BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1773

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of Request for Proposals (RFP) Schedule	))))))))))	REDACTED FINAL COMMENTS OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

I. INTRODUCTION

The Northwest and Intermountain Power Producers Coalition ("NIPPC") files these final comments regarding Portland General Electric Company's (the "Company" or "PGE") Revised Petition for a Partial Waiver of Competitive Bidding Guidelines and Approval of Request for Proposal ("Revised RFP") Schedule ("Revised Petition"). NIPPC recommends that the Oregon Public Utility Commission (the "Commission" or "OPUC") reject the Revised RFP because, as practical matter, it will not result in a fair evaluation between company owned resources and power purchase agreements ("PPA"), and will fail to lead to the acquisition of the least cost and least risk resources.

NIPPC still **supports** PGE conducting a properly designed renewable RFP at this time. Specifically, NIPPC recommends that the Commission approve the Revised RFP, if all the changes identified in these final comments are adopted, and the Commission ultimately acknowledges a final short list that includes significant ownership diversity. NIPPC also notes that, while PGE revised its RFP, PGE and the independent evaluator

("IE") refused to make many of NIPPC's and other stakeholders' recommended changes. Therefore, NIPPC is not pushing for a perfect RFP, but is only holding out for the minimally sufficient revisions.

While NIPPC supports moving forward with an RFP now, NIPPC remains concerned that there are fundamental flaws with the Commission's current competitive procurement policies because they have not historically protected ratepayers from utility bias and have prevented diverse ownership. In addition, NIPPC is concerned about the ability of this IE to protect against utility bias, and NIPPC disagrees that there is a time sensitive need to immediately conduct an RFP. Even if the specifically identified flaws in the Revised RFP are corrected, PGE may still be able to bias the results in favor of more expensive, utility-owned resources. NIPPC's fears are best encapsulated with the following report from UBS, which highlight and directly explain the risks to ratepayers and competitive markets:

> Although [PGE] appears to be structuring the RFP to account for independent developer concerns and maintain a level playing field, we note the company ultimately **maintains a good deal of flexibility in driving RFP design**. **PGE has won each of the last 3 RFPs** and while Carty related issues may garner increased scrutiny around any ratebased power facilities, we think the **renewable (likely wind) opportunity appears tilted in the company's favor at this stage**. We expect an RFP to be launched in '16 could drive a project by year-end '18 **via a build-and-transfer project**.
>
> The question is whether [PGE] can push forward with an expedited RFP as well **as succeed in winning an arrangement under a build and transfer structure to win[] the award**.[1]

1 UBS Investment Bank, Portland General Electric Company Racing to the Finish Line at 4-5 (July 12, 2016).

Finally, NIPPC wants to once again emphasize that it is not opposed to utility ownership of generation assets, but wants a process that ensures that PPA bid options are treated under equal footing as bid proposals that contemplate utility ownership. A truly competitive market would include a healthy (rather than a token) mix of build-own transfers, PPAs with utility ownership options, and pure PPAs. A competitive market that achieves the best savings for ratepayers includes all ownership options rather than only a monoculture in which utility ownership is the only practical alternative.

II. BACKGROUND

PGE filed its original RFP on May 4, 2016 ("Original RFP") asking the Commission to partially waive its competitive bidding guidelines, allow the Company to proceed with its pre-selected IE, and significantly reduce the opportunity for stakeholder comment and participation in the RFP's design. NIPPC conducted an expedited review of the original RFP and submitted detailed comments on June 6, 2016. NIPPC's comments: 1) supported PGE's recognition that it needs new renewable resources to meet the expanded renewable portfolio standard; 2) disagreed with the claims that there was a time-sensitive need to move quickly to capture benefits of phased out production tax credits ("PTC") for wind generation; and 3) identified significant flaws and corrections that should be made to PGE's Original RFP. There was no basis to proceed with an RFP that did not comply with the spirit and intent of this Commission's policies to protect ratepayers and competitive markets against utility bias and SB 1547's generation ownership diversity requirements.

The Commission did not approve PGE's Petition and Original RFP, but instead "encourage[d] PGE and other stakeholders to engage in timely dialogue with respect to any issues or concerns regarding the proposed RFP ...."[2] The Commission allowed the parties to recommend future proceedings following the filing of public comments and informal discussions, and specifically took "no action at this time on whether to approve PGE's final draft RFP."[3]

NIPPC has spent considerable effort and time over the last nearly two months in an effort to convince PGE to make changes that would allow NIPPC to support the RFP. In addition to the comments filed in this docket, NIPPC provided PGE with two drafts of informal written comments, participated in two three-hour in-person meetings with PGE and the IE, discussed the RFP with PGE in numerous telephonic meetings, and has met with the IE individually numerous times in person and over the phone. NIPPC is still continuing discussions with the IE in an attempt to make the RFP more fair and balanced. While the process was not always smooth, NIPPC appreciates PGE staff's professionalism in working with NIPPC. For example, PGE was more willing to recognize merit in and make changes to address certain of NIPPC's concerns than the IE, and PGE assisted NIPPC in educating the IE about Northwest energy markets. In the end, PGE had more than sufficient time to revise and redline the RFP in a way that resolved NIPPC's concerns, and PGE was not willing or able make NIPPC's recommended changes.

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2 Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of Request for Proposals (RFP) Schedule, Docket No. UM 1773, Order No. 16-221 at 1 (June 8, 2016).

3 Id. at 2.

III. COMMENTS

1. Price Factors Should Be Increased to 80% of the Scoring Evaluation

The Revised RFP should be adjusted to increase the scoring percentage for price factors from 60% to 80% and reduce the non-price factors from 40% to 20%. NIPPC originally objected to PGE's proposed price/non-price weighting on the grounds that a 60/40 weighting of price and subjective non-price factors: 1) was inconsistent with PGE's stated reason for requesting a waiver of bidding rules in order to capture the cost savings of near term tax incentives; 2) was inherently subjective and could allow PGE to unfairly bias the evaluation; and 3) handicapped the IE from applying its quantitative analysis.

Over the course of the last month, NIPPC's concerns regarding the non-price factor weighing has only increased, and NIPPC has concluded that the weighing is not actually 60/40, but could weight non-price factors at more than [redacted] of price factors. Such a high focus on non-price factors is inconsistent with PGE's justifications for this RFP. PGE has requested to move forward with an RFP at this time because of the gradual phase out of the PTC. Regardless of the merits or accuracy of this justification,[4]

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[4] NIPPC believes that, while there are potentially some cost savings that could be achieved by moving quickly with the RFP, this view presents a fundamentally inaccurate assessment of the erosion of the value of the PTC for most new wind generation resources. NIPPC's view is largely reflected by actual market dynamics, as illustrated by the UBS report:

> <u>Small timing-related risk.</u> Previously, [PGE] was arguing for expedited RFP processing in light of PTC eligibility through 2018 only, but start of construction guidance allowing 4 years of leeway (through 2020 in this case) could add complications to the argument if the PUC were to scrutinize closely. We believe many large contractors have already reserved turbines for PTC compliance this year so there could be risk to the argument that [PGE] needs to expedite the process accordingly. [PGE] downplays this specific concern on timing of the

this means that PGE believes the RFP needs to be issued immediately to capture potentially low-cost generation resources that will not be available unless the RFP is completed this year. Given that the reason for issuing the RFP right now is to obtain a low-cost resource that will not be available next year, the primary focus should be on price factors.

