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September 17, 2024

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street, Ste. 100
P.O. Box 1088
Salem OR 97308-1088

Re: UM 2274 - Request for Acknowledgment of the Final Shortlist of Bidders in Portland General Electric Company's 2023 All-Source Request for Proposals

Attention Filing Center:

Portland General Electric Company (PGE) submits the enclosed redacted Request for Acknowledgment of the Final Shortlist of Bidders in the 2023 All-Source Request for Proposals (2023 RFP). This filing contains redacted Appendix A Bates White's (the Independent Evaluator) Final Closing Report to this Request and redacted Appendix B Updated List of PGE Personnel.

A Highly Confidential version of this filing is submitted via password protected zip file. A Confidential version of Appendix B is submitted via password protected zip file.

Please direct any questions regarding this filing to Jacob Goodspeed at Jacob.goodspeed@pgn.com.

Sincerely,

Erin Apperson
Managing Corporate Counsel

EEA: dm
Enclosures

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 ACKNOWLEDGMENT OF THE FINAL SHORTLIST OF BIDDERS IN 2023 ALL-SOURCE REQUEST FOR PROPOSALS**

I. INTRODUCTION

In accordance with Oregon's competitive bidding rules, codified as Oregon Administrative Rule (OAR) Division 89 (Competitive Bidding Rules, CBRs, or Rules), Portland General Electric Company (PGE or Company) requests that the Public Utility Commission of Oregon (OPUC or Commission) acknowledge PGE's 2023 All-Source Request for Proposals (2023 RFP) final shortlist of bidders. The 2023 RFP was conducted fairly and transparently and was run in accordance with the Competitive Bidding Rules and Commission Order No. 24-011 (as corrected by Order Nos. 24-024 and 24-085). The final shortlist is reasonable based on information available at the time of this filing and determined in a manner consistent with the Rules. The final shortlist includes bids aimed at providing customers with cost-effective resources to address PGE's capacity need, and to make progress toward the identified energy actions from the 2023 Integrated Resource Plan (IRP) and Clean Energy Plan (CEP). PGE requests that the Commission acknowledge the 2023 RFP final shortlist as discussed in this filing.

The projects included on the final shortlist are reasonable for PGE to pursue on behalf of customers and, once online, will aid PGE's path to reducing emissions in accordance with Oregon House Bill 2021's targets at the lowest price and risk available to customers in the current market that can deliver by no later than December 31, 2027. This RFP's final shortlist makes progress toward decarbonizing our energy grid (as described in Section III.E, regarding portfolio results), while prioritizing customer affordability and minimizing the risk of an unfilled capacity position in 2028. As described below, the final shortlist includes a primary list of projects (Group A), as well as an optional list of projects (Group B), totaling up to 1,700 MW of nameplate resources, at an estimated net price impact of approximately 1.5% (for Group A projects) up to less than 3% (if Group B projects are needed to meet PGE's capacity need once Group A negotiations are complete).[1,2]

PGE intends to initiate its next procurement process on an accelerated timeline in advance of 2030, seeking additional resources from the market that offer reliability and efficiency at the lowest cost to customers while continuing to make progress toward decarbonization targets.

The remainder of PGE's filing is organized as follows:

- **Target and Need:** discussion of PGE's final shortlist, and how Group A and Group B projects together meet the outstanding capacity need and facilitate progress toward PGE's decarbonization targets.
- **RFP Design and Response from the Market:** PGE—in collaboration with staff, stakeholders, and the IE—designed this RFP in compliance with applicable rule and the response from the competitive market was robust.
- **2023 RFP Selection Process and Results:** PGE evaluated the RFP in compliance with the assessment of minimum criteria designed to evaluate risk and the approved

[1] Final shortlist includes 416 MW of renewable and renewable-hybrid resources, and up to 1,285 MW of dispatchable carbon-free capacity options in the form of Lithium-Ion (Li-Ion) batteries.
[2] PGE calculates net price impact for the purposes of the RFP as: the average of the first five years of the revenue requirement model which includes total project cost, minus the long-term project benefit in the form of energy, capacity, and flex capacity. The benefit of energy, capacity, and flex capacity is as calculated in PGE's acknowledged 2023 IRP. Actual future price impacts may vary from this estimate. This is intended to be demonstrative in this proceeding and not a forecast of guarantee of price impacts.

scoring and modeling methodology, and the final shortlist represents the least-cost, least-risk resources offered from the market.

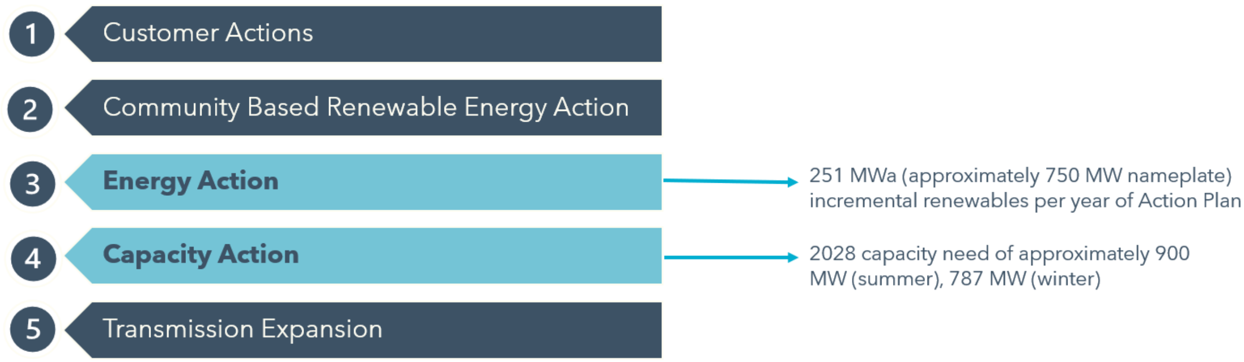
- **Procurement Strategy and Risk:** Upon making this filing, PGE anticipates proceeding to commercial negotiations with projects on the final shortlist and will appropriately mitigate risk.
- **Compliance with Commission Order:** PGE has appropriately ensured compliance with relevant Commission Orders, and the 2023 RFP was run in a manner consistent with Commission direction in consultation with Staff and the IE.
- **Compliance with Oregon's Competitive Bidding Rules:** The 2023 RFP was run fairly, transparently, and in compliance with OAR 860-089.

II. TARGET AND NEED

In this 2023 RFP, PGE is pursuing non-emitting resources to facilitate a reliable energy supply for our service area while reducing the greenhouse gas emissions associated with energy generated to serve customers. PGE's 2023 IRP and CEP found that the company has a need for additional capacity resources beginning in 2026, with an additional capacity need in 2028. Further, the 2023 IRP Action Plan identified that procuring additional energy resources is needed to support the reduction of greenhouse gas emissions within PGE's portfolio. The 2023 RFP was designed and approved, subject to conditions,[3] to seek resources from the competitive market that can address these needs within a 2025-2027 commercial online date (COD) window, consistent with PGE's 2023 IRP Action Plan. PGE's 2023 IRP Action Plan items are shown in Figure 1 below, with the targets for energy and capacity actions targeted by the 2023 RFP shown in light blue.

[3] *See* Order No. 24-011, as modified by Order Nos. 24-024 and 24-085.

Figure 1: PGE's 2023 IRP Action Plan, and associated targets for 2023 RFP



As shown above, the 2023 IRP Action Plan included both a capacity and energy action: the capacity action identifies a need in 2028 of 905 MW in summer and 787 MW in winter. The response from the market to the 2023 RFP was robust, and PGE's final shortlist includes 361 MW of capacity contribution from renewable resources, plus an additional 695 MW of capacity contribution from dispatchable capacity options in the form of Li-Ion battery storage. In this RFP, PGE sought the identified capacity needs entirely from non-emitting resources and has identified resources sufficient to meet this need.

Regarding the annual energy need, PGE evaluated the costs, risks, and benefits of renewable procurement volumes to make progress toward the identified energy action outlined in PGE's 2023 IRP Action Plan. While PGE saw a robust response to this RFP, the total number of renewable energy resources recommended for procurement based on customer value was not sufficient to fully address PGE's 2025-2027 energy action as described in the IRP. Where the IRP recommended up to 750 MWa (2,250 MW nameplate) of renewable energy acquisition, the volume of renewable options on PGE's initial shortlist for this RFP was approximately 1,500 MW nameplate. PGE's price scoring process identified 416 MW nameplate of renewable energy resources that were high-performing and likely to represent least-cost, least-risk for customers. An additional 1,000 MW nameplate of renewable resources – represented by four projects – were not identified as high performing. PGE anticipates future procurement actions before 2030 to continue addressing the remaining need for renewable energy.

PGE's portfolio analysis described in Section IV of this filing examines final shortlist selections with respect to reducing costs and risks while optimizing benefits to PGE customers. PGE constructed the final shortlist to provide optionality and address PGE's capacity need. PGE has ranked this final shortlist as:

- Group A – projects that are top performing in price scoring, including multiple renewable-hybrid projects that help address PGE's energy need while providing capacity contribution to the system. Upon making this filing, PGE expects to enter commercial negotiation with these projects. Group A is comprised of three third-party bids and one benchmark bid.
- Group B – capacity options via battery energy storage systems that also perform well through price scoring. PGE *may* enter commercial negotiations with some or all of these projects, allowing flexibility to address the outstanding capacity need and to fill for any Group A projects should any be unattainable or unavailable. Group B is comprised of two third-party bids and three benchmark bids.

Figure 2: Final shortlist construction and estimated net price impact

Top-performing; approx. price impact: 1.5%

Group	Bidder	MW	Location	Technology
Group A	16	250	OR	Solar + Battery
	71	41	OR	Solar
	88	400	OR	Li-Ion Battery
	150 (benchmark)	125	OR	Solar + Battery

Alternate choices; approx. price impact if all are needed: 1.5%

Group	Bidder	MW	Location	Technology
Group B	23.1	185	OR	Li-Ion Battery
	23.2	200	OR	Li-Ion Battery
	74.1 (benchmark)	200	OR	Li-Ion Battery
	74.2 (benchmark)	200	OR	Li-Ion Battery
	92 (benchmark)	100	OR	Li-Ion Battery

Based on project performance with the Commission-approved price scoring, PGE expects to prioritize the projects in Group A as they present the best value to customers contributing toward both the capacity and energy needs on PGE's system. Upon making this filing, Group A projects will be the first to be engaged in commercial negotiations, and PGE anticipates procurement of all of these projects if they are able to hold their price and if they are still available. If PGE is successful in acquiring this group in total, the potential estimated net price impact to customers would be approximately 1.5%[4] in 2028 when all resources are online and serving customers. This would include all the renewable energy projects identified as top performing.

Projects from Group B also perform well in price scoring and present a compelling opportunity to add non-emitting capacity at a reasonable price impact and within the COD timeline set for this RFP. These projects may be necessary if PGE is unable to execute contracts with

[4] PGE calculates net price impact for the purposes of the RFP as: the average of the first five years of the revenue requirement model which includes total project cost, minus the long-term project benefit in the form of energy, capacity, and flex capacity. The benefit of energy, capacity, and flex capacity is as calculated in PGE's acknowledged 2023 IRP. Actual future price impacts may vary from this estimate. This is intended to be demonstrative in this proceeding and not a forecast of guaranteed price impacts.

projects from Group A or if there is any remaining capacity need after Group A negotiations are complete. For these reasons, PGE may also choose to procure projects from Group B depending on the facts and circumstances, targeting the projects that represent least-cost, least-risk, and commercially reasonable options to facilitate a reliable system.

As noted above, there remain four additional renewable and renewable-hybrid projects that were otherwise conforming with the RFP structure and rules but not selected at this time based on price performance relative to the final shortlist projects selected. These projects are not included in either Group A or Group B. PGE invites these projects to bid into a future RFP as PGE believes they could have value to the PGE system but were not competitive based on price scoring in this RFP.

Through this filing, PGE seeks acknowledgment of its final shortlist, comprised of Group A and Group B, to support procurement of resources sufficient to meet the remaining capacity need as acknowledged in PGE's 2023 IRP and 93 MWa of renewable resources on behalf of customers. Procurement decisions aligned with the grouping of the final shortlist and accompanying portfolio analysis will promote least-cost and least-risk outcomes for customers, while balancing affordability and progress toward decarbonization targets. PGE's portfolio analysis demonstrates a least-cost, least-risk path associated with the acquisition of renewable and non-emitting resources that will meaningfully move PGE toward HB 2021's targets.

II. DESIGN OF THE 2023 RFP AND RESPONSE FROM THE MARKET

On January 31, 2023, PGE filed a notice and request for a partial waiver of the Competitive Bidding Rules, specifically OAR 860-089-0200(1), OAR 860-089-0200(2), OAR 860-089-0250(2)(a), and OAR 860-089-0250(3)(g), to expedite the 2023 RFP process. PGE held a workshop on March 2, 2023, to outline the proposed path for the RFP and to seek feedback from stakeholders. PGE, Staff and Stakeholders provided comments on March 14, 2023. At the Public Meeting on March 18, 2023, the Commissioners adopted Staff's recommendation to grant PGE's request for partial waiver.

PGE, in collaboration with Staff and stakeholders, designed the 2023 RFP in compliance with the Rules. PGE conducted the solicitation in accordance with the Commission-approved RFP structure[5] and with the active participation of, and oversight by, the Commission-selected third-party independent evaluator (IE) Bates White,[6] ensuring a fair and transparent procurement process for all bidders.

The IE, in accordance with the Rules, and as directed by the Commission:

- Attended the pre-RFP Scoring and Modeling workshops on May 26, 2023, and June 5, 2023.
- Consulted with PGE during PGE's preparation of this 2023 RFP and submitted assessments of PGE's draft RFPs to the Commission on May 31 and July 14, 2023.
- Attended the post-issuance RFP bidder workshop on February 13, 2024.
- Conferred with OPUC Staff.
- Oversaw the 2023 RFP process to ensure it was administered fairly.
- Separately evaluated and scored PGE's Benchmark bids.
- Separately evaluated and scored Third-Party Solar BTA/APA bids.
- Reviewed all correspondence between bidders and PGE's RFP Evaluation Team.
- Reviewed all bids to ensure conformance with the 2023 RFP's identified requirements.
- Reviewed and edited all memoranda sent to bidders of non-compliant bids.
- Independently scored all bids, including benchmark bids, to determine whether the selections for the initial and final shortlists were consistent with the bid evaluation criteria.
- Compared the results of the IE's scoring with PGE's scoring.
- Prepared a Final Closing Report and a Sensitivity Analysis for the Commission after PGE selected the final shortlist. The IE's report provides its assessment of the solicitation process and the IE's involvement, including detailed bid scoring and evaluation results, which is included as Attachment A to this filing.

[5] The Commission approved PGE's 2021 RFP with modifications in Order No. 24-011.
[6] On January 31, 2023, PGE filed for a partial waiver of OAR 860-089-0200(1) to streamline the selection of an IE. On April 21, 2023, the Commission adopted Staff's recommendation to appoint Bates White, LLC as the IE.

On May 19, 2023, PGE filed its draft 2023 RFP. PGE held workshops with stakeholders and potential bidders on May 26, 2023, and June 5, 2023. On May 31, 2023, the IE filed its assessment of PGE's draft 2023 RFP and noted lessons learned from the 2021 RFP. On June 16, 2023, Staff and Stakeholders filed comments on the draft 2023 RFP.

In response to feedback received from Staff, stakeholders, and the IE, PGE incorporated several changes to the draft 2023 RFP and included revised documents with reply comments on June 28, 2023. Notable changes included:

- Added Commercial Online Date flexibility by extending the RFP's procurement window an additional year, so projects online by December 31, 2027, are eligible.
- Adjusted the draft 2023 RFP schedule to align with the IE's proposed modifications.
- Modified the transmission requirement to include bids with the transmission product Conditional Firm Service (CFS) System Conditions if bids with Long-Term Firm or CFS Number of Hours are not sufficient in obtaining the RFP's target procurement levels.

The IE provided a second assessment of PGE's updated draft 2023 RFP on July 14, 2023. The IE's report highlighted key remaining issues to be resolved in the draft 2023 RFP between PGE and other parties, but also "commend[ed] PGE for making several positive changes to the draft RFP in response to stakeholder comment[.]"[7]

On August 28, 2023, PGE filed a motion to suspend the procedural schedule to work through questions that might have impact on the structure and timing of the 2023 RFP. The ALJ

[7] The Independent Evaluator's Second Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals at 1 (July 14, 2023).

granted this request on August 29, 2023. On November 2, 2023, Staff filed a motion to reestablish the procedural schedule and the ALJ granted this request on November 3, 2023.

Staff issued their report on the draft 2023 RFP on December 12, 2023, recommending approval of both PGE's scoring and modeling methodology and PGE's final draft 2023 RFP subject to certain conditions. PGE and Stakeholders provided reply comments to the Staff report on December 21, 2023.

The Special Public Meeting to discuss the 2023 RFP was held on January 4, 2024, where the Commissioners adopted Staff's recommendations, with modifications, regarding PGE's 2023 RFP. Three categories of requests were communicated by Staff, relating to Scoring and Modeling Methodology conditions (SMM), All-Source Request for Proposal conditions (RFP), and conditions related to the Portland Renewable Resource Company, LLC (PRR). The Commission adopted many of these conditions, modified or rejected some, and adopted several conditions proposed by NIPPC.

PGE received bids from 19 counterparties, who collectively offered 81 distinct proposals, including 37 Benchmark proposals. The process, designed in compliance with the Rules, required Benchmark bids to be received and evaluated prior to PGE's receipt of all other bids. PGE scored, conferred with the IE, and sealed Benchmark bids on April 4, 2024.[8] PGE then scored, conferred with the IE, and sealed ITC-eligible bids from third-party bidders, with bids sealed on April 29, 2024. All remaining bids were received on April 30, 2024, and then scored and evaluated.

Following the receipt and initial evaluation of bids, on June 10, 2024, PGE notified bidders on the initial shortlist that they could revise prices as part of the best and final offer process as outlined in the 2023 RFP documents. Following the opportunity for bidders to provide best and

8 PGE sealed Benchmark bids on April 4, 2024, to align with the filing of the errata to the IE's report.

final offers, PGE performed additional due diligence (i.e., Final Shortlist eligibility screening as outlined in the 2023 RFP Appendix N) and updated scores reflecting best and final offer updates to help identify PGE's final shortlist. Finally, PGE performed Portfolio Analysis on all initial shortlist offers. The price scoring and portfolio analysis results were used to inform the identification of a final shortlist and top performing bids.

PGE, working in collaboration with the IE, requested clarifying and additional information from bidders throughout the process as each bid package required. These requests were made to properly determine compliance with 2023 RFP requirements, to allow PGE to fully evaluate offers, and to identify execution risks.[9] PGE proactively engaged with bidders by conducting pre-issuance workshops designed to answer questions raised from bidders during the bid submittal process. PGE also engaged bidders by conducting a post-issuance workshop to answer any remaining questions, by posting an effective load carrying capacity (ELCC) calculator to allow bidders to estimate the capacity contribution of their resources, and by engaging in a robust Q&A process with bidders, much of which is posted publicly on PGE's RFP website.

PGE identified the final shortlist projects from the initial shortlist after performing price analysis (updated for best and final offer prices), incorporating feedback from the independent variable energy resource expert's review of variable energy resource assessments,[10] an independent engineer's owner's cost analysis, making shortlist RFP compliance determinations, completing portfolio risk analysis, and conducting additional sensitivity studies as described in Section IV.

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[9] For example: interconnection timelines, permitting progress, counterparty credit quality, etc.

[10] *See* OAR 860-089-0400(5)(a).

III. 2023 RFP SELECTION PROCESS AND RESULTS

The 2023 RFP was well received by the market. PGE received proposals from bidders offering 81 bid alternatives for wind, solar, pumped storage, hydrogen storage, and battery storage projects, and several hybrid technology bids:

- 711 MW of wind resources
- 417 MW of solar resources
- 3,078 MW of hybrid resources (MW figure excludes paired storage)
- 1,855 MW of standalone storage technologies
- 803 MW of other generation/capacity projects

The bids received presented a diversity of choices for PGE in terms of resource type and geography—project sites were in Oregon, Washington, and Montana. The bids included unique commercial structures including power purchase agreements, utility-ownership, and hybrid structures.

The following table, Table 1, summarizes all offers received in the 2023 RFP solicitation, the technology types and unique MW included, and the distinction between benchmark and third-party bids.

Table 1: Offers Received in PGE's 2023 RFP

Technology	Benchmark Bids Received	Unique MW – Benchmark Bids	Third-Party Bids Received	Unique MW – Third Party Bids	Total Bids	Total Unique MW
Wind	-	-	3	711	3	711
Solar	3		10	417	13	417
Wind/Solar/Storage	8	1,064	-	-	8	1,064
Solar/Storage	16	1,065	5	638	21	1,703
Wind/Storage	-	-	2	311	2	311
Standalone Battery	10	600	19	1,255	29	1,855
Pumped Storage	-	-	4	793	4	793
Geothermal	-	-	1	10	1	10
Total	37	2,279	44	4,135	81	6,864

A. Bid Submittal Process

The Benchmark bids were submitted for evaluation on February 23, 2024, reviewed for conformity with minimum bid requirements, and scored and sealed on April 4, 2024, before other bids were received or accessed by PGE, consistent with OAR 860-089-0350(1)-(3). The IE filed its Analysis of the PGE Benchmark Bids on March 28, 2024 (with an errata filed on April 4, 2024). The IE report noted that "PGE's evaluation scoring was done per RFP requirements."[11] Third-Party Solar BTA/APA bids were due and accessed April 5, 2024 (consistent with PRR Condition 2). All remaining bids, including straw bids (consistent with RFP Condition 6), were due April 30, 2024. PGE reviewed all bids for conformance with the minimum bid requirements—these minimum requirements are outlined in the 2023 RFP Appendix N document. PGE received 81 variants from 30 unique projects.

PGE sought clarification and/or additional information from bidders as necessary. The IE, in parallel to PGE's review process, also reviewed bid information, requests for clarification and/or additional information and responses from the bidders. PGE and the IE identified and agreed that certain bids were non-conforming and failed to meet the 2023 RFP's initial bidder eligibility requirements for one or multiple of the following reasons: inability to meet the resource online date, lack of a viable plan to secure transmission rights, or failure to conform with an acceptable delivery point. All bids found initially to be non-conforming were presented with non-conforming notices granting a "cure" period, during which bidders could remedy their bids (through modification or clarification) to conform to the 2023 RFP requirements. In total, 23 variants from nine unique projects were identified as non-conforming, all of which were withdrawn by the bidders.

[11] IE Report at 2.

B. Determination of Initial Shortlist

On June 10, 2024, PGE and the IE completed its initial evaluation and scoring of conforming bids and PGE notified identified bidders of an opportunity to provide a best and final offer price revision by June 24, 2024. Projects receiving notification of the best and final offer opportunity are considered to comprise the Initial Shortlist. PGE's Initial Shortlist included all unique projects found to be conforming by PGE and the IE. Many bidders submit multiple variants of the same project to provide optionality to the evaluation team. The Initial Shortlist selected the best performing variants. Additionally, at Staff's request, PGE also included certain identified projects that, while non-conforming to RFP minimum bidder requirements, had perceived value to customers. The filed Initial Shortlist included 36 variants from 21 projects and 14 bidders. However, after consultation with Staff and the IE, one unique project, which had one variant, was removed shortly after the Initial Shortlist announcement, as it was found to be non-compliant with the RFP minimum bidder requirements. Additionally, another bidder withdrew a variant offer. The remaining Initial Shortlist included 34 variants from 20 unique projects and 14 bidders. No projects were excluded from the Initial Shortlist on account of a resource's individual offer analysis.

C. Individual Offer Analysis: Price Scoring

All conforming bids were scored within PGE's Individual Offer Analysis and assigned a price score. Price scoring utilized models and methodologies consistent with the 2023 IRP. Revenue requirement modeling determined the bid cost, while AURORA calculated energy values, Sequoia determined the capacity value, and results from GridPath will provide flexibility value assessments. Price scoring employed the methodology described in Section 4 of the 2023 RFP Appendix N document. During the Individual Offer Analysis, PGE sent clarifying questions to bidders to ensure PGE possessed all required information to score the bids accurately. The IE was included in this question-and-answer process for all bidders.[12]

Within Individual Offer Analysis, price scoring is designed to identify how project costs compare to the relative economic value they return to PGE's customers. Those bids that offered the lowest priced project with the greatest delivered economic benefit received the best price scores. Project costs generally included items such as forecasted fixed payments, capacity charges, wheeling costs, integration costs, ancillary services, upgrade costs, energy payments, and other ownership-specific costs in the case of BTA or hybrid ownership structures.[13] Within Individual Offer Analysis, the size of the project did not directly contribute to a resource's assigned price score, as that is addressed through PGE's Portfolio Analysis process. Those projects with the highest total price score generally present the least-cost and least-risk for PGE's customers.

