BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1934

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2018 Request for Proposals for Renewable Resources.	)))))))	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION COMMENTS ON STAFF REPORT

I. INTRODUCTION

Northwest and Intermountain Power Producers Coalition ("NIPPC") provides these Comments to the Oregon Public Utility Commission (the "Commission") on the Staff Report regarding Portland General Electric Company's ("PGE's") 2018 Request for Proposal ("RFP"). NIPPC urges the Commission to adopt many of the Independent Evaluator's ("IE's") and Staff's recommendations as well as direct PGE to make several additional changes to ensure the overall fairness of this RFP, including:

- Removal of the requirement to obtain long term firm transmission
- Removal of the Public Utility Regulatory Policies Act ("PURPA") restrictions
- Allowing bidders to dynamically transfer into PGE's service territory
- Removal of the requirement to obtain balancing services from BPA
- Removal of the Specified Energy penalties
- Allowing additional process to review non-price and "generic fill" scoring
- Removal of the threshold requirements to provide a letter of credit, tax opinion and confidential bid pricing information
- Removal of the preferred commercial operation ("COD") date, language precluding capital additions and damages cap

Overall, NIPPC agrees with the IE assessment (the "IE Report") that there are too many threshold requirements in PGE's RFP and too much emphasis has been placed on non-price factors.[1] To level the playing field between PGE's Benchmark bid and power purchase agreement ("PPA") bidders, NIPPC recommends the Commission remove all of the anticompetitive elements, including the requirement for firm transmission, the PURPA restrictions, the unreasonable scheduling and delivery requirements (i.e., "Specified Energy"), and PGE's refusal to allow bidders to use the same kind of dynamic transfers (i.e., pseudo-ties) that PGE uses for its own off-system variable resources. NIPPC also asks the Commission to provide additional process to evaluate PGE's non-price and generic fill scoring.

While each of the issues addressed in these comments deserve the Commission's careful scrutiny, NIPPC cautions that transmission is the most important issue in this RFP by far. If the Commission does not get the transmission issues right, there is no way this RFP will be fair. The Commission can resolve most of the transmission issues by recognizing that PGE has or will have excess transmission available and direct PGE to allow non-utility bidders to use that transmission.

NIPPC is also concerned that much of the conversation surrounding this RFP is out of context with the Commission's decisions regarding PGE's integrated resource plan ("IRP"). In this RFP, PGE is seeking renewable energy that will provide renewable energy credits ("RECs") to meet PGE's long-term renewable portfolio standard ("RPS") obligations. PGE is not seeking a capacity resource to meet peak load. The types of generation being procured here (likely wind and solar) are not dispatchable. It makes

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[1] IE Report at 2, 3 (Apr. 6, 2018) ("All bidders want to know that they are competing on a 'level playing field,' and that they can win the RFP by offering the best deal in terms of price and risk allocation"). NIPPC also agrees that PGE's Benchmark bid should be held to its assumptions regarding cost and operating performance. Id. at 8-9 ("This will help ensure a level playing field for all offers.").

littles sense to issue an RFP that requires PGE's Benchmark and non-utility developers to pair those kinds of resources with firm transmission service in all circumstances. PGE's ratepayers should not be required to pay the full cost of firm transmission (with 100% availability and increased balancing costs) to deliver generation resources where the primary value is for energy and RECs (with a 35% capacity factor). Delivering renewable energy (at a 35% capacity factor) on firm transmission (with 100% availability) is also an unnecessarily wasteful use of the limited transmission capacity on Bonneville Power Administration ("BPA"). Instead, the Commission should allow more flexible and creative uses of transmission to ensure that ratepayers do not miss out on significantly lower cost generation.

II. COMMENTS

Most of the issues NIPPC highlights in this RFP appear to have been designed by PGE to limit the number of bids that can compete against its Benchmark bid. As the IE Report acknowledges, limiting the bidder pool is bad for ratepayers.[2] The IE cautions "[i]n an RFP such as this, which features a large self-build project offer which will presumably meet all [of PGE's threshold] requirements we think it better to err on the side of allowing more offers in."[3] The Commission should embrace this strategy and affirmatively act to expand the number of bids that are able to compete in PGE's RFP.

NIPPC appreciates Staff's efforts to quantify all of the issues raised by parties in the Staff Report. It is important to note that Stakeholders are disadvantaged by the accelerated schedule in this docket, a problem created by PGE's delays in releasing the

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[2] Id. at 2 ("fairness and transparency attract bidders and encourage them to bid aggressively … and the more competitors, the more likely that ratepayers will enjoy net benefits").

[3] Id.

RFP and refusal to work with the parties to address issues prior to the RFP's release. Stakeholders may not have had the time to thoroughly scrutinize all of the issues with PGE's filing, and that is a problem entirely of PGE's creation. PGE's failure to proactively even identify issues that it knew would be a concern has hampered the ability of the Commission to fairly evaluate the RFP. For example, NIPPC has been raising issues with PGE's anticompetitive transmission use for years, and PGE should have explained in its initial draft RFP why it elected to use its transmission assets and rights to favor its own resource. Instead, PGE refused to provide this information. PGE withheld key information in its initial filing—in a proceeding that had to be expedited due to PGE's own delays. This effectively allows PGE to successfully impose many restrictions that limit non-utility ownership options simply because there is a lack of time to adequately review, analyze and resolve them. NIPPC therefore asks the Commission to carefully consider how each of these issues affects the overall fairness of PGE's procurement process.

