ORDER NO. 24-011

ENTERED Jan 12 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2274

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 All-Source Request for Proposals.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

This order memorializes our decision, made and effective at the January 4, 2024 Special Public Meeting, to adopt Staff's recommendation with modifications. Staff recommended three categories of conditions for approval of Portland General Electric Company's 2023 All-Source Request for Proposals, and partial waiver of the competitive bidding rules. Staff recommended Scoring and Modeling Methodology (SMM) conditions, All-Source Request for Proposals (RFP) conditions, and Portland Renewable Resource Company, LLC (PRR) Participation conditions, many of which we adopted and some of which we modified or eliminated. Additionally, we adopt several conditions proposed by the Northwest & Intermountain Power Producers Coalition (NIPPC). Below, we review the amended or eliminated conditions, the conditions proposed by NIPPC we adopt, and provide discussion for some. Staff recommendations not listed below are adopted as recommended.

SMM Participation Conditions

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

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.

SMM Condition 4: We adopt SMM condition 4 as written, taking it to mean that 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.

We note that this condition operates in conjunction with SMM Condition 10, which will allow bidders to propose their own curtailment parameters for analysis of the capacity value of bids with CF-SC transmission arrangements, for consideration by PGE and review by the IE. We expect that, with the IE present to ensure curtailment assumptions are realistic, portfolio analysis will demonstrate how well projects using CF-SC meet PGE's reliability needs. A broader RFP pool that includes projects using CF-SC transmission has the advantage of promoting price discipline by projects with firmer transmission arrangements.

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.

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.

RFP Conditions

RFP Condition 3: 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.

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 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.

Form Contract

Prior to issuance, PGE will amend Appendix P of the RFP to change five to seven terms that the IE, based on its analysis of the last RFP and its understanding of the bidding environment, deems most likely to be unacceptable to bidders, paying special attention to termination, delay, and credit requirement provisions. The IE will propose replacement terms, again based on its previous reporting on and current understanding of terms the market rejected in previous RFPs.

Our reason for requiring this change is not to express a preference for particular terms; terms remain subject to negotiation by PGE and bidders, with IE oversight. We are persuaded, however, that the bidder community sees PGE's form contract not merely as a starting place for negotiation, but instead as the terms PGE wants priced into bid. We expect that beginning from a form that reflects the IE's view of the market's expectations will help avoid skewing bid prices higher than necessary. We do not intend to diminish PGE's freedom to negotiate terms that it believes are in ratepayers' best interests, which we will review in a later rate proceeding.

PRR Participation Conditions

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.

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.

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.

NIPPC Recommendations Adopted

The affiliate PPA must include a provision that allows regular (*e.g.*, quarterly) audits by Commission Staff to ensure compliance with the affiliate PPA terms.

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.

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.

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.

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.

We note that several remaining conditions proposed by NIPPC are addressed, as noted by Staff, by Order No. 23-294 in docket UI 489. Where not specifically addressed, they can be elevated to the Commission through reporting, may be addressed in the Affiliated Interest docket, and may also be examined in prudence review.

The Staff Report with the recommendation is attached as Appendix A.

Made, entered, and effective Jan 12 2024.

Megan W. Decker Chair	**Letha Tawney** Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
SPECIAL PUBLIC MEETING DATE: January 4, 2024

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** ____N/A____

DATE: December 12, 2023

TO: Public Utility Commission

FROM: Kim Herb

THROUGH: JP Batmale **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2274)
2023 All-Source Request for Proposals, Request for Partial Waiver of Competitive Bidding Rules.

STAFF RECOMMENDATION:

1. Approve Portland General Electric's Scoring and Modeling Methodology, subject to the conditions outlined in this memo.

2. Approve Portland General Electric's Final Draft of the 2023 All-Source Request for Proposals, as modified by the Company in Reply Comments filed June 28, 2023, with an update to Appendix P filed September 1, 2023, and the supplemental filing on December 11, 2023, for issuance, subject to the conditions outlined in this memo.

DISCUSSION:

Issue

1. Whether the Commission should approve Portland General Electric's (PGE or Company) Scoring and Modeling Methodology (SMM), with or without conditions.

2. Whether the Commission should approve PGE's Final Draft of the 2023 All-Source (AS) Request for Proposals (RFP), with or without conditions.

Applicable Rule or Law

The Commission's competitive bidding rules (CBRs) in OAR Chapter 860, Division 89 apply when an electric utility may acquire a resource or a contract for more than an aggregate 80 megawatts and five years in length, as specified in OAR 860-089-0100(1).

Under OAR 860-089-0200(1), when an electric utility is subject to the CBRs, it must engage the services of an independent evaluator (IE) to oversee the RFP process. The duties of an IE are set forth in OAR 860-089-0450. In fulfilling its duties, the IE must be provided with full access to the utility's production cost and risk models and sensitivity analyses.

The CBRs require that a draft RFP utilize the RFP elements, scoring and associated modeling described in a Commission-acknowledged Integrated Resource Plan (IRP). The draft RFP must reference and adhere to the IRP section that describes the RFP design and scoring. Or, prior to preparing a draft RFP, the utility must develop and file for approval an RFP proposal with scoring and any associated modeling in the IE selection docket.

Requirements for RFPs are set forth in OAR 860-089-0250. Under OAR 860-089-0250(5), the Commission may approve an RFP with any necessary conditions if the Commission finds the RFP meets the requirements of the CBRs and will result in a fair and competitive bidding process.

In 2021, House Bill 2021 (HB 2021)[1] imposed new decarbonization requirements on large electric utilities, as well as the obligation to file a Clean Energy Plan (CEP). PGE filed its first CEP, along with its 2023 IRP, on March 31, 2023, in Docket No. LC 80.

Under 860-089-0500 the utility must seek Commission acknowledgement of the RFP final short list prior to commencing any negotiations.

"Affiliated interest," as defined in ORS 757.015(6), includes "[e]very corporation and person, five percent or more of which is directly or indirectly owned by a public utility." Affiliated interest contracts are subject to ORS 757.495 and the applicable rules of the Commission.

Under OAR 860-089-0300(1)(a) an electric utility may allow affiliates to submit bids in response to an RFP and must be treated in the same manner as other bids.

[1] Generally codified as relevant here in ORS 469A.400 to ORS 469A.475.

OAR 860-089-0300(1)(b) dictates that any individual who participates in the development of the RFP or the evaluation or scoring of bids on behalf of the electric company may not participate in the preparation of benchmark or affiliate bids and must be screened from the process.

Under OAR 860-0890300(3)(a) – (b) if benchmark bid elements secured by the electric company are not made available to all bidders, it must provide analysis explaining that decision when seeking RFP acknowledgement and recovery of the costs of the resource in rates.

Analysis

Background

On January 31, 2023, Portland General Electric filed an application seeking to commence the RFP process that included multiple partial waivers from the Commission's CBRs.[2,3] The Company argued that the 2023 CEP/IRP had identified energy and capacity needs beginning in 2026 and growing throughout the decade as the first House Bill (HB) 2021 2030 compliance milestone approaches. PGE stated that filling those needs in a timely fashion would require a partial waiver that would streamline the approval process of the 2023 AS RFP it intended to file. PGE's waiver request consisted of three parts:

1. Allow the Company to continue using Bates White as the Independent Evaluator (IE) for its 2023 RFP without going through another selection process;
2. Allow the Company to use a streamlined process with combined review of its Draft RFP and the associated Scoring and Modeling Methodology (SMM); and
3. Allow for concurrent review of the 2023 RFP and the 2023 CEP/IRP.

The Commission granted the first two parts of the Company's waiver requests in Order No. 23-146, issued on April 21, 2023. That order permitted the simultaneous review of the CEP/IRP and the 2023 RFP while finding that such review was permissible within Commission rules and did not require a partial waiver of the CBRs. PGE subsequently filed its Draft RFP on May 19, 2023. The Company has held a total of three stakeholder workshops to date: one on March 2, 2023, to describe its waiver requests and its overall strategy for this procurement in the context of its 2023

[2] *See* UM 2274, PGE's Notice and Request for Partial Waiver of Competitive Bidding Rules, January 31, 2023.
[3] See Oregon Administrative Rules, Chapter 860, Division 89, Resource Procurement for Electric Companies.

CEP/IRP; and two on May 26, 2023, and June 5, 2023, to walk potential bidders through the Draft RFP and answer questions.

Comments were filed by Staff, Northwest and Intermountain Power Producers Coalition (NIPPC), Oregon Solar + Storage Industries Association (OSSIA), PGE Benchmark Team (PGE Benchmark), Renewable Northwest (RNW), BrightNight, and Swan Lake and Goldendale pumped hydro storage projects (Swan Lake and Goldendale).

A special public meeting was held on July 6, 2023, to provide the Commissioners with an opportunity to discuss some of the issues in this docket and seek input from Staff, PGE, and stakeholders. No deliberations occurred during that workshop and no decisions were made. The main topics of discussion at that meeting were the RFP's proposed Commercial Operation Dates (CODs), transmission, and interconnection, although other issues were also discussed.

Staff's report on the draft Request for Proposals was scheduled to be filed on August 25, 2023. Shortly before filing, Staff was notified that Portland General Electric Company intended to file a motion to suspend the procedural schedule. Therefore, Staff withheld filing its Report until the schedule was reestablished.

In parallel to the Company's efforts to issue this RFP, on May 22, 2023, the Company filed an application for approval of an affiliated interest transaction between itself and Portland Renewable Resource Company, LLC (PRR) in docket UI 489. PGE sought to provide service to PRR under its Master Service Agreement. As part of the application, PGE provided nine conditions intended to protect customers. At the public meeting held on August 8, 2023, the Commission adopted Staff's recommendation to approve PGE's application with modifications to Staff's proposed Conditions 1 and 2. On September 15, 2023, PGE filed an application for reconsideration and a motion for clarification regarding the Commission's modified Condition 2. On October 17, 2023, the Commission held a special public meeting to discuss the request for reconsideration. A final order addressing the reconsideration and clarification request was issued on October 18, 2023.[4]

Staff worked with stakeholders to determine an updated schedule for UM 2274 and on November 2, 2023, moved to reestablish the procedural schedule. PGE filed a Supplemental Filing describing the role of PRR in this RFP, based on updated filings and the Commission's order in UI 489. Stakeholders were given a brief opportunity to issue discovery and allotted ten business days to file comments on the Supplemental

[4] See UM 489, Order No. 23-369.

Filing. This Staff Report is issued following consideration of the Supplemental Filing and stakeholder comments.

2023 CEP/IRP

PGE's 2023 RFP is being reviewed and considered in parallel with the Company's 2023 CEP/IRP, which was filed on March 31, 2023.[5] While this parallel process presents some challenges, the Commission found in granting PGE's partial waiver requests that the fast-approaching 2030 milestone for HB 2021 compliance warranted a flexible process.

One challenge is that the SMM that will be used to score bids in this RFP has yet to be acknowledged by the Commission. Broadly speaking, Staff's approach to the SMM in this docket is to evaluate the reasonableness of modeling elements from PGE's 2023 CEP/IRP, for any issues that would inhibit a fair and competitive process for all resources.

Table 1: Venue for Commission Decisions & Recommendations

Venue for Commission Decisions & Recommendations		
Docket	**CEP/IRP (Docket No. LC 80)**	**RFP (Docket No. UM 2274)**
Needs Assessment	Energy and Capacity Needs 2023 RFP	-COD Requirement -Sensitivities/scenario analysis
Resource Valuation	-Energy, Capacity, and Flexibility Modeling issues/concerns impacting Action Plan or future IRPs -Transmission issues/concerns impacting Action Plan or future IRPs	Reasonableness of Bid Scoring Methods: -Use of IRP Energy, Capacity, Flexibility models for valuation -Transmission -Affiliate Bias
Procurement Strategy	Future procurement approaches	Consideration of transmission constraints this RFP

The energy, capacity, and flexibility modeling elements referenced in the RFP are currently being evaluated for planning purposes in the 2023 CEP/IRP Docket No. LC 80. If Staff identifies changes to the IRP modeling that could impact the competitiveness of the RFP, Staff will make determinations, as part of the RFP final short list acknowledgement process, regarding the implications of those issues as applied to scoring in this RFP docket. If PGE materially changes modeling elements contained in the CEP/IRP, that are deemed to make use of the original elements

[5] See UM 2274, Order No. 23-146, April 21, 2023.

inappropriate for scoring in this RFP, then Staff will suggest rescoring or other remedies.

Another critical area requiring alignment between the CEP/IRP and the RFP is the identification of resource needs. This procurement volume will be affected by, among other things, the acknowledged load forecast and the final acquisition targets for CBREs, energy efficiency (EE), and other demand side resources.

PGE's amended CEP/IRP forecast calls for an accelerating level of resource acquisition throughout the Action Plan time frame through to 2030.[6]

Table 2: PGE 2023 RFP Capacity and Energy Target Updates

Action	As Filed: March 31, 2023	As Updated: July 7, 2023
Capacity	506 MW summer 430 MW winter	944 MW summer 827 MW winter
Energy	181 MWa (905 MWa/5 total years) per year through 2028 (543 MWa in Action Plan window)	261 MWa (1307 MWa/5 total years) per year through 2028 (783 MWa in Action Plan window)

The 2023 RFP is currently seeking both non-emitting dispatchable capacity resources in a volume yet to be determined and non-emitting energy resources totaling approximately 261 MWa per year through 2028. The 2023 CEP/IRP articulated capacity and energy needs, which were subsequently updated as of July 7, 2023, as shown in Table 2. The RFP is also seeking up to 100 MW of renewable resources for the PGE supplied option of the Green Energy Affinity Rider (GEAR).

As specified in PGE's initial waiver requests, PGE does not intend to finalize its procurement targets until the Commission has acknowledged its resource needs in the CEP/IRP. Upon acknowledgment, PGE would proceed to develop a final shortlist (FSL) based on the targets.

In its comments, RNW highlighted the importance of maintaining communication between the CEP/IRP and RFP dockets. RNW requested that PGE and the Commission work diligently to ensure that developments in one docket are communicated clearly to participants in both proceedings to maintain close alignment to the greatest extent possible.[7] Staff agrees with RNW that there are upcoming comment deadlines and commissioner workshops in LC 80 that will, and have,

[6] See PGE's Planning and Procurement Forecast, July 17, 2023, pages 3 and 5.
[7] See RNW Comments on Final Draft RFP, June 16, 2023, pages 1-2.

included feedback germane to this RFP. Staff will seek to align the two proceedings as closely as is practical. Staff encourages the Company and Stakeholders to provide feedback in LC 80 that may impact the scoring, modeling, size, project selection, or general competitiveness of this RFP. Staff plans, at a minimum, to conduct regular meetings with the IE to communicate IRP developments, especially at the key junctures of initial and final short list development. Staff will also ensure the RFP acknowledgement process reflects the final findings from the acknowledged CEP/IRP.

Scoring and Modeling Methodology
Staff finds that the SMM as described in Appendix N to the RFP, with its specific elements further described in referenced sections of the CEP/IRP, reasonable. The IE arrived at a similar assessment in its initial report, while acknowledging the challenge of evaluating scoring and modeling elements that have not yet been acknowledged by the Commission.[8]

In the following section of this report, Staff describes the RFP evaluation process and modeling elements. Staff then focuses on issues impacting the bid scoring.

Figure 1:PGE Bid Evaluation Process[9]

<u>Minimum Bidder Requirements</u>

The first step for bid evaluation in this RFP will be a screening for compliance with the minimum bidder requirements (MBRs) contained in Appendix N of the RFP. These MBRs are akin to those in PGE's 2021 RFP but now include absorbing modified elements of non-price scoring, which are no longer being used as part of this RFP's SMM.

[8] See The Independent Evaluator's Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals, May 31, 2023, page 11.
[9] See Final Draft RFP, Appendix N, page 1.

Staff notes that in Opening Comments, it provided a table showing how it understood non-price elements migrating to other aspects of bid evaluations, including how some non-price score elements were understood to move to the MBRs.[10] Staff has an updated understanding of how the non-price scoring elements were handled and reflects that below.

Table 3: Non-price Scoring Changes and Associated MBR Impacts

Non-Price Scoring Element in 2021 RFP	Description	2023 AS RFP Approach	Change to MBR
Commercial Performance Risk	Points were allocated based on adherence to commercial terms and conditions that focus on performance guarantees and limitations of liability and remedies	Form contracts and term sheets are provided for informational purposes, with all final terms subject to commercial negotiation[11]	No
ELCC (renewable only)	Points were allocated based on the ratio of the resource's capacity contribution to its expected energy production	Reflected in the Capacity Values assigned each resource by PGE's Sequoia model based on 2023 CEP/IRP modeling assumptions	No
Transmission Plan (renewable only)	Additional points were allocated based on the risk of service reassessment or withdrawal as well as those that have more of the facility's potential output met with long-term transmission rights	The non-price scoring for higher percentages of interconnection limits was removed, but the MBRs regarding transmission are unchanged.	No
Commercial Operation Date (Dispatchable only)	More points were allocated to bids with earlier online dates	MBRs delineate what milestones must be met at what times (e.g. at initial shortlist, at final shortlist) to demonstrate ability to meet the specified COD	Yes

[10] See Staff's Opening Comments page 5.
[11] Staff's Opening Comments indicated that this was converted to an MBR, however, the proposed redlining process has been removed entirely from the Draft RFP and was not converted to an MBR.

Stakeholder Feedback
RNW suggested that bidders should be provided with notice by PGE and given an opportunity to cure any bids that are initially deemed not to conform with the minimum bidder requirements.[12]

BrightNight opined that the minimum bidder requirements were too stringent and would likely result in valuable projects being excluded from consideration. To remedy this issue, BrightNight proposed converting these requirements into a scoring rubric that would be considered in conjunction with the ROSE-E model to score and evaluate bids.[13]

OSSIA opined that the labor requirements included in the Scoring and Modeling Methodology went beyond what was legally required. OSSIA suggested that this provision should be altered to only require bidders to adhere to labor requirements in state law, rather than requiring use of a Project Labor Agreement (PLA) as currently set out in the MBRs.[14]

OSSIA also expressed concerns with the structure and application of the RFP's MBRs. OSSIA stated that moving to 100 percent price scoring and MBRs could exclude competitive resources. OSSIA suggested at least some of the scoring be based on non-price scoring components, specifically mentioning attributes like providing living wage jobs, promoting workforce equity, and increasing energy security and resilience.

NIPPC sought clarification of the permitting requirements included in the RFP.[15] In response to a question at PGE's stakeholder workshop on May 26, PGE stated that it would allow a narrative description from bidders that had not yet secured all the permits included in the minimum requirements. NIPPC sought to have this response confirmed.

Staff Analysis
Staff appreciates that there are nuances to some minimum requirements and that non-price scoring can potentially tease out some of those nuances, as some stakeholders noted. However, the Commission's CBRs encourage that wherever possible, RFPs should rely on objective measures like minimum requirements and price scores.[16] Further, a sensitivity analysis performed in PGE's 2021 RFP indicated

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[12] See RNW Comments on Final Draft RFP, June 16, 2023, page 4.
[13] See BrightNight Comments on Final Draft RFP, June 16, 2023, page 2.
[14] See OSSIA Comments on Final Draft RFP, June 16, 2023, page 3.
[15] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 41.
[16] See OAR 860-089-0400.

that the non-price scores, even at varied proportions of a combined price and non-price score, did not result in material effects on the final short list.[17]

As such, Staff is not recommending that PGE include non-price scoring elements in this RFP. However, Staff will work with the IE and stakeholders to examine the impact of this issue and potentially make recommendations for future RFPs. Further, Staff recommends adopting the suggestion that bidders must include a contract redline that illuminates their bid's nuances and pricing so as to make project selection more transparent and so the IE can comment around tradeoffs or irregularities in PGE's ISL or FSL project selection.

In its redlined draft included in reply comments, PGE confirmed that it would provide a cure period for bidders, addressing the concern raised by RNW.[18] Staff appreciates PGE's willingness to resolve that issue.

With respect to labor requirements, Order No. 21-460 approving PGE's 2021 RFP removed the requirement for a PLA in favor of requiring compliance with HB 2021's provisions. As noted by OSSIA and NIPPC, a PLA is one means of complying with HB 2021 labor requirements, but not the only one. Staff therefore supports OSSIA's recommendation to remove the PLA requirement from the MBRs.

The IE noted in its second report on the RFP that it shared NIPPC's understanding of permitting requirements and the ability of bidders to provide a narrative description in lieu of demonstrating that they had acquired all permits included in PGE's matrix. The IE also pointed to footnotes within Appendix N of the RFP confirming this understanding.[19] Staff concurs with the IE that the RFP adequately reflects bidders' option to provide a narrative description in lieu of demonstration. However, the Draft RFP appears to include two similar, but not identical, footnotes addressing this. Staff recommends that footnote 5, rather than footnote 4, be retained, because it includes clarification regarding how the narrative would be used in the evaluation of the bid.