D. Final Shortlist Selection Process

Consistent with the bid evaluation and selection process outlined in the 2023 RFP, PGE performed additional analysis and due diligence to select a final shortlist. PGE performed the following additional analysis on the conforming bids remaining on the Initial Shortlist to determine the final shortlist, inclusive of both Groups A and B.

1. Best and Final Offer Process

As part of PGE's 2023 RFP design, PGE invited "Best and Final Offers" (BAFO) from eligible bidders on PGE's Initial Shortlist.[14] The process provided eligible bidders the opportunity

[12] As noted previously, the IE was copied on all email correspondence between PGE's RFP team and bidders.
[13] Summarized in PGE 2023 RFP, Appendix N, Section 4.
[14] *See* Section 6 of Appendix N.

to provide price updates. The BAFO allowed for price adjustments only. BAFOs could not be used to propose new bid variants, change bid structures, or make significant changes to project design.[15]

2. Wind and Solar Capacity Factor (Hendrickson Renewables)

Consistent with OAR 860-089-0400(5)(a), PGE retained an independent renewable energy expert—Hendrickson Renewables (Hendrickson)—to provide an analysis and opinion on the accuracy of Variable Energy Resource (VER) studies submitted to PGE by the renewable bid variants on the initial shortlist. Hendrickson provided reports on each VER study received, each of which outlined adjustments related to the gross energy estimate, the gross to net conversion process, the uncertainty evaluation, and the combination of the three. Hendrickson proposed adjusted net capacity factors (NCF) to the bidders' original resource evaluations. PGE incorporated Hendrickson's proposed adjusted NCFs into the price scoring model for all initial shortlisted bidders as part of the final shortlist selection process.

3. Owner's Cost (1898 and Company)

PGE assigned a generic owner's cost to all utility-ownership resources during the initial evaluation analysis phase. After the initial shortlist selection on June 10, 2024, bidders, with projects that contemplate resource ownership, were requested to supply redlines to the relevant PGE Technical Specifications (Appendix M).

PGE contracted 1898 & Co. (1898), an engineering and construction firm, to review the redlined technical specifications and provide an independent assessment of the approximate owner's cost for only those bids proposed under a utility-owned commercial structure. 1898 provided owner's costs estimates based on bidder's proposed modification of PGE's Technical Specifications. PGE reviewed bidder's proposed modifications to PGE's Technical

[15] Significant changes include, but not limited to, the following: technology, location, AC nameplate capacity and interconnection limit.

Specifications, and where those modifications were found unacceptable due to their increased risk, 1898 added the estimated cost to reverse such modification to the tabulated owner's costs for each bidder. PGE incorporated the proposed estimated owner's cost adjustments from 1898 for the utility-ownership bids into the price scoring model. PGE also estimated both security and control costs for each proposed utility-owned bid and incorporated these costs into the price scoring model as well.

Additionally, PGE requested 1898 to also evaluate the reasonableness of bidder provided O&M costs for ownership bids and certain dispatchable resource parameters (for example round trip efficiency) for both owned and PPA bids.

4. Final Shortlist Requirements

Following additional due diligence and bidder responses, PGE reviewed all initial shortlist bids for conformance with all 2023 RFP eligibility requirements (including those requirements effective prior to final shortlist). These threshold requirements are outlined in the 2023 RFP Appendix N, Table 6, "Final Shortlist Eligibility Screening." Based on feedback from the Commission, the IE, and various stakeholders during the 2023 RFP approval process, PGE's RFP requirements were designed to give bidders additional time and flexibility to satisfy the RFP's eligibility requirements. During the due diligence process, PGE sought some clarification and additional information from bidders.

5. Initial Shortlist Non-Compliance

PGE, in consultation with both Staff and the IE,[16] identified nine variants from seven unique projects on the initial shortlist that were non-conforming with the 2023 RFP. These projects were notified of their non-compliance and were removed from final shortlist consideration.

[16] Per email correspondence from Staff on August 7, 2024.

Additional detail related to the non-compliance of these bids is described below. The remaining projects, 25 variants from 13 unique projects, were input into portfolio modeling.

a. Pumped Storage Hydro

The two pumped storage hydro projects were included on the initial shortlist for further evaluation as per request from Staff,[17] who noted that there was perceived value in the projects to customers. However, neither pumped storage hydro projects met the required 2023 RFP minimum bidder requirements **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** After consulting with Staff and the IE, PGE determined these projects were non-compliant and did not include them in consideration for the final shortlist.

b. On-System Batteries

After consultation with Staff and IE,[18] PGE exercised flexibility by including nine variants from six on-system battery projects on the initial shortlist. The six projects were of varying maturity in PGE's interconnection queue process, but none had yet received a System Impact Study (SIS). However, the projects scored well in the initial price scoring. PGE Transmission (PGET) is transitioning between a serial interconnection queue and a cluster study approach. All projects that have not received a SIS by November 2024 will be analyzed under the cluster study process, which will begin in 2025.[19] While this transition is ongoing, projects that enter the cluster study process will not likely meet the RFP's resource online date requirement.

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[17] Per email correspondence from Staff on May 30, 2024.
[18] Per email correspondence with Staff on June 10, 2024.
[19] This modification is in line with industry standards and is reflective of FERC Order 2023.

Two of the on-system battery projects are on track to receive their SIS before the transition begins and are likely to meet the resource online date requirement. One project has been included in Group A and the other has been included in Group B on PGE's final shortlist.

However, four of the on-system battery projects will not receive a SIS before PGE's transition to a cluster study and are therefore unlikely to meet the COD requirement even with PGE taking a more flexible approach to the interconnection and COD non-conformance. These four projects would not know final interconnection related costs until the end of 2025. Additionally, the four projects would be unable to meet their respective 2027 CODs. As a result, these four projects were outside of the given procurement window in the 2023 RFP, which requires projects to be online by end of 2027, and were therefore not conforming with the RFP requirements. PGE issued formal non-compliance memos notifying the bidders of their non-conformance with the Commission-approved RFP structure.

Two of the bidders responded and expressed confidence that they could meet the timelines required for conformance. However, PGET was unwilling to opine on the likelihood of the bidders' proposed timelines, beyond their advice to the RFP evaluation team that the bids were very unlikely to meet the COD requirement. PGE discussed the situation with the IE and briefly considered *additional* flexibility in the form of a contractual remedy. PGE informed the four similarly-situated bidders of the alternative remediation. Three of the four bidders agreed, while one of the bidders declined the offer. PGE ultimately determined that there was too much remaining risk that was not appropriately addressed with the contractual proposal.

c. Benchmark Bid

[Begin Highly Confidential] [redacted] **[End Highly Confidential]** as initially bid, relied on transmission service requests that were funded by PGE shareholders and therefore were not disclosed in RFP Appendix P (in which the Benchmark team discloses what utility-controlled assets are being used in support of Benchmark bids). The RFP evaluation team scored, consulted with the IE, and sealed the bid score with that ownership structure.

On June 24, the Benchmark team provided a best and final offer for **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** On July 29, the Benchmark team provided a proposed update to Appendix P confirming that the utility planned to take transfer and control of the rights as of August 1. On August 14, PGE's RFP evaluation team—following consultation with Staff and the IE—notified the bidder that we did not plan to further evaluate **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** and it would not be included in the final shortlist due to its emerging reliance on PGE assets that were not made available in this RFP.

d. Straw Bid

Consistent with RFP Condition 6, interested entities were permitted to submit a straw bid into this RFP. Straw bids were not assessed a bid fee and were allowed to propose the use of utility assets described in Appendix P at no cost. PGE made siting and permitting information available to aid in the preparation of this straw bid if bidders wished to access that information. Entities submitting a straw bid were not assessed against the minimum requirements; PGE's RFP Evaluation team scored the submitted bid based on the price proposed.

PGE received one straw bid, which proposed to use the "Approximately 300-600 acres located adjacent to the Carty generating station and owned by PGE… and capacity on the gen-tie from the Grasslands Substation to BPA's Slatt Substation." As the concept was a straw proposal, the bidder communicated that they did not have any information to share on permitting and did not provide other detail or due diligence documents for review, which was acceptable to PGE for the purposes of the straw bid.

The straw bidder proposed a **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** facility on the PGE-owned site. The production profile of the renewable generation was based on non-specific meteorological data, which was a close enough approximation for PGE to move forward with scoring. The bidder proposed a PPA commercial structure.

The straw bid was evaluated against other bids—both PPA and BTA—within this RFP and did not perform competitively from a price perspective compared to the expected benefit to customers. If the straw bid were treated as a live offer and it was assumed that all minimum requirements were met (which was not the case given that it was a straw bid), it would not have been selected as part of either Group A or Group B on PGE's proposed final shortlist based on its performance in price scoring.

6. Final Shortlist Selections

PGE selected the nine top-performing bids from the 34 bids on the initial shortlist for inclusion in Groups A and B of the final shortlist.

Table 2: Breakdown of projects between the ISL to FSL stage

Stage	Bidders	Unique Projects	Variants
Initial Shortlist	14	20	34
ISL Non-Compliance (detailed above):			
Pumped Storage	(2)	(2)	(2)
On-System Batteries	(3)	(4)	(5)
Benchmark Bid	(1)	(1)	(2)
Renewable projects not included on FSL	(3)	(4)	(7)
Lower scoring variants of FSL Group A and B	-	-	(9)
Final Shortlist (Group A and B)	5	9	9

The FSL Group A and Group B projects represented the optimal intersection of value to customers at the least-cost and the least-risk. The 2023 RFP's objective is to execute on the 2023 IRP Action Plan, which identifies a capacity need in 2028 and targets continual progress to decarbonize. The FSL Group A reflects a prioritization of top performing bids from price scoring, which help address the 2028 capacity need and advance PGE toward its decarbonization targets while balancing customer affordability. Additionally, the FSL Group B provides PGE the ability to address any remaining capacity need. The results of PGE's final shortlist are included in Tables 3 and 4. The highly confidential rank order results of PGE Individual Offer Analysis (IOA) are also included.

The final shortlist selections vary from the portfolio analysis results described below. This is primarily because the portfolio analysis model prioritizes inputted need (energy and capacity) and timing (i.e., earlier resources tend to be selected sooner). Portfolio 14 (P_14) – which has the following portfolio modeling characteristics: Yes Generic VER, No Energy Need, No Hydro Extensions and Reference Load Growth – serves as a reference case to the FSL Group A as they both are trying to fill a similar capacity need. One important distinction is that P_14's 2028 emissions level, which is noted below in the Portfolio Analysis section, is based on the modeling characteristic of No Energy Need. Therefore, that emissions level is not representative of meeting anticipated energy needs in 2028.

Three of the five bids selected in P_14 have an online date of December 31, 2026, whereas Group A is comprised of four bids with an online date of December 31, 2027. The P_14 bids with an earlier COD are relatively more expensive than the FSL Group A selections. Both P_14 and FSL Group A have similar estimated net customer pricing impacts – 1.3% vs 1.5%.[20] However, FSL Group A better supports PGE's decarbonization efforts by providing an additional 29 MWa of renewable resources.

The FSL Group B selections represent the most cost competitive variants of the capacity products from the conforming initial shortlist projects. Group B serves as an important set of options to filling any remaining identified capacity need after Group A procurements. Group A and Group B exclude the higher cost renewable projects (seven variants from four unique projects), which were eligible selections from the remaining initial shortlist projects.

[20] PGE calculates net price impact for the purposes of the RFP as: the average of the first five years of the revenue requirement model which includes total project cost, minus the long-term project benefit in the form of energy, capacity, and flex capacity. The benefit of energy, capacity, and flex capacity is as calculated in PGE's acknowledged 2023 IRP. Actual future price impacts may vary from this estimate. This is intended to be demonstrative in this proceeding and not a forecast of guarantee of price impacts.

Table 3: PGE's 2023 RFP Final Shortlist (Group A):

Begin Highly Confidential

Bidder	Unique Project	Variant	Technology	Location	Commercial Structure	IOA Rank	MW	MWa	ELCC
16	1	Base	Solar + Battery	OR	PPA	[redacted]	[redacted]	56	210
71	1	Alt2	Solar	OR	PPA	[redacted]	[redacted]	11	18
88	2	Alt2	Battery	OR	BTA	[redacted]	[redacted]	-	189
150	1	Alt1	Solar + Battery	OR	BTA	[redacted]	[redacted]	26	133

[End Highly Confidential]

Table 4: PGE's 2023 RFP Final Shortlist (Group B):

[Begin Highly Confidential]

Bidder	Unique Project	Variant	Technology	Location	Commercial Structure	IOA Rank	MW	MWa	ELCC
23	1	Base	Battery	OR	PPA	[redacted]	[redacted]	-	101
	2	Base	Battery	OR	PPA	[redacted]	[redacted]	-	109
74	1	Base	Battery	OR	Hybrid	[redacted]	[redacted]	-	118
	2	Alt1	Battery	OR	Hybrid	[redacted]	[redacted]	-	114
92	1	Alt4	Battery	OR	BTA	[redacted]	[redacted]	-	63

[End Highly Confidential]

E. Portfolio Analysis

PGE conducted analysis of each available bid on the initial shortlist (after initial shortlist non-compliance findings) to evaluate the differing system cost, risk, and emissions impact associated with the acquisition of varying combinations of bids.

1. Input Data

To evaluate the impact of differing portfolios of bids, PGE first created an estimate of system need, which is defined as the difference between system demand and generation supply. The default choice was to use the estimates contained in the last iteration of portfolio analysis in the 2023 IRP and CEP proceeding (LC 80). Individual components, their associated vintages in this FSL filing, and the last vintage used in the LC 80 docket are displayed below in Table 5:

Table 5: Input data vintage

	Analytical Component	FSL Data Vintage	LC 80 Vintage
Demand	Corporate Load Forecast	Jun-23	Jun-23
	DER & EE Forecast	Jan-23	Jan-23
	Capacity Need	Nov-23	Nov-23
Supply	Owned and Contracted Non-emitting Generation	Jun-23	Jun-23
	Thermal generation for Retail Load	Jun-23	Jun-23
	Hydro Contracts	Nov-23	Nov-23
	Qualified Facility (QF)	Jun-23	Jun-23
	Community-based Renewable Energy (CBRE)	Mar-23	Mar-23
	Energy Efficiency (EE)	Nov-23	Nov-23

Once establishing system need, PGE's portfolio analysis evaluated the options available to fill that need. All remaining bids from the RFP are available for selection, providing their energy, capacity, and emission reduction benefits as well as their associated costs. This information largely comes directly from the individual bids themselves, and the scoring and modeling methodology is fully described in Appendix N to PGE's 2023 RFP.

In addition to the bids, PGE's capacity expansion model (ROSE-E) had access to two generic resources (a generic VER and generic perfect capacity product). Generic resources are made available for selection to allow the model to solve by providing sufficient resources to meet needs beyond what can be supplied by bids. The generic capacity resource provides perfect capacity and no energy. The generic VER provides both energy and capacity, with an ELCC curve and capacity factor defined by a weighted average of renewable resources in the Preferred Portfolio from the 2023 CEP and IRP. PGE includes these generic resources as proxies but does not have any specific detail about the availability nor the cost associated with resources outside of those bids in this RFP.

Given this uncertainty, ROSE-E in some cases had access to a generic emitting energy product. This option could be met by the procurement of such a resource on the bilateral market or the increase in owned thermal generation serving retail load above the levels established in the linear emissions reduction glidepath toward HB 2021 targets from LC 80. This option and its implications are discussed further in the results section below.

Cost assumptions for generic resources made for the purposes of this analysis are as follows: 1) to prevent competition between actual bids and generic resources, generics are priced at a cost higher than the most-costly bid in years in which bids are available for selection (through 12/31/2027). To focus bid additions on meeting needs through 2028, rather than being added to meet needs in the more distant years of the analysis, starting in 2029 when bids are no longer available for selection the cost of the generics is lowered to be equal to the highest cost bid from the target bid additions. This encourages the model to rely on the generics to meet needs in the distant years of the analysis, rather than pre-loading with bids to avoid costly generic resource additions in the future.

2. Portfolio Design and Analysis

PGE, Staff and the IE developed the following portfolio sensitivities. PGE varied the identified four main components to test key questions of interest in portfolio analysis, which included the following.

> *Hydro Extension*: In November 2023 PGE extended contracts for approximately 500 MW of new hydro capacity from Douglas County PUD and Grant County PUD. These contracts run through 2025 and 2026, respectively. Under the 'No Hydro Extension' assumption, these contracts (and all other contracts) are assumed to expire in accordance with the agreements as currently signed. Under the 'Hydro Extension' assumption, all hydro contracts are assumed to be renewed through the end of 2030. The assumed extension of hydro contracts reduces PGE's energy need by approximately 323 MWa in 2028.
>
> *Availability of Generic VER*: Given the uncertainty of the availability and cost of PGE acquiring non-emitting generation beyond what is available in this RFP, portfolios are analyzed with and without access to generic renewable energy resources to meet needs beyond what can be provided by bids. When generic renewable resources are not available, energy need not met with the selection of bids is met with additional energy from natural gas beyond the quantities that are compliant with HB 2021 emissions goals.
>
> *Load Scenario*: Given the uncertainty in load growth, in addition to the Reference Case need future, portfolios are analyzed under High and Low load growth scenarios.
>
> *Energy Need*: To test the impact on portfolio outcomes of addressing HB 2021 policy goals, portfolios are analyzed with and without an energy need requirement. While HB 2021 emissions reductions goals are not the only driver of PGE's energy needs, they are a substantial driver of energy need. Analyzing portfolios without an energy need is therefore used to illustrate a scenario where resources are added only to meet reliability needs, without energy needs (of which decarbonization is a key driver) influencing resource additions.
>
> *No Ownership Bids*: Staff requested this additional portfolio sensitivity to assess the benefit and impact of evaluating the RFP without any utility ownership options. This scenario excludes from portfolio analysis any bid with an ownership component – whether from a benchmark or non-benchmark bid. As a result, this scenario only contemplated 10 variants from 6 unique projects as opposed to the other scenarios which contemplated 25 variants from 13 unique projects. The results were intuitive, with fewer options the portfolios had to rely on the generic VER, generic CAP and generic NG resources to fill both energy and capacity needs and, as a result, were more costly and made less immediate progress to address PGE's capacity need and to decarbonize the grid.

Varying these four components leads to the creation of 24 unique portfolios, described below in Table 6:

Table 6: Final Shortlist Portfolios

Portfolio	Hydro Extension	Generic VER	Load Scenario	Energy Need
1	Yes	Yes	Reference	Yes
2	No	Yes	Reference	Yes
3	Yes	No	Reference	Yes
4	No	No	Reference	Yes
5	Yes	Yes	High	Yes
6	No	Yes	High	Yes
7	Yes	No	High	Yes
8	No	No	High	Yes
9	Yes	Yes	Low	Yes
10	No	Yes	Low	Yes
11	Yes	No	Low	Yes
12	No	No	Low	Yes
13	Yes	Yes	Reference	No
14	No	Yes	Reference	No
15	Yes	No	Reference	No
16	No	No	Reference	No
17	Yes	Yes	High	No
18	No	Yes	High	No
19	Yes	No	High	No
20	No	No	High	No
21	Yes	Yes	Low	No
22	No	Yes	Low	No
23	Yes	No	Low	No
24	No	No	Low	No

3. Results

Results from portfolio analysis are summarized in terms of capacity and energy contribution provided by the bids, cost and risk metrics, and emissions. Capacity contribution of bids is the sum of the ELCC of each individual bid added in the portfolio and represents the total contribution of the bids to meeting PGE's annual capacity need.[21] Average megawatts (MWa) of bids in each portfolio is the total annual energy expected to be provided by bids in each portfolio to meet PGE's energy needs. Energy contribution is calculated using bid nameplate MW size and estimated annual average capacity factor, inclusive of losses associated with storage roundtrip inefficiencies. Portfolio cost is the net present value of revenue requirement (NPVRR) for the full analysis timeline of 2024-2043. In addition to bid costs, NPVRR accounts for costs of PGE's existing portfolio of resources and the cost of generic resource added to meet needs beyond what is met by bids.[22] Portfolio risk is illustrated using the tail value at risk (TailVAR) at the 90th percentile of NPVRR across all futures. Portfolios with lower TailVAR scores tend to have less costly worst-case scenario outcomes for customer cost impacts. 2028 portfolio emissions are shown in million metric tons of carbon dioxide equivalent (MMTCO2e). Portfolios with 2.99 MMTCO2e, are consistent with PGE's linear glidepath toward achieving the HB 2021 1.62 MMTCO2e 2030 target for emissions. For Portfolio 1-12, this assumes the acquisition of additional non-emitting resources in addition to initial shortlist projects. Conversely, Portfolios 13-24 do not contemplate an energy need and therefore their resulting emissions are not representative of meeting anticipated energy needs in 2028. These results are shown for the 24 unique portfolios below in Table 8.

Table 7 shows the combination of bids that are added in each of the 24 portfolios. The presence of a bid in each portfolio is indicated with an "x" mark. The presence of generic resources is also indicated with an "x." Because nearly all bids are one of two or more mutually exclusive

[21] Because the ELCC of bids are calculated independently, interactive effects between the bids are not accounted for and the diminishing value of incremental bid additions is not captured, making these estimates likely representative of an upper bound of the total capacity contribution of each portfolio of bid additions.
[22] The NPVRR metric presented here is useful for comparison of relative costs across the portfolios included in this analysis. Because of the impact of baseline assumptions about variables such as the cost of generic resources, the cost values should not be compared directly against portfolios from other PGE analyses.

variants from a common bidder, the maximum number of bids that can be added in any portfolio is 13. The maximum number of bids added in any portfolio is nine. Fifteen of the 25 bids were selected at least once. The bids that are never selected are less competitive than the other bid(s) from within their own group of mutually exclusive variants. There are no bids that are selected in every portfolio. Bid 71.2 Base is selected the greatest number times, appearing in 22 of the 24 portfolios.