A. PGE is Using Transmission to Limit Competition

Above all else, the transmission problem is tantamount. PGE should be using its transmission assets to ensure the best deal possible for its ratepayers and to maximize its ability to integrate new resources into its generation portfolio. Instead, PGE is using its transmission to ensure that utility-owned generation can out-compete other bidders. PGE's claim that its transmission rights are the result of shareholder investments rather than ratepayer investments[4] does not mean that PGE should use its transmission assets

[4] PGE's Reply at 5 (Apr. 13, 2018). PGE's admission that it has 675 MW of deferred transmission rights on BPA's system is inconsistent with its responses to

anti-competitively. Unfortunately, stakeholders do not have time to verify PGE's claims regarding who paid for its existing transmission assets (including those deferred) under the accelerated schedule requested by PGE, but the Commission should not rely upon unverified factual information. The Commission should at a minimum recognize PGE is using transmission to favor utility-ownership options over PPAs and direct PGE to remove threshold requirements as a threshold requirement and affirmatively allow non-utility bidders to calculate their bid price using PGE's transmission. At a later date, the Commission should separately confirm whether PGE's transmission rights are bought and paid for by PGE's ratepayers, as this issue is likely to be of import going forward.

By sanctioning an unfair RFP, the Commission will make it harder to identify the lowest cost and risk option and expose PGE's ratepayers to harm. The Commission must make changes to PGE's transmission requirements to avoid another PacifiCorp RFP scenario in which there are claims by some parties that the RFP is unfair because transmission limitations too significantly reduced the pool of bidders. PGE's RFP will likewise remain contested if the Commission does not correct these transmission problems. All issues need to be satisfactorily resolved now rather than when PGE brings its short list in for acknowledgment.

PGE says its Benchmark bid will face the same requirements as other bids and Staff is convinced that should alleviate stakeholders concerns.[5] It does not. Imposing an inherently unreasonable requirement that PGE-owned resources may be uniquely qualified to meet does not make the RFP fair. While the Staff Report highlights many of

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NIPPC in LC 66 where PGE denied having any rights that were not reported to the Commission.

[5] Staff Report at 12 (Apr. 23, 2018).

the important ways that PGE is able to use transmission anti-competitively, it falls short of actually protecting bidders and ratepayers. As Staff points out, for example, neither PGE nor the IE even commented on the South of Allston constraint[6] or its impact on potential bidders.[7] And as NIPPC points out, the requirement to secure long term firm transmission in and of itself limits competition tenfold.[8] The Commission should not allow PGE to use its transmission to limit competition and must go beyond the modifications proposed in the Staff Report to ensure PGE's RFP is fair.

1. Requiring Long Term Firm Transmission Reduces Bidders

PGE should not be permitted to require long term firm transmission in this RFP. As both NIPPC and the IE noted, because PGE has determined its interface with PacifiCorp is not usable in this RFP, the majority of the bids are expected to come from BPA service territory.[9] This requirement in and of itself affects which projects will be able to compete with PGE's Benchmark bid. While the IE believed "requiring a plan to achieve firm transmission service is reasonable" it also noted that "it would be beneficial to remove the current restriction [requiring a nearly-complete firm transmission process] in order to allow more bids to participate."[10] The IE suggested PGE replace its more stringent requirement with the language used in PacifiCorp's current RFP, which merely requires that firm transmission has been requested.

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6 Id. at 13.

7 Staff similarly points out that neither the PGE nor the IE address Montana Wind. PGE's failure to address Montana Wind is inconsistent with the Commission Order No. 18-044. Id. at 14.

8 NIPPC Comments at 8 (Mar. 30, 2018) (comparing BPA's interconnection queue of 18,000 MW to the 1,365 MW of available transmission).

9 IE Report at 3.

10 Id. at 4.

It is important to consider that PGE is not seeking a new capacity resource here. This RFP is for renewables resources that will provide RECs to meet PGE's RPS obligations. Renewable generation has a meaningful and reliable capacity contribution, but it is still variable. Assuming that these resources will have a capacity factor under 50%, it is not clear why this project needs transmission capacity 24 hours per day, 365 days per year, for 10 or 20 years. If a project could obtain conditional firm transmission, which provides 95% availability, why should it be disqualified? PGE's argument that it needs long term firm transmission for reliability is a red herring because renewable resources already have a certain degree of variability and are not available 100% of the time anyway. NIPPC maintains its position that bidders should be allowed to provide other options, like conditional firm transmission, to bring their power to PGE's system. The costs savings are staggering and the risks are minimal.

PGE's contention that this would allow BPA to curtail the new resources and expose PGE ratepayers to increased risk is not reasonable in the context of this particular RFP.[11] Staff presents this as a balance between risk and cost, and states that it is not entirely convinced either side is correct.[12] Because PGE has stated deliveries must occur through its interface with BPA, and those rights are difficult to obtain quickly, this issue has a significant impact on bidder eligibility.

