	Hot Springs
Rattlesnake - Dixon	230	NWE	Rattlesnake
Rattlesnake - Garrison	230	NWE	Rattlesnake
Kerr - Kalispell #1	115	BPA	Kerr
Thompson Falls - Burke	115	NWE/AVA	Burke
Crow Creek - Burke	115	NWE/AVA	Burke

Montana has historically been an exporter of energy. The bulk grid system between Montana and the Northwest developed based on the east-to-west transfer of surplus energy from coal fired generation in Montana. Historical usage of the path has been heavily oriented toward E>W flow. West-to-east capacity across WOG has typically not shown congestion. With the retirement of coal fired generation in Montana, there is heightened usage and interest in WOG W>E in order to serve load in Montana using capacity resources in the Northwest. If additional coal fired generation in Montana also retires, there could be additional demand for WOG W>E capacity to replace that coal fired generation. The loads in Montana are winter peaking consistent with colder winter weather in Montana. WOG W>E flows would similarly be expected to occur in winter if more coal fired generation in Montana retires.

Assumptions

BPA's primary obligations on WOG W>E is for BPA's Network Integration Transmission Service (NT) customers served by transfer service by NorthWestern Energy. There are additional NT obligations in Southeast Idaho and Southern Idaho served by transfer service by PacifiCorp and Idaho Power on the Amps line (part of WECC Path 18 Montana to Idaho). BPA also has a modest amount of PTP obligations for service on WOG W>E. The table below summarizes BPA's existing obligations to provide Long Term Firm transmission service across the WOG W>E path.

Delivery	Total (MW)
BPA NT Customers in Montana	366
PTP	130
Southeast Idaho Delivery (via PacifiCorp)	80
South Idaho Delivery (via Idaho Power)	80
Total existing Obligations on WOG W>E	656

The Needs Assessment for the 2022 Cluster Study did not conduct a flow based evaluation of the West of Garrison W>E path. Rather, the Needs Assessment analyzed the existing obligations that BPA has (shown above). The Needs Assessment analysis used BPA's currently posted LT TTC for WOG W>E of 931 MW in order to make an initial assessment of how much capacity might be needed in order to accommodate the requests for service in the 2022 TSEP Cluster Study.

For the 2022 TSEP Cluster Study, BPA received the following TSRs seeking delivery at Garrison 230 kV. There were additional TSRs seeking delivery at Garrison 230 kV, but, the additional requests for service did not qualify for Right of First Refusal (ROFR). Section 5 (Conditional Firm Service study results) will address those requests for service that do not qualify for ROFR.

Customer	AREF	TSR Start Date	TSR Stop Date	Source	Sink	Demand (MW)
Powerex Corp.	93419250	1/1/2022	1/1/2028	USCNDNBDRCNTGS	GARRISON230	60
Powerex Corp.	93419251	1/1/2022	1/1/2028	USCNDNBDRCNTGS	GARRISON230	100
Powerex Corp.	93462425	1/1/2022	1/1/2027	USCNDNBDRCNTGS	GARRISON230	100
Powerex Corp.	93462431	1/1/2023	1/1/2028	USCNDNBDRCNTGS	GARRISON230	100
TOTAL						360

The existing obligations plus incremental requests for service with right of first refusal (ROFR) considered in the 2022 TSEP result in a target WOG W>E capacity requirement of at least 1016 MW, which would exceed BPA's current LT TTC of 931 MW. The study needed to identify requirements to increase the capacity by a minimum of 85 MW. Note that BPA determined that increasing W>E WOG capacity cannot be accomplished prior to termination of the TSRs that were submitted with durations not qualifying for ROFR. TSRs without RORF rights have stop dates that are fixed in time (i.e., the termination date cannot be moved out, as is the case for TSRs with ROFR rights) to allow for the period of time required to scope, permit, and construct an infrastructure expansion project.

Existing Performance

As part of BPA's 2022 System Assessment, BPA studied the West of Garrison W>E path to validate and update the LT TTC for the path. As a result of that System Assessment and in consideration of BPA's contractual arrangements, BPA's LT TTC can be increased above 1,016 MW while remaining within BPA's share of the West of Garrison capacity.

Proposed Plan of Service

For the 2022 TSEP Cluster Study, there is no plan of service necessary to provide WOG W>E capacity for 2022 TSEP TSRs with ROFR.

System Performance with Proposed Plans of Service
The 2022 TSEP CS identified that there would not be a need to reinforce the West of Garrison W>E path for the TSRs with ROFR (path expansion could not be completed prior to termination of the requested service for TSRs with durations that do not qualify for ROFR). The existing system is adequate to meet BPA's existing obligations plus the requests for service with ROFR in the 2022 TSEP CS.

4. Cluster Study Sub-Grid Area Results

All TSRs in the 2022 TSEP CS as well as relevant pending earlier queued TSRs were evaluated for sub-grid impacts. In addition to BPA Paths, several sub-grid areas were identified as having additional reliability requirements, based on the 2022 CS TSR PORs and PODs. Sub-grid areas are comprised of facilities that are not part of the monitored commercial paths. The sub-grid evaluations relied, to the maximum extent possible, on operational experience and previous studies (such as Generation Interconnection studies) to identify where reliability concerns exist. These analyses are described in the following sections.

The technical studies performed take into account the information provided by the Customers for the study of their transmission service as well as other studies conducted by BPA. Many of the requests cite potential future resources such as those in the BPA queue for Generator Interconnection service.

At the outset of the 2022 TSEP CS, there were a number of requests for transmission service that did not cite either existing generation or cited proposed resources without adequate studies in the Generator Interconnection process to inform the studies for LTF service. The studies for LTF service therefore made assumptions about the result of the Generator Interconnection process for study in the 2022 TSEP CS. The study for LTF service identified requirements based on those assumptions.

The 2022 TSEP CS does not address and is separate from requirements under Bonneville's Large Generation Interconnection Procedure (LGIP) or Small Generation Interconnection Procedure (SGIP) process. The process for requesting and securing LTF service and the process for Generator Interconnection are separate processes. There is no certainty that the assumptions used for the study of LTF transmission service will be used in the Generator Interconnection study process. For those requests where information regarding the resource that would provide the energy to support the request for transmission service was inadequate (including those requests that did not have a viable resource or had no results from the Generator Interconnection process), the 2022 TSEP CS cites a requirement for the request to complete requirements under a separate Generator Interconnection process. The Generator Interconnection process may identify technical requirements for interconnection that do not align and are in addition to the results in the LTF studies performed for the 2022 TSEP CS.

BPA conducted the studies for the 2022 TSEP CS using the best available information at the time of the study. Findings and recommendations are based on assumptions, which could change. BPA reserves the right to add, delete, or modify any content in this report. TSRs associated with the following areas received detailed sub-grid analysis.

4.1 Mid-Columbia Area

Background
The Mid-Columbia (Mid-C) load area stretches over 100 miles along the Columbia River in Central Washington, from Chelan and Douglas County in the north to Grant County in the east and Yakima County in the west. The Mid-C load area is divided into three sub-areas; west, north, and east. To the west is the Yakima County load served by PacifiCorp, and load served by BPA customers in the Ellensburg and surrounding area (load served by the Columbia-Ellensburg, Ellensburg-Moxee, and Moxee-Midway 115 kV lines). To the north is load served by Douglas (DOPD) and Chelan County PUD (CHPD). To the east is load served by Grant County PUD and a pocket of Avista load located in Central Washington connected to Chelan and Grant PUD.

4.1.1 Mid-C Area #1: North of Columbia

Background
The Mid-C North of Columbia area covers requests with PORs at and north of BPA's Columbia 230 kV substation, including Sickler 500 kV. This area also includes TSRs utilizing existing resources at DOPD Wells and CHPD Rocky Reach and Rock Island hydropower facilities.

For the 2022 TSEP CS, BPA received:
- Two TSRs for service totaling 200 MW with a POR of Sickler 500 kV
- One TSRs for service totaling 40 MW with a POR of Columbia 230 kV
- One FTSR for service totaling 475 MW representing an NT market purchase from the entire Mid-C area

Existing obligations (NT and PTP) and earlier queued TSRs prior to the 2022 TSEP potentially exceed the cited resources within the overall Mid-C area. The capability or availability of all TSRs to simultaneously acquire these resources is outside the scope of this study.

Assumptions
Two cases were used to assess the TSRs associated with Mid-C North of Columbia PORs for the 2022 TSEP CS.

- 2026 HS case: Peak summer case used for modeling generation interconnections (GI) in the Mid-C area. This case models high hydroelectric plant generation in the Upper and Mid-Columbia regions as well as BPA and foreign utility GIs in the region
- 2027 HS TSEP case: Peak summer case that models high hydroelectric plant generation in the Upper and Mid-Columbia. This case modeled 2022 TSEP CS TSRs directly at their POR.

Generator interconnection requests at Sickler 500 kV were recently studied in the interconnection process. The 2022 TSEP CS validated and relies on the results of these interconnection studies to assess the TSRs associated with generation interconnections.

The 2022 TSEP CS considered generation levels modeling existing obligations as well as 2022 TSEP CS TSRs and earlier queued pending LTF requests. The 2022 TSEP CS considered the generation levels shown in the table below:

Source	Existing TSR Obligations	Pre-2022 Requests	2022 Requests	Studied Total
Sickler 500 kV (new resource)	0 MW	0 MW	200 MW	200 MW
Mid-C North of Columbia (existing resources)	2,387 MW	0 MW	40 MW	2,427 MW
Total	**2,387 MW**	**0 MW**	**240 MW**	**2,627 MW**

Generation Assumptions

- Generation associated with the 2022 TSEP CS TSRs was modeled as follows:
  - 2026 HS study case:
    - All resources associated with the TSRs were modeled at their requested points of interconnection, including GI plans of service
  - 2027 HS TSEP study case:
    - Modeled 200 MW of new resources at Sickler 500 kV bus associated with the TSRs
- Generation interconnection requests that are earlier in BPA's Interconnection Queue but not associated with the 2022 or prior TSEP CS TSRs were not modeled.
- For existing generation, the base cases were modified to reflect generation patterns typically experienced during the studied seasons.
  - North of Columbia hydro (Wells, Rocky Reach, and Rock Island): outputs were modified to reflect TSR amounts as close as possible
  - Nameplate output was not modeled, but aggregated totals reflect plausible worst case seasonal levels during critical north-to-south flows through the Mid-C sub-grid area.

Load Assumptions

- Projected 2026 and 2027 peak summer load levels were modeled in the base cases.

Topology Assumptions

- The Columbia-Rapids 230 kV line was modeled as a sensitivity in these cases. This line was identified as a contingent facility in the interconnection studies for the TSRs associated with G0639 at the Rocky Reach 230 kV.
- The Columbia-Valhalla RAS was modeled in these cases.
- For the 2026 HS study case, applicable GI plans of service were modeled.

Existing Performance

The existing system in the 2022 TSEP CS Mid-C North of Columbia area has sufficient transmission capacity to accommodate existing LTF obligations, pending earlier queued TSRs and the 2022 TSEP CS TSRs.

Proposed Plans of Service

No new plans of service are proposed for TSRs with a POR in the 2022 TSEP CS Mid-C North of Columbia area. There are no requirements beyond the requirements identified by the generation interconnection process.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the existing Mid-C North of Columbia transmission system meets both existing obligations and requested uses of the 2022 TSEP CS TSRs.

4.1.2 Mid-C Area #2: Midway

Background

The Mid-C Midway area covers requests with PORs near Midway 230 kV substation.

For the 2022 CS, BPA received:

1. Five TSRs for service totaling 500 MW with a POR of Potholes 230 kV
2. One TSR for service totaling 80 MW with a POR of Moxee 115 kV
3. Four TSRs for service totaling 200 MW with a POR of Midway 230 kV
4. One TSR for service totaling 125 MW with a POR of Spring Creek 230 kV

Existing obligations and earlier queued TSRs prior to the 2022 TSEP include:

- 80 MW at Moxee 115 kV
- 300 MW at Spring Creek 230 kV

In addition to what is modeled for the 2022 TSEP CS Mid-C substation PORs, per customer Data Exhibit information, BPA modeled maximum generation limits to be dispatched for any given scenario at the following PORs for this study:

- 500 MW at Potholes 230 kV
- 160 MW at Moxee 115 kV
- 200 MW at Midway 230 kV
- 425 MW at Spring Creek 230 kV

Assumptions

Two cases were used to assess the TSRs associated with Mid-C Midway area for the 2022 TS CS.

- 2026 HS case: Peak summer case initially used for modeling generation interconnections (GI) in the Mid-C area. This case models high hydroelectric plant generation in the Upper and Mid-Columbia as well as BPA and foreign utility GIs in the region up to the latest GI request in the Mid-C area.
- 2027 HS: Peak summer case that models high hydroelectric plant generation in the Upper and Mid-Columbia. This case modeled 2022 TSEP CS TSRs directly at their POR.

Generator interconnection requests at Moxee 115 kV, Potholes 230 kV, and Midway 230 kV were recently studied in the interconnection process. The 2022 TSEP CS validated and relies on the results of these interconnection studies to assess the TSRs associated with generation interconnections.

The 2022 TSEP CS considered generation levels modeling existing obligations as well as 2022 TSEP CS TSRs and earlier queued pending LTF requests. The 2022 TSEP CS considered the generation levels shown in the table below:

Source	Existing Resource Modeled Output	Pre-2022 Requests	2022 Requests	Studied Total

Potholes 230 kV	0 MW	0 MW	500 MW	500 MW
Midway 230 kV	0 MW	0 MW	200 MW	200 MW
Moxee 115 kV	0 MW	80 MW	80 MW	160 MW
Spring Creek 230 kV	300 MW	0 MW	125 MW	425 MW
TOTAL	**300 MW**	**80 MW**	**905 MW**	**1,285 MW**

Generation Assumptions

- Generation associated with the 2022 TSEP CS TSRs was modeled as follows:
  - 2026 HS study case:
    - All resources associated with the TSRs were modeled at their requested points of interconnection, including GI plans of service
  - 2027 HS TSEP study case:
    - Potholes 230 kV: modeled 500 MW
      - 300 MW of new resource TSRs were modeled at a mid-point on the Potholes-Grand Coulee 230 kV line, to match the associated GI plan of service
      - 200 MW of new resource TSRs were modeled directly at Potholes 230 kV, because they did not cite an associated GI
    - Midway 230 kV: modeled 200 MW
    - Moxee 115 kV: modeled 160 MW
    - Spring Creek 230 kV: modeled 425 MW
- Generation interconnection requests that are earlier in BPA's Interconnection Queue but not associated with the 2022 TSEP CS TSRs were not modeled.
- For existing generation, the base cases were modified to reflect generation patterns typically experienced during the studied seasons.
  - GCPUD Priest Rapids & Wanapum: outputs were modified to reflect TSR amounts as close as possible, while also reflecting critical north-to-south flow conditions through the entire Mid-C sub-grid for the summer season

Load Assumptions

- Projected 2026 and 2027 peak summer load levels were modeled in the base cases.

Topology Assumptions

- The Columbia-Rapids 230 kV line was modeled as a sensitivity in these cases. This line was identified as a contingent facility in the interconnection studies for the TSRs associated with G0639 at the Rocky Reach 230 kV.
- The Columbia-Valhalla RAS was modeled in-service for these cases.
- Applicable GI plans of service for associated TSRs were modeled.

Existing Performance

The existing system in the Mid-C Midway area has sufficient transmission capacity to accommodate existing LTF obligations, pending earlier queued and the 2022 TSEP CS TSRs.