Table 7: Portfolios contents

		Portfolios																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Bids	10.1.Base	X	X	X	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	-	-	-	-
	10.1.Alt1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	16.1.Base	X	X	X	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	-	-	-	-
	23.1.Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23.1.Alt2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23.2.Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	23.2.Alt2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	27.1.Alt2	-	-	X	X	-	-	X	X	-	-	-	X	-	X	-	X	X	X	X	X	-	X	-	X
	27.1.Alt3	X	X	-	-	X	X	-	-	X	X	X	-	-	-	-	-	-	-	-	-	-	-	-	-
	71.1.Alt1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	71.1.Alt2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	X	-	X	-
	71.2.Base	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	-	X	-	X
	71.3.Base	X	X	X	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	-	-	-	-
	74.1.Base	-	X	-	X	-	X	X	X	-	-	-	X	X	X	X	X	X	X	X	X	-	X	-	X
	74.1.Alt2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	74.2.Base	-	-	-	X	X	X	X	X	-	-	-	X	-	X	-	X	X	X	X	X	-	X	-	X
	74.2.Alt1	-	X	X	-	-	-	-	-	-	X	-	-	-	-	X	-	-	-	-	-	X	-	X	-
	88.2.Alt1	-	-	-	-	-	-	-	-	-	-	-	-	X	-	-	-	-	-	-	-	-	X	X	X
	88.2.Alt2	-	-	-	-	-	-	-	-	-	-	-	-	-	X	-	X	X	X	X	X	-	-	-	-
	92.1.Alt3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	92.1.Alt4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	105.1.Alt1	-	X	-	-	X	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	105.1.Alt4	-	-	X	X	-	-	X	X	-	-	X	X	-	-	-	-	-	-	-	-	-	-	-	-
	150.1.Alt1	X	X	X	X	X	X	X	X	X	X	X	X	-	-	-	-	-	-	-	-	-	-	-	-
	150.1.Alt2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generics	VER	X	X	-	-	X	X	-	-	X	X	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Capacity	-	X	X	X	X	X	X	X	-	X	X	X	X	X	X	X	X	X	X	X	X	X	-	X
	NG	-	-	X	X	-	-	X	X	-	-	-	X	-	-	-	-	-	-	-	-	-	-	-	-

Table 8: Portfolios results summary for 2028

[Begin Confidential]

Portfolio	Bid nameplate (MW)	Bid capacity contribution (MW)	Bid energy (MWa)	Portfolio cost – NPVRR (Million $)	Portfolio risk - TailVAR 90 (Million $)	Portfolio 2028 emissions (MMTCO2e)
1	1802	678	332	[redacted]	[redacted]	2.99
2	2802	1154	422	[redacted]	[redacted]	2.99
3	2602	1067	426	[redacted]	[redacted]	3.39
4	2802	1188	423	[redacted]	[redacted]	4.62
5	2602	1039	427	[redacted]	[redacted]	2.99
6	2802	1157	423	[redacted]	[redacted]	2.99
7	2802	1188	423	[redacted]	[redacted]	4.11
8	2802	1188	423	[redacted]	[redacted]	5.33
9	1802	678	332	[redacted]	[redacted]	2.99
10	2002	792	328	[redacted]	[redacted]	2.99
11	2402	953	430	[redacted]	[redacted]	2.99
12	2802	1188	423	[redacted]	[redacted]	4.09
13	462	257	3	[redacted]	[redacted]	2.99
14	1227	618	55	[redacted]	[redacted]	2.99
15	462	261	3	[redacted]	[redacted]	2.99
16	1227	618	55	[redacted]	[redacted]	2.99
17	1227	618	55	[redacted]	[redacted]	2.99
18	1227	618	55	[redacted]	[redacted]	2.99
19	1227	618	55	[redacted]	[redacted]	2.99
20	1227	618	55	[redacted]	[redacted]	2.99
21	241	132	7	[redacted]	[redacted]	2.99
22	1027	539	59	[redacted]	[redacted]	2.99
23	441	242	3	[redacted]	[redacted]	2.99
24	1027	539	59	[redacted]	[redacted]	2.99

[End Confidential]

The most-costly portfolio in the analysis (Portfolio 8) results from a combination of High load growth, no hydro extensions, and no access to the generic VER resource, while having to meet both energy and capacity needs. Portfolio 8 adds 2802 MW of bids and has a NPVRR of **[Begin Confidential]** [redacted] **[End Confidential]**. The outcomes of Portfolio 8 are illustrative of findings across the range of portfolio configurations and the main conclusions, which are generally intuitive. The key findings are summarized below.

a. A large quantity of non-emitting capacity is required

PGE's capacity needs are significant. PGE's Response to Staff's Round 2 Comments and Recommendations in the LC 80 docket identified 2028 capacity needs of 905 MW in summer and 787 MW in winter.[23] Across all 24 portfolios, an average of 1710 MW (748 MW of capacity contribution) of bids are added.[24] Portfolios that are analyzed without the presence of any energy need still added an average of 919 MW (473 MW of capacity contribution) of bids just in service of meeting capacity needs.

b. Bilateral hydroelectric contracts have significant value

Results of portfolios with current hydro contracts extended perform much better than those without. On average, portfolios that do not include hydro contract extensions add 409 nameplate MW more bids (and additional generics) and have an increase in NPVRR of $1.69 billion and an increase in risk of $2.04 billion compared to those that include hydro contract extensions.

c. Elevated load growth will increase the need for resource additions

In portfolios with High load growth assumptions an average of 1990 nameplate MW of bids are added. High load portfolios contain 316 MW more bids compared to portfolios analyzed with Reference load growth.

d. Increasing energy additions increase cost and risk

Portfolios subject to energy needs add on average 401 MWa of energy from bids, while portfolios with no energy need add only 39 MWa of energy from bids (the bids in portfolios without an energy need are added for the capacity they provide rather than the 39 MWa of

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[23] LC 80, PGE's Response to Staff's Round 2 Comments and Recommendations.

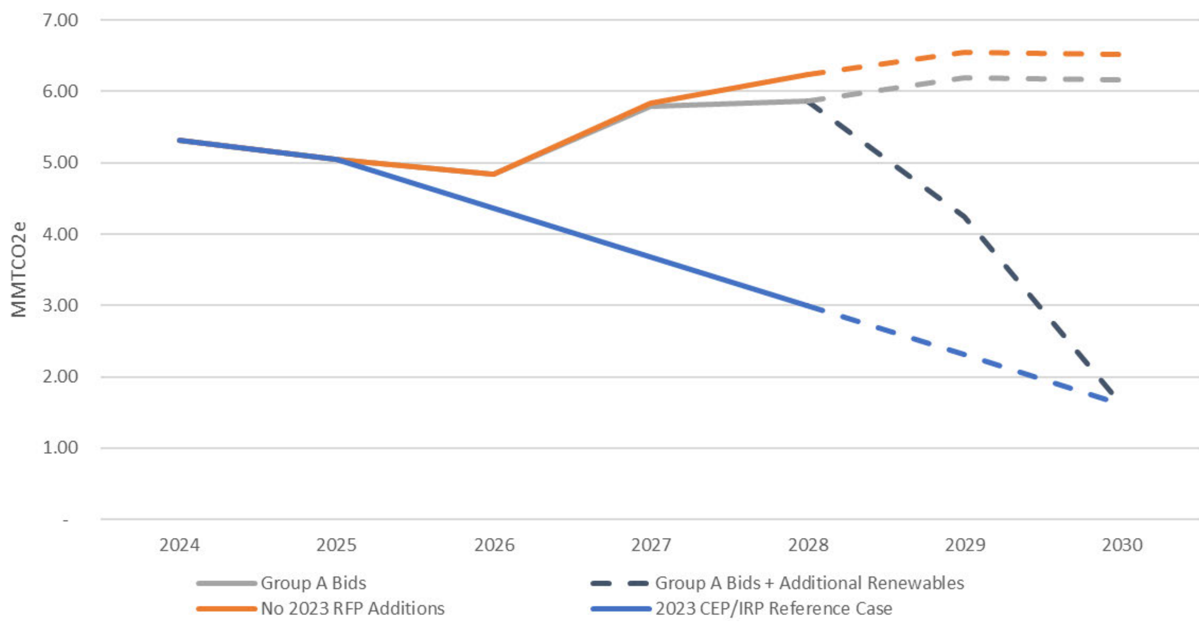
[24] PGE notes that the portfolio construction methods used in the 2023 CEP/IRP aggregate individual resources' capacity contributions, which omits the portfolio effect of the resources acting in concert together. Some combinations of resources could increase the total capacity contribution beyond the individual components: solar and storage is an intuitive example. However, other combinations such as multiple battery storage resources could result in a lower aggregated capacity contribution, as the battery storage becomes less effective at reducing capacity need as more of the resource is added.

associated energy). On average the portfolios with energy need have higher cost and risk, with average NPVRR $12.73 billion higher and average risk $17.04 billion higher than portfolios required to meet capacity need-only.

e. Achieving PGE's emission reduction forecast will require more non-emitting generation than is available in this RFP

No portfolios can meet energy needs without the addition of generic VERs such as resources likely to be acquired via future RFPs. The 2023 CEP/IRP Action Plan included an action to acquire approximately 250 MWa every year between 2026-2030 (for resources beginning operation on or before those given years). The 2023 RFP was developed to solicit bids to fill the approximately 750 MWa need through 2028 (resources with CODs on or before December 31, 2027). Selecting the largest variant of all available energy bids would only lead to the addition of 425 MWa. PGE anticipates continuing acquisition toward these targets in future RFPs. Figure 3 below shows multiple emissions levels associated with various future acquisition scenarios, all of which allow PGE to meet forecasted reference case energy needs. Shown with the 'Group A Bids' line is the emissions trajectory with the addition of the Group A bids without the ability to rely on generic non-emitting resources, including future RFP acquisitions, or hydro contracts extensions. With future acquisitions via RFPs, including one that will be issued following this RFP, PGE's emissions trajectory will likely continue to fall, as shown in the 'Group A Bids + Additional Renewables' scenario line. For comparison, Figure 3 also shows the 2023 CEP/IRP reference case emissions trajectory and PGE's projected emissions in the absence of the addition of bids from the 2023 RFP.

Figure 3: Forecasted Emissions between 2023 CEP/IRP and Group A Bids



This is an intuitive result. PGE has consistently maintained since the filing of the 2023 CEP/IRP that the only means available for PGE to unilaterally reduce emissions has been the acquisition of non-emitting generation resources, including both resources acquired through RFPs like this one, smaller resources acquired via methods like our CBRE RFP, bilateral contracting, and qualifying facilities, or behind-the-meter generation. The CEP/IRP Update will continue to explore PGE's next steps in procurement and decarbonization following the completion of this RFP.

4. Generic Resource Cost Sensitivity

Given the uncertainty in the cost and availability of non-emitting generation in the future beyond this RFP, PGE tested the impact of higher resource costs in the future on optimal portfolio outcomes. PGE tested a future with more expensive resource acquisition beyond this RFP by re-analyzing all portfolios with the generic resources cost after 2028 doubled compared to the initial analysis. Table 9 below shows the total nameplate MW of bids added in each portfolio under the original and higher-cost assumptions for generic resources. The results of this analysis are logical;

when faced with higher-cost resources in the future, it becomes optimal to add a larger quantity of bids to not only target near-term needs but also future needs, thus avoiding more-costly resource additions in the future.

Table 9: Portfolios results summary for higher-cost generics 2028

Portfolio	Bids added (nameplate MW)		Increase in MW quantity (%)
	Original analysis	Higher-cost generics	
1	1802	2932	63%
2	2802	2802	0%
3	2602	3032	17%
4	2802	2802	0%
5	2602	3632	40%
6	2802	3532	26%
7	2802	3232	15%
8	2802	3232	15%
9	1802	2402	33%
10	2002	2602	30%
11	2402	2602	8%
12	2802	2802	0%
13	462	2462	433%
14	1227	2462	101%
15	462	2462	433%
16	1227	2462	101%
17	1227	2462	101%
18	1227	2462	101%
19	1227	2462	101%
20	1227	2462	101%
21	241	2441	913%
22	1027	2362	130%
23	441	2441	454%
24	1027	2362	130%

5. Increased Energy Storage Additions

At the request of OPUC Staff, PGE evaluated its ability to reduce forecasted emissions by adding additional storage resources. The Company is currently developing its capacity to robustly estimate its hourly energy position in response to stakeholder and Commission feedback in LC 80. PGE is including this information in this filing per Staff's request, but anticipates that these issues will be developed and discussed more fully in the upcoming IRP Update process. A corresponding emissions forecast can then be created assuming the availability of energy on the bilateral market that carries emissions at the unspecified rate. PGE can apply the currently available methodology to this RFP by examining what reduction of forecasted emissions can be realized by adding additional storage bids. Storage resources can move non-emitting energy from times when the Company is long to times when it is short, which removes the need for PGE to acquire energy with associated emissions.

PGE simulated its energy position in 2028 using the forecasted supply and demand articulated above in Table 5. The forecast assumes that existing hydro contracts are extended through 2028. Importantly, PGE attempted to constrain its existing thermals to the emissions reduction glidepath established in LC 80 by limiting the total plant output MWh to the thresholds established in the IRP's IGHG model. Resource additions were considered by adding characteristics of the bids described below in Table 10: three groups of resource additions were created by adding different quantities of energy bids.

Table 10: Base resource additions considered

Additions	Portfolio A	Portfolio B	Portfolio C
Base storage addition (MWa)	977	977	977
Energy addition (MWa)	0	585	1170

PGE simulated the 2028 hourly position of each of these three options. This simulation was conducted in IRP PGE-Zonal Model (PZM) using Aurora. There were several changes incorporated in the PZM to better reflect the goal of meeting both load requirements and emissions compliance. This was accomplished by changing the dispatch logic from dispatching resources to WECC prices to dispatching resources to meet demand at minimum cost. The model dispatched thermal generation subject to two constraints: (1) the annual cap on total output (established by the IGHG model) and (2) hourly cap on thermal generation subject to the output from the economic dispatch established in the 2023 CEP/IRP. This second constraint was incorporated to prevent the model from dispatching thermals outside of the range deemed economic by the unconstrained PZM optimization.

The model also modified the dispatch logic of storage resources to shape charging and discharging to net demand (load minus must-run resources) instead of price. This logic uses dispatchable storage to smooth the hourly shape of the system by moving energy from periods of deficit to periods of shortage.

PGE then entered the total resource output and demand into its outboard hourly model. The outboard hourly model then applies market purchases in accordance with the quantity (MWhs) specified in the IGHG model. For hours where a short position remains, the hourly model applies the unspecified emissions rates consistent with ODEQ emissions accounting methodology to these remaining short positions. The assumption is that after applying the thermal generation and market purchases calculated in the IGHG model, any remaining need required to serve load must be met by additional unspecified market purchases. Using these assumptions, the outboard hourly model then calculated the average hourly position and emissions forecast. The average hourly position and associated emissions forecast for each of the base resource additions are displayed below in Table 11.

Table 11: Resulting energy position and annual emissions forecast of base resource additions

System Metrics	Portfolio A	Portfolio B	Portfolio C
Averaged energy position (MWa)	-544.89	-353.41	-141.51
Forecasted emissions (mmtCO2e)	2.85261	2.24555	1.62000

PGE then added incremental quantities of storage and optimized the resource's operation. This was performed in the excel-based hourly accounting model to reduce the total short position. The additional storage resources further levelized the hourly position to reduce any remaining short hourly positions. This led to the emissions reductions displayed in Table 12.

Table 12: Resulting energy position and reduction in annual emissions forecast due to incremental storage additions

Additional Storage (MW)	**Portfolio A** MWa (mmtCO2e)	**Portfolio B** MWa (mmtCO2e)	**Portfolio C** MWa (mmtCO2e)
50	-545.13 (0.00289)	-353.74 (0.00418)	-141.95 (0.00562)
100	-545.28 (0.00559)	-354.05 (0.00811)	-142.31 (0.01085)
150	-545.43 (0.00805)	-354.25 (0.01192)	-142.64 (0.01576)
200	-545.55 (0.01036)	-354.4 (0.01556)	-142.95 (0.02035)
250	-545.67 (0.01263)	-354.71 (0.01905)	-143.36 (0.02455)
300	-545.77 (0.01485)	-354.74 (0.02235)	-143.48 (0.02848)

These results highlight that energy and capacity resources can complement each other; the total emission reductions are greater than the sum of the resource additions. However, PGE has several concerns about the specificity of these results, which are discussed here and will be more fully analyzed in future IRP cycles.

First, these are draft analyses based on an evolving approach: it is probable that PGE refines these methods and the results presented in the CEP/IRP Update are tangibly different. Several variables in the PZM have not been updated to reflect the same data that will be used in modeling for the CEP/IRP Update.

Second, the storage logic in the hourly model is a layered approach and is optimized around the remaining position after applying market purchases and thermal generation. This avoids any additional benefits available from co-optimization with thermal generation and the ability to address short positions prior to applying market purchases.

Third, the model does not include any estimates of the availability of non-emitting market energy from outside of PGE's own generation supply.

Fourth, the storage logic employed in the PZM does not allow the storage resource to be charged by resources outside of PGE. No efforts were taken to allow storage resources to charge with non-PGE resources given that current ODEQ rules require any energy flowing into PGE from energy imbalance markets or other centralized markets administered by a market operator to be assigned the unspecified rate. Since this is the same emissions rate that is applied to the remaining short positions in the hourly accounting model, there is no reason to introduce charging to grid unless market or regulatory changes are made.

Fifth, the PZM uses a deterministic view of future years for variable energy resources, resource adequacy modeling scenarios and the hourly load profile. Without stochastic representation of these sources of uncertainty, the model will suffer from overfitting and may be too closely aligned with historical data.

As noted above, PGE included this analysis per Staff's request, but cautions against reliance on these results for the aforementioned reasons and looks forward to discussing these issues in subsequent IRPs.

IV. Procurement Strategy and Risks

PGE's RFP price scoring and portfolio analysis provides a strong analytical foundation to facilitate PGE's procurement decisions. PGE assessed all bids against a set of minimum requirements, which were designed in consultation with Staff, the IE, and regulatory stakeholders to reduce risk associated with project delivery. With respect to the identification of the best projects for customers, PGE focused on price scoring analysis primarily to identify least-cost, least-risk projects. PGE prioritized reliability and customer affordability in its FSL construction. The Group

A projects represent top performing price scoring projects. This selection of projects provides up to 550 MW of capacity contribution and 93 MWa of incremental renewable energy.

The FSL Group A projects present the most compelling value to customers while addressing both energy and capacity needs, as these projects have up to an estimated net price impact of 1.5%.[25] PGE's FSL Group B projects are similarly well-positioned to help us meet our remaining capacity need via non-emitting resources. Group B is comprised of five projects that may or may not be procured; if all are procured, we currently estimate an additional net price impact of approximately 1.5%. While these projects do not have the technology diversity available in Group A, they are valuable as capacity options if needed.

Separate from Groups A and B, there were four unique renewable projects that PGE has chosen not to pursue, which were on the initial shortlist but not selected for the final shortlist and are therefore not included on either Group A or B final shortlist. The primary reason these projects were not included in the final shortlist for the 2023 RFP was their anticipated impact to customer prices. In PGE's opinion, customers may be better served by delaying acquisition of these or similar projects. PGE intends to run additional All-Source RFPs before 2030 in order to find additional clean energy resources from the market that offer reliability and efficiency at the lowest cost to customers.

Upon making this filing, PGE intends to commence negotiations with the identified top performing counterparties (Group A) and PGE will look to execute agreements with those top performing bidders who honor the price and design features of their bids. PGE looks to finalize

[25] PGE calculates net price impact for the purposes of the RFP as: the average of the first five years of the revenue requirement model which includes total project cost, minus the long-term project benefit in the form of energy, capacity, and flex capacity. The benefit of energy, capacity, and flex capacity is as calculated in PGE's acknowledged 2023 IRP. Actual future price impacts may vary from this estimate. This is intended to be demonstrative in this proceeding and not a forecast of guarantee of price impacts.

this work by the end of Q1 2025 and will continue working with counterparties until PGE's capacity resource needs are satisfied. Renewable resource supply chains are presently disrupted, particularly for solar and lithium-ion batteries. It remains unclear whether all projects on the final shortlist will be able to honor the terms and conditions of their offer due to: 1) the loss of the bifacial module exclusion under Section 201 Tariffs, 2) Section 301 Tariffs, which apply to both solar and storage projects, 3) the Auxin Anti-Circumvention Case, and, 4) the ongoing Solar 3 anti-dumping and countervailing duty petition, with Department of Commerce determinations not expected until later this year. PGE's due diligence thus far indicates that solar and storage bidders expect to be impacted unevenly by this investigation. These uncertainties highlight the importance of PGE identifying both FSL Group A and FSL Group B for commercial negotiations.

VI. COMPLIANCE WITH COMMISSION ORDERS

Below is a comprehensive accounting of each of the conditions adopted by the Commission when approving PGE's 2023 RFP and how PGE complied with each condition. These conditions are grouped into the categories of SMM, RFP, and PRR conditions.

When developing the 2023 RFP, PGE stated its intent to use an affiliate, Portland Renewable Resource Company (PRR), as a potential vehicle to enable full realization of the Investment Tax Credit for the benefit of PGE customers. However, on April 25, 2024, the IRS released final regulations on rules to transfer eligible credits. The guidance explained that a taxpayer is not subject to the normalization rules for any credit that is transferred. As a result of this guidance, PGE no longer needs to make use of the affiliate to avoid normalization. Instead, PGE would opt to transfer tax credits and avoid normalization that way. For these reasons, PGE did not contemplate the use of PRR in its 2023 RFP evaluation. However, PGE includes its compliance with the PRR conditions in this filing for completeness.

A. Scoring and Modeling Methodology Conditions

SMM Condition 1: "PGE will remove footnote 4 regarding permitting from the Minimum Bidder Requirements in Appendix N."[26]

To comply with this condition, PGE deleted Footnote 4 from Appendix N in advance of final issuance of documents on February 2, 2024.

SMM Condition 2: "Staff's recommendation is eliminated. The Project Labor Agreement requirement will remain as a minimum bidder requirement."[27]

No further action was required from PGE as the Commission declined to adopt the recommendation to eliminate PGE's Project Labor Agreement.

SMM Condition 3: "The RFP will be adjusted to require all bids to include a term sheet with redlines that are reflected in their bid price. Bidders may, but are not required to, supply contract redlines."[28]

For the 2023 RFP, PGE applied feedback from 2021 process and eliminated this non-price scoring element, and instead used a voluntary redlined form contract. The Commission adopted Staff's recommendation but modified it so that bidders were required to redline term sheets rather than form contracts.

To comply with this condition, PGE updated the 2023 RFP documents to include this redline requirement and updated the bid form to reflect this change. In the updated bid form's Minimum Bid Requirements, including question numbers 16 and 17 were changed and PGE also updated the Main RFP document.[29]

[26] Order No. 24-011, Appendix A at 73.
[27] Order No. 24-011 at 1.
[28] Order No. 24-011 at 1.
[29] See 2023 RFP Main Document, Pages 13-14.

SMM Condition 4: "PGE's RFP will make clear that the company will treat all bids using Conditional Firm - System Conditions (CF-SC) transmission products as conforming, including both energy and dispatchable capacity resources."[30]

To comply with this condition, PGE made the relevant changes to the bid form (Tab 6), adding renewable resource data to include two questions (one each for PPA and ownership proposals). PGE also adjusted pages 6 and 12 in Appendix N. These changes were included in the issuance of final documents on February 2, 2024.

SMM Condition 5: "PGE will reduce the transmission requirement for renewable resources included in Appendix N of the RFP from 80 percent of the resource's interconnection limit to 75 percent of the resource's interconnection limit, to align with the requirements of the Western Resource Adequacy Program."[31]

To comply with this condition, PGE adjusted Appendix N to clarify that the minimum requirement was 75%, and adjusted question number 26 in the minimum bidder requirements segment of the bid form. The adjustment to the bid form and Appendix N were both included as part of the final issuance of the RFP on February 2, 2024.

SMM Condition 6: "We adopt PGE's revision to Staff's recommendation, which is that PGE will use the transfer discount rate approved in docket UP 424, Order No. 23-459 for the purpose of price scoring."[32]

To comply with this condition, PGE updated the price scoring model to incorporate the transfer discount rate from UP 424 for all credits from ownership-based projects in the 2023 RFP. PGE also updated page 10 of Appendix N to reflect this change.

[30] Order No. 24-011 at 1.
[31] Order No. 24-011 at 2.
[32] Order No. 24-011 at 2.

SMM Condition 7: "PGE does not add or apply any cost of imputed debt to the price scores of any bids, specifically those using PPAs or similar contractual structures that do not involve the utility taking ownership."[33]

To comply with this condition, PGE removed this element from Page 9, Appendix N of the RFP document and did not add or apply any cost of imputed debt as part of price scoring.

SMM Condition 8: "PGE must require all bidders to provide their actual reserve rate costs and use those costs in its price scoring rather than assess all bids using BPA reserve rates."[34]

To comply with this condition, PGE modified both Appendix N, Page 9 and the bid form, offer details tab. No bidder provided an alternative reserve rate cost in the submitted bids.

SMM Condition 9: "All RFP bids must include one price with and one price without assumed EIR financing. PGE must develop the rules/methodology for all bids to calculate this additional bid price as part of the RFP."[35]

To comply with this condition, PGE modified the RFP's Main Document, Page 15, under the Final Shortlist section.

SMM Condition 10: "For resources with CF-SC transmission rights, PGE will allow bidders to propose their own curtailment parameters, subject to commercial negotiation with PGE and review by the IE."[36]

PGE consulted with Staff and the IE to ensure a common understanding of this element. The IE recommended allowing bidders to propose a contractual mechanism that would serve to cap the risk associated with CF-SC rights. PGE adopted this recommendation and included a description of the opportunity for bidders to propose curtailment parameters within Appendix N.

[33] Order No. 24-011, Appendix A at 74.
[34] Order No. 24-011, Appendix A at 74.
[35] Order No. 24-011, Appendix A at 74.
[36] Order No. 24-011, Appendix A at 74.

<u>SMM Condition 11:</u> "For resources with CF-NH transmission products, PGE will value their capacity on the assumption that those projects will be curtailed such that 50 percent of curtailable hours would occur within PGE's peak hours of need."[37]

PGE confirms that this modeling approach was already incorporated into draft 2023 RFP documents and is described in Appendix N, Page 11.