In its Reply Comments, PGE states it will allow bids that are earlier along in the transmission acquisition process. This is not adequate because long term firm transmission should not be required in the first place. The Commission should direct PGE to either relax the firm transmission requirement and allow bidders to propose more

11 PGE's Reply at 6-8.
12 Staff Report at 13.

creative solutions or adopt the IE's proposal that bidders merely provide a plan to acquire transmission.

2. PGE Has Excess Transmission Rights, Some of Which Are Obvious

The IE agrees with NIPPC that PGE should not be permitted to use its existing transmission rights, which derive from PGE's status as a network provider, to advantage its Benchmark bid.[13] According to the IE,

> PGE has been clear that the benchmark will be required to make the same demonstrations as other offers but it has yet to say how the bid will fulfill its obligation to present a plan to acquire third-party service (presuming that it will be located outside of PGE's service territory). **If the bid is relying on reserved PGE transmission capacity then this capacity should be made available to all bidders.** PGE should publically inform potential bidders as soon as possible if this is the case. If PGE is acquiring new capacity in anticipation of serving load with the benchmark offer and the offer is not selected they should not be allowed to use that capacity to serve native load; in other words, they should be required to bear the same risks as other developers.[14]

Staff does not appear to have determined *whether* PGE was holding excess transmission rights, but similarly states that "[i]f PGE is holding transmission rights in excess of its need, then requiring long term firm transmission limits competition"[15]

NIPPC reiterates that PGE currently has excess rights, which presumably costs either PGE's ratepayer or shareholders to maintain.[16] The full extent of PGE's rights may be difficult to identify in OASIS, due to agreements made in connection with BPA's first Network Open Season settlement. But for simplicity sake, NIPPC has also pointed out that 500 MW associated with PGE's Boardman rights will be "excess rights" when

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13 IE Report at 4.
14 Id. at 5.
15 Staff Report at 8.
16 PGE asserts that its ratepayers hold the majority of its long-term firm BPA transmission rights and that its shareholders hold an additional 675 MW of deferred rights. PGE's Reply at 4-5.

that plant it retired. This means that by not allowing bidders to repurpose the Boardman transmission, PGE is effectively hoarding those rights. By hoarding transmission rights, rather than making them available to bidders, PGE is able to drastically limit its competition in this RFP.

Despite acknowledging it holds more than 1,500 MW of transmission rights in excess of its peak load requirements, PGE nonetheless claims it does not have excess rights according to the 1-in-10 methodology, because its existing rights may be needed to serve peak load.[17] Staff has verified PGE's calculation and agrees that PGE is correctly calculating its peak demand, but notes that this calculation underscores the idea that long term firm transmission may not be needed, as PGE "will likely attempt to sell this transmission in non-peak times."[18]

Staff is correct that this calculation demonstrates that long term firm transmission is not needed, but fails to point out that PGE's entire argument rests on a faulty premise. The comparison should be whether PGE has more BPA point-to-point transmission reservations than it has generation interconnected to BPA's system. PGE compared its BPA transmission rights to its entire peak load. This is the wrong metric because PGE has resources that are directly connected to its own system and do not need any BPA transmission. Staff should expressly state whether it has investigated PGE's holdings on OASIS to determine whether PGE is hoarding other transmission rights, or whether the Boardman transmission should be made available to bidders.[19] NIPPC has strong

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17 Id. at 4.

18 Staff Report at 8.

19 PGE's Reply at 7 ("PGE can support CREA's recommendation that the Commission audit the application of PGE's BPA transmission rights.").

concerns that PGE is using out-of-context factual information to undercount its available transmission.[20]

The premise of PGE's argument is also off-base in the context of this RFP, however, because PGE is not seeking a capacity resource. The 1-in-10 methodology PGE refers to is a reliability metric that governs PGE's ability to meet its load obligations.[21] Yet PGE is seeking new resources that are not going to be the dispatchable capacity needed to ensure load service. The new renewable resources will provide cost-effective RECs to put PGE on a better "glide path" to meet its long-term RPS obligations. While renewables provide some important capacity value, this in an energy RFP that should focus on how PGE uses its transmission portfolio for the entire year (or the other roughly 36,500 days in the ten-year period) rather than one day in 10-year scenario.

Finally, rather than provide real flexibility on the firm transmission requirement, PGE has decided to allow bidders an additional year to establish their firm transmission service.[22] Simply changing from a one-year to a two-year bridge to establish long term firm transmission is not useful to bidders because BPA's South of Alston is unlikely to ever be completed. Staff says it appreciates this change, but maintains its overall concerns about the requirement to acquire long term firm over other options, like

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[20] E.g., PGE claims that it has only 949 MW of transmission with a point of origin at the Slatt substation rather than the 1,744 MW shown in its rate case workpapers. PGE claims that the larger amount of transmission is not available because it is in deferral status. Attachment A (PGE Response to Staff data request 145 in UE 335). BPA deferrals are for one year increments. PGE should be open to activating these deferred rights to minimize the cost of transmission service for its rate payers. Otherwise, PGE is asking new projects to finance upgrades of the transmission system; when there is currently unused capacity sitting idle in deferral status.

[21] The 1-in-10 methodology refers to an annual capacity need based on a reliability target of losing load one day in 10 years—or 2.4 hours per year.