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

SMM Condition 2: PGE will remove the requirement for a Project Labor Agreement from the Minimum Bidder Requirements in Appendix N.

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[17] See UM 2166 Staff Report on Final Shortlist Acknowledgment, June 29, 2022, page 33.
[18] See PGE Reply Comments, June 28, 2023, page 320.
[19] The Independent Evaluator's Second Assessment of Portland General Electric Draft 2023 All Source Request for Proposals, July 14, 2023, page 8.

SMM Condition 3:The RFP will be adjusted to require all bids to include a contract with redlines that reflects the rationale behind their bid price and other elements of their bid.

Interconnection

Queues for interconnection studies were noted as a significant impediment to resources meeting aggressive CODs by the IE in its initial report. The IE recommended easing the requirement for submission of a completed facilities study until after selection to the final shortlist. PGE accommodated this suggestion. Even with this adjustment, however, Staff notes that the interconnection process remains a potential bottleneck due to long queues and delays in Bonneville Power Administration (BPA) cluster studies.

Stakeholder Feedback
The PGE Benchmark Team proposed easing the requirement that off-system bidders have an active transmission service request (TSR). In most cases, satisfying this requirement would mean participating in the BPA Transmission System Expansion Process (TSEP). The PGE Benchmark Team noted delays in in the TSEP would make it difficult for projects to meet the CODs sought by PGE and requested the requirement be eased.[20]

NIPPC also commented on interconnection issues and agreed with the IE's recommendation to remove the requirement for a completed facilities study for selection to the final shortlist.[21]

Staff Analysis
In reply comments, PGE suggested that off-system resources could provide a narrative description of a plan to meet the proposed COD even if they did not meet the proposed TSR requirements.[22] Staff appreciates this flexibility and is not recommending that the TSR requirements for off-system bidders be eased further as proposed by the PGE Benchmark Team. Staff also appreciates PGE's decision to ease the requirement for a completed facilities study as suggested by the IE and NIPPC.

[20] See PGE Benchmark Team Comments on Final Draft RFP, June 16, 2023, page 1.
[21] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 6.
[22] See PGE Reply Comments, June 26, 2023, pages 7-8.

Transmission

One of the MBRs includes a requirement that bidders have transmission rights using one of three conforming equal to 80 percent of the project's maximum interconnection limit.

Transmission requirements were a point of significant discussion in PGE's 2021 RFP. Given the nature of PGE's balancing area, many of the potential resources in this RFP will require secure transmission rights over the BPA system.

The MBRs in the Draft RFP allow for three eligible transmission products: Long Term Firm (LTF); Conditional Firm Bridge, Number of Hours (CFB-NH); and Conditional Firm Reassessment, Number of Hours (CFR-NH). These are the same three transmission products that were included as eligible in PGE's 2021 RFP.

Table 4: Acronyms for Transmission Products

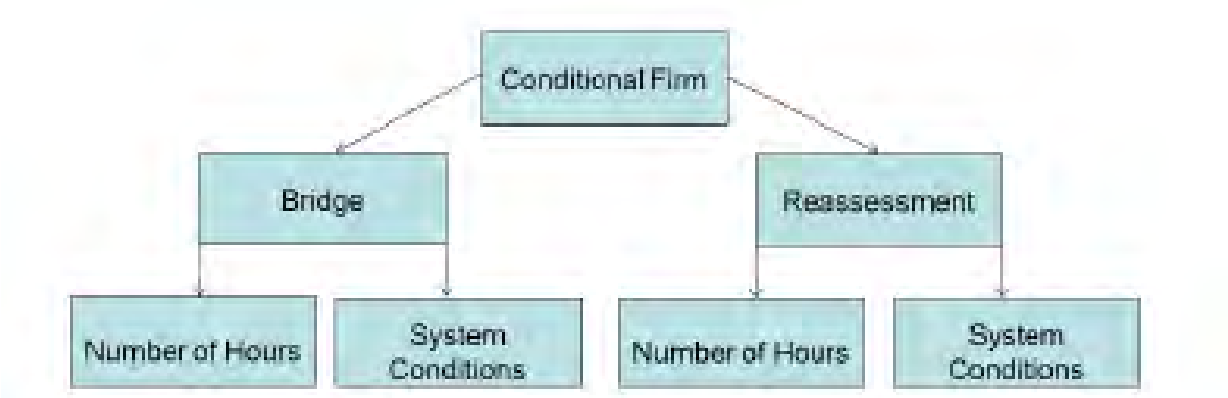
Acronym	Description
LTF	Long Term Firm
CFB-NH	Condition Firm Bridge, Number of Hours
CFR-NH	Conditional Firm Reassessment, Number of Hours
CF	Conditional Firm
CF-SC	Conditional Firm, System Conditions

LTF transmission is the most secure of the transmission products offered by BPA, providing an uncurtailable right to deliver energy over BPA's system up the contractual interconnection limit. LTF transmission is also the product in shortest supply; PGE suggested in reply comments that approximately 700 MWs of LTF TSRs are available directed towards PGE's balancing area.[23]

BPA offers four different types of conditional firm (CF) transmission products, as illustrated in the diagram below.[24]

[23] See PGE Reply Comments, June 28, 2023, page 10.
[24] Conditional Firm Service, BPA Transmission Business Practice, Version 26, January 1, 2022, page 2.

Figure 2: BPA Conditional Firm Transmission Products



The Final Draft RFP currently considers two of those four products CFB-NH, and CFR-NH, to be conforming. Both CFB-NH and CFR-NH stipulate that transmission rights may be curtailed for a certain number of hours per year with the number of hours specified in the contract at the time it is signed. In general, the hours of potential curtailment are presumed to occur during hours of peak congestion, such as on hot summer days.

As seen in the graphic above, BPA also offers two CF System Conditions (CF-SC) products. CF-SC transmission rights base curtailment on system congestion conditions that are stipulated at the time the contract is signed. CF-SC products are more recent additions to the suite of BPA transmission products. This relative newness and the corresponding shallowness of data form the basis of PGE's argument not to allow resources relying on CF-SC transmission to bid into the RFP. However, BPA has also ceased offering CFB-NH and CFR-NH transmission products to PGE's service territory in favor of System Conditions rights.

Stakeholder Feedback
The PGE Benchmark Team suggested that PGE should expand the transmission products included in its minimum bidder requirements to include CF-SC products. This suggestion was based on BPA ceasing to offer CFB-NH and CFR-NH transmission rights in favor of CF-SC products due to long-standing congestion in the greater Portland area.[25]

NIPPC also suggested that CF-SC transmission should be permitted for resources bidding into this RFP. NIPPC raised several points, particularly noting that BPA no longer offers CF-NH contracts for resources included in the 2022 TSEP process. In

[25] See PGE Benchmark Team Comments on Final Draft RFP, June 16, 2023, page 2.

practice, this would significantly shrink the pool of resources eligible for the 2023 RFP.[26]

OSSIA also offered comments regarding PGE's treatment of transmission in the RFP. OSSIA proposed that the requirement that resources demonstrate transmission rights equal to at least 80 percent of their interconnection limit was overly stringent and should be reduced to 70 percent. OSSIA further suggested that the requirement for bidders to demonstrate an "achievable plan" was subjective and discretionary. As such, OSSIA proposed that if PGE determines a proposal does not meet its standard, the Company should be required to provide its reasoning to the bidder and grant an opportunity to update or otherwise cure its plan.[27]

Staff Analysis
Staff appreciates the thorough discussion of transmission issues in written comments and at the July 6 Commissioner workshop. Staff also recognizes that this issue presents significant challenges to both PGE and potential bidders given constraints on the transmission system, particularly for transmission rights directed to PGE's territory.

Staff finds that PGE's approach of prioritizing resources that utilize the remaining inventory of LTF and CF-NH rights is justified with respect to bids for dispatchable capacity resources, especially those intending to achieve the December 31, 2025 COD to meet PGE's immediate capacity needs. The immediacy of those needs represents a strong argument for preferencing resources that will provide the highest capacity contribution possible.

However, as described later in this report, PGE is also agreeing to a more flexible approach to filling its need for non-emitting energy resources. This flexibility is most apparent in PGE's extension of allowable CODs out to the end of its CEP/IRP action plan period, or December 31, 2027. In Staff's view, this flexible approach to resources that are mostly providing energy, rather than capacity, suggests an opportunity to expand eligible transmission products.

Staff is recommending that CF-SC transmission rights be considered conforming. A as several parties mentioned at the July 6 Commissioner workshop, the Western Resource Adequacy Program (WRAP) allows CF transmission whether the contract

[26] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 5.
[27] See OSSIA Comments on Final Draft RFP, June 16, 2023, page 2.

in question is Number of Hours or System Conditions.[28] Given that PGE is participating in WRAP, there is substantive justification for considering CF-SC transmission eligible for this procurement. Moreover, while data may be thin on the likely curtailments for CF-SC products, Staff believes this uncertainty can be managed through adjustments to resource ELCCs.

Staff agrees with OSSIA's recommendation to reduce the transmission threshold in the MBRs from 80 percent to 70 percent. Given the large need for both capacity and non-dispatchable energy identified by PGE in its 2023 CEP/IRP, Staff believes PGE should pursue the largest universe of potential projects in this RFP. Staff also notes that PGE's willingness to accept narrative descriptions of project's plans to meet transmission requirements implies that the Company itself sees the 80 percent threshold as a useful but flexible cutoff. Reducing this threshold will allow more projects to proceed to scoring and potentially inclusion in the ROSE-E modeling that will be used later in the scoring and modeling process. At those later stages, projects that have lower amounts of secure transmission or less firm transmission rights may still be excluded from elevation to the final shortlist. However, in the first instance, Staff believes that scoring more projects is beneficial given PGE's system needs.

However, Staff does not agree with OSSIA's argument that "the requirement for bidders to demonstrate an "achievable plan" was subjective and discretionary." The Transmission Requirements listed in Table 1 of Appendix N describe transmission product and quantity requirements. Further, footnote 7 (and 8) describes what a bidder should provide when describing an alternative transmission path "PGE … invites bidders to include clear and executable paths to procuring transmission service (including study process milestones and reference to public study results for similar projects). Any clear and executable plan must meet the transmission product and quantity requirements specified in this section."[29] That said, PGE confirmed that it would provide a cure period for bidders, which Staff notes would afford bidders an opportunity to address deficiencies in alternative transmission paths as identified by PGE.

SMM Condition 4: PGE will consider projects using Conditional Firm, System Conditions transmission products as conforming to transmission requirements.

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[28] See Western Power Pool, WRAP Interoperability with Markets, June 16, 2023 https://www.westernpowerpool.org/private-media/documents/WPP_WRAP_Interoperability_with_Markets_June_2023.pdf.
[29] See Final Draft RFP, Appendix N, pages 5-6.

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 70 percent of the resource's interconnection limit.

Initial Scoring

Following the screening for MBRs, each bid will receive its price score. Price scores will be determined by evaluating both the costs and benefits of each resource based on following components:

1. Bid Cost,
2. Energy Value,
3. Capacity Value, and
4. Flexibility Value.

Bid Cost

Bid costs will be based on the pricing information provided by the bidder and will reflect the total costs, fixed and variable, associated with the resource's delivery of energy, capacity, and ancillary services, including transmission to deliver the supply to PGE's load. PGE will use a revenue requirement model (in Excel) to convert the price elements provided by bidders to a total cost expressed on a present-value basis. This approach is unchanged from prior RFPs and Staff finds this aspect bid cost evaluation acceptable. However, PGE included two new bid cost elements: an imputed debt adder for power purchase agreements and a tax credit transferability discount. Both are discussed in more depth below.

Tax Credit Transferability

In prior RFPs, PGE applied a carrying cost for tax credits such as the Production Tax Credit (PTC) and Investment Tax Credit (ITC) associated with utility-ownership bids. However, the federal Inflation Reduction Act (IRA) included a policy change that allows the transfer of those credits to other eligible taxpayers. Secondary markets will likely apply a discount to any tax credits transferred from a utility in this manner. However, given that this is a new policy, PGE has little firm data on which to propose a specific rate of discounting. In its presentation at the May 26, 2023, stakeholder workshop, PGE stated it is currently estimating discount rates of 5-10 percent.[30]

[30] See 2023 All-Source RFP Stakeholder and Bidder Workshop, May 26, 2023, slide 18.

Stakeholder Feedback
RNW opined that while it agreed in theory with PGE's plan to apply a discount to tax credits, this discounting may lend itself more to a sensitivity analysis than a fixed assumption.[31] NIPPC made a similar suggestion, requesting that PGE perform sensitivities on the ranking of projects with various transferability percentages. NIPPC also argued that the uncertainty in this new market necessitated a steeper discount and proposed 50 percent as an appropriate level.[32]

Staff Analysis
Staff declines to accept NIPPC's proposal to increase the discount rate to 50 percent. However, Staff agrees with RNW and NIPPC that this issue lends itself to a sensitivity and commits to working with the IE and PGE after issuance of the RFP to develop appropriate levels for that analysis. As PGE stated in its RFP workshops, it expects to continue refining its analysis as more information becomes available and will adjust its discount rate accordingly. In its second report on the RFP, the IE also agreed that while the appropriate discount rate was uncertain, 50 percent was likely too high.[33] Given the lack of data on which to base a discount rate, Staff instead recommends PGE continue to apply the carrying cost model from the prior RFP to the price scores for utility-ownership bids. Staff will work with the Company and the IE to develop a sensitivity analysis on this topic for informational purposes in future RFPs.

SMM Condition 6: PGE will apply the same tax credit carrying cost from its 2021 RFP for purposes of price scoring.

<u>Imputed Debt</u>

The Draft RFP includes within its price scoring a proposal to apply an imputed debt adder to the price scores for third-party owned resources secured under contractual structures such as PPAs. This issue has been discussed at some length in Staff comments to this docket as well as in Idaho Power Company ongoing RFP (see Docket No. UM 2255). As such, Staff will recapitulate the issue only briefly in this report.

In short, imputed debt is a financial measure evaluated by some bond ratings agencies, namely Standard and Poor's (S&P). The measure is intended to capture the debt-like quality of long-term financial arrangements such as PPAs that obligate a utility to make payments to another entity, in this case the resource owning

[31] See RNW Comments on Final Draft RFP, June 16, 2023, page 4.
[32] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 8.
[33] The Independent Evaluator's Second Assessment of Portland General Electric Draft 2023 All Source Request for Proposals, July 14, 2023, page 7.

counterparty to the PPA. S&P totals the net present value of a utility obligations for the full term of each contract and calculates the share of those payments attributable to the capacity value of the contract. S&P applies a risk factor to this calculated amount that varies depending on the regulatory recovery mechanisms available to the utility. In PGE's case, S&P uses a risk adjustment of 25 percent.[34]

PGE maintains that the imputed debt adder is necessary to allow for comparability between utility-owned and third-party-owned resource bids into the RFP and to accurately reflect the effect that PPAs and similar contracts have on its overall financial position. PGE also stated at the July 6 Commissioner workshop that the Company believes the salience of this issue has increased given the large amount of energy it is likely to acquire via PPAs as it seeks to comply with HB 2021. For reference, the proposed imputed debt adders are included in the Table 5 below.[35]

Table 5: Imputed Debt Adder by Contract Length and COD

Contract Length (Years)	Adder (2026 COD)	Adder (2027 COD)
15	2.92%	2.86%
20	3.87%	3.79%
25	4.83%	4.74%
30	5.82%	5.70%

Stakeholder Feedback

Both RNW[36] and NIPPC[37] opposed the inclusion of an imputed debt adder in this RFP for similar reasons. Both parties cited long-standing Commission precedent on this issue as reflected in Order No. 11-001 as well as the Commission's recent decision to exclude Idaho Power's proposed imputed debt adder in Order No. 23-260.

Staff Analysis

Staff noted in earlier comments to this docket that prior Commission decisions have found that while imputed debt assessments by bond ratings agencies might have an impact on a utility's financial position, the appropriate venue to consider that impact is in a general rate case.[38] Staff appreciates the additional clarification PGE provided in reply comments and at the Commissioner workshop but does not find sufficient justification to reconsider its opposition to including an imputed debt adder in the

[34] See PGE Reply Comments, June 28, 2023, page 15.
[35] See Final Draft RFP, Appendix N, page 9.
[36] See RNW Comments on Final Draft RFP, June 16, 2023, page 3.
[37] See NIPPC Comments on Final Draft RFP, June 16, 2023, pages 14-17.
[38] See Staff Opening Comments on Final Draft RFP, June 16, 2023, page 11.

price scoring for this RFP. This issue was also raised at the Special Public Meeting on July 6, 2023. To this end, Staff does not find that PGE has provided an adequate reason to reconsider the Commission's very recent decision in Order No. 23-260.

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.

Integration

In Appendix N, PGE states that in the interest of comparability between bids, all resources outside its own balancing authority area will be assessed BPA reserve rates.

Stakeholder Feedback
NIPPC noted in its comments that for reserve rates, PGE intends to assess all bids from third-party balancing authorities using the reserve rates for BPA.[39] NIPPC acknowledged that this was the simplest way to assess reserve rates but noted that that it would be inaccurate in many cases and could skew the results of price scoring. PGE did not respond to this concern.

Staff Analysis
In its second report, the IE partially agreed with NIPPC's recommendation, starting that where possible, PGE should use the actual reserve rates attributable to a bid. The IE stated that if detailed data were not available, assessing a bid the BPA rate was reasonable.[40] Staff agrees with NIPPC and recommends that PGE adjust its price scoring. Although applying a uniform integration cost to all bids may be a simpler process, Staff finds that bidders should be assessed on the actual, demonstrable costs of their specific projects to generate fair, competitive comparisons. Bidders should be required to provide their actual reserve rate costs based on their bids.

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.

[39] See NIPPC Comments on Final Draft RFP, June 16, 2023, pages 11-13.
[40] See The Independent Evaluator's Second Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals, July 14, 2023, page 8.

Long Lead-Time Resources

PGE provides special treatment for long lead-time (LLT) resources with respect to CODs. However, some stakeholders raised another issue that directly relates to the scoring of those projects.

Stakeholder Feedback
Swan Lake and Goldendale suggested that the proposed 38-year useful life for pumped storage resources, contained in PGE's 2023 CEP/IRP, is unreasonable. The parties suggested that based on both the long history of such resources and more recent studies, a 50-year useful life would be more reasonable.[41]

Staff Analysis
Regarding the assumed useful life of LLT resources, Staff declines to adopt the recommendation made by Swan Lake and Goldendale. However, if a decision were to be made in PGE's CEP/IRP docket to adjust the assumed useful life of pumped storage hydro resources, then Staff would expect that the price scores for any non-benchmark pumped storage projects that bid into this RFP would be adjusted accordingly.

Leveraging Low-Cost U.S. Department of Energy Financing: Energy Infrastructure Reinvestment Program

As part of the 2022 Inflation Reduction Act (IRA) the Energy Infrastructure Reinvestment (EIR) Program was launched within the U.S. Department of Energy's Loan Program Office (LPO). The EIR provides low-cost financing to select projects that leverage existing U.S. energy infrastructure to enable the transition to a clean energy system. Selected EIR projects must retool, repower, repurpose or replace energy infrastructure that enables a utility to operate energy infrastructure that reduces greenhouse gas emissions. The EIR financing can cover not only infrastructure but also environmental remediation and refinancing of outstanding debt as part of a larger reinvestment plan. The EIR can finance up to 80 percent of eligible project costs and provide a loan guarantee up to 100 percent, if using the U.S. Treasury's Federal Financing Bank (FFB).[42] The financing can be extended to non-utility owned assets, such as PPA projects if it is part of portfolio of projects.

The EIR has funding for up to $250 billion in financing at the current Treasury rate plus 3/8ths (0.375 percent) for a 30-year loan. As of December 1, 2023, the U.S. Treasury Rate for a 30-year bond is approximately 4.5 percent, making the estimated

[41] See Swan Lake and Goldendale Comments on Final Draft RFP, June 16, 2023, pages 4-5.
[42] See U.S. DOE LPO presentation to Staff in Attachment A.

borrowing rate for a qualified portfolio of projects designed to decarbonize PGE's system approximately 4.875 percent.

if financed at the EIR's lower rate. Applications must be received before the program's expiration date in September 2026. However, projects do not need to commence construction until as late as 2031 and the financing does not limit the utilization of any tax credits.[43]

According to U.S. DOE LPO staff, over $100 billion of EIR financing has already allocated.[44] Given the potential savings and the alignment of this RFP's purpose to the intent of the U.S. DOE's EIR program, Staff recommends that the RFP require ***all bids*** to submit two prices: one with and one without the use of EIR financing. While the initial bids may be higher due to required elements such as compliance with prevailing wage rates, the benefits to ratepayers from this much lower cost financing should outweigh that impact. PGE will need to develop and include instructions in the RFP on how to accomplish this. Further, PGE will need to allocate the internal resources to begin developing an EIR project application in 2024. Staff also recommends that the IE's scope be extended to include in its final report an update PGE's EIR application. This information should be available in future rate cases for a review of the reasonableness and prudence of any rate recovery request for financing costs associated with this RFP's projects and associated infrastructure.

