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November 10, 2021

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street Southeast, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: UM 2166 – In the Matter of Portland General Electric Company, Application for Approval of an Independent Evaluator for 2021 All-Source Request for Proposals

Dear Filing Center:

Enclosed for filing today in the above-referenced docket is Portland General Electric Company's ("PGE") Reply Comments. This document is being filed by electronic mail with the Filing Center.

Thank you in advance for your assistance.

Sincerely,

Loretta Mabinton
Managing Assistant General Counsel

LM:dm
[Enclosure]

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2166

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Application for Approval of the 2021 All Source Request for Proposals Final Draft	**REPLY COMMENTS OF PORTLAND GENERAL ELECTRIC COMPANY**

Pursuant to the scheduling order issued in this docket, Portland General Electric Company (PGE) submits these comments in support of its Final Draft 2021 All-Source Request for Proposals (RFP). These comments also provide response to the Independent Evaluator's (IE) October 20, 2021, assessment of the draft RFP, and to comments submitted on November 1, 2021, by Swan Lake North Hydro LLC and the Goldendale Energy Storage Project (Swan Lake), the Alliance of Western Energy Consumers (AWEC), Renewable Northwest (RNW), The Northwest & Intermountain Power Producers Coalition (NIPPC), and Staff of the Public Utility Commission of Oregon (Staff).

PGE appreciates the IE's assessment that PGE's Final Draft RFP is "generally consistent with the Oregon Competitive Bidding Guidelines"[1] as well as the opinion of Staff that the Final Draft RFP largely reflects the modifications outlined in Commission Order No. 21-320.[2] PGE is grateful for the comments and recommendations from the IE and stakeholders, and many of those recommendations will be incorporated – as noted below – into our final RFP.

[1] That is the Commission's Competitive Bidding Rules. See Independent Evaluator's Assessment, pg. 1
[2] Comments of Public Utility Commission of Oregon Staff, pg. 4

I. INTRODUCTION

PGE filed a notice and request to select an IE on April 28, 2021, in support of the 2021 RFP. An IE RFP was issued on May 5, 2021, with the Commission selecting Bates White to serve as the IE and setting the remainder of the proceeding schedule during the July 13, 2021, Public Meeting. Following the selection of the IE, PGE made an RFP scoring and modeling methodology presentation during an August 9, 2021 workshop, with stakeholders commenting on August 23 and PGE responding with additional information. The Public Utility Commission of Oregon (Commission) issued Order No. 21-320 on October 6, outlining modifications in the scoring and modeling methodology. PGE held an additional workshop on October 11, with the Final Draft RFP filed on October 15. The Final Draft RFP incorporated modifications consistent with Order No. 21-320 and incorporated recommendations from stakeholders received throughout the process.

In the 2021 All-Source RFP, PGE proposes to procure approximately 150 MWa of qualifying renewable energy resources and sufficient dispatchable capacity resources to meet the remainder of PGE's 375 MW capacity need. Following renewable procurement on behalf of PGE's cost of service customers, PGE will look to procure an incremental 100 MW of renewable resources to supply PGE's Green Tariff Phase II PGE Supply Option (GEAR PSO). Additionally, PGE has indicated that procurement could potentially be expanded as part of this RFP in pursuit of the House Bill (HB) 2021 requirements. Any additional procurement would depend on bids received and whether the projects would be beneficial to PGE's customers. PGE's initial estimates indicate that procuring approximately an additional 65 MWa of renewable resources beyond the targets described above will allow PGE to meet one-third of PGE's forecasted clean energy resource needs required to meet the 2030 emissions reduction target.[3] PGE will continue to work closely with the IE, Staff, and Stakeholders in examining paths forward to ensure that the system remains reliable and affordable throughout the decarbonization effort to comply with HB 2021.

In response to recommendations made by the IE and stakeholders, PGE will make changes to the Final RFP as discussed in Section II.

II. REPLY

PGE's Reply organizes the comments and recommendations from the IE and stakeholders into the following categories: transmission and interconnection requirements, commercial performance risk, RFP scoring, system need and accelerated action toward HB 2021 compliance, minimum bid requirements, and recommendations related to the benchmark and affiliate bids. In these comments, PGE will address the major recommendations proposed by parties and the IE and identify the associated RFP changes – when applicable – adopted by PGE. The comments will also address recommendations that were considered but that PGE did not ultimately incorporate into the final RFP. In light of the comments filed and changes made by PGE to the final RFP, the Commission should approve PGE's RFP application, which retains essential design elements to select resources that balance cost and risk while furthering decarbonization for the benefit of our customers.

1. Transmission and Interconnection Requirements

Some parties provided comments on PGE's transmission and interconnection requirements. The IE supports PGE's transmission and interconnection requirements generally but recommends that PGE consider allowing bidder participation should bidder prove that the transmission provider

[3] 215 MWa (150 MWa + 65 MWa) is initial estimate of approximately 1/3 of needed resources based on 2019 IRP Update estimates and is subject to update.

is solely at fault and that transmission upgrades will be online prior to 2028.[4] Swan Lake[5], RNW[6], and NIPPC[7] provided recommendations on Appendix P's statements around transmission availability. Swan Lake recommends that PGE make transmission more broadly available to bidders in addition to the potential use of Colstrip-associated transmission rights; RNW recommends that PGE remove the reference to the "same constraints and limitations" when discussing the potential for Colstrip transmission availability; and NIPPC recommended additional assurances and detailed descriptions of the Colstrip transmission rights in the event that they are used by the benchmark or affiliate bids. PGE responds to these reply comments below.

a.) PGE does not have excess transmission rights to offer for use

PGE appreciates the comments received and has considered the recommended changes. The challenges associated with transmission planning and procurement are broadly experienced by Northwest wholesale participants - including PGE. PGE-M's transmission portfolio includes network transmission on PGE-T's transmission system for both on-system and off-system resources and point-to-point transmission for off-system resources. PGE's Final Draft RFP noted that the company's utility-controlled transmission rights will not be relied upon to meet RFP bid requirements for benchmark resources and/or affiliate bids, and no utility-controlled transmission rights are made available for bidders as part of the solicitation. PGE did note that if additional certainty develops regarding the removal of Colstrip from PGE's portfolio, the company may consider whether Colstrip-available transmission rights could become available for all bidders.

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4 Independent Evaluator's Assessment, pg. 17
5 Comments of Swan Lake and Goldendale, pg. 6
6 Comments of Renewable Northwest, pg. 6
7 Comments of Northwest and Intermountain Power Producers' Coalition, pg. 35

Regarding Swan Lake's proposal that PGE make its transmission rights more broadly available for resources to serve customers through this solicitation[8], PGE notes that the company's transmission rights are currently used to serve customers' peak load requirements, and PGE-M does not have transmission rights capacity reserved for future projects, including benchmark or affiliate projects, such as those bidding into an RFP. With the increased frequency and magnitude of weather-related supply shortages throughout Western power markets, PGE's existing transmission rights are increasingly essential to meeting customer needs. During the June 2021 heat event in the Portland area – in which Portland set multiple new high temperature records and PGE set a new all-time peak load of approximately 4,500 MW – PGE-M's transmission rights were critical to balancing supply to customer demand. Holding these rights in reserve for future projects would reduce supply flexibility during some of the most critical hours of the year.