[22] PGE's Reply at 10.

conditional firm.[23] NIPPC agrees, but believes that the Commission should go further to recognize that conditional firm on BPA's system is curtailed only a small number of hours every few years, if at all. NIPPC asks the Commission to direct PGE to allow other transmission options, like conditional firm, to provide ratepayers significant cost savings and allow more bidders to participate.

B. PURPA Limitations Are Unnecessary, Illegal and Should Be Removed

With respect to PURPA, PGE states that its RFP "was designed to protect the sanctity of contracts" and "should not incent or provide the basis for project owners to breach their agreements or allow project owners to game the system."[24] In its Reply Comments, PGE clarifies that qualifying facilities ("QFs") with existing contracts can participate in this RFP, but states that PGE "makes no commitment as to whether it would be willing to mutually terminate an existing Schedule 202 contract."[25] Staff suggests this is an "optimal solution."[26] It is not. This does not address whether an independent power producer ("IPP") should be required to give up their future PURPA rights should they be the winning bidder.

PGE ignores that its Schedule 201 contracts (which apply to QFs under 10 MW) expressly prohibit QFs from securing a new PPA with a more advantageous rate. This means that the prices and terms available to PURPA projects in any new contract that might win the RFP would be limited to those in their existing (and soon to be) terminated

23 Staff Report at 11.
24 PGE's Reply at 18.
25 Id. at 19.
26 Staff Report at 7.

contract.[27] While PGE's Schedule 202 contracts are negotiated, and not publicly available, it stands to reason that similar provisions have likely been included. Also, PGE only has a couple existing Schedule 202 contracts, and it is not clear why either of those potential bidders would not be preferred by PGE if they were able to offer the lowest cost and risk bid in this RFP. Because PGE already has the power to ensure ratepayers are at worst neutral (and at best receive a cost savings) in this scenario, it is not clear why PGE is being so resistant to allowing PURPA projects to participate.

PGE's potential willingness to allow a QF with a Schedule 202 contract is an almost meaningless concession. There is only one QF that has been able to obtain a Schedule 202 contract. The more likely situation is that a QF with a Schedule 201 PPA will want to re-size the planned 10 MW facility and bid into the RFP with a much larger facility. That kind of QF may be more than willing to agree to a lower price per kilowatt hour in exchange for the right to achieve economies of scale and sell power under a new PPA.

There is no benefit to ratepayers associated with PGE's proposal to forever bar an IPP that defaults on its PPA from selling power as a QF. The only benefit is to PGE's shareholders by limiting the pool of available non-utility generators that can sell power to PGE in the future. Consider how PGE's proposal would work. A developer defaults on their contract with PGE. Then the developer wants to sell their power again to PGE as a QF. Or more realistically, a new developer purchases the generation asset and wants to sell power to PGE as a QF. The new contract would need to contain provisions,

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27 Re Commission Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities, Docket No. UM 1129, Order No. 06-538 at 29-30 (Sept. 20, 2006).

including pricing provisions, at least as good as the original and terminated contract ensuring ratepayers are held harmless. The practical result is that PGE has successfully ensured that this generation resource (and its potential competitor) can never sell power to PGE again.

In addition to being unnecessary, PGE's requirement to waive future PURPA rights is also illegal. According to the Federal Energy Regulatory Commission ("FERC") precedent, PGE cannot contract away a QF's PURPA rights in perpetuity.[28] Thus, the Commission should direct PGE to remove its PURPA restrictions.

C. PGE's Refusal to Pseudo-Tie New Resources Also Limits Competition

PGE can offer a lower Benchmark bid price knowing that it can dynamically transfer its own resources and avoid incurring BPA's balancing costs. This means that PGE's refusal to dynamically transfer the new resource—and its insistence that bidders imbed balancing costs in their bid—may alone ensure that PGE will be able to out-compete other bidders. Although PGE claims that PPAs cannot be pseudo-tied, that is incorrect.[29] As Staff points out, PGE did not comment on the competitive advantage this provides self-build options.[30] In these comments, NIPPC addresses 15-minute scheduling, PGE's Specified Energy penalty and BPA balancing service and escalation costs in this same group to point out that all of these issues could be avoided if PGE would simply treat any new resources the same way it treats its own resources. This

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[28] NIPPC Comments at 19 (citing Delta Montrose, 151 FERC ¶ 61,238 (2015)).

[29] While PPA bidders cannot negotiation a pseudo-tie as an element of its bid, PGE can establish a pseudo-tie with BPA to bring the new resources into its BAA. As such, PGE should allow PPA bidders to price their bids based upon real-time delivery to PGE as the power is produced, and remove the requirement to obtain balancing services from BPA.

[30] Staff Report at 11.

would mean that PGE agrees to take title to the electric energy of the generation resource at the busbar and allow PPA bidders to use PGE's transmission portfolio to deliver the output to load or elsewhere. This could allow PPA bids to compete more equitably with both PGE's Benchmark bid and any potential asset sales.

PGE provides several inaccurate reasons why a PPA cannot be pseudo-tied into PGE's balancing authority area ("BAA"). First, PGE claims that allowing "third-party pseudo-ties would create onerous contracting and settlement requirements."[31] This ignores that PGE's 2012 RFP "accept[ed] bids proposing to deliver intermittent resources via dynamic transfer" and could do so again here.[32] As Staff point out, PGE's customers bought the Port Westward 2 facility so PGE could balance new variable generation resources.[33] Next, PGE states that pseudo-ties "would shift costs and risk to PGE" but does not provide any cost-analysis or acknowledge that this could also significantly reduce the costs of transmitting energy for PGE's customers. Finally, PGE claims pseudo-ties "could jeopardize PGE's safety and reliability" while simultaneously acknowledging that it allows pseudo-ties for its own off-system wind resources.