Proposed Plans of Service

No new plans of service are proposed for the 2022 TSEP CS Mid-C Midway area PORs beyond the requirements identified in the generation interconnection process.

System Performance with Proposed Plans of Service
The 2022 TSEP CS demonstrates that the existing Mid-C Midway transmission system meets both existing obligations, pending earlier queued and the 2022 TSEP CS TSRs in the Mid-C Midway area.

4.1.3 Mid-C Area #3: South of Knight

Background
The Mid-C South of Knight area covers requests with PORs at Wautoma 500 kV and Knight 500 kV substations.

For the 2022 TSEP CS, BPA received:
- Thirty five TSRs for service totaling 1000 MW with a POR of Wautoma 500 kV
- Four TSRs for service totaling 160 MW with a POR of Knight 500 kV

Existing obligations and earlier queued TSRs prior to the 2022 TSEP include:
- 450 MW at Knight 500 kV

In addition to what is modeled for the 2022 TSEP CS Mid-C North of Columbia and Mid-C Midway PORs, BPA modeled maximum generation limits to be dispatched for any given scenario for the following PORs for this study (as provided by customer Data Exhibits):
- 1000 MW at Wautoma 500 kV
- 610 MW at Knight 500 kV

Assumptions
The case below was used to assess the TSRs associated with Wautoma 500 kV and Knight 500 kV PORs in Mid-C South of Knight area for the 2022 TSEP CS.

- 2026 HS: Peak summer case used for modeling generation interconnections in the Mid-C area. This case models high North of Hanford (NOH) north-to-south flow (5200 MW) with high hydroelectric plant generation in the Upper and Mid-Columbia.

Generator interconnection requests at Wautoma 500 kV and Knight 500 kV were recently studied in the interconnection process. The 2022 TSEP CS validated and relies on the results of these interconnection studies to assess the TSRs associated with generation interconnections.

The 2022 TSEP CS considered generation levels modeling existing obligations as well as 2022 TSEP CS TSRs and earlier queued pending LTF requests. The 2022 TSEP CS considered the generation levels shown in the table below:

Source	Existing Resource Modeled Output	Pre-2022 Requests	2022 Requests	Studied Total
Wautoma 500 kV	0 MW	0 MW	1000 MW	1000 MW
Knight 500 kV	0 MW	450 MW	160 MW	610 MW

Generation Assumptions

- Generation associated with the 2022 TSEP CS TSRs was modeled as follows:
    - 610 MW at Knight
    - 1000 MW at Wautoma
- Generation interconnection requests that are earlier in BPA's Interconnection Queue but not associated with the 2022 TSEP CS TSRs were not modeled.
- For existing generation, the base cases were modified to reflect generation patterns typically experienced during the studied seasons.

Load Assumptions

- Projected 2026 peak summer load levels were modeled in the base cases.

Topology Assumptions

- Schultz-Wautoma 500 kV series capacitor (expected energization 2024)

Existing Performance

The existing system in the Mid-C South of Knight area does not have sufficient capacity to accommodate the requested TSRs. The study results show that when North of Hanford flow is high and Rock Creek generation is also high, the flows can combine to cause overloads on the Rock Creek – John Day #1 500 kV line for multiple contingencies.

Proposed Plans of Service

The proposed plan of service to mitigate Mid-C South of Knight main grid issues is to rebuild Rock Creek – John Day #1 500 kV line to higher rated conductor. The project involves a construction of new 500 kV double circuit Columbia River crossing to replace the existing single circuit Rock Creek – John Day, and will include switchgear additions at John Day 500 kV substation.

BPA's good faith cost estimate and project schedule can be found in summary of projects in section 6.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the Mid-C South of Knight area system performance, with the reinforcements described above, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.2 West Side Load Areas

4.2.1 NW WA Area

Background

The Northwest Washington (NW WA) area is served by the West of Cascades North (WOCN) path to the east, the South of Custer (SOC) path to the north, and the Raver-Paul (R-P) path to the south. It is a highly interconnected network of 500 kV, 230 kV and 115 kV facilities owned by BPA, PSE, SCL, SNPD, TPU, and other smaller municipal utilities.

For 2022 TSEP, BPA has identified WOCN path (east-to-west) as a proxy to measure reliability impacts from proposed deliveries within the NW WA sub-grid.

Assumptions

The 2022 TSEP CS cases for Puget Sound area were based on BPA's 2022 System Assessment (SA) cases for the NW WA Planning Area which includes Seattle, Tacoma, Olympia, SOC, NOEL, and WOCN. The 2022 SA cases were based on WECC-approved 2027 heavy winter (27HW) and 2031 heavy winter (31HW) base cases modified with updated topology and load forecasts. The 2022 SA cases represent best-available modeling information for planned transmission projects and load forecasts.

The 2022 TSEP CS cases were further modified to model existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs. In accordance with BPA's LT ATC methodology, no additional loads were modeled beyond the forecasts provided for the 2022 SA within impactful load serving entities (PSE, SCL, SNPD, TPU). Instead, existing resources adjacent to the loads or owned by the respective load serving entities were displaced with resources associated with the new 2022 TSRs. The following case information table shows pertinent flows. All cases assume Puget Sound Area (PSA) G0 generation pattern (PSA total output of 238 MW in winter).

There are notable differences between the 2022 TSEP Needs Assessment cases and these 2022 Puget Sound Area reliability cases. For the reliability cases, nearly all of NW WA area generation was reduced to nearly zero, in order to model use of all currently confirmed TSRs delivering to PSE's contiguous POD. For the reliability cases, the smaller hydro projects around the greater NW WA area were assumed online. The generation increased to offset NW WA reduced local generation included renewable generation east of the Cascade Mountains.

BPA has existing firm obligations to serve Seattle area load from resources outside the Seattle area which exceed the load modeled in the 2022 TSEP CS study. The 2022 TSEP CS modeled most I-5 and Seattle Area resources offline as the worst-case obligation for the existing system. This reflects a plausible scenario whereby most Seattle area load is served from these remote resource TSRs.

Resources that were reduced and offset with resources east of the Cascades, to reflect use of TSRs across CCN, NOEL and into the Seattle area included:

- PSE: Enserch, Ferndale, Fredrickson, March Point, Sumas, Whitehorn
- SCL: Diablo, Gorge, Ross
- SNPD: Jackson
- Grays Harbor

Significant BPA transmission projects assumed in service:

- Schultz-Wautoma 500 kV series capacitor (expected energization 2024)
- Covington 500/230 kV transformer banks #4 and #5 upgrade to 1300 MVA (expected energization 2026)
- Schultz-Raver #3 & #4 500kV series compensation (phase 1)

Significant non-BPA transmission projects assumed in service:

1. PSE Energize Eastside (expected energization 2023)
2. SCL PSANI projects (expected in phases, energization 2021-2023)

Existing Performance

For the 2022 TSEP CS, a review of existing TSRs with PODs in NW WA and sensitivity studies were performed to confirm if existing TSRs impact the NW WA Area. The studies show WOCN/NW WA during heavy winter peak conditions coupled with zero gen or NOEL/SOC PSA gen pattern "G0" is voltage stability limited. These limitations will be addressed by the 2022 TSEP CS Cross Cascades North (CCN) plan of service.

Proposed Plan of Service

No plan of service is required for NW WA sub-grid. Voltage stability limitations in the NW WA sub-grid during peak winter and low NW WA generation scenarios will be addressed by the CCN plan of service. The CCN plan includes new discrete and dynamic shunt reactive devices at Olympia and Paul substations.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the NW WA Area system performance, with the reinforcements described above, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.2.2 Portland Area

Background

The Portland sub-grid is served by Cross Cascades South (CCS) path to the east and South of Allston (SOA) path to the north. It is a highly interconnected network of 500 kV, 230 kV and 115 kV facilities owned by BPA, PGE, PAC and other smaller municipal utilities. PGE and PAC also operate 57 kV sub-transmission inside the Portland sub-grid. Portland is adjacent to and connected with several other BPA load areas, including Vancouver, Longview, North Oregon Coast and Salem/Albany.

For 2022 TSEP, BPA has identified one significant Portland sub-grid reliability impact: Pearl-Keeler 500 kV line flows (south-to-north). Pearl-Keeler reinforcements required for earlier queued TSRs associated with prior TSEP cycles are also required for TSRs associated with this 2022 TSEP that have a non-*de minimis* impact on Pearl-Keeler south to north flows.

Assumptions

The 2022 TSEP CS cases for CCS and Portland were based on BPA's 2022 System Assessment (SA) cases for the Willamette and SW Washington (WILSWA) region (includes Portland, Vancouver, South of Allston, and WOCS). 2022 SA cases were based on WECC-approved 2027 and 2031 heavy summer (27HS) and (31HS) base cases modified with updated topology and load forecasts. The base cases were additionally modified by adding 2022 SA identified and required projects.

The 2022 SA cases represent best-available modeling information for planned transmission projects and load forecasts.

The TSEP CS cases were further modified to reflect all existing TSRs, plus 2022 TSEP CS TSRs. Per BPA's LT ATC methodology, no additional loads were modeled beyond the forecasts provided for 2022 SA within impactful BAAs (Clark PUD, BPA, PAC or PGE). Instead, existing resources adjacent to the loads or owned by the respective BAAs were displaced with resources associated with the new 2022 TSRs. The following case information table shows pertinent flows. All cases assume PGE, PAC, PSE and Clark PUD I-5 generation is offline except for Clark owned River Road as worst case pattern for reliability checks.

2022 CCS and Portland Reliability Base Case Info

	27HS case (MW)	27HS case with Project* (MW)	31HS case (MW)	31HS case with Project* (MW)
SOA Path flows	-66	-234	335	168
WOCS Path flows	7200	7434	7200	7434
CCS Path flows	6965	7210	6975	7209
PERL->KEEL flows	1526	1745	1358	1572
OSTR->PERL flows	1424	**2290	1357	**2181
PGE BA Load	4821	4821	5192	5192
PAC PDX Load	453	453	480	480
* proposed Big Eddy-Ostrander #2 500kV line included in WOCS Path definition **combined new Ostrander-Pearl #2 500 kV with existing Ostrander-Pearl #1 500 kV				

There are notable differences between the 2022 TSEP Needs Assessment cases and these 2022 CCS/Portland reliability cases. For the Reliability cases, nearly all of PGE's "Portland Area generation" was reduced to zero, in order to model simultaneous use of all currently confirmed TSRs delivering to PGE's contiguous POD. The "PGE Portland Area Generation" includes: Beaver, Port Westward I, II, and various smaller PGE Hydro Projects around the Greater Portland Metropolitan Area. For the reliability cases, the PGE Pelton and Round Butte Hydro were assumed online, to capture PGE's transmission rights on the Round Butte-Bethel 230 kV portion of CCS. The generation increased to offset PGE's reduced generation included PGE wind and NWPP hydro project east of the Cascade Mountains.

BPA has existing firm obligations to serve Portland area load from resources outside the Portland area which exceed the load modeled in the 2022 TSEP CS. The 2022 TSEP CS modeled most I-5 and WILSWA resources offline as the worst-case obligation for the existing system. This reflects a plausible scenario whereby most Portland area load is served from these remote resource TSRs.

Resources that were reduced and offset with resources east of the Cascades, to reflect use of TSRs across CCS and into the Portland area included:

- Clark PUD: River Road
- PAC: Merwin, Yale and Swift hydro, Chehalis
- PSE: Mint Farm, Fredrickson

- Grays Harbor
- Centralia retired for these studies

Significant BPA transmission projects assumed in service:

- Schultz-Wautoma 500 kV series capacitor (expected energization 2024)
- Keeler 500/230 transformer addition (expected energization 2027-2029)
- Keeler 500 kV breaker additions (expected energization 2027)
- Keeler 230 kV bus sectionalizing breaker addition (expected energization 2026, coordinating with PGE)
- Pearl 230 kV bus sectionalizing breaker addition (expected energization 2027)
- Troutdale 230 kV bus sectionalizing breaker addition (expected energization 2025)
- Pearl-Sherwood 230 kV Reconfiguration (expected energization unknown), scope includes:
    - Split & retermination of Pearl-Sherwood #1 & #2 230 kV
    - PGE/BPA upgrade of Pearl-Sherwood-McLoughlin 230 kV (at least 2000 A @ 40C MOT)
    - Split & retermination of Pearl-Sherwood-McLoughlin 230, creation of new Pearl-Sherwood #3 230 kV
    - Upgrade all Pearl 230 kV terminal equipment to 3000 A @ 40 C (including CTs)

Significant non-BPA transmission projects assumed in service:

1. PGE Murray Hill-St. Mary's 230 kV rebuild (expected energization 2022)
2. PGE Harborton Reliability Project (expected in phases, energization 2021-2027)
3. PGE Hillsboro Reliability Project (expected in phases, energization 2022-2028)
4. PGE SE Portland-Holgate 115 kV conversion project (expected in phases, energization 2024-2029)
5. PAC St. Johns-Albina-Knott 115 kV conversion (expected energization 2025)

Existing Performance

The requested service cannot be met with the existing system. As discussed in the CCS report section, Portland sub-grid issues are exacerbated by both load service in the local area as well as by through flow.

Reinforcements required for the earlier queued TSRs associated with the 2021 TSEP are required for later queued 2022 TSEP CS TSRs with south-to-north impact across the Pearl-Keeler 500 kV in the Portland sub-grid. These previously identified reinforcements that are not yet energized include:

- Pearl-Sherwood-McLouglin 230 kV Reinforcement (joint project with PGE)

Proposed Plan of Service

The plan of service to mitigate Portland sub-grid issues and accommodate 2022 TSEP CS TSRs includes:

- PGE 3rd Party Affected System impact notices (impacts on PGE's system north of Sherwood)
- Previously identified TSEP Project: Pearl-Sherwood-McLoughlin 230 Reinforcement (P-S-M upgrade)

The additional impacts to PGE system impacts are north of Sherwood 230 kV station in the Pearl-Keeler corridor. These impacts will require resolution with PGE before service can be granted. The impacts to

PGE’s network as result of these 2022 TSEP CS TSRs are summarized in the following list.

- PGE Murray Hill-St Mary’s 230 kV
- PGE Sherwood-Murray Hill #1 & #2 230kV
- PGE Sherwood 230/115 ckt 1 transformer

A 3rd Party Affected System notice to PGE will be required for any 2022 TSEP CS TSRs with impact in the south-to-north direction across Pearl-Keeler 500kV line in order for PGE to determine acceptable mitigation(s). Third party affected system studies and coordination with PGE will be required in order to determine the plan of service necessary to grant these 2022 TSEP CS TSRs.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the Portland Area system performance, with the reinforcements described above, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.3 Central Planning Area

The Central Planning Area covers Southeast WA, South Central WA, Northeast OR, and North Central OR. Requests in the 2022 TSEP that involve the Central Planning Area include the following four sub-areas.