A. PGE States that It Is Willing to Use a Different Price/Non-Price Weight

PGE believes that the 60/40 price to non-price ratio is the appropriate balance of cost and risk because it was used it PGE's last renewable RFP, and is allegedly consistent with the Commission's policies regarding balancing risk and cost.[5] PGE, however, "is willing to use a different price-risk scoring ratio, if directed to do so by the Commission."[6]

The fact that any aspects of the Revised RFP are consistent with past RFPs should not be considered evidence of their reasonableness, given the lack of ownership diversity and higher cost generation resource acquisitions from past RFPs. Until new policies are adopted to finally ensure that utilities acquire the least cost/risk resources, the Commission should not hesitate to carefully scrutinize any and all aspects of previous RFPs that have failed to achieve results that adequately mitigate against utility bias.

RFP as project would still need to be selected by year-end 2016, it's just a matter of asset in-service. There's a credible argument to suggest ratable increases rather than lumpy long-term procurement of wind around PTC expiration.

5 Revised Petition at 8, 21.

6 Id. at 9.

PGE claims that giving price factors 60% "also appears to be inconsistent with Commission policy . . . ."[7] PGE does not refer to the Commission's competitive bidding guidelines or policies, and cannot point to any Commission precedent for any specific price/non-price weighing. Instead, PGE supports its claim with a generic citation to the Commission's order adopting Integrated Resource Planning Guidelines, stating that a resource decision with the lowest expected cost might result in higher costs than other resource strategies because of associated risks.[8] As explained by the Commission in that order, and immediately prior to the section PGE referenced, the goal of considering risk in "the IRP is to help identify the lowest realized cost over the planning horizon."[9] NIPPC supports consideration of risk, but the purpose of accounting for risk is to keep overall costs down; and risk factors should not have equal or greater weight than price. In addition, consideration of risk in an IRP process is to select a "**a portfolio of resources** with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[10] This does not suggest any specific weighting of cost and risk factors when selecting individual generation resources.

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7 Id.

8 Id. (citing Re Investigation into Integrated Resource Planning, Docket No. UM 1056, Order No. 07-002 at 6 (Jan. 8, 2007)).

9 Re Investigation into Integrated Resource Planning, Docket No. UM 1056, Order No. 07-002 at 6 (Jan. 8, 2007).

10 Id. at 5

B. PGE's Implementation of the Price/Non-Price Factors Ensure that Subjective Non-Price Factors Are Far More Important than Price Factors

PGE maintains that non-price scoring is "fundamentally an objective exercise" using "detailed scoring rubrics inclusive of 195 detailed criteria";[11] however, PGE will not share these detailed criteria with the bidders, or even explain what these criteria actual mean. This means that bidders cannot adequately respond to the RFP to even know how to meet the non-price factors. PGE has also not demonstrated to NIPPC that the non-price factors are objective or that the IE is capable of verifying their reasonableness. PGE's discretion to reject lower cost resources in favor of utility-owned options should be limited by removing or minimizing as many inherently subjective factors as possible.

The there is a possibility that the price scores could result in a number of projects that are very close on price, so that a wide diversity of non-price scores could have the practical effect of giving non-price factors greater value than the price factors. In other words, if all the projects with a price that is fairly close are scored in a narrow range, then the entire decision is left to the vague non-price factors. This means that PGE would be able pick the winner that may not be the least cost and least risk resource.

PGE proposes to evaluate resource bids based on a 1,000 point scale with a maximum of 600 points awarded based on price and a maximum of 400 points awarded based upon "non-price" factors. PGE refers to this evaluation framework as 60% scoring for price and 40% scoring for non-price. [redacted]

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11 Revised Petition at 21.

[redacted]

What is important in evaluating the effect of non-price factors on the ultimate value of a bid is the ratio of non-price factor scores to price scores. More specifically, the actual description of weighting is less important than the degree to which non-price scoring adjustments can affect (and/or distort) the evaluated price of a resource. In practice, a bid evaluation framework for resources should make every effort to monetize non-price factors, so the adjustment to a resource score for non-price factors is commensurate with the relative risk or benefit of the non-price factor on the overall evaluated risk-adjusted price. [redacted]

This can be demonstrated by using a hypothetical example of the proposed scoring. PGE will assign a point score to each bid resource, will summarize each bid price in levelized dollars per kilowatt hour ("kWh"), and will award the lowest price bid the maximum 600 points possible for price. For example, if the dollar/kWh price of "Bidder X" is 10% higher than the lowest price bid, [redacted]

After concluding the pricing score, PGE will adjust the score by up to 400 points based upon non-price factors. [redacted]

PGE's approach may result in oddly distorted results. For example, PGE proposes to automatically award the 150 non-price points in the "Project Development Criteria" to any project that is completed and operating. Biasing the results toward operating projects is inconsistent with PGE's claimed need to rush an RFP to take advantage of the phase out of the PTC. [redacted]

The same illustration can be presented by translating pricing points into dollars. For example, assume a present value revenue requirement (cost paid by ratepayers) of a wind resource totaling approximately $1 billion over the life of the resource. In the example above, each point deduction from the price score equates to approximately [redacted] million higher life-cycle costs for that resource compared to the lowest cost resource ([redacted]). Stated another way, each [redacted] million in lower lifecycle costs to PGE's ratepayers will earn a resource one (1) additional point in price score, and the lowest cost bid will be deemed to save ratepayers [redacted] million over the highest cost bid.

By definition under this approach, each non-price point awarded will also have an implicit value of [redacted] million in the evaluation process, and PGE has a significant degree of discretion to award the 400 non-price points (or up to [redacted] million) to individual projects.

The total 400 points available to PGE for assigning non-price scores [redacted] the pricing component in PGE's evaluation regime. Specifically, the scoring system and underlying weighting proposed by PGE, where subjective non-price factors could be more [redacted] of the evaluated price score. Not only does this severely depreciate PGE's consideration of pricing in the evaluation process, but creates an opportunity for PGE to bias the evaluation in favor of whatever resource they want to choose (e.g., utility-owned or an existing project), regardless of the price or value of that resource to ratepayers.

2. PGE Has Not Revised the Draft RFP PPA to Pay the PPA Price for All Power Generated and Delivered

PGE should pay the seller the PPA contract price for the full amount of generation from the renewable resource delivered to PGE. While PGE has revised the RFP, PGE will still not pay the PPA price for all the power produced by the resource that exceeds the schedule on any hour, but will pay the PPA price minus market price for at least a portion of that power. PGE's approach fails to recognize that imbalances will already be trued up and financially settled on a monthly basis between the third party provider of integration services and the resource seller. This means that there is no need for PGE to also calculate and assess a penalty on energy payments under a PPA. Even more important, this penalty is a clear example of ownership bias because it does not apply to PGE owned generation resources.