<u>SMM Condition 12</u>: "If the RFP includes PRR bids, PGE must provide a comparison of its ISL with and without the participation of PRR bids. Further, the IE will provide an analysis and report on any impacts, finding, and recommendations regarding impact of PRR bids on the ISL."[38]

As noted above, following the Public Meeting, IRS guidance released on April 25, 2024, which clarified that tax credits sold by a public utility are not subject to normalization, and removed the need or use of PRR to avoid tax normalization. Thus, the principal adjustment to the 2023 RFP docket was that PGE would no longer contemplate use of PRR as a procurement vehicle for ITC subject to normalization. As a result, PGE made no further adjustments.

B. RFP Conditions

<u>RFP Condition 1</u>: "PGE shall ensure that the IE shall monitor and report PGE's progress on its EIR application as part of its closing report. The closing report must include a comparison analysis of with/without EIR Financing on the FSL."[39]

To comply with this condition, PGE adjusted the RFP's main document, updating the IE's roles and responsibilities on Page 6. PGE emailed the Department of Energy (DOE) Loan Program Office (LPO) on March 27, 2024, to receive clarity in how EIR financing could be extended to non-utility owned assets. On April 5, 2024, the DOE LPO responded that they cannot finance

[37] Order No. 24-011, Appendix A at 74.
[38] Order No. 24-011, Appendix A at 74.
[39] Order No. 24-011, Appendix A at 74.

utility expenses associated with PPAs, but the developers could seek LPO funding directly. As a result of this clarification, PGE understood that it could not file an EIR application on behalf of bidders and no further action was necessary. PGE shared this outcome with Staff, and they confirmed that PGE correctly posed the question to DOE consistent with Staff's understanding of the program at the time.

RFP Condition 2: "Prior to issuance, PGE must provide a description of how it would prioritize resources to fill its capacity needs. PGE must ensure that this description, and PGE's execution of the prioritization, will be evaluated by the IE in its closing report."[40]

To comply with this condition, PGE updated Appendix N, page 10. PGE confirms that this was evaluated in the IE's report attached as part of this filing.

RFP Condition 3: "Prior to issuance, PGE will provide the 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) for each benchmark bid and if they will be transferred to the Affiliate Interest, PRR."[41] "Staff's recommendation is adopted, except that Staff, PGE, and the IE shall examine and, if appropriate, revise the list of information in Staff's condition to ensure that it (a) is no broader than the information other Oregon-regulated utilities have provided in recent RFPs; and (b) does not require PGE to violate any existing or reasonably negotiated non-disclosure agreements."[42]

To comply with this condition, Staff and the IE worked directly with the Benchmark team. The Benchmark team updated Appendix P, which was filed on February 2, 2024, and made available with the 2023 RFP issuance, which was available on a publicly accessible website.

[40] Order No. 24-011, Appendix A at 75.
[41] Order No. 24-011, Appendix A at 75.
[42] Order No. 24-011 at 1.

RFP Condition 4: "Prior to issuance, PGE will update Appendix P to include analysis supporting its decision not to make the elements associated with the Biglow Canyon Wind Farm available to non-utility-ownership bids."[43]

To comply with this condition, PGE updated Appendix P to provide more analysis on why the different utility owned assets were not being made available for third-party ownership. This analysis was included in the issuance of final documents and filed in the docket on February 2, 2024.

RFP Condition 5: "Prior to issuance, PGE will update Appendix P to provide a more thorough analysis of its security concerns regarding the parcels of land that will be made available for benchmark bids if they will not be made available to third-party bids. This analysis should specifically discuss note any existing examples of co-location on its system."[44]

To comply with this condition, PGE updated Appendix P to include a Security and Operational Analysis section which was included in the issuance of final documents and filed in the docket on February 2, 2024.

RFP Condition 6: "We adopt RFP Condition 6 and direct the IE to review whether any of the additional information requested by Renewable Northwest and NIPPC is reasonable to provide. We understand PGE's argument that this condition goes beyond the analysis required by our competitive bidding rules, and yet we consider the condition justified by (a) the unique circumstances of our decision to allow PRR to participate in this RFP; (b) PGE's continuing reluctance to seriously consider and analyze the potential benefits of making ratepayer-funded assets available; and (c) our need to gather information to determine whether PGE has overlooked more cost-effective ways to leverage ratepayer-funded assets. If PGE has security concerns

[43] Order No. 24-011, Appendix A at 75.
[44] Order No. 24-011, Appendix A at 75.

regarding the release of critical infrastructure information or other asset details, it should not disclose that information. The IE and, if necessary, the Commission, will review disclosure concerns."[45]

To comply with this condition, PGE added straw bid description and instructions to Main Document on page 9, and site info was made available in the weeks after discussions with Staff and the IE in late-January 2024. Straw bids are discussed further in Section III.

RFP Condition 7: "PGE shall retain the IE to oversee Contract Negotiations and include evaluation of the role of performance guarantee in negotiations and drivers and outcomes of price updates."[46]

In the 2021 RFP, both the Commission and Staff asked the IE to remain involved in providing oversight to the process after acknowledgement of the final shortlist, to observe the contract negotiation phase, to gain further transparency into that stage of PGE's acquisition process. The IE provided a closing report of the negotiations process in the 2021 RFP. Commission has requested that IE perform the same duties in the 2023 RFP process.

PGE had previously incorporated those expectations for the IE's role and responsibilities in the RFP Main Document, so no changes were necessary to comply with this requirement.

RFP Condition 9: "Form Contracts must clarify that a project can comply with state and federal labor requirements in the various applicable ways under those laws."[47]

To comply with this condition, PGE confirmed the form contracts aligned with this requirement, therefore no further changes were necessary. On February 2, 2024, PGE made

[45] Order No. 24-011 at 2.
[46] Order No. 24-011, Appendix A at 75.
[47] Order No. 24-011, Appendix A at 75.

available redlines of form contracts and term sheets on its public 2023 RFP website to allow both the IE and stakeholders to see the changes as requested by the Commission order.

RFP Condition 10: "In our initial written order, we did not address RFP Condition 10, which reads:

> PGE will require contract redlines from all bidders if their bid price is based on contractual or commercial terms other than those contained in the form contracts provided by the Company.
>
> We determined at the public meeting, and reiterate here, that we do not adopt this condition in full. Instead, the requirement will be for redlined term sheets, not a full redlined contract.[48]

To comply with this condition, PGE ensured that both term sheets and form contracts were posted on the company's RFP website for transparency with the developer community, but made clear in the RFP Main Document, Pages 13-14, that only redlined term sheets were required.

RFP Condition 11: "PGE shall retain the IE through final resource selection. PGE will require the IE to monitor all contract negotiations. In addition to filing a final resource selection closing report with the Commission no later than 30 days after final resource selection, the IE will report at least monthly on contract negotiations and any impacts to pricing or bid withdrawals. The final report will include a full analysis of how the specific commercial terms shaped the Final Shortlist seeking acknowledgement and any impact to bid prices, including but not limited reporting on contract negotiations, which shall include, but not be limited to analysis of negotiations on the following contract terms: Guaranteed COD; Transmission Upgrade Cost; Transmission Scheduling of Energy Effective Date; curtailment; and output guarantees."[49]

To comply with this condition, PGE updated the RFP Main document, Page 6, to reflect these IE requirements.

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[48] Order No. 24-024 at 1.
[49] Order No. 24-011, Appendix A at 75-76.

RFP Condition 12: "Prior to issuance, PGE will amend Appendix P of the RFP to include a proposed cost adder for the long-term service agreement costs associated with any utility-ownership bid. PGE will ensure that the IE will evaluate the appropriateness of this cost adder in its report on benchmark bids."[50]

PGE clarified the intent of Condition 12 with Staff and verified that the information provided in Appendix P should be generic LTSA costs to provide a comparative baseline for bid submissions. PGE was unable to find publicly available LTSA information (i.e., service level, term, pricing, etc.) so discussed alternative options with the IE. To comply with this requirement, PGE, with agreement from the Staff and IE, used 2021 RFP data to provide a basis for LTSA costs in an updated Appendix P.

RFP Condition 13: "PGE amend the RFP to allow bidders to provide a price with and without RECs should they so choose with no penalty or preference given either way. PGE and the IE in their reports to the Commission will include an analysis on the cost and risks tradeoffs in assessing the value of RECs from bids and how the logic behind the valuing of RECs is reflected in the bids making the initial shortlist and final shortlist along with the final projects selected."[51]

To comply with this condition, PGE updated the bid form's Offer Details tab to allow bidders the opportunity to submit pricing with and without RECs. No bidder provided pricing with and without RECs during the 2023 RFP evaluation. Therefore, there was no further actionable analysis regarding the cost and risks tradeoff in assessing the value of RECs.

C. PRR Participation Conditions

PRR Participation Condition 1: "PGE will provide the IE a list of all employees working as part of the RFP team, the Benchmark team, and any employees performing duties on behalf of PRR,

[50] Order No. 24-011, Appendix A at 76.
[51] Order No. 24-011, Appendix A at 76.

including the roles, and associated dates of their work for the various teams at the time it files its benchmark score, at the time it files its FSL, and again after it has completed negotiations for all PRR bids."[52]

To comply with this condition, PGE submitted a list of personnel for each of the three groups when it filed its benchmark score. PGE has also included an updated list as confidential Appendix B to this filing.

PRR Participation Condition 2: "PRR participation in this RFP is conditional upon Third-Party ITC-e bids being treated in a similar manner as benchmark bids."[53]

To comply with this condition, PGE documented the adjustment in a disclosure attached to the Main RFP Document, page 7. PGE accessed ITC-e bids on April 5, 2024, and scored, consulted with the IE, and sealed these bids before accessing all remaining third-party bids.

PRR Participation Condition 3: "PGE must publish in the RFP, its formula for forecasting PPA prices as part of the RFP evaluation for ISL / FSL selection as well as its methodology and/or formula for converting BTA / APA costs to PPA as a condition of PRRs inclusion in the RFP."[54]

In a January 2024 meeting with Staff, PGE shared that the utility relies on a process rather than a singular formula. PGE would utilize a set of standardized economic practices, described in the RFP Main Document, page 13, to convert the BTA price to PPA price. After detailing PGE's process and proposed update to the RFP document, Staff agreed to that course of action.

To comply with this condition, PGE included this process in the RFP Main Document to outline PGE's approach.

[52] Order No. 24-011, Appendix A at 76.
[53] Order No. 24-011, Appendix A at 76.
[54] Order No. 24-011, Appendix A at 76.

PRR Participation Condition 4: "ITC-e bidders are allowed to include a forecasted PPA price in their bid that the IE can compare with the forecasted price calculated by the RFP team and the ultimate PPA price resulting from executed BTA/APA contract terms and conditions."[55]

To comply with this condition, PGE added a question in the bid form, on the offer details tab, to allow bidders to provide a forecasted PPA price and included an explanation in Appendix N, page 9.

PRR Participation Condition 5: "RFP Evaluation team is responsible for converting BTA/APA prices to PPA prices."[56]

To comply with this condition, PGE updated the Main RFP Document, page 13, to describe this process.

PRR Participation Condition 6: "The PRR Form PPA should remove section 2.5 regarding the option to purchase or extend terms."[57]

To comply with this condition, PGE modified the PRR form PPA document, and the result was submitted to the IE on February 6, 2024.

PRR Participation Condition 7: "PGE must remove Section 8.4 from the PRR Form PPA."[58]

To comply with this condition, PGE modified the PRR form PPA document, and the result was submitted to the IE on February 6, 2024.

[55] Order No. 24-011, Appendix A at 76.
[56] *Id*..
[57] *Id*. at 77.
[58] *Id*..

PRR Participation Condition 8: "PGE shall align Pre-COD and Security Delivery amounts across PPA and EPC/APA contracts."[59]

To comply with this condition, PGE conferred with Staff and the IE as to how the requested terms should be aligned. The IE proposed the pre-COD security be $125/kW for all form contracts. PGE updated the form PPA and SCA to the proposed amounts. PGE provided these changes to the IE in January 2024. PGE then met with Staff and the IE to address the issue, with an email documenting the requested change dispatched in late January 2024. After the change, the IE confirmed its opinion that a pre-COD 100% performance bond is adequate in the form BTA and EPC and agreed that no further changes were needed to those forms.

PRR Participation Condition 9: "We do not adopt Condition 9. Instead, Staff is directed to address the explicit exclusion of PGE Benchmark team employees from the list of Receiving Party Representatives in PRR Power Purchase Agreements (PPA) in subsequent Affiliated Interest proceedings."[60]

No further action necessary by PGE.

PRR Participation Condition 10: "Transmission requirements in the form contracts shall match those specified in the RFP."[61]

To comply with this condition, PGE updated the form PPA and PPA/SCA.

[59] Order No. 24-011, Appendix A at 77.
[60] Order No. 24-011 at 3.
[61] Order No. 24-011, Appendix A at 77.

PRR Participation Condition 11: "The PRR PPA must include a value for the transmission upgrade cost cap consistent with the project's executed Build Transfer Agreement and or Asset Purchase Agreement, removing any negotiation of the cost cap in the PRR PPA agreements."[62]

To comply with this condition, PGE modified the PRR form PPA document, and the result was submitted to the IE on February 6, 2024.

PRR Participation Condition 12: "PRR PPA must include a value for the Transmission Scheduling of Energy Effective Date."[63]

To comply with this condition, PGE modified the PRR form PPA document, and the result was submitted to the IE on February 6, 2024.

PRR Participation Condition 13: "The IE will be required to oversee and report on contract negotiations between PGE and PRR, including negotiations on performance guarantees."[64]

To comply with this condition, PGE modified the IE's listed responsibilities in the RFP Main Document, page 5.

D. NIPPC Recommendations

The Commission adopted certain recommendations made by NIPP, and PGE has outlined these additional modifications.

[62] Order No. 24-011 at 3.
[63] Order No. 24-011, Appendix A at 77.
[64] Order No. 24-011 at 3.

<u>NIPPC Recommendation 1:</u> "The affiliate PPA must include a provision that allows regular (e.g., quarterly) audits by Commission Staff to ensure compliance with the affiliate PP A terms."[65]

To comply with this condition, PGE updated the PRR Form PPA, Section 17.2 to incorporate the requested change. PGE shared the modified PRR Form PPA with the IE on February 6, 2024, for their compliance review.

<u>NIPPC Recommendation 2:</u> "The affiliate PPA must include a provision providing that when any default occurs, or at the direction of the Commission, a Special Master may be appointed to the Commission to represent PGE customers. The Special Master will be independent of PGE and PRR and will oversee and enforce any defaults or disputes. The Commission must approve the appointment of the Special Master and PGE's shareholders will pay for the Special Master."[66]

To comply with this condition, PGE updated the PRR Form PPA, Article 5 with a note to draft that this provision would be included. PGE shared the modified PRR Form PPA with the IE on February 6, 2024, for its compliance review.

<u>NIPPC Recommendation 3:</u> "The affiliate PPA must include a provision stating that PRR will report to the Commission when the project is commercially operational, and that the Commission will determine if the project has achieved commercial operation consistent with the terms of the PPA."[67]

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[65] Order No. 24-011 at 3.
[66] *Id.*
[67] *Id.*

To comply with this condition, PGE updated the PRR Form PPA, Section 3.1.10 to include the conditions specified language. PGE shared the modified PRR Form PPA with the IE on February 6, 2024, for their compliance review.

NIPPC Recommendation 4: "Sections 11.1.1 and 11.1.2 in the affiliate PPA on the Mobile Sierra standard of review and the waiver of Federal Energy Regulatory Rights must be deleted."[68]

To comply with this condition, PGE updated the PRR Form PPA by removing Sections 11.1.1 and 11.1.2. PGE shared the modified PRR Form PPA with the IE on February 6, 2024, for their compliance review.

NIPPC Recommendation 5: "NIPPC argued in comments that we should require as a condition of approval, that PRR be required to post cash security rather than utilize a parental guarantee to support any specific project proposal. We decline to require such a condition but note specifically that though PRR may utilize a parental guarantee, the approved affiliated agreement makes clear that such a guarantee provides no recourse to ratepayers, and instead such a guarantee must fall to shareholders."[69]

No further action was required from PGE as the Commission declined to adopt NIPPC's recommendation that PRR be required to post cash security.

VII. COMPLIANCE WITH COMPETITIVE BIDDING RULES

A. OAR 860-089-0100 Applicability of Competitive Bidding Requirements

PGE's development and issuance of the 2023 RFP satisfies OAR 860-089-0100. OAR 860-089-0100 requires an electric company issue an RFP for all major resource acquisitions with

[68] Order No. 24-011 at 3.
[69] *Id*.

durations greater than five years and quantities greater than 80 MW. PGE's 2023 IRP action plan included both a capacity and energy action: the capacity action identifies a need in 2028 of 905 MW in summer and 787 MW in winter and the energy action recommended up to 750 MWa (2,250 MW nameplate) of renewable energy acquisition. The 2023 RFP—with the request for resources that could be online by December 31, 2027 (except in the case of long lead-time resources)—was intended to address the capacity need and make progress toward the identified energy actions from the 2023 IRP.

B. OAR 860-089-0200 Engaging an Independent Evaluator

As described in OAR 860-089-0200, prior to issuing an RFP, the electric company must engage the services of an IE. The IE will oversee the competitive bidding process to ensure it is administered fairly and in accordance with the Rules. The company asked for a partial waiver of OAR 860-089-0200(1), (2) and for the approval of Bates White to serve as IE for the 2023 RFP. The Commission adopted Staff's recommendation to grant the partial waiver and approve Bates White as the IE for the 2023 RFP.

C. OAR 860-089-0250 Design of Request for Proposals

PGE requested a partial waiver of OAR 860-089-0250(2)(a) to allow for concurrent consideration of the SMM and draft RFP for the 2023 RFP. The Commission adopted Staff's recommendation to grant the partial waiver on April 18, 2023.[70]

PGE filed the draft request for proposals on May 19, 2023, and the draft included:

- Minimum bid requirements;
- Standard form contracts;
- Bid evaluation and scoring criteria;

[70] Order No. 23-146.

- Language to allow bidders to negotiate mutually agreeable final contract terms that may differ from the standard contracts;
- Description of how PGE would share information about bid scores, including what information about the bid scores and bid ranking may be provided to bidders and when and how it will be provided; and
- Resource need consistent with the 2023 IRP.

PGE scheduled a pre-issuance workshop to solicit feedback from the stakeholder and bidder community. The IE submitted an assessment of PGE's initial draft RFP on May 31, 2023, stating that the draft was "generally consistent with the Oregon Competitive Bidding Guidelines"[71] and also provided specific recommended modifications. Following recognition of feedback, PGE submitted a subsequent draft on June 28, 2023, and following another round of feedback, again submitted a draft RFP on December 21, 2023.

Staff filed its report on December 12, 2023, recommending the Commission approve PGE's SMM and draft RFP, subject to specific conditions. On January 4, 2024, the Commission adopted Staff's recommendation with modifications.[72]

PGE issued the 2023 RFP on February 2, 2024, and held a post-issuance bidder workshop to review the structure, scoring, resource need, standard contracts, and other key provisions on February 13, 2024.

D. OAR 860-089-0300 Resource Ownership

Under OAR 860-089-0300, an electric company may submit bids in response to its RFP, which must be treated in the same manner as other bids. PGE submitted benchmark bids into this

[71] The Independent Evaluator's Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals at 2.
[72] Order No. 24-011

RFP and took precautions to ensure that the benchmark development and bid process was kept distinctly separate from the development of the RFP, evaluation of bids, or scoring of bids, consistent with OAR 860-089-0300. Additionally, consistent with PRR Participation Condition 1, PGE provided the IE a list of all employees working as part of the RFP team, the Benchmark team, and any employees performing duties on behalf of PRR. PGE provided this list in June 2023 and provided an updated list March 2024, and again with this filing.

Under OAR 860-089-0300, the electric company may make elements of the benchmark resource owned or secured by the electric company available for use in third-party bids, and if not made available, the electric company must provide analysis explaining that decision. Appendix P discussed these elements owned, which was posted publicly on PGE's 2023 RFP webpage and filed with the Commission. Additionally, consistent with RFP Conditions 4 and 5, PGE including an analysis supporting its decision not to make the elements associated with Biglow Canyon available to non-utility-ownership bids and provided a more thorough analysis of its security concerns regarding the parcels of land made available for benchmark bids.

Appendix P discussed three bid elements. The first two bid elements were made available for use to third-party bidders under utility owned commercial structures. The first bid element was 300-600 acres (located at coordinates 45.696,-119.797) and included generation capacity on the gen-lead line from Grasslands substation to BPA's Slatt substation. This element was made available to utility-owned commercial structures only to avoid multiple entity operation within the site perimeter. The second element was Biglow Canyon Wind Farm's LGIA, which was made available to only utility-owned commercial structures and on the condition that rights cannot be redirected away on a long-term basis. The third bid element was Wheatridge Wind Farm's LGIA and transmission rights, which were not made available to third-party bidders.

While these bid elements were not made available, bidders were provided the opportunity to develop a straw bid, consistent with RFP Condition 6. PGE provided additional information related to the bid elements disclosed in Appendix P to bidders interested in developing a straw bid.

Under OAR 860-089-0300(5), the electric company must allow independent power producers to submit bids with and without an option to renew and may not require that bids include an option for transferring ownership of the resource. The 2023 RFP allowed for these options as provided in PGE's RFP bid form.

E. OAR 860-089-0350 Benchmark Resource Score

OAR 860-089-0350 directs that prior to the opening of bidding on an approved RFP, PGE must file with the Commission and submit to the IE, for review and comment, a detailed score for any benchmark resource with supporting cost information, any transmission arrangements, and all other information necessary to score the benchmark resource. As part of this RFP, PGE applied the same assumptions and bid scoring and evaluation criteria to the benchmark bid that are used to score other bids consistent with OAR 860-089-0350.

PGE made the filing required under OAR 860-089-0350(1)-(3) on March 28, 2024, before allowing bidders to email third-party ITC eligible bids. PGE made a filing required under PRR Participation Condition 2 on April 29, 2024, which served to seal the scoring of third-party ITC eligible bids. PGE then instructed all remaining bids to email bids on April 30, 2024. No updates have been made to the benchmark or third-party ITC eligible scores other than the opportunity to provide best and final offer price updates, consistent with the opportunity offered simultaneously to all other bids in the RFP.

F. OAR 860-089-0400 Bid Scoring and Evaluation by Electric Company

OAR 860-089-0400 states that the utility must provide all proposed and final scoring criteria and metrics in its draft and final RFPs filed with the Commission. The scoring of bids and selection of the initial shortlist must be based on price and non-price factors with non-price factors converted to price factors where practicable.

PGE converted all non-price criteria that were better suited as minimum requirements to the "minimum bidder requirements" as outlined in PGE's RFP documents. Per OAR 860-089-0400(6), the IE had full access to all price scoring, including any production models, cost models, and sensitivity analyses.

Following identification of the initial shortlist, PGE retained Hendrickson Renewables to complete a review of the variable energy resource production curves submitted by bidders, and 1898 & Co. to provide an assessment of owner's costs associated with BTA bid structures.

G. OAR 860-089-0450 Independent Evaluator Duties

Consistent with OAR 860-089-0450(1), the IE oversaw the 2023 RFP process to ensure it was conducted fairly, transparently, and consistently with the Rules. The IE participated in review meetings, workshops, and submitted assessments as part of the RFP structure process. The IE attended both pre-RFP issuance workshops.[73] Consistent with OAR 860-089-0450(3), the IE consulted with PGE during PGE's preparation of the draft 2023 RFP and submitted its assessment of the final draft RFP to the Commission on July 14, 2023.

In accordance with OAR 860-089-0450, the IE had access to all PGE scoring documents and models, was included on communications as PGE sought additional information and clarification from bidders, scored all benchmark bids, and was consulted as PGE determined bidder

[73] The Pre-Issuance workshops were held on May 19, 2023 and June 5, 2023.

conformance, selected the initial and final shortlists. The IE separately evaluated and scored PGE's Benchmark bids. The IE also reviewed all bids to ensure conformance with the 2023 RFP's identified requirements, reviewed all correspondence between bidders and the RFP evaluation team, and reviewed all memoranda sent to bidders of non-complaint bids. The IE independently scored all bids to determine whether the selections for the initial and final shortlists were consistent with the bid evaluation criteria and compared the results of the IE's scoring with PGE's scoring to determine whether PGE's scoring of the bids and selection of the initial and final shortlists were reasonable. The IE prepared a Final Closing Report for the Commission after PGE selected the final shortlist. The IE's Final Closing Report provides its assessment of the solicitation process and the IE's involvement, including detailed bid scoring and evaluation results. The IE Closing Report is included in this filing as Appendix A.