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.

RFP Condition 1: 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.

Energy Value

Each bid will have an energy value assigned by PGE based upon the generation information provided by the bidder. PGE will then use the reference market price forecast from its 2023 CEP/IRP and, in the case of dispatchable resources, the Aurora production cost simulation tool used for the CEP/IRP and described in Appendix H. The same market price forecast will be used to determine the energy value of each bid. A determination may be made in the CEP/IRP that a different price

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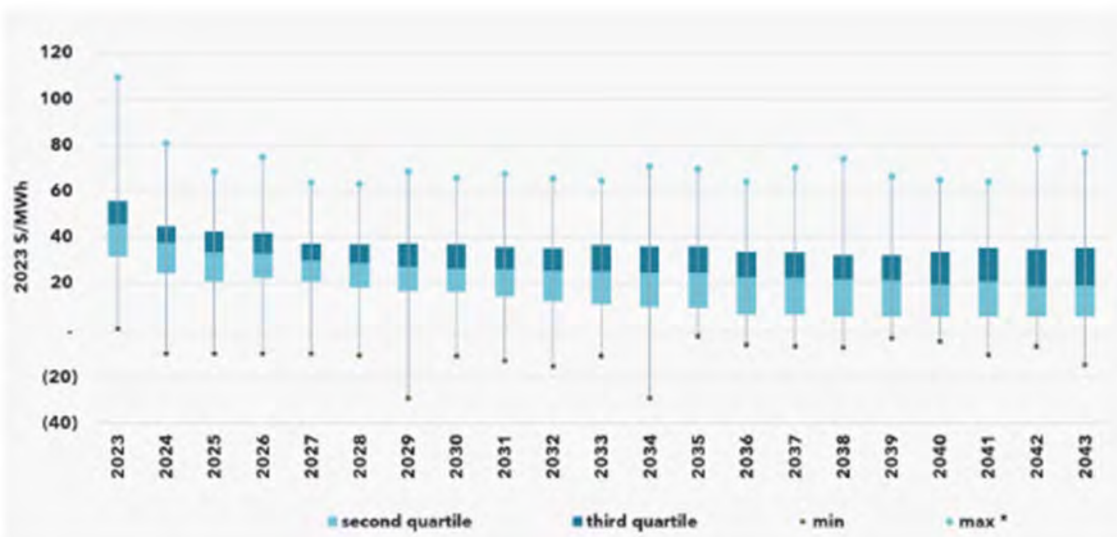
[43] For more information beyond this section and Attachment A, go to https://www.energy.gov/lpo/energy-infrstructure-reinvestment.
[44] US DOE Staff to OPUC Staff communication on November 14, 2023.

forecast should be used to better reflect PGE's long-term planning purposes. With that said, if issues with the CEP/IRP price forecast are identified that are deemed to potentially skew scoring in this RFP, Staff reserves the right to require rescoring or other remedies as necessary. The reference electricity price forecasts from the CEP/IRP can be seen in the figure below.[45]

Figure 3: Reference Case Hourly Electricity Price Range by Year from PGE's 2023 CEP/IRP (Figure 128)



Capacity Value

PGE will generate a capacity value for each bid using the capacity contribution of the resource and the avoided capacity cost used by the Company in its 2023 CEP/IRP. In a departure from prior IRPs, the 2023 CEP/IRP generates an avoided capacity cost utilizing the "real-levelized cost, net of wholesale revenues and flexibility value, adjusted for Effective Load Carrying Capacity (ELCC) of a four-hour battery"[46] as opposed to a thermal generating unit as in prior IRPs. The capacity contribution of each resource will be calculated using Sequoia. Sequoia uses loss-of-load probability models and stochastic analysis to evaluate resources under many possible futures and scenarios to determine their capacity contribution. The capacity contribution and associated capacity values for resources will also account for the transmission product provided by the bidder, with resources relying on Conditional Firm Bridge and Conditional Firm Reassessment products having their capacity contributions reduced or eliminated, respectively.

[45] See PGE 2023 CEP/IRP, page 515.
[46] See Final Draft RFP, Appendix N, page 10.

Staff finds the methodology for capacity valuation generally reasonable and competitively fair. While Staff and other parties to Docket No. LC 80 have made, and will continue to make, suggestions to improve PGE's approach to capacity modeling in future IRPs, Staff finds no evidence that the approach described in PGE's 2023 CEP/IRP will advantage or disadvantage any particular technology or ownership structure. The change in the avoided cost resource from a simple cycle turbine to a four-hour battery will lead to higher valuations for capacity contributions. Given the changing resource mix in Oregon, Staff finds this change in the avoided cost resource appropriate but notes this likely impact on scoring of various projects.

Again, as this change is uniform across all projects, it should not have any anti-competitive impact. However, this change will have the effect of making dispatchable resources and those with a higher ELCC more valuable according to the scoring methodology. Given the reductions to the ELCC of bids using conditional firm rather than long-term firm transmission, this may further skew resource rankings on the shortlist in favor of those with firm transmission rights. Staff is not making any recommendation to alter the calculation of capacity values and still believes this methodology will not introduce any anti-competitive bias into the process, but believes the likely impact of these changes should be noted.

Finally, Staff notes that in PGE's July 31, 2023, Application to Update Schedule 201 Qualifying Facility Information, Avoided Cost Interim Solar-Plus-Storage Rate (see Docket No. UM 1728), PGE will be using a tuned ELCC to determine the capacity contribution of Qualifying Facilities. In this RFP, and for portfolio modeling in the CEP/IRP, PGE is using untuned ELCCs. In brief, tuned ELCCs are calculated on a resource adequate system, while untuned ELCCs calculate the capacity contribution of a resource on a resource deficient system. Staff makes no recommendation in this docket but notes the inconsistency across the two dockets.

<u>ELCC Calculator</u>

NIPPC requested that PGE provide a tool on its website to allow bidders to estimate their project's ELCC. As noted by NIPPC, PGE had provided such a tool in its 2021 RFP.[47] In reply comments, PGE agreed to create such a tool and make it available on the Company's procurement website.[48] Staff appreciates PGE's willingness to accommodate this request.

[47] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 17.
[48] See PGE Reply Comments, June 26, 2023, page 18.

Transmission

In both UM 2166 and UM 2274, PGE has taken a conservative approach to assessing the likely curtailment of resources using CF transmission rights. In its 2021 RFP, PGE argued that resources with CFB-NH product should be assumed to be curtailed during 100 percent of all of PGE's peak hours. PGE has not provided any data to substantiate this position. In PGE's 2021 RFP, the Commission ordered that resources utilizing CFB-NH rights would be modeled such that 50 percent of curtailable hours would occur within PGE's peak hours of need.[49]

In its second IE report, Bates White suggested that PGE should accept CF-SC transmission rights over paths and flowgates for which the Company has sufficient data to model the likelihood of curtailment.[50]

Stakeholder Feedback
Several participants at the July 6 special public meeting stated that curtailments under SC contracts were unlikely to exceed those of NH contracts.

In reply comments, NIPPC proposed that bidders using CF-SC products should be permitted to propose their own capacity value. NIPPC suggested that this value would be subject to commercial negotiation and review by the IE.[51]

Staff Analysis
Regarding capacity valuation of bids with CFB-NH, without further evidence supporting an argument to change how curtailment is modeled, Staff recommends that this be modeled the same way it was modeled in UM 2166, namely, such that 50 percent of curtailable hours would occur within PGE's peak hours of need.

Regarding capacity valuation of bids with CFB-SC, Staff supports NIPPC's proposal to allow bidders to propose their own curtailment parameters, subject to commercial negotiation and review by the IE. Staff believes this approach allows for more accurate assumptions, and ultimately allows for management of the risk of optimistically low curtailment assumptions in the negotiation process. Further, Staff believes the IE's proposed approach to rely on curtailment-potential data where flowgate data is available, can provide an objective comparison to bidder proposed curtailment assumptions. Staff invites discussion of this suggestion in reply comments prior to a Commission decision.

[49] Order No. 21-320, page 23.
[50] The Independent Evaluator's Second Assessment of Portland General Electric Draft 2023 All Source Request for Proposals, July 14, 2023, page 3.
[51] See NIPPC.

Staff lacks sufficient supporting information to respond to the argument that curtailments on CF-SC products were unlikely to be higher than CF-NH products.

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.

SMM Condition 11**: 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.**

Flexibility Value

PGE will also calculate a flexibility value for each bid. This value is meant to capture the benefit a resource can provide to PGE's overall system by responding quickly to forecast errors and meeting reserve requirements. The flexibility values assigned to resources in this RFP were derived from the GridPath model produced by Blue Marble Analytics.[52] A study describing this model can be found in the appendices of the 2023 CEP/IRP. Due to the nature of the benefits captured by the flexibility value, only dispatchable resources will be assigned flexibility values. Those values are shown in the Table 6 below.[53] As only dispatchable resources will receive any credit for flexibility values, this may disadvantage non-dispatchable renewable resources such as solar or wind. However, Staff finds that the referenced study captures a real value that dispatchable resources provide to PGE's overall portfolio which should be reflected in the price scores of those resources.

Table 6: Flexibility Values

Estimated 2026 Flexibility Value (2023$/kW-yr)	
2-hour Battery	$8.35
4-hour Battery	$9.77
6-hour Battery	$10.68
8-hour Battery	$11.78
10-hour Pumped Storage	$11.47

[52] See PGE 2023 CEP/IRP, Ext. Study-IV. Flexibility Study, page 675.
[53] See Final Draft RFP, Appendix N, page 12.

Price Score and Initial Shortlist

Bids will be assigned price score points on a sliding scale, with the resources with the most desirable cost-to-benefit price ratio based on the four components described above receiving 1,000 points. As in the 2021 RFP, renewable resources and dispatchable capacity resources will be evaluated and scored in two separate groups. After each eligible bid has been scored, PGE will develop an initial shortlist using those scores and notify bidders that have been selected at this stage.[54]

No Stakeholders commented on this aspect of the RFP and Staff has no concerns related to this approach. However, as discussed later in this Report, PGE has proposed leveraging its Affiliate, PRR, as a vehicle to consider utility owned solar projects that are eligible for the ITC without normalization. Price scores for bids leveraging PRR would reflect this normalization. Staff discusses the method by which PRR related pricing is achieved in the Section below on Affiliate Interest Participation. Because this is a new approach, and there are concerns about the impacts to competitiveness with the participation of PRR projects, Staff would like to ensure visibility to the impacts of PRR at the Initial Shortlist stage. Staff recommends that PGE share with Staff and the IE a comparison of the Initial Shortlist both with and without the impact of PRR, and that the IE provide an analysis to Staff of the impacts along with recommendations regarding the inclusion or removal of bids from the ISL. This should take place before the Company conducts sensitivity analysis on the ISL.

SMM Condition 12: 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.

Best and Final Offer (BAFO) and Portfolio Modeling

After being notified of their selection to the initial shortlist, bidders will be asked to provide a BAFO. PGE will also request any redlines to the technical specifications for projects. An additional eligibility screening will also occur at this stage based on updates from bidders on hitting milestones on issues like interconnection studies, permitting, and credit required prior to possible selection to the final shortlist.

All projects that have passed this additional eligibility screening will then be analyzed using the portfolio analysis function in ROSE-E, the capacity expansion model used by PGE in its CEP/IRP.[55] ROSE-E will analyze projects both individually and in

[54] See Final Draft RFP, Appendix N, page 13.
[55] See PGE's 2023 CEP/IRP, Appendix H.4, page 529.

combined portfolios under constraints to meet the carbon reduction targets of HB 2021 while maintaining a resource adequate system. Within those constraints, ROSE-E will seek to minimize long-term costs and produce portfolio price scores for various combinations of resources from the initial shortlist.

The top performing portfolios will receive price scores based on expected cost and the standard deviation of forecasted costs, with each component weighted at 50 percent. Price scores will then be scaled such that the best performing portfolio on a cost and risk basis will receive 1,000 points.

Stakeholder Feedback
RNW supported PGE's approach to pricing flexibility and its commitment to offering all bidders from the initial shortlist an opportunity to provide a BAFO prior to the development of the Final Shortlist.[56]

NIPPC requested clarification of the credit requirements in Appendix K of the RFP, which are one of the additional eligibility thresholds at the shortlist state. NIPPC suggested that as drafted, Appendix K seemed to include duplicative credit requirements. In reply comments, PGE provided a redlined version of Appendix K with the requested clarification. As such, Staff considers this issue resolved.

<u>Final Shortlist</u>

Finally, after consultation with the IE and Commission Staff, PGE will use the price scores of conforming bids and the portfolio price scores generated by ROSE-E, PGE to generate and file a final shortlist.

No Stakeholders provided comments regarding PGE approach to generating the Final Shortlist. Staff, however, takes this opportunity to reiterate concerns regarding PGE's evaluation of Final Shortlist volumes in UM 2166. Staff asks the Company to comment on whether it intends to conduct a similar analysis to that it conducted in UM 2166, which evaluated multiple procurement volume sizes, as a way to support its ultimate procurement volume decisions. Further, Staff asks that the Company explain whether it anticipates similar challenges providing "total clarity" around the level of resources it intends to procure in this RFP.[57]

Further, PGE clarified its intention to consider bids that can leverage the Company's recently approved affiliate, PRR. These bids, as appropriate, will reflect full recognition of the ITC and not have the tax benefit be subject to normalization. This

[56] See RNW Comments on Final Draft RFP, June 16, 2023, page 4.
[57] See Order No. 22-315, page 3.

ultimately effects the price score and as noted elsewhere in this report, staff recommends be subject to additional conditions.[58]

DRAFT RFP Review

Staff finds that PGE's Draft 2023 AS RFP, with conditions recommended below by Staff, is generally compliant with the Commission's CBRs in OAR Chapter 860, Division 89 that are applicable to this RFP, except as otherwise waived by the Commission.

General RFP Themes

Staff finds there are three main areas that warrant discussion and potential modification prior to issuance:

- Allowable CODs for resources bidding into the RFP;
- The benchmark and affiliate bids that may participate in the RFP and additional processes; and
- The contract terms for resources that are selected to the final shortlist and potentially engaged by PGE for commercial negotiations.

These three topics are discussed below. This list is not exhaustive, and Staff will also more briefly address other issues raised by stakeholders.

<u>Commercial Operation Date</u>

The Draft RFP filed by PGE on May 19, 2023, required that eligible resources be able to meet a COD of December 31, 2025. This date was predicated on the capacity need the Company identified in its planning process. In its initial report on the Draft RFP, the IE identified this COD as extremely aggressive and potentially problematic given the realities of the regulatory and commercial landscape.[59] At its first stakeholder workshop, held on May 26, 2023, several stakeholders and potential bidders raised similar concerns.

In response to this feedback, PGE agreed to adjust its approach to CODs in this RFP. In addition to the capacity need beginning in 2026, PGE's CEP/IRP process also identified significant need for non-emitting energy resources which the Company hoped to procure in roughly equal blocks each year through the end of the decade in order to comply with the 2030 emission reduction targets set by HB 2021. In light of the feedback from stakeholders and its identified energy needs, PGE agreed to allow

[58] See Section on Affiliate Interest Participation.
[59] See The Independent Evaluator's Assessment of Portland General Electric's draft 2023 All Source Request for Proposals, May 31, 2023, page 9.

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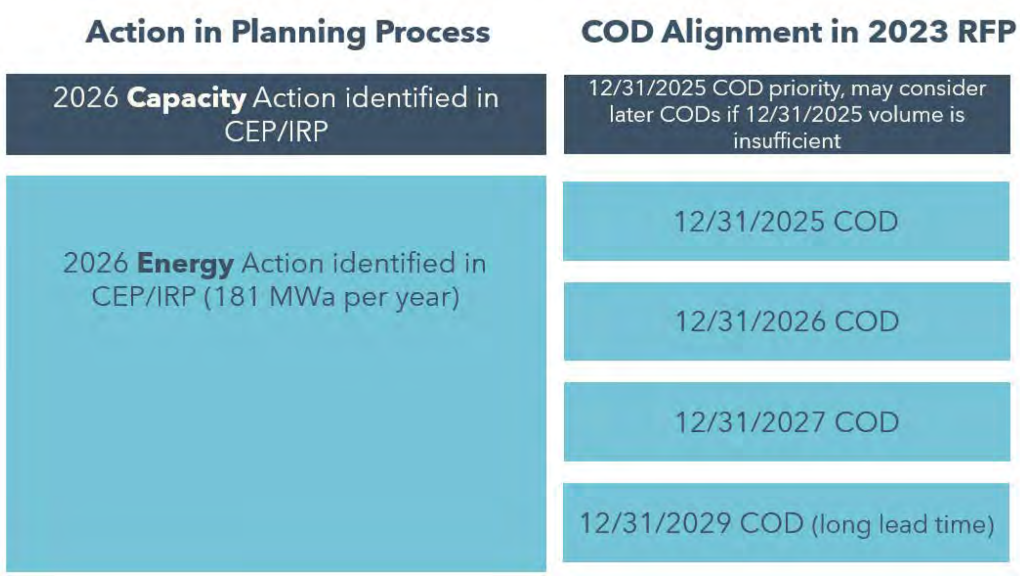
CODs through December 31, 2027, for resources seeking to meet its energy needs. However, the Company prioritized the December 31, 2025 COD for non-emitting, dispatchable capacity resources. The diagram below illustrates PGE's adjusted approach to CODs in this RFP.[60]

Figure 4: COD Prioritization



Stakeholder Feedback
Several stakeholders commented on the proposed COD for this procurement. PGE's Benchmark Team suggested that a December 31, 2025 COD would be difficult to achieve for bidders who achieved all required development milestones throughout the process, specifically noting the lead time for transformers, which can exceed twenty-four months. PGE Benchmark requested that PGE consider the long-term capacity contributions of resources with CODs after December 31, 2025.[61]

BrightNight also suggested that the RFP should allow projects with CODs beyond the initially proposed December 31, 2025 cutoff. Specifically, BrightNight proposed that projects with CODs anywhere in the decade should be permitted to bid into the RFP given the needs identified in PGE's 2023 CEP/IRP.[62]

[60] See PGE Reply Comments, June 26, 2023, page 4.
[61] See PGE Benchmark Team Comments on Final Draft RFP, June 16, 2023, page 1.
[62] See BrightNight Comments on Final Draft RFP, June 16, 2023, page 2.

Similarly, RNW suggested extending the COD for eligible resources to the end of 2026, rather than the end of 2025 as contained in the Draft RFP.[63]

OSSIA also raised concerns with the proposed December 31, 2025 COD. Noting many of the same constraints as other parties, OSSIA suggested that projects with CODs in 2026 should be deemed eligible for participation in the RFP.[64]

Staff Analysis
Staff appreciates PGE's flexibility and willingness to adjust its approach to CODs in this procurement. Notwithstanding the additional requests for clarification from some stakeholders, PGE's response to early feedback immediately resulted in an improved RFP.

However, the updated approach to CODs as provided in PGE's reply comments raises a new concern. PGE now stipulates that if insufficient resources are available to meet its capacity need by the December 31, 2025 COD, it may consider resources with later CODs to meet that need.[65] At the Commissioner workshop held on July 6, PGE suggested that in that instance, it would prioritize among those projects that cannot meet the preferred COD based on criteria such as capacity contribution or transmission rights.

While this approach makes sense theoretically, leaving such prioritization to PGE's discretion without any structure or process would make it impossible for bidders to evaluate PGE's decision-making post-facto. In Staff's opinion, the IE could be tasked with analyzing PGE's process for prioritization if this situation emerges, but without some formal statement of its decision-making process, the IE would have a similarly difficult time determining whether it was done fairly and appropriately. The IE made this point in its second report on the RFP.[66]

Therefore, Staff requests that prior to issuance, PGE must develop a set of guidelines to describe how it would go about prioritizing its selection of projects in this case. Staff acknowledges that these guidelines may be somewhat qualitative by necessity, but nevertheless finds that some sort of strictures are necessary.

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

[63] See RNW Comments on Final Draft RFP, June 16, 2023, page 2.
[64] See OSSIA Comments on Final Draft RFP, June 16, 2023, page 1-2.
[65] See PGE Reply Comments, June 28, 2023, page 4.
[66] The Independent Evaluator's Second Assessment of Portland General Electric Draft 2023 All Source Request for Proposals, July 14, 2023, page 4.

description, and PGE's execution of the prioritization, will be evaluated by the IE in its closing report.

Long Lead-Time Resources

PGE's Draft RFP contemplated a special carve-out with later CODs for long lead-time (LLT) resources such as pumped storage hydro projects. This was consistent with the Company's 2021 RFP.