In effect, PGE takes the position that the only generation resources that will be allowed to pseudo-tie into PGE's balancing authority are generation resources owned by PGE's shareholders. PGE points to unidentified reliability issues with accepting a pseudo-tie from resources owned by IPPs. However, this alleged reliability issue with accepting pseudo-ties from IPPs is a problem that other transmission providers and balancing authorities do not experience. For example, the California ISO, which

31 PGE's Reply at 13.
32 NIPPC Comments at 13 (citing PGE RFP for Renewable Resources, OPUC Docket No. UM 1613, PGE Revised Draft RFP at 26 (Sept. 10, 2012)).
33 Staff Report at 9.

obviously owns no generation resources at all, has had no trouble accepting pseudo-ties and other forms of dynamic transfers from any generator (regardless of ownership) for at least a decade.[34] It has had tariffs approved implementing both imports to its balancing authority ("BA") and exports from its BA of dynamic deliveries. Indeed, any BA in a regional transmission organization ("RTO") and independent system operator ("ISO") region would also be accepting pseudo-ties from generation resources it does not own. Yet numerous ISOs and RTOs across the country accept such pseudo-ties every day.

If the Commission endorses PGE's argument, the Commission will itself be cooperating in a discriminatory transmission policy. As FERC noted in Order No. 888, the keystone in the regulatory architecture supporting FERC's current market-based approach to electricity regulation, "[n]on-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition."[35] PGE's acceptance of pseudo-ties, and other forms of dynamic scheduling, must occur under the same non-discrimination principles that apply to any other form of transmission.[36] FERC

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34 California ISO Corp., 107 FERC ¶ 61,329 at P.24 and Ordering Paragraph A (2004) (approving dynamic transfer tariffs).

35 Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed.Reg. 21,540, (1996), FERC Stats. & Regs., Regulations Preambles 1991-1996 ¶ 31,036, at 31,652 (Apr. 24, 1996); order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs., Regulations Preambles 1991-1996 ¶ 31,048 (Mar. 4, 1997); order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997); order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd, Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd, New York v. FERC, 535 U.S. 1 (2002).

36 See Order No. 888-A, at P.630 (Mar. 4, 1997) ("to the extent a transmission provider currently accepts telemetered generation schedules for its native load, the transmission provider must accept such schedules from its network customers on a comparable basis").

has made clear that transmission providers may not raise "unreasonable obstacles to dynamic scheduling,"[37] and just as with all other forms of transmission a dynamic transfers must "be available on a not unduly discriminatory basis to all similarly situated parties that wish to use them."[38] Even though FERC's requires non-discriminatory transmission offerings, PGE asks this Commission to thwart that policy by arbitrarily making the most advantageous forms of intra-hour and dynamic delivery available only to PGE-owned generation.

In fact, and even more amazingly, PGE recently argued to FERC that *PGE*, as a BPA transmission customer, should be awarded dynamic transfer capacity on BPA's system on a non-discriminatory basis as compared to other generation owners:

> Because [Dynamic Transfer Capacity ("DTC")] on BPA's system is so limited, PGE must ensure that its current and future DTC rights that will be used to serve PGE load will not be impacted by the [California ISO Energy Imbalance Market ("CAISO EIM")]. The increased flows and DTC usage in PacifiCorp's BAAs and any future Pacific Northwest BAA that joins CAISO EIM must be considered and evaluated thoroughly. *PGE requests that the Commission ensure that DTC is awarded in a non-discriminatory and transparent manner*.[39]

Just as PGE itself argued, non-discriminatory use of dynamic transfer capacity on BPA's system must be available to use by IPPs hoping to provide PGE a lower cost resource than PGE can itself deliver. The Commission should not allow PGE to engage in a practice of unlawfully refusing to deal with its competitors in the generation sector who wish to deliver energy to PGE's BA using such dynamic deliveries.

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37 New Horizon Electric Cooperative, Inc. v. Duke Power Co., 95 FERC ¶ 61,146 at 61,470 (2001).

38 PJM Interconnection, LLC, 134 FERC ¶ 61,048 at P.36 (2011).

39 PGE Comments on the PacifiCorp-California ISO EIM, FERC Docket ER14-1386-000 at 5 (Mar. 31, 2014).

Essentially, PGE asks the Commission to believe that it may not be safe or cost effective for PGE to pseudo-tie variable resources, despite the fact that it previously allowed this in the 2012 RFP and subsequently decided to pseudo-tie its Biglow and Tucannon windfarms. Despite this long history, PGE states that it *might* determine *later* that it could more broadly integrate resources this way.[40] This is a glaring example of utility bias, and illustrates the lengths that PGE will go to ensure it has the winning bid in its RFP. With so many cost advantages at stake, the Commission should direct PGE to allow bids proposing to deliver via dynamic transfer. Allowing bidders to submit bids based upon real-time delivery of actual project output to PGE, rather than requiring PPA bidders to assume 20 years of costs to have an intermediary (BPA) perform balancing services for PGE precludes PGE ratepayers from receiving future benefits from participation in the EIM.