NIPPC's Comments explained that the Original RFP would prevent renewable generators that sell their power through a PPA from being fully paid the contract price for all the power that they generate and deliver.[12] In the Original RFP, the seller paid for balancing services to ensure that deliveries match schedules, but PGE would not pay the seller the contract price for any resource output above scheduled amounts. PGE, but not the IE, recognized that NIPPC's concern was legitimate. NIPPC recommended that PGE simply pay the PPA seller the contract price for all energy generated and delivered. Instead, PGE has re-designed the RFP in a manner that will continue to penalize sellers if their variable renewable resources' generation does not perfectly match schedules.

NIPPC specifically recommends that the RFP PPA forms be revised to state that PGE will pay the PPA price for the lower of: 1) all energy produced from the resource during a monthly billing period; or 2) all energy delivered during a monthly billing period. In addition to paying the PPA price for all renewable energy produced and delivered during the month, the RFP PPA forms should require PGE to pay the transmission provider's monthly energy imbalance price for any energy delivered in excess of the renewable energy produced by the resource in that month. In other words, the seller should be paid full PPA price for all energy generated and delivered, and pay an average market price for any imbalance energy delivered in excess of the energy actually generated.

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12 NIPPC Comments at 10-13.

Given the late date in this process and the complex draft PPA language, NIPPC does not believe it is possible to revise PGE's draft PPA language to accomplish the same result. If the Commission, however, approves the RFP upon the condition that PGE revise its own language again, then these comments attempt to explain how the RFP should be revised. The specific changes should include requiring any net positive energy imbalances (i.e., amounts by which delivered energy exceeds generated energy) at the end of the month to be paid for by PGE using an average market imbalance index rate. There is no reason to track hourly market prices and adjust the PPA price depending on hourly deviations between schedules and deliveries.

To understand how PPA sellers are penalized, the specific language of both the draft PPA term sheets and the relevant balancing area authority ("BAA") tariff must be walked through. The relevant provision of the Revised RFP draft PPA regarding energy payments reads:

> For each Scheduling Period during the Delivery Period in which the energy Scheduled to PGE at the Delivery Point is less than the Facility Output, PGE shall pay to Seller (i) the Contract Price for the energy Scheduled to PGE at the Delivery Point, and (ii) the Contract Price *minus* the applicable BAA Imbalance Price for the quantity by which the Facility Output exceeds the energy Scheduled at the Delivery Point.[13]

"Scheduling Period" is the hourly or 15-minute scheduling period in the BAA in which the resource is located,[14] and the "Delivery Period" is the life of the PPA.[15]

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13 Revised RFP at Draft PPA § 2.3.2(b)

14 Id. at Draft PPA § 1.1.112 ("[T]he hourly or other applicable scheduling period during which Energy is Scheduled to the Delivery Point in accordance with the tariff and business practices of the Facility's native Balancing Area Authority").

15 Id. at Draft PPA § 2.3.1 ("Starting on [________ [*Date*]] [the Commercial Operation Date], Seller shall Schedule all of the Facility Output to PGE as Energy

These provisions spell out that PGE will track the actual amount of power scheduled in hourly or 15-minutes increments and compare it to the power actually generated for every hourly or 15-minute period. When the seller generates more power than scheduled, the amount of power that is generated up to the scheduled amount is paid the contract price. This is appropriate. Next, however, when the energy generated **exceeds** the energy scheduled, then the seller is paid the contract price **minus** a market price for all power produced by the resource in that scheduling period that exceeds the scheduled amount.

In theory, PGE's Revised RFP could allow the energy generated above scheduled amounts to be credited against the times when the facility generates less than the scheduled amount, which would not penalize the PPA seller. When the scheduled energy exceeds the amount of power that is generated, the draft PPA terms state that PGE will pay the contract price for the energy generated plus the market price for any imbalance energy provided by the BAA to ensure deliveries match schedules. The draft PPA reads:

> Subject to Section 3.7 [Curtailment], for each Scheduling Period during the Delivery Period in which the energy Scheduled to PGE at the Delivery Point exceeds the Facility Output, PGE shall pay to Seller (i) the Contract Price for the Facility Output, *plus* (ii) the BAA Imbalance Price applicable to the quantity by which the energy Scheduled at the Delivery Point exceeds the Facility Output.[16]

Deviations less than and greater than schedules are not explicitly offset against each other, but are separately tracked for each and every hourly or 15-minute period.

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at the Delivery Point and shall continue such deliveries for the Term (the 'Delivery Period').").

16 Revised RFP at Draft PPA § 2.3.2(a).

Whether or not differences between scheduled and actual generation are offset against each other depends on the specific tariff terms of the relevant BAA transmission provider. As a preliminary matter, NIPPC objects in principle to a PPA seller potentially being subject to significant changes in its **energy** contract price that varies based on how a separate third-party transmission provider decides to bill and collect its imbalance payments for **transmission** service over the contract term.

As many sellers will likely be using Bonneville Power Administration ("BPA") imbalance services, these comments will explain, for illustrative purposes, how PGE's proposal penalizes sellers using the **current** BPA tariff. BPA's transmission tariff has a complex balancing system in which differences between energy generated and scheduled is assigned within three deadbands, spill exceptions, persistent deviations, and multiple ways to price and account for the energy.[17]

Under the Revised RFP, market-price reductions are based on the "BAA Imbalance Price". For example, BPA's Band 2 applies deviations larger than 1.5% of the scheduled energy or 2 MW, and sets the "BAA Imbalance Price" for this imbalance energy using "an hourly energy index in the Pacific Northwest" and "[f]or any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled)."[18]

Since BPA's tariff has a price for every hour or 15-minute period when deviations exceed 1.5% or 2 MW, PGE will adjust the PPA price paid based on an hourly index,

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17 BONNEVILLE POWER ADMINISTRATION, 2016 Transmission Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2016-2017) at 53-54 (2015).

18 Id.

except when the price is negative. As the market price during any particular hourly or 15-minute period may vary widely, the PPA price for each of these deviations will also be reduced by spot market prices. This results in a multitude of different prices for energy included in BPA's Band 2.

Attached to these comments is an illustrative example of how the PPA price would be adjusted using a hypothetical example in which there were only two hours in a billing period with deviations.[19] The critical aspect to understand is that PGE does not allow the deviations to be summed or added up before they are adjusted by the market price, which means that a different market price is applied to each hour in which schedules do not match generated energy. This means that the contract price for a firm renewable energy product in any particular hourly or 15-minute period could wildly differ depending on spot market prices that are used to settle transmission imbalances. This is true even if at the end of the month total net imbalances were zero.