The potential use of PGE-M's transmission rights associated with Colstrip is largely impacted by a specific circumstance around a potential retirement, divestiture, or exit of a generating resource and is not broadly representative of PGE's transmission rights availability. PGE declines to incorporate the recommendations into the Final RFP to make utility-controlled transmission rights available to bidders in the 2021 RFP. As referenced above, making PGE-M's existing transmission rights more broadly available would reduce PGE's ability to transport energy to customers and increases risks during peak-load days.

Regarding RNW and NIPPC's recommendations to define (or remove) the "constraints and limitations" when referencing the potential availability of Colstrip-associated transmission[9], PGE notes that the availability of Colstrip transmission rights is not currently known and there is

[8] Comments of Swan Lake and Goldendale, pg. 6
[9] Comments of Renewable Northwest, pg. 6; Comments of Northwest and Intermountain Power Producers' Coalition, pg. 35

uncertainty around the timing and form of removal of the generating asset from PGE's portfolio.

b.) PGE retains the requirement for bidders to provide transmission reservations representing 80% of the project's interconnection limit

The IE recommends that PGE require 80% of long-term transmission based upon a project's maximum capacity as opposed to the nameplate capacity.[10] PGE agrees and clarifies that its long-term transmission requirements are based on a project's interconnect limit rather than nameplate capacity.[11] The IE's comments note that in some instances, transmission availability may limit the capacity offer (as opposed to the nameplate capacity or interconnection limit).[12] As a practical matter, transmission reservations would not necessarily limit the long-term maximum capability of project output as additional output could be supported by supplemental transmission rights acquired at a later date. For this reason, PGE maintains that the interconnection limit is the appropriate figure to associate with the 80% long-term requirement. For bids with multiple co-located technology types that may have interconnection limits higher than transmission availability due to specific project characteristics, PGE will consider these configurations on a case-by-case basis.

c.) PGE will consider alternative transmission plans provided bidders provide a clear and executable pathway to procuring transmission rights consistent with the interim transmission solution at time of bid submittal

Swan Lake recommends that for long-lead time resources, it may be preferable to allow for the submission of a "viable transmission plan" rather than a TSR or current transmission rights. Swan Lake and RNW make the case that resources that will have a COD of 2027 at the earliest are

[10] Independent Evaluator's Assessment, pg. 18
[11] See Appendix N Page 7
[12] Independent Evaluator's Assessment, pg. 18

unlikely to hold transmission rights currently, and that it may in fact be too early to have an active TSR.[13] Similarly, RNW asks the requirement to be relaxed, as viable 2024 COD projects could potentially find multiple feasible pathways to transmission service by end of year 2024.[14]

PGE maintains that for all resources, particularly dispatchable resources, long-term transmission rights are essential to ensure that the resources deliver capacity to maintain necessary reliability on behalf of customers. Transmission availability plays a key role in project viability and economics, and PGE does not foresee a path to accurately scoring a project and its associated risk in absence of concrete steps to procure transmission rights. Should federal tax credit policy continue to incentivize 2023 COD projects, PGE will need to ensure that all projects have a viable and achievable plan to secure transmission rights. PGE maintains that this circumstance will continue to require bidders to provide evidence of participation and progress in transmission study processes as is required in the 2021 All-Source RFP.

However, PGE recognizes that certain circumstances could arise within the bid evaluation process that may require PGE to reevaluate the timing of PGE's transmission requirements. For example, should Congressional action extend the availability of federal tax credits, PGE will work with the IE to consider how additional time made available for tax credit qualification could allow for broader bidder satisfaction of PGE's transmission requirements. PGE appreciates that timelines for obtaining such transmission can be strenuous and lengthy, and as such, will consider alternative transmission plans provided bidders provide a clear and executable path to procuring transmission service. Such plans would necessarily include study process milestones and reference to public study results for similar projects. For the avoidance of doubt, any clear and executable plan to procure transmission service must meet the transmission product and quantity requirements

[13] Comments of Swan Lake and Goldendale, p. 4-5
[14] Comments of Renewable Northwest, pg. 5

specified in the 2021 All-Source RFP. PGE's review of transmission plan viability will focus on the assurance that required transmission service would be awarded in time to support project COD and any effective date of signed definitive agreements. Any transmission plan that does not meet PGE's 2021 All-Source RFP requirements will be reviewed by PGE and the IE to assess its viability prior to any disqualification decision.

d.) A system-impact study (SIS) is necessary prior to the publication of the initial shortlist to ensure that the timeline between the initial short list and final short list can be accommodated

In their comments, NIPPC recommends that PGE modify the requirement to obtain a System Impact Study (SIS) to allow bidders to submit prior to the publication of the final shortlist, and to require only a SIS for the final shortlist, rather than a SIS and an Interconnection Facilities Study (FAS).[15] Currently, the draft RFP requires the SIS to be received prior to the publication of the initial shortlist.

It remains important to consider FAS results prior to making publishing the final shortlist. The FAS is essential to estimate the cost of equipment, engineering, procurement, and construction work to implement the conclusions of the SIS. Were PGE to relax its interconnection requirements to require just a SIS at the final shortlist, there would not be adequate time for BPA to issue a FAS before the point at time in which PGE must initiate negotiations to reach a definitive agreement. As noted in BPA's large generator interconnection process, the FAS processes are the most time intensive component of the interconnection study process.[16] Due to the important cost and planning elements included in the FAS, PGE declines to incorporate NIPPC's recommendation of making only the SIS a requirement of the final shortlist. While PGE will retain the requirements

[15] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 37
[16] https://www.bpa.gov/transmission/Doing%20Business/Interconnection/Documents/lgip_process_timeline.pdf

noted above, should Congressional action extend the availability of federal tax credits within the timeline of the solicitation, PGE will consult with the IE to evaluate the impacts of allowing for additional time for bidders to complete the SIS and FAS studies.

e.) Unlimited transmission and interconnection study delays due to transmission provider cannot be accommodated

The IE assessment notes that there is the potential for otherwise qualified projects to be delayed solely due to the actions of the transmission provider and points out that transmission providers can experience delays in conducting appropriate studies and implementing needed upgrades. The IE recommends that when this is the case, PGE could consider making those bidders eligible for a later online date, rather than the bidders being at risk of disqualification.[17] NIPPC agrees, and supports the IE's recommended allowance for bids that are otherwise qualified but are delayed beyond 2024 solely due to a transmission provider's actions, and NIPPC further recommends that "PGE also clarify specifically which information it requires from bidders to qualify for an online date beyond 2024 on account of the need for additional construction time…"[18]

While PGE is sympathetic to the risk of delay due to a transmission provider, the company is unlikely to have sufficient information necessary to discern whether the delay was solely due to transmission provider actions. The developer community has known since the acknowledgement of the 2019 IRP that PGE would likely initiate a proceeding to procure resources within the action plan window, and developers have had ample time to work with transmission and interconnection partners to make progress toward meeting transmission and interconnection milestones. The potential for delay is a development risk that should be managed by the potential bidders to the RFP. Furthermore, it will be difficult to determine whether a delay of study results is solely

[17] Independent Evaluator's Assessment, pg. 17
[18] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 32

due to the transmission provider, or in part due to the bidder's strategic decision regarding the timing of its study application and whether that decision included the possibility of transmission provider delays. Without knowledge of the cause of the delay or the ability to verify that it was due to the transmission provider, any extension or additional consideration would be inherently subjective. For these reasons, PGE declines to update the COD requirements. However as noted above, PGE will consider how its transmission requirements are impacting bidders generally. Should bidders be broadly affected by the macroeconomic challenges associated with supply chain and labor shortages, PGE may consider identifying additional sources of flexibility – upon consultation with the IE – provided there is alignment with the overall RFP timeline.