1. Requiring BPA Balancing Services Adds Unnecessary Costs

As NIPPC points out ancillary services are expected to be a substantial portion of a PPA's bid, because PGE is requiring bidders to obtain BPA balancing services and imbed them into their bid price. PGE ignores that paying *any* BPA balancing charges may be completely unnecessary if PGE ultimately decides to make the new resource an EIM resource, or if it agrees to accept a pseudo-tie from such resource. This is especially significant because balancing charges could add up to 2/3 of the costs over a 20-year term. Rather than require PPAs to imbed the these prices, PGE could just assign the prices it has estimated for its Benchmark bid and agree to handle balancing in whatever fashion it determines is best.

[40] PGE's Reply at 14.

PGE states that it is requiring bidders to provide balancing services "to ensure the 2018 RFP is fair and equitable" but does not acknowledge that it would actually be more fair if PGE did not require bidders to provide BPA services. The cost projections are highly speculative and PGE could simply assess the same rate it plans to use on its Benchmark bid to all of the other bids. This would actually be more equitable and transparent.

2. Not allowing 15-Minute Scheduling Adds Unnecessary Costs

The IE acknowledges that 15-minute scheduling is intended to reduce integration costs for renewable resources and noted it was "unclear as to why [a 60-minute scheduling] requirement is in the RFP." The IE therefore requested PGE provide an explanation in its comments. In its Reply Comments, PGE suggested that the 15-minute scheduling would shift costs from the project owner to PGE, perhaps due to EIM scheduling requirements.[41] Staff took a different approach in evaluating this issue. Staff argues that because the Port Westward 2 facility was paid for by customers to pay the costs associated with balancing intermittent resources, PGE should be able to balance the new generation resources.

NIPPC agrees that the costs of balancing generation are real, and will be paid by someone, but points out that the entire reason for allowing 15-minute scheduling is to reduce balancing costs assessed by BPA. The larger issue here is whether balancing costs are going to be paid to BPA (in the case of the 60-minute scheduling) or incurred entirely by PGE (in the case of a pseudo-tie). Allowing 15-minute scheduling would be a hybrid result with reduced balancing costs paid to BPA and additional variability for PGE

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41 Id. at 11.

to balance with either its Port Westward facility or other resources in PGE's BA, which could involve EIM costs.

At bottom, NIPPC agrees with Staff that PGE is equipped to balance the new generation resources within its own BA, and that it placed a major resource in rate base very recently for that express purpose. This is how PGE was able to pseudo-tie its own resources out of BPA's BAA and completely avoid paying these costs to BPA. The Commission should require PGE to similarly absorb these costs for its PPA resources—just like it would for its own generation resources. If the Commission decides not to require PGE to pseudo-tie the new resources, at a minimum, it should require PGE to allow 15-minute scheduling to minimize the amount of BPA balancing services that will be necessary.

3. PGE's Specified Energy Concept Penalizes PPA Bidders

The IE agrees with NIPPC that PGE's Specified Energy concept should be removed. The IE described PGE's scheme as "both an overly tight ceiling and an extreme penalty to place on a PPA bidder" and cautioned that it "could serve bidders into offering utility ownership options."[42] Staff considered it a competitive imbalance between PPA and self-build options and recommends that PGE either modify the Benchmark bid to face similar risk or remove the Specified Energy concept entirely.[43] NIPPC is not certain how the Benchmark bid could be modified to face similar risk and

[42] IE Report at 6. The concept is so odd, and blatantly discriminatory, that the IE had to admit "[i]t is certainly possible that this was not PGE's intention, or that we are not reading the contract correctly, but the fact that other interveners have pointed out this issue means that it is likely not clear." Id.

[43] Staff Report at 4.

reiterates that this problem could be eliminated if PGE would simply agree to accept bids that deliver project output to PGE as it is generation.

4. PGE's BPA Escalation Costs Should be Published

NIPPC appreciates Staff's acknowledgement that BPA's escalation Rate poses a significant risk for PPAs and skepticism of PGE's proposal. PGE suggested that bidders submit variable and fixed costs, including balancing costs as variable instead.[44] That does not work because the costs should be put on the benchmark side of the ledger. Staff notes that requiring PGE to publish the escalation cost assumptions for the Benchmark bid is a simpler solution. NIPPC agrees with Staff's observation and therefore requests the Commission direct PGE to publish this information. While publishing PGE's escalation rates provides transparency, requiring PGE to accept unbalanced energy delivered to PGE would provide a more equitable solution.