Tri-Cities Area Sources:

- 7 TSRs with a POR at Bofer Canyon 230 kV (planned substation on McNary-Franklin 230 kV)
- 9 TSRs with a POR at Webber Canyon 500 kV (planned substation on Ashe-Marion 500 kV)
- 2 TSRs with a POR at Ninemile Tap on the Franklin-Walla Walla 115 kV line

Central Planning Area Delivery Points:

- 3 TSRs with a POD at Central Ferry 500 kV
- 1 TSR with a POD of Franklin Contiguous
- 1 TSR with a POR of Coyote Springs 500 kV and a POD on the Avista interconnection to Benton 115 kV

Boardman Area Sources:

- 8 TSRs with a Source radial into a POR of Boardman 115 kV
- 6 TSRs with a POR at Longhorn 230 kV (new station on McNary-Coyote Springs 500 kV)
- 1 TSR with a POR of Slatt 230 kV
- 5 TSRs with a POR of Slatt 500 kV (via PGE 500 kV line to Grassland)

Umatilla Delivery Point:

- 1 FTSR with a POD of Umatilla Electric Coop (NT service forecast)

4.3.1 Central Planning Area #1: Tri-Cities Area Sources

Background

The seven TSRs with a Source at Bofer Canyon totaled 700 MW. As a result of information provided by customer Data Exhibits, BPA will limit its offers of service to 350 MW of cumulative demand for these TSRs with a Source at Bofer Canyon. Therefore, BPA modeled a maximum of 350 MW of generation interconnected on the McNary-Franklin 230 kV line for any given scenario in the study.

The nine TSRs with a Source at Webber Canyon total 570 MW. As a result of information provided by customer Data Exhibits, BPA will limit its offers of service to 500 MW of cumulative demand for these TSRs with a Source at Webber Canyon. Therefore, BPA modeled a maximum of 500 MW of generation interconnected on the Ashe-Marion 500 kV line for any given scenario in the study.

The two TSRs with a Source at Nine Mile Tap were modeled with a maximum of 200 MW.

Assumptions

WECC approved base cases were used as developed for the Central Planning Area 2022 System Assessment study.

- 2022 Light Spring
- 2030 Heavy Summer

Generation interconnection requests that may be earlier in BPA's Interconnection Queue but are not associated with 2022 TSEP CS TSRs were not modeled.

For existing generation, the base cases were modified to reflect generation patterns typically experienced during the studied seasons.

- Ice Harbor generation
  - Spring – 550 MW
  - Summer – 65 MW
- Chandler, SCBID projects
  - Spring – nameplate
  - Summer – Off

The generation interconnection at Webber Canyon is a combined project with the BPA South Tri-Cities Reinforcement which adds a Webber Canyon 500/115 kV transformer and 115 kV line to Badger Canyon. This project was also modeled in all scenarios where the Webber Canyon generation was included.

The generation interconnection at Nine Mile Tap required an additional 115 kV line from Nine Mile Tap to Sacajawea. This line was modeled in all scenarios where the Nine Mile Tap generation was included.

Existing Performance

The existing system in the Tri-Cities area, along with necessary Webber Canyon expansion referenced above, has sufficient capacity to accommodate the requested TSRs. The plans of service (including RAS) identified for the associated generation interconnections are assumed in place.

Proposed Plan of Service

No additional plan of service beyond the associated GI requirements are required for transmission service.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the Tri-Cities Area system performance, with the GI requirements identified above, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.3.2 Central Planning Area #2: Delivery Points

Background

The three TSRs with a POD at Central Ferry total 150 MW. There is no load at Central Ferry 230 kV substation. The customer is responding to a Puget Sound Energy (PSE) RFP that identifies 150 MW of transmission capacity from Central Ferry that could be “paired with” deliveries to Central Ferry.

One TSR for 40 MW requests a delivery to the Franklin PUD system. The base load modeled for Franklin PUD in the study cases is greater than the existing reserved capacity for delivery on a long-term basis plus the new TSR capacity.

One TSR for 50 MW requests delivery to Avista on the 115 kV line out of Benton.

Assumptions

The TSRs delivering to Central Ferry are assumed to displace resources at Central Ferry.

Existing Performance
The existing system did not identify any limitations with delivering to the identified PODs.

4.3.3 Central Planning Area #3: Boardman Area Sources

Background

- 5 TSRs with an existing source radial into a POR of Boardman 115 kV and redirected PODs. These TSRs had no incremental impact to the Boardman area.
- 2 TSRs with a source radial into a POR of Boardman 115 kV (Boardman – Alkali 115 kV line)
- 1 TSR with a source radial into a POR of Boardman 69 kV (Boardman – Ione 69 kV line)
- 1 TSR with a POR of Slatt 230 kV
- 5 TSRs with a POR of Slatt 500 kV (via PGE 500 kV line to Grassland)

Assumptions
A WECC approved 2026 Heavy Summer base case was developed for this study with light seasonal loading in the Boardman area. A proposed project to reterminate the Boardman – Ione 69 kV line into the planned Longhorn 230 kV network was not modeled. If and when this project moves forward the POR for 1 TSR will be moved from the Boardman 69 kV bus into the Longhorn 230 kV bus and additional transmission may be required.

Existing Performance
The existing system has capacity for 141 MW of the total 161 MW requested by 2022 TSEP CS TSRs at Boardman. For the 2 TSRs at the Boardman 115 kV POR (Boardman – Alkali 115 kV line) a thermal limitation is encountered during light summer loading in the area.

For 2022 TSEP CS TSRs at Slatt, there are no constraints on the sub-grid elements. The 500/230 kV transformer is capable of serving the 2022 TSRs on the 230kV bus, and there are no constraints on the 500 kV bus.

Proposed Plan of Service
A transmission reinforcement is required to enable the 2022 TSEP CS TSRs. Based on generator interconnection requirements, the Boardman – Alkali 115 kV conductor must be upgraded between Boardman substation and the expected location of the pending resource (9 miles from Boardman). The new conductor must have a capacity of at least 1500 A during summer hours.

System Performance with Proposed Plans of Service
The 2022 TSEP CS demonstrates that the Boardman system performance, with the required additional reinforcement, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.3.4 Central Planning Area #4: Umatilla Delivery Point

Background
One FTSR was identified in the 2022 TSEP CS for an incremental 475 MW of NT resource delivery to the Umatilla Electric Cooperative (UEC) system. This reflects a total 1825 MW of non-federal market purchases delivered to UEC.

Assumptions
A WECC approved 2026 Heavy Summer base case was developed for this study with heavy seasonal loading in the Boardman area and low levels of local generation. The proposed Longhorn 500/230 kV substation was assumed in-service, as identified in the interconnection studies.

Existing Performance
The existing BPA system has sufficient capacity to accommodate the 1825 MW of non-federal resources delivering to the UEC system assuming that system upgrades as identified in associated interconnection studies are completed.

Proposed Plan of Service
No additional plan of service is required for transmission service, beyond the associated Line and Load Interconnection requirements.

System Performance with Proposed Plans of Service
The 2022 TSEP CS demonstrates that the UEC delivery point system performance, with the reinforcements identified in the corresponding interconnection studies, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.4 South Planning Area

The South Planning Area covers Central and South Oregon. Requests in the 2022 TSEP that involve the South Planning Area include the following 3 sub-areas.

Central Oregon-South:
- 2 TSRs with a POR at Chemult 230 kV (planned substation on La Pine-Chiloquin 230 kV)
- 8 TSRs with a POR at Ponderosa 500 kV
- 3 TSRs with a POR at Fort Rock 500 kV (planned substation on the John Day-Grizzly 500 kV)

Central Oregon-Buckley:
- 2 TSRs with a POR at Buckley 500 kV

Central Oregon-Maupin:
- 4 TSRs with a POR at Maupin 230 kV

4.4.1 South Planning Area #1: Central Oregon-South

Background

For the purposes of the 2022 TSEP CS, the South Planning Area Central Oregon-South (C.OR-South) encompasses LaPine, Fort Rock, and Ponderosa stations. COR-South is defined by the Redmond Import sub-area, and includes the 115 kV system between Harney and Redmond. This area also includes the 500 kV system south of Grizzly substation extending down to the California-Oregon Border (COB).

This area is a winter load peaking area. As of April 2022, there are 283 MW of existing solar generation in the South Planning Area.

The South Planning Area covers requests with PORs at Ponderosa and La Pine. This area also covers requests with Newpoint PORs on the La Pine-Chiloquin #1 230 kV line at a location identified as Chemult 230 kV; on the Grizzly-Summer Lake #1 500 kV line at a location identified as Fort Rock 500 kV; and at Ponderosa 500 kV.

For the 2022 TSEP CS, BPA received 12 TSRs for service in the C.OR-South sub-grid totaling 1364 MW.

Source	2022 TSRs	MW Amount
Chemult 230 kV	2	164
Ponderosa 500 kV	8	800
Fort Rock 500 kV	3	400
TOTAL	**12**	**1364**

Assumptions

Existing interconnection studies associated with the identified resources were leveraged to confirm the POR limits at Ponderosa 230 kV, Ponderosa 500 kV, Chiloquin/Chemult 230 kV, La Pine 115 kV, and Fort Rock 500 kV.

The 2022 TSEP CS considered generation levels modeling existing Long Term Firm (LTF) obligations, 2022 TSEP CS TSRs, and earlier queued LTF TSRs. The 2022 TSEP CS considered the generation levels shown in the table below:

Source	Existing Obligations (MW)	Pre-2022 Requests (MW)	2022 Requests (MW)	Study Total (MW)
Ponderosa 230 kV	0	700	0	700
Ponderosa 500 kV	0	0	800	800
Chemult 230 kV (La Pine-Chiloquin)	21	0	164	185
Harney 115 kV & Brasada-Harney 115 kV line	45	0	0	45
La Pine 115 kV	92	373	0	465
Fort Rock 500 kV	0	0	400	400
TOTAL	**158**	**1073**	**1364**	**2595**

Generation Assumptions

- 2022 TSEP CS TSRs at Maupin 230 kV and Buckley 500 kV were modeled as part of the Central Oregon-South area study, however they are covered by plans of service described separately in the Central Oregon-Maupin and Central Oregon-Buckley sections:
  - Maupin 230 kV: 300 MW
  - Buckley 500 kV: 750 MW
- The study team modeled several PacifiCorp generation interconnections (GI):
  - Q0687 415.5 MW POI: PacifiCorp's Malin 500 kV substation
  - Q0721 55 MW POI: Malin – Snow Goose 230 kV transmission line
  - Q0825-Q0830 50 MW POI: Bullard 115 kV
  - Q0971 2.7 MW POI: Turkey Hill substation 12.5 kV
- For existing generation, the base cases were modified to reflect generation patterns typically experienced during the studied seasons.

Load Assumptions

- Projected 2025 peak summer and winter load levels were modeled in the base cases, as well as off peak load levels in a 2022 spring case.

Topology Assumptions

- PacifiCorp's Sam's Valley project was assumed in service in all cases.
- PacifiCorp's Malin – Snow Goose 230 kV line was replaced with Malin – Q0721 230 kV and Q0721 – Snow Goose 230 kV lines for the Q0721 GI
- The following topology changes were made based on applicable GI plans of service:
  - A Ponderosa 500 kV substation, referred to as Bonanza, was assumed in-service
  - BPA's Grizzly – Summer Lake #1 500 kV line was converted to three separate lines in series:
    - Grizzly – Ponderosa (Bonanza) #3 500 kV line
    - Ponderosa (Bonanza) – Fort Rock #3 500 kV line
    - Fort Rock – Summer Lake #3 500 kV line
  - BPA's Grizzly – Captain Jack #1 500 kV line was converted to two separate lines in series:
    - Grizzly – Ponderosa (Bonanza) #1 500 kV line

        - Ponderosa (Bonanza) – Captain Jack #1 500 kV line
    - The BPA/PAC La Pine – Chiloquin #1 230 kV line was converted into a La Pine – Chemult 230 kV and Chemult – Chiloquin 230 kV line
    - A new Ponderosa – La Pine 230 kV line was assumed in-service

Existing Performance

La Pine 115 kV

Existing LTF obligations plus pending earlier queued TSRs at La Pine 115 kV total 465 MW. The existing system sub-grid performance is sufficient provided that plans of service identified prior to the 2022 TSEP CS are met and provided associated GI requirements are met.

La Pine – Chiloquin #1 230 kV (Chemult 230 kV)

For TSRs at Chemult 230 kV the existing system has sufficient capacity to accommodate existing LTF obligations; 2022 TSEP CS TSRs; and earlier queued LTF requests, provided their associated GI requirements are met.

Ponderosa 230 kV

For TSRs at Ponderosa 230 kV, the existing system has sufficient capacity to accommodate existing LTF obligations plus pending earlier queued TSRs, provided their associated GI requirements are met.

Ponderosa (Bonanza) 500 kV

For TSRs at Ponderosa 500 kV, the existing system does not have sufficient capacity to accommodate 2022 TSEP CS TSRs.

Fort Rock 500 kV

For TSRs at Fort Rock 500 kV, the existing system does not have sufficient capacity to accommodate 2022 TSEP CS TSRs.

Proposed Plans of Service

La Pine 115 kV (Fort Rock 230 kV)

The existing system performance is sufficient provided that plans of service identified prior to the 2022 TSEP CS are met and provided associated generator interconnection requirements are met. No new plans of service have been identified for this 2022 TSEP.

La Pine – Chiloquin #1 230 kV (Chemult 230 kV)

For TSRs at Chemult 230 kV, the existing system has sufficient capacity to accommodate existing LTF obligations, 2022 TSEP CS TSRs, and earlier queued TSRs, provided their associated GI requirements are met.

Ponderosa 230 kV

For TSRs at Ponderosa 230 kV, the existing system has sufficient capacity to accommodate existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs, provided their associated GI requirements are met.

Fort Rock 500 kV and Ponderosa 500 kV

To grant transmission service to 2022 TSEP CS TSRs requesting service from Fort Rock 500 kV and from Ponderosa (Bonanza) 500 kV, transmission system reinforcements will be required. These reinforcements require a new 156 mile Ponderosa-Captain Jack 500 kV transmission line, complete with three series capacitors, a new 500/230 kV transformer at Ponderosa, and expansion of the Ponderosa and Captain Jack substation facilities.

Due to space limitations at the existing Ponderosa substation, a separate substation tentatively named “Bonanza” will be necessary to expand capacity on the local sub-grid and main grid system. GI plans of service will create a Bonanza 500 kV and 230 kV substation, however 2022 TSEP CS TSRs requesting service at the Ponderosa 500 kV POR will need to expand the Bonanza 500 kV yard and 230 kV yard.

The 500 kV expansion at Bonanza will require a new bay to accommodate a new 500/230 kV transformer and a new bay to accommodate a line terminal position for the new transmission line between Bonanza and Captain Jack.

Existing GI plans of service call for a Bonanza 230 kV yard with one 500/230 kV transformer and a 230 kV bus in breaker-and-a-half layout. The 2022 TSEP CS plan of service will require expansion of this Bonanza 230 kV yard. As part of this build, the existing BPA Ponderosa – Pilot Butte #1 230 kV line will be looped into the Bonanza 230 kV substation, creating a Pilot Butte – Bonanza #1 230 kV line and a Bonanza – Ponderosa #1 230 kV line. The Ponderosa – La Pine 230 kV line, required under GI plans of service, will also be looped into the Bonanza 230 kV substation, creating a La Pine – Bonanza #1 230 kV line and a Bonanza – Ponderosa #2 230 kV line. A second 1300 MVA 500/230 kV transformer bank will be connected between the Bonanza 500 kV and 230 kV buses.

A new 500 kV line approximately 156 miles long between Bonanza and Captain Jack will be required. This Bonanza – Captain Jack 500 kV line will require three series capacitors at the existing Sand Springs, Fort Rock, and Sycan compensation stations.

Captain Jack Substation will require expansion for the new Bonanza – Captain Jack 500 kV line terminal.

The 2022 TSEP plan of service requires the line section between Sycan and Captain Jack on the Grizzly – Captain Jack #1 500 kV line be re-sagged to a maximum operating temperature (MOT) of 100° C.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the Central Oregon-South Area system performance, with identified reinforcements, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.4.2 South Planning Area #2: Central Oregon-Buckley

Background

For the purposes of the 2022 TSEP CS, the Central Oregon-Buckley Area covers TSRs associated with interconnections at Buckley Substation. For the 2022 TSEP CS, BPA received 2 TSRs with PORs associated with interconnection at Buckley totaling 300 MW.