2. Commercial Performance Risk

The IE, NIPPC, Staff, and RNW provided comments on the Commercial Performance Risk portion of PGE's Final Draft RFP. NIPPC provided multiple recommendations on revising (or removing) provisions of the Commercial Performance Risk and advocated that providing redline edits to the Commercial Performance Risk sections should not impact non-price score.

In its assessment, the IE recommends that PGE "adjust the non-price scoring for EPC/APA bids such that the points for 'Forecasting and Scheduling' be allocated to the "Credit and Security" and "Utility Owned Asset Output Guarantee" categories and recommends that since there is a considerable reduction in non-price score for not completing form contracts, that PGE emphasize the importance of completing the form contracts.[19]

Both NIPPC and the IE provide comment on the delay damages portion of the Commercial Performance Risk section, with the IE suggesting aligning the delay damages ranges of

[19] Independent Evaluator's Assessment, pg. 2, pg. 14

dispatchable capacity resources and all other resources. NIPPC suggests removing the delay damages amounts altogether.

PGE responds to the recommendations and suggestions on Commercial Performance Risk below.

a.) PGE's Commercial Performance Risk section is intended to appropriately insulate PGE customers from performance risks

In their comments, NIPPC recommends multiple revisions to PGE's "Commercial Performance Risk" section of the non-price scoring criteria. NIPPC argues that PPA bidders face ongoing risks as asset owners, while utility-owned resources do not.[20] PGE disagrees with NIPPC's suggestion that a utility owner experiences little if any risk as an asset owner. Cost of service utility owned structures are fundamentally different than the rate-of-return driven, private capital financed PPAs, however in both instances the asset owner experiences meaningful risk. Importantly, a utility-owned resource places the utility at risk when it is sold on a forecasted basis to its customers through power cost rate making proceedings.

When a PGE owned resource does not perform in any hour, month, or year the utility must cover the cost of replacement in all performance periods. This financial and physical liability arises when, through year-ahead power-cost forecasting, PGE guarantees to deliver customers a specified resource volume, at a specified price, at a forecasted wholesale value. All variances between actuals and forecasts – such as those that naturally arise from volatile market prices and unpredictable variable energy resources - are generally borne by the utility and in limited circumstances by customers through the Power Cost Adjustment Mechanism process. Privately financed PPAs also experience performance risk, but as a general matter are exposed to limited

[20] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 7

market and variability risk as those counterparties are frequently unwilling to manage the financial risk associated with ensuring delivery. Utilities such as PGE bear the physical and financial risks associated with load service and this risk can be mitigated or magnified depending on the terms and conditions of structured transactions like those contracted for in this solicitation.

PGE has provided a non-price scoring framework that fairly distinguishes between commercial structures and allows for comparative scoring that fairly recognizes the benefits and limitations of both commercial structures. Both utility-owned and third-party owned PPA commercial structures introduce risk to PGE and its customers. Some of these risks can be mitigated through terms and conditions in definitive agreements. To add clarity to the risks that PGE intends to mitigate through the Commercial Performance Risk section, PGE includes the table below, which contains a non-comprehensive summary of important risks faced by PGE and its customers.

Table 1: Commercial Performance Risks and Mitigants

	Risk Faced by Utility and Customers	
Risk	**PPA Structure**	**Utility-owned structure**
Pre-COD	Project delay and/or abandonment results in mark-market replacement damages. Possible reliability or compliance consequences. Mitigated with strong security, credit, liquidated damages provisions.	Project delay and/or abandonment results in replacement damages and stranded assets. Possible reliability or compliance consequences. Mitigated with strong security, credit, and liquidated damages provisions.
Wholesale Market Price	Market price volatility and forecast risk borne by utility through replacement purchases. Generally unmitigated in RFP term sheets but for narrow negative price and excess energy provisions.	Market price volatility and forecast risk borne by utility through replacement purchases. Mitigated through utility guarantee of short-term forecast revenues and project shortfalls.
Plant Performance	Long-term project underperformance borne by	Medium-term project underperformance borne by utility through replacement

	asset owner through reduced payment and cover damages. Mitigated through volumetric pricing provisions, output guarantees and termination provisions.	purchases. Long-term project underperformance shared with customers through ratemaking. Mitigated through third-party warranties and long-term service agreements.
Forecasting, Delivery and Integration	Third party scheduling and forecasting intermediary increases operational complexity, decreases system awareness, and portfolio control with potential impacts to cost and reliability. Integration costs borne by customers. Mitigated through forecasting and scheduling agents and failure to deliver provisions. Integration challenges mitigated with third-party tariffed integration services.	Forecast and delivery risk borne by utility through replacement purchases. Integration costs borne by utility. Mitigated through centralized forecasting, scheduling, dispatch. Integration challenges mitigated through integration service optionality and facility dispatch control.
Termination	Project interruption risk due to non-performance, third-party sales, end of term, or market transformation. Mitigated through termination damages, force majeure, product definitions, rights of first refusal and limitations of third-party sales.	Project continuity through utility ownership aligned with load service obligation. Long-term asset competitiveness risk mitigated through prudent plant asset management.

In its assessment, the IE recommends that PGE "adjust the non-price scoring for EPC/APA bids such that the points for "Forecasting and Scheduling" be allocated to the "Credit and Security" and "Utility Owned Asset Output Guarantee" categories.[21] The suggested change is motivated by that apparent absence of forecasting and scheduling provisions contained with the Engineering, Procurement, Construction (EPC) and Asset Purchase Agreement (APA) bids. PGE maintains that utility-owned bids do provide meaningful risk benefits to customers through centralized and

[21] Independent Evaluator's Assessment, pg. 14

integrated forecasting, scheduling, and dispatch despite the absence of analogous forecasting and scheduling provisions as are contained in a PPA. These benefits are reasonable to recognize in a non-price scoring framework, particularly when PPA bidders are generally quite capable and amendable to satisfying PGE's form requirements regarding forecasting and scheduling.