Stakeholder Feedback
Swan Lake and Goldendale provided comments on the proposed COD specific to the concerns of pumped storage hydro and other LLT resources. The parties noted that in PGE's 2021 RFP, LLTs were permitted to participate in the process if they could achieve a COD of December 31, 2027. While PGE provided a special provision for LLTs in this RFP, the COD for LLT was initially set at December 31, 2028. However, the parties noted that maintaining the same lead time as in the 2021 RFP would imply a permissible COD of December 31, 2029, for LLTs seeking to bid into the 2023 RFP.[67]

Staff Analysis
In the redlined Draft RFP provided in reply comments, PGE agreed to the requested change regarding CODs for LLT resources. However, PGE declined to adjust its assumption regarding the useful life of these resources.[68] Staff appreciates PGE's willingness to accommodate a change in the COD for LLT and as noted in the Long Lead-Time Resources section under Bid Costs, is comfortable with the Company's argument for retaining 38 years as the useful life of these resources. However, PGE declined to adjust its assumption regarding the useful life of these resources.[69] Staff has no further conditions or recommendation on this topic, but notes that future conversations are anticipated on the competitive procurement of long lead-time resources in PGE's anticipated Request for Information, which is discussed further below in the section on Request for Information.

Benchmark Bids

PGE stated that it is contemplating potential benchmark bids including wind, solar, hybrid, and standalone energy storage resources. Appendix P of the redlined Draft RFP included in reply comments also includes a discussion of utility-controlled bid elements that may be used in support of either benchmark of affiliate bids. PGE

[67] See Swan Lake and Goldendale Comments on Final Draft RFP, June 16, 2023, pages 2-4.
[68] See PGE Reply Comments, June 26, 2023, page 17.

further updated the list of Utility Controlled Bid Elements on September 1, 2023 – adding a third resource.

These resources include approximately 300-600 acres of land, the coordinates of which were provided, the Large-Generator Interconnection Agreement (LGIA) and associated transmission rights for the Biglow Canyon Wind Farm, and the LGIA and transmission rights at Wheatridge Renewable Energy Facility when the facility generates below nameplate capacity.

The CBRs require that a utility must specify whether utility-owned resources supporting benchmark bids will be made available to third-party bidders and, if those elements will not be made available, provide analysis explaining its decision to withhold them.

Regarding the parcel of land described in Appendix P, PGE initially stated that the land is contiguous with other PGE operations and that for security reasons, the land in question would only be available for third-party bids under a utility-ownership structure.

With respect to the Biglow Canyon LGIA and transmission rights, PGE similarly stated that these elements will only be made available to third-party bidders under utility-ownership structures.

Stakeholder Feedback
RNW noted in its comments that PGE had partially complied with the CBRs by identifying Company assets that could potentially support a benchmark or affiliate bid. However, the Company had not fully complied with the rule requiring it to specify whether those resources would be made available to third-party bids and to justify any decision to preclude their use by other bidders.[70]

NIPPC requested that PGE provide significantly more detail on any potential benchmark bids into this RFP. Specifically, NIPPC request that the following information be provided for each benchmark bid: 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).[71] NIPPC noted in its comments that both PacifiCorp and Idaho Power have provided these details on benchmark bids in their most recent RFPs (see Docket Nos. UM 2193 and UM 2255, respectively).

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[70] See RNW Comments on Final Draft RFP, June 16, 2023, , page 3.
[71] See NIPPC Comments on Final Draft RFP, June 16, 2023, pages 19-20.

NIPPC also argued that Appendix P was not in compliance with the CBRs, as PGE had not provided sufficient detail on utility owned elements that would support benchmark or affiliate bids and had not provided analysis supporting a decision not to make such elements available to third-party bidders.

Staff Analysis
While the CBRs do not strictly require the inclusion of all the details requested by NIPPC for each benchmark, Staff agrees that transparency with respect to PGE assets available to benchmark and affiliate bids is important to a competitive process. As referenced by NIPPC, recent RFPs for both PacifiCorp and Idaho Power Company have provided this information.[72] Staff therefore concurs that PGE should provide the benchmark details requested by NIPPC in its comments.

Staff also agrees with RNW and NIPPC that Appendix P, as updated in PGE's reply comments, is not in compliance with the spirit of the CBRs. Although the rules do not specify that the RFP itself must contain analysis supporting decisions to withhold assets from third-party bidders, the Commission states in Order No. 18-324 that this information should be provided to the Commission at the time of RFP development.

Based on PGE's experience with joint-facilities and a review of the map of the Northeast Oregon 300-600 acre facility, Staff is unconvinced by PGE's claims of the risks associated with co-location.[73] This risk needs to be better described to justify PGE's decision to not make the location available to bidders.

PGE should also provide further justification for its decision regarding the Biglow Canyon LGIA and transmission rights. In its justification, PGE should consider the IE recommendation in its 2021 RFP, which was reiterated in the IE's initial report for the 2023 RFP, that PGE consider allowing resources with countervailing generation profiles to share transmission and interconnection capacity.[74]

PGE should clarify whether the utility assets located at Wheatridge Wind Farm would be available to third party bidders and if not, provide justification for its decision. Lastly, if PGE intends for any of these benchmark resources to be associated with bids leveraging PRR, it should make that explicitly clear in Appendix P.

More broadly, Staff wishes to use this docket as an opportunity to explore the provision of utility-owned elements to third-party projects. While the CBRs do not

[72] See dockets UM 2193 (PacifiCorp) and UM 2255 (Idaho Power Company).
[73] See Final Draft RFP, Appendix N, Page 338.
[74] See The Independent Evaluator's Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals, May 31, 2023, page 12.

require these assets to be shared, the requirement to disclose them is nevertheless important. There is a public interest in ensuring that assets like transmission and interconnection rights that were funded by ratepayers should be put to the greatest beneficial use for ratepayers.

To that end, Staff proposes that third-party bidders be permitted to provide one straw project bid designed to take advantage of the utility-owned elements disclosed in Appendix P. These bids may be submitted without the bidder providing any additional bid fees or other expenses. While these projects will have no presumed expectation of making either the initial or final shortlist, the bids will be scored by both PGE and the IE. Further, Staff invites such bids to include a description of the bidder's experience operating within a joint-facility or one owned by utility, to address PGE's claims regarding security risks.

Staff's goal is to use these straw bids to perform sensitivity analyses to determine whether any benchmark project or affiliate bid utilizing the utility-owned assets is making the greatest, most beneficial use of those assets. The inclusion of such bids can be determined during Final Short List acknowledgement, based on IE, stakeholder, and Staff analysis.

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.

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.

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.

RFP Condition 6: PGE will allow third-party bidders to provide one straw project bid designed to take advantage of the utility-owned elements disclosed in Appendix P, without charging bidders bid fees or other expenses. The bids will be scored by both PGE and the IE. Bids should include a description of the

bidder's experience operating within a joint-facility or one owned by utility to address PGE's concerns about security risks.

Affiliate Interest Participation

PGE has stated its intention to leverage its recently approved affiliate, Portland Renewable Resource Company, LLC (PRR) in this RFP. In Docket UI 489, and specifically Order Nos. 23-294[75] and 23-369, Staff and the Commission communicated overarching issues that should be addressed in UM 2274, pertaining to potential ratepayer and anticompetitive risks of PRR's participation in this RFP. While Staff and stakeholders had limited time to understand and analyze potential risks, the supplemental information provided by PGE resulted in a list of issues unique to the inclusion of PRR and suggestions to mitigate those risks.

Background
At its Public Meeting on August 8, 2023, the Commission voted in Docket UI 489 to approve PGE's application to allow transactions between itself and PRR, a wholly owned direct subsidiary of PGE. The Commission's Order No. 23-294 in UI 489 requires benchmark treatment for PRR bids. It also included additional prohibitions against certain PGE staff working for the affiliate interest. The Staff report called out potential concerns about the activities of the affiliate, if gone unchecked. These included the affiliate engaging in activities beyond addressing ITC normalization issues, potential harm to customers associated with underperforming PRR assets, potential anticompetitive outcomes, and the comingling of assets. Most importantly for this docket, the Commission stated that given the risks to the competitive market and ratepayers attributable to transactions between PGE and its affiliate, "…the RFP process must review and consider these unique risks and ensure that they are addressed."[76]

On September 15, 2023, PGE submitted an application for reconsideration and/or a motion for clarification on the modifications the Commission made to Condition 2 in Order No. 23-294.[77] On October 17, 2023, the Commission granted PGE's request for reconsideration and clarification for Order 23-294 and, following consideration of the various positions, as reflected in Order No. 23-369, adopted Staff's proposed revised language to Condition 2. Staff does not reiterate the various positions, which

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[75] *In the Matter of Portland General Electric, Application for Affiliated Interest Transaction with Portland Renewable Resource Company, LLC*, Docket UI 489, Order No. 23-294 (August 10, 2023).
[76] See Order No. 23-294.
[77] See PGE Application for Reconsideration and Motion for Clarification, Docket No. UI 489, (September 15, 2023).

can be found in Order No. 23-369. However, Staff presents the resulting modified language for Condition 2 below:

> PGE and PRR will maintain separation of duties and prohibit sharing of certain information between individuals engaged in the development of any PRR bids and any individuals engaged in the evaluation or scoring of bids as part of the PGE RFP process such that PGE employees who participate in the development of the RFP or the evaluation or scoring of bids may not participate in the preparation of any PRR bids and will be screed off from the process. All employees will abide by the Federal Energy Regulatory Commission (FERC) Standards of Conduct. ~~No PGE employee that has had previous access to Highly Confidential information from bidders in previous PGE Integrated Resource Plan or RFP processes may provide services for PRR~~. **No PGE employee that has had previous access to Highly-Confidential information from non-benchmark or nonaffiliate bidders in PGE's most recent RFP process may provide services for PRR with respect to a project bidding into an RFP conducted under the Commission's Competitive Bidding Rules if those services are provided before the final short-list has been filed by PGE with the Commission**.

During deliberations at the October 17, 2023, public meeting, the Commission reiterated the need for clarity regarding whether the inclusion of PRR in this RFP would introduce incremental unfairness and whether protections could be put in place to address any concerns unique to the inclusion of PRR. The Commission sought written confirmation from PGE about how PRR will be used and the related protections and actions that were described at the public meeting. PGE filed a Supplemental Filing on November 3, 2023 (also described as PGE Affiliate memo) in UM 2274 describing how PRR would be used in the RFP, breaking out detail by three phases: 1) RFP evaluation, 2) Steps after the final shortlist has been filed, and 3) Steps after BTA/APA and PPA execution.

PGE's Supplemental Filing, along with communications with PGE clarified key areas of confusion, namely that:

- PRR will not submit bids into the 2023 RFP.
- PGE-Sponsored benchmark ITC eligible solar ownership (Benchmark ITC-e) bids will be required to be submitted and scored consistent with the treatment of benchmark bids as described in the CBRs. *Verbal communications with the Company indicated that Third-Party ITC eligible solar utility ownership (Third-*

party ITC-e) bids would also be submitted and scored as benchmark bids, but written communication does not clearly indicate that.

- When evaluating any ITC-e bid, PGE's RFP team will assume full monetization of the ITC in forecasting cost of service.
- PRR is not engaged during RFP bidding and evaluation.
- PGE will use standard financial formulas to ensure PRR's ownership costs are recovered through PPA contract prices. PGE informally explained via email to Staff "…standard financial formulas would be applied so that the present value revenue requirement of all future forecasted PPA payments is less than or equal to the present value of the future forecasted revenue requirement of the APA or BTA as evaluated in the RFP."
- If a Third-Party ITC-e is selected and PRR is the owner, PGE employees working on finalizing the associated PPA on behalf of PRR will have access to confidential information regarding the bid. PGE states this is required to finalize the PPA and is consistent with the CBRs and Condition 2 of Order No. 23-269 because the services are being offered to PRR by PGE employees after submission of the final short list. CBRs and non-disclosure agreements will be applicable so PGE employees with access to confidential information will be obligated to keep this confidential and not share it with PGE employees on the benchmark team.

Stakeholders submitted comments on PGE's Supplemental Filing in this docket on November 17, 2023, but the Company has not since been afforded an opportunity to respond to those comments.

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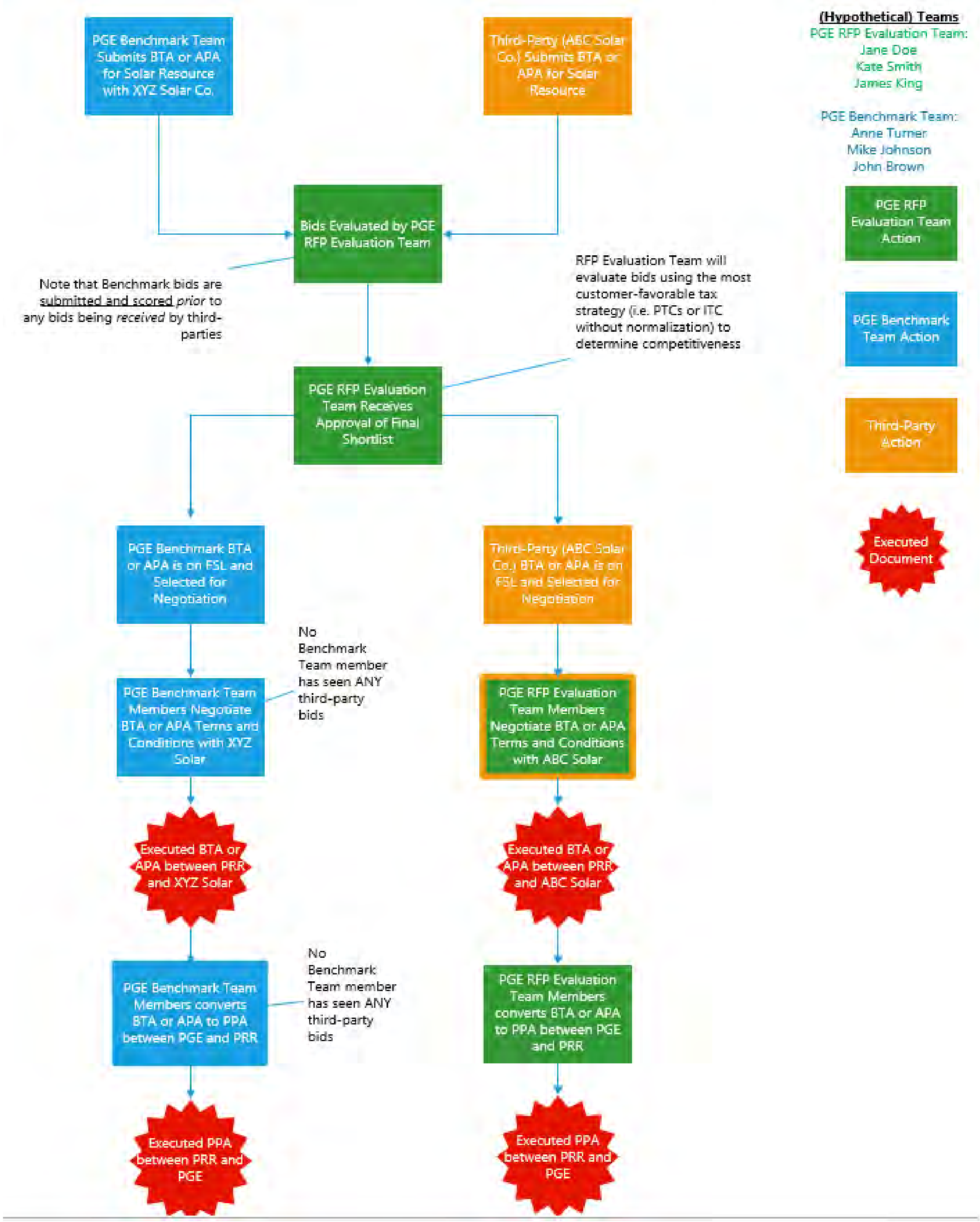
Figure 5: PGE Affiliate Process Diagram provided in its November 3, 2023 Supplemental Filing



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Stakeholder Feedback
NIPPC, NewSun, and OSSIA submitted comments in response to PGE's Supplemental Filing with concerns and recommendations to address those concerns. All three parties strongly recommended against inclusion of PRR in the 2023 RFP, noting that there has not been sufficient time to assess and mitigate potential harms. NIPPC expressed concern about PGE not seeking approval of the affiliate earlier in the process, the lack of transparency and "minimal to no meaningful" RFP changes to address unique risks from the affiliate participation.[78] Additionally, stakeholders raised concerns about non-conformity with the Competitive Bidding Rules (CBR); PGE/PRR employee access to confidential third-party bidder information in this and future RFPs; and NewSun and OSSIA further noted that the inclusion of PRR exacerbates existing unfair practices favoring utility bids. These issues are addressed in the section below, Overarching Concerns.

Listed below are additional issues and the areas in which they are addressed:

Issue	Section
Process for converting BTA / APA bids to PPA prices	Post FSL
Post FSL Contract negotiations	Post FSL
Proposed Affiliate (or PRR) Form PPA provisions	PRR Form PPA
Dispute resolution and contract enforcement	Post PPA Execution

<u>Overarching Concern</u>

Inadequate Time and Inadequate RFP Changes

Stakeholder Feedback
In its June 16, 2023, Comments on Final Draft RFP, NIPPC raised several concerns with the participation of an affiliate in this RFP. In brief, NIPPC argued that the affiliate was not appropriate given the expedited review schedule for this RFP; that the Commission should require special protections and revise the design of this RFP to accommodate an affiliate; and that the affiliate should be treated as a benchmark bid for purposes of this RFP. Finally, NIPPC requested that PGE provide an affiliate PPA along with other form contracts in this RFP.[79] Overall, NIPPC argued that given the large number of unknowns surrounding affiliate participation, the affiliate should be prohibited from bidding into this RFP.[80]

[78] See NIPPC Comments on PGE Supplemental Filing, October 17, 2023, pages 1-2.
[79] See NIPPC Comments on Final Draft RFP, June 16, 2023, pages 20-29.
[80] Ibid, page 20.

Staff Analysis
This Staff Report was originally due to be filed on August 25, 2023. On that day, PGE requested the schedule be suspended. Staff was originally prepared to agree that there had not been sufficient time to consider and mitigate risks of PRR's participation in this RFP. However, the schedule delay afforded time for some additional clarification and filings from the Company and for stakeholders to identify potential harms, introduce remedies, and generally reduce the number of unknowns.

PGE agreed to apply benchmark-like treatment of sponsored affiliate bids in this RFP. Specifically, PGE agreed to require PGE-sponsored affiliate bids in this RFP to be submitted at the same time as benchmark bids and scored and evaluated with benchmark bids prior opening any independent bids. Furthermore, PGE agreed to disclose whether any elements supporting PGE sponsored-affiliate bids are owned or secured by PGE and whether they will be made available to all bidders.[81] PGE clarified that the Form PPA included in the Draft RFP would be the affiliate PPA to be used by PRR.

Conformance with CBRs

PGE explained in Docket UI 489 that PRR will not bid any projects into the 2023 RFP, but instead PGE will use PRR "as a vehicle to realize tax benefits for either a benchmark-sponsored resource or a traditional third-party developed resource if selected on the final shortlist and ultimately acquired through a build and transfer agreement."[82]

Stakeholder Feedback
NIPPC raised concerns about the proposed structure not conforming with the CBRs.[83] They point to the CBRs specifically talking about an affiliate 'bidding in' to an RFP and that Staff's position in UI 461 was that "PRR's sole and exclusive purpose shall be limited to bidding into PGE's RFPs." In UI 489 they changed it to "…submit bids or to be used as a vehicle for evaluating utility ownership bids" and now, in PGE's supplemental filing, they say that PRR would not submit bids at all, but "PRR will be used as a potential vehicle to enable full realization of Investment Tax Credits (ITC) for the benefit of PGE customers to help manage power costs." And further "PGE has committed that PRR will not submit a bid into the 2023 RFP."

NIPPC pointed to the language in the CBRs noting that it only contemplates an affiliate bidding in, and what PGE is proposing does not conform. NIPPC cites the

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[81] See PGE Reply Comments, June 26, 2023, page 21.
[82] See Docket UI 489, PGE Application for Reconsideration or Motion for Clarification, page 5.
[83] See NIPPC Comments on PGE Supplemental Filing, October 17, 2023, pages 4-6.

rules noting that an electric company “may submit or allow its affiliate to submit bids” into the RFP. If they submit their bids, then “affiliate bids must be treated in the same manner as other bids.”[84]

Staff Analysis
Staff agrees that the way PGE has described PRRs role in this RFP has changed multiple times since its initial introduction. However, it does not agree with NIPPC that the proposed role of PRR as described in PGE’s Supplemental Filing does not conform with the CBRs. The CBRs address parameters related to bids submitted by affiliates and for benchmark resources. They address the competitive bidding process and were not intended to describe what an affiliated interest may or may not do. The authority of the affiliated interest is addressed in the approval of affiliate interest agreements. Whereas concerns about the competitiveness or fairness of an affiliated interest’s engagement in a specific procurement process is addressed in the RFP docket.