Source	# of TSRs	MW Amount
Buckley 500 kV	2	300

Assumptions
Existing interconnection studies associated with the identified resources were leveraged to confirm the POR limits at Buckley 500 kV.

The 2022 TSEP CS considered generation levels modeling existing Long Term Firm obligations, 2022 TSEP CS TSRs, and earlier queued LTF TSRs. The 2022 TSEP CS considered the generation levels shown in the table below:

Source	Existing Obligations (MW)	Pre-2022 Requests (MW)	2022 Requests (MW)	Study Total (MW)
Buckley 500 kV	0	450	300	750

Generation Assumptions

- 2022 TSEP CS TSRs at Maupin 230 kV and the Central Oregon-South area study are included, but covered by plans of service described in separate sections
    - Maupin 230 kV: 300 MW
    - Central Oregon South: 2595 MW
- The study team modeled several PacifiCorp GI:
    - Q0687 415.5 MW POI: PacifiCorp's Malin 500 kV substation
    - Q0721 55 MW POI: Malin – Snow Goose 230 kV transmission line
    - Q0825-Q0830 50 MW POI: Bullard 115 kV
    - Q0971 2.7 MW POI: Turkey Hill substation 12.5 kV
- For existing generation, the base cases were modified to reflect generation patterns typically experienced during the studied seasons.

Load Assumptions

- Projected 2025 peak summer and winter load levels were modeled in the base cases, as well as off peak load levels in a 2022 spring case.

Topology Assumptions

- PacifiCorp’s Sam’s Valley project was assumed in service in all cases.
- PacifiCorp’s Malin – Snow Goose 230 kV line was replaced with Malin – Q0721 230 kV and Q0721 – Snow Goose 230 kV lines for the Q0721 GI
- The following topology changes were made based on applicable GI plans of service:
    - A Ponderosa 500 kV substation, referred to as Bonanza, was assumed in-service
    - BPA’s Grizzly – Summer Lake #1 500 kV line was modified to consider proposed intervening substations:
        - Grizzly – Ponderosa (Bonanza) #3 500 kV line
        - Ponderosa (Bonanza) – Fort Rock (Obsidian) #3 500 kV line
        - Fort Rock (Obsidian) – Summer Lake #3 500 kV line

- BPA's Grizzly – Captain Jack #1 500 kV line was modified to consider the proposed Bonanza substation:
  - Grizzly – Ponderosa (Bonanza) #1 500 kV line
  - Ponderosa (Bonanza) – Captain Jack #1 500 kV line
- The BPA/PAC La Pine – Chiloquin #1 230 kV line was converted into a La Pine – Chemult 230 kV and Chemult – Chiloquin 230 kV line
- A Ponderosa – La Pine 230 kV line was assumed in-service

Existing Performance
Existing LTF obligations plus pending earlier queued TSRs at Buckley 500 kV total 750 MW. The existing system sub-grid performance is sufficient provided that plans of service identified prior to the 2022 TSEP CS are met and provided associated GI requirements are met.

Proposed Plans of Service
For TSRs at Buckley 500 kV, the existing system has sufficient capacity to accommodate existing LTF obligations, 2022 TSEP CS TSRs, and earlier queued TSRs, provided their associated GI requirements are met.

System Performance with Proposed Plans of Service
The 2022 TSEP CS demonstrates that the Central Oregon-Buckley Area system performance, with identified reinforcements, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS.

4.4.3 South Planning Area #3: Central Oregon-Maupin

Background
For the purposes of the 2022 TSEP Cluster Study, Central Oregon-Maupin area includes BPA's Big Eddy-Redmond #1 230 kV line. The 97 mile Big Eddy-Redmond #1 230 kV line is looped in to BPA's Maupin Substation, approximately 29 miles south of Big Eddy.

For the 2022 TSEP CS, BPA received the following number of TSRs:

Source	Number of TSRs	TSR Cumulative Demand MW amount
Maupin 230 kV	4	100

Based on information provided by the customer during Data Exhibit validation, the following table shows the total generation to be dispatched for any given scenario as modeled for this study which corresponds to cumulative TSR demand, including existing obligations, pending requests prior to the 2022 TSEP CS, and requests in the 2022 TSEP CS:

Source	Cumulative Demand (MW)
Maupin 230 kV	300

Assumptions
Existing interconnection studies associated with the identified resources were leveraged to confirm the

POR limits Maupin 230 kV.

The 2022 TSEP CS considered generation levels modeling existing obligations, 2022 TSEP CS TSRs, and earlier queued pending LTF requests. The 2021 TSEP CS considered the generation levels shown in the table below:

Source	Existing Obligations (MW)	Pre-2022 Requests (MW)	2022 Requests (MW)	Study Total (MW)
Maupin 69 kV	20	0	0	20
Maupin 230 kV	60	140	100	300
Total	**80**	**140**	**100**	**320**

Generation Assumptions

- Generation was modeled according to the table in the Assumptions section above.
- For existing generation, the base cases were modified to stress the California-Oregon Intertie (COI) path north-to-south and West of Slatt path east-to-west to their respective TTCs:
  - Jones Canyon wind generation
    - Summer – 430 MW
  - PGE Coyote Springs
    - Summer – 492 MW
  - PGE Carty
    - Summer – 320 MW
  - Slatt wind generation
    - Summer – 1200 MW
    - An additional 1270 MW generator was added at Slatt to stress the West of Slatt path to its east-to-west TTC.
  - Lower Columbia River
    - John Day – 1000 MW
    - The Dalles – 1150 MW
    - McNary – 780 MW

Load Assumptions

- Projected 2026 summer load levels were modeled in the base cases.

Topology Assumptions

- BPA's Schultz-Wautoma 500 kV series capacitor is assumed completed. Expected in-service date is spring 2024.

Existing Performance

The existing system has sufficient capacity to accommodate existing LTF obligations plus the 2022 TSEP CS TSRs plus pending earlier queued TSRs. While the 2022 TSEP did not identify any reinforcements to accommodate the requested service, BPA notes that there are no corresponding interconnection studies that support 300 MW output from the identified resource for the 2022 TSEP CS TSRs. The GI study associated with Maupin 230 kV identified a 200 MW limit to the output of the identified resource. An updated generation interconnection study will be required to confirm that 300

MW can be interconnected and dispatched to 300 MW at Maupin 230 kV. The results of that updated interconnection may identify additional requirements for interconnection of 300 MW.

Proposed Plans of Service
Accounting for the cumulative demand total generation capability of 300 MW, there are no plan of service requirements to grant the requested transmission service.

While the 2022 TSEP did not identify any reinforcements to accommodate the requested service, BPA notes that there are no corresponding interconnection studies that support 300 MW output from the identified resource for the 2022 TSEP CS TSRs. The generation interconnection (GI) study associated with Maupin 230 kV GIs identified a 200 MW limit to the output of the identified resource. An updated or new generation interconnection study will be required to confirm that resources can be interconnected and dispatched up to 300 MW at Maupin 230 kV. The results of that updated interconnection study may identify additional requirements for interconnection of 300 MW.

System Performance with Proposed Plans of Service
The 2022 TSEP CS demonstrates that the Central Oregon-Maupin Area system performance is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS. Additional interconnection requirements may result from subsequent interconnection studies to support the full output of 300 MW from the resource identified by the requestor.

4.5 South Oregon Coast Area

Background
For the purposes of the 2022 TSEP CS, the South Oregon Coast area is defined by the following lines: Alvey-Fairview #1 230 kV, Dixonville-Reston #1 230 kV, Lane-Wendson #1 115 kV, Lane-Wendson #2 230 kV, and Toledo-Wendson #1 230 kV. There are currently no generation facilities in this area; the nearest generation facilities are located in the adjacent Eugene and Salem/Albany load areas.

For the 2022 TSEP CS, BPA received 4 sets of TSRs for service in the South Oregon Coast area totaling 2,200 MW. None of these TSRs cited a pending resource from BPA's or any other GI queue in their TSR data exhibits.

2022 TSR Sources	Study Total (MW)
Fairview 230 kV	300
Fairview-Rogue 230 kV (Port Orford)	300
Rogue 115 kV	400
Rogue 230 kV	1,200
TOTAL	**2,200**

Assumptions
WECC approved base cases were modified for the 2022 TSEP CS with the latest available information for Western Oregon were considered including the Willamette and SW Washington (WILSWA) region (includes Portland, Vancouver, South of Allston, and WOCS) and the Southwest Oregon Planning region (includes Salem/Albany, Eugene, and South Oregon Coast). The following base cases were used to analyze critical scenarios:

- 2027 Heavy Summer
- 2031 Heavy Summer

Generation Assumptions

- WOCS path flow was modeled at 6,950 MW prior to TSEP upgrades
- Eugene and Salem/Albany generation was modeled for typical summer conditions.

Load Assumptions

- The most limiting condition for this area is during light summer load conditions. Load levels corresponding to forecasts for years 2027 and 2031 were analyzed both for peak and off peak load levels.

Topology Assumptions

- No significant topology differences from the existing system in the Southwest Oregon Planning Region were modeled.
- The impacts resulting from the 2022 TSEP CS CCS reinforcement were considered for the study as a sensitivity. See the Cross Cascades South section for details on the Big Eddy-Chemawa 500kV rebuild and reconfiguration project.

Existing Performance
The existing system has insufficient capacity to accommodate all the 2022 TSEP CS TSRs. The South Oregon Coast currently has no generation facilities modeled and the 2,200 MW generation exceeds what the South Oregon Coast area sub-grid is capable of exporting. The first 2 TSRs at Rogue 115 kV (totaling 80 MW) can be offered service without any South Oregon Coast sub-grid transmission reinforcements

Proposed Plans of Service
Transmission system reinforcements will be required to grant transmission service to 2022 TSEP CS TSRs requesting service at the Rogue 115 kV, Rogue 230 kV, Rogue-Fairview #2 230 kV, and Fairview 230 kV PORs. BPA will require new 500 kV line additions to connect the TSRs to BPA's existing 500 kV backbone system along the I-5 corridor. The scope includes a new Rogue 500/230/115 kV substation, a new Fairview 500/230 kV substation, expansions at existing Lane 500 kV substation, and expansions at existing Alvey 500 kV substation. New 500 kV transmission lines will connect the Alvey 500 kV and Lane 500 kV substations to the new Fairview 500 kV substation; and new 500 kV lines will connect the new Fairview 500 kV substation to the new Rogue 500 kV substation. Finally, sub-grid reinforcements to 230 kV elements in the Eugene and Salem/Albany area will also be required.

BPA's good faith cost estimate and project schedule can be found in summary of projects in section 6. A more detailed description of the overall project scope is described below.

New 500 kV Transmission lines

These reinforcements require a new 97 mile long 500 kV transmission line from Alvey 500 kV to the new Fairview 500 kV, a new 100 mile long 500 kV transmission line from Lane 500 kV to the new Fairview 500 kV, and a new 65 mile long 500 kV double circuit transmission line between the new Fairview 500 kV and the new Rogue 500 kV substations. The new lines are:

- Fairview-Rogue #3 500 kV line
- Fairview-Rogue #4 500 kV line
- Alvey-Fairview #2 500 kV line
- Lane-Fairview #1 500 kV line

New 500 kV/230 kV/115 kV Substations: Fairview & Rogue

The new proposed 500/230 kV substation near Fairview will be electrically separate from the existing Fairview substation. The 500 kV switchyard will be a breaker and a half configuration to add line terminations for the Alvey-Fairview #3 500 kV, new Lane-Fairview #1 500 kV line, new Rogue-Fairview #3 and #4 500 kV lines, a new 500/230 kV transformer bank, and a 500 kV bus terminated shunt reactor. The 230 kV switchyard will be breaker and a half configuration to facilitate two line terminals for the TSR generation interconnections.

The new proposed 500/230/115 kV substation near Rogue will be electrically separate from the existing Rogue substation. The 500 kV switchyard will be a breaker and a half configuration to add a line terminations for the new Fairview-Rogue 500 kV #3 and #4 lines, a new 500/230 kV transformer bank, a new 500/115 kV transformer bank, and a 500 kV bus terminated shunt reactor.

The 230 kV switchyard will be a breaker and a half configuration to facilitate two line terminals for the TSR generation interconnections. The 115 kV switchyard will be a breaker and a half configuration to facilitate a line terminal position for a generation interconnection.

Existing 500 kV Substation Expansion: Alvey & Lane

The 500 kV expansion at Alvey will require one new line terminal position and associated 500 kV switchgear, to accommodate the new transmission line between Alvey and Fairview and a new shunt reactor. The 500 kV expansion at Lane will require one new line terminal position and associated 500 kV switchgear, to accommodate a line terminal position for the new line between Lane and Fairview and a new shunt reactor.

Other Required Upgrades: Eugene and Salem/Albany sub-grid

- PGE Santiam-Bethel #1 230 kV:
  Rating increase to at least 1,970 A (summer) is required. This line is approximately 20.5 miles in length, and the limiting segment is approximately 3.6 miles of 795 ACSR conductor. The limiting segments are owned by Portland General Electric. Requestors will be required to work with PGE as an Affected System to address the impacts to PGE system and confirm the project requirements to mitigate those impacts.

- BPA Santiam-Chemawa #1 230 kV:
  A rating increase to at least 1,970 A (summer) is required. This line is approximately 24.4 miles in length and the limiting segment is approximately 7.4 miles of 795 ACSR Drake.

- Santiam series bus sectionalizing breaker 230 kV:
  An additional bus sectionalizing breaker is required to mitigate the impact of losing both Santiam buses with the addition of the requested transmission service.

System Performance with Proposed Plans of Service

The 2022 TSEP CS demonstrates that the South Oregon Coast Area system performance, with identified reinforcements, is sufficient to meet existing obligations and anticipated uses considered in the 2022 TSEP CS. Only two of the TSRs at Rogue 115 kV with total of 80 MW can be offered service without South Oregon Coast sub-grid system reinforcements.

5. Summary Results for Conditional Firm Transmission Service

The 2022 TSEP CS included the customer option to request a Conditional Firm Service (CFS) study for System Conditions and Number of Hours CFS. Customers requested a CFS study for 142 TSRs that participated in the 2022 TSEP CS totaling 10,553 MW of TSR demand. Three categories delineate the CFS study requests:

1. One hundred and six (106) TSRs were studied for both Number of Hours and System Conditions totaling 8,126 MW of demand;

2. Eighteen (18) TSRs were studied for only Number of Hours totaling 1,041 MW of TSR demand;

3. Eighteen (18) TSR were studied for only System Conditions totaling 1,386 MW of TSR demand.

5.1 Conditional Firm Service Study Findings

BPA studied 142 PTP TSRs for 10,553 MW for Conditional Firm Service (NT requests are ineligible to request study of CFS service). This included 9,167 MW of requested study for Number of Hours CFS and 9,512 MW of requested study for System Conditions CFS. Note that 8,126 MW requested to be studied for both types of CFS service.

In 2022, BPA's analysis of CFS capability shifted to a fully studied approach. Unlike previous years, no utilization of CFS inventory methodology is involved in CFS capability assessment for the TSRs requesting study of CFS in the 2022 TSEP CS. This enables BPA to take a more specific and precise determination of CFS capability and conditions.