The IE also suggested that PGE make changes to its EPC/APA term sheets to provide more visibility into the nature of some asset ownership risks. Specifically, the IE recommends that changes be made to those term sheets to allows bidders to specifically identify the nature of any warranty and long-term service agreement that are to be included in the bid.[22] PGE agrees that this change would be an improvement to PGE's term sheets and evaluation process and will include this change in the final RFP.

b.) PGE's proposed term-sheet provisions reflect market

PGE's proposed form agreements are designed to protect customers while remaining consistent with market expectations. PGE has successfully executed numerous renewable PPAs and several battery energy storage contract inclusive of the terms proposed in the form agreements. Many of NIPPC's suggested form agreement changes would be inconsistent with market practice as reflected in PGE's existing agreements but also the many form agreements published by utilities and Commissions nationally. The broad form agreement changes proposed by NIPPC would shift risk away from independent power producers and onto PGE and its customers. These changes aren't warranted, and the bidding companies are more than capable of negotiating for themselves. Participants in this RFP are generally large, sophisticated, and well capitalized companies with vast experience in energy procurements. Amending the Commercial Performance Risk section

[22] Independent Evaluator's Assessment, pg. 9

would inappropriately shift risk from bidding PPA projects onto PGE and its customers and would allow sophisticated energy majors to avoid risk that is industry standard.

c.) Adherence to form contracts is an essential component of bid evaluation and the singular place to evaluate critical commercial risks

The most significant risk posed by bids relates to terms and conditions in definitive agreements. When projects do not perform, the terms and conditions protect PGE and its customers. This is true for both utility-owned and third-party owned structures, and Oregon's Competitive Bidding Rules have a long-standing history of allowing bidders to propose changes to form agreements and allow non-price scores to be based on adherence to form agreements, as acknowledged by the IE.[23] In their comments, NIPPC proposes that no consideration can be made on specifics of bidder's proposed changes.[24] While PGE appreciates NIPPC's comments and the proposed redlined changes to the form agreement scoring filed with NIPPC's November 1 comments, PGE maintains that allowing no consideration of changes to form agreements through non-price scoring is not a credible argument as it would allow for the unlimited transfer of risk from project developers and asset owners to PGE's customers.

Further, the IE notes that the penalty for not providing redlines – or deferring discussion of certain items – is a score of zero. While the IE calls this "acceptable" the IE suggested that PGE emphasize the decision to bidders.[25] PGE appreciates the IE's recommendation and will add emphasis in the Final RFP reiterating the importance of completing the form contracts as part of the bid.

[23] Independent Evaluator's Assessment, pg. 14
[24] NIPPC Reply Comments Page 6
[25] Independent Evaluator's Assessment, Pg. 14

d.) Delay damages should differentiate between capacity and energy products

NIPPC observes that the PPA and SCA term sheets and form contracts contain delay liquidated damages penalties, while EPC bids do not contain the same provision. NIPPC recommends aligning the forms by deleting the delay liquidated damages penalties from the SCA and PPA term sheets and form contracts and leaving the issue of damages to be determined based on actual damages at the time of default.[26]

PGE responds that delay damages provisions are in fact included in APA/EPC term sheets and directs NIPPC to page 8 of the EPC agreements in the Final Draft RFP.

The IE's assessment notes that there is a difference in the delay liquidated damages for commercial operation date delay between storage resources and all other resources (PGE proposes damages that range from $150 to $350 per MW for storage, for all other agreements these damages range from $100 to $300 per MW).[27]

The purpose of delay damages generally is to help insulate PGE customers from macroeconomic factors that could materially increase project risks and/or lead to the need to procure replacement power should a project not materialize. In particular, there are currently constraints – or concerns of near-term constraints – related to supply-chain[28] and labor,[29] and PGE's delay damages provisions are meant to manage these tangible risks on behalf of customers.

Regarding the IE's suggestions on proposed damages differing from $100 to $300 per MW for most agreements, but $150 to $350 per MW for storage, PGE confirms that this difference is intentional and reflective of the increased costs of procuring dispatchable capacity. The risks

[26] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 2
[27] Independent Evaluator's Assessment, pg. 8
[28] Wall Street Journal "When Will the Supply-Chain Strains Finally Ease?" (Published 11/5/2021) https://www.wsj.com/articles/when-will-the-supply-chain-strains-finally-ease-11636106400
[29] Nasdaq "What Can Fix America's Supply and Labor Shortage Issues?" (Published 11/4/2021) https://www.nasdaq.com/articles/what-can-fix-americas-supply-and-labor-shortage-issues-2021-11-04

managed by the delay damages provisions are intended to include the cost of replacement market products (energy and/or capacity) in the event that the project is delayed, and current capacity supply constraints in the West during peak times means that the risk is elevated and more difficult to manage when the product being delayed is providing the ability to meet that on-peak capacity need. PGE's decision to price the delay damages for a non-emitting dispatchable capacity product slightly higher than non-dispatchable products is intentional and reflective of energy storage's important role in customer reliability.

3. RFP Scoring

The IE, Swan Lake, NIPPC, and Staff provided comment on RFP scoring metrics and methodology within PGE's Final Draft RFP. Regarding effective load carrying capacity (ELCC) Swan Lake supports the ELCC value attributed to storage resources[30], while OPUC Staff asks for additional clarity on how ELCC is calculated and how bidders can estimate their ELCC score[31]. NIPPC similarly asks for additional ELCC clarity and additional guidance on Level Capacity Ratio[32].

Regarding permitting timelines, NIPPC and the IE recommend that bidders be given the opportunity to submit a narrative explanation if their permitting timeline differs from the timeline in PGE's permitting matrix.[33] Swan Lake notes that CODs after 2024 would impact the non-price score, and requests that the scoring outcome for long-lead time projects be reconsidered.[34][35]

[30] Comments of Swan Lake and Goldendale, pg. 2
[31] Comments of Public Utility Commission of Oregon Staff, pg. 7
[32] Comments of Northwest and Intermountain Power Producers' Coalition, p. 24-25
[33] Comments of Northwest and Intermountain Power Producers' Coalition, pg. 26
[34] Comments of Swan Lake and Goldendale, pg. 3
[35] Independent Evaluator's Assessment, pg. 13

NIPPC and RNW recommend changes to PGE's Project Labor Agreements (PLAs) specified in the Final Draft RFP.[36][37]

PGE responds to the comments and recommendations on RFP Scoring below.

a.) Traditional and non-traditional scoring metrics will be reported

In its assessment of the IRP, the IE recommended PGE provide additional information and description of its portfolio modeling scoring practice. Specifically, the IE requests additional clarity on the conversion of traditional portfolio cost and risk metrics into a price score.[38] As PGE describes in Appendix N, PGE will perform portfolio analysis for a population of designed portfolios to identify the expected portfolio cost across multiple economic futures. Comparing the costs of these portfolios across multiple economic futures will allow PGE to calculate the traditional portfolio scoring metrics including cost, variability, and severity as are described in Section 7.2.1 of the 2019 IRP. The traditional metrics will be used to perform a portfolio performance evaluation to identify a sub-population of portfolios as top performing using the efficient frontier framework described on page 191 of the 2019 IRP. All top performing portfolios will receive a price score based upon each portfolios price and risk performance which is based 50% on the portfolios expected cost and 50% on the standard deviation of forecasted costs across all futures. Each portfolio's price and risk performance will be converted into a portfolio price score allocated on a scaled bases with 700 points allocated to the lowest price and risk results. Upon completing this analysis, PGE will share its results with the IE and Staff for further discussion. Additionally, as suggested by the IE, PGE can also include some of the non-traditional metrics used in the 2019 IRP.[39] PGE finds it reasonable to report out these metrics for

[36] Comments of Northwest and Intermountain Power Producers' Coalition, pg. 30
[37] Comments of Renewable Northwest, pg. 6
[38] Independent Evaluator's Assessment, pg. 5
[39] Independent Evaluator's Assessment, pg. 5

informational purposes but maintains that traditional scoring metrics are best used for resource procurement decisions.

b.) ELCC, Level Capacity Ratio, conformance to commercial terms, and other non-price scoring criteria are objective and reasonably subject to self-scoring.