Order 23-369 at page 13 in UI 489 says,

> However, as suggested by some responses, continued examination of issues related to PRR may be necessary during the RFP. **For example, some concerns of stakeholders would be alleviated if PRR was to only act as a potential owner of PGE’s benchmark bid.** In argument and comment, PGE seems at times to indicate this is its primary purpose; but at others that PRR will submit independent bids or seek to enter into a BTA with other bidders. The RFP process can be utilized to provide clarity on the specific role of PRR in the near term. Additionally, in the RFP process stakeholders, Staff, and the independent evaluator can review PRR’s engagement to ensure it acts consistent with the goals articulated by PGE; namely to serve customers by lowering overall costs.

With the language in bold, the Commission indicates it was not concerned with this activity by PRR when it approved the AI. The CBRs do not address it, but there is no reason they would need to, and no reason to say that the activity of an affiliate must be approved in the CBRs to be authorized.

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[84] See OAR 860-089-0300(1)(a).

Confidentiality and Future RFP Protections

Stakeholder Feedback
NewSun reiterated its concerns about PGE Benchmark team having access to confidential information, both in this RFP and in future RFPs, noting that the current rules regarding a separation between the Benchmark team and the RFP team do not address a case where RFPs happen in quick succession, that employee lists need to be maintained, and that PGE needs to develop separation protocols to ensure no confidentiality breech or the anti-competitive use of confidential data occurs. To address this NewSun recommended that there be no shared employees between PRR and PGE Benchmark team for the 2023 RFP and any RFP that takes place in a reasonable amount of time after this RFP has concluded; that PGE must provide detailed lists of employees working on the various teams; and that PGE should describe its training and protocols used to ensure protections.

Staff Analysis
While recognizing that this docket is limited to addressing the present RFP, Staff shares some of NewSun's concerns. However, Staff believes that UI 489 issued direction regarding these protections and will not reopen the issue here. In the spirit of transparency, Staff believes it is reasonable to require that PGE provide to the IE the list of employees working on behalf of the Benchmark and the employees working on behalf of PRR on any PRR sponsored bids – be they benchmark or third-party bids at the time it files its Benchmark scoring, at the time it files its FSL, and again after it has completed negotiations for all PRR bids. Staff agrees that without this information, it is impossible to know whether PGE has maintained the separation it represented. Staff sees this as a way to support enforcement of OAR 860-089-0300(1)(b). Staff further sees value in the Company providing a description of training and protocols used to maintain the required separations between RFP teams, Benchmark teams, and in this case, employees performing any duties on behalf of PRR. Staff does not see this as an RFP Condition but expects this description to be filed with the IE in UM 2274.

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, 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.

General Unfairness

NewSun and OSSIA generally described issues they saw as unfair in the current procurement practices of the Company, noting in particular that the Company is able to develop form contracts with provisions that they believe are generally rejected by third party bidders. Third party bidders must either modify contracts to monetarily reflect those risks and decrease their competitiveness or accept that risk and absorb related costs. This is unlike utility bids, which can either similarly reflect that risk mitigation in price or accept that risk and attempt to pass costs to ratepayers. Staff saw great value in retaining the IE to oversee and report on contract negotiation in UM 2166 and recommends the same for this RFP.

Draft RFP and RFP Evaluation

PGE explains that ITC-e bids would be required to follow the CBR process applicable to benchmark bids and that the RFP team would adjust the price score of ITC-e bids to reflect an ability to immediately recognize (not normalize) the ITC. Staff and Stakeholder concerns focused primarily on benchmark treatment of Third-Party ITC-e bids.

Benchmark Treatment of all ITC-e bids

PGE explains that benchmark ITC-e bids will be treated in the same manner as a benchmark bid, meaning that they would be submitted earlier than third-party bids, subject to more rigorous review by the IE, and include disclosures regarding the use of any PGE property.[85] As noted above in the section about Conformance with CBRs, the description of the role of PRR has evolved and now reflects that PRR will not bid into the RFP. Based on conversations with the Company, Staff understood that both benchmark and third-party bids eligible and interested in leveraging PRR, would be treated as benchmark bids. However, this is not clearly reflected in Figure 5: PGE Affiliate Process Diagram. This figure does not reflect detail about how benchmark bids would be treated differently from third party bids. Further, in describing the RFP Evaluation Process in its Supplemental Filing, the Company says “Any PGE-sponsored [B]enchmark ITC-eligible solar ownership bid will be submitted and scored consistent with the competitive bidding rules.” But the filing is silent regarding whether Third-Party ITC-eligible solar ownership bids would similarly be submitted and scored.

[85] PGE first made this statement with regard to a PRR ‘bid’ in UI 489, and later revised this approach and explained that 1) PRR would not be bidding and 2) benchmark bids eligible and interested in leveraging PRR, would be treated as benchmark bids.

Staff recommends that PRR's participation in this RFP be conditional on the RFP treating Third-Party ITC-e bids similar to benchmark bids, namely:

- Submitted and scored earlier than non-ITC-e bids, but after benchmark bids.
- Subject to more rigorous review by the IE.
- Disclosing usage of PGE property.

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.

Initial Shortlist – PRR

PGE's description of the role of the Affiliate lacks any description of whether PRR bids will be treated any differently with regard to the ISL. As noted above in the Scoring and Modeling Methodology section on Price Score and Initial Shortlist, Staff recommends that PGE provide ISLs both with and without PRR bid participation, and that the IE provide an analysis and report on the impacts of PRR bid inclusion. See Price Score and Initial Shortlist above.

<u>Post FSL</u>

Per the CBRs, PGE can begin negotiations with bidders on the FSL once it has filed the FSL and the IE Closing Report with Commission. There are two steps that are necessary for executed agreements for ITC-e bids, the first is the BTA or APA agreement between the project developer or owner and PRR, and the next is the "conversion" of the BTA or APA agreement with a PPA executed between PRR and PGE.

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Figure 6 show an excerpt from PGE's November 3 Supplemental Filing, showing the how the describes two parallel paths for arriving at the executed PPA agreement with PRR, depending upon whether the bid is submitted by a PGE-sponsored benchmark (Benchmark ITC-e) or a third-party non-benchmark bid (Third-party ITC-e).[86]

If the bid is a Benchmark ITC-e, PGE's Benchmark Team would represent PRR in negotiating the BTA or APA terms and conditions with the third-party owner of the development or resource. Then the PGE Benchmark Team appears to be intended to represent PRR in converting the BTA / APA to a PPA using the Form PPA.

Whereas, if the bid is a Third-Party ITC-e, the RFP Evaluation team would represent PRR in negotiating the BTA or APA terms and conditions with the third-party owner of the development or resource. Then the PGE RFP Evaluation team appears to be intended to represent PRR in converting the BTA / APA to a PPA using the Form PPA.

Figure 6: PGE PRR Parallel Contract Development

The Company further explains that the conversion of the BTA / APA to a PPA would be done using "standard economic practices" and then updating exhibits and project specific information in the Form PPA referenced in the RFP. The executed BTA/APA forms the basis of the PPA price. This price would be captured, along with project details, in the PRR Form PPA and becomes the critical elements of the contract between PRR and PGE. PGE explained that it is through the BTA/APA contract negotiation process that details about project costs can be solidified and then accurately converted into the PPA price.

[86] See UM 2274 PGE Supplemental Filing, November 3, 2023, Page 4.

Ultimately, the final price of the BTA/APA project that gets converted to a PPA is not necessarily the same as the one that is used to achieve a spot on the FSL. This highlights a concern raised by Stakeholders and Staff in UM 2166, PGE's 2021 RFP, that decisions made during contract negotiations have material implications on the final pricing and selection of projects. Staff does not see this as a new issue regarding the inclusion of PRR, but does see a need for the IE to closely monitor this additional aspect of contract negotiations.

The following section addresses concerns about activities occurring after PGE's filing of the FSL and before contracts are executed. Stakeholders raised many questions about the timing, method and the party conducting price conversions of the BTA/APA bids into a PPA. They were concerned about the risk of PGE allowing less favorable terms to benchmark projects than third-party projects, and the risk of exposing highly confidential information to members of the benchmark team, akin to past concerns about how benchmark bids are handled. Staff is concerned about the lack of clarity around who will participate in the negotiations. Lastly NIPPC raised concerns and suggested changes to the Form PPA being used as the PRR PPA.

PPA Pricing

PGE's proposed use of PRR is to act as a vehicle to allow solar projects involving utility ownership to take advantage of, and efficiently pass ITC benefits to customers, which the Company would otherwise have to normalize. This value is realized in the PPA pricing of benchmark or third-party BTA or APA, ITC-e bids that are acquired by PRR. PPA pricing activities include both a forecasted price, conducted by the RFP evaluation team, and then a final PPA price that reflects the negotiated and executed BTA or APA between the owner of the development/resource and PRR.

PGE's Supplemental Filing explains that for ITC-e bids, the PGE RFP team will develop a forecasted cost of service associated with the BTA or APA bids assuming the ITC can be immediately recognized. This forecasted cost of service is what would be used to evaluate and score the bids for inclusion on the final short list.

ITC-eligible solar ownership bids that make it to the FSL using the forecasted pricing and that are selected for contract negotiations, then proceed through the BTA/APA contract negotiation to finalize terms and conditions and a final price. That BTA/APA price will then be what is used to determine the PPA price. PGE explains that:

> Upon execution of the PGE-sponsored benchmark BTA or APA between PRR and the third-party, PGE's benchmark team would then convert the BTA or APA price to a PPA price utilizing standard

> economic practices and update the RFP form PPA contract and exhibits for project specific information for ultimate execution between PRR and PGE…Should a third-party non-benchmark ITC-eligible solar ownership bid be selected on the final shortlist and selected to negotiate contracts, PGE's RFP evaluation team would negotiate a BTA (or APA for an existing facility) with the third-party owner of the development resource for ultimate execution by PRR.[87]

The table below captures the negotiations that take place leading up to the development of the PPA between PGE and PRR and the parties participating in those negotiations.

Table 7: Negotiations to Establishing PPA between PRR and PGE

Forecast PPA for RFP Scoring	RFP Evaluation team forecasts ***all*** ITC-e PPA prices for scoring	
	Benchmark ITC-e	Third Party ITC-e
BTA/APA T&C Negotiation	Benchmark team negotiates T&C with project owner / developer on behalf of PRR – price update possible	RFP team negotiates T&C with project owner / developer on behalf of PRR – price update possible
Parties to BTA/APA	Project owner and PRR	Project owner and PRR
BTA/APA to PPA Price Conversion for PRR PPA	Benchmark Team converts final negotiated price to PPA	RFP Evaluation Team converts final negotiated price to PPA.
Parties to Form PRR PPA	PGE and PRR	

Stakeholder Feedback
NIPPC expressed concern about the price conversion formula, the timing of the price conversion, and the parties conducing the price conversion. NIPPC said the price conversion explanation is too vague and bidders and stakeholders would not be able to review the conversion. They noted it could be "affected by the discount rate used or whether the PPA price is levelized (front loaded in the early years) or escalates to

[87] See PGE's Supplemental Filing in UM 2274, page 2.

higher prices in later years," and that the price conversion has not be shared with the IE. NIPPC recommended PGE provide a more detailed explanation of how prices will be converted from BTA or APA to PPA to inform the reasonableness of its use and that its current description is not acceptable for use.[88]

Regarding the timing, NIPPC noted the BTA and APA bid prices should be converted to PPA prices before selection on the FSL. Lastly, it alleges allowing the Benchmark team to convert PPA prices gives it unfair advantage.

Staff Analysis
Staff shares NIPPC's concerns and reached out to PGE seeking more information. In an email to Staff, PGE elaborated on the anticipated method for this conversion. It explained:

> PGE plans to use standard financial formulas to ensure that PRR's ownership costs whether through an APA or BTA are recovered through PPA contract prices. The standard financial formulas would be applied so that the present value revenue requirement of all future forecasted PPA payments is less than or equal to the present value of the future forecasted revenue requirement of the APA or BTA as evaluated in the RFP. This standard financial formula would be applied to all bids, including both benchmark APA and BTA and third-party APA and BTA bids. The terms and conditions of the formula are set in advance.

The PPA Conversion Methodologies Should Be Transparent
Staff appreciates this additional detail but finds that it is insufficient to address concerns about the how the cost will be converted, especially as the term "standard financial formula" and associated key inputs are entirely undefined at this point, prior to approving the RFP. In further conversations with the Company, PGE explained that the conversion is more "formulaic" than a set formula.

Staff believes this should be akin to self-scoring elements of the RFP, wherein bidders are provided structure for determining what their scores would be. The IE can then compare self-scored PPAs with what is ultimately calculated, and differences can be discussed and reconciled as appropriate. Staff agrees with NIPPC that PGE should publish its methodology and/or formula for converting BTA / APA costs to PPA costs as part of the posted RFP with input and approval from the IE as a condition of PRRs inclusion in the RFP.

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[88] See NIPPC's Comments on PGE Supplemental Filings, page 14.

Regarding the timing of the conversion, Staff understands that the conversion of the executed BTA/APA agreement may reflect changes resulting from negotiations and that the final PPA needs to reflect actuals costs. Staff also understands NIPPC's concerns about price conversions happening after the FSL is filed, as changes to various aspects of terms and conditions can have a material impact on price. Staff believes these concerns can be addressed by requiring both the forecasted PPA price conversion formula, as well as its methodology, if not a formula, for converting BTA/APAs to PPA. Bidders should be allowed to submit their PPA scoring with their bid. This, combined with IE oversight of contract negotiations to see whether and how prices change after negotiations, provides additional transparency to the PPA price creation process. Staff foresees three key junctures when the PGE RFP may be called upon to convert a bid price into a PPA: (1) to develop price scores for consideration in the Initial Short List; (2) any bid price updates impacting the FSL; and (3) for conversion of executed BTA or APAs to a PPA after the FSL has been filed.

Lastly, Staff agrees with NIPPC that allowing the Benchmark team to conduct the PPA conversion could afford them unfair advantage. While the Benchmark team may be the party best suited to consider how negotiation should be converted to a PPA price for its projects, the same can be said for Third Party bidders, who would not have that same opportunity. Instead, Staff recommends that the PGE RFP team be responsible for converting all BTA/APA prices to PPA prices.

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.

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.

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

Asymmetric Consideration of Terms and Conditions

NewSun expressed concerns about PGE's ability to negotiate less favorable PPA terms with third-party bidders than it might with PRR and warns of the "asymmetry between the impact of 'standard' terms on third-parties as compared to utility-owned resources." [89] They further note that the proposed PPA includes performance guarantee language they note the Commission has pervious found problematic, pointing to Order No. 22-130 (UM 2193):

> We acknowledge...that stakeholders have raised serious issues for PPA resources, particularly regarding the issue of third-party financers being unwilling to support the performance guarantee. We also recognize that utility-owned resources are based upon utility forecasts of expected performance, but a utility can later request recovery of actual costs of performance and, absent ratepayer protections, customers could be at risk for paying more than forecasted. On the other hand, PPA performance guarantees mean that the PPA asset owners carry the risk of underperformance. This dynamic could mean that the performance risks are treated differently for the two types of assets and that customers could bear more risk of utility asset underperformance than PPA asset underperformance.

Staff Analysis
The Company is allowed to begin contract negotiations after filing of the FSL. This is when PPA terms are negotiated, prices and terms change, and deals can fall through. In both this docket and UM 2166, both Staff and stakeholders expressed concern about potential unfairness during this negotiation phase. In UM 2166, this resulted in the retention of the IE to oversee contract negotiations and the submission of a report to the Commission on findings. Staff generally does not see these concerns as different from concerns about the treatment of benchmark projects as part of the negotiation process. Staff recommends the IE include in its contract negotiation oversight report information about the role of performance guarantees in negotiations, and post-FSL price updates and the associated drivers and outcomes of price updates. Staff further expects to meet with the IE regularly during negotiations.

FSL Price Updates – Confidentiality

NIPPC expressed concerns about the timing of possible price updates, noting that PRR should not be allowed to do a price update until after the FSL acknowledgement due to concerns that members of the PRR team will have had access to highly confidential bidder information from the prior RFP.

Staff Analysis Staff generally addresses issues of confidentiality in the section above on Overarching Concerns but notes the timing of price updates may not be full

[89] See NewSun Comments on PGE Supplemental Filing, October 17, 2023, page 8.

addressed by the separation required in Docket UI 489. The Company's proposed process allows for a BAFO upon notification of inclusion on the ISL. Staff notes that prices should not be updated again before submission of the FSL – barring unforeseen market circumstances. NIPPC's request, however, is that price updates should not be allowed until after FSL acknowledgment. As discussed above and throughout, Staff recognizes that bid elements may change during the negotiation phase and recommends IE oversight of this process.

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.

Negotiating Parties

PGE explains that PRR will not have staff but will ultimately leverage PGE staff both to negotiate PPAs and after PPAs have been signed. Regarding negotiations, PGE appears to represent, in figure X, that the PGE Benchmark team would represent PRR in the BTA/APA contract negotiation with a third-party project developer/owner of the Benchmark ITC-e project. Alternatively, the PGE RFP Evaluation team would represent PRR in BTA/APA contract negotiations with a third-party project developer/owner of a Third-party ITC-e project. The outcome of these negotiations is an executed BTA/APA between PRR and the project developer.

NIPPC alluded to concerns about this lack of clarity regarding roles related to contract execution in the context of the Form PPA, noting that it was not clear which party would be responsible for ensuring projects met commercial operation events necessary to demonstrate meeting COD obligations.[90]

Staff sees a similar lack of clarity regarding the role of negotiating parties and has concerns about how the required separations would be executed, maintained, and demonstrated. Staff notes that even if the PGE RFP Evaluation team is responsible for converting the BTA/APAs into PPA prices, it is unclear which PGE employees would be representing PPR, and it appears that it would be a combination of both Benchmark and RFP teams, threatening the requirements for separation. As shown in Figure 7, Staff's primary concern is regarding knowing who specifically on the PGE Benchmark and RFP teams will be engaged in the negotiations captured in the red box and how the Company will demonstrate that it maintains the necessary separations, as indicated by the dotted line. This concern becomes more acute after contracts are executed and need to be enforced.

[90] See NIPPC's Comments on PGE Supplemental Filings, page 13.

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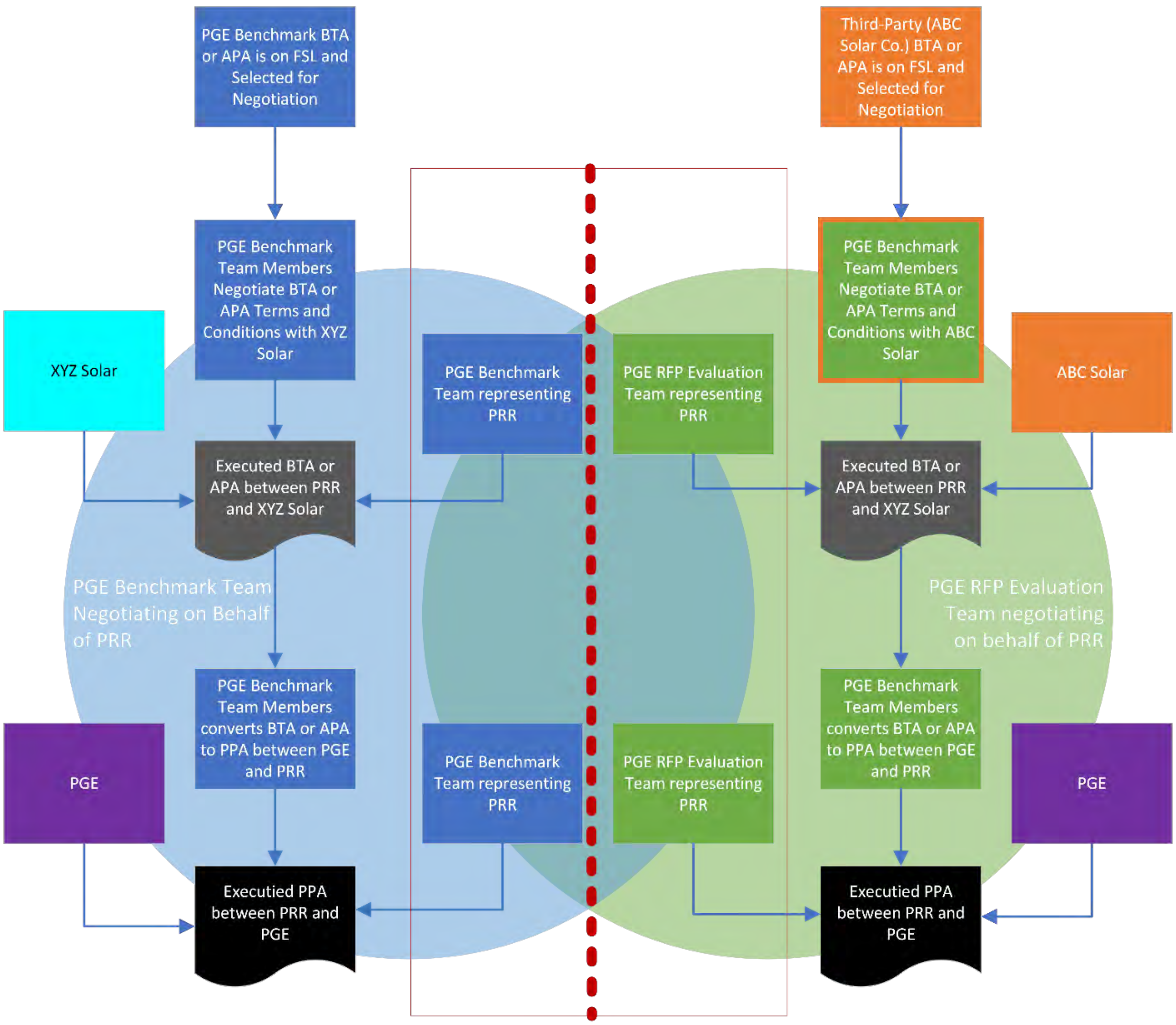
Regarding negotiations, Staff provides recommendations in the section on PRR Form PPA regarding documentation. Staff addresses this issue further in the Section on Post PPA Execution.