The study found that there was sufficient CFS capability on BPA's managed transmission system paths to reliably offer CFS service to all eligible TSRs in the 2022 TSEP study. Since there is no longer a pre-defined point beyond which BPA stops offering CFS on a path, the assumption BPA has sufficient capability to offer additional CFS was based on a variety of factors, such as: a historically low level of curtailments of 6-NN service, the overall capability to incorporate risk-informed criteria into the assessment of the system, or other varying features pertinent to the operation of any particular path. This finding does not include evaluation of external interconnections and sub-grid areas which are further discussed below.

Number of Hours offers were calculated using risk-informed metrics, and were primarily based on data from two sources: historical performance of the system, and maximum flows from Needs Assessment commercial powerflow studies. Powerflow studies supply an estimate of increased flows on the BPA transmission system driven directly by TSRs in the 2022 TSEP CS, and these estimates were used to inflate historical flows as a projection of potential maximum utilization. The projection was translated into a number of hours of potential risk of congestion driven by 2022 TSEP CS TSRs. Risk was built into the calculations through multiple assumptions, such as use of reduced path limits than would trigger curtailments, and assuming all requests will remain in the queue following the completion of the 2022 TSEP CS. A number of hours offer for each individual path with constraints was initially calculated using this methodology. Each combination of multiple path requirements observed within the 2022 TSEP CS was then analyzed for an overlap in the drivers behind peak flows. This led to a determination of whether an overall number of hours offer would be the sum of all applicable individual path offers, or if an overlap in drivers allowed for a reduction in the total number of hours.

5.1.1 New Path: South of Knight

This path is relevant to TSRs with a Source at either Knight 500 or Wautoma 500 impacting Rock Creek-John Day 500 kV. BPA currently does not have a path to manage flow on these facilities of its transmission system. However, BPA has determined that it can add a path referred to here as South of Knight. This would enable reliable offers of CFS, and BPA will do so if one or more TSRs requiring such path executes a contract for CFS service. The start date for CFS service for such TSRs would be dependent upon the timeline for implementation of this new managed path. However, because BPA does not currently have a South of Knight path, such CFS offers can only be made on a System Conditions basis at this time due to a lack of TTC on which to base determination of Number of Hours and associated congestion data. As a result, BPA does not possess the information required to determine a reasonable Number of Hours value necessary to sufficiently protect existing long-term firm reservations associated with the South of Knight path.

5.1.2 Portland Area Local Constraints

The Portland sub-grid area is becoming more congested. This trend has been observed for a number of years, and continues to be in evidence in the 2022 study cases. Specifically, south-to-north flow on Pearl-Keeler is continuing to increase in the study models. As a result, BPA notes that additional means of managing flows in the Portland sub-grid may be needed at some point in the future. Due to these findings, BPA will continue to offer CFS for TSRs that impact the Pearl-Keeler facilities and will currently utilize West of Cascades South path to manage that CFS. However, BPA reserves the right to add CFS conditions associated with any future new paths that BPA implements to manage CFS on the constraints identified in the Portland sub-grid associated with these study findings. BPA does not have the ability to offer a Number of Hours CFS for these TSRs currently, because those paths have not yet been identified, do not have path TTCs, and do not have congestion frequency data.

As a result, BPA will only offer CFS to TSRs impacting the greater Portland area (either as a sink or due to flow-through impacts) on a System Conditions basis. Associated with that, such CFS offers will, while they will continue to currently be managed using West of Cascades South, also contain the right for BPA to manage such CFS service utilizing any new paths that BPA identifies the need to implement in the future.

5.1.3 CFS Study Outcomes with New Path

With the addition of the South of Knight path if needed, and a determination of continued CFS eligibility for TSRs that impact facilities in the Portland metro area, along with evaluation of sub-grid impacts for all TSRs in the 2022 TSEP CS, BPA has determined that 96 TSRs totaling 5,947 MW of TSR demand are eligible for CFS. Of these studied findings, BPA is found that 22 TSRs are eligible for a total of 1,191 MW of Number of Hours or System Conditions CFS and 74 TSRs are eligible only for a total of 4,756 MW of System Conditions CFS service.

5.1.4 West of Garrison W>E

BPA studied the ability to reliably provide CFS on its share of the West of Garrison capacity W>E[1]. Because there was system capacity for all of the TSRs impacting WOG W>E that have terms which qualify for ROFR, this analysis was limited to TSRs that do not have ROFR rights. That analysis included examination of historical flows, historical use of BPA LTF transmission reservations over that path, historical use of all schedules (LTF, STF, and non-firm) over that path, and prospective modeling of flows and schedules with these additional 2022 TSEP CS transactions. BPA also examined the tools currently available to managed CFS over West of Garrison W>E. This analysis found that there is sufficient unutilized capacity on BPA's share of the West of Garrison W>E to reliably offer CFS to the TSRs requiring that capacity in the 2022 TSEP CS. However, commercial transactions between areas are a significant driver of the utilization of this path, which is managed using a one-for-one methodology. Therefore, BPA will only offer System Conditions CFS due to the difficulty in accurately estimating a Number of Hours associated with CFS for this path. This allows BPA to assure that Firm reservations will not be negatively impacted by the offer of CFS due to under-estimation of the number of hours of curtailment that may be needed on this path under some commercial conditions. Further,

[1] The Study evaluated requested transmission service on BPA's transmission network sinking at Garrison 230 kV, and did not consider or evaluate impacts related to transmission on BPA's double circuit 500 kV system east of Garrison 230 kV. Transmission service beyond BPA's network east of Garrison 230 kV will require a separate, additional transmission arrangement.

BPA determined that the tools are in place to reliably manage CFS on WOG W>E on a System Conditions basis.

5.1.5 Northern Intertie N>S

BPA studied its ability to reliably provide CFS on its share of the Northern Intertie N>S. That analysis included examination of historical flows, historical use of BPA LTF transmission reservations over that path, historical use of all schedules (LTF, STF, and non-firm) over that path and prospective modeling of flows and schedules with these additional transmission. BPA also examined the tools currently available to manage CFS over Northern Intertie N>S. This analysis found that there is sufficient unutilized capacity on BPA's share of the Northern Intertie N>S to reliably offer CFS to the TSRs requiring that capacity in the 2022 TSEP. However, commercial transactions between areas are a significant driver of the utilization of this path which is managed using a 1:1 inventory methodology. Therefore, BPA will only offer System Conditions CFS due to the difficulty in accurately estimating a Number of Hours associated with CFS for this path. This allows BPA to assure that Firm reservations will not be negatively impacted by the offer of conditional firm service due to under-estimation of the number of hours of curtailment that may be needed on this path under some commercial conditions.

5.1.6 Areas Ineligible for CFS

Thirty six (36) TSRs totaling 4,035 MW of TSR demand are currently ineligible for CFS due to one or more of the issues described below. TSRs that remain active in BPA's transmission queue by taking the steps necessary to pursue LTF service will be periodically re-evaluated to determine whether the circumstances causing ineligibility for CFS have been ameliorated.

- Potential Third-Party impacts to Northwest AC Intertie (NWACI) Capacity and Facility Owners. BPA is currently unable to provide CFS to TSRs that have a potential impact on NWACI Capacity and Facility Owners. Pending the outcome of a third-party evaluation from the NWACI Capacity and Facility owners, BPA may determine whether these TSRs are eligible and will periodically reevaluate whether CFS can be provided reliably.

- Potential Third-Party impacts on PAC's South Oregon 230 kV Network system BPA is currently unable to provide CFS to TSRs that have a potential impact on PAC's South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey. Pending the outcome of a third-party evaluation from PAC, BPA may determine whether these TSRs are eligible and will periodically reevaluate whether CFS can be provided reliably.

- BPA is currently unable to provide more than 80 MW of CFS to TSRs with a Source studied at Gold Beach (which includes TSRs for which the data exhibit referenced Rogue 115, Rogue 230, Fairview 230 (FAVW), Fairview-Rogue at Fairview 230, Fairview-Rogue (Rogue Sub vicinity 230), Fairview-Rogue 230 in Port Orford vicinity, etc.) above levels enabled by current local infrastructure. There is insufficient capacity in the local area to flow more than 80 MW of CFS. Section 4.5 of this report contains more information on the South Oregon Coast sub-grid area.

- Central Oregon South Sub-grid Plan of Service – The transmission system in the Central Oregon area is electrically complex and BPA does not have the ability to reliably manage CFS for TSRs sourcing in the Central Oregon area at this time. Further, while the additional of new paths are under consideration for this area, those paths will not provide the ability to reliably manage CFS for TSRs sourcing in this area. Finally, BPA is unable to make a determination at this time that the potential third-party transmission provider impacts which can be managed on BPA's transmission facilities without impacting the third party transmission provider. Such a determination would be required prior to offer of CFS for these TSRs.

- Boardman 115 Source Sub-grid – Requests for new service at Boardman 115 are not eligible for CFS. The local facilities do not have capacity for CFS, and there is no way to currently manage CFS. Further, CFS requiring this plan of service cannot be appropriately managed in the local area. Redirect requests that currently have service sourcing from Boardman do not require CFS in the Boardman sub-grid area, because they were already granted LT Firm service in a prior TSEP cluster study.

- Unspecified source generation in the data exhibit can prohibit BPA's ability to fully assess the flow impacts of a TSR (particularly in the local POR area) and therefore may result in a determination of ineligibility of the TSR for CFS. Submission of associated GI for the TSR and maturation or completion of the study can allow for subsequent reassessment of CFS capability. Determination of eligibility and associated conditions would be made at the time of availability of that information and subsequent study cycle.

5.2 Number of Hours or System Conditions for CFS Eligible TSRs

Based on the study results, CFS Number of Hours and System Conditions capabilities on BPA's network path are defined in the table below. Customers with NEWPOINT TSRs are required to take certain conformance actions consistent with BPA's Requesting Transmission Service Business Practice.

Conditional Firm Service Options by Path/Path Combination		
Path/Path Combination	**Number of Conditional Curtailment Hours per year**[1]	**System Condition – When real-time analysis identifies curtailment on the paths below to mitigate transmission constraints**[2]
Cross Cascades North	33	Cross Cascades North E>W
Cross Cascades North, and Cross Cascades South	154	Cost Cascades North E>W path or the Cross Cascades South E>W
Cross Cascades North, Cross Cascades South, and North of Echo Lake	218	Cross Cascades North E>W, Cross Cascades South E>W, and North of Echo Lake S>N
Cross Cascades North, Cross Cascades South, and Raver-Paul	177	Cross Cascades North E>W, Cross Cascades South E>W, and Raver-Paul N>S
Cross Cascades North, Cross Cascades South, and South of Allston	224	Cross Cascades North E>W, Cross Cascades South E>W, and South of Allston N>S
Cross Cascades North, Cross Cascades South, Raver-Paul, and South of Allston	247	Cross Cascades North E>W, Cross Cascades South E>W, Raver-Paul N>S, and South of Allston N>S
Cross Cascades South and	191	Cross Cascades South E>W and

Conditional Firm Service Options by Path/Path Combination

Path/Path Combination	Number of Conditional Curtailment Hours per year[1]	System Condition – When real-time analysis identifies curtailment on the paths below to mitigate transmission constraints[2]
South of Allston		South of Allston N>S
Cross Cascades North and North of Echo Lake	97	Cross Cascades North E>W and North of Echo Lake S>N
South of Allston and South of Custer	156	South of Allston N>S and South of Custer N>S
South of Custer	156	South of Custer N>S
Pearl-Keeler	Cannot be determined at this time due to lack of existing path.	Pearl-Keeler S>N (Note this may be in combination with other CFS paths).
South of Knight	Cannot be determined at this time due to lack of existing path.	South of Knight N>S (Note this may be in combination with other CFS paths).
West of Garrison	N/A - Cannot be forecasted sufficiently due to commercial nature of path utilization and changing generation levels	West of Garrison W>E (Note – this may be in combination with other CFS paths).
Northern Intertie	N/A - Cannot be forecasted sufficiently due to commercial nature of path utilization	Northern Intertie N>S Note – this may be in combination with other CFS paths).

[1] TSRs eligible for a Number of Hours CFS offer that is CFS on more than one path may or may not be subject to an additive number of hours for the multiple paths, depending on the relationship of conditions causing likelihood of curtailment on the relevant paths.

[2]TSRs requiring System Condition CFS on more than one path may be subject to conditional curtailment any time the System Condition defined in the table occurs on the CFS path(s) to which the TSR is subject.

The Conditional Firm Transmission Service Business Practice contains more information about the operational attributes of CFS.

6. Conclusion: Plan of Service Summary Results

The following table lists the reinforcements identified in the 2022 TSEP CS, the associated estimate of a good-faith, non-binding direct costs and an estimated energization date for each project. The table summarizes system reinforcement projects on the BPA Transmission System that would be required to accommodate one or more of the 2022 TSEP CS TSRs. The estimated direct project costs do not include overhead loadings. These cost estimates are made prior to project scoping activities. More refined cost estimates are developed in the Preliminary Engineering process, if requestors pursue service. The projected energization dates provide a good-faith, non-binding estimate of the time required to complete the project, including preliminary engineering and construction; these efforts would begin upon execution of preliminary engineering agreements under the TSEP. Schedules for environmental review are determined upon completion of the Preliminary Engineering phase, and can vary by project.

The table below does not list project requirements associated with fixes or other mitigations to third-party systems. Those requirements will, however, need to be addressed before commencement of LTF service can begin for those affected TSRs. BPA has identified potential impacted third-party transmission systems following the table below.

	2022 TSEP CS Projects	Direct Costs (millions $)[2]	Estimated Energization[4]
BPA Paths			
South of Allston	• BPA/PGE Ross-Rivergate 230 kV rebuild	**$109.26[1]**	**2030[1]**
	• Schultz-Wautoma 500 kV series capacitor	n/a	**2024**
South of Custer	• BPA/BCH New South of Custer WS-RAS Algorithm	**$0.92[1]**	**2028[1]**
Raver-Paul	• BPA Chehalis to Cowlitz Tap 230 kV Rebuild	**$35.39**	**2028**
	• Schultz-Wautoma 500 kV series capacitor	n/a	**2024**
Cross Cascades North	• BPA Schultz-Raver 3 & #4 500 kV series cap additions (phase 1)	**$65.3**	**2026**
	• BPA Schultz-Raver #3 & #4 500kV Reconductor • BPA Schultz-Raver #4 500 kV series cap upgrade (phase 2) • BPA Olympia 230 kV +350/-300 MVAR SVC • BPA Paul 500 kV 221 MVAR shunt cap	**$196.10**	**2030**
Cross Cascades South	• BPA Big Eddy-Chemawa 500 kV re-build & reconfiguration	**$233.00**	**2030**
BPA Sub-grids			
Boardman	• BPA Boardman-Alkali 115 Reconductor	**$3.56**	**2028**
C.OR--500 kV	• BPA Grizzly-Captain Jack 500 kV re-sag (100C MOT) • BPA Bonanza 500kV and 230 kV station additions • BPA New Bonanza 500/230 kV new transformer bank • BPA New Bonanza-Captain Jack 500 kV circuit with Series Compensation at Sand Springs, Fort Rock & Sycan	**$382.21**	**2033**
	• PAC Chiloquin-K.Falls-Dixonville 230 kV line impacts	n/a[1]	n/a[1]
	• BPA/PGE Pearl-Sherwood-Mcloughlin Reinforcement	**$9.1**	**TBD[3]**
Portland--Pearl-Keeler	• PGE North of Sherwood 230kV impact	n/a[1]	n/a[1]
S.OR Coast	• BPA Alvey-Rogue-Fairview-500 kV (ARF500) • BPA Santiam 230 kV series BSB • BPA Chemawa-Santiam 230 kV rebuild	**$903.66**	**2033**
	• PGE Santiam-Bethel 230 kV rebuild/reconductor	n/a[1]	n/a[1]
South of Knight	• BPA Rock Creek-John Day 500 kV rebuild	**$38.73**	**2028**

[1]Estimates & schedule provided here do not account for 3rd party scope and are subject to change. Affected requestors must coordinate with impacted 3rd party to determine necessary non-BPA scope & schedule.
[2]BPA cost estimates do not include overheads or other contingencies. Those will be applied after the Preliminary Engineering phase.
[3]Energization of BPA components is dependent upon energization of PGE components, in-service date is unknown.
[4] Schedule for Environmental Review is determined after completion of the Preliminary Engineering phase and is not addressed in the above estimated energization dates.