Swan Lake commends PGE for the development of the Sequoia model in-house and supports the ELCC value attributed to storage resources in Sequoia.[40] OPUC Staff recommends that PGE consider providing a tool to bidders to help them self-score the ELCC of a bid and notes that while PGE has provided additional information on the ELCC as part of the October scoring and methodology workshop, the information has not allowed the potential bidders to calculate ELCC more precisely.[41] NIPPC recommended further clarity from PGE on how bidders could more accurately self-score and calculate a potential project's ELCC. OPUC Staff recommends that PGE consider providing an ELCC calculation tool, while NIPPC recommends that PGE include a detailed description for bidders on how to self-score the ELCC values.[42] Commission Order No. 21-320 specifies that PGE should provide details on the calculation of ELCC that would allow a bidder to calculate the ELCC using information from the 2019 IRP and IRP Update and a sample calculation.

Through the course of the evaluation, bidders should be able to identify the capacity contribution assigned to their bid. All bids that have met PGE's minimum criteria will be summarized in PGE's final shortlist filing. While this summary will not reveal bidder identities, it will make apparent the different resources and technologies received in bidding. Each bid's forecasted annual energy and forecasted capacity contribution will be reported on an anonymous

[40] Comments of Swan Lake and Goldendale, pg. 2
[41] Comments of Public Utility Commission of Oregon Staff, pg. 7
[42] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 25

basis. This information will allow all bidders to self-score their bid for those bid scoring elements dependent on PGE's forecasted ELCC.

For bidders who wish to gain additional insights on a project's expected capacity contribution before bidding, PGE directs bidders to several sources of information. PGE presented initial capacity calculation details during the August 9 Scoring and Methodology workshop, with additional information presented as part of the October 11 workshop. As noted in Staff's comments, the details and presentations provided by the company allow bidders to calculate an estimated ELCC within a range. To provide a more precise ELCC estimate based on the results of the most recent 2019 IRP Update capacity simulation, PGE has developed a simple calculator to aid in the estimate of a particular resource type's ELCC. Upon sharing this calculator with stakeholders through the discovery process, PGE can make this tool available to bidders on its procurement website. While PGE understands the request for a more accurate and precise ELCC estimate for each unique bid type, the company notes that short of running Sequoia (the resource adequacy model to be used in this RFP) with both the most current forecast of PGE's existing and contracted generation assets and load as well as the precise parameters associated with the particular bid, any intermediate calculation method would only produce a high-level estimate of the bid's capacity contribution. Further refinement of the ELCC calculation will occur as part of the 2023 IRP as the Sequoia model and associated load forecast inputs are updated.

NIPPC recommended that the ELCC details be included as the calculation of Level Capacity Ratio is downstream from the ELCC calculation, and that bidder self-scoring on Level Capacity Ratio is not possible otherwise. PGE presented a formula to determine the Level Capacity Ratio as part of the August 9 Scoring and Methodology presentation.[43] As the calculation of the

[43] https://edocs.puc.state.or.us/efdocs/HAH/um2166hah11316.pdf

Level Capacity Ratio is dependent on ability to calculate the ELCC, PGE anticipates that bidders can use ELCC estimates as described in the preceding paragraph, combined with a project MWa and the number of possible non-price points to provide a reasonable self-score of Level Capacity Ratio prior to bidding and a complete self-score following PGE's result publication.

c.) Consideration for bidders who may not meet permitting timelines prescribed in the RFP Matrix

In the Final Draft RFP, PGE has included a permitting matrix which lists – as threshold requirements – permitting requirements for bidders. The IE notes that PGE has added some flexibility to the permitting process already by stating in Draft Appendix N that "in the event that a specific permit is not required for resources that is bid into this RFP, the Bidder may provide a narrative explanation on the bid form regarding why it is not applicable." The IE recommends expanding the ability for a narrative explanation to include situations in which a permit is required but will not be acquired within the timeline suggested in the Draft RFP.[44] The IE clarifies that any additional flexibility "would not excuse a bidder from adhering to the timeline as the evaluators would still have to judge whether the explanation provided has merit." Staff agrees with the IE recommendation and recommends that PGE include the changes – the ability for a bidder to provide a narrative explanation of potential schedule changes – into the permitting requirements of the Final RFP.[45] NIPPC similarly requests additional flexibility and notes that PGE "should not have the unilateral ability to reject a bid or lower the bid score based on the narrative explanation provided.[46]

[44] Independent Evaluator's Assessment, p. 13-14
[45] Comments of Public Utility Commission of Oregon Staff, pg. 7
[46] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 14

PGE appreciates these comments and recommendations and understands the potential for permitting activity to encounter scheduling changes based on the project type, technology, and location. Similar to the flexibility already included in Appendix N for permit applicability, PGE will allow bidders to submit a narrative explanation if they are unable to meet the permitting matrix timeline included in the RFP. PGE views the permits and associated timeline as key to reducing risk as part of the RFP process and retains the discretion – to be discussed with the IE – to determine whether the explanation provided has merit.

Swan Lake raised that the non-price score for CODs after 12/31/2024 will be zero, which will decrease the competitiveness for long-lead time projects. Swan Lake and RNW recommended that the non-price score for projects with a later COD be aligned with the additional flexibility around considering long-lead time projects. Given the regional capacity shortfalls, impending resource adequacy compliance obligations, and the risks associated with long-dated CODs, PGE requires that projects with long-lead times must demonstrate significantly improved price score benefits to justify their consideration. When evaluating two resources—one with a 2024 COD and another with a 2027 COD—with roughly comparable levelized economic performance, PGE should prioritize the selection of the 2024 COD resource given the significantly reduced risk associated with that proposal particularly as it relates to PGE's approaching capacity and expected resource adequacy needs. This preference is incorporated into PGE's non-price scoring design and is an important principle to retain.

d.) Timing and process to update for "best and final" pricing

NIPPC recommends that PGE extend the time granted to bidders to submit "best and final" pricing from one week to "a month or five weeks" to allow additional time for analysis and coordination between suppliers and finance professionals.[47] RNW recommends that PGE consider allowing bidders to potentially increase pricing as part of the "best and final" pricing process.[48]

While PGE appreciates that the timeline associated with moving from publishing the initial shortlist to providing best and final pricing is bounded, it is necessary to keep on schedule for the procurement process in this RFP. The timeline from publication of the initial shortlist to publication of the final shortlist is only 30 days, so the addition of up to five weeks to update pricing as recommended by NIPPC would materially impact the procurement schedule of this solicitation. Additionally, PGE suggests and anticipates that bidders will be contemplating best and final offers throughout the process – from the initial bid submittal until the potential opportunity exists to submit best and final pricing. This iterative approach provides a timeframe considerably longer than five weeks to coordinate best and final pricing. Regarding RNW's suggestion that PGE remove the term that "best and final price updates will only be accepted if the offer's total price is reduced relative to the initial offer," PGE recognizes RNW's concern that new risks or contingencies may require a price increase to remain viable. However, PGE must balance this with the concern that if best and final pricing increases are allowed, bidders may be incentivized to price more aggressively prior to selection of the initial shortlist, knowing that they can later submit upward price revisions in advance of the final shortlist. PGE elects not to modify the term for best and final pricing updates at this time, as the company believes the current structure to represent an acceptable balance of mitigating development risk and capturing benefit for customers. PGE further notes that should risk or contingency situations change, bidders could elect not to submit best and final price updates, instead retaining a higher price based on the initial offer.