It should not be forgotten that the PPA seller is already paying the third party provider of integration services to ensure firm deliveries, including imbalance charges and penalties. The penalty charges imposed upon PPA sellers are **in addition** to any imbalance payments the seller pays to the transmission provider to ensure that PGE receives all power generated by the resource pursuant to a firm schedule. As long as the seller has made appropriate transmission arrangements for the firm delivery of all energy generated, PGE should not impose a penalty on all power generated above scheduled for each 15-minute or hourly period. Because PGE will always receive the output from the

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19 See Attachment A.

renewable resource on a firm schedule, PGE does not see any imbalances and incurs no costs associated with any imbalances.

The Commission should reject PGE's complex method of reducing the PPA price for all power that is generated and delivered because is it inequitable and targets PPA bids only with this penalty. This provision is an example of how PGE can bias the results of the RFP in favor of utility-owned resources since only sellers will need to include these projected financial losses into their bid or simply absorb them over time.[20] Conversely, PGE's ratepayers will pay the full costs of PGE-owned resources plus any costs associated with power generated that exceeds schedules. If the Commission approves PGE's Revised RFP, then PGE's PPA price provisions should be removed, and PGE should be required to pay the seller the PPA price for all energy generated by the facility and delivered by the transmission provider.

3. PGE Should Not Be Protected From a Jury Trial if the Company Steals Trade Secrets

PGE's Original RFP included several provisions that waived all rights to a trial by jury and capped damages for violations of a non-disclosure agreement at $100,000. NIPPC recommended that PGE's jury waiver and damage cap be completely removed from the RFP. This is not a theoretical risk in the energy development market, as a Utah jury verdict recently found PacifiCorp misappropriated trade secrets from a developer

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[20] NIPPC notes that PGE's proposal to penalize PPAs for inadvertent imbalances within scheduling periods is not an evaluation issue for the IE since it not a true cost of any resource that should affect the evaluation. Rather, rather it is a prospective financial penalty imposed on PPA sellers during the entire delivery period.

that submitted a bid in PacifiCorp's RFP.[21] This verdict raises reasonable concerns from developers submitting bids in PGE's RFP and should not be dismissed summarily.

PGE removed the damages cap, but has refused to remove the jury waiver provision. PGE believes that the waiver is "standard industry practice for complex and technical contracts such as those contemplated by the RFP" and that bidders are free to propose redlines to this provision. In its filing, PGE added that it "believes that the matters included in the form agreements are technical, complex and not suitable for jury trial."[22] The IE never objected to the damages cap or this provision, and, in substantially the same language as PGE, observed that the waiver provision is "common to contracts and similar confidentialities used in other jurisdictions".[23] However, other jurisdictions may not protect the right to a jury trial in the same manner as Oregon does in its state constitution.

PGE's statement that bidders are free to propose revisions to the jury trial waiver rings hollow. PGE has clearly expressed a preference for a jury trial waiver, and it is inappropriate for PGE to emphatically insist on keeping the provision, but suggest that bidders can propose redlines. The RFP is not an arms length transaction in which two equal parties enter into a mutually beneficial contract, but a situation in which a monopsony utility's competitors are attempting to sell power to the utility. The RFP must be designed correctly to limit PGE's ability to use its market power to either extract unreasonable concessions or bias the results to a preferred outcome, including

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21 USA Power, LLC v. PacifiCorp, 372 P.3d 629 (Utah 2016).
22 Revised Petition at 19.
23 Accion Report at 10.

inappropriate waivers of legal rights. This underscores the very purpose of the OPUC's existence and oversight authority.

In an effort to resolve this issue, NIPPC would not oppose PGE including a partial jury waiver, but only if PGE is willing to revise the RFP to ensure that bidders have the right to a jury trial involving misappropriation of trade secrets or other confidential material without any non-price scoring penalty. NIPPC believes this accommodates PGE's concerns about the suitability of more complex and technical aspects by focusing only on the simple misappropriation concern raised by NIPPC.

4. PGE Should Not Evaluate Bids Based on Congestion Risks

PGE should remove ambiguity from its congestion scoring practices to ensure that the RFP is designed to score bids consistently. PGE's Original RFP included the point of delivery ("POD") as both a price and a non-price factor, but the RFP did not make clear exactly how the scoring for potential transmission constraints and curtailments would be applied. Moreover, PGE reserved the right to adjust delivery risk contemporaneously with its evaluation process based upon progress in BPA transmission expansion projects, unspecified long-term transmission distributions factors, and available long-term transfer capacity evaluations.[24] This introduced an unnecessary amount of subjective and arbitrary scoring to the evaluation.

NIPPC argued that POD risks should be identified objectively by PGE, early in the process, and then applied identically to all resources rather than subjectively considered on a case-by-case basis to ensure consistency in scoring different types of resource or ownership models. PGE's proposal was unnecessary because BAAs are

[24] Revised RFP at 24-25.

required by law to manage congestion without regard to ownership and these RFP criteria should follow suit, and NIPPC requested the RFP be revised to remove POD risk from the non-price scoring factors and make separate POD-specific adjustments to the bids.

As requested by NIPPC, PGE removed two paragraphs in Section 8.2.2 and informally claimed that no transmission congestion factors would be considered in the non-price scoring.[25] PGE has not provided additional clarification requested by NIPPC about how an additional non-price scoring criteria, namely "Curtailment and dispatch limitations", relates to this issue.[26] PGE has had sufficient time to respond, and it is unclear whether PGE intends to uphold its informal commitment that congestion factors would not be considered in the non-price scoring, based on its decision not to also address another non-pricing curtailment criteria. NIPPC recommends that the additional non-price scoring criteria ("Curtailment and dispatch limitation") that allows for vague project-specific scoring of transmission congestion be removed.

With respect to the pricing factors, the IE report notes that a stakeholder expressed concerns that revised congestion pricing may be introduced after the bids were received. The IE proposed "locking" the evaluation model and assuaged the bidder's fears by noting that un-locking the model is only permitted if extenuating circumstances justify, "such as, needing to evaluate a bid with unique terms or conditions."[27] Given that PGE has informally agreed that congestion is not supposed to be a factor, NIPPC questions whether the IE's proposal adequately addresses the concern about revised congestion pricing.

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25 Id. at 20-27.
26 See id. at 22.
27 Accion Report at 9.

5. PGE Should Revise the Right of First Refusal, Notice of Sale, and Change in Control

PGE's Original RFP included a right of first offer ("ROFO") and other provisions that would limit the successful bidder's opportunity to sell either its product or project for two years, if PGE terminates the PPA before the project's commercial operation date. The Revised RFP still needs to be changed, rather than remain subject to ongoing negotiations between parties with such unequal bargaining power. Specifically, PGE needs to remove its ROFO because the operator cannot accept an unsolicited offer from a buyer, and the "Change of Control" in ownership limitation needs to be removed, or (at the least) PGE needs to exclude approval of a tax equity partner, partnership flips or redemptions.