6.1 Third Party Impacts

1. For TSRs requiring the Pearl-Sherwood-Mcloughlin 230 kV Reinforcement project, PGE is an impacted Third-Party Transmission Provider. Cost and schedule associated with PGE's portion of the project is not included in the above summary table and must be coordinated with PGE through the Third Party Impact process. Customers will be responsible to pursue any required mitigation with PGE, including development of cost and schedule.
2. PGE is an impacted Third-Party Transmission Provider for mitigations associated with the Pearl-Keeler line impacting PGE elements North of Sherwood 230 kV. Customers will be responsible to pursue mitigation with PGE, including development of cost and schedule.
3. PGE is an impacted Third-Party Transmission Provider for TSRs sourced from South Oregon Coast, due to impacts on the PGE Bethel-Santiam 230kV circuit from BPA's proposed plan of service. Customers will be responsible to pursue any required mitigation with PGE, including development of cost and schedule.
4. PGE is an impacted Third-Party Transmission Provider for TSRs need South of Allston capacity, due to the proposed plan of service requiring upgrades on PGE-owned elements. Customers will be responsible to pursue any required mitigation with PGE, including development of cost and schedule.
5. PAC, PGE and the NWACI Capacity Owners are impacted Third-Party Transmission Provider for TSRs associated with Ponderosa 500 kV, La Pine 230 kV, Bonanza 500 kV, La Pine-Chiloquin #1 230 kV line and Buckley 500 kV. Customers will be responsible to pursue any required mitigation with PGE and PAC, including development of cost and schedule.
6. PAC is an impacted Third-Party Transmission Provider for TSRs that have an impact on PAC's South Oregon 230 kV network between South Oregon 230 kV network including elements between Chiloquin, Klamath Falls, and Alvey. Customers will be responsible to pursue any required mitigation with PAC, including development of cost and schedule.
7. PSE in an impacted Third-Party Transmission Provider for TSRs needing South of Custer capacity, due to impacts on PSE elements at PSE's Portal Way substation. Customers will be responsible to pursue any required mitigation with PSE, including development of cost and schedule.
8. BCH is an impacted Third-Party Transmission Provider for TSRs needing South of Custer capacity, due to impacts associated with the proposed WS-RAS Addition scope. Customers will be responsible to pursue any required mitigation with BCH, including development of cost and schedule.

6.2 Other Projects Required to Provide Service

BPA also identified certain projects as required to accommodate certain 2022 TSEP CS TSRs. These projects originated outside of the 2022 TSEP. The projects are part of active plans for reinforcements of BPA and adjacent transmission systems; and are necessary to accommodate the TSRs participating in the 2022 TSEP.

Puget Sound Area Study Team Reinforcements

Congestion in the Puget Sound Area has been an issue for decades, thus several Puget Sound Area/Northern Intertie (PSANI) reinforcements were developed jointly between Seattle City Light, Puget Sound Energy and BPA in 2011 as a result of the Columbia Grid Puget Sound Area Study Team (PSAST). These reinforcements are required to accommodate TSRs impacting the North of Echo Lake (NOEL) path. The reinforcements include:

- BPA's 500/230 kV transformer and associated 230 kV line at BPA's Raver substation (energized)
- Puget Sound Energy's Energize Eastside 230 kV project (refer to PSE's Attachment K process for information on this project)
- Joint BPA-Seattle City Light (SCL) Bothell-Snoking #1 and #2 230 kV transmission line upgrade (energized)
- SCL's Broad Street 115 kV (currently estimated to be energized in 2023) and Denny 115 kV series inductors (energized)

Portland Sub-grid: Pearl-Sherwood-McLoughlin 230 kV Reinforcement project

This project was identified in 2020 TSEP CS and 2021 TSEP CS, required to alleviate south-to-north impacts in the Portland sub-grid across the Pearl-Keeler 500 kV line. 2022 TSRs that have an impact on this Portland sub-grid element will be required to participate in this project. This project is currently in scoping, energization date is unknown.

SOA & R-P Paths: Schultz-Wautoma 500 kV Series Capacitor addition

This project was identified in 2020 TSEP CS and 2021 TSEP CS, required to alleviate impacts to the SOA path and R-P path. 2022 TSRs that have require capacity on SOA or R-P will require this project be energized before service can be granted. This project is currently in design, with an expected energization date of spring 2024.

CCN Path: Schultz-Raver #3 & #4 500 kV Series Capacitor additions (phase 1)

This project was identified in 2021 TSEP CS, required to alleviate impacts to the CCN path. 2022 TSRs that require capacity on CCN will be required to participate in this project. This project is currently in scoping, energization date is unknown.

Appendix A: 2022 TSEP Cluster Study Results by Customer

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
Avangrid Renewables, LLC					**17 TSRs**	**941 MW**	
92121127	LTF-YEARLY PTP	01/01/24	01/01/31	NEWPOINT (Maupin 230)	PGE_CNTGS	50	1. Schultz-Wautoma Series Capacitor Project 2. Schultz-Raver Series Capacitor Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
92121140	LTF-YEARLY PTP	01/01/24	01/01/31	NEWPOINT (Maupin 230)	PGE_CNTGS	50	1. Schultz-Wautoma Series Capacitor Project 2. Schultz-Raver Series Capacitor Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
92121145	LTF-YEARLY PTP	01/01/24	01/01/31	NEWPOINT (Maupin 230)	COVNGTN230PSEI	50	1. Schultz-Raver Series Capacitor Project 2. Pearl-Sherwood-Mcloughlin Reinforcement Project 3. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
92121174	LTF-YEARLY PTP	01/01/24	01/01/31	NEWPOINT (Maupin 230)	COVNGTN230PSEI	50	1. Schultz-Raver Series Capacitor Project 2. Pearl-Sherwood-Mcloughlin Reinforcement Project 3. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94731579	LTF-YEARLY PTP	06/01/24	06/01/29	NEWPOINT (Boardman 115)	PGE_CNTGS	75	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Boardman-Alkali 115 kV Reconductor Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94731597	LTF-YEARLY PTP	06/01/24	06/01/29	NEWPOINT (Sickler 230)	COVNGTN230PSEI	100	Cross Cascades North Reinforcement Project
94731605	LTF-YEARLY PTP	06/01/24	06/01/29	NEWPOINT (Sickler 230)	COVNGTN230PSEI	100	Cross Cascades North Reinforcement Project
94731606	LTF-YEARLY PTP	06/01/24	06/01/29	SPRNCRK230AVRN	COVNGTN230PSEI	125	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 4. PSAST 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94731620	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Midway 230)	COVNGTN230PSEI	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project
94731626	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Midway 230)	COVNGTN230PSEI	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project
94731628	LTF-YEARLY PTP	06/01/24	06/01/29	NEWPOINT (Boardman 115)	PGE_CNTGS	10	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94763672	LTF-YEARLY PTP	09/01/23	09/01/28	SLATT230AVRN	PSEI_CENTCNTGS	41	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 4. PSAST 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94764470	LTF-YEARLY PTP	06/01/23	04/01/26	BOARDMAN115GEN	PSEI_CENTCNTGS	5	1. Cross Cascades North Reinforcement Project 2. PSAST
94764491	LTF-YEARLY PTP	06/01/23	04/01/26	BOARDMAN115GEN	PSEI_CENTCNTGS	10	1. Cross Cascades North Reinforcement Project 2. PSAST
94764505	LTF-YEARLY PTP	06/01/23	04/01/26	BOARDMAN115GEN	PSEI_CENTCNTGS	25	1. Cross Cascades North Reinforcement Project 2. PSAST
94764516	LTF-YEARLY PTP	06/01/23	04/01/26	BOARDMAN115GEN	PSEI_CENTCNTGS	25	1. Cross Cascades North Reinforcement Project 2. PSAST
94764526	LTF-YEARLY PTP	06/01/23	10/01/25	BOARDMAN115GEN	PSEI_CENTCNTGS	25	1. Cross Cascades North Reinforcement Project 2. PSAST
Avista Corporation					**1 TSR**	**50 MW**	
92502375	LTF-YEARLY PTP	11/01/21	11/01/26	COYTSPRGS2_500	BENTONINTRCON	50	Awardable
BrightNights LLC					**12 TSRs**	**600 MW**	
94754445	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	25	Rock Creek-John Day 500 kV Rebuild Project
94754447	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	25	Rock Creek-John Day 500 kV Rebuild Project
94754450	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50	Rock Creek-John Day 500 kV Rebuild Project
94754451	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	100	Rock Creek-John Day 500 kV Rebuild Project
94762830	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94762834	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94762837	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	25	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94762839	LTF-YEARLY PTP	01/01/25	01/01/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	25	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94763009	LTF-YEARLY PTP	01/01/25	01/01/31	MIDWAY230MIDCR	WHITERIVER230	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project
94763010	LTF-YEARLY PTP	01/01/25	01/01/31	MIDWAY230MIDCR	WHITERIVER230	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project
94763013	LTF-YEARLY PTP	01/01/25	01/01/31	MIDWAY230MIDCR	WHITERIVER230	25	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
94763015	LTF-YEARLY PTP	01/01/25	01/01/31	MIDWAY230MIDCR	WHITERIVER230	25	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project
Clark Public Utilities					**1 TSR**	**90 MW**	
95188087	LTF-YEARLY NT	10/01/21	10/01/31	BOXCNYN115	CLARKNTDP	90	1. Pearl-Sherwood-Mcloughlin Reinforcement Project 2. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
Cypress Creek Renewables Transmission LLC					**5 TSRs**	**240 MW**	
94763073	LTF-YEARLY PTP	12/01/24	12/01/29	KNIGHT500	MIDWAY230MIDCR	100	Rock Creek-John Day 500 kV Rebuild Project
94763122	LTF-YEARLY PTP	12/01/24	12/01/29	KNIGHT500	MIDWAY230MIDCR	20	Rock Creek-John Day 500 kV Rebuild Project
94763127	LTF-YEARLY PTP	12/01/24	12/01/29	KNIGHT500	MIDWAY230MIDCR	20	Rock Creek-John Day 500 kV Rebuild Project
94763150	LTF-YEARLY PTP	12/01/23	12/01/28	NEWPOINT (Moxee 115)	MIDWAY230MIDCR	80	Awardable
94763155	LTF-YEARLY PTP	12/01/24	12/01/29	KNIGHT500	MIDWAY230MIDCR	20	Rock Creek-John Day 500 kV Rebuild Project
Energy of Utah LLC					**5 TSRs**	**360 MW**	
94241057	LTF-YEARLY PTP	11/01/23	11/01/29	SLATT500PGE	MCLOUGHLIN230	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 7. Pearl-Sherwood-Mcloughlin Reinforcement Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94241195	LTF-YEARLY PTP	11/01/23	11/01/29	SLATT500PGE	RIVERGATE230	40	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94241209	LTF-YEARLY PTP	11/01/23	11/01/29	SLATT500	RIVERGATE230	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94241231	LTF-YEARLY PTP	11/01/23	11/01/29	SLATT500	TOUTDL230PAC	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate)
94539901	LTF-YEARLY PTP	11/01/24	11/01/30	SLATT500	REDMOND115PACW	80	Awardable
Franklin County PUD					**1 TSR**	**40 MW**	
94712980	LTF-YEARLY PTP	01/01/23	01/01/29	COLMBIA230CHPD	FRANKLINCNTGS	40	Awardable

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
Fremont Solar LLC					**3 TSRs**	**400 MW**	
93171915	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (FORT_RK_31_500)	SEATTLECNTGSB	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Central Oregon South 500 kV Project 6. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 7. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 8. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
93262637	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (FORT_RK_31_500)	COVNGTN230PSEI	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Central Oregon South 500 kV Project 5. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 6. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 7. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
93616421	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (FORT_RK_31_500)	VANTAGE230MIDC	200	1. Pearl-Sherwood-Mcloughlin Reinforcement Project 2. Central Oregon South 500 kV Project 3. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 4. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 5. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
Gallatin Power Partners, LLC					**6 TSRs**	**440 MW**	
94761421	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94761930	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94761945	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94761951	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94761959	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94761975	LTF-YEARLY PTP	12/01/24	12/01/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	40	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
Harney Solar I LLC					**8 TSRs**	**800 MW**	
94771071	LTF-YEARLY PTP	01/01/28	01/01/48	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94771103	LTF-YEARLY PTP	01/01/28	01/01/48	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94771114	LTF-YEARLY PTP	01/01/28	01/01/48	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94771138	LTF-YEARLY PTP	01/01/28	01/01/33	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
94771155	LTF-YEARLY PTP	01/01/28	01/01/33	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94771167	LTF-YEARLY PTP	01/01/28	01/01/33	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94771172	LTF-YEARLY PTP	01/01/28	01/01/33	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94771177	LTF-YEARLY PTP	01/01/28	01/01/48	PONDEROSA500	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp)

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
Innergex Renewables USA LLC					**27 TSRs**	**1,350 MW**	
94730212	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730286	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730307	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730320	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730342	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730356	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730371	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730384	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730399	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	CNTRLFRRY230	50	Rock Creek-John Day 500 kV Rebuild Project
94730436	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	CNTRLFRRY230	50	Rock Creek-John Day 500 kV Rebuild Project
94730454	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	CNTRLFRRY230	50	Rock Creek-John Day 500 kV Rebuild Project
94730552	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730574	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							4. Rock Creek-John Day 500 kV Rebuild Project
94730586	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730602	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project
94730640	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50	Rock Creek-John Day 500 kV Rebuild Project
94730663	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50	Rock Creek-John Day 500 kV Rebuild Project
94730678	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50	Rock Creek-John Day 500 kV Rebuild Project
94730696	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50	Rock Creek-John Day 500 kV Rebuild Project
94730709	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50	Rock Creek-John Day 500 kV Rebuild Project
94730720	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50	Rock Creek-John Day 500 kV Rebuild Project
94730939	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50	Rock Creek-John Day 500 kV Rebuild Project
94730962	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50	Rock Creek-John Day 500 kV Rebuild Project
94730974	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50	Rock Creek-John Day 500 kV Rebuild Project
94730986	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50	Rock Creek-John Day 500 kV Rebuild Project
94730992	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50	Rock Creek-John Day 500 kV Rebuild Project
94730999	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50	Rock Creek-John Day 500 kV Rebuild Project
Invenergy Energy Management LLC					**1 TSR**	**76 MW**	
94770532	LTF-YEARLY PTP	01/01/26	01/01/31	BOARDMAN115GEN	PGE_CNTGS	76	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Boardman-Alkali 115 kV Reconductor Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
NextEra Energy Marketing LLC					**7 TSRs**	**664 MW**	
94728178	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (LaPine 230)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
94728186	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (LaPine 230)	PGE_CNTGS	64	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94728201	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (Stateline Wind Project)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94728211	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (Pot Holes-Grand Coulee 230 kV)	PSEI_STHCNTGS	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Covington-Chehalis 230 kV Rebuild Project 4. Schultz-Wautoma Series Capacitor Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94728214	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (Pot Holes-Grand Coulee 230 kV)	PSEI_STHCNTGS	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Covington-Chehalis 230 kV Rebuild Project 4. Schultz-Wautoma Series Capacitor Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94728221	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (Pot Holes-Grand Coulee 230 kV)	SEATTLECNTGSB	100	1. Cross Cascades North Reinforcement Project 2. PSAST
94730584	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (Stateline Wind Project)	VANTAGE230MIDC	100	Awardable
Parasol Renewable Energy Holdings					**2 TSRs**	**300 MW**	
94770897	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (Buckley 500)	COVNGTN230PSEI	200	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Central Oregon South 500 kV Project 6. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 7. Impact to Third-Party Transmission System (Portland General