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[47] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 38
[48] Comments of Renewable Northwest, pg. 4

e.) Other comments received

RNW, NIPPC, and the IE each made recommendations regarding the use of labor standards as part of the current RFP. NIPPC proposes that the project labor agreements (PLAs) should be removed as a requirement, as HB 2021 provides sufficient labor standards protections.[49] RNW expresses concern that a PLA may add confusion, and recommends that instead, PGE should align – either by reference or comparison – with the HB 2021 requirements.[50]

The requirement for bidders to have a PLA in place in executed EPC agreements is intended to mitigate risk for both project developers and PGE customers, and to maximize benefit to all parties. PGE maintains that the PLA standards would conclusively allow all bidders to meet the HB 2021 standards while allowing for coordination throughout the process. NIPPC's recommendation to remove the PLA requirement entirely is unpersuasive and removing the labor plan altogether may materially increase the uncertainty of finding labor and material supply in a constrained market. PGE appreciates RNW's recommendation to align the requirements with HB 2021, and PGE responds that the PLA helps to add structure and stability, while building upon the HB 2021 requirements.

PGE recognizes the significant milestone associated with the inclusion of language in HB 2021 that supports family-wage jobs for the construction and repowering of renewable energy resources in the state. The COVID-19 pandemic and its after-effects have contributed to the NIPPC and RNW identified issues of "…ongoing uncertainty regarding both labor and material supply" and the "current[ly] constrained labor market." It's for these very reasons why PGE is requiring the use of a Project Labor Agreement (PLA) and union labor. PLAs bring stability to labor, management, and owners in these uncertain and sometimes volatile markets. In addition,

[49] Comments of the Northwest and Intermountain Power Producers' Coalition, pg. 30
[50] Comments of Renewable Northwest, pg. 4

PLAs also allow for much closer coordination between all parties, which regularly results in monthly meetings between labor, management, and owners and provides for the identification of issues early in the construction planning cycle. PGE recognizes that the requirements in HB 2021 may be new to contractors who have not previously worked on jobs where these requirements were in place and adding the additional structure will help ensure compliance with all provisions of the new law. In addition, as a company that employs union represented employees, PGE believes the apprenticeship structure that has long been used by unions that provides a clear path to journey worker status is critical to the success of building the necessary workforce to aid PGE and our customer in PGE's long-term decarbonization requirement.

4. System Need and Accelerated Action Toward HB 2021 Compliance

OPUC Staff requested additional information on the ROSE-E portfolio analysis tool, including whether it would be "frozen" from a capacity expansion perspective when evaluating RFP bids.[51] Swan Lake and RNW recommended PGE consider the likelihood of what capacity need may exist in years outside of the 2019 action plan window, primarily capacity need in 2025-2027, and beyond 2027.[52][53]

Staff recommended – consistent with the language adopted in Order No. 21-320 – that PGE continue to collaborate with stakeholders to develop analysis that shows how the 2021 RFP could maximize action toward the HB 2021 requirements.[54] RNW requested clarification that there is no procurement limit on the 2021 RFP and recommended early action toward HB 2021

[51] Comments of Public Utility Commission of Oregon Staff, pg. 8
[52] Comments of Swan Lake and Goldendale, p. 6-7
[53] Comments of Renewable Northwest, pg. 7
[54] Comments of Public Utility Commission of Oregon Staff, pg. 10

compliance.[55] AWEC noted that any additional procurement must be justified and is subject to prudence review.[56]

PGE responds to the questions and recommendations on HB 2021 compliance and portfolio modeling below.

a.) Use of ROSE-E

As noted in the Final Draft RFP, PGE will use the ROSE-E portfolio analysis tool to develop cost and risk metrics and compare resources across portfolios. The model will forecast the long-term economic performance of bids in isolation as well as when combined, allowing comprehensive evaluation that ensures that the final short list is in the best long-term interest of customers.

OPUC Staff requested additional clarification regarding changes to proposed ROSE-E methodology from a capacity expansion perspective when evaluating 2021 RFP bids.[57] As is correctly noted by Staff, PGE had initially proposed to limit capacity expansion actions following PGE's procurement actions but now proposes to allow ROSE-E to perform its capacity expansion methodology consistent with IRP practice. This change is driven by the desire to be in position to describe for the Commission how procurement actions taken through this solicitation increase/decrease costs while specifically accounting for the long-term implications associated with HB 2021 compliance. PGE looks forward to continued discussion with the IE and Staff on potential sensitivities to be considered within its portfolio analysis framework.

[55] Comments of Renewable Northwest, pg. 2
[56] Comments of Alliance of Western Energy Consumers, pg. 3
[57] Comments of Public Utility Commission of Oregon Staff, pg. 8

b.) Discussion of capacity need post-2025

As noted above, multiple parties requested additional guidance regarding what capacity needs exist in the 2025-2027 and post-2027 timeframes and how procurement may help meet that system need. In accordance with Order No. 20-152, PGE provided updated needs assessments within the 2019 IRP Update. That update included the latest available econometric load forecast at that time, sensitivities for recent GFI procurements, market capacity information, and Qualifying Facilities (QF) assumptions.

The most current resource needs information is contained in Appendix Q of the Final Draft RFP, and PGE is unable to offer additional guidance at this time. However, the company generally agrees with the recommendations of Swan Lake that capacity need will likely persist after the 2025 timeframe and that additional procurements may continue to be needed. This is consistent with PGE's assessment of the potential of multiple procurements included in the October 15 Final Draft RFP. PGE's 2023 IRP will address capacity needs following 2025 as part of the action plan.

c.) Potential expanded procurement to maximize this RFP for HB 2021 compliance

PGE currently intends to procure approximately 150 MWa of renewable resources through this solicitation in addition to 100 MW of renewable resources for GEAR Phase II PSO customers and approximately 375 MW of non-emitting capacity resources necessary to meet PGE's 2025 capacity needs. This planned activity aligns with the 2019 IRP Action Plan and will place PGE on a feasible path to HB 2021 compliance. However, PGE will continue to evaluate its planned action up until making an irrevocable commitment. PGE will necessarily evaluate all bids that are received in this solicitation, and should PGE receive renewable offers of compelling value to customers, that reduce cost and risks associated with HB 2021, PGE will consider procuring volumes in excess of approximately 150 MWa. PGE will work closely with the IE and the

Commission to clearly articulate what would constitute favorable procurement conditions under HB 2021. In particular, PGE anticipates working with Staff – as outlined in Order No. 21-320 – to determine what additional analysis could be provided within the existing RFP timeline to further inform how the current RFP might be maximized for HB 2021 compliance. Initial conversations have indicated that this analysis to determine the benefit to customers of expanded procurement may include sensitivity studies on a future with low market prices, a sensitivity that would analyze the impact of potential tax credit extension, and/or sensitivities reviewing non-traditional portfolio scoring metrics. PGE looks forward to continuing to discuss what analyses might be most useful.