Under OAR 860-089-0450(6), the IE must "evaluate the unique risks and advantages associated with any company owned resources (including but not limited to the electric company's benchmark), and may apply the same evaluation to third-party bids," including an evaluation of certain issues. The IE discusses these factors as part of the Closing Report.

Under OAR 860-089-0450(7), the IE reviews the reasonableness of any score submitted by PGE for a benchmark resource and once PGE and the IE have both scored and evaluated the competing bids and any benchmark resource, the IE and the Company must file their scores with the Commission. The IE and Company must compare results and attempt to reconcile and resolve any scoring differences. Here, as discussed above, the IE reviewed scores submitted by PGE for the benchmark prior to PGE filing scores on March 4, 2024.

Consistent with PRR Participation Condition 2, the third-party ITC eligible bids were treated the same as benchmark bids. Therefore, the IE also reviewed the reasonableness of any score submitted by third-party ITC eligible resources and once PGE and the IE had both scored and evaluated the competing bids, the IE and the Company filed their scores with the Commission. The IE and Company compared results and attempted to reconcile and resolve any scoring differences. The IE reviewed third-party ITC eligible bidder scores submitted prior to PGE filing scores on April 29, 2024.

Under OAR 860-089-0450(8), the IE is required to review the Company's sensitivity analysis of the bid rankings required under OAR 860-089-0400 and file a written assessment with the Commission before the Company requests acknowledgment of the final shortlist. Here, the Company provided its sensitivity analysis to the IE on September 4, 2024, and the IE filed its written assessment on September 17, 2024 contemporaneously with this Request for Acknowledgement.

H. OAR 860-089-0500 Final Shortlist Acknowledgement

PGE's final shortlist is consistent with PGE's 2023 IRP Action Plan and PGE seeks acknowledgment of the final shortlist. PGE requests Commission acknowledgment of this final shortlist by November 19, 2024, to enable PGE to timely finalize negotiations with final shortlist bidders.

OAR 860-089-0500 directs utilities to request acknowledgement of the final shortlist before negotiations may begin with bidders. "Acknowledgement" is defined as "finding by the Commission that an electric company's final shortlist of bid responses appears reasonable at the time of acknowledgment and was determined in a manner consistent with the rules in this division."[74]

[74] OAR 860-089-0500.

In accordance with OAR 860-089-0500, PGE's request for acknowledgement includes the IE's Final Closing Report, PGE's final shortlist of responsive bids, the sensitivity analyses performed, and a discussion of the consistency between the final shortlist and PGE's last-acknowledged IRP Action Plan or acknowledged IRP Update. Consistent with this rule, PGE will begin contract negotiations with bidders after filing this request for acknowledgment.

VIII. CONCLUSION

The Commission's acknowledgment of PGE's final shortlist will enable PGE to secure long-term value for customers, fill the 2028 capacity need identified in the 2023 IRP process, and to achieve progress toward the HB 2021 decarbonization compliance targets. PGE is committed to continuing to provide safe, reliable, affordable and increasingly clean electricity to our customers. The 2023 RFP had robust participation and provided PGE a competitive selection process. PGE's final shortlist represents resources with the best combination of cost and risk for customers to implement the 2023 IRP Action Plan and clean energy need associated with the HB 2021 greenhouse gas reduction targets.

PGE respectfully requests Commission acknowledgement of the 2023 RFP final shortlist November 19, 2024, to enable PGE to timely finalize negotiations with final shortlist bidders for the benefit of PGE's customers.

DATED this 17th day of September 2024.

Respectfully submitted,

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ECONOMIC CONSULTING

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THE INDEPENDENT EVALUATOR'S FINAL REPORT ON PORTLAND GENERAL ELECTRIC'S 2023 ALL SOURCE REQUEST FOR PROPOSALS

Presented to:
OREGON PUBLIC UTILITY COMMISSION

Prepared by
Frank Mossburg

September 11, 2024

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I. INTRODUCTION AND SUMMARY

A. INTRODUCTION

Bates White, LLC (Bates White) is the Independent Evaluator (IE) for Portland General Electric (PGE)'s 2023 All Source RFP (RFP). The primary purpose of this report is to provide the Oregon Public Utility Commission (Commission) with the IE's findings with respect to the Company's selection of a Final Shortlist. This report is also intended to provide the Commission with a record of the development and evaluation process for the shortlist.

B. THE FINAL SHORTLIST

The Company has selected a total of nine projects for the Final Shortlist. Of these projects, four are targeted for contract signing with the remaining five offers serving as backup in case deals cannot be reached with the targeted projects. These four targeted projects provide a total of approximately 93 average megawatts (MWa) of energy and 550 MW of capacity on the basis of Effective Load Carrying Capability (ELCC). The shortlist is shown in the table below (PGE Benchmark offers are shaded here and throughout the report).

Table 1: PGE Proposed Final Shortlist

Target

[Begin Highly Confidential]

Bid #	Bid	Nameplate MW	ELCC (MW)	Mwa	Transaction
88.2.Alt2	[redacted]	400	189	0	BTA
71.1.Alt2		41	18	11	PPA
150.1.Alt1		250	133	26	BTA
16.1.Base		500	210	56	PPA

[End Highly Confidential]

Backup

[Begin Highly Confidential]

Bid #	Bid	Nameplate MW	ELCC (MW)	Mwa	Transaction
23.1.Base	[redacted]	185	101	0	PPA
23.2.Base		200	109	0	PPA
74.2.Alt1		200	114	0	PPA/BTA
92.1.Alt4		100	63	0	BTA
74.1.Base		200	118	0	PPA/BTA

[End Highly Confidential]

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We have the following findings:

The RFP process was run in accordance with the rules laid out in the RFP document. All bidders were treated fairly under the rules of the RFP. We reviewed all bids that were found to not meet the minimum qualification criteria and agreed with the Company's decision to disqualify these projects.

The RFP process was reasonably competitive. In total, the RFP received bids from 19 suppliers offering a total of 30 projects.[1] Some of these projects offered multiple options. In total there were 81 bid options presented. Offers were received from wind, solar, pumped storage and standalone battery storage projects. Offers included power purchase agreements (PPA) and build-transfer agreements (BTA).

The offers selected for the final shortlist were selected fairly, via the approved RFP scoring system. Bates White was able to independently evaluate each offer. We were able to conclude that PGE's scoring was reasonable.

The final shortlist contains several Company-sponsored Benchmark bids, one of which is in the group of projects targeted for contracting and three of which are on the backup list in case deals cannot be reached with the targeted projects. We confirmed the accuracy of the Benchmark costs and independently scored the projects and provided the Commission with a complete review of all costs of each project prior to receipt of third party bids. We also confirmed each project's status by independently verifying that each offer met the minimum RFP requirements and reviewing the project cost inputs and benefits as calculated by PGE. It's important to state here that the Benchmark offers are all developed in conjunction with third parties and sold under a mix of power purchase agreements and build-transfer agreements, just as the other non-Benchmark offers would be. These are not traditional "cost-plus" offers, where the cost is just an estimate and final costs are as-incurred (subject to a prudence finding), meaning many risks of the projects are mitigated via contract.

The RFP aligns with the Company's Integrated Resource Planning (IRP) process. The models and processes used to select the Final Shortlist were the same models that the Company uses in its IRP process. Inputs either matched what was used in the IRP process or were updated to reflect more current market conditions.

We participated in the entire RFP process from design, through bid receipt and analysis, to the selection of the final shortlist. During that time we:

1. Reviewed and commented on drafts of the RFP;

[1] Of these, the PGE Benchmark team and its seven developer partners offered nine projects. A total of fifteen third party developers offered a total of 21 projects. Three developers offered both Benchmark projects and third-party projects.

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2. Authored multiple reports on the RFP design;

2. Attended the pre-bid conference;

3. Monitored bidder contact, including the answers to bidder questions;

4. Confirmed the assumptions, models and processes used in the analyses;

5. Confirmed the initial qualification of bidders and the confirmation of proposal details;

6. Provided input with respect to bidder disqualifications;

7. Reviewed the scores and models for the Company's shortlist process and confirmed the Company's selection of a shortlist; and

8. Reviewed the portfolio modelling of the shortlisted offers.

Throughout the process, we were in constant contact with PGE's evaluation team. The Company was transparent in their discussions with us and provided all the information that we requested.

C. ADDITIONAL COMMENTS AND RECOMMENDATIONS

We do have some additional recommendations and observations from this process.

This RFP sought projects to fulfill reliability needs as well as decarbonization needs under State law. In part because of the limited benefits and high cost of the renewable projects offered PGE has selected a group of projects targeted towards meeting the former need. While three renewable projects are targeted for contracting the proposed acquisition of 93 MWa is far below the procurement target of 753 MWa. This leaves the utility with large needs for renewable supply if it is to meet its emissions glidepath targets. PGE will have at least one more RFP in order to acquire supply to come on line by 2030 (and there are other options available such as the extension of existing contracts or bilateral agreements).

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As always, transmission and interconnection play an important role in bid development. PGE is currently working to comply with FERC Order 2023 and move to a cluster study process. We would recommend that future RFPs be coordinated such that their evaluation lines up with the timing of the cluster study results (assuming such alignment does not unreasonably delay PGE's RFP process). This would allow for a more streamlined process.

Some on-system battery storage projects offered in this RFP will be studied in the planned cluster study process. Some developers indicated that they were willing to sign contracts and bear the risk of these projects meeting their required commercial operation date at the prices offered in this RFP. Two projects in particular appear to have provided competitive offers which PGE ultimately decided to leave off the final shortlist due to the risk inherent in their development status. While this is understandable, we do observe that a larger tolerance for risk on PGE's part would have allowed these two projects to be included on the final shortlist as well.

As is made clear from PGE's planning process PGE will need a large amount of renewables in the future in order to meet the emissions requirements of current legislation. Parties may want to consider a more standardized RFP template that can be deployed more rapidly. This would, necessarily, require a standardized contract that can allow for a simple, price only evaluation and can be executed quickly.

II. IRP APPROVAL TO BID RECEIPT

The RFP is based on the findings of PGE's 2023 Clean Energy Plan and Integrated Resource Plan (CEP/IRP). The CEP/IRP was filed on March 31, 2023 in OPUC Docket LC-80. The IRP was acknowledged with conditions and additional directives on April 18, 2024.[2] In the same Order the CEP was not acknowledged but PGE was directed to revise and resubmit certain elements of the CEP with its next CEP/IRP update.

PGE's original CEP/IRP included an action plan to acquire 181 MWa of non-emitting resources each year through 2028 (a total of 543 MWa) and over 600 MW of summer and winter capacity.[3] After further revisions these numbers increased and in April of this year the Commission acknowledged an action plan that included 251 MWa/year of renewable acquisition 905 MW of summer capacity and 787 MW of winter capacity.[4]

Bates White was approved as the IE on April 28, 2023.[5] Bates White has previously served as the IE for PGE's 2021 All Source RFP and 2018 Renewable Request for Proposals and PacifiCorp's 2017R RFP. Bates White personnel have also served as IEs for several previous RFPs from PacifiCorp dating back to 2007.

Our first major task as IE was to review the draft RFP. As part of its request for a partial waiver of Oregon Competitive Bidding Rules PGE asked to have its scoring and modelling methodology considered concurrently with its draft RFP as opposed to before the filing. This was approved in Order 23-146.

PGE filed the Draft RFP in Docket UM-2274 on May 19, 2023. Prior to filing PGE held a call with the IE to notify us of the general design of the RFP and point out some specific changes from the 2021 All Source RFP design. PGE also held stakeholder workshops. Specifically, PGE held a workshop on March 2, 2023 to provide a high-level overview of the Draft RFP process. PGE held a stakeholder and bidding workshop on May 26, 2023.

We provided our assessment of the Draft RFP on May 31, 2023.[6] In this report we assessed the draft RFP against Oregon Competitive Bidding Requirements. We also provided some lessons

[2] Order No. 24-096, Docket LC-80, April 18, 2024.
[3] PGE CEP/IRP p 32.
[4] Order No. 24-096. Appendix A, p 5.
[5] In Order 23-146 in Docket UM-2274 the Commission approved a PGE request for a partial waiver of the Competitive Bidding Rules to continue utilizing Bates White as the IE for the 2023 All Source RFP. Bates White was, at the time, serving as the IE for the 2021 All Source RFP.
[6] The Independent Evaluators Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals. OPUC Docket UM-2274, May 31, 2023.

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learned from our work in the 2021 All Source RFP. We concluded that the Draft RFP was generally consistent with Oregon Competitive Bidding Requirements but we did make some suggestions to improve the process.

Subsequent to the filing of our report we attended a workshop on June 5, 2023 where PGE provided proposed details regarding resource need and the scoring process and answered questions from stakeholders. After review of stakeholder comments we provided a second assessment of the draft RFP in which we discussed key issues raised by stakeholders and assessed PGE's proposed changes to the draft RFP.[7]

We continued to review comments and supplemental filings made in the docket and hold regular discussions with Staff in the run-up to the approval hearing. We virtually attended the January 4, 2024 Special Public Meeting where the RFP was approved with modifications.

Since the RFP approval the following steps have been completed.

Table 2: Milestone Events to Date

Milestone	Date
RFP Issued to Market	2/2/2024
Bidder's Conference	2/13/2024
Notices of Intent to Bid Due	2/16/2024
Benchmark Bids Due	2/23/2024
Third-Party Solar BTA bids Due	4/5/2024
Remaining RFP Bids Due	4/30/2024
Initial Shortlist Notification	6/10/2024
BAFO Price Update Due	6/24/2024
Final Shortlist submitted to OPUC	9/17/2024

The RFP was issued to market with the modifications as requested by the Commission on February 2, 2024. PGE held a bidder's conference on February 13, 2024. The conference was held online. PGE personnel walked through the RFP process, including bid qualification and valuation. At the conference, PGE answered several questions regarding the RFP, qualification and bid evaluation. Bates White attended the conference and reviewed all questions and answers as bidders continued to ask questions until bid receipt. All questions and answers were posted publicly on the RFP website so that all bidders would have access to the same information.

[7] The Independent Evaluators Second Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals. Docket UM-2274, July 14, 2023.

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III. BENCHMARK AND SOLAR BTA BID ANALYSIS

A. BENCHMARK ANALYSIS

On February 23, 2024, in accordance with the RFP timeline, PGE's Benchmark team submitted their offers to the IE and the PGE evaluation team. Bates White was copied on the submissions, which were done via email. As in past RFPs PGE's benchmark team partnered with established developers to sponsor the developers' projects. While the offers were partnered with PGE the offers were essentially submitted as a third-party offer might be. That is, the bidder offered either a Power Purchase Agreement (PPA) or Build-Transfer Agreement (BTA) under which the developer would build the facility and then turn it over to PGE. These were not "cost-plus" offers in the traditional sense (i.e. not price estimates wherein the actual costs will be recovered as spent subject to a prudence check). Bidders offered edits to the same term sheets that third-party offers used. This helped mitigate the traditional risks of benchmark offers to a good degree.

Projects presented a "base" offer for consideration. Most projects also presented alternative offers which varied terms such as size or commercial operation date (COD). The base offers for the projects offered are summarized in the table below. There were a total of nine projects representing almost 1,500 MW of renewable capacity and 1,265 MW of storage capacity in their base case.

Table 3: Benchmark Summary Data – Base Offers Only

[Begin Highly Confidential]

Project	Developer	Technology	Renewable Capacity	BESS Capacity	Transaction Type
[redacted]		Solar+BESS	250	125	BTA
		Solar+BESS	175	90	BTA
				100	BTA
		BESS		100	PPA
		Wind	176.8		PPA
		Wind	187		BTA
		Solar	100		PPA
		Storage		50	BTA
		Wind	166.6		PPA
		Wind	173.4		BTA
		Solar	260		PPA
		Storage		155	BTA
		BESS		200	BTA
				100	BTA
		BESS		100	PPA
			200	200	BTA
		Solar+BESS	200	200	PPA
			100		PPA
		Solar	80		BTA

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After the bid receipt, Bates White undertook a multi-part review of the offers in order to validate the Benchmark submissions and scoring. First, we reviewed the full contents of the submissions. Second, we assessed each bid and bid variant against the minimum qualification requirements in the RFP. Third, we reviewed eliminations proposed by PGE's evaluation team to ensure we agreed on their actions. Fourth, we reviewed PGE's cost/benefit scoring, including operations and maintenance costs and calculations of effective load carrying capability (ELCC) to ensure that all inputs were correct, models functioned properly, and that all analysis was done in line with the RFP rules.

Finally, we examined the impact of changes in key inputs upon bid scores.[8] This was meant to fulfill, in part, our obligations under OAR 860-089-0450.(6)., which charges the IE with evaluating the "unique risks and advantages associated with any company owned-resources."

We were copied on all Q&A to the benchmark team so we could follow the lines of inquiry and use the same data PGE used. Unlike past RFPs there was no non-price score.

We concluded that the evaluation scoring was done per RFP requirements. We reviewed the PGE scoring model and associated cost/benefit calculations. While we noted some issues such as incorrect inputs corrections were made and the models appeared to correctly calculate the levelized costs of the bids.

We also observed that the benefits of each bid appeared to be calculated in accordance with the RFP rules. Benefits were verified by comparing bids of similar technology type. Energy values were fairly consistent across bids and flexibility values matched those in the RFP rules. Capacity values were more difficult to verify as they depend on the output of a more complex modelling process. We validated them by comparing the capacity contribution (i.e. the percentage of nameplate capacity that is credited as ELCC) for each resource to the contribution level presented in the 2023 CEP/IRP for that particulate technology type.[9] Where bids appeared to be outliers based on this analysis we asked PGE for explanations. We were ultimately satisfied with PGE's answers.

One key to note was that some projects and options offered were eliminated for not meeting the minimum requirements in the RFP. Specifically, **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** were eliminated due to not being able to meet the COD requirement of December 31, 2027. We agreed with these eliminations.

[8] Specifically, we looked at changes in assumptions regarding capital costs, O&M costs, tax credit monetization costs and unit performance.
[9] PGE 2023 CEP/IRP, p 241.

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B. THIRD PARTY SOLAR BTA ANALYSIS

During the development of the RFP PGE had proposed the creation of a new affiliate in order to better utilize tax credits provided to solar developers. Under this plan PGE would convert selected shortlisted solar BTA offers into PPA offers to contract with this new affiliate. PGE decided not to utilize this transaction structure as IRS Guidance, which came out after the Commission's final order on the RFP, clarified that transferred Investment Tax Credits were not subject to IRS normalization rules. Nonetheless, one concern with this potential structure was the ability of PGE to review and adjust utility-owned offers after review of third-party data. For this reason a separate bid due date was set for solar BTA or Asset Purchase Agreement (APA) offers.

Per the RFP schedule the original submission date for these proposals was March 26. This was moved back to April 5 in order to finish the evaluation of the Benchmark offers. PGE received bids on April 5 from two bidders. These bidders offered a total of three projects.

[Begin Highly Confidential]

[redacted]

[End Highly Confidential]

All three projects failed the minimum requirements screen. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** failed on the basis of interconnection status as well as providing an unacceptable delivery point. Per the RFP bidders must have an active generation interconnection request in the transmission provider's interconnection queue and a completed system impact study by the transmission provider.[10] Neither project had **[Begin Highly Confidential]** [redacted][11] **[End Highly Confidential]** In addition, neither offer proposed an acceptable point of delivery (POD). **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

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[10] RFP, Appendix N, p 5.

[11] In a public Q&A PGE did allow that bidders without a SIS could provide a narrative describing how the project would secure the appropriate studies to support the proposed COD. The bidder provided [Begin Highly Confidential] [redacted] [End Highly Confidential]

[12] RFP Appendix N, p 4-5.

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[Begin Highly Confidential] [redacted] **[End Highly Confidential]** failed on the basis of transmission requirements. The project was to **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** to deliver power to PGE. Per the RFP bidders had to propose an achievable plan to provide long-term firm service for at least 75% of the resource's interconnection limit.[13] **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Neither of these options was acceptable under RFP rules. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** The bidder was informed of these deficiencies and agreed that they did not meet the requirements in the RFP.

[13] Ibid, p 5-6. Long term firm service included conditional firm, bridge, number of hours and reassessment number of hours services as well as system conditions service.
[14] Ibid, p 6.

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IV. BID RECEIPT AND QUALIFICATION

Remaining offers from third-party bidders were due on April 30, 2024. We monitored bid receipt to make sure that all bidders could submit their documents. Ultimately, all bidders were able to submit all their files.

At this stage, fourteen third party suppliers submitted a total of eighteen projects for consideration. The projects consisted of;

- 7 standalone battery energy storage systems (BESS),
- 4 wind facilities,
- 4 solar facilities,
- 2 pumped storage facilities, and
- 1 geothermal project.

These projects offered several different variants in terms of contract length, storage pairing and more. A total of 37 options were presented, 28 PPAs, 6 BTAs and 3 Joint Ownership (i.e. a mix of PPA and BTA). Most renewable facilities were located in the service territory of the Bonneville Power Administration (BPA). These projects represented a maximum total of 1,420 MW of nameplate renewable generating capacity 2,668 MW of nameplate storage capacity.

After the receipt of offers, PGE went to work confirming bid details with bidders. PGE sent multiple sets of questions to bidders and bidders confirmed project information and provided updated information where their original response was lacking. Bates White was copied on all questions and responses. PGE and the IE reviewed the offers for qualification purposes. Bids were held to several minimum requirements. Key requirements included: (a) demonstrating that the project could be commercially operational no later than December 31, 2027[15], (b) having a completed system impact study[16], (c) demonstrating site control[17] and (d) demonstrating a clear transmission plan to deliver firm supply to PGE's territory.[18]

The following table summarizes the count of third party offers received and disqualifications. Note this does not include the three renewable BTA offers received from third-party developers

[15] RFP Appendix N, p 2-3. Per the RFP, this requirement was relaxed for pumped-storage facilities as they feature much longer lead times for construction.
[16] Ibid p 5.
[17] Ibid p 3.
[18] Ibid p 5-7. Dispatchable bids had to deliver 100% of their output with firm transmission while renewable offers had to have at least 75% of their offer secured with firm transmission. Renewable bidders were able to use conditional firm products in addition to standard long term firm transmission.

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discussed in the section above that were disqualified for filing to meet interconnection **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** and transmission **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** requirements. It also does not include the Benchmark project **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** that was rejected for failing to meet the COD requirement.

Table 4: Count of Third-party Projects and Offers Accepted and Rejected

Status	Projects	Options
Received	18	37
Disqualified - Interconnection & Transmission	1	1
Disqualified - Transmission	4	6
Disqualified - Commercial Operation Date	1	1
Remaining	12	29

There were a number of projects that failed to meet the minimum requirements for participation in the RFP and were either rejected or withdrawn by the bidder. These projects were;

1. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** was disqualified for failure to meet the interconnection and transmission requirements. The project was to interconnect to **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**. After several follow-ups the bidder noted they were in communication with BPA but they were not able to produce any timely information to support a COD by the end of 2027.

2. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** was withdrawn due to insufficient transmission. The bidder proposed two options; **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** Neither of these were options made available in the RFP. The bidder was given a chance to submit alternative plans but was not able to offer one.

3. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** was rejected for failure to meet the transmission requirements. The project was to **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**. The RFP required that any BPA request had to be in the most recent

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TSEP process or a prior process.[19] The bidder acknowledge that the project did not meet the RFP requirements and could not provide an alternative arrangement.

4. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** was disqualified for failure to mee the required COD. Per the bidder the project COD was December 2028. PGE discussed an earlier COD with the bidder but **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** was unable to commit to this due to interconnection and transmission issues.

5. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** was disqualified due to failure to meet the transmission requirements. The project was located in **[Begin Highly Confidential]** [redacted] **[End Confidential]** and the bidder had not applied for any transmission service.

6. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** was disqualified due to lack of a transmission pathway. The project was planning to **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Bates White was consulted on the decision to remove each of these bidders and bid options and we agreed with the decisions. In each case bidders were given opportunities to cure deficiencies and were not able to do so. We hope to see these projects in future RFPs when they have reached a more commercially ready state.