D. Non-Price Points Lead to Opaque Subjective Scoring and Should Be Minimized

The IE agreed with NIPPC that the PGE's 60/40 split relied too heavily on non-price factors. The IE proposed two options, either: 1) adjusting the scoring to a 80/20 split (like PacifiCorp's current RFP) or a 70/30 split (like PacifiCorp's past RFPs); or 2) allowing the IE to run sensitivities to see if any offers were unfairly excluded from the short list.[45] PGE says 60/40 is the norm, but agreed to the additional sensitivity.[46] Staff says that is ok, but "expects a stronger explanation of why the specific split chosen is

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44 PGE's Reply at 13.
45 IE Report at 8.
46 PGE's Reply at 17.

appropriate in future RFPs."[47] NIPPC reiterates that PGE's non-price score could very easily outweigh the price score. The lack of transparency regarding non-price scoring should concern the Commission. There is no reason PGE cannot adequately account for risk using the same 80/20 split that PacifiCorp finds appropriate. Nevertheless, NIPPC recognizes that additional up-front process to revise the scoring system is problematic at this stage and can accept the IE's recommendation to conduct sensitivity analysis to determine whether any bids are unfairly excluded from the short list. NIPPC does not believe, however, that this goes far enough. A second sensitivity analysis should be performed on the final short list after evaluations are complete. The Commission should then allow additional process so that stakeholders can review the sensitivities performed on short list. This is the only way to address whether the 60/40 split can be seen as appropriate (here) or equitable (going forward).

NIPPC also identified specific concerns with PGE's non-price factors, which PGE did not respond to. These are located in Attachment B to NIPPC's initial comments. NIPPC incorporates by reference into these comments. Since PGE has elected not to respond, PGE has failed to rebut their reasonableness, and the Commission should adopt them.

E. Generic Fill Manipulates Bid Pricing and Requires More Transparency

Staff expressed concern for PGE's use of "generic fill" costs when comparing PPAs with shorter time periods to PGE's Benchmark bid. Similar concerns have been addressed in the Commission's competitive bidding investigation and rulemaking

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47 Staff Report at 12. Separately, Staff notes price reductions from negotiations are inconsistent with Guideline 6 and recommends removing the redline penalty. Id at 4. NIPPC agrees this penalty should be removed.

proceedings.[48] PGE's commitment to perform a planning horizon sensitivity analysis does not adequately address these concerns due to the overall lack of transparency. The Staff Report does not address what will happen if those sensitivities reveal there was an impact on the short list. Additional process is therefore needed.

F. PGE's Interconnection Requirement is Not Reasonable

NIPPC argued that bidders should not be required to have a completed interconnection agreement to reach the short list, because much of that process is out of a bidder's control. The IE pointed out that PGE's interconnection requirements were inconsistent, lacked clarity, and could be used to limit potential bidders.[49] PGE modified the requirement to provide more flexibility and clarity, but maintained that it could not "provide a blanket waiver for interconnection delays and put at risk the potential to capture expiring tax credit benefits for customers."[50] NIPPC again points out that PPA bids embed all of the risk associated with losing expiring federal tax credits[51] in their PPA score. Thus, PGE should explain how allowing for reasonable interconnection delays in PPA bids would put customers at risk?

G. Other Onerous Eligibility Requirements Imposed Upon PPA Bidders

There are several other requirements, like obtaining an interconnection agreement, that are not fair to PPA bidders. For example, the IE stated that PGE's permitting requirement should not be a threshold obligation. PGE responded by changing this from an eligibility requirement to a non-price score. Staff was amendable

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[48] The parties in Docket No. UM 1776 (the competitive bidding guideline investigation) held a workshop on February 15, 2017 addressing how utilities evaluate resources with different terms that addressed "generic fill" concerns.

[49] IE Report at 4.

[50] PGE's Reply at 10.

[51] Either Production Tax Credit ("PTC") or Investment Tax Credit ("ITC").

to that change.[52] As discussed above, both NIPPC and the IE believe that PGE relies too heavily on non-price scoring. Adding more non-price considerations does little to make the RFP more fair.

PGE's RFP imposed other onerous requirements on bidders that were not addressed in the Staff Report. For example, NIPPC objected to PGE's requirement that bidders provide a letter of credit from a qualified institution, which may prevent smaller companies from submitting bids.[53] This is unnecessary because PGE also requires a good faith commitment from a financial institution. These two requirements are duplicative. NIPPC also objected to PGE's requirement that bidders provide confidential quote information or purchase documentation, noting that this kind of confidential information may be reasonable for bids on the short list, but should not be an eligibility requirement.[54]

H. PTC Assurances and COD Extension Are Unnecessary

NIPPC pointed out that PPA bidders should not be required to provide a tax opinion stating that they are able to take advantage of the PTC because those tax savings are included in the bid price. If the project is not able to qualify for the PTC in the end, the project still receives the PPA price. Neither PGE nor any of the other stakeholders commented on this issue. The Staff Report suggests this may be "part of a broader question surrounding PURPA" and stated "the stakes are low either way." NIPPC does not understand why this would be considered a part of a broader question surrounding PURPA. And because Staff understands the stakes are not low (i.e., zero), the Commission should direct PGE to modify its RFP to remove this requirement.

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52 Staff Report at 14.
53 NIPPC Comments at 21.
54 Id. at 30.

Similarly, NIPPC agrees with AWEC that PGE's COD provisions are not reasonable since projects can qualify for full federal tax credits with later CODs. AWEC explains that PGE's "preferred" 2020 online date is not appropriate because the federal safe harbor provisions allow renewable resources to come online as late as 2023 and still receive the full tax benefit.[55] PGE did not comment on this issue and Staff does not think any change is necessary, suggesting "an extension of this deadline to the last possible COD" may lead to benefits that do not appear to justify the costs.[56] NIPPC believes the benefits, namely increasing the amount of potential bidders, justify any nominal costs, which are unclear. The Commission should therefore direct PGE to extend the COD to allow all bidders that can take advantage of the federal tax credits to compete.