Should favorable procurement conditions arise, PGE expects to substantiate that evidence in its final short-list acknowledgement filing prior to making procurement commitments. In the October 15, 2021, Final Draft RFP PGE noted that an expanded procurement of 65 MWa would mean that the 2021 RFP would be procuring approximately 1/3 of the renewable and non-emitting resources needed for HB 2021 compliance based on current estimates from the 2019 IRP. PGE notes that these forecasts will need to be refreshed and makes clear that this 65 MWa was not intended to be a cap, but rather was intended to serve as an initial estimate of what might serve as a reasonable acceleration of procurement toward HB 2021 requirements. PGE acknowledges AWEC's stated concerns that any additional procurement should be justified,[58] and PGE anticipates producing analysis in support of additional procurement – dependent on favorable procurement conditions – as part of the RFP timeline.

Advancing the 2021 All-Source RFP and successfully procuring renewable resources and non-emitting dispatchable capacity resources on schedule is one of the most important near-term actions that PGE can make to allow for timely HB 2021 compliance. For this reason, PGE

[58] Comments of the Alliance of Western Energy Consumers, pg. 2

underscores the importance of avoiding procedural delays that would be associated with efforts to reassess fundamental planning methods and findings. As discussed above, the methodologies and specific Action Plan activities remain appropriate in Oregon's current policy environment. In addition, should conditions arise that create opportunity for PGE to reduce long-term costs and risks, established portfolio methodologies adjusted for current policy requirements will enable PGE to consider and evaluate procurement scenarios that may exceed proposed action plan procurement targets.

PGE appreciates Staff's recommendation that any pathway to show more robust analysis demonstrating how expanded procurement would align with HB 2021 requirements would be helpful. PGE looks forward to continuing to discuss what reporting and analysis would be most helpful to demonstrate the value of additional resource procurement for customers.

5. Minimum Bid Requirements

In the assessment, the IE notes an opportunity for PGE to clarify what credit requirements are needed for non-investment grade or unrated bidders.[59] NIPPC also comments on the potential to clarify.[60] NIPPC requests flexibility for a cure period for bidders who intended to submit a bid and two alternatives and instead is deemed to have submitted multiple bids.[61] NIPPC requests modifications to PGE's non-disclosure agreements (NDAs).[62]

The IE recommended additional clarification on what transaction types are accepted within the 2021 RFP – primarily regarding development rights bids – and recommended flexibility in selecting the initial shortlist so that fuel type and technology diversity could be considered.[63]

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[59] Independent Evaluator's Assessment, pg. 7
[60] Comments of Northwest and Intermountain Power Producers' Coalition, pg. 22
[61] Comments of Northwest and Intermountain Power Producers' Coalition, p. 38-39
[62] Comments of Northwest and Intermountain Power Producers' Coalition, p. 27-29
[63] Independent Evaluator's Assessment, pg. 6

PGE responds to the comments and recommendations on minimum bid requirements below.

a.) Credit requirements

The IE recommended[64] that PGE clarify what credit requirements are needed for non-investment grade or unrated bidders with regard to either a letter of credit, a guaranty, or both. As outlined in Appendix K of the Final Draft RFP, PGE's 2021 RFP requirements require *both* a letter of credit and parent guarantee for non-investment grade bidders. As a general matter a letter of credit is a stronger security instrument and is not exposed to the limitations associated with a defaulting parental guarantor. PGE also recognizes that at the time of bidding, many bidders may not have identified the parent or financial institution that may extend financing to the project. For this reason, PGE's Appendix K allows for flexibility for PPA bidders by only requiring a letter of credit commitment at time of bidding and a parental guarantee at time of contract execution.

The IE raises the question of what happens if a bidder is rated by only one or two rating agencies listed, and/or the bidder has ratings that are investment grade from some agencies but not others. The IE includes the recommendation that when a bidder is rated by only two agencies, the bidder be assigned the lower of the two ratings, or in the case of multiple ratings, be assigned the majority opinion.[65] PGE agrees with these recommendations and will include updated language in the Final RFP.

b.) Opportunity to cure discrepancy in bid alternatives vs. separate bids

In their comments, NIPPC noted that under PGE's current allowance for one bid and two alternatives (under the same bid fee), there is potential for confusion from bidders whose proposed alternatives may be deemed to be separate bids. NIPPC requests the ability to cure any bid aspects that would cause an alternative to be deemed a separate bid – and subject to an additional bid fee.

[64] Independent Evaluator's Assessment, pg. 7
[65] Independent Evaluator's Assessment, pg. 8

PGE is willing to offer a short cure period if a bidder did not intend for their alternative scenarios to be structured as an additional bid. PGE recommends bidders mitigate the risk of this scenario by using PGE's RFP website and communicating the proposal for variants to PGE and the IE in advance of bids being due.

c.) Liability damages and non-disclosure agreements

In their comments, NIPPC provides multiple recommendations to change the term of NDAs and to modify the damage provisions.[66] PGE cannot enter into the unlimited and indefinite liabilities that NIPPC suggests and finds NIPPCs recommendations out of market and not reasonable. PGE will not accept modifications to its non-disclosure agreement.

d.) Multiple transaction types are encouraged

The IE notes that development rights are specifically mentioned as a potential acquisition. In the IE assessment, PGE was advised to clarify whether development rights would be accepted, as the structure of such transactions "are not often included due to the difficulty of comparing such offers with more complete offers from PPAs and build-own-transfer transactions."[67]

PGE confirms that project development rights are included in the acceptable resource types and commercial arrangement options within this RFP. Project development offers would provide PGE the option to purchase the rights to develop a project at a specified site and would include transfer of all project assets to PGE, including site control agreements, site permits, and resource data. Such offers can be distinguished from Engineering Procurement Construction (EPC), Build Own Transfer (BOT) and Power Purchase Agreements (PPA) as they usually do not include tendered agreements to construct the facility and ultimately reach a commercial on-line date. While development rights agreements may not include tendered agreements to support project

[66] Comments of the Northwest and Intermountain Power Producers' Coalition, p. 27-29
[67] Independent Evaluator's Assessment, pg. 6

construction, PGE finds these alternatives to be important to include in the Company's RFPs as they increase competition within an RFP and support PGE's goal to identify least cost and least risk resources.

In order to properly evaluate options for project development rights, an offer must include all required due-diligence information in order to fairly evaluate the project development rights against alternatives. In accordance with this need, the Draft RFP has strict bid-eligibility thresholds for all bid proposals, including project development rights. These information requirements include the need for the offer to include site control agreements, necessary site permits, OEM equipment quotes, EPC quotes, interconnection studies and agreements, transmission studies, and sufficient historical resource data. In short, bidders proposing to offer development rights are required to have performed pre-bid development and project assessment work equivalent to EPC and PPA bidders. Such requirements give PGE confidence that mature development rights offers could be acquired to achieve the desired COD date and ultimately perform as is forecasted in the RFP evaluation.

e.) Selection to the initial short list

The IE characterizes the scoring of renewable and non-emitting resources separately as a "positive step for resource diversity as it ensures that a minimum amount of offers from each category are included in the initial shortlist." Coupled with that endorsement, the IE recommends that PGE add language to ensure that selections can be made to the initial shortlist to provide diversity with respect to fuel type, transaction type, technology, and location.[68] Otherwise, PGE's flexibility would be limited and the top scoring resources in each of the two categories would be

[68] Independent Evaluator's Assessment, pg. 6

selected – which may limit some of the benefits of portfolio diversity and risk protection. PGE appreciates this suggestion and plans to add appropriate language to the Final RFP.