PGE's provisions are overly restrictive by, for example, precluding the operator from accepting even an unsolicited offer from a buyer. Moreover, because the ROFO applied immediately after a PPA is entered into, this provision would technically also apply to definitive agreements and signing up tax equity. The Notice of Sale provision largely mirrors the ROFO, but applies after the commercial operation date.

PGE stated informally that it did not intend to limit financing opportunities and that it welcomed redline revisions that address "undue limitations on the project's ability to obtain financing as it relates to tax equity partners, partnership flips or redemptions."[28] PGE also expressed a willingness to receive such redlines in an announcement from

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28 Revised Petition at 25.

bidders.[29] In its filing, PGE stated that the parties reached agreement and that PGE clarified that the final draft RFP is designed as requested on both issues.[30]

In contrast, the IE report observed that PGE was not willing to remove the ROFO restriction.[31] The IE explained the issue as whether a project in default would be completed when termination is imminent, and whether PGE should have the right to approve a replacement developer. While the ROFO applies for the entire term of the contract, the IE appears to incorrectly believe the purpose of the ROFO is to address "the risks associated with a builder in default," and the IE ultimately determined that PGE was correct to be "cautious in establishing terms to ensure completion of a project."[32]

The responses from PGE and the IE bear absolutely no resemblance to each other. While PGE claims the issue has effectively been resolved, the IE (while supporting PGE's decision), at least recognizes that there remains a significant dispute because PGE is not willing to remove or revise the ROFO language. NIPPC notes that, based on the IE's interpretation of PGE's otherwise-unstated objections, PGE may be unlikely to accept redline revisions that it expressed unofficial willingness to receive, or may penalize bidders who strike the ROFO with non-price scoring penalties.

NIPPC reiterates that the ROFO needs to be revised. An announcement that PGE will accept mark ups, without revised language, is insufficient. While there will be unique ownership situations and language changes may be needed in certain

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29 Id.

30 Id. at 19.

31 Accion Report at 10.

32 Id.

circumstances, the actual RFP language should specifically allow these options and limit PGE's right of first offer, without any input on bid scoring whatsoever.

6. Transmission and Integration Costs Should Be Evaluated Consistently Across Utility-Owned and IPP Bids

PGE's ability to use transmission access and costs to discriminate against non-Company owned resources has been controversial in this and past RFPs.[33] PGE has made some important changes in how bidders submit transmission and integration costs that address some of NIPPC's concerns. The Revised RFP remains unclear, and there remains a risk that transmission and integration costs can introduce bias in the evaluation process. NIPPC recommends that the Commission order further changes to prevent PGE from treating ownership options preferably when it makes its actual resource procurement decisions.

NIPPC originally proposed that: 1) PGE explain how and at what cost it plans to integrate utility-owned renewable resources; and 2) PGE accept bids in which PGE will provide transmission and integration services available for its owned resources, including dynamic scheduling.[34] PGE and the IE were unwilling to make NIPPC's recommended changes.

NIPPC proposed a less than perfect alternative solution that transmission costs should be treated as an exogenous variable for each resource based on the actual tariff of the transmission provider from which the resource must take transmission services and the costs of any additional transmission "wheels" to the PGE system. NIPPC

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33 See e.g., Re PGE RFP for Capacity Resources, Docket No. UM 1535, Order No. 11-371 at 4 (Sept. 27, 2011); Re PGE RFP for Capacity and Baseload Energy Resources, Docket No. UM 1535, Order No. 12-215 at 2-3 (June 7, 2012).

34 NIPPC Comments at 2, 6-10, 13-15.

recommended that the RFP should require bidders to identify the native balancing authority area, but not embed the costs of transmission, losses, and required ancillary services in their bids. PGE should add these costs to the bids based on the filed tariff costs in the subject balancing area authority. NIPPC made these suggestions orally, and in two drafts of informal written comments to PGE.

PGE agreed in principle to make NIPPC's alternative recommendation, and has made some important revisions to the RFP, but the Revised RFP should be further clarified to reduce the risk of utility bias. Consistent with NIPPC's recommendation, PGE added language to Section 8.1 of the RFP to state that bidders must identify the relevant BA, and that bids will be evaluated using the tariff rates of the transmission provider to the transmission path identified by the bidder for the bidding facility.[35] The Revised RFP does not specifically exclude PGE from assuming that utility-owned projects will be balanced by PGE as the transmission provider or by PGE using dynamic scheduling. These revisions should be easy to make and are consistent with the revisions PGE has already made.

7. NIPPC Will Not Oppose PGE's Test Energy Provisions, if the Seller Retains the Right to Sell the Test Energy to a Third Party

PGE's Original RFP defined test energy as all energy scheduled and delivered before the commercial operation date, and stated that PGE would purchase test energy at 50% of the contract price. NIPPC determined that basing compensation for test energy

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35 Despite the IE's insistence to contrary, PGE did not change the RFP language in Section 8.1 that asks bidders to list their ancillary services costs, which may be adjusted by the bidder. Accion Report at 5-6. While contradictory, NIPPC assumes that the revised language will trump the inconsistent original language that has never been removed.

on discounted contract price was arbitrary and open to future disputes because the value was directly related to market prices when the power was produced. NIPPC requested that PGE pay for test energy at the (or a) market index price rather than 50% of the contract price. PGE responded that paying near market prices for test energy does not recognize the diminished quality and cost of test energy, and the Revised RFP maintains the 50% discount, but changes the price from the contract to the market price.[36] While NIPPC believes that PGE should pay bidders for more than 50% of the market or contract price, NIPPC is willing to agree to PGE's approach, if bidders are allowed the option to sell their test energy to a third party.

PGE never seriously addressed NIPPC's concern that the value of test energy was being too significantly discounted. NIPPC was less concerned about whether the price was based on a market or contract price than the fact that PGE reduced the value by 50%. While test energy should occur over only a short period of time, disputes between PGE and the successful bidder as to whether a facility is completed could result in longer test periods, which would increase the amount of test energy purchased by PGE at well-below market rates.

In an effort to resolve this issue, NIPPC would not oppose PGE paying 50% of the market price, but only if PGE is willing to revise the RFP to provide bidders the opportunity to sell its test energy to third parties. When it revised the RFP, PGE elected not adopt this recommendation to allow bidders the option to sell pre-commercial operation date energy to third parties. NIPPC believes this is a better reflection of the

[36] Revised Petition at 10, 19.

parties' mutual concerns over test energy, because it allows PGE to reflect a highly diminished value without exposing the successful bidder to unascertainable risk.

