Attachment A

Rulemaking for Integrated Resource Planning,
WAC 480-100-238, WAC 480-90-238, and WAC 480-107,
Docket No. UE-161024,
NIPPC Comments (Nov. 2, 2016)

BEFORE THE WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

UE-161024

In the Matter of Rulemaking for Integrated Resource Planning, WAC 480-100-238, WAC 480-90-238, and WAC 480-107	)))))))	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION COMMENTS

I. INTRODUCTION

1. The Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these comments regarding the Washington Utilities and Transportation Commission's (the "Commission" or "WUTC") rulemaking to examine whether the Commission's rules related to the integrated resource plan ("IRP") process, energy storage, requests for proposals ("RFP"), avoided costs, transmission and distribution planning, and flexible resource modeling require an update to keep up with recent trends in the energy industry. NIPPC recommends that the Commission significantly modify its RFP and competitive bidding rules to attract innovative resource proposals and achieve lower customer rates by fostering the development of competitive electricity markets and diverse ownership of generating facilities.

2. The Commission's current IRP and RFP rules were adopted in 2006 and have not adequately protected customers from electric utility bias to own electric generation resources rather than enter into power purchase agreements ("PPAs") with independent

power producers ("IPPs").[1] The Commission originally issued competitive bidding rules in 1989 as part of its Public Utility Regulatory Policies Act ("PURPA") implementation with the stated intention of ensuring that regulated utilities were not paying too much for purchased power resources.[2] The original rules also sought to require utilities to compare opportunities in competitive wholesale markets with the cost of utility owned projects.[3] While the latter aim could potentially encourage competitive markets, the process of developing rules and procedures to ensure meaningful competition from the wholesale market have yet to be put in place. Specifically, there are no rules in place to ensure utilities actually undergo any meaningful comparison between building and buying generation, which has stifled meaningful participation in the RFP process and increased customer rates.[4]

3. In 2003, the Commission proposed reviewing its competitive bidding rules to, among other things, ensure effectiveness and efficiency.[5] Despite active stakeholder

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1 For the purposes of these comments, the term PPA can include both traditional PPAs and tolling agreements with an IPP.

2 Re Notice of Inquiry: Examining Regulation of Electric Utilities in the Face of Changes in the Electric Industry, Docket No. UE-940932, Notice of Termination of Notice of Inquiry (Apr. 22, 1998).

3 Id.

4 Compared to other Northwest states that have modest amounts of small scale renewable energy projects, Washington also has not created conditions that would at least allow IPPs to sell their generation through PURPA. Despite similarities to Oregon, PacifiCorp's Washington territory has resulted in almost zero QF development and demonstrates that severe rules will drastically limit the opportunity for new QF development. See WUTC v. Pacific Power, Docket No. UE-144160, Exhibit 1, List of QFs REDACTED (only three Washington QFs with about 4 MW). Washington has a number of significant untapped renewable energy resources that could be developed to benefit utility customers and the local economy if the Commission were to adopt PURPA rules more consistent with other Northwest and Intermountain states.

5 Re Repealing, Amending and Adopting Rules in Chapter 480-107 WAC, Docket No. UE-030423, Notice of Opportunity to File Written Comments and Notice of

involvement and comments over about three years,[6] the Commission ultimately adopted, revisions that did not significantly modify the rules. Generally, the 2006 revisions: 1) removed the requirement to issue an RFP if an IRP does not demonstrate a need within the next three years; 2) permitted bidders to request (and pay for) an Independent Evaluator ("IE") when a utility submits a bid within its own RFP; and 3) clarified how environmental effects should affect ranking criteria.[7] These modifications did little to address utility bias. Although the changes likely increased efficiency of the WUTC's process, they have done little to ensure its effectiveness or advance the Commission's intent.

4. As one might expect from these results, the competitive market has no confidence that the current rules will limit the utilities' bias in favor of owning resources, will ever allow for diversity of generation ownership, or will result in a resource portfolio that is the least cost and least risk to ratepayers. There are very real impacts to the utilities' ratepayers resulting from anticompetitive behavior and discrimination against competitive resource offers. The mere appearance of unfairness chills the market and limits the effort and resources that IPPs are willing to commit to what seems be a losing bid.

5. The Commission needs to act proactively if it is to protect customers because utilities are structurally incented to select ownership options over PPAs due to the fact

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Workshop, (Apr. 18, 2003). WUTC contemporaneously considered revising its least cost planning rules in a separate proceeding under Docket No. UE-030311.

6 E.g., Cogeneration Coalition of Washington and NIPPC requested the UTC review how utilities impute additional costs on long term PPAs due to debt equivalence and the Commission opted to consider the issue on a "case-by-case" basis instead.