In conducting the review of minimum requirements Bates White and PGE evaluators identified two areas which required more advanced consideration. The first was around the transmission and interconnection requirements for long lead-time resources. This RFP required bids to be on line by the end of 2027 but an exception was made for these resources due to the development time involved. Per the RFP such resources could come on line as late as the end of 2029.[20] Both long lead-time projects **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** to deliver their supply. While this was not permitted under the RFP we argued that these offers did have additional time to secure other transmission services if selected and should continue to be

[19] Ibid, p 6.
[20] RFP Appendix N, p 3.

considered in the evaluation. Beyond this, the resources did offer some unique benefits in terms of longer-duration storage that were worth examining. PGE evaluators and Staff agreed and PGE continued to review the projects.

A second area of discussion centered around storage projects attempting to interconnect to PGE's system. The RFP required projects to have a completed System Impact Study upon bid submission and a completed Facilities Study upon selection to the final shortlist.[21] As noted in past reports PGE's interconnection process has seen extensive delays. As a result, many projects could not meet these requirements despite having been in the queue for a good deal of time. The table below shows BESS projects (including Benchmarks) and their interconnection status as of Late April 2024.

Table 5: BESS Interconnection Status as of April 2024[22]

[Begin Highly Confidential]

Bidder	Project	Type	MW	Location	Queue Request Date	Status
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	LGIA Complete
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	Facility Study Complete
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	Facility Study Underway
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	System Impact Study Complete
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	System Impact Study Underway
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	Feasibility Study Complete
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	Feasibility Study Complete
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	Feasibility Study Underway
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	Feasibility Study Complete
[redacted]	[redacted]	BESS	[redacted]	[redacted]	[redacted]	Scoping Meeting Planned

[End Highly Confidential]

Only one of the third-party projects **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** technically met the minimum requirement of having a completed system impact study at bid submission. As of the mid-July (the latest data currently posted on PGE's OASIS site) none of the third-party projects had a completed Facilities Study as required by the RFP.[23] This is despite the fact that most of these projects have been in the queue for anywhere up to three years.

As we noted in our Final Shortlist Report for the 2021 All Source RFP this is, unfortunately, a common occurrence as projects have overwhelmed queues across the country – a combination of the proliferation of smaller projects and the deficiencies of the serial-queue system which requires reassessment when higher-ordered projects drop out. Due to these issues FERC recently issued new rules to reform interconnection procedures.[24] In compliance with these orders PGE is now transitioning to a cluster study process. This raised the question of the path forward to interconnection for lingering projects such as the ones above.

[21] RFP Appendix N p 5 and p 14.
[22] Source http://www.oasis.oati.com/pge/ Access date 4.22.2024.
[23] Ibid, accessed 8/22/24.
[24] Order 2023. Docket RM22-14-000. July 28, 2023.

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We discussed the issue with PGE evaluators and PGE Transmission personnel. We also reviewed PGE transmission fillings. Per posted documentation PGE would no longer start Feasibility studies after May of 2024. PGE would continue performing System Impact Studies up until November of this year. Projects with a completed System Impact Study would be tendered a Facilities Study Agreement and could then move to sign a Large Generator Interconnection Agreement (LGIA). Projects without system impact studies would be able to take part in the transmission cluster study, which would issue results in late 2025.[25]

Given the overall uncertainty in the process we argued that most of the projects in the queue should continue to be considered as they appeared to have some pathway to meeting the required end of 2027 COD. PGE evaluators agreed and proposed continuing to evaluate all of the above projects – returning to the discussion should any be considered for final shortlisting. We agreed with this path forward.

[25] PGE. Pre-Order 2023 Interconnection Queue Process. Posted July 15, 2024. http://www.oasis.oati.com/woa/docs/PGE/PGEdocs/Final_Draft_PreOrder_2023_transitional_process.pdf

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V. INITIAL SHORTLIST DEVELOPMENT

After the bids were received, minimum qualifications were evaluated, and bid details were confirmed and the Company began the initial shortlist evaluation. Per the RFP, the bid score was based entirely on price. Specifically, the cost/benefit ratio of the offer. This is in contrast to past RFPs which featured a non-price component.

The scoring and modeling methodology is laid out in Appendix N of the RFP. The price score was based on a comparison of the cost of the bid to the benefits of the bid. Costs differed based on the type of bid. For BTA bids the costs were:

(a) the revenue requirement needed to cover the project's capital cost,
(b) O&M costs,
(c) insurance, land lease and other services costs,
(d) network upgrade costs,
(e) any transmission services needed to deliver the power to PGE's territory, including wheeling, line losses, reserves, and balancing costs and,
(f) the value of tax credits. PGE planned to sell off any tax credits received from projects which they were to own. PGE presumed that any such sales would carry a **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** discount.

For PPA bids the costs included:

(a) the PPA price, and
(b) all applicable transmission costs.

To calculate the benefits of each offer PGE had to first determine how often a bid would run (i.e. its capacity factor). For renewable resources this was done by looking at the bidder-provided forecast generation information. For dispatchable resources this was done by simulating dispatch using the Aurora production cost simulation tools used in the CEP/IRP.[26] PGE also had to determine the bid's capacity contribution. This was done by calculating the bid's effective load carrying capability (ELCC) using the Sequoia model. This model assesses the capacity contribution of incremental system additions via a Monte Carlo simulation.[27]

[26] RFP, Appendix N, p 10.
[27] Ibid.

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Bids which relied on conditional firm transmission could have their capacity value adjusted depending on the type of service they held.[28] The table below shows the transmission service held for each renewable project.

Table 6: Transmission Service for Renewable Projects

[Begin Highly Confidential]			
Bidder	Project	Service	Conditional Through
[redacted]			
[End Highly Confidential]			

PGE looked at three categories of benefits:

(a) Energy Value – This is the value of the energy that is being purchased from the unit. It is calculated by using the Company's forward price curve and the hourly unit dispatch projections from the bid using the AURORA production cost model and bidder-provided output projections.

(b) Capacity Value – This is the value of capacity from the project. The quantity of capacity provided by each offer was calculated by using the Sequoia model and the output projections, transmission service, location, and dispatch limitations from the bidder. The price of capacity was based on the cost of a new four-hour BESS unit.

(c) Flexibility Value – PGE used the values produced by the Gridpath model from the 2023 CEP/IRP to value dispatch flexibility.[29] This was a set value per kW-year depending on the type of resource.

Costs and benefits were calculated on a real-levelized basis per megawatt-hour – the net present value of all (cost or benefit) dollars were discounted back to the present using a real discount rate. This was divided by the net present value of all MWh produced over the useful life of the asset. Price scores were created by looking at the cost to benefit ratio.

[28] Specifically, bids with "number of hours" CF service were assumed to have 50% of their annual curtailment hours occur in PGE's times of highest need. Bids with "system conditions" firm transportation were given no capacity value. See RFP Appendix N p 11-12.

[29] 2023 IRP, p 163.

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A. RENEWABLE CATEGORY

Bates White independently verified the rankings via several steps. We reviewed each model run to make sure that the details of the bids were properly input and that all bids used the same default assumptions. We double-checked the calculations in the model to assure that they functioned properly. We checked the benefits of each offer by checking that the capacity factors either reflected the submitted bid information (in the case of dispatchable resources) or were similar across technology types. We reviewed the ELCC of each bid by comparing bids of the same technology type and looking for outliers, then seeking explanations for those outliers.

Bids were separated into two categories, dispatchable (i.e. energy storage) and renewable. Hybrid offers (that is, storage and renewable resources) were considered in the renewable category. In the table below we show the offers from the renewable category. Most projects offered, at a minimum, a mix of ownership options under one project, so those are separated out here. The table below shows the total costs and benefits for each project, all on a nominal-levelized cost per MWh basis. Again, Benchmark bids are shaded.

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Table 7: Qualifying Renewable Projects – Nominal Levelized Cost and Benefit ($/MWh)

[Begin Highly Confidential]

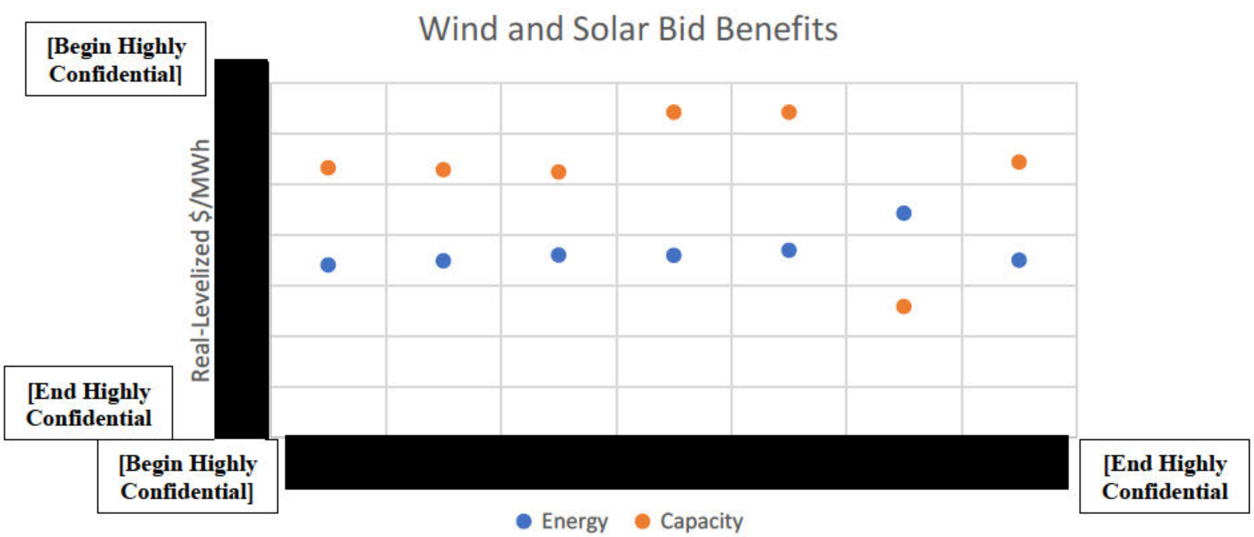
Bid Number	Bidder	Proejct Name	Technology	Capacity	Transaction	Cost NL	Benefit
10.1.Base	[redacted]	[redacted]	Wind	187	BTA	[redacted]	[redacted]
			Wind	176.8	PPA		
			Solar	100	PPA		
			BESS	50	BTA		
10.1.Alt1			Wind	171	BTA		
			Solar	100	PPA		
			BESS	50	BTA		
27.1.Base			Solar	100	PPA		
			Solar	80	BTA		
27.1.Alt1			Solar	100	PPA		
			Solar	80	BTA		
27.1.Alt2			Solar	130	PPA		
			Solar	110	BTA		
			BESS	60	PPA		
			BESS	65	BTA		
27.1.Alt3			Solar	130	PPA		
			Solar	110	BTA		
			BESS	60	PPA		
			BESS	65	BTA		
55.1.Base			Solar	175	BTA		
			BESS	90	BTA		
55.1.Alt1			Solar	175	BTA		
55.1.Alt2			Solar	175	BTA		
			BESS	135	BTA		
105.1.Base			Solar	200	PPA		
			Solar	200	BTA		
			BESS	200	PPA		
			BESS	200	BTA		
105.1.Alt1			Solar	200	PPA		
			Solar	200	BTA		
			BESS	100	PPA		
			BESS	100	BTA		
105.1.Alt2			Solar	200	PPA		
			Solar	200	BTA		
			BESS	200	PPA		
			BESS	200	BTA		
105.1.Alt3			Solar	200	PPA		
			Solar	200	BTA		
			BESS	200	PPA		
			BESS	200	BTA		
105.1.Alt4			Solar	200	PPA		
			Solar	200	BTA		
			BESS	100	PPA		
			BESS	100	BTA		
105.1.Alt5			Solar	200	PPA		
			Solar	200	BTA		
			BESS	200	PPA		
			BESS	200	BTA		
150.1.Base			Solar	250	Solar		
			BESS	125	BESS		
150.1.Alt1			Solar	125	Solar		
			BESS	125	BESS		
150.1.Alt2			Solar	100	Solar		
			BESS	100	BESS		
150.1.Alt3			Solar	250	Solar		
			BESS	125	BESS		
150.1.Alt4			Solar	125	Solar		
			BESS	125	BESS		
150.1.Alt5			Solar	100	Solar		
			BESS	100	BESS		
16.1.Base			Solar	250	PPA		
			BESS	250	PPA		
71.1.Base			Solar	41	PPA		
71.1.Alt1			Solar	41	PPA		
71.1.Alt2			Solar	41	PPA		
71.2.Base			Solar	41	PPA		
			BESS	20.5	PPA		
71.3.Base			Wind	111	PPA		

[End Highly Confidential]

These bids total of 5,974 MW of renewable capacity and 3,545 MW of storage capacity. Of that renewable capacity 5,329 MW is solar and the rest is wind. Per PGE this list represents in total 1,914 MWa (average megawatt hours, i.e. the average hourly output of the resources) and 3,570 MW of ELCC capacity. Removing duplicate offers (i.e. multiple offers from the same project) left the list at 509 MWa and 946 MW of ELCC capacity.

To get a better sense of the valuation dynamics and validate the benefit calculations we grouped the bids into two basic categories (wind/solar and hybrid) and looked first at the benefits each project provided. The figure below shows the benefits PGE calculated for each wind and solar project on a real-levelized $/MWh basis. Renewable resources without batteries have no flexibility value in PGE's scoring system.

Figure 1: Wind and Solar Offer Benefits (Real-Levelized $/MWh)

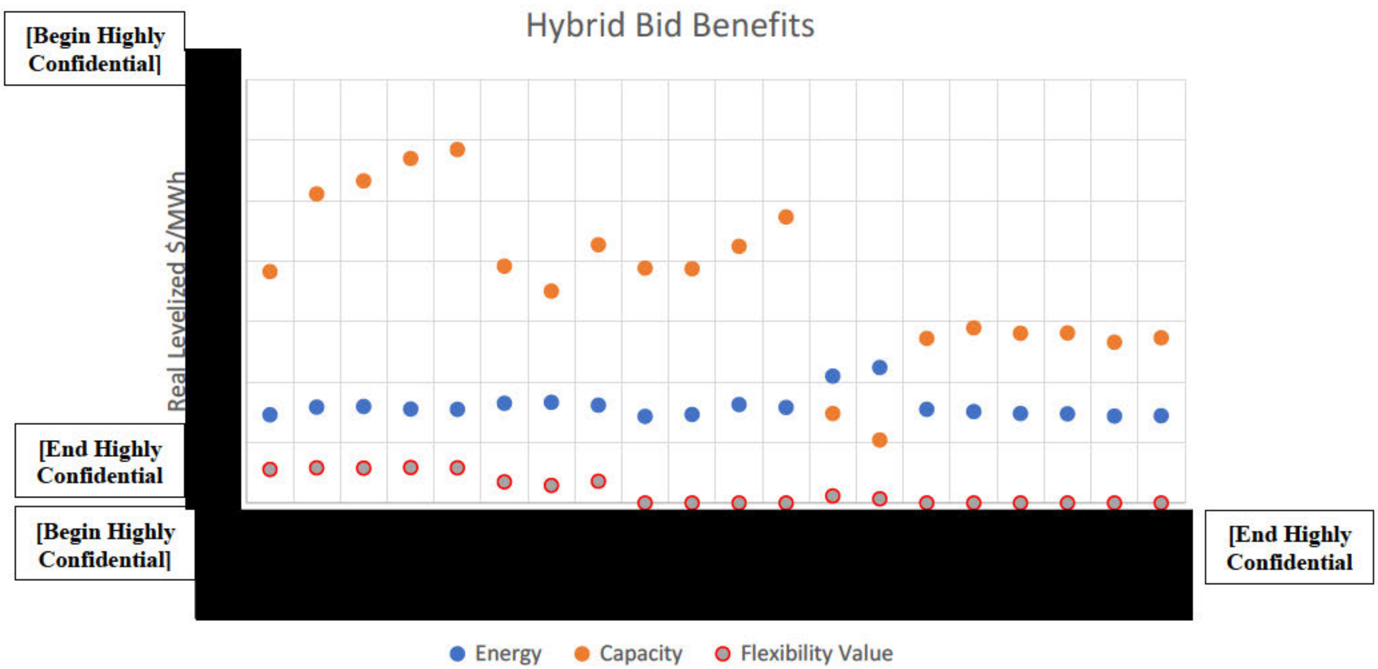


Here we see all projects provided roughly similar energy benefits, as might be expected. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** does offer a bit higher energy value, but lower capacity value. This is because it is a wind project, while the others are solar facilities. It has a slightly higher capacity factor than the other projects but a different operating profile.

Capacity values are similarly grouped. What is interesting is that on a dollar per MWh basis the capacity value is higher than the energy value. This is a change from the last RFP where energy provided a larger benefit. The change here is mainly due to the very low market values of energy used in the analysis. These values come from PGE's 2023 CEP/IRP and reflect a future with higher renewables penetration and consequently much lower energy market prices. In fact, energy benefits are roughly half of what they were when we conducted this analysis in the 2021 RFP. By contrast we do note that capacity benefits – previously around **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** - have increased quite a bit on a per MWh basis. This is driven by changes to the cost of replacement capacity (which is now a BESS unit instead of a combustion turbine) and updated modelling parameters.

For the hybrid offers – mostly solar paired with BESS units - the benefits of each offer are shown in the next Figure.

Figure 2: Hybrid Offer Benefits (Real-Levelized $/MWh)



Again we see that the energy benefits are reasonably consistent across each offer and generally below **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** with only the wind-powered **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** exceeding that threshold. Flexibility values are generally low when present. Some bids, offer no flexibility value and lower capacity values in part due to the fact that they rely on conditional firm transmission.[30] Overall, capacity value provides the most benefit, though values vary much more. **[Begin Highly Confidential]** [redacted]

[30] This includes the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

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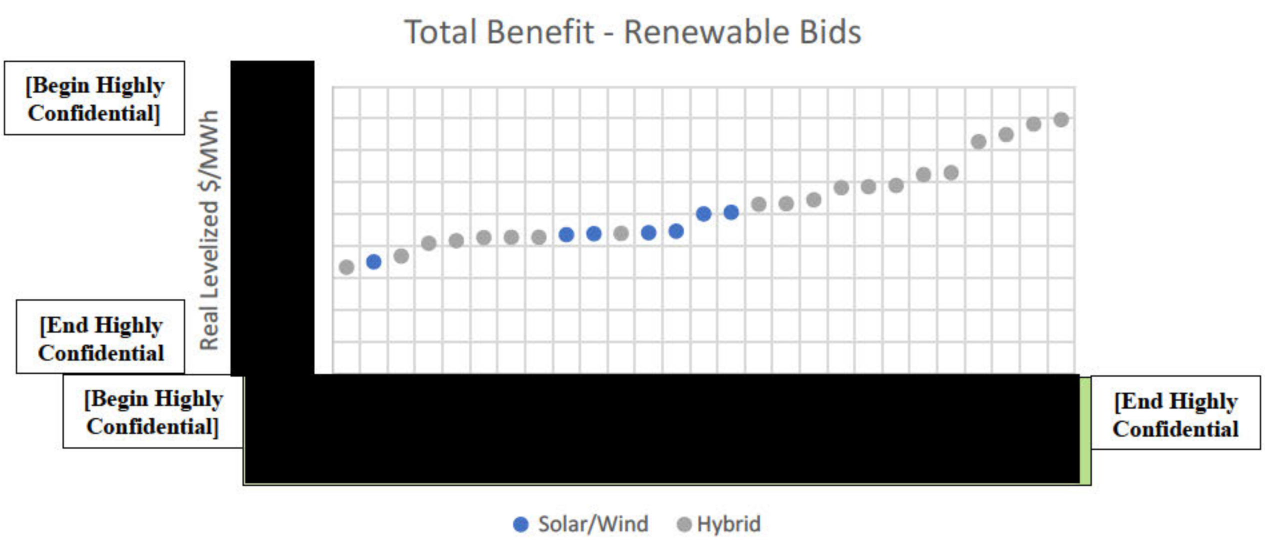
[redacted] **[End Highly Confidential]** seems to be an outlier in that it provides a very high capacity benefit relative to other bids. Per PGE this is due to the operating profile of the bid, which generates in the highest need hours.[31]

Looking at the total benefits we see that, as we might suspect, hybrid offers are generally more beneficial due to their capacity and flexibility contributions. The following Figure shows the total benefits for each offer.

Figure 3: Total Benefits for Renewable Bids (Real-Levelized $/MWh)



The benefits are generally in the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**. Of course, this analysis does not include the cost of each offer. The next Figure adds the cost on top of this benefit.

[31] Highest need hours are based on PGE's Sequoia analysis and vary depending on system conditions. Bidders do not know when these hours are though the 2023 CEP/IRP provides some general outputs via heatmaps (see CEP/IRP p 125).

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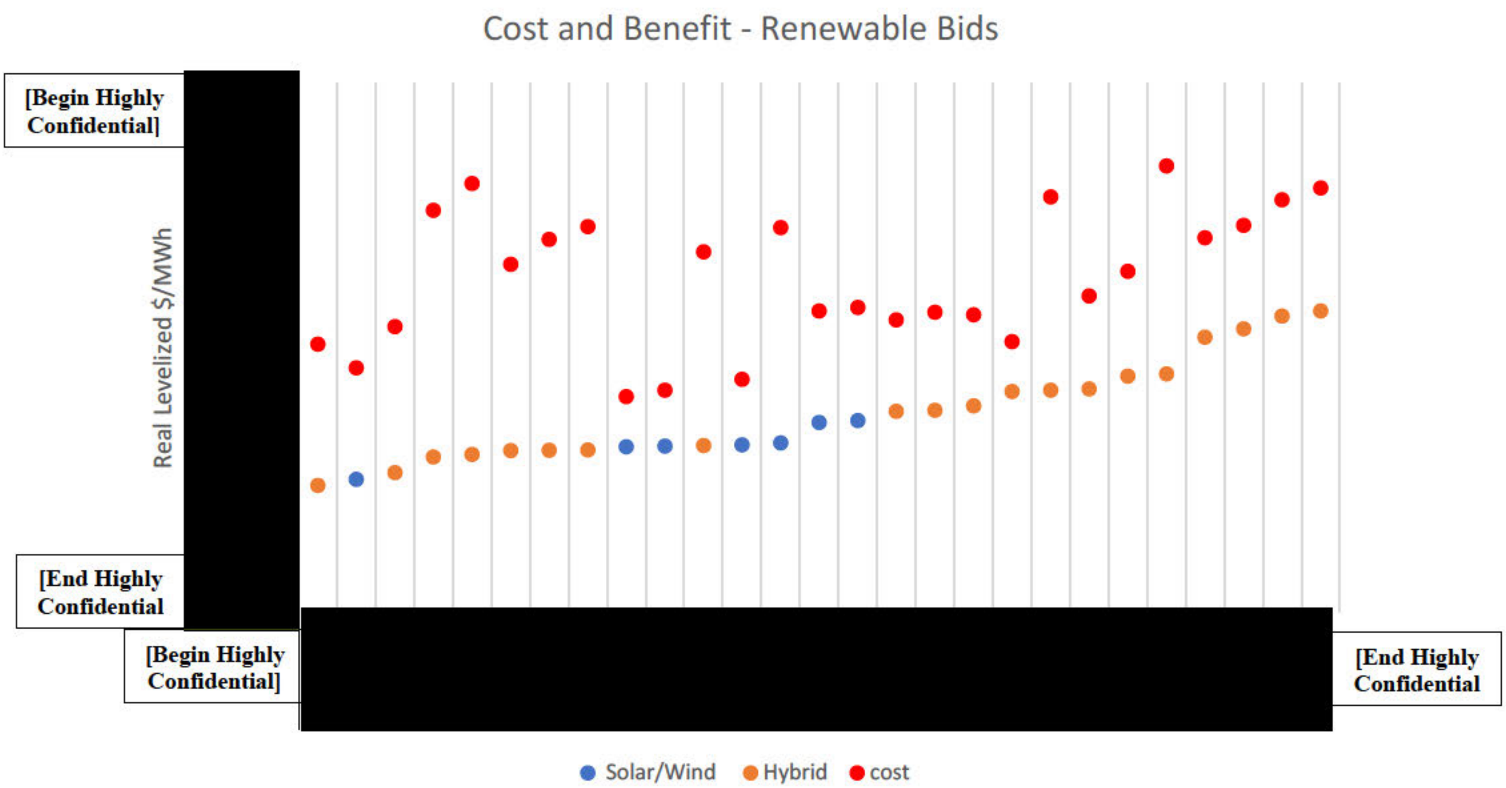
Figure 4: Costs and Benefits for Renewable Bids (Real-Levelized $/MWh)



Here we see that costs exceed benefits in all cases but the magnitude varies with each offer. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** has benefits that come close to its costs as does **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** The fact that costs exceed benefits is primarily a factor of the low energy benefit produced by the bids. As discussed above, PGE's market price projections are reflective of a surplus market and most bids have less than **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** of real-levelized energy benefit

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as compared to over **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** in the 2021 RFP.