8. Delivery Period Security Provisions Should Be Less Burdensome

PGE's Original and Revised RFPs include a Delivery Period Security provision that requires sellers to post and maintain performance assurance as security equal to $50 per kilowatt of expected capacity **and** in an amount sufficient to provide replacement power (and renewable energy certificates) for the next 18 calendar months of revenue. A bidder commented on Accion's website that Section 9.2 of the PPA term sheet should be amended to remove the latter portion ("in an amount sufficient to provide replacement power and corresponding RECs for the next 18 calendar months of revenue").[37] A different bidder pointed out that the post commercial operation date security amount is substantially above industry comparable amounts.[38] Instead of a fluctuating amount of security, the bidder proposed that PGE require a fixed amount of $75/kW post-COD for the purposes of forecasting a fixed security amount.[39]

PGE declined to adopt this proposal, claiming that it failed to "satisfy PGE's risk management requirements."[40] Instead, PGE reminded bidders that further redline changes would be considered during the negotiation process. The IE report did not address this issue.

NIPPC agrees that the delivery period security provision should be changed. It would be inappropriate to leave this and other similar issues to be addressed in post-

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37 Id. at 37.
38 Id. at 39.
39 Id.
40 Id.

bidding negotiations after PGE has already stated that any changes are unacceptable. Although this is a commercial term, NIPPC believes these security amounts are large, and are not commercially reasonable numbers that add significant costs to a PPA. Moreover, this term does not affect ownership bids, because PGE proposes that PGE ratepayers will self-insure utility-owned-project bids against poor operational performance in the operational phase.[41]

9. Bidders Should Be Provided Their Bid Scores

Bidders should be provided their scoring information for each bid, which will allow them an opportunity to verify the accuracy of how their bids were scored and understand how to correct their bids for future RFPs. Bidders should not, however, be provided the scoring of other bids.

PGE has committed to provide for the opportunity for bidders to receive feedback on the competitiveness of their bid. PGE has not clarified what or how relevant that information will be, but it will not include detailed price and non-price scores.[42] The IE agrees that limited feedback should be provided but recommends no "detailed bid scoring data as that would be an invitation for the bidder to tailor a future bid to manipulate the scoring matrix to the bidder's advantage."[43] Essentially, the IE is arguing that bidders should not have access to the detailed scoring matrix because it is subjective and can be manipulated. While PGE has only adopted part of NIPPC's recommendation, NIPPC does not request that the Commission resolve this issue at this time. NIPPC will review

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41 It is unclear to NIPPC how in the evaluation process, if at all, PGE and the IE will reflect the costs to PGE ratepayers of self-insuring against resource underperformance.

42 Revised Petition at 26.

43 Accion Report 12.

the adequacy of the bid information PGE provides to the bidders and address this issue in the future.

10. PGE's Four-Year Rolling Average Excess Energy Provision May Need Revision

PGE's Original RFP included a provision that assessed a penalty for excess output. Section 2.3.3 provides that the contract price for output in excess of the "expected output" will only receive 75% of the price otherwise payable. This provision unfairly targeted PPAs and NIPPC requested it be removed in its entirety, or at a minimum, PGE's penalty at least be based on a four-year rolling average of energy production instead, with no penalty assessed during the first four years of commercial operation.

PGE adopted a revised version of a four-year rolling average requested by NIPPC.[44] The IE reports that PGE "proposed clarifications for the calculation of payments for excess power delivered from a project providing pursuant to a PPA . . . to avoid the prospect for disagreement or misunderstanding."[45] PGE declined to adopt the portion of NIPPC's proposal that PGE's penalty continue to apply only to output that exceeds 110% of the expected output. To resolve the issue, however, NIPPC will not oppose PGE's proposal for a four-year rolling average, with any excess output penalty beginning no earlier than the fifth contract year.

PGE's four-year average approach, however, is illustrative of the negative implications of PGE's refusal to pay the full PPA price for all power generated and delivered. Under any excess output provision and PGE's PPA minus market approach,

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44 Revised Petition at 10, 24.
45 Accion Report at 7.

there will be a portion of the output that exceeds schedule and is fully delivered, but is compensated at contract price minus market. PGE proposes that energy for which PGE has never paid contract price should still be included in the calculation of "excess output", even though PGE never fully paid for it.

11. The Final Short-List Should Have Diverse Ownership Options

The Commission should require that PGE's final short-list include a quantifiable percentage of ownership diversity. PGE claims that any ownership diversity requirement in the shortlist is inconsistent with obtaining the best combination of resources and would violate the Commission's recent orders regarding requiring utility ownership.[46] The IE does not support a requirement that the final short list include a diversity requirement, which is consistent with the fact that it did not identify any concerns that PGE's RFP might be biased in favor of utility ownership and actively resisted most of the stakeholders recommended changes, including ones that PGE ultimately agreed to.

PGE misconstrues both NIPPC's specific request and Commission precedent. PGE is targeting approximately 175 average megawatts ("MWa"), but may also transact for more than the 175 MWa target.[47] This could be as much as 500 MW of wind or about 1,000 MW of solar. If PGE proceeds with the RFP, then PGE will select a final short list of bids that will have "a minimum of 150% of anticipated final contracted capacity."[48] This short list is not the final list of resources to be acquired, and PGE will negotiate to transact with some of the bidders only after it obtains Commission acknowledgement of

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46 Revised Petition at 21-22.
47 Revised RFP at 11.
48 Id. at 8-9.

the short list.[49] Essentially, both PGE and the IE believe that it would harm customers if the Commission required that this non-final list of hundreds of megawatts of power that PGE intends to negotiate final agreements with included a single PPA option or even considered the topic of resource diversity.

PGE also inaccurately argues that such a direction is inconsistent with the Commission's 2014 decision in which "the Commission explicitly stated that, absent clear legislative direction, it is unwilling to consider any mechanism that would require a utility to procure certain types of resources regardless of impact on customer rates."[50] SB 1547 has provided sufficient legislative direction, and the only way to fix the Gordian knot of utility bias may be to simply require the utilities to limit the amount of owned generation in any particular RFP. Despite this, NIPPC already recognized that the Commission is not going to impose a binding ownership limitation in this specific RFP and did not request one.[51] Requiring PGE to include diverse ownership options on a list of bidders to negotiate with is a far cry from requiring any particular outcome.

12. The RFP Scoring Is Unlikely to Fairly Compare PPA and Ownership Operational Costs, Risks, and Benefits

PGE's Revised RFP has not been modified to better account for operational costs, risks, and benefits. NIPPC requested that the RFP more clearly identify and explain how the operational costs and risks will be scored for utility-owned resources so that the best

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49 Id. at 4-5.

50 Revised Petition at 22 (citing Re Investigation Regarding Competitive Bidding, Docket No. UM 1182, Order No. 14-149 at 16 (Apr. 30, 2014)).

51 NIPPC Comments at 20.

resources can be identified and the Commission could identify for future disallowance as imprudent any PGE ownership costs that exceed what PGE estimated in this RFP.[52]

There are a wide variety of differences between PPA and ownership options that can drive the price and non-price comparisons. These include but are not limited to construction risks of delay, cost overruns, material breach by general contractor, long-term equipment risk, early equipment failure, latent construction defects, and inflation assumptions. Given that a PPA seller must account for and absorb these costs, accurately estimating them can make or break the winning bid. In addition, the IE must ensure that all costs, risks and benefits associated with a company-owned resource are accurately accounted for.[53]

Unlike many of the issues raised by stakeholders, "the IE understands the concern" and recognizes that the "evaluation process does not include a quantification of risk of failure of parts for either PPA or ownership options, once a determination is made concerning suitability of components."[54] In the end, this IE believes that this concern must be resolved by "the role of diligent regulators and the requirement for utilities to prove that all expenditures were prudent."[55]

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52 NIPPC Comments at 19; see also Obsidian Comments at 3-4.