Figure 7: PRR Contract Negotiation Parties



PRR Form PPA

PGE states, in its Affiliate Memo filing on November 3, 2023: "Further, in Order No. 23-294, the Commission has instructed PGE to use the form agreement ultimately approved within UM 2274. PGE has issued draft form PPA agreements that would govern the terms between PGE and PRR (and avoid any need for a negotiation to take place), and PGE confirms that the company will use these form agreements as they are approved by the Commission."

Stakeholder Feedback
NIPPC provided overarching concerns about the use of the Form PPA for PRR bids, including that the form should state that PRR cannot rely directly or indirectly on PGE to pay any damages owed under the PPA to PGE or any third parties and that the affiliate interest costs must not be paid for by PGE or PGE customers. NIPPC also identified various provisions in the Form PPA that it noted as problematic when applied to PRR.

Company Feedback
In PGE's Affiliate Memo filing of November 3, 2023, PGE states:

> We have heard no reasonable basis for this position. The terms and conditions of the PRR-PGE PPA are standard commercial terms that PGE will enforce in the same manner as any other PPA. The Commission and stakeholders have ample experience reviewing the prudency of a utility's administration of PPA terms and conditions and will be able to follow those same practices in reviewing PGE's actions under the PRR-PGE PPA. It is also noteworthy that there will be additional opportunities to address concerns in other future proceedings. PGE will be required to submit the PRR-PGE PPA in a future affiliate interest filing. Moreover, any prudency issues with PGE's contract administration can be reviewed in the rate proceeding in which the cost associated with the PRR-PGE PPA will be included in customer rates.

Staff agrees and understands from conversations with the Company that any damages would be paid by PGE shareholders, not ratepayers. Staff agrees with NIPPC and recommends this be clearly stated in the Form PPA.

Staff agrees with NIPPC that the affiliate, as a component in the RFP process, warrants close attention to ensure that it is not used in an anti-competitive fashion and that ratepayer protections are sufficient in any potential contract between PGE and the PRR. NIPPC provided many specific recommendations regarding PRR PPA contract provisions. Staff addressed them in Table 8: NIPPC PRR PPA Recommendations and Staff Responses. Staff generally agrees with NIPPC that additional protection should be included in a PPA between PRR and PGE to protect ratepayers and ensure equitable treatment between the affiliate and independent bidders.

Staff Analysis

Table 8: NIPPC PRR PPA Recommendations and Staff Responses

Topic	Section	PRR PPA NIPPC Recommendation	Staff Recommendation
Guaranteed COD	1.1	Change Guaranteed COD from 120 to 180 days after the Scheduled COD.	Provision remains negotiable for non-PRR PPAs. RFP Condition: The IE assigned to contract negotiation oversight should report on Guaranteed COD negotiations. Expectation: In future rate case filings PGE will file PRR PPA CODs and actual CODs with a statement addressing any differences.
Project sale	2.4	Amend the PRR PPA to require that any sale of the project under Section 2.4 would first require Commission approval.	Staff believes this concern is addressed under the direction in UI 489 Order No. 23-369, Condition 5, which mandates that PGE will report any events that materially impacts PRR operations within 30 days of becoming aware of the event.
Purchase / Extend terms	2.5	PRR Form PPA should remove the option to purchase or extend terms in section 2.5.	Staff agrees with NIPPC that options to purchase should not be allowed for PRR. RFP Condition: The PRR Form PPA should remove section 2.5 regarding the option to purchase or extend terms.
Force Majeure	4	Remove force majeure, instead PRR should owe PGE contract damages for any traditional force majeure events	Staff does not recommend any changes regarding this provision. PGE will bear the burden of proof in any rate proceeding concerning any PRR force majeure damages.
Consequential damages	8.4	Remove Section 8.4 on No Consequential Damages	Staff agrees. RFP Condition: PGE must remove Section 8.4 from the PRR Form PPA.

<table>
<tr><th>Topic</th><th>Section</th><th>PRR PPA NIPPC Recommendation</th><th>Staff Recommendation</th></tr>
<tr><td>Performance Assurance - Pre-COD Security</td><td>9.1</td><td>PRR PPA Performance Assurance requirements should be met with cash instead of letter of credit from Qualified Institute. Pre-COD Security for PRR PPA should be at least $200/kW.</td><td rowspan="2">Provision remains negotiable for non-PRR PPAs.
Staff agrees with NIPPC that these values should align across PPA and EPC/APA bids but is not convinced of the merit of having PRR PPA Performance Assurance being met with cash instead of a letter of credit.
RFP Condition: PGE shall align Pre-COD and Security Delivery amounts across PPA and EPC/APA contracts.</td></tr>
<tr><td>Performance Assurance - Delivery Period Security</td><td>9.2</td><td>PRR PPA Performance Assurance requirements should be met with cash instead of letter of credit from Qualified Institute. Delivery Period Security for PRR PPA should be $100/kW, and $25/kW higher than the security proposed by any PPA bidder in the last RFP due to the greater risk of harm to ratepayers than traditionally independent power producer PPA.</td></tr>
<tr><td>Assignments</td><td>15</td><td>Any assignment referenced under Section 15 must be subject to Commission approval.</td><td>Staff believes this concern is addressed under the direction in UI 489 Order No. 23-369, Condition 3, which requires PGE to submit any changes to PRR governing documents to the Commission within 30 days of any changes. However, Staff is not opposed to adding language identifying process.</td></tr>
</table>

Topic	Section	PRR PPA NIPPC Recommendation	Staff Recommendation
Disputes	18	Revise Article 18.1 of PRR PPA identifying the names of senior managers to whom matters would be referred, including titles and organization affiliation. Revise Article 18.2 and 18.3 of PRR PPA identifying who would file legal action and participate in mediation. Add language specifying how dispute resolution would work in the case of a disagreement between PGE and PRR and noting that a Special Master should be appointed when a dispute arises between PGE and PRR.	Staff agrees that it is unclear who would be the parties participating in a dispute between PRR and PGE and that disputes might benefit from the engagement of a Special Master appointed when such disputes arise. However, Staff believes concerns regarding dispute resolution clauses can be addressed in AI approval filings.
Attorney/Legal fees	18.5	Modify Section 18.5 such that PGE does not have to owe attorneys' and legal fees to PRR	Staff believes this concern is addressed under the direction in UI 489 Order No. 23-294, Condition 4, which protects PGE retail customers from any adverse effects of startup costs, operational costs, changes to cost of capital, production problems, or decommissioning costs associated with PRR.
Confidentiality	20	Delete Article 20 regarding confidentiality for the PRR PPA.	Staff understands this to be pertaining only to the PRR PPA and not to confidentiality provisions in BTA/APA contracts with PRR. NIPPC argues everything on the PRR Form PPA should be publicly available and be able to be reviewed. Staff is concerned that making this information public, combined with understanding the methodology for converting the BTA/APA price to a PPA, may reveal commercially sensitive information of third parties. Staff further notes that this information will be available for the IE to review in contract negotiation oversight. RFP Condition: The PRR Form PPA must specify that PGE Benchmark team employees are explicitly excluded from the list of Receiving Party Representatives.

Topic	Section	PRR PPA NIPPC Recommendation	Staff Recommendation
Mobile Sierra / FERC rights	11.1.1 and 11.1.2	Remove Sections 11.1.1 and 11.1.2 on the Mobile Sierra standard of review and the waiver of Federal Energy Regulatory Rights.	Staff does not support this change without a clear understanding of the benefit to PGE customers.
Delay Damages	3.1.11	PRR PPA should clearly state that PRR cannot rely directly or indirectly on PGE to pay any damaged owed under the PPA to PGE or to any third parties related to the proposed facility.	Provision remains negotiable for non-PRR PPAs. Staff believes concerns around proper accounting have already been addressed in UI 489 and that such protections exist in the AI filing and approval process.
Transmission	3.8.1 and 3.8.2	In Section 3.8.1 of the PRR PPA, the Transmission Upgrade Cost Cap should not be blank and should be the highest amount of any bid from PGE's 2021 RFP.	RFP Condition: Transmission requirements in the form contracts should match those specified in the RFP. RFP Condition: PRR PPA must include a value for the transmission upgrade cost cap. RFP Condition: PGE shall ensure that the IE assigned to contract negotiation oversight shall report on Transmission Upgrade Cost negotiations.
TX Effective date of TS agreement	3.8.2	In Section 3.8.2 of the PRR PPA, the Transmission Scheduling of Energy Effective date should not be blank and should be the shortest time period of any bid from PGE's 2021 RFP.	RFP Condition: PRR PPA must include a value for the Transmission Scheduling of Energy Effective Date. RFP Condition: PGE shall ensure that the IE assigned to contract negotiation oversight shall report on Transmission Scheduling of Energy Effective Date negotiations.

Topic	Section	PRR PPA NIPPC Recommendation	Staff Recommendation
Notices	21.1	Require that notices sent to PGE or PRR under Section 21.1 are also sent to the Commission	Staff believes this concern is addressed under the direction in UI 489 Order No. 23-369, Condition 5, which mandates that PGE will report any events that materially impacts PRR operations within 30 days of becoming aware of the event.
PRR Costs not paid for by PGE or PGE customers		Affiliate PPA includes provision for accounting protection to ensure affiliate expenditures and any potential damaged owned to PGE under the PPA are accurately tracked and paid by PRR. Affiliate form PPA should clearly state the PRR cannot rely directly or indirectly on PGE to pay any damaged owned under the PPA to PGE or to any third parties related to the proposed facility.	Staff believes this concern is addressed under the direction in UI 489 Order No. 23-294, Condition 4, which protects PGE retail customers from any adverse effects of startup costs, operational costs, changes to cost of capital, production problems, or decommissioning costs associated with PRR.
Output Guarantee		Eliminate blanks for PRR PPA performance guarantees. Performance assurances for affiliate should be the highest number from bidders in the last RFP or 90% annual output guarantee.	Provision remains negotiable for non-PRR PPAs but should specify the timeframe over which the output guarantee is determined. RFP Condition: Eliminate blanks for PRR PPA performance guarantees. RFP Condition: PGE shall ensure that the IE assigned to contract negotiation oversight should report on output guarantees negotiations.
Curtailment		PGE should remove any uncompensated curtailment provisions from form contracts.	Provision remains negotiable for non-PRR PPAs. Staff believes this concern is addressed under the direction in UI 489 Order No. 23-369, Condition 6, which states that PRR will maintain separate financial books and records from PGE. The Commission shall be given access to these records, among others, through Condition 7. Upon Commission request and subject to existing law and attorney-client privilege the Commission shall be given access to any documents, internal communications, meeting

Topic	Section	PRR PPA NIPPC Recommendation	Staff Recommendation
			minutes, financial statements, books, and records from PGE and PRR. RFP Condition: PGE shall ensure the IE assigned to contract negotiation oversight reports on curtailment negotiations.

Summary of PRR Participation Conditions Relating to the Proposed PRR Form PPA

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

PRR Participation Condition 7: PGE must remove Section 8.4 from the PRR Form PPA.

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

PRR Participation Condition 9: The PRR Form PPA must specify that PGE Benchmark team employees are explicitly excluded from the list of Receiving Party Representatives.

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

PRR Participation Condition 11: PRR PPA must include a value for the transmission upgrade cost cap.

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

PRR Participation Condition 13: PGE shall eliminate blanks for PRR PPA performance guarantees.

Staff notes that IE contract negotiation oversight recommendations listed in Table 8 can be found after the section below on Form Contracts

Post PPA Execution

PGE explains that PRR is not expected to have any employees and that "asset management, financial accounting, regulatory, legal and any other services will be rendered by PGE employees governed by the affiliate services agreement."[91] As provided in PGE's Supplemental Filing, PGE describes the types of activities expected to take place after PRR contracts have been executed, as shown in Table 7.

[91] PGE Affiliate Memo, page 3.

Table 9: Example Services Provided to PRR

PRR Asset Purchase	PRR Power Sale	Asset Management and Operations	Corporate Activities
• Executing APA/BTA with 3rd Parties and related governance actions • Contract Administration	• Determining PPA price utilizing standard economic methods • Converting RFP form PPA and exhibits with project specific information • Executing PPA with PGE and all related governance actions • Contract Administration	• All asset O&M activities • Power Operations including forecasting, scheduling, and tagging	• Financing decisions and actions • Corporate accounting actions • Financial reporting • Regulatory filings

Stakeholder Feedback
Stakeholders' primary concerns were around how contracts between PGE and PRR could manage dispute resolution and contract enforcement, including concerns about ensuring contract terms are met, such as commercial operations events, and performance; protecting customers from damaged and in appropriate costs, how to handle disputes, including understanding what parties would be involved, and generally concerns about lenient enforcement of terms. Apart from contract enforcement and dispute resolution, NewSun also raised a concern about how, given the anticipated quick succession of future RFPs, confidentiality would be maintained such that market bid information, which would have little time to get stale, remains protected future PGE Benchmark teams.

Staff Analysis
Except for NewSun's concern about quick succession of RFPs, Staff finds that Stakeholder Post PPA execution concerns about contract enforcement and dispute resolution were addressed in UI 489 and do not need to be addressed in this docket. Staff notes that the Commission has various vehicles to review and make associated determinations related to the reasonableness and prudence of contract administration and contract enforcement through future PGE rate dockets. Further the terms of any parental guaranty or executed PPA between PRR and PGE will be submitted in a

separate affiliated interest filing for Commission approval.[92] Below is supporting language from Staff Report attached to Order No. 23-294 in UI 489.

> The Commission retains the ability to review all of PGE's affiliate transactions through both its annual affiliated interest report and in general rate case filings. Conditions 3, 5, 6, and 7 provide the Commission additional access to PRR records, and the ability to be informed of any changes to PRR governing documents and activities.[93]
>
> Staff believes that there are plenty of venues for the Commission, the Independent Evaluator, and stakeholders to examine anti-competitive aspects of an affiliate bid or subsequent project. In particular, Staff notes that the Company clarifies that a PRR bid would be evaluated on the same timeline as a benchmark bid, be reviewed by the Independent Evaluator, be part of the acknowledged RFP final shortlist, approved again in a subsequent affiliated interest filing, and then incorporated into a power cost ratemaking proceeding. Staff also believes that these same steps provide adequate opportunity to inquire about an underperforming PPA and any possible damages PRR would owe to PGE and ultimately retail customer.[94]
>
> Staff believes that the questions of whether the affiliate be allowed to participate in UM 2274, how to treat an affiliate bid, and how to enforce damages in the event of PRR non-compliance or breach of the terms of any PPA should be addressed in UM 2274 or in a future rate proceeding.[95]

Staff share's NewSun's concerns about the risk to confidential third-party bidder information in the event of a quick succession of RFPs. However, Staff believes it has addressed these concerns in the section above on Confidentiality and Future RFP Protections in which Staff recommended PGE be required to maintain list of all employees working as part of the RFP team, the Benchmark team, and any employees performing duties on behalf of PRR, including the roles, and associated dates of their

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[92] See UI 489, Order No. 23-294 pg. 9.
[93] See UI 489, Order No. 23-294 pg. 10.
[94] See UI 489, Order No. 23-294 pg. 11.
[95] See UI 489, Order No. 23-294 pg. 12.

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.

Conclusion Regarding PRR Inclusion in the 2023 RFP

While stakeholders and Staff raised many concerns about PRR's participation in this RFP that have not been fully analyzed, resolved, or even fully discussed among by parties, Staff believes that the potential for negative impacts on the competitiveness and fairness of the competitive bidding process with PRR's participation is mitigated by the Commission and IE oversight of this process, as part of the CBRs, Staff's recommendation for additional IE oversight of contract negotiations, Staff recommended conditions regarding PRR, the requirements of Order Nos. 23-294 and 23-369 in Docket UI 489, and the requirements generally for affiliate transactions in ORS 757.495 and the Commission's Division 27 rules.

Staff recommends inclusion of PRR in the 2023 RFP contingent upon the following:

- PGE making the recommended changes to the PRR Form PPA,
- Assigning the IE responsible for overseeing contract negotiations additional PRR related duties pertaining to
    - Review of key areas of concern, and
    - Capturing data to inform an analysis of any additional customer benefits secured through PRR participation.

Form Contracts
While PGE is not requiring bidders to provide redlines to the form contracts attached as appendices to the RFP, in SMM Condition 3 Staff recommends they be included to improve bid and bid selection transparency. Staff hopes this position is seen as supporting PGE's statements in multiple forums that the Company views all terms in those form contracts as subject to commercial negotiations between the Company and bidders from an acknowledged final shortlist.

In the 2021 RFP, commercial performance risk was one of the elements of non-price scoring. It was intended to reflect the likelihood of successful contract execution based on the differences between PGE's preferred commercial terms and the preferred terms of bidders. Without the requirement for redlines, bidders will no longer lose points based on contract terms. However, this change also introduces some uncertainty into pricing, as some bidders may price based on terms that are unlikely to be agreed to by PGE if the bidder is selected to the final shortlist.

Stakeholder Feedback
RNW suggested that bidders should be permitted—but not required—to provide redlines of any form contracts of term sheets to support the pricing of their bids. RNW suggested that this approach could provide additional transparency to bidders' price proposals.[96] NIPPC suggested that bidders should be required to provide redlines that aligned with the pricing of their bids. NIPPC argued that knowing the contractual terms on which a price was based would lead to a more transparent process.[97]

In both written comments and at the July 6 Commissioner workshop, NIPPC raised a general concern that even if there is no scoring or other penalty to bidders providing redlines, form contracts that are "out of market" may cause bidders to design projects to meet PGE's preferred terms with higher prices, especially compared to a benchmark or affiliate interest bid.[98] This fact was also acknowledged by the IE's initial report and was raised extensively as an issue in UI 489.[99,100] As a result, bidders may be forced to price their projects higher, potential skewing the results in favor of benchmark or company-owned resources. As noted above, Staff agrees and recommends inclusion of a redline contract with all bids.

In addition to this broad concern, NIPPC objected to several specific contractual terms described below.[101] NIPPC also requested that PGE be required to provide a form of the Long-Term Service Agreement and Operation & Maintenance, or the minimum terms for utility-ownership structures. Finally, NIPPC requested term sheets for all technologies and contractual structures.[102]

Below are key portions of the RFP's Form Contract and the changes NIPPC suggests making prior to finalizing and issuing the RFP.

Guaranteed COD
The form contracts currently include a Guaranteed COD 120 days after the Scheduled COD. NIPPC recommended changing this to 180 days.[103]

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[96] See RNW Comments on Final Draft RFP, June 16, 2023, page 4.
[97] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 13.
[98] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 30.
[99] See The Independent Evaluator's Assessment of Portland General Electric's Draft 2023 All Source Request for Proposals, May 31, 2023, page 7.
[100] See UI 489, New Sun Comments, Aug. 7, 2023, page 1.
[101] See NIPPC Comments on Final Draft RFP, June 16, 2023, pages 30-40
[102] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 39.
[103] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 30.

Delay Damages
NIPPC objected to the delay damages assessed in the Form PPA agreement and noted the disparity in damages between the PPA and Storage Capacity Agreement (SCA) contracts and the Engineering, Procurement, and Construction (EPC) contract for utility-ownership structures. NIPPC suggested the damages in all contracts should be based on actual damages at time of default.

Output Guarantee
NIPPC noted that the Form PPA was unclear, but that output guarantees should be annual, rather than monthly. NIPPC proposed an annual output guarantee of 80 percent.

Mechanical Availability
The Form PPA currently requires mechanical availability of 97 percent for two out of three contracts years. NIPPC recommended reducing the mechanical availability to 80 percent.

BESS Availability
The Draft Storage Capacity Agreement (SCA) currently requires guaranteed availability of 98 percent. NIPPC recommended reducing this to 85 percent.