To complete its analysis PGE next ranked the bids by cost benefit ratio. Per the RFP rules there was no non-price score so this represented the only ranking of the offers. The next table shows the bids ranked by this metric.

Table 8: Renewable Projects Rankings

[Begin Highly Confidential]

Bid	Description	Cost Benefit
[redacted]		

[End Highly Confidential]

[Begin Highly Confidential] [redacted]

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[redacted] **[End Highly Confidential]**

Given the potential size of their renewable needs in the future PGE proposed taking all projects on to the shortlist however they did not take all bid variants from each offer. PGE dropped some lower-ranked variants. The table below shows the offers selected for BAFOs. Bids in red were not selected to the shortlist. We thought the selections seemed reasonable as it took the top scoring offers while maintaining a variety of offers, including at least two options from each project.

Table 9: Shortlisted Projects and Rejections

[Begin Highly Confidential]

Bid	Description	Cost Benefit
[redacted]		

[End Highly Confidential]

B. DISPATCHABLE CATEGORY

For the dispatchable bids PGE conducted the same process. The Table below shows the qualifying dispatchable offers and their associated costs and benefits.

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Table 10: Qualifying Dispatchable Projects – Nominal Levelized Costs and Benefits ($/MWh)

[Begin Highly Confidential]

Bid Number	Bidder	Proejct Name	Technology	Capacity	Transaction	Cost NL	Benefit	CB
97.1.Base	[redacted]	[redacted]	BESS	150	PPA	[redacted]	[redacted]	[redacted]
22.1.Alt2	[redacted]	[redacted]	BESS	200	PPA	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
22.1.Alt4	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
22.1.Alt3	[redacted]	[redacted]	BESS	200	PPA	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
22.1.Alt5	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
22.1.Base	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
63.2.Base	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
9.1.Base	[redacted]	[redacted]	BESS	20	PPA	[redacted]	[redacted]	[redacted]
22.1.Alt1	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
88.2.Alt1	[redacted]	[redacted]	BESS	200	PPA	[redacted]	[redacted]	[redacted]
88.2.Alt2	[redacted]	[redacted]	BESS	400	BTA	[redacted]	[redacted]	[redacted]
63.2.Alt1	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
23.1.Alt2	[redacted]	[redacted]	BESS	130	PPA	[redacted]	[redacted]	[redacted]
88.2.Base	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
23.1.Base	[redacted]	[redacted]	BESS	185	PPA	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
74.2.Alt1	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
74.1.Alt2	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
74.1.Base	[redacted]	[redacted]	BESS	100	PPA	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	BESS	75	BTA	[redacted]	[redacted]	[redacted]
74.1.Alt1	[redacted]	[redacted]	BESS	75	PPA	[redacted]	[redacted]	[redacted]
23.2.Alt2	[redacted]	[redacted]	BESS	200	PPA	[redacted]	[redacted]	[redacted]
23.2.Base	[redacted]	[redacted]	BESS	200	PPA	[redacted]	[redacted]	[redacted]
92.1.Alt4	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
92.1.Alt3	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
92.1.Alt2	[redacted]	[redacted]	BESS	100	BTA	[redacted]	[redacted]	[redacted]
23.1.Alt1	[redacted]	[redacted]	BESS	185	BTA	[redacted]	[redacted]	[redacted]
79.1.Alt1	[redacted]	[redacted]	Pumped Storage	100	PPA	[redacted]	[redacted]	[redacted]
35.1.Base	[redacted]	[redacted]	Pumped Storage	403	BTA	[redacted]	[redacted]	[redacted]
23.2.Alt1	[redacted]	[redacted]	BESS	200	BTA	[redacted]	[redacted]	[redacted]
35.1.Alt1	[redacted]	[redacted]	Pumped Storage	400	PPA	[redacted]	[redacted]	[redacted]
79.1.Base	[redacted]	[redacted]	Pumped Storage	393.3	PPA	[redacted]	[redacted]	[redacted]

[End Highly Confidential]

This list is a total of 5,716 MW of nameplate capacity. Removing duplicate offers reveals 12 separate projects and a maximum offer of 2,548 MW of nameplate capacity. This represents a maximum ELCC of 1,449 MW.

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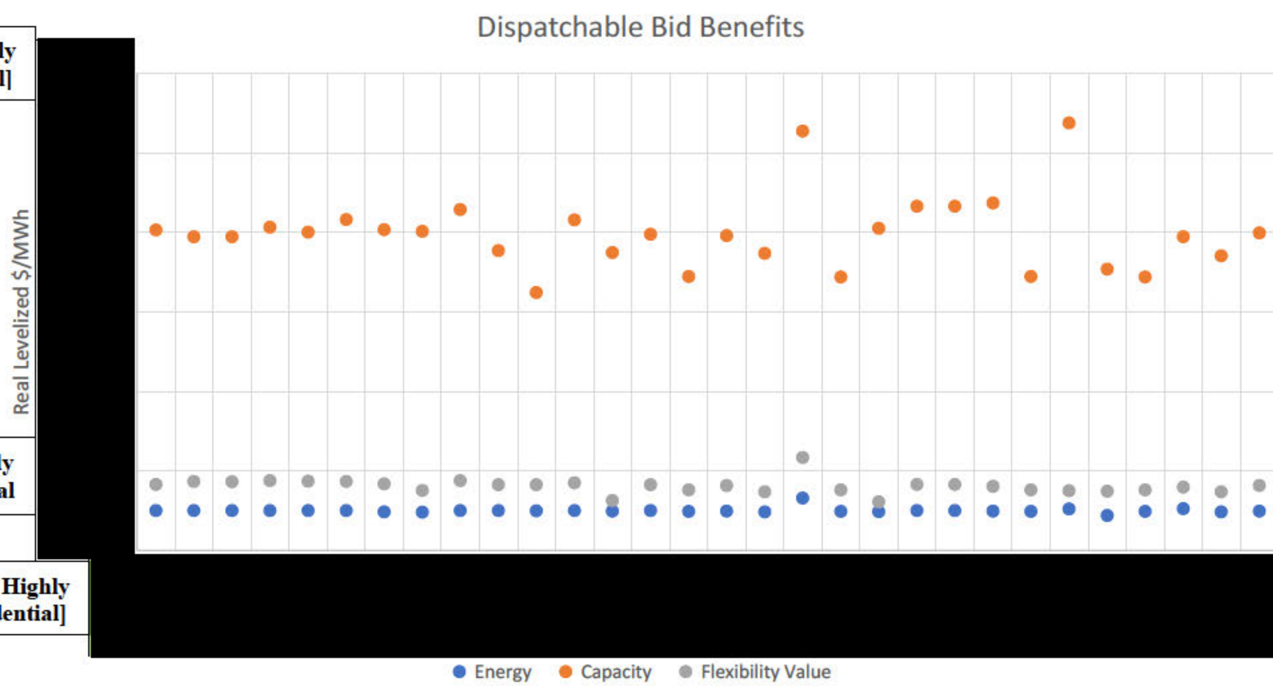
From this table we can see that while the bids all have costs that exceed their benefits they are more cost-effective than the renewable offers. As before we reviewed the scoring including inputs and benefits. The top renewable offers have cost-benefit ratios from about 123%-145% whereas the best offers here are from about 100-125%. The next table breaks out the benefits by category.

Figure 5: Benefits of Dispatchable Bids

[Begin Highly Confidential] [redacted] **[End Highly Confidential**



[Begin Highly Confidential] [redacted] **[End Highly Confidential**

Again, we see the value of the capacity provided as being very high while the other value streams are relatively low. This is in line with the results from the renewable category. The overall capacity $/MWh here is higher in part due to the fact that the batteries have a lower capacity factor when compared to renewable projects – this leads to a higher capacity value on a per MWh basis. Even accounting for this there are some outliers **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** that are the result of the bids having longer-term storage than the standard 4 hours.

As with the renewable category PGE ranked these offers by cost-benefit ratio. PGE proposed taking all offers again, though they did remove some lower-ranked offers. The table below shows the offers selected with rejected offers in red.

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Table 11: Dispatchable Offers for Shortlist

[Begin Highly Confidential]		
Bid	Description	Cost Benefit
[redacted]		
[End Highly Confidential]		

As noted above, the top offers have a much better ratio than the renewable offers. There is also a large split between the BESS offers and the pumped-storage offers. We agreed with this selection as it took the top offers in general and preserved multiple variants. **[Begin Highly Confidential]** [redacted]

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[redacted] [End Highly Confidential]

VII. PORTFOLIO MODELING

A. ADDITIONAL REMOVALS

Bids selected to the initial shortlist were asked to provide a best and final offer (BAFO) and provide additional documentation and updates concerning interconnection, financing, equipment and more.

At this point it was determined that several projects did not meet the requirements of the RFP. Specifically, several on-system BESS projects would not be set to receive interconnection related costs until the end of 2025. These were all projects (discussed above) that had submitted into PGE's interconnection queue but not received System Impact Studies at submission time.

Based on information from PGE transmission the last project that would likely have their System Impact Study this year (and thus be able to skip the transmission cluster study process and move on with interconnection) would be **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Without clear estimates from PGE transmission on how long it would take and how much it would cost to interconnect these projects there was a real risk that projects would not make the 12/31/27 COD and/or would have to raise their bid prices to account for higher than expected interconnection costs. This is why the RFP required a facilities study at the point of final shortlisting. These bids were removed from consideration with our agreement.

In addition, PGE determined that the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** We agreed with this decision as well. We also note that while

[32]**[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

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both projects may have value their cost/benefit ratios did not look particularly competitive when matched against other dispatchable resources.

Finally, in late July the Benchmark team contacted the evaluation team with an update to the RFP Appendix P. The update proposed adding to the disclosures around utility assets for Benchmark use a **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

PGE (at the utility level and independent of this RFP process) procured these rights. These costs are not in base rates but will be recovered at first though the Power Cost Adjustment Mechanism and PGE will likely seek cost recovery of the rights in a 2025 filing. The Benchmark team argued that this made these rights a customer asset used by the Benchmark and, therefore, something to include in Appendix P. The Benchmark team also argued that there should be no additional cost added to their offer as it would be part of customer rates.

The PGE evaluation team was uncomfortable with this update as it did as it did not meet the spirit of Appendix P: providing a clear and understandable inventory of what rate base assets are being used by the Benchmark in advance of all other bids being submitted, and allowing stakeholders to debate whether or not the assets can be made more widely available to other bidders. It also appeared to violate the disclosure requirements in the Oregon Administrative Rules, which require that the utility declare which assets will support a bid when seeking RFP acknowledgement and either make them available to all bidders or justify why they are not doing so.[33]

As a result, the RFP evaluation team proposed to no longer consider the specific Benchmark bid for inclusion on the final shortlist. We agreed with this rejection. We (and the evaluation team) agreed that the point of Appendix P was to provide notice in advance to the market and policy makers regarding utility-supported assets and that adding items in the process violated that spirit as well as the process laid out in OAR. We also were concerned with setting future precedent where the Benchmark

[33] OAR 860-089-0300.(3).

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team would adjust their disclosures during the process and use utility assets to "backstop" the Benchmark.

B. BAFO PROCESS AND UPDATED RANKINGS

PGE received updated price offers from all remining bid options. They then updated calculated cost/benefit ratios. We reviewed the new scores to confirm that the bid offers had been properly scored. The table below shows the re-ranked renewable options along with their average megawatts (MWa) and capacity contribution (ELCC)

Table 12: Cost-Benefit of Renewable Projects

[Begin Highly Confidential]				
Bid	Description	Score	MWa	ELCC (MW)
[redacted]				
[End Highly Confidential]				

While the order switched a bit, the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** general rank order is similar to the initial shortlist. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

The next table shows the updated information for the dispatchable projects.

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Table 13: Cost-Benefit of Dispatchable Projects

[Begin Highly Confidential]			
Bid	Description	Score	ELCC (MW)
[redacted]			
[End Highly Confidential]			

Here the bids are a bit more concentrated in their scoring. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

C. METHODOLOGY

PGE began the portfolio modelling process as described in the RFP. In this process PGE used the ROSE-E model to select bids from among the offers which would result in the lowest cost outcome while still meeting reliability goals and PGE's HB 2021 glidepath emissions targets over the 2024-2043 period. Generic renewable and capacity resources were used to fill in shortfalls if needed.[34]

PGE looked at optimal portfolio selection under the change of four key variables. These were a) low, high and reference case load, b) whether or not additional renewables (known as Variable Energy resources or VER) were available in the near future, c) whether or not PGE could extend current hydro generation supply contracts and d) whether or not the portfolio would meet the HB 2021 glide path. This last sensitivity was added because we had observed that dispatchable resources appeared to be the most cost-effective bids but the Company's renewable needs seemed as if they would drive it to select less cost-effective renewable assets to meet glidepath targets. Varying each of these four items produced optimal portfolios under a total of 24 possible futures.

After the portfolio was selected it was then further evaluated under a variety of circumstances. This included cases for

[34] Generic resources were not assumed to be of any particular size. They can be added in 1 MW increments in any quantity required by the model. Their purpose is to allow the model to solve given the fact that there is insufficient capacity and energy provided by bids alone to meet needs. To prevent competition between bids and generic resources, generics are priced at a cost higher than the most-costly bid in years in which bids are available for selection (through 2028).

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a. Load (reference, low and high cases)
b. Future technology costs (reference low and high cases)
c. Hydro levels (reference low and hydro levels)
d. Market price futures (these varied depending on carbon costs, gas prices, hydro levels and aurora model setup)

In total portfolios were evaluated against 351 different scenarios. All major inputs are unchanged from the CEP/IRP process. The table below shows the vintage of key assumptions.

Table 14: Key Assumptions

	Analytical Component	FSL Data Vintage	LC 80 Vintage
Demand	Corporate Load Forecast	Jun-23	Jun-23
	DER & EE Forecast	Jan-23	Jan-23
	Capacity Need	Nov-23	Nov-23
Supply	Owned and Contracted Non-emitting Generation	Jun-23	Jun-23
	Thermal generation for Retail Load	Jun-23	Jun-23
	Hydro Contracts	Nov-23	Nov-23
	Qualified Facility (QF)	Jun-23	Jun-23
	Community-based Renewable Energy (CBRE)	Mar-23	Mar-23
	Energy Efficiency (EE)	Nov-23	Nov-23

D. RESULTS

The basic results of the modelling are provided in Attachment A. This shows the options for a given future and the bids selected for each portfolio which minimize costs and meet the given needs.

We began by looking at the overall amount of supply selected in each case, broken out by MW and asset class (renewable or dispatchable). Recall that there was a maximum of 2,402 MW of renewable (nameplate) capacity available, which would provide approximately 425 MWa of energy and 868 MW of ELCC. Given PGE's large renewable targets coming into this RFP –251 MWa per year - we suspected that most or all of the renewable bids would be selected in most cases. Because the capacity contribution of those bids roughly matched the going-in capacity need we assumed a limited procurement of BESS units.

The table below shows the amount of nameplate capacity selected in each portfolio by asset class as well as the key variables in each portfolio.

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Table 15: Total MW selected under Portfolios

Portfolio	Generic VER	Energy Need	Hydro Extension	Load Scenario	Renewable	Dispatchable
P_1	Yes	Yes	Yes	Reference	1802	0
P_2	Yes	Yes	No	Reference	2402	400
P_3	No	Yes	Yes	Reference	2402	200
P_4	No	Yes	No	Reference	2402	400
P_5	Yes	Yes	Yes	High	2402	200
P_6	Yes	Yes	No	High	2402	400
P_7	No	Yes	Yes	High	2402	400
P_8	No	Yes	No	High	2402	400
P_9	Yes	Yes	Yes	Low	1802	0
P_10	Yes	Yes	No	Low	1802	200
P_11	No	Yes	Yes	Low	2402	0
P_12	No	Yes	No	Low	2402	400
P_13	Yes	No	Yes	Reference	62	400
P_14	Yes	No	No	Reference	427	800
P_15	No	No	Yes	Reference	62	400
P_16	No	No	No	Reference	427	800
P_17	Yes	No	Yes	High	427	800
P_18	Yes	No	No	High	427	800
P_19	No	No	Yes	High	427	800
P_20	No	No	No	High	427	800
P_21	Yes	No	Yes	Low	41	200
P_22	Yes	No	No	Low	427	600
P_23	No	No	Yes	Low	41	400
P_24	No	No	No	Low	427	600

Here we see that nearly the maximum amount of renewable offers are selected in all cases in which the energy need is enforced. Some cases contain the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** while other do not. Otherwise all renewable offers are selected. This is supplemented by 200 to 400 MW of dispatchable capacity in some cases – either where load is higher or where the existing hydro contracts are not able to be extended. When the energy need is removed the renewable buy decreases significantly – to between 62 and 427 MW supplemented by up to 800 MW of dispatchable capacity. Again, higher loads and or lack of extension of hydro contracts leads to even higher dispatchable selections.

This is generally in line with what we would expect based on the cost/benefit ratios of the bids. Next, we drill down to see what specific projects are selected in key cases. For the cases below we start with the "base" case (i.e. Portfolio number 1) and vary one factor in each case to see what bids are added or dropped.

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Table 16: Bids Selected in Select Portfolios

Bid Number	Bid	Base Case (P1)	No Hydro Extension (P2)	Low Load (P9)	High Load (P5)	No Energy Need (P 13)
[Begin Highly Confidential]						
[redacted]						
[End Highly Confidential]						

Again, in the base case all renewable projects save for **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** and no dispatchable bids are selected. Increasing the load estimate to the high load case adds **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**. If the hydro contracts are not extended both **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** Finally, if energy needs are not enforced the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** This again supports the general thesis that bid selection is being driven to a large extent by meeting the HB 2021 glidepath needs.

The next table shows the total number of times each bid option is included in a portfolio. Recall that there are a total of 24 portfolios.

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Table 17: Total Selection Count per Offer

[Begin Highly Confidential]		
Bid Number	Bid	Times Selected
[redacted]		
[End Highly Confidential]		

From this table we have a few observations. On the renewable side the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** are selected the most. Several others are only selected when the energy need is enforced. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** Dispatchable selections have a clear preference order, with the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

We also looked at the total cost of each portfolio and the risk of each bid selection. The following table shows additional metrics from each portfolio, including the total net present value of

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revenue requirements (NPVRR) for the portfolio, the 90th percentile NPVRR, 2028 emissions and generic capacity added.

Table 18: Portfolio Details

[Begin Confidential]

Portfolio Number	Generic VER	Energy Need	Hydro Extension	Load Scenario	NPVRR ($ Million)	Risk ($ MM)	Emissions (2028 MMCo2)	MW of Bid capacity	Mwa of Bid energy	Generic VER (MW)	Generic Cap (MW)	Generic NG (MWa)
P_1	Yes	Yes	Yes	Reference	[redacted]	$32,039	2.99	678	332	631	0	-
P_2	Yes	Yes	No	Reference	[redacted]	$35,522	2.99	1,154	422	1,532	218	-
P_3	No	Yes	Yes	Reference	[redacted]	$41,581	3.39	1,067	426	-	12	114
P_4	No	Yes	No	Reference	[redacted]	$43,938	4.62	1,188	423	-	391	443
P_5	Yes	Yes	Yes	High	[redacted]	$32,039	2.99	1,039	427	1,010	157	-
P_6	Yes	Yes	No	High	[redacted]	$35,305	2.99	1,157	423	1,868	506	-
P_7	No	Yes	Yes	High	[redacted]	$41,581	4.11	1,188	423	-	135	307
P_8	No	Yes	No	High	[redacted]	$43,938	5.33	1,188	423	-	635	633
P_9	Yes	Yes	Yes	Low	[redacted]	$32,039	2.99	678	332	347	-	-
P_10	Yes	Yes	No	Low	[redacted]	$35,305	2.99	792	328	1,204	102	-
P_11	No	Yes	Yes	Low	[redacted]	$41,581	2.99	953	430	-	95	-
P_12	No	Yes	No	Low	[redacted]	$43,938	4.09	1,188	423	-	195	303
P_13	Yes	No	Yes	Reference	[redacted]	$20,581	2.99	257	3	-	187	-
P_14	Yes	No	No	Reference	[redacted]	$21,812	2.99	618	55	-	391	-
P_15	No	No	Yes	Reference	[redacted]	$20,581	2.99	261	3	-	183	-
P_16	No	No	No	Reference	[redacted]	$21,812	2.99	618	55	-	391	-
P_17	Yes	No	Yes	High	[redacted]	$20,581	2.99	618	55	-	143	-
P_18	Yes	No	No	High	[redacted]	$21,812	2.99	618	55	-	643	-
P_19	No	No	Yes	High	[redacted]	$20,581	2.99	618	55	-	143	-
P_20	No	No	No	High	[redacted]	$21,812	2.99	618	55	-	643	-
P_21	Yes	No	Yes	Low	[redacted]	$20,581	2.99	132	7	-	71	-
P_22	Yes	No	No	Low	[redacted]	$21,812	2.99	539	59	-	195	-
P_23	No	No	Yes	Low	[redacted]	$20,581	2.99	242	3	-	-	-
P_24	No	No	No	Low	[redacted]	$21,812	2.99	539	59	-	195	-

[End Confidential]

One major takeaway from this table is the cost impact of the energy need. Removing this requirement drops the NPVRR in the base case from **[Begin Confidential]** [redacted] **[End Confidential]** In general all cases in which this requirement is dropped are much less expensive. Another note is that even with the renewable projects selected additional renewable buys are needed to meet energy needs as can be seen by the large amounts of generic VER added in several cases. Without these adds emissions in 2028 increase significantly (though this may also be caused by the addition of a generic gas generation unit in these cases).[35]

[35] Note that the "no energy need" cases show no increase in emissions. PGE explained that this was because "in this ROSE-E analysis emissions come from two sources: 1.Existing emitting sources used to meet PGE's load, which are determined by the iGHG model and constrained to the linear GHG reduction glidepath and 2.Additional NG energy used to meet energy need. Energy need is the remaining load to be met after accounting for existing emitting and non-emitting energy in our portfolio. When there is no energy need in the model the only source of emissions is #1, which is set by the GHG glidepath and therefore does not vary across portfolios."

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While PGE could not forecast a true rate impact at this time they did look at the net annual cost increase as a result of the added resources in each portfolio in the first five years. The base case (P1) portfolio had an average annual increase of 5.1%. All cases in which the energy need was enforced averaged 7.2% per year in annual increases in the first five years with a range from 5.1%-8.0% depending on the portfolio. Without the energy need the average annual increase drops to a range from 0.6% to 1.3% per year for the first five years.

This all suggests that PGE's ability to procure renewable energy as envisioned in its 2023 CEP/IRP appears to be impacted by current renewable energy project pricing and value. As noted above, PGE's renewable MWa in the targeted final shortlist deviates from the procurement anticipated in the CEP/IRP. This may be reasonable, but the Company should explain and support deviations, and articulate whether the Company has an alternative procurement strategy envisioned to demonstrate its plan for meeting HB 2021.

PGE also looked at a "high cost" sensitivity in which they increased the cost of future capacity by 50% and a "low cost" sensitivity which decreased the cost of future capacity. The table below shows the total selections in this case as compared to the standard case.

Table 19: Total Selections in Base and High/Low Cost Cases

[Begin Highly Confidential]				
Bid				
[redacted]				
[End Highly Confidential]				

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Here there is little difference between the base and low-cost cases. The high-cost scenario results, not surprisingly, in much heavier additions.

C. ADDITIONAL SENSITIVITIES

PGE also produced some additional sensitivities. These mostly centered on changing the characteristics of individual offers and looking at the change in ranking when key assumptions were adjusted. Attachment B shows the full results of this analysis.

PGE tested four scenarios; a) a 10% increase in EPC capex, b) a 10% increase in O&M and maintenance Capex, c) an increase in the discount for selling tax credits on the open market from **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** to 15% and d) a tax credit discount of 9%. The table below shows the base rankings and scoring of all bids and the change in rank order in each case.