53 As an illustrative example, one stakeholder raised the issue of scheduling expenses and requested that PGE identify these costs for company owned resources and make its existing scheduling services available to a PPA bidder. Obsidian Comments at 2. Without taking a position on the specific scheduling request, the IE must at a minimum ensure that costs associated with company owned services are accurately accounted for and charged to the company owned resource. In addition, NIPPC believes, absent compelling circumstances, it would be imprudent for PGE to only use a unique and low cost asset for a company-owned resource and not offer it to PPA options.

54 Accion Report at 7.

55 Id.

After discussions with PGE and the IE, NIPPC determined that, unless there was an IE willing and able to challenge these assumptions, there is insufficient time to resolve this issue. The best way to address this type of risk at this time is for the Commission to exercise its power as a diligent regulator to ensure that the final short list is evaluated to determine if the RFP actually allowed for diverse ownership, and change the price/non-price scoring factors to 80/20 to reduce reliance upon more inherently fungible evaluation criteria.

13. The IE Should Not Participate In Any Short-List Acknowledgment Phase of this Proceeding

The Commission's competitive bidding guidelines require the IE to prepare a closing report for the Commission after the utility has selected the final short list; however, there will be a case-by-case determination "whether the Commission should require IE involvement through final resource selection at the time of acknowledgement of the utility's final shortlist of resources."[56] In other words, the IE's participation is not required during any proceedings to acknowledge the short list or negotiations with the bidders. NIPPC has consistently supported more active involvement of independent evaluators; however, given the unique circumstances of this particular RFP, NIPPC does not believe that additional participation by the IE should be required.

IV. CONCLUSION

For the reasons discussed in these and NIPPC's previous comments, NIPPC recommends that the Commission approve PGE's Revised RFP upon the condition that it be revised consistent with the recommendations in these comments.

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56 Re Investigation Regarding Competitive Bidding, Docket No. UM 1182, Order No. 14-149 at Appendix A at 4-5 (Apr. 30, 2014) (Guidelines 11 and 13).

Dated this 27th day of July 2016.

Respectfully submitted,

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Attachment A

To ensure that sellers receive the contract price for all energy produced from the renewable resource and delivered to PGE, the pricing terms in Section 2.3 should be revised to read as follows:

> "PGE will pay the contract price for the lower of: 1) all energy produced from the resource during the monthly billing period, or 2) all energy delivered during the monthly billing period. In addition to the above (paying the contract price for all renewable energy produced and delivered during the month), PGE will pay the seller the monthly energy imbalance price of the third party provider of integration services, for energy delivered to PGE in excess of the renewable energy actually produced by the resource in that month, if any."

The following examples show how this would work in practice if PGE adopted NIPPC's language and agreed to pay contract price for all energy produced by the renewable resource, and how PGE's proposed compensation proposal will financially penalize a PPA seller by paying less than the contract price for a portion of the energy produced by the renewable resource and delivered to PGE. The examples both use the same assumptions, and are simplified only in that they use a 2 hour billing period to represent a month, and ignore heavy load hour ("HLH") and light load hour ("LLH") detail.

Assumptions:

- <u>Hours in Billing Period</u> = 2
- <u>Contract Price</u> = $50 MWh
- <u>Hourly and Average Market Price</u> = $25 in hour 1 and $35 in hour 2, or $25 average
- <u>Scheduled Amount</u> = 100 MWh in hour 1 and 100 MWh in hour 2 = 200 MWh total
- <u>Actual Resource Output</u> = 80 MWh in hour 1 and 110 MWh in hour 2 = 190 MWh renewable energy

As is shown below, under NIPPC's proposal, PGE will pay for the exact amount of energy scheduled and delivered (200 MWh) but will pay contract price only for 190 MWh of power actually produced from the renewable resource in the billing period. PGE will pay a market price for the 10 MW of energy scheduled and delivered that exceeds the output of the renewable resource in that billing period. Total compensation to the Seller by PGE for the month in this example is $9,800 and the amount purchased is 200 MWh which matches precisely the amount of power actually scheduled and delivered to PGE ($9,500 for 190 MWh of project energy at the contract price and $300 for 10 MW of imbalance energy at the market price).

PGE's Proposal below repeats the analysis using the same assumptions but PGE's proposal does not pay contract price for all energy produced by the resource. PGE compensates the Seller at a level of only $9,650 ($150 less).

	Hour 1	Hour 2	Total	Average		
Scheduled Output (MWh)	*100*	*100*	***200***			
Actual Output (MWh)	*80*	*110*	***190***			
Contract Price ($/MWh)	*50*	*50*				
Market Price ($/MWh)	*25*	*35*		***30***		
PGE Price ($/MWh) (Contract Price - Market Price)	*25*	*15*				
NIPPC PROPOSAL (Monthly Settlement)						
Purchased by PGE	*100*	*100*	***200***			
Hourly Imbalance	*20*	*-10*	***10***			
Payment for Actual Output (Actual Output X Contract Price)			**$9,500**			
Payment for Balancing Energy delivered (Net Imbalance X Avg. Market Price)			**$300**			
Total Amount Paid by PGE to Seller			**$9,800**			
					Total MWh Receiving Contract Price From PGE	**190**
					Average Price paid by PGE per MWh	**$49**
PGE PROPOSAL (15 Min Settlement)						
Purchased by PGE	*100*	*100*	*200*			
Hourly Imbalance	*20*	*-10*	***10***			
Payment for Output (Partial Output X Contract Price)	$4,000	$5,500	**$9,500**			
Payment for Balancing Energy Delivered to PGE (Imbalance Energy Delivered X Hourly Market Price)	$500		**$500**			
Charge for Balancing Energy Absorbed by BA (Energy Absorbed X PGE Price)		-$350	**-$350**			
Total Amount Paid by PGE to Seller	**$4,500**	**$5,150**	**$9,650**			
					Total MWh Receiving Contract Price From PGE	**180**
					Average Price paid by PGE per MWh	**$48.25**