Test Energy
In the current form agreements, PGE would not compensate bidders for test energy. NIPPC recommended requiring PGE to compensate bidders for test energy at 85 percent of either the Index Rate or Contract Price.

Curtailment
NIPPC recommended that PGE should remove any uncompensated curtailment provisions from form contracts.

Performance Assurance/Security
The Form PPA currently requires pre-COD security in the amount of $200/kW and delivery security of $100/kW, which NIPPC says is unreasonably high and different from how Engineering Procurement, and Construction/Asset Purchase Agreement (EPC/APA) bids are treated. EPC/APA bids are only required to post pre-COD security of $100/KW and post a performance bond, payment bond, and warranty bond. NIPPC recommended setting both pre-COD and security delivery amounts around$100/kW.

Labor Requirements
NIPPC requested both clarification and changes to the labor requirements in the RFP. NIPPC requested that projects outside Oregon not be held to the labor requirements contained in HB 2021. NIPPC further requested that the form contracts clarify that projects can comply with the labor requirements of HB 2021 and the federal IRA with a PLA but may comply by other means as well and notes that the Commission directed PGE to remove the PLA requirement in the 2021 RFP and recommends PGE provide clarification on how bidders can comply.[104]

Staff agrees with NIPPC and recommends the Form Contracts clarify that a project may comply with state and federal labor requirements in the various applicable ways under those laws.

Carbon Emissions on Imbalance Energy
NIPPC requested that the Form PPA be amended to remove the requirement that bidders compensate PGE for carbon emissions associated with imbalance energy.

Transmission
NIPPC requested that the transmission requirements in the form contracts should be amended to match those specified by the RFP.

Force Majeure
NIPPC requested changes to the force majeure provisions of the Form PPA and the Form SCA. NIPPC noted provisions of the Form PPA related to unavailability of energy or bundled renewable energy certificates that excludes “changes in climactic conditions” and “environmental obstructions caused by events or circumstances that may impact the Facility's generation output but without causing a Facility outage (e.g., forest fire or volcanic eruption located out of the Facility site).” Regarding the PRR Form PPA, NIPPC noted concerns about PGE being more lenient in enforcement of this provision with PRR bids and that PRR bids should instead owe PGE contract damage for any traditional Force Majeure event. NIPPC requested these provisions be removed for non-PRR PPAs.

Regarding the Form SCA, NIPPC noted an exclusion from the force majeure of loss events such as property loss, casualty, or a condemnation event. If a loss event occurs, bidders must pay PGE to buy down the storage capacity even if caused by a force majeure event. NIPPC requested this provision be removed.

[104] See Docket No. UM 2166, Order No. 21-460, pages 8-9.

Step-In Rights
NIPPC requested that the provision regarding step-in rights be removed entirely.

Non-Disclosure Agreement
NIPPC requested the NDA provisions be amended to reflect those directed by the Commission in PGE's 2021 RFP. PGE has already agreed to this change.

Staff Analysis
Staff appreciates this level of detail from NIPPC. Staff's suggested elimination of the non-price scoring component for commercial performance risk mitigates some of NIPPC's specific concerns with elements of the form contracts, as all these terms will be subject to commercial negotiations between the parties. As such, Staff declines to adopt recommendations on specific terms, except where otherwise noted.

Staff takes NIPPC's broader concern about PGE's preferred terms and their potential anti-competitive impact seriously. In Order No. 22-315, the Commission directed that the IE, Bates White be retained to monitor commercial negotiations. Staff believes this was a useful addition to the role of the IE. To complement the elimination of non-price scoring Staff recommends the IE once again be retained to monitor and report on commercial negotiations for this RFP after a final shortlist is eventually acknowledged. However, Staff further recommends that the IE has more robust and specific direction to analyze the broad issues raised by NIPPC concerning the basic commercial terms offered in PGE's form contracts. To this end, and as discussed above, the IE should be given specific direction to monitor and provide analysis on how PPA terms are negotiated as part of the overall selection process for all projects, and specifically reporting to the Commission a comparison of PPA terms between all PRR projects to non-PRR projects on the FSL, regardless of selection.

To more fully assess the overall competitive and pricing impacts of PGE's preferred contractual terms, Staff requests that the IE track negotiations over all specific terms and perform an analysis of the terms that are sticking points, or for which PRR related bids may have been able to leverage PRR's staffer's potentially unique access to information, as compared with non-PRR bids. Staff will also direct the IE to note any instances in which a bidder responds to PGE's insistence on certain commercial terms by altering the price of its bid. Staff believes this analysis will be useful in evaluating NIPPC's concern about commercial terms inflating bid prices and having an anti-competitive effect.

In order to facilitate this analysis by the IE, Staff also supports NIPPC's recommendation to require contract redlines from all bidders, especially to capture how their bid price is based on commercial terms different than those suggested by PGE in its form contracts. Without the these redlines and the corresponding bid prices, the IE will not have sufficient data to evaluate the impact of contractual terms on price.

The goal of the RFP process is to ensure least-cost, least-risk outcomes for Oregon's ratepayers. However, Staff has inadequate evidence to weigh the competing claims made by PGE and stakeholders regarding the role contractual terms play in delivering that outcome. In future RFPs, Staff will make recommendations based on its findings from this analytical exercise.

Regarding NIPPC's request that PGE include forms of the long-term service and operation and maintenance contracts that will be used for utility-ownership bids, whether they are benchmark bids or build-transfer resources, Staff agrees in part. Staff agrees that the requirement that BTA resources only provide long-term service agreements for a minimum of five years is insufficient given the much longer useful life of those assets. NIPPC recommended that the IE could be tasked with developing appropriate cost adders to project those costs over the useful life of BTA resources.[105] Instead, Staff recommends that PGE should include cost adders in the RFP prior to filing and that the IE will evaluate the appropriateness of the adder in its benchmark bid report.

RFP Condition 8: Form Contracts must clarify that a project can comply with state and federal labor requirements in the various applicable ways under those laws.

RFP Condition 9: 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.

RFP Condition 10: 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 Short List 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

[105] See NIPPC Comments on Final Draft RFP, June 16, 2023, page 11.

COD; Transmission Upgrade Cost; Transmission Scheduling of Energy Effective Date; curtailment; and output guarantees.

RFP Condition 11: 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.

Request for Information

PGE has stated that it intends to issue at least one Request for Information (RFI) in the relatively near future to explore issues beyond its current 2023 RFP, such as the procurement of CBRE projects as required by HB 2021 and long-term changes to its procurement process.[106]

Figure 8: PGE Request for Information

	2023 RFPs	2023 Requests for Information (through end of decade)
All-Source	Will align with the IRP, once acknowledged. Based on IRP as filed, will seek: • 181 MWa of non-emitting energy resources per year • Capacity sufficient to meet any remaining 2026 need, adjusted for bilateral acquisition, EE/DR, contract renewals, or other actions.	Seeks information on project development technologies and locations through the end of the decade. Will prepare PGE and stakeholders for enabling actions needed to maximize resource value (such as additional transmission, regional RA evolution, etc.)
CBRE	Will seek to procure up to 66 MW of resources with a 2026 COD. Nimble process to be co-developed with customers.	Highlights technologies and funding mechanisms not currently transactable that may hold potential in the future Will help to inform the remaining CBRE acquisition target through 2030 Response may help direct PGE program development
	Bilateral acquisition and contract renewals will inform RFP/RFI volumes and timing	

Staff appreciates this approach and is supportive. Staff suggests PGE begin its RFI process by soliciting feedback on design in the current CEP/IRP, LC 80. That said, Staff

106 See PGE's Presentation for the May 26, 2023 Workshop, slide 7.

finds that a robust discussion is currently taking place in LC 80 regarding the type and timing of resources needed to achieve the goals of HB 2021, and defers direction regarding the RFI to that coming from LC 80. After receiving feedback from LC 80 stakeholders, PGE can choose the most appropriate method or docket in which to issue an RFI. In terms of timing, Staff would expect the results of an RFI to be concluded prior to the Company's next RFP for any type of resource.

In comments filed to PGE's CEP/IRP, RNW suggested that PGE should issue an RFP specifically for long lead-time resources in 2025.[107] RNW made several points that Staff believes are worthy of examination in an RFI in the near-term that could possibly inform the design of a subsequent LLT-specific RFP. Specifically, RNW noted the unique issues facing developers of resources like offshore wind, which require major capital allocation decisions much earlier than resources such as solar and onshore wind.[108] Staff therefore recommends PGE issue an RFI on LLTs seeking input from developers and other stakeholders in conjunction with its already planned RFI on CBREs in LC 80, and should follow timeline direction from that docket. Staff believes this RFI should study offshore wind, pumped hydro storage, advanced geothermal, and any other resources identified by the Company or by stakeholders. At a minimum, Staff would like that RFI to explore the following questions:

1. How much time should be allotted between RFP issuance, the signing of a contract, and the commercial operation date for LLTs?
2. Can a traditional RFP resource valuation accommodate LLT resources and, if so, what should be changed to account for unique benefits provided by various LLT technologies to ensure they can compete fairly against more traditional resources? If not, what other procurement approaches best protect customers with least cost, least risk procurement options?
3. How should transmission requirements be altered with respect to LLTs bidding into an RFP, whether that RFP is for all resources or specifically for LLTs.
4. What aspects of a LLT project should be considered as within the control of the project, and what aspects should be considered outside of its control.

Renewable Energy Certificates (RECs)
Staff notes there is some uncertainty around the role of and need for RECs in HB 2021 implementation, an issue that has been raised and explored in depth in Docket No. UM 2273. As such, the Commission's decision to approve PGE's RFP with a requirement that bids must include the transfer of RECs to PGE may limit optionality.

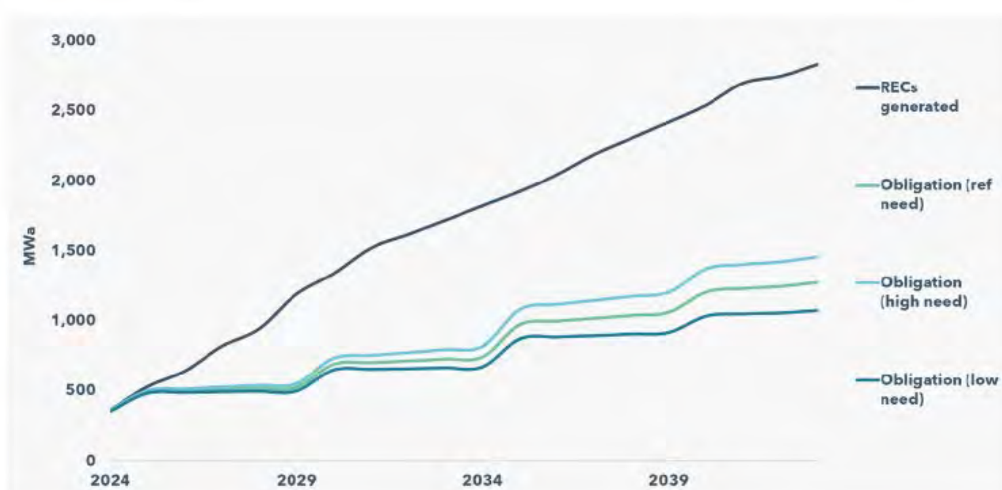
[107] See Docket No. LC 80, RNW Comments, July 27, 2023, page 43.
[108] *Ibid,* page 46.

PGE does not project a near-term need for RECs for RPS compliance.[109] However, the Company requires bids to include these assets. From Staff's perspective, PGE's requirement hamstrings the Company's ability to avoid potential risks. Providing bidders the option to submit bids, with or without RECs, gives PGE and bidders greater optionality to explore least-cost, least-risk approaches to meeting the Company's energy and capacity needs. It also allows time for further Commission consideration of the role of RECs in HB 2021 compliance before PGE begins contracts for resources.

For this RFP, Staff views the tradeoffs of whether or not to include RECs as follows:

- **Need:** LC 80 forecasts that PGE's existing generation resources, new resources, and REC bank will keep PGE RPS compliant, see graphic below: [110]

  Figure 9: PGE CEP/IRP RPS Compliance of Preferred Portfolio (Figure 105 of the CEP/IRP)

  In short, Staff finds that PGE need not acquire all of the RECs from this RFP's new RPS-eligible resources acquired to be RPS compliant. Bids without RECs may help to lower costs.

- **Regional Necessity**: Neither California Independent System Operator's (CAISO) nor the Southwest Power Pool's (SPP) day ahead markets consider REC retirement in their dispatch of non-emitting resources in line with state emissions policies. Any potential state policy requiring REC retirements to match renewable dispatch would happen outside of these markets. Further, the RPS requirement

[110] PGE IRP LC 80, March 31, 2023, page 294.

of 60 percent is less than HB 2021's need for renewables and PGE has a sizeable and growing REC bank.

- **Ratepayer Value:** If bidders can contract to sell unbundled energy in this RFP, retaining the RECs for themselves to monetize, there is the possibility of low lower bid prices. This should result in greater optionality to develop a least cost, least risk resource portfolio. RPS compliance can be maintained while weighing considerations around future price streams.

Staff suggests that the RFP and RFP form contract be amended to allow bidders the choice of including a REC price. Allowing bidders such a choice may also result in lower cost bids and may help avoid the acquisition of any unneeded RECs.

RFP Condition 12: 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 short list and final short list along with the final projects selected.

Miscellaneous Considerations

- **RFP Schedule:** Due to concerns about complementary policy actions, RFP fairness and transparency, and ratepayer protection the process and dates for RFP Final Short List acknowledgement needs to reflect the nuances of the order acknowledging PGE's IRP, LC 80. The RFP Final Short List acknowledgement schedule may also need to be adjusted following any policy direction from the Commission on the use of RECs.

  Staff intends to regularly suggest changes to this RFP's schedule that reflect progress in LC 80 and any other related dockets. While Staff is not recommending any Commissioner action now, Staff is using this opportunity to request that in interested parties' reply comments they consider responding to Staff's announced approach to regularly adjust this RFP schedule to reflect progress and/or decisions in LC 80.

- **Process Prerequisites to FSL Acknowledgment**: As part of the Staff's future FSL acknowledgement memo, Staff plans to suggest how PGE should determine the size of the FSL and how projects should be ranked and selected. These recommendations will build on the recommendations from Staff's final memo in UM 2166, as captured in Commission Order No. 22-315, and any lessons learned from the final selected projects in UM 2166.

Again, Staff is not seeking any Commissioner action here, but invites parties to include in their reply comments any suggestions on how PGE should structure the FSL and FSL project selection process. This includes timing considerations, such as having the FSL process fully solidified prior to the deadline of Best And Final Offers (BAFOs) are made. We look forward to this feedback.

- **Planning & Procurement Going Forward**: Per Order No. 23-146, PGE filed very helpful and constructive comments detailing ideas and pathways to accelerating the procurement process to meet the goals of HB 2021.[111] Most notably, this included the concept of a future IRP action plan that informs multiple bid windows as part of the next RFP.[112]

  Again, Staff seeks no Commissioner action on this topic. Instead, Staff requests Stakeholders suggest the best docket and associated timing to consider, discuss, and potentially refine PGE's proposal.

Conclusion

Per Staff's analysis, Staff believes PGE's Final Draft 2023 All-Source Request for Proposals and its associated Scoring and Modeling Methodology should be approved for issuance, subject to the conditions recommended by Staff. Below is a list of Staff's recommendations:

SMM Conditions

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

SMM Condition 2: PGE will remove the requirement for a Project Labor Agreement from the Minimum Bidder Requirements in Appendix N.

SMM Condition 3:The RFP will be adjusted to require all bids to include a contract with redlines that reflects the rationale behind their bid price and other elements of their bid.

[111] See UM 2274, PGE Planning & Procurement Forecast, July 17, 2023.
[112] *Ibid,* page 3.

SMM Condition 4: PGE will consider projects using Conditional Firm, System Conditions transmission products as conforming to transmission requirements.

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 70 percent of the resource's interconnection limit.

SMM Condition 6: PGE will apply the same tax credit carrying cost from its 2021 RFP for purposes of price scoring.

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.

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.

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.

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.

SMM Condition 11: 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.

SMM Condition 12: 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.

RFP Conditions

RFP Condition 1: 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.

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.

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.

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.

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.

RFP Condition 6: PGE will allow third-party bidders to provide one straw project bid designed to take advantage of the utility-owned elements disclosed in Appendix P, without charging bidders bid fees or other expenses. The bids will be scored by both PGE and the IE. Bids should include a description of the bidder's experience operating within a joint-facility or one owned by utility to address PGE's concerns about security risks.

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.

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.

RFP Condition 10: 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.

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 Short List 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.

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.

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 short list and final short list along with the final projects selected.

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, 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.

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.

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.

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.

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

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

PRR Participation Condition 7: PGE must remove Section 8.4 from the PRR Form PPA.

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

PRR Participation Condition 9: The PRR Form PPA must specify that PGE Benchmark team employees are explicitly excluded from the list of Receiving Party Representatives.

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

PRR Participation Condition 11: PRR PPA must include a value for the transmission upgrade cost cap.

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

PRR Participation Condition 13: PGE shall eliminate blanks for PRR PPA performance guarantees.

PROPOSED COMMISSION MOTION:

Approve PGE's Scoring and Modeling Methodology, subject to the SMM Conditions recommended by Staff.

Approve Portland General Electric's Final Draft of the 2023 All-Source Request for Proposals, as modified by the Company in Reply Comments filed June 28, 2023, with an update to Appendix P filed September 1, 2023, and the supplemental filing on December 11, 2023, for issuance, subject to the conditions outlined in this memo.

UM 2274

Attachment A- U.S. DOE LPO Presentation

Loan Programs Office

Program Overview

Title 17 Clean Energy Financing

Oregon Public Utilities Commission

Leslie Rich, Senior Consultant

Alanya Schofield, Program Coordinator

November 17, 2023

What LPO Does

ORDER NO. 24-011

"There are many areas that are mature from a technology standpoint but not mature from an access to capital standpoint — **that's a nexus where there's a clear mandate** for LPO to participate.

LPO Director Jigar Shah

The U.S. Department of Energy Loan Programs Office (LPO) works with the private sector to finance the deployment and scale-up of innovative clean energy technologies, build energy infrastructure and domestic supply chains, create jobs, and reduce emissions in communities across the United States.

A History of Portfolio Success Across Sectors

Over $40 billion in innovative clean energy & advanced transportation loans and commitments

Advanced Nuclear | $12 Billion
First AP1000 reactor in the U.S. **(Vogtle)**

Advanced Vehicles & Components | $10.4 Billion
Accelerated domestic electric vehicles manufacturing.
(Ford, Nissan, Tesla, Ultium Cells)

Concentrating Solar Power | $5.8 Billion
Five CSP plants utilizing diverse technologies.

Utility-Scale PV Solar | $4.7 Billion
First five photovoltaic (PV) solar projects larger than 100 MW in the U.S.

Critical Materials | $3.2 Billion
Supporting domestic supply chains for electric vehicles battery manufacturing in the U.S. **(Li-Cycle, Redwood Materials, Rhyolite Ridge, Syrah Vidalia)**

Virtual Power Plants | $3.0 Billion
Landmark commitment to scale up access to DERs nationwide. **(Hestia)**

Wind Energy | $1.7 Billion
Four onshore farms, including one of the world's largest. **(Shepherds Flat)**

Advanced Fossil | $1 Billion
Conditional commitment for industrial decarbonization & clean hydrogen project. **(Monolith)**

Geothermal | $546 Million
Innovative thermal extraction, revitalizing the sector.

Hydrogen | $504 Million
Innovative clean hydrogen storage facility.
(Advanced Clean Energy Storage)

Transmission | $343 Million
Advanced transmission lines for improved grid reliability. **(One Nevada Line)**

NOTE: Loan amounts represent the approximate amount of the loan facility approved at closing including principal and any capitalized interest.

ORDER NO. 24-011

Portfolio Impact

Catalyzing U.S. Markets

Over a decade of success in building a bridge to clean energy commercialization

Critical Materials Supply Chain

Financed critical minerals processing and recycling projects, supporting battery cell manufacturing and bolstering domestic EV supply chains.

Utility-Scale Renewables Innovation

Financed large-scale, innovative solar, wind, geothermal, and transmission projects across the West.

Advanced Auto Manufacturing

Financed the upgrade of advanced auto manufacturing facilities across the Midwest, creating tens of thousands of jobs.

Advanced Nuclear Energy

Financed the construction of the first new nuclear reactor in the U.S. in 30 years.