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94770901	LTF-YEARLY PTP	12/01/25	12/01/30	NEWPOINT (Buckley 500)	COVNGTN230PSEI	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Central Oregon South 500 kV Project 5. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
Powerex Corp.					**8 TSRs**	**720 MW**	
93419250	LTF-YEARLY PTP	01/01/22	01/01/28	USCNDNBDRCNTGS	GARRISON230	60	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. WS-RAS Addition 4. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate) 5. Impact to Third-Party Transmission System (BC Hydro: RAS) 6. Impact to Third-Party Transmission System (Puget Sound Energy: SOC project)
93419251	LTF-YEARLY PTP	01/01/22	01/01/28	USCNDNBDRCNTGS	GARRISON230	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. WS-RAS Addition 4. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate) 5. Impact to Third-Party Transmission System (BC Hydro: RAS) 6. Impact to Third-Party Transmission System (Puget Sound Energy: SOC Project)
93462425	LTF-YEARLY PTP	01/01/22	01/01/27	USCNDNBDRCNTGS	GARRISON230	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. WS-RAS Addition 4. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate) 5. Impact to Third-Party Transmission System (BC Hydro: RAS) 6. Impact to Third-Party Transmission System (Puget Sound Energy: SOC Project)
93462431	LTF-YEARLY PTP	01/01/23	01/01/28	USCNDNBDRCNTGS	GARRISON230	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. WS-RAS Addition 4. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate) 5. Impact to Third-Party Transmission System (BC Hydro: RAS) 6. Impact to Third-Party Transmission System (Puget Sound Energy: SOC Project)
94202869	LTF-YEARLY PTP	01/01/24	01/01/25	USCNDNBDRCNTGS	GARRISON230	100	Inability to expand system to meet requested service term.
94202894	LTF-YEARLY PTP	01/01/25	09/01/26	USCNDNBDRCNTGS	GARRISON230	100	Inability to expand system to meet requested service term.
94227076	LTF-YEARLY PTP	01/01/22	01/01/24	USCNDNBDRCNTGS	GARRISON230	60	Inability to expand system to meet requested service term.

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
94497708	LTF-YEARLY PTP	09/01/26	01/01/32	USCNDNBDRCNTGS	GARRISON230	100	Inability to expand system to meet requested service term.
Scout Clean Energy LLC					**16 TSRs**	**1,270 MW**	
94182216	LTF-YEARLY PTP	12/01/23	12/01/28	NEWPOINT (Franklin 230)	PEARL230	200	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94182272	LTF-YEARLY PTP	12/01/23	12/01/28	NEWPOINT (Franklin 230)	COVNGTN230PSEI	250	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 4. PSAST 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673590	LTF-YEARLY PTP	01/01/24	01/01/29	NEWPOINT (Franklin 230)	PEARL230	50	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673605	LTF-YEARLY PTP	01/01/24	01/01/29	NEWPOINT (Franklin 230)	PEARL230	50	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673610	LTF-YEARLY PTP	01/01/24	01/01/29	NEWPOINT (Franklin 230)	PEARL230	50	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673681	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
94673685	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	100	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673700	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673706	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673709	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94673718	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	50	Awardable
94673720	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	70	Awardable
94673740	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	50	Awardable
94673742	LTF-YEARLY PTP	01/01/25	01/01/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	50	Awardable
94721654	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (Franklin 230)	COVNGTN230PSEI	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
94721681	LTF-YEARLY PTP	10/01/24	10/01/29	NEWPOINT (Franklin 230)	COVNGTN230PSEI	50	1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)
Seattle City Light					**2 TSRs**	**2 MW**	
94770341	LTF-YEARLY PTP	10/01/22	10/01/23	NWMRKTHUB(NWH)	SEATTLECNTGSB	1	Inability to expand system to meet requested service term.
94770357	LTF-YEARLY PTP	10/01/22	10/01/23	SNOHMSH230SCLM	NWMRKTHUB(NWH)	1	Awardable
Shell Energy North America					**1 TSR**	**100 MW**	
94762753	LTF-YEARLY PTP	01/01/23	10/01/24	VANTAGE230	GARRISON230	100	Inability to expand system to meet requested service term.
TX NW I LLC					**20 TSRs**	**2,200 MW**	
94763604	LTF-YEARLY PTP	01/01/27	01/01/32	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	40	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94763614	LTF-YEARLY PTP	01/01/29	01/01/34	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	40	1. Schultz-Wautoma Series Capacitor Project

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)
94763615	LTF-YEARLY PTP	01/01/29	01/01/34	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763628	LTF-YEARLY PTP	01/01/31	01/01/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763670	LTF-YEARLY PTP	01/01/31	01/01/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763679	LTF-YEARLY PTP	01/01/31	01/01/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763714	LTF-YEARLY PTP	01/01/31	01/01/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763717	LTF-YEARLY PTP	01/01/31	01/01/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763721	LTF-YEARLY PTP	01/01/31	01/01/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763749	LTF-YEARLY PTP	01/01/31	01/01/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763753	LTF-YEARLY PTP	01/01/31	01/01/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763767	LTF-YEARLY PTP	01/01/31	01/01/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763774	LTF-YEARLY PTP	01/01/31	01/01/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94763807	LTF-YEARLY PTP	01/01/31	01/01/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
							Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94770338	LTF-YEARLY PTP	08/01/31	08/01/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Southern Oregon Coast Reinforcement Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94770390	LTF-YEARLY PTP	08/01/31	08/01/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Southern Oregon Coast Reinforcement Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94770399	LTF-YEARLY PTP	08/01/31	08/01/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Southern Oregon Coast Reinforcement Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94770405	LTF-YEARLY PTP	08/01/31	08/01/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Southern Oregon Coast Reinforcement Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
94770701	LTF-YEARLY PTP	08/01/31	08/01/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)

2022 TSEP -- Project Requirements by Customer					144 TSRs	11,118 MWs	
AREF	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand (MWs)**	**Plan of Service**
94770718	LTF-YEARLY PTP	08/01/31	08/01/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)
Umatilla Electric Cooperative					**1 TSR**	**475 MW**	
95128258	LTF-YEARLY NT	10/01/20	10/01/30	COLMBIA230CHPD	UMATILANTDP	475	Awardable

Appendix B: 2022 TSEP Cluster Study Results by Requirements

2022 TSEP -- Project Requirements by Project Grouping						**144 TSRs**	**11,118 MW**
Customer	**AREF**	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand**
Awardable						**11 TSRs**	**1,046**
Avista Corporation	92502375	LTF-YEARLY PTP	11/1/21	11/1/26	COYTSPRGS2_500	BENTONINTRCON	50
Cypress Creek Renewables Transmission LLC	94763150	LTF-YEARLY PTP	12/1/23	12/1/28	NEWPOINT (Moxee 115)	MIDWAY230MIDCR	80
Energy of Utah LLC	94539901	LTF-YEARLY PTP	11/1/24	11/1/30	SLATT500	REDMOND115PACW	80
Franklin County PUD	94712980	LTF-YEARLY PTP	1/1/23	1/1/29	COLMBIA230CHPD	FRANKLINCNTGS	40
NextEra Energy Marketing LLC	94730584	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (Stateline Wind Project)	VANTAGE230MIDC	100
Scout Clean Energy LLC	94673718	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	50
Scout Clean Energy LLC	94673720	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	70
Scout Clean Energy LLC	94673740	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	50
Scout Clean Energy LLC	94673742	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	MIDWAY230PAC	50
Seattle City Light	94770357	LTF-YEARLY PTP	10/1/22	10/1/23	SNOHMSH230SCLM	NWMRKTHUB(NWH)	1
Umatilla Electric Cooperative	95128258	LTF-YEARLY NT	10/1/20	10/1/30	COLMBIA230CHPD	UMATILANTDP	475
Inability to expand system to meet requested service term.						**6 TSRs**	**461 MW**
Powerex Corp.	94202869	LTF-YEARLY PTP	1/1/24	1/1/25	USCNDNBDRCNTGS	GARRISON230	100
Powerex Corp.	94202894	LTF-YEARLY PTP	1/1/25	9/1/26	USCNDNBDRCNTGS	GARRISON230	100
Powerex Corp.	94227076	LTF-YEARLY PTP	1/1/22	1/1/24	USCNDNBDRCNTGS	GARRISON230	60
Powerex Corp.	94497708	LTF-YEARLY PTP	9/1/26	1/1/32	USCNDNBDRCNTGS	GARRISON230	100
Seattle City Light	94770341	LTF-YEARLY PTP	10/1/22	10/1/23	NWMRKTHUB(NWH)	SEATTLECNTGSB	1
Shell Energy North America	94762753	LTF-YEARLY PTP	1/1/23	10/1/24	VANTAGE230	GARRISON230	100
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Covington-Chehalis 230 kV Rebuild Project 4. Schultz-Wautoma Series Capacitor Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**2 TSRs**	**200 MW**
NextEra Energy Marketing LLC	94728211	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (Pot Holes-Grand Coulee 230 kV)	PSEI_STHCNTGS	100
NextEra Energy Marketing LLC	94728214	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (Pot Holes-Grand Coulee 230 kV)	PSEI_STHCNTGS	100
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project						**6 TSRs**	**400 MW**
Avangrid Renewables, LLC	94731620	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Midway 230)	COVNGTN230PSEI	100
Avangrid Renewables, LLC	94731626	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Midway 230)	COVNGTN230PSEI	100
BrightNights LLC	94763009	LTF-YEARLY PTP	1/1/25	1/1/31	MIDWAY230MIDCR	WHITERIVER230	100
BrightNights LLC	94763010	LTF-YEARLY PTP	1/1/25	1/1/31	MIDWAY230MIDCR	WHITERIVER230	50
BrightNights LLC	94763013	LTF-YEARLY PTP	1/1/25	1/1/31	MIDWAY230MIDCR	WHITERIVER230	25
BrightNights LLC	94763015	LTF-YEARLY PTP	1/1/25	1/1/31	MIDWAY230MIDCR	WHITERIVER230	25

2022 TSEP -- Project Requirements by Project Grouping						**144 TSRs**	**11,118 MW**
Customer	**AREF**	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand**
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Central Oregon South 500 kV Project 5. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 6. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 7. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**100 MW**
Fremont Solar LLC	93262637	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (FORT_RK_31_500)	COVNGTN230PSEI	100
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Central Oregon South 500 kV Project 5. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 6. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**100 MW**
Parasol Renewable Energy Holdings	94770901	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (Buckley 500)	COVNGTN230PSEI	100
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**7 TSRs**	**450 MW**
Scout Clean Energy LLC	94673681	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	100
Scout Clean Energy LLC	94673685	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	100
Scout Clean Energy LLC	94673700	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	50
Scout Clean Energy LLC	94673706	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	50
Scout Clean Energy LLC	94673709	LTF-YEARLY PTP	1/1/25	1/1/30	NEWPOINT (COLUMBIAGEN500)	COVNGTN230PSEI	50
Scout Clean Energy LLC	94721654	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (Franklin 230)	COVNGTN230PSEI	50
Scout Clean Energy LLC	94721681	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (Franklin 230)	COVNGTN230PSEI	50
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Central Oregon South 500 kV Project 6. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 7. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 8. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**100 MW**
Fremont Solar LLC	93171915	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (FORT_RK_31_500)	SEATTLECNTGSB	100

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Customer	**AREF**	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand**
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Central Oregon South 500 kV Project 6. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 7. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**200 MW**
Parasol Renewable Energy Holdings	94770897	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (Buckley 500)	COVNGTN230PSEI	200
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Rock Creek-John Day 500 kV Rebuild Project						**16 TSRs**	**800 MW**
BrightNights LLC	94762830	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	100
BrightNights LLC	94762834	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	50
BrightNights LLC	94762837	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	25
BrightNights LLC	94762839	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	WHITERIVER230	25
Innergex Renewables USA LLC	94730212	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730286	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730307	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730320	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730342	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730356	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730371	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730384	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	PSEI_CENTCNTGS	50
Innergex Renewables USA LLC	94730552	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50
Innergex Renewables USA LLC	94730574	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50
Innergex Renewables USA LLC	94730586	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50
Innergex Renewables USA LLC	94730602	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	SEATTLECNTGSB	50
1. Cross Cascades North Reinforcement Project 2. Big Eddy-Chemawa 500 kV Rebuild Project 3. PSAST 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**3 TSRs**	**416 MW**
Avangrid Renewables, LLC	94731606	LTF-YEARLY PTP	6/1/24	6/1/29	SPRNCRK230AVRN	COVNGTN230PSEI	125
Avangrid Renewables, LLC	94763672	LTF-YEARLY PTP	9/1/23	9/1/28	SLATT230AVRN	PSEI_CENTCNTGS	41
Scout Clean Energy LLC	94182272	LTF-YEARLY PTP	12/1/23	12/1/28	NEWPOINT (Franklin 230)	COVNGTN230PSEI	250
1. Cross Cascades North Reinforcement Project 2. PSAST						**6 TSRs**	**190 MW**
Avangrid Renewables, LLC	94764470	LTF-YEARLY PTP	6/1/23	4/1/26	BOARDMAN115GEN	PSEI_CENTCNTGS	5
Avangrid Renewables, LLC	94764491	LTF-YEARLY PTP	6/1/23	4/1/26	BOARDMAN115GEN	PSEI_CENTCNTGS	10
Avangrid Renewables, LLC	94764505	LTF-YEARLY PTP	6/1/23	4/1/26	BOARDMAN115GEN	PSEI_CENTCNTGS	25
Avangrid Renewables, LLC	94764516	LTF-YEARLY PTP	6/1/23	4/1/26	BOARDMAN115GEN	PSEI_CENTCNTGS	25

2022 TSEP -- Project Requirements by Project Grouping						144 TSRs	11,118 MW
Customer	**AREF**	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand**
Avangrid Renewables, LLC	94764526	LTF-YEARLY PTP	6/1/23	10/1/25	BOARDMAN115GEN	PSEI_CENTCNTGS	25
NextEra Energy Marketing LLC	94728221	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (Pot Holes-Grand Coulee 230 kV)	SEATTLECNTGSB	100
1. Pearl-Sherwood-Mcloughlin Reinforcement Project 2. Central Oregon South 500 kV Project 3. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 4. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 5. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**200 MW**
Fremont Solar LLC	93616421	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (FORT_RK_31_500)	VANTAGE230MIDC	200
1. Pearl-Sherwood-Mcloughlin Reinforcement Project 2. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**90 MW**
Clark Public Utilities	95188087	LTF-YEARLY NT	10/1/21	10/1/31	BOXCNYN115	CLARKNTDP	90
1. Schultz-Raver Series Capacitor Project 2. Pearl-Sherwood-Mcloughlin Reinforcement Project 3. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**2 TSRs**	**100 MW**
Avangrid Renewables, LLC	92121145	LTF-YEARLY PTP	1/1/24	1/1/31	NEWPOINT (Maupin 230)	COVNGTN230PSEI	50
Avangrid Renewables, LLC	92121174	LTF-YEARLY PTP	1/1/24	1/1/31	NEWPOINT (Maupin 230)	COVNGTN230PSEI	50
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate)						**1 TSR**	**80 MW**
Energy of Utah LLC	94241231	LTF-YEARLY PTP	11/1/23	11/1/29	SLATT500	TOUTDL230PAC	80
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Southern Oregon Coast Reinforcement Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)						**3 TSRs**	**600 MW**
TX NW I LLC	94770390	LTF-YEARLY PTP	8/1/31	8/1/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200
TX NW I LLC	94770399	LTF-YEARLY PTP	8/1/31	8/1/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200
TX NW I LLC	94770405	LTF-YEARLY PTP	8/1/31	8/1/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200