Attachment B

Summary of Positions

NIPPC's Critique	PGE's Filing Ref(s).	PGE's Filing "Response" Status	PGE's Rationale from Filing	PGE's RFP Redline Ref(s).	NIPPC Comments
Price / Non-price Factors	Pages 8-9 (Section C), 18, 19	Disagree, Clarified Agreement	Price / Non-Price Scoring Ratio, PGE claims that the existing 60/40 structure is consistent with previous approved RFPs, and aligns with PGE's IRP and OPUC policy, has been vetted in UM 1535, but PGE will follow OPUC direction.		NIPPC opposes the use of 60/40 structure. PGE has implemented the scoring methodology so that it could result in higher weighting of non-price factors than price factors.
PPA price for all power	Page 10	Agree, Clarified	The terms of the PPA form agreement now indicate that section 2.3 refers to the scheduling period elected by bidders from the transmission provider. PGE claims that the terms related to section 2.3 will be consistent with the imbalance settlement and billing practices imposed by the native balancing authority.	PPA term sheet at 2 (Delivery Period; Contract Price and Adjustments) and PPA term sheet at 3 (Price Adjustments for Excess Output)	PGE's redline states that PGE will not pay PPA price for any power produced by the resource that exceeds the schedule on any hour. Instead, PGE will pay the PPA price MINUS market price.
Jury Trial	Page 19	Disagree	PGE believes that the matters included in the form agreements are technical, complex and not suitable for jury trial.		NIPPC will not oppose the RFP if the jury trial retained, except it must be removed from the NDA.

NIPPC's Critique	PGE's Filing Ref(s).	PGE's Filing "Response" Status	PGE's Rationale from Filing	PGE's RFP Redline Ref(s).	NIPPC Comments
Congestion Risks	Pages 10, 27	Adopted, Clarified Agreement	PGE has removed two paragraphs in Section 8.2.2 to address NIPPC's concerns regarding evaluation of congestion risks. No transmission congestion factors are considered in non-pricing scoring.	Page 24	NIPPC agrees that PGE has removed the two paragraphs as requested. The language in the non-price scoring portion of the RFP needs to be removed.
Transmission	Page 18	Clarified Agreement	PGE claims that it has clarified that RFP is designed as NIPPC requested regarding Application of Dynamic Transfers, Application of Transmission Access (and Transmission Costs), and Application of Interconnection Costs.		NIPPC largely agrees. The Revised RFP should be further changed to specifically exclude PGE from assuming that utility owned projects will be balanced by PGE as the transmission provider or by PGE using dynamic scheduling.
Integration	Page 18	Clarified Agreement	Application of Integration Costs, PGE has clarified that ownership bids may be adjusted to consider the necessary owner's costs.	Pages 27, 29	NIPPC largely agrees. The Revised RFP should be further changed to specifically exclude PGE from assuming that utility owned projects will be balanced by PGE as the transmission provider or by PGE using dynamic scheduling.

NIPPC's Critique	PGE's Filing Ref(s).	PGE's Filing "Response" Status	PGE's Rationale from Filing	PGE's RFP Redline Ref(s).	NIPPC Comments
Right of First Refusal	Page 19	Clarified Agreement	Right of First Offer, PGE has clarified that the final draft RFP includes a ROFO, but PGE claims it will accept revisions. Notice of Sale, PGE has clarified that the final draft RFP is includes a notice of sale, but PGE claims it will accept revisions.		PGE needs to remove its "Right of First Offer" because the operator cannot accept an unsolicited offer from a buyer or negotiate a sale of the project for a fair price at any time during the life of the project. Bidders are required to incorporate costs of ROFR into bid, which penalizes PPAs in the bidding process, even if they mark up the RFP.
Test Energy	Pages 10, 19	Disagree	PGE states that Test Energy, the request to pay near market price for test energy does not recognize the diminished quality and cost of test energy.	PPA at 17-18	PGE has changed the RFP to 50% of the market price for Test Energy rather than 50% of the PPA price. NIPPC believes 75% of the market price is more equitable and PGE should permit the bidder to sell the Test Energy to a third party. NIPPC will not oppose the RFP with 50% of the market price if PGE revises the terms so that the bidder has the option to sell the Test Energy to a third party.

NIPPC's Critique	PGE's Filing Ref(s).	PGE's Filing "Response" Status	PGE's Rationale from Filing	PGE's RFP Redline Ref(s).	NIPPC Comments
18 Months of Replacement Power – Delivery Period Security	Pages 19, 38	Disagree	PGE declines to adopt the redline because PGE's analysis demonstrates that a diminished delivery period security does not meet PGE's established risk management requirements. However, bidders are free to red-line the PPA as they see fit, such edits will be considered in the negotiation process.		Commercial term but the number is large and will add significant costs to a PPA bid but not affect ownership bids because PGE places all the risks on ratepayers at no cost to PGE. NIPPC supports the bidder's proposed change.
Fixed post-COD Amount	Page 40	Disagree	PGE declines to adopt the proposed change for the PPA as it does not satisfy PGE's risk management requirements. However, bidders are free to red-line the PPA as they see fit, such edits will be considered in the negotiation process.		Commercial term but the number is large and will add significant costs to a PPA bid but not affect ownership bids because PGE places all the risks on ratepayers at no cost to PGE. NIPPC supports the bidder's proposed change.
Bidders Should Be Provided Their Scores	Page 26	Agree	PGE will provide for the opportunity for bidders, upon request, to receive indicative feedback on the competitiveness of their bid. Feedback will not include detailed price and non-price scores.		PGE's scoring information provided to bidders is likely to be insufficient, but PGE's proposal is acceptable for this RFP.

NIPPC's Critique	PGE's Filing Ref(s).	PGE's Filing "Response" Status	PGE's Rationale from Filing	PGE's RFP Redline Ref(s).	NIPPC Comments
Four Year Rolling Average	Pages 10, 25	Agree	PGE has adopted, in part, the 4 year rolling average requested by NIPPC.	PPA term sheet at 3 (Price Adjustments for Excess Output)	NIPPC opposes that energy PGE has never paid contract price for is included in the calculation of "excess output", even though PGE never fully paid for it. NIPPC will not oppose PGE's proposal for a 110% four year rolling average trigger, with a penalty for deliveries above 100% of expected output.
Final Short List Diversity Requirement	Page 19	Disagree	The proposal is inconsistent with OPUC Order No. 14-149.		PGE's RFP is inconsistent with SB 1547 and the Commission's policies because it is biased in favor of a particular category of resources and promotes a utility owned shortlist, which is contrary to the underlying goal of the IRP and RFP processes of obtaining resources representing the best combination of risk and cost for customers.

NIPPC's Critique	PGE's Filing Ref(s).	PGE's Filing "Response" Status	PGE's Rationale from Filing	PGE's RFP Redline Ref(s).	NIPPC Comments
The RFP Scoring Is Unlikely to Fairly Compare PPA and Ownership Operational Costs, Risks and Benefits	Page 21	Disagree	Price scoring of the RFP bids is inclusive of all life cycle costs for all ownership bids.		There is insufficient time to resolve this issue. The Commission should ensure that the final short list is evaluated to determine if the RFP actually allowed for diverse ownership, and change the price/non-price scoring factors to 80/20.
IE Participation		Issue not raised.	No position yet.		The IE should not participate in any proceeding acknowledging the short list or in any aspect of the proceeding after completing its Closing Report.