6. Affiliate and Benchmark

In the assessment, the IE "did not object" to the restricted availability of Hillsboro land for third-party ownership structures.[69] OPUC Staff requested additional information regarding what types of risks PGE is considering in the decision to restrict use of the Hillsboro land.[70]

The IE noted that providing a list of personnel detailing who is working on an RFP and a benchmark/affiliate bid is "standard practice," and PGE confirms that it plans to provide a list to the IE.[71] NIPPC requests that PGE expand the organizational barrier between the RFP and affiliate/benchmark teams to also include a barrier between the affiliate/benchmark team and the IRP process. NIPPC requests that the affiliate bid be treated as a benchmark.[72]

PGE responds to the comments and recommendations on the affiliate and benchmark bids below.

a.) Availability of Hillsboro land for PPA bids and associated risks

As discussed in Appendix P of the Final Draft RFP, PGE may make certain utility-owned assets available in support of benchmark resources or affiliate bids, which would also be made available to third-party bidders at market value. The only exception was a specific property asset in the Hillsboro area that resides adjacent to existing PGE critical infrastructure. Due to security risks, the Hillsboro area land will be made available to third-party developers only under a utility-owned commercial structure.

[69] Independent Evaluator's Assessment, pg. 16
[70] Comments of Public Utility Commission of Oregon Staff, pg. 6
[71] Independent Evaluator's Assessment, pg. 16
[72] Comments of Northwest and Intermountain Power Producers' Coalition, pg. 32

As part of the RFP assessment, the IE specifically stated that it did not object to this restriction.[73] In their comments, Staff mentioned that it would be helpful to have any additional information that the company is able to share to "inform an understanding of the reasonableness of this limitation and PGE's attempts to mitigate the associated risks."[74] NIPPC reiterates that PGE should "meet the requirement to make utility-owned assets available to all bidders or provide an explanation explaining why PGE did not."[75]

As explained in Appendix P, PGE intends to submit two individual battery energy storage Benchmark Resources, with a nameplate capacity not expected to exceed 200 MW each.[76] The approximately 7-acre site in Hillsboro being evaluated is contiguous with PGE operations.

As large-scale battery energy storage is a relatively new operational technology, the safety and operational security of PGE's system must be considered, and steps to reduce the risks associated with multiple-entity operation within the site perimeter should be deemed acceptable. Currently, the most analogous example of a large-scale battery is the 300 MW Moss Landing facility that was brought online in California in December 2020. In September 2021, an unspecified number of batteries on the site overheated, and fire crews found "battery racks that had been scorched and wires melted."[77] No injuries were reported, and in a statement, the operator credited "multiple layers of safety integrated into the battery facility and [that] the risk mitigation and safety systems worked as designed, detecting these modules were operating at a temperature above operational standards and triggering targeted sprinkler systems aimed at the affected modules"[78]

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[73] Independent Evaluator's Assessment, pg. 16
[74] Comments of the Public Utility Commission of Oregon Staff, p. 6-7
[75] Comments of Northwest and Intermountain Power Producers' Coalition, pg. 37
[76] PGE Final Draft RFP, Appendix P, Page 2
[77] https://pv-magazine-usa.com/2021/09/07/moss-landing-energy-storage-facility-knocked-offline-after-batteries-overheat/
[78] https://investor.vistracorp.com/news?item=197

In 2019, a runaway thermal event caused an explosion at the McMicken Battery Energy Storage System (BESS) facility in Arizona, which injured multiple first responders. As a result, Arizona Public Service and industry experts identified multiple safety issues to be addressed in future battery energy storage installations, including response procedures that incorporate system monitoring, the detection of gases, ventilation practices, extinguishing methods, and information to gather before entry; and procedures that should be documented, available outside the BESS container or building, and demonstrated through training that is refreshed and updated periodically.[79]

A U.S. Energy Storage Association task force produced a white paper, "Operational Risk Management in the U.S. Energy Storage Industry: Lithium-Ion Fire and Thermal Event Safety"[80] intended to outline best practices for secure operation of utility-scale battery energy storage systems. The white paper identified that stationary energy storage systems must manage operational risks that include cybersecurity risks, extreme weather and natural disasters, and fire and thermal events.

Due to the need to mitigate operational risks, ensure sufficient monitoring and response, and to ensure that safety and security best-practices are followed, PGE has determined that multi-entity operations would not be possible at the Hillsboro land being evaluated.

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[79] APS says runaway thermal event caused 2019 battery explosion, outlines 4 steps to avoid a repeat | Utility Dive
[80] Operational Risk Management in the U.S. Energy Storage Industry: Lithium-Ion Fire and Thermal Event Safety - Energy Storage Association

b.) Benchmark and affiliate team(s)

NIPPC and the IE noted that standard practice is for PGE to provide a list of personnel, specifying who from PGE worked on the RFP and who worked on the benchmark/affiliate bids. OAR 860-089-0300(b) reads "[a]ny individual who participates in the development of the RFP or the evaluation or scoring of bids on behalf of the electric company may not participate in the preparation of an electric company or affiliate bid and must be screened from that process." PGE confirms that it will provide a personnel list of the RFP and benchmark/affiliate teams to the IE in compliance with Oregon Administrative Rules.

NIPPC requests that PGE further confirm that members of the benchmark and affiliate teams were not involved in the "IRP process."[81] PGE notes that the IRP process is public, with supporting studies and analysis posted on PGE's IRP webpage, and monthly public roundtable meetings to discuss modeling and outputs. NIPPC's request regarding work on the IRP appears to be beyond the scope of the relevant Oregon Administrative Rules, and PGE declines to adopt the recommendation.

c.) Affiliate bid treatment as a benchmark

NIPPC recommends that as PGE's regulatory docket to amend the Master Service Agreement and establish a new affiliate is ongoing, that PGE treat any affiliate bid as a benchmark. Docket UI 461, concerned with increasing the competitiveness of PGE's renewable procurement processes via an affiliate structure, is ongoing and has had two workshops with Staff and stakeholders to date. PGE looks forward to continued collaboration with the Commission and regulatory stakeholders on the potential for an affiliate and reiterates that any PGE – or affiliate – bids into the 2021 RFP will be compliant with OAR 860-089's competitive bidding rules.

[81] Comments of Northwest and Intermountain Power Producers' Coalition, pg. 36

III. CONCLUSION

PGE is seeking to achieve a balance of identifying least cost and least risk resources through this RFP, while moving on an accelerated timeline to ensure that the value of expiring PTCs is captured for the benefit of customers. As detailed in the language adopted as part of Order No. 21-320, PGE is seeking to maximize action toward HB 2021 if favorable procurement conditions indicate that early action is most beneficial to customers, and the requirements included in this RFP are designed to demonstrate project preparedness and commitments consistent with the requirements to quickly and efficiently complete final negotiations and due diligence.

PGE's 2021 RFP – incorporating the recommendations of stakeholders as discussed in these comments – will be consistent with the Commission's Competitive Bidding Rules, is expected to attract competitive bids, and is likely to result in the procurement of least-cost, least-risk resources on behalf of customers. PGE requests that the Commission issue an order approving the 2021 RFP process to acquire approximately 150 MWa of qualifying renewable energy resources, sufficient dispatchable non-emitting capacity resources to meet the remainder of PGE's 375 MW capacity need, and approximately 100 MW of renewable resources to support Phase II of PGE's GEAR PSO.

DATED this 10th day of November, 2021.

Respectfully submitted,

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