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Customer	**AREF**	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand**
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 5. Big Eddy-Chemawa 500 kV Rebuild Project 6. Pearl-Sherwood-Mcloughlin Reinforcement Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**80 MW**
Energy of Utah LLC	94241057	LTF-YEARLY PTP	11/1/23	11/1/29	SLATT500PGE	MCLOUGHLIN230	80
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. WS-RAS Addition 4. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate) 5. Impact to Third-Party Transmission System (BC Hydro: RAS) 6. Impact to Third-Party Transmission System (Puget Sound Energy: SOC project)						**4 TSRs**	**360 MW**
Powerex Corp.	93419250	LTF-YEARLY PTP	1/1/22	1/1/28	USCNDNBDRCNTGS	GARRISON230	60
Powerex Corp.	93419251	LTF-YEARLY PTP	1/1/22	1/1/28	USCNDNBDRCNTGS	GARRISON230	100
Powerex Corp.	93462425	LTF-YEARLY PTP	1/1/22	1/1/27	USCNDNBDRCNTGS	GARRISON230	100
Powerex Corp.	93462431	LTF-YEARLY PTP	1/1/23	1/1/28	USCNDNBDRCNTGS	GARRISON230	100
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)						**2 TSRs**	**80 MW**
TX NW I LLC	94763604	LTF-YEARLY PTP	1/1/27	1/1/32	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	40
TX NW I LLC	94763614	LTF-YEARLY PTP	1/1/29	1/1/34	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	40
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)						**14 TSRs**	**1,320 MW**
TX NW I LLC	94763615	LTF-YEARLY PTP	1/1/29	1/1/34	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80
TX NW I LLC	94763628	LTF-YEARLY PTP	1/1/31	1/1/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80
TX NW I LLC	94763670	LTF-YEARLY PTP	1/1/31	1/1/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80
TX NW I LLC	94763679	LTF-YEARLY PTP	1/1/31	1/1/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	80
TX NW I LLC	94763714	LTF-YEARLY PTP	1/1/31	1/1/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94763717	LTF-YEARLY PTP	1/1/31	1/1/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94763721	LTF-YEARLY PTP	1/1/31	1/1/36	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100

2022 TSEP -- Project Requirements by Project Grouping						144 TSRs	11,118 MW
Customer	**AREF**	**Service Type**	**Start Date**	**Stop Date**	**POR**	**POD**	**Demand**
TX NW I LLC	94763749	LTF-YEARLY PTP	1/1/31	1/1/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94763753	LTF-YEARLY PTP	1/1/31	1/1/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94763767	LTF-YEARLY PTP	1/1/31	1/1/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94763774	LTF-YEARLY PTP	1/1/31	1/1/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94763807	LTF-YEARLY PTP	1/1/31	1/1/41	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94770701	LTF-YEARLY PTP	8/1/31	8/1/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
TX NW I LLC	94770718	LTF-YEARLY PTP	8/1/31	8/1/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	100
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: Portland General Electric, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls, and Alvey) 9. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)						**10 TSRs**	**964 MW**
Harney Solar I LLC	94771071	LTF-YEARLY PTP	1/1/28	1/1/48	PONDEROSA500	PGE_CNTGS	100
Harney Solar I LLC	94771103	LTF-YEARLY PTP	1/1/28	1/1/48	PONDEROSA500	PGE_CNTGS	100
Harney Solar I LLC	94771114	LTF-YEARLY PTP	1/1/28	1/1/48	PONDEROSA500	PGE_CNTGS	100
Harney Solar I LLC	94771138	LTF-YEARLY PTP	1/1/28	1/1/33	PONDEROSA500	PGE_CNTGS	100
Harney Solar I LLC	94771155	LTF-YEARLY PTP	1/1/28	1/1/33	PONDEROSA500	PGE_CNTGS	100
Harney Solar I LLC	94771167	LTF-YEARLY PTP	1/1/28	1/1/33	PONDEROSA500	PGE_CNTGS	100
Harney Solar I LLC	94771172	LTF-YEARLY PTP	1/1/28	1/1/33	PONDEROSA500	PGE_CNTGS	100
Harney Solar I LLC	94771177	LTF-YEARLY PTP	1/1/28	1/1/48	PONDEROSA500	PGE_CNTGS	100
NextEra Energy Marketing LLC	94728178	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (LaPine 230)	PGE_CNTGS	100
NextEra Energy Marketing LLC	94728186	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (LaPine 230)	PGE_CNTGS	64
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Boardman-Alkali 115 kV Reconductor Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**75 MW**
Avangrid Renewables, LLC	94731579	LTF-YEARLY PTP	6/1/24	6/1/29	NEWPOINT (Boardman 115)	PGE_CNTGS	75

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1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)						**9 TSR**	**570 MW**
Avangrid Renewables, LLC	94731628	LTF-YEARLY PTP	6/1/24	6/1/29	NEWPOINT (Boardman 115)	PGE_CNTGS	10
Energy of Utah LLC	94241195	LTF-YEARLY PTP	11/1/23	11/1/29	SLATT500PGE	RIVERGATE230	40
Energy of Utah LLC	94241209	LTF-YEARLY PTP	11/1/23	11/1/29	SLATT500	RIVERGATE230	80
Gallatin Power Partners, LLC	94761421	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80
Gallatin Power Partners, LLC	94761930	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80
Gallatin Power Partners, LLC	94761945	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80
Gallatin Power Partners, LLC	94761951	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80
Gallatin Power Partners, LLC	94761959	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	80
Gallatin Power Partners, LLC	94761975	LTF-YEARLY PTP	12/1/24	12/1/29	NEWPOINT (Coyote Springs 500)	PGE_CNTGS	40
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Boardman-Alkali 115 kV Reconductor Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, North of Sherwood)						**1 TSR**	**76 MW**
Invenergy Energy Management LLC	94770532	LTF-YEARLY PTP	1/1/26	1/1/31	BOARDMAN115GEN	PGE_CNTGS	76
1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV						**5 TSRs**	**450 MW**
NextEra Energy Marketing LLC	94728201	LTF-YEARLY PTP	12/1/25	12/1/30	NEWPOINT (Stateline Wind Project)	PGE_CNTGS	100
Scout Clean Energy LLC	94182216	LTF-YEARLY PTP	12/1/23	12/1/28	NEWPOINT (Franklin 230)	PEARL230	200
Scout Clean Energy LLC	94673590	LTF-YEARLY PTP	1/1/24	1/1/29	NEWPOINT (Franklin 230)	PEARL230	50
Scout Clean Energy LLC	94673605	LTF-YEARLY PTP	1/1/24	1/1/29	NEWPOINT (Franklin 230)	PEARL230	50
Scout Clean Energy LLC	94673610	LTF-YEARLY PTP	1/1/24	1/1/29	NEWPOINT (Franklin 230)	PEARL230	50

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1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Covington-Chehalis 230 kV Rebuild Project 7. Southern Oregon Coast Reinforcement Project 8. Impact to Third-Party Transmission System (Portland General Electric: Ross-Rivergate, Pearl-Sherwood-Mcloughlin, Santiam-Bethel, North of Sherwood)						**1 TSR**	**200 MW**
TX NW I LLC	94770338	LTF-YEARLY PTP	8/1/31	8/1/51	NEWPOINT (GOLDBEACH115)	PGE_CNTGS	200
1. Schultz-Wautoma Series Capacitor Project 2. Schultz-Raver Series Capacitor Project 3. Pearl-Sherwood-Mcloughlin Reinforcement Project 4. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-Mcloughlin, North of Sherwood)						**2 TSRs**	**100 MW**
Avangrid Renewables, LLC	92121127	LTF-YEARLY PTP	1/1/24	1/1/31	NEWPOINT (Maupin 230)	PGE_CNTGS	50
Avangrid Renewables, LLC	92121140	LTF-YEARLY PTP	1/1/24	1/1/31	NEWPOINT (Maupin 230)	PGE_CNTGS	50
Cross Cascades North Reinforcement Project						**2 TSRs**	**200 MW**
Avangrid Renewables, LLC	94731597	LTF-YEARLY PTP	6/1/24	6/1/29	NEWPOINT (Sickler 230)	COVNGTN230PSEI	100
Avangrid Renewables, LLC	94731605	LTF-YEARLY PTP	6/1/24	6/1/29	NEWPOINT (Sickler 230)	COVNGTN230PSEI	100
Rock Creek-John Day 500 kV Rebuild Project						**23 TSRs**	**1,110**
BrightNights LLC	94754445	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	25
BrightNights LLC	94754447	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	25
BrightNights LLC	94754450	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50
BrightNights LLC	94754451	LTF-YEARLY PTP	1/1/25	1/1/31	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	100
Cypress Creek Renewables Transmission LLC	94763073	LTF-YEARLY PTP	12/1/24	12/1/29	KNIGHT500	MIDWAY230MIDCR	100
Cypress Creek Renewables Transmission LLC	94763122	LTF-YEARLY PTP	12/1/24	12/1/29	KNIGHT500	MIDWAY230MIDCR	20
Cypress Creek Renewables Transmission LLC	94763127	LTF-YEARLY PTP	12/1/24	12/1/29	KNIGHT500	MIDWAY230MIDCR	20
Cypress Creek Renewables Transmission LLC	94763155	LTF-YEARLY PTP	12/1/24	12/1/29	KNIGHT500	MIDWAY230MIDCR	20
Innergex Renewables USA LLC	94730399	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	CNTRLFRRY230	50
Innergex Renewables USA LLC	94730436	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	CNTRLFRRY230	50
Innergex Renewables USA LLC	94730454	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	CNTRLFRRY230	50
Innergex Renewables USA LLC	94730640	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50
Innergex Renewables USA LLC	94730663	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50
Innergex Renewables USA LLC	94730678	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50
Innergex Renewables USA LLC	94730696	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50
Innergex Renewables USA LLC	94730709	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50
Innergex Renewables USA LLC	94730720	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230PAC	50
Innergex Renewables USA LLC	94730939	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50
Innergex Renewables USA LLC	94730962	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50
Innergex Renewables USA LLC	94730974	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50
Innergex Renewables USA LLC	94730986	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50
Innergex Renewables USA LLC	94730992	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50
Innergex Renewables USA LLC	94730999	LTF-YEARLY PTP	10/1/24	10/1/29	NEWPOINT (WAUTOMA 500)	MIDWAY230MIDCR	50

Attachment B

PGE Responses to NIPPC Data Requests

June 8, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 012
Dated May 30, 2023

Request:

PGE's 2023 RFP states PGE will include a transferability discount on the value of tax credits for utility-owned bids related to the discounted value of the tax credits sold to third parties (PGE 2023 RFP, Appendix N at page 9).

a. Please provide all information supporting the specific transferability discount.
b. Please identify what other transferability discounts were reviewed.
c. Please explain why other transferability discounts were not selected.
d. Please explain how this transferability discount would have impacted utility-owned bids in PGE's 2021 RFP, and what changes, if any, would have been made to the scoring of all bids that were on the shortlist.

Response:

a. PGE objects to this request as overly broad. Without waiving this objection, PGE provides the following response. PGE's assumed discounted value of tax credits sold to third parties is a forecast of a nascent market and incorporates the best information available from current market-makers, consultants, and PGE's experience in the market.
b. PGE considered a range of potential values and actively sought information to correctly value this discount from third-party entities currently creating and participating in this market. PGE does not have any discrete discount values that were reviewed and ultimately not selected.
c. PGE considered a range of potential values and actively sought information to correctly value this discount from third-party entities currently creating and participating in this market. PGE does not have any discrete discount values that were reviewed and ultimately not selected.
d. PGE objects to this request as not reasonably calculated to elicit or lead to relevant evidence in this proceeding. In particular, this request seeks information about the results of the 2021 RFP, which are not relevant to the 2023 RFP. In addition, responding to this request would require PGE to perform a new analysis and study, which PGE is not required to perform.

June 8, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 016
Dated May 30, 2023

Request:

Please provide contract forms for a renewable and storage hybrid resource, build transfer agreement ("BTA"), PGE's affiliate, LTSA, and O&M agreement.

Response:

PGE objects to the request as overly broad and unduly burdensome. Without waiving these objections, PGE provides the following responses.

Any renewable energy and storage hybrid resources will incorporate the material terms of the Renewable PPA Form Agreement and Storage Capacity Form Agreement, which were provided as Appendices E and F, respectively, with PGE's draft RFP filing. PGE plans to supplement the May 19 filing with a Renewable and Storage PPA Form Agreement, consistent with the recommendation of the IE report (page 13).

Material terms and conditions that would exist in any BTA bid are reflected in the Asset Purchase Agreement (APA) Form Agreement and Engineering, Procurement, and Construction (EPC) Form Agreement, which were provided as Appendices H and I, respectively, with PGE's draft RFP filing.

Any affiliate bid into this RFP would utilize the Renewable PPA Form Agreement provided as Appendix E with PGE's draft RFP filing.

PGE does not use standard form contracts for LTSA or O&M agreements.

June 8, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 017
Dated May 30, 2023

Request:

Please explain how PGE would enforce provisions in the power purchase agreement ("PPA") against PGE's affiliate. Provisions include, but are not limited to damages, legal disputes, performance guarantees, and security.

Response:

See **Attachment 2 – Customer Protection Conditions**, developed in consultation with OPUC Staff, Citizen's Utility Board, and Alliance for Western Energy Consumers, and submitted as part of PGE's affiliate application in Docket No. UI 489 provides the requested information.

PGE has conducted extensive outreach to parties within UI 489 and in relation to PGE's 2021 affiliate application (UI 461). PGE expects that any additional customer protection conditions needed will be discussed and ultimately adopted through the affiliated interest docket process.

June 15, 2023

To: Irion Sanger
Northwest and Intermountain Power Producers Coalition

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
UM 2274
PGE Response to NIPPC Data Request 024
Dated June 1, 2023

Request:

Please reference PGE's 2023 RFP at page 12 where PGE states it will consider submitting an affiliate bid in the 2023 RFP.

a. Please clarify what site the affiliate resource will use.
b. Please clarify whether the site for the affiliate resource will be made available to other bidders. If not, please provide an analysis explaining why the site for the affiliate resource will not be made available to other bidders.
c. Please clarify what transmission rights the affiliate resource will use.
d. Please clarify whether the transmission rights for the affiliate resource will be made available to other bidders. If not, please provide an analysis explaining why the transmission rights for the affiliate resource will not be made available to other bidders.

Response:

a. PGE objects because the request is not reasonably calculated to elicit or lead to relevant information in this case. PGE further objects because PGE is not required by Commission rules or policy to disclose this information to the parties.
b. Please see response to DR 24(a).
c. Please see response to DR 24(a).
d. Please see response to DR 24(a).