What LPO Offers Borrowers

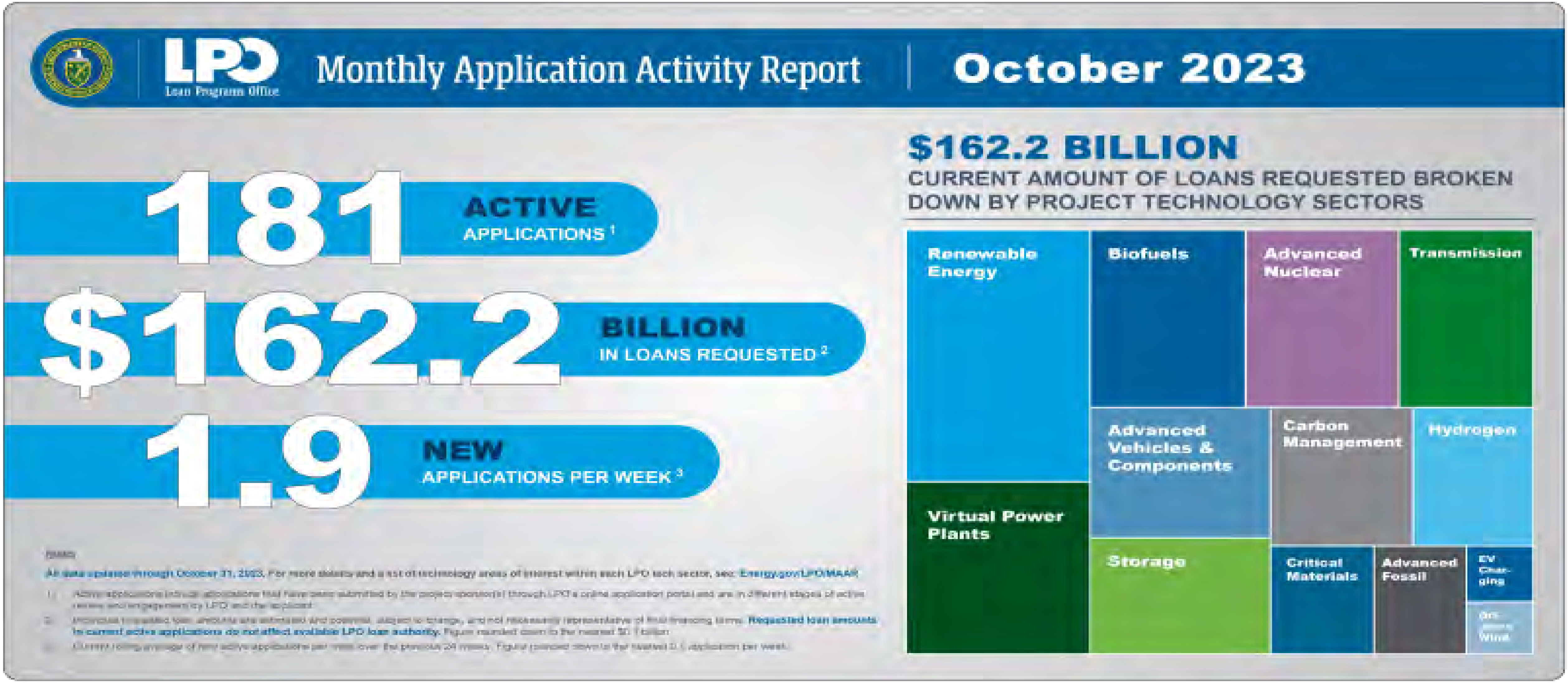
LPO loans and loan guarantees are differentiated in the clean energy debt capital marketplace in **three primary ways:**

Access to Patient Capital
that private lenders cannot or will not provide.

Flexible Financing
customized for the specific needs of individual borrowers.

Committed DOE Partnership
offering specialized expertise to borrowers for the lifetime of the project.

Monthly Application Activity Report October 2023



Monthly Application Activity Report October 2023

LPO Loan Programs Office

Monthly Application Activity Report | October 2023

181 ACTIVE APPLICATIONS [1] WITH

222 PROPOSED PROJECT LOCATIONS ACROSS ALL REGIONS OF THE U.S. [2]

WEST	AK, CA, HI, NV, OR, WA (AS, GU, MP)	53
PLAINS	KS, ND, NE, OK, SD, TX	33
SOUTHEAST	FL, GA, NC, SC (PR, VI)	27
MID-ATLANTIC	DE, MD, NJ, PA, VA, WV (D.C.)	24
MIDWEST	IA, IL, IN, MI, MN, OH, WI	24
MOUNTAIN	AZ, CO, ID, MT, NM, UT, WY	23
SOUTH	AL, AR, KY, LA, MO, MS, TN	20
NORTHEAST	CT, MA, ME, NH, NY, RI, VT	18

Notes:

All data updated through October 31, 2023. For more details and a list of technology areas of interest within each LPO tech sector, see: Energy.gov/LPO/MAAR

1. [illegible]
2. [illegible]

LPO Financing Programs

Title 17 Clean Energy (Title 17)

Financing for:

- Innovative Energy & Innovative Supply Chain (1703)
- State Energy Financing Institution (SEFI)-Supported (1703)
- Energy Infrastructure Reinvestment (EIR, 1706)

Tribal Energy (TELGP)

Financing for:

- Tribal energy development projects

Advanced Transportation (ATVM)

Financing for:

- Manufacturing of advanced technology vehicles, several modes of ATVs, components, and EV charging infrastructure

CO_2 Transportation Infrastructure (CIFIA)

Financing for:

- Large-capacity, common carrier CO_2 transportation projects

Title 17 Clean Energy Project Categories

Innovative Energy (1703)

Financing for commercial-scale deployment of innovative energy projects.

Innovative Supply Chain (1703)

Financing for commercial-scale deployment of innovative manufacturing processes and technologies.

State Energy Financing Institutions (1703)

Financing that aligns federal dollars with state clean energy priorities.

Energy Infrastructure Reinvestment (1706)

Financing to leverage existing U.S. energy infrastructure for the clean energy future.

Title 17 Program Eligibility

All Projects Must:

1. Be located in the United States, territories, or possessions.
2. Be an energy-related project.
3. Achieve significant and credible GHG or air pollution reductions.
4. Have a reasonable prospect of repayment.
5. Involve technically viable and commercially ready technology.
6. Include a Community Benefits Plan.
7. Not benefit from prohibited federal support.

Category-Specific Requirements:

Projects must also meet additional requirements specific to their category:

Innovative Energy (1703)

Innovative Supply Chain (1703)

State Energy Financing Institutions (1703)

Energy Infrastructure Reinvestment (1706)

TITLE 17

Energy Infrastructure Reinvestment (EIR) Projects (1706)

Energy Infrastructure Reinvestment (EIR) Projects (1706)

EIR projects retool, repower, repurpose, or replace energy infrastructure that has ceased operations or enable operating energy infrastructure to reduce air pollutants or emissions of greenhouse gases.

EIR projects are not required to employ innovative technology.

Energy Infrastructure Reinvestment 1706

Financing to leverage existing U.S. energy infrastructure for the clean energy future

Project Eligibility

In addition to meeting the common Title 17 eligibility requirements, EIR projects must:

1. Retool, repower, repurpose, or replace energy infrastructure that has ceased operations, **OR**
2. Enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse gases.

What is "Energy Infrastructure"?

A facility, and associated equipment, used for:

- The generation or transmission of electric energy;

OR

- The production, processing, and delivery of fossil fuels, fuels derived from petroleum, or petrochemical feedstocks.

Notes

- EIR projects **DO NOT** have an innovation requirement.
- Conditional commitments must be issued by **September 30, 2026**.
- **Environmental remediation** costs and **refinancing outstanding indebtedness directly relevant to the energy infrastructure** can be eligible for EIR financing as part of a larger reinvestment plan.

Loan Programs Office

Energy Infrastructure Reinvestment 1706

Financing to leverage existing U.S. energy infrastructure for the clean energy future

Example Projects

Power plant (or associated infrastructure) <u>retooled, repowered, repurposed or replaced</u> with:

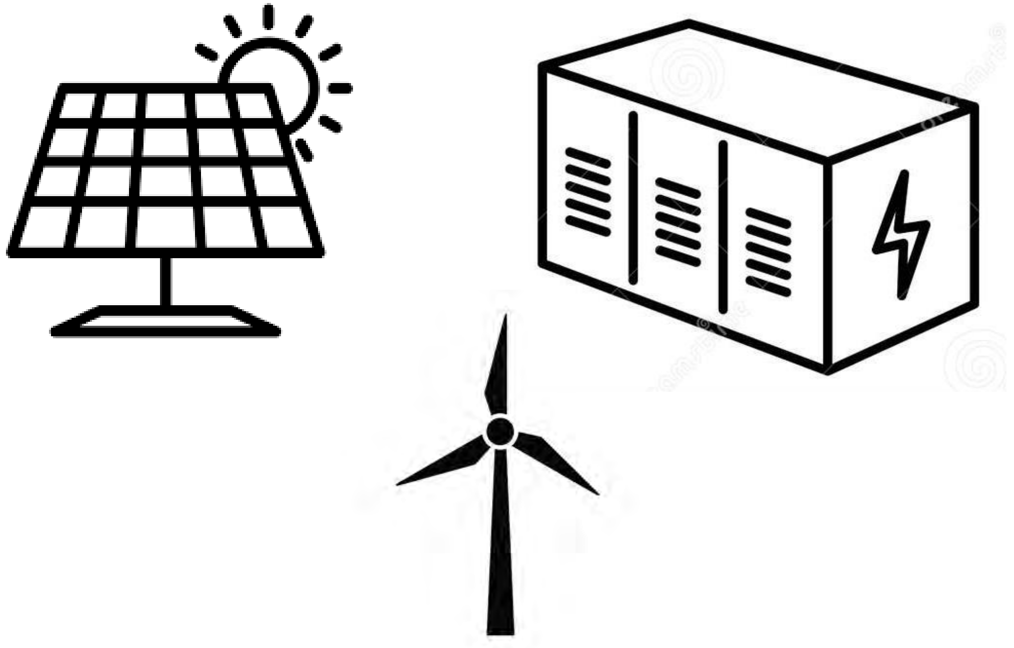
- Renewable energy (and storage)
- Distributed energy (e.g., VPPs)
- Transmission interconnection to off-site clean energy
- New manufacturing facilities for clean energy products or services
- Nuclear generation

- Reconductoring transmission lines and upgrading voltage
- Installing emissions control technologies, including carbon capture and sequestration (CCS)
- Repurposing oil and gas pipelines (e.g., for H_2, CO_2)
- Upgrading refineries for biofuels or hydrogen
- Upgrading or uprating existing generation facilities (with emissions control technologies for projects involving fossil generation)

Example deal: Fossil to Renewable Portfolio

Project Description:

- IRP identifies 2,400 MW of new renewables and storage will replace **1,400 MW of announced coal retirements**
- **Identified near-term investments:** 2 projects, combined ~500 MW solar and ~200 MW storage
- **Planned additional investments:** ~1,000 MW solar, ~200 MW storage, and ~500 MW wind
- Rebuild or refurbish existing hydro generation (approx. 100 MW existing capacity)

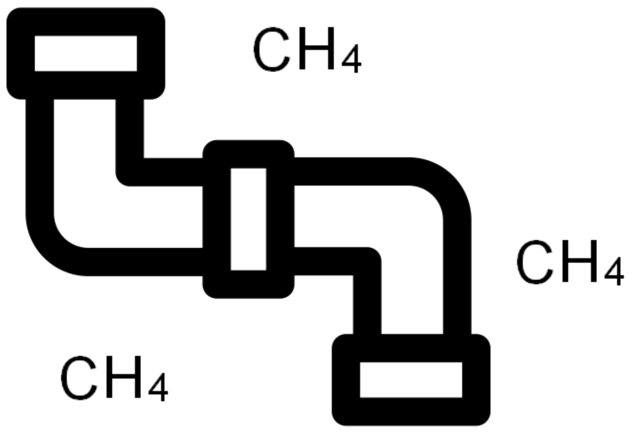


EIR Qualification
1706 a(1): The project will retool, repower, repurpose or replace retiring fossil energy infrastructure.

Example deal: Gas Pipeline Replacement

Project Description:

- Program seeking to renew legacy pipeline infrastructure to reduce methane leaks.
- Over 4,000 miles needed replacement. On track to complete by 2035 at a rate of ~200 miles per year.
- Investments would improve distribution system safety and reliability and remove ~1.4m metric tons of GHGs per year by 2050



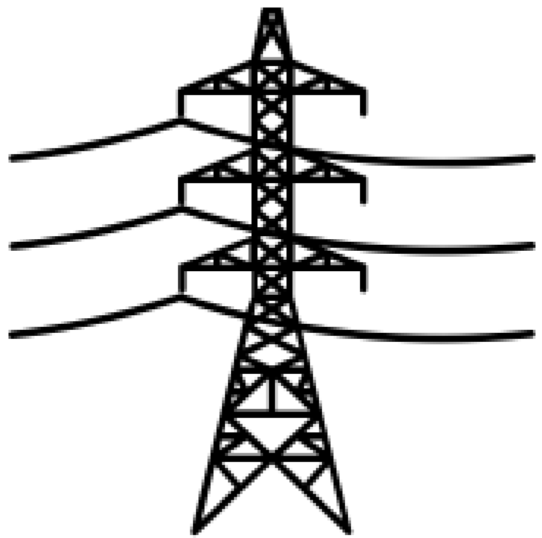
EIR Qualification

1706 a(2): The project will enable operating Energy Infrastructure to avoid and reduce GHG emissions.

Example deal: Transmission Upgrades

Project Description:

- Multi-billion proposal for **transmission reconductoring** and grid modernization across multiple RTOs.
- Investments could improve capacity by 50%, while avoiding / limiting challenges associated with construction of new transmission.
- Projects will **enable interconnection of new clean generation**, and address safety and reliability risks associated with aging infrastructure.



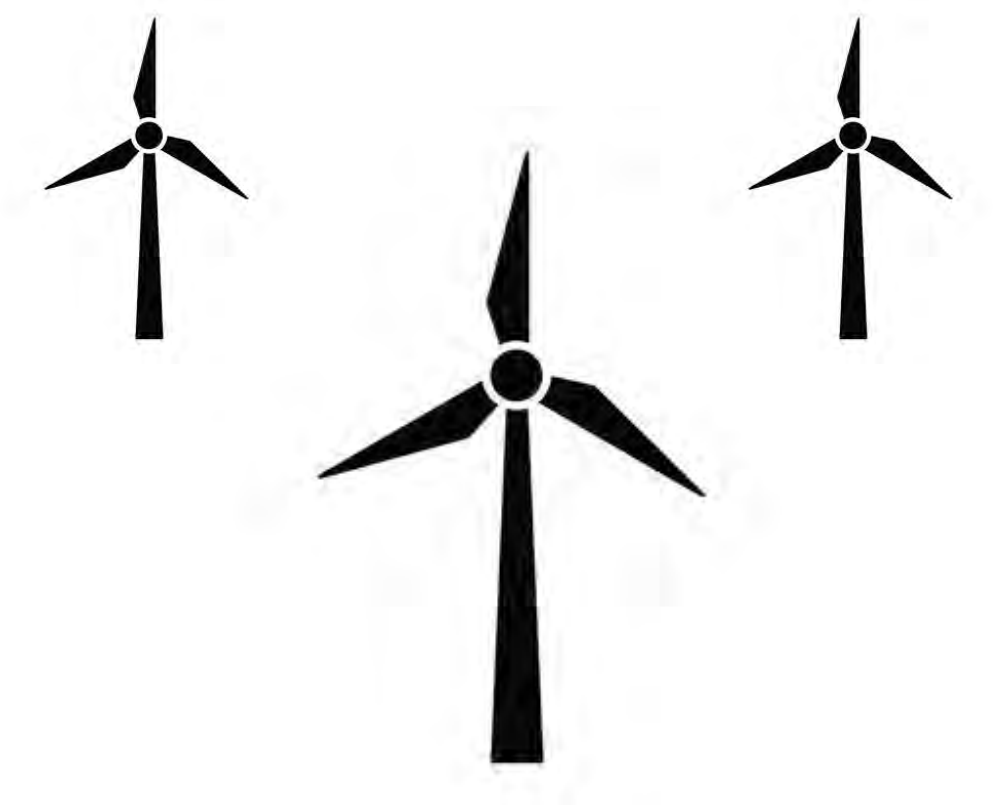
EIR Qualification

1706 a(2): The project will enable operating Energy Infrastructure to avoid and reduce GHG emissions.

Example deal: Wind repowering

Project Description:

- Existing onshore wind assets identified for upgrades. Improvements will be made to blades, gearboxes, hubs, generators, and other components
- Market size potentially tens-of-GW that could be vital to meeting the US's 2030 climate goals by ensuring wind projects are not shut down prematurely and existing developed land and transmission are used efficiently.
- LPO funding would make marginal projects feasible and prolong the life of assets.



EIR Qualification

1706 a(2): The project will enable operating Energy Infrastructure to avoid and reduce GHG emissions.

Title 17 Lending Overview

Loan Guarantee Features

- No minimum or maximum loan size
- Total loan amount up to 80% of eligible project costs.
- Loan guarantees (up to 100%) of U.S. Treasury's Federal Financing Bank (FFB) loans, or partial guarantees (up to 90%) of commercial loans
- Applicants **do not** apply directly to FFB; Title 17 loan applications are managed through LPO
- Typically structured as project financing, but LPO can accommodate other structures.

Loan Products

- Direct loan from FFB backed by 100% "full faith and credit" DOE guarantee
- DOE partial guarantee of commercial debt from Eligible Lenders

Interest Rates and Fees

Interest Rate (for FFB loans)

- Treasury + 3/8ths (0.375%) + risk-based charge
- Treasury rate is fixed according to loan tenor (maximum 30 years)

No Application Fees

Transaction Costs

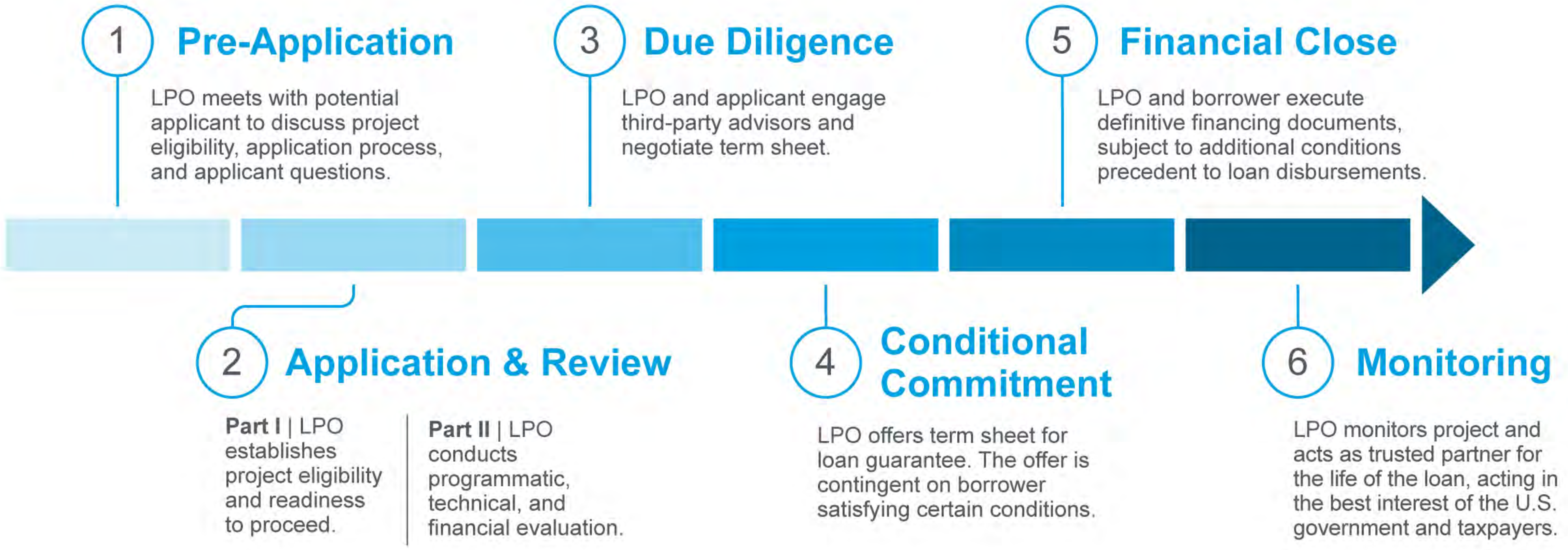
- External advisor fees

Fees

- Facility fee (0.6% on first $2.0bn, 0.1% for excess; required at financial close)
- Maintenance fee (required annually post-closing)

Title 17 Loan Transaction Process

- **LPO engages early with applicants and remains a partner for the lifetime of the loan**



Common Questions From Utilities

- Our utility opco debt is unsecured. Can LPO lend on an unsecured basis?
- Our utility opco debt consists of First Mortgage Bonds. How does LPO debt fit within that structure?
- How long does the application process take?
- How long does the NEPA process take?
- Are other utilities applying?

Let’s Talk About Your Project

Contact LPO to see what financing options may be available for your project

Questions?

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(301) 550-0257

Download the full Title 17 Guidance document at: **Energy.gov/LPO/Clean-Energy**

Learn more about LPO and all of its financing programs at: **Energy.gov/LPO**