Table 20: Sensitivity Results – Change in Rank Order

[Begin Highly Confidential]							
	Bid	Base Rank	Score	Scenario 1: EPC CapEx + 10%	Scenario 2: O&M and Maint CapEx + 10%	Scenario 3: ITC discount of 15%	Scenario 4: ITC discount of 9%
[redacted]							
[End Highly Confidential]							

Note here that in the initial rankings several projects are extremely close together in scoring, with about 9 options between **[Begin Highly Confidential]** [redacted] **[End Highly**

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Confidential] cost benefit ratio. This means small changes might be expected to change the rankings in this group.

Under these scenarios the top and bottom bids are relatively static. In the middle, where bids are more closely bunched the rankings will change somewhat. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** This is expected given the tight bunching of the scores and the expected effect of these scenarios on company-sponsored bids. Because the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** this does not necessarily provide any additional insight into the procurement decision.

[Begin Highly Confidential] [redacted] **[End Highly Confidential]** However, we can expect that this risk should be mitigated by the BTA contract that would put this risk on the developer. Other scenarios -where the O&M costs are higher than predicted or tax credits are sold at a higher discount than predicted – are risks that are borne by ratepayers with a BTA structure. However, what this sensitivity analysis shows is that even if those costs are higher than predicted in the base case the project's rank order does not change, meaning it is still a better project than the bids below it even with these risks.[36]

[36] We also note that bidders were required to provide long-term service agreement (LTSA) quotes, which were used to develop project O&M cost estimates, giving some more validation to the estimates used.

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VIII. FINAL SHORTLIST SELECTION

PGE proposed to take a several projects on to the final shortlist. One group of projects is targeted for contracting while the second serves as backup in case final deals cannot be negotiated with the chosen projects. The table below shows the final shortlist. Recall that the overall targets for PGE from their IRP approval were 251 MWa/year of renewable acquisition (a total of 753 MWa from 2025-2027), 905 MW of summer capacity and 787 MW of winter capacity.[37]

Table 21: Final Shortlist Project Ranks

Target

	[Begin Highly Confidential]					
Bid #	Bid	Cost/Benefit	Nameplate MW	ELCC (MW)	Mwa	Transaction
88.2.Alt2	[redacted]	[redacted]	400	189	0	BTA
71.1.Alt2	[redacted]	[redacted]	41	18	11	PPA
150.1.Alt1	[redacted]	[redacted]	250	133	26	BTA
16.1.Base	[redacted]	[redacted]	500	210	56	PPA
	[End Highly Confidential]					

Backup

	[Begin Highly Confidential]					
Bid #	Bid	Cost/Benefit	Nameplate MW	ELCC (MW)	Mwa	Transaction
23.1.Base	[redacted]	[redacted]	185	101	0	PPA
23.2.Base	[redacted]	[redacted]	200	109	0	PPA
74.2.Alt1	[redacted]	[redacted]	200	114	0	PPA/BTA
92.1.Alt4	[redacted]	[redacted]	100	63	0	BTA
74.1.Base	[redacted]	[redacted]	200	118	0	PPA/BTA
	[End Highly Confidential]					

These are essentially the top offers by cost/benefit ratio so the selection makes sense based on that analysis.[38] The total ELCC selected in the target portfolio is 550 MW with 93 MWa in renewable generating output. What is immediately evident with this selection is that it is far below the renewable acquisition targets and does not match up with the basic portfolio modelling results. Recall that with energy needs "on" that is, with HB 2021 glidepath requirements active the optimization models dictated taking all (or nearly all) renewables available. When that requirement was removed a much more limited selection was proposed.

[37] Order No. 24-096. Appendix A, p 5.

[38] [Begin Highly Confidential] [redacted] [Begin Highly Confidential]

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PGE explained that they were looking to serve capacity needs first. To confirm this statement it is helpful to look back at the amount of capacity selected when the energy needs were not binding. The table below shows the capacity buy in those situations.

Table 22: ELCC Capacity Selected in "No Energy Need" Scenarios

Portfolio Number	Generic VER	Energy Need	Hydro Extension	Load Scenario	MW of Bid capacity selected	MW of Generic capacity selected	Total
P_13	Yes	No	Yes	Reference	257	187	444
P_14	Yes	No	No	Reference	618	391	1,009
P_15	No	No	Yes	Reference	261	183	444
P_16	No	No	No	Reference	618	391	1,009
P_17	Yes	No	Yes	High	618	143	761
P_18	Yes	No	No	High	618	643	1,261
P_19	No	No	Yes	High	618	143	761
P_20	No	No	No	High	618	643	1,261
P_21	Yes	No	Yes	Low	132	71	203
P_22	Yes	No	No	Low	539	195	734
P_23	No	No	Yes	Low	242	0	242
P_24	No	No	No	Low	539	195	734

Assuming reference case load, the availability of generic VER and extension of the hydro contracts only 444 MW of capacity is needed in the model. With a lower load and holding the other assumptions constant the acquisition drops to 203 MW. Switching to a high load scenario increases the need to 761 MW. The average purchase from RFP bids across all these scenarios is 473 MW with an average total need of 738 MW. The biggest factor beyond load that changes this need is the extension of hydro contracts, which can reduce or increase the need by roughly 500 MW depending on if they are extended or not. PGE states that they are currently in negotiations for **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** of these contracts but the rest will be negotiated in the future.

The 550 MW acquisition seems to reasonably reflect the modelling in terms of bid capacity selected. We note that the modeling suggests additional acquisition might be needed in other situations but based on the results of this RFP it does appear that additional capacity would be available in the future should the need arise.

As discussed earlier there were some battery projects which were in PGE's interconnection queue but were not forecast to receive interconnection agreements prior to the transition to a cluster study process and were rejected by PGE. Bidders did push for reconsideration of this decision based on the fact that they believed they might still be able to meet the end of 2027 COD requirements. After consultation with the IE the bidders were asked if they were willing to sign a contract wherein they would both bear the risk of the project meeting the required COD (complete with appropriate damages

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if this milestone was not met) and stick to the prices offered in this RFP. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Despite this, PGE did not wish to pursue contracting opportunities with these projects given the risks involved in predicting interconnection timelines and costs. Two of the projects **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** had cost/benefit ratios that were better than targeted projects. This is not to say that the targeted projects should have been displaced by these two units, the units only provided about **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** capacity and they did have additional risks that are not present in the selected bids. Our observation is that a higher tolerance for risk on PGE's part may have included these two projects in the final shortlist as well.

On the energy side, the decision is more difficult. The table below shows the acquisitions of bid and generic VER MWa in the scenarios in which energy need is enforced.

Table 23: MWa Selected in "Energy Need" Scenarios

Portfolio Number	Generic VER	Energy Need	Hydro Extension	Load Scenario	Mwa of Bid energy	Generic VER (MWa)	Total Mwa
P_1	Yes	Yes	Yes	Reference	332	240	572
P_2	Yes	Yes	No	Reference	422	582	1,004
P_3	No	Yes	Yes	Reference	426	-	426
P_4	No	Yes	No	Reference	423	-	423
P_5	Yes	Yes	Yes	High	427	384	810
P_6	Yes	Yes	No	High	423	710	1,133
P_7	No	Yes	Yes	High	423	-	423
P_8	No	Yes	No	High	423	-	423
P_9	Yes	Yes	Yes	Low	332	132	464
P_10	Yes	Yes	No	Low	328	458	786
P_11	No	Yes	Yes	Low	430	-	430
P_12	No	Yes	No	Low	423	-	423

In the reference load scenario with hydro contracts extended the portfolio modelling selected 332 MWa of bid energy and 240 MWa of generic VER for a total of 572 MWa. Lower load assumptions drop this number to 464 MWa while higher load assumptions raise this to 810 MWa. The extension of the hydro contracts causes large swings in the need on the order of 500 MWa.

PGE is proposing to take only 93 MWa of renewable supply. Again, the target was 251 MWa per year in the 2025 to 2029 period. This RFP targeted needs through 2027 or 753 MWa. This leaves 660 MWa of need unfulfilled. Given that PGE may only be able to conduct one more RFP prior to 2030 this would seem to be a risky strategy. When asked about meeting this need PGE suggested additional RFPs, bilateral agreements and extensions of existing contracts could fill this need.

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It seems very likely that PGE can execute at least one more RFP (and have projects in place) for a 2030 deadline. Several projects offered here **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** will be likely participants in that RFP since they were Benchmark proposals in this procurement. This would account for **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** of supply. In addition some other projects that were rejected for not being far enough along in the development stage will be able to participate. PGE also noted they have other methods to fulfill this need beyond RFPs such as contract extensions and bilateral negotiations. Still, this would leave a very large need to be filled by 2030.

One key reason for PGE's strategy is the limited value of the proposed renewable projects here. The "best" renewable project left off the list **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** From a rate impact standpoint the targeted final shortlist here has an estimated average annual rate impact of 1.5% per year for the first five years of operation. The renewable-heavy portfolios in which energy need was enforced had an average rate impact of 7.2% per year. This is a clear and direct benefit of this lower-cost portfolio.

Attachment A

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Portfolio Number	P_1	P_2	P_3	P_4	P_5	P_6	P_7	P_8	P_9	P_10	P_11	P_12	P_13	P_14	P_15	P_16	P_17	P_18	P_19	P_20	P_21	P_22	P_23	P_24
Portfolio Characteristics																								
Generic VER	Yes	Yes	No	No	Yes	Yes	No	No	Yes	Yes	No	No	Yes	Yes	No	No	Yes	Yes	No	No	Yes	Yes	No	No
Energy Need	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No	No	No	No	No	No
Hydro Extension	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
Load Scenario	Reference	Reference	Reference	Reference	High	High	High	High	Low	Low	Low	Low	Reference	Reference	Reference	Reference	High	High	High	High	Low	Low	Low	Low

Year 2028

Bid MW [Begin Highly Confidential]

Solved all Futures	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
[redacted]	514	514	514	514	514	514	514	514	514	514	514	514	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	500	500	500	500	500	500	500	500	500	500	500	500	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	365	365	0	0	365	365	0	0	0	365	0	365	0	365	365	365	365	365	0	365	0	365
	365	365	0	0	365	365	0	0	365	365	365	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	0	41	0
	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	0	62	0	62
	111	111	111	111	111	111	111	111	111	111	111	111	0	0	0	0	0	0	0	0	0	0	0	0
	0	200	0	200	0	200	200	200	0	0	0	200	200	200	200	200	200	200	200	200	0	200	0	200
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	200	200	200	200	200	0	0	0	200	0	200	0	200	200	200	200	200	0	200	0	200
	0	200	200	0	0	0	0	0	0	200	0	0	0	0	200	0	0	0	0	0	200	0	200	0
	0	0	0	0	0	0	0	0	0	0	0	0	200	0	0	0	0	0	0	0	0	200	200	200
	0	0	0	0	0	0	0	0	0	0	0	0	0	400	0	400	400	400	400	400	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	600	0	0	600	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	600	600	0	0	600	600	0	0	600	600	0	0	0	0	0	0	0	0	0	0	0	0
	250	250	250	250	250	250	250	250	250	250	250	250	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generic_VER [End Highly Confidential]	631	1532	0	0	1010	1868	0	0	347	1204	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generic_Cap	0	218	12	391	157	506	135	635	0	102	95	195	187	391	183	391	143	643	143	643	71	195	0	195
Generic_NG (Mwa)	0	0	114	443	0	0	307	633	0	0	0	303	0	0	0	0	0	0	0	0	0	0	0	0

Attachment B - Sensitivities

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Base Case:

[Begin Highly Confidential]

Rank	Total Bid #	
1	88.2.Alt1	[redacted]
2	71.1.Alt2	
3	71.1.Alt1	
4	88.2.Alt2	
5	23.1.Base	
6	23.1.Alt2	
7	16.1.Base	
8	150.1.Alt1	
9	150.1.Alt2	
10	23.2.Base	
11	23.2.Alt2	
12	71.2.Base	
13	74.2.Alt1	
14	74.2.Base	
15	92.1.Alt4	
16	74.1.Base	
17	74.1.Alt2	
18	92.1.Alt3	
19	27.1.Alt3	
20	27.1.Alt2	
21	71.3.Base	
22	105.1.Alt1	
23	10.1.Base	
24	10.1.Alt1	
25	105.1.Alt4	

[End Highly Confidential]

Scenario 1: EPC CapEx + 10%

[Begin Highly Confidential]

Rank	Bid	Descri
1	88.2.Alt1	[redacted]
2	71.1.Alt2	
3	71.1.Alt1	
4	23.1.Base	
5	23.1.Alt2	
6	16.1.Base	
7	23.2.Base	
8	23.2.Alt2	
9	71.2.Base	
10	88.2.Alt2	
11	150.1.Alt1	
12	150.1.Alt2	
13	74.2.Alt1	
14	74.2.Base	
15	74.1.Alt2	
16	74.1.Base	
17	27.1.Alt3	
18	92.1.Alt4	
19	27.1.Alt2	
20	92.1.Alt3	
21	71.3.Base	
22	105.1.Alt4	
23	105.1.Alt1	
24	10.1.Alt1	
25	10.1.Base	

[End Highly Confidential]

Scenario 2: O&M and Maint CapEx + 10%

Rank	Bid	Description	Score
1	88.2.Alt1	[redacted]	
2	71.1.Alt2		
3	71.1.Alt1		
4	88.2.Alt2		
5	23.1.Base		
6	23.1.Alt2		
7	16.1.Base		
8	23.2.Base		
9	23.2.Alt2		
10	71.2.Base		
11	150.1.Alt1		
12	150.1.Alt2		
13	74.2.Alt1		
14	74.2.Base		
15	92.1.Alt4		
16	74.1.Base		
17	74.1.Alt2		
18	27.1.Alt3		
19	92.1.Alt3		
20	27.1.Alt2		
21	71.3.Base		
22	10.1.Alt1		
23	105.1.Alt4		
24	105.1.Alt1		
25	10.1.Base		

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Scenario 3: ITC discount of 15%

[Begin Highly Confidential]

Rank	Bid	Description	Score
1	88.2.Alt1	[redacted]	
2	71.1.Alt2		
3	71.1.Alt1		
4	88.2.Alt2		
5	23.1.Base		
6	23.1.Alt2		
7	16.1.Base		
8	23.2.Base		
9	23.2.Alt2		
10	71.2.Base		
11	150.1.Alt1		
12	150.1.Alt2		
13	74.2.Alt1		
14	74.2.Base		
15	74.1.Alt2		
16	74.1.Base		
17	92.1.Alt4		
18	92.1.Alt3		
19	27.1.Alt3		
20	27.1.Alt2		
21	71.3.Base		
22	10.1.Alt1		
23	105.1.Alt4		
24	105.1.Alt1		
25	10.1.Base		

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Scenario 4: ITC discount of 9%

[Begin Highly Confidential]

Rank	Bid	Description	Score
1	88.2.Alt1	[redacted]	
2	71.1.Alt2		
3	71.1.Alt1		
4	88.2.Alt2		
5	23.1.Base		
6	23.1.Alt2		
7	16.1.Base		
8	23.2.Base		
9	23.2.Alt2		
10	150.1.Alt1		
11	150.1.Alt2		
12	71.2.Base		
13	74.2.Alt1		
14	74.2.Base		
15	92.1.Alt4		
16	74.1.Base		
17	74.1.Alt2		
18	92.1.Alt3		
19	27.1.Alt3		
20	27.1.Alt2		
21	71.3.Base		
22	10.1.Alt1		
23	105.1.Alt4		
24	105.1.Alt1		
25	10.1.Base		

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Appendix A to Staffing Principles

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RFP Team		Dates	Role
[redacted]	~~Senior Director Strategic Markets Development and Transmission Integration~~	Added 7/25/23 – 4/19/2024 (left company)	RFP development and evaluation
[redacted]	Senior Regulatory Consultant	01/01/2023 - present	Regulatory support
[redacted]	Senior Energy Supply Procurement Originator	01/01/2023 - present	RFP development and evaluation
[redacted]	Manager – Resource Planning	01/01/2023- present	RFP development and evaluation
[redacted]	Principal Strategy & Planning Analyst	01/01/2023 - present	bid evaluation (flex value and portfolio analysis)
[redacted]	Senior Regulatory Consultant	01/01/2023 - present	Regulatory support and price scoring
[redacted]	Senior Principal Strategy Integrator	January 2023 only	consultation on regulatory strategy aspects of the waiver filed in January 2023 to start the 2023 RFP process
[redacted]	Attorney	01/01/2023 - present	Commercial legal support
[redacted]	Attorney	01/01/2023 - present	Regulatory legal support
[redacted]	Attorney	01/01/2023- present	Regulatory legal support
[redacted]	~~Principal Energy Supply Procurement Originator~~ Manager Origination & Structuring	01/01/2023 - present	RFP development and evaluation
[redacted]	~~Senior Energy Supply Procurement Originator~~	4/14/2023 - 1/10/24 (left company)	Transmission requirements, and bid evaluation
[redacted]	Senior Environmental Science Specialist	4/14/2023 - present	Bid evaluation, permitting
[redacted]	Principal Financial Analyst	4/14/2023 - present	RFP price scoring model support
[redacted]	Senior Environmental Science Specialist	4/14/2023 - present	Bid evaluation (environmental)
[redacted]	Principal Originator	4/14/2023 - present	Commercial Support / Contract Review

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[redacted]	Principal Financial Risk Analyst	4/14/2023 - present	Bid evaluations: finance and credit
[redacted]	Senior Environmental Science Specialist	4/14/2023 - present	Bid evaluation, focusing on wildlife and terrestrial resources permit requirements.
[redacted]	Senior Environmental Science Specialist	4/14/2023 - present	Bid evaluation, permitting
[redacted]	~~Operational Analyst (Now Senior IRP Analyst)~~	4/14/2023 - 4/5/2024 (left company)	Bid evaluation: capacity value
[redacted]	Principal Financial Analyst	2/29/24 – present	Bid evaluations: finance plans and credit
[redacted]	Senior Originator	4/14/2023 - present	Commercial Support / Bid Review / Contract Review
[redacted]	~~Principal Technical Project Manager~~	4/14/2023 - 8/30/2024	Lead technical bid evaluation team
[redacted]	Principal Monitoring & Diagnostics Engineer	4/14/2023 - present	Wind technical support
[redacted]	Principal Control Systems T&D Engineer	2/1/2023 - present	Developing the technical specification for the 2023 RFP
[redacted]	~~Principal Strategy and Planning Analyst~~	4/14/2023 - 9/5/2023 (left company)	Price scoring and portfolio construction
[redacted]	~~Principal Strategy and Planning Analyst~~	4/14/2023 - 2/2/2024 (left company)	Price scoring and portfolio construction
[redacted]	Principal Treasury Analyst	4/14/2023	Bid evaluations: finance plans and credit
[redacted]	Senior Manager Origination & Structuring	4/14/2023	Commercial Support / Bid Review / Contract Review
[redacted]	Manager Property Services	01/2024 – present	Bid evaluation, site control
[redacted]	Cultural Resources Lead (Senior Environmental Science Specialist)	4/14/2023 - present	Bid evaluation, permitting focused on cultural resources surveys and tribal consultation.
[redacted]	Environmental Science Specialist	4/14/2023 - present	Bid evaluation
[redacted]	Senior Security Specialist	4/14/2023 - present	Advising on physical and cybersecurity

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[redacted]			considerations as part of the RFP process
	Principal Control Systems Plant Engineer	4/14/2023 - present	RFP development and evaluation
	~~Senior Civil Structural Engineer~~	4/14/2023 - 6/16/2023 (left company)	Development and evaluation of minimum technical requirements
	Manager Distribution Operations Engineering	4/14/2023 - present	Develop technical specifications and bid compliance with technical specifications
	Senior Electrical Design Plant Engineer	4/14/2023 - present	Develop electrical technical specifications
	Mechanical Design Plant Engineer	4/14/2023 – present	Wind mechanical technical support
	Senior Director Energy Supply	4/14/2023 - present	RFP development
	Senior Transmission & Market Services Analyst	4/14/2023 – present	Bid evaluation/scoring - Interconnection; Tx support
	Principal Financial Analyst	4/14/2023 – present	RFP price scoring model
	Principal Treasury Analyst	4/14/2023 - present	Finance subject matter expert
	Principal Insurance Risk Analyst	4/14/2023 – present	Insurance support
	~~Manager Corporate Communications~~	10/1/2023 – 8/15/2024	Communications Support
	Principal Communications Consultant	5/10/2023 – present	Communications strategy & execution
	Senior Government Affairs Manager	5/16/2023 – present	Subject matter expert on labor standards
	Senior Manager Tax	7/25/23 – present	Tax Consulting
	Contingent IRP Analyst	1/10/24 – present	Analyst for bid energy valuation
	Contingent IRP Analyst	1/10/24 – present	Analyst for bid evaluations
	Senior Transmission Services Analyst	1/24/24 – present	Bid evaluation/scoring - Transmission and Delivery
	Senior Product Portfolio Specialist	2/9/24 – present	Bid evaluation/scoring
	Senior Product Portfolio Specialist	2/9/24 - present	Bid evaluation/scoring

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[redacted]	Associate Environmental Science Specialist	2/28/24 – present	Bid evaluation, focusing on cultural resource requirements.
	Principal Strategy & Planning Analyst	3/4/24 – present	Bid evaluation
	Senior Director Policy Planning and Sustainability	4/30/24 - present	RFP development and evaluation
	Civil/Structural engineering plant design	6/25/24 - present	Develop technical specifications and bid compliance with technical specifications
	Senior Paralegal	3/1/2024 - present	Regulatory legal support

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Benchmark Team		**Dates**	**Role**
[redacted]	Director Resource Planning ~~Manager – Renewable Initiatives~~	01/01//2023 - 09/16/2024 (changed job position and responsibility)	Commercial manager
[redacted]	Senior Originator	01/01/2023 - present	Commercial lead
[redacted]	Senior Originator	01/01/2023 – present	Commercial lead
[redacted]	Technical Program Manager ~~Senior Energy Analyst~~	01/01/2023 – 07/08/2024 (changed organization and responsibility)	Bid analyst
[redacted]	Senior Construction Project Manager	01/01/2023 - present	Technical Due Diligence Support
[redacted]	Attorney	01/01/2023 – present	Legal support
[redacted]	Attorney	01/01/2023 – present	Legal support
[redacted]	~~Principal Planning Engineer~~	4/14/2023 – 7/12/2024 (left company)	Technical Due Diligence Support
[redacted]	Senior Control Systems Plant Engineer	4/14/23 – present	Attended meetings as generation Controls/Cyber representative.
[redacted]	Senior Environmental Science Specialist	4/14/2023 - present	Environmental Diligence support, permitting support.
[redacted]	Senior Environmental Science Specialist	4/14/2023 - present	Wildlife Diligence support, permitting support
[redacted]	Sr Manager, Transmission Development	4/14/2023 - present	Transmission and interconnection support
[redacted]	Senior Director Clean Energy Origination & Structuring	4/14/23 - present	Commercial and Strategic oversight
[redacted]	Staff Construction Project Manager	5/1/23 - present	Technical Due Diligence Support

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[redacted]	Director Plant	4/14/23 – present	Represented Operations for review and commentary
	Tax Manager	7/3/23 – present	Tax Advice
	Senior Manager Financial Planning and Analysis	7/25/23 – present	Financial Analysis Advice
	Senior Principal Real Estate Specialist	4/14/23 – present	Real Estate Due Diligence Support
	~~Manager Plant Electrical Design Engineering~~	1/11/24 – 3/15/24 (left company)	Technical Due Diligence Support
	Principal Electrical Design Plant Engineer	1/11/24 - present	Technical Due Diligence Support
	~~Director Project Management Office~~	1/24/24 – 8/16/2024 (left company)	Project Management Support
	Manager Construction Project Management	1/24/24 - present	Project Management Support
	Manager Insurance Risk	2/28/24 - present	Consultation for general insurance questions
	Government Affairs Manager	2/9/24 - present	Permitting – Washington EFSEC Comments
	Government Affairs Manager	2/9/24 – present	Permitting – Washington EFSEC Comments
	Senior Manager Engineering Services	3/1/24 – present	BESS Operations
	~~Manager T&D Control Systems Engineering~~	3/1/24 – 5/1/2024	BESS Operations
	Senior Manager Engineering Services	3/1/24 - present	BESS Operations
	Principal Control Systems Meter Engineer	3/18/24 – present	Technical Metering Design
	Director Plant	1/2/24 – present	Carty Site Support
	Government Affairs Manager	3/1/24 – present	Oregon Solar Permitting Strategy

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the **Highly Confidential Request for Acknowledgement of Final Shortlist and Final Report** to be served by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket UM 2274.

Dated this 17th day of September 2024.

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