I. PGE Should Not Preclude Project Owners From Making Improvements

NIPPC pointed out that PGE's PPA unreasonably limits project owners from making capital improvements to their projects. PGE's long term resource planning shows an increasing need for renewable power, but if PGE were concerned about near-term capacity increases from the winning bidder, then PGE should just add contractual limitations to the amount of power PGE is willing to buy rather than try to limit capital additions to the project.[57] As written, PGE's PPA binds property owners from making business decision that may not effect PGE at all. PGE did not address this issue in its

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55 AWEC Comments at 2-3 (Mar. 30, 2018). The PTC will have phased partially out by 2023, even under the safe harbor, but the full ITC will still be available.

56 Staff Report at 15.

57 PGE already has similar provisions in its PURPA contracts. See PGE Schedule 201 at Section 4.3, available at https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/sell-power-to-pge (allowing capital additions, but capping the prices available for capacity increases above the standard size threshold).

comments, but the Staff Report did. Curiously, Staff's entire assessment of this issue states:

> Similar to [PGE's permitting requirement], Staff believes this is part of a larger PURPA discussion. For this RFP, however, PGE at a minimum should justify the need for this provision: where has this been a problem before?

Although NIPPC does not see this as part of a larger PURPA issue, it is clear that Staff believes that PGE should "*at a minimum*" explain why it needs this kind of protection and identify whether this is even a legitimate problem. Even still, Staff has failed to include any such requirement with the conditions and modifications listed on page four of the Staff Report. NIPPC asks the Commission to confirm this is not a PURPA issue and direct PGE to remove this language from PGE's PPA.

J. PGE's Damages Cap is Not Reasonable

PGE proposed bidders agree to a $100,000 damages cap. NIPPC pointed out that this cap was unreasonable.[58] We also reminded the Commission that the Supreme Court of Utah affirmed a jury award of more than $133 million to compensate a developer for the loss of this exact type of information after a Utah jury found that PacifiCorp "willfully and maliciously misappropriated a trade secret from USA Power . . . ."[59] Staff agrees with NIPPC that PGE's cap is too low.[60] Staff points out that "bids should not face point reductions for modifying/redlining the PPA form" on this issue. But Staff's imprecise recommendation is only that PGE "[s]ignificantly increase the damage cap."[61]

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58 NIPPC Comments at 31-32.

59 USA Power, LLC v. PacifiCorp, 2016 UT 20 (2016).

60 Staff Report at 16.

61 Id. at 4.

As the PacifiCorp award illustrates, even a significant increase could still be inadequate. NIPPC therefore urges the Commission require PGE to remove the damages cap.

III. CONCLUSION

For the reasons described above, NIPPC urges the Commission to adopt the conditions and modifications recommended in the Staff Report; but also asks the Commission require PGE to make the more meaningful changes listed above.

Dated this 30th day of April 2018.

Respectfully submitted,

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Attachment A

UE 335 PGE Response to Staff data request 145

April 5, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 145
Dated March 22, 2018

Request:

Please refer to the minimum filing document #Transmission Summary for Monet 03212017 – Copy.

a. **Does PGE have 1,744 MW of transmission capacity with a point of origin from the Slatt substation? (calculated as the sum of cells F9 through F22 and cells F46 through F51.) If no, what is PGE's total current transmission capacity to ship energy with a point of origin of the Slatt substation.**
b. **Please identify all transmission contracts for the Slatt substation that PGE has released or not renewed in 2016 or 2017.**
c. **Please identify each PGE energy resource that requires transmission through Slatt substation in order to reach customers. Please include the capacity of each resource.**

Response:

a) No. PGE currently maintains 949 MW of transmission capacity with a point-of-receipt (POR) at SLATT.[1] There is one additional Transmission Service Agreement with a POR at SLATT that will be redirected to serve the Coyote Springs generating plant.

Cells F46 through F51 of the referenced worksheet include Transmission Service Agreements that are already included in cells F9 through F22 and Transmission Service Agreements that are not currently active (in deferral status). PGE's response to OPUC Data Request No. 141, Attachment 141-A provides all active Transmission Service Agreements at SLATT making up the 949 MW transmission capacity. Also, see PGE's response to OPUC Data Request No. 140, Attachment 140-B for currently deferred transmission capacity rights at SLATT.

[1] See sum of cells F9 through F22 of the referenced worksheet.

b) PGE did not release or allow to expire any SLATT Transmission Service Agreements in 2016 or 2017. As mentioned in part (a) above, one SLATT Transmission Service Agreement will be redirected to Coyote Springs.

c) The Boardman Plant and Carty Generating Plant interconnect to BPA at the SLATT substation. PGE reported plant capacities in the 2016 Energy Information Administration (EIA) Form 860[2] as follows:
   i. Carty Generating Plant:
      - Nameplate capacity of 500MW;
      - Summer Capacity of 413MW;
      - Winter Capacity of 467MW.
   ii. Boardman Plant:
      - Nameplate capacity of 642MW;
      - Summer Capacity of 585MW;
      - Winter capacity of 585MW.

[2] The plant capacities reported in the 2016 EIA Form 860 are not equivalent to the plant capacities modeled in MONET because of different calculation methodologies.