7 Re Repealing, Amending and Adopting Rules in Chapter 480-107 WAC, Docket No. UE-030423, Adoption Memorandum at 2 (Feb. 22, 2006).

that utilities can recover their costs and earn a return on their own equity capital investments—no such return is permitted when they purchase power from IPPs. Nevertheless, shareholder value should not trump the Commission's obligation to protect ratepayers by eliminating barriers to competitive markets and ensuring customers are served with a least cost and least risk generation portfolio.

6. Customers will never be fully protected against utility bias unless the Commission acknowledges that a comparison of cost-plus utility-owned bids to competitive bids with fixed prices and contract terms for performance is simply not viable. The difficulty in comparison is because it is impossible to truly compare the unique advantages and disadvantages of the different ownership structures on a head to head basis, especially considering that the utility has an economic incentive to select its own self-built generation resource. The consequence is captive customers paying more costs and assuming more risks than would be the case if there were true diversity of ownership.

7. NIPPC believes that the best way to fully protect customers and ensure the lowest cost and least risk generation costs would be to: 1) bar utilities from owning new generation unless they can demonstrate that the market has failed, or there is some unique and valuable opportunity for ratepayers, which can only be realized through utility ownership; or, alternatively 2) cap utility ownership at a specific percentage. Without structured rules, then it will be difficult for any competitive bidding process to clearly allow for diversity of ownership and the least cost/risk generation for customers. The best of intentions will fall far short of true ratepayer protection as long as utility and IPP resource offerings are evaluated side by side.

8. Despite the inadequacies of the current regulatory construct, NIPPC understands that the utilities will strongly oppose any firm limitations on their ability to pursue self-build of new generation assets. To the extent the Commission does not impose such limitations, NIPPC proposes the second best solution: significant revisions of the Commission's current IRP and RFP rules that will increase the prospects for greater diversity of resource ownership. NIPPC specifically recommends that the Commission:

- Require a utility to hold a Commission-supervised RFP prior to acquiring 50 megawatts ("MWs") or more of new generation resources and certain energy storage with a term of five years or more in an RFP, with limited exceptions;

- Retain an independent evaluator to protect against utility bias and due diligence expert to ensure ownership bids are fairly priced;

- Provide stakeholders an opportunity to comment on both the draft and final RFPs, which must be approved by the Commission;

- Adopt highly-specific RFP scoring and evaluation criteria to ensure that they are transparent to all bidders;

- When the utility could own a generation asset at the completion of the RFP, requiring a two stage RFP with the price scores of the ownership options made available prior to the bidding for the PPA options, which may attempt to "beat" the utility-ownership score;

- If a utility ownership bid wins the RFP, subject the utility's resource short list to an acknowledgement proceeding that has the same effect as IRP acknowledgment; and

- Cap the costs included in rates for utility owned generation at the cost included in the bid used for comparative analysis in the RFP.

II. COMMENTS

1. Customers Benefit from Robust Competitive Electricity Markets and Diverse Ownership of Generation

9. The Commission has long recognized "competition should be accommodated and encouraged" to reduce costs when it can be done in an efficient and fair manner.[8] Competitive wholesale electricity markets in which monopoly utilities are not the sole resource owners have produced significant savings for Northwest ratepayers. Robust competition drives down the costs of all generation resources regardless of ownership and provides significant rate savings for customers. Non-utility ownership in and of itself provides significant cost and other customer benefits because PPAs are more cost effective and reduce risks associated with project failure, construction delays, cost overruns, and poor operating performance. Competitive markets ensure that the shareholders of IPPs rather than the captive ratepayers shoulder the risks associated with development, operation, and management of generation.

10. Electric service in Washington, like most of the United States, has historically been provided by vertically integrated utilities. Electric utility monopolies in Washington, however, are *de facto* rather than *de jure*. While the Washington constitution bars monopolies and the granting of privileges to any citizen that are not granted equally to all citizens,[9] the courts have allowed monopolies as well as the creation of new monopolies.[10] While most Washington utilities operate with bi-lateral

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8 Re the Commission's Notice of Inquiry: Examining Regulation of Elec. Utils. in the Face of Competition in the Elec. Indus., Docket No. UE-940932, Policy Statement- Guiding Principles for Regulation in an Evolving Elec. Indus. at 1 (Dec. 13, 1995).

9 WASH. CONST. art I § 12; id. art XII § 22.

10 E.g., Ventenbergs v. City of Seattle, 178 P.3d 960, 163 Wash.2d 92 (Wash. 2008).

exclusive service territory agreements, Washington law does not explicitly favor service territories. Instead, Washington discourages duplication of electric distribution and transmission facilities, and allows for the creation of exclusive service territories by public utilities and cooperatives entering "into agreements for the purpose of avoiding or eliminating such duplication."[11] Historically, competition has benefited customers, but was generally limited to competition between public and private utilities, with the publicly owned utilities often using (or attempting to use) legal tools, including municipalization, the formation of people's utility districts, and condemnation.[12] This competition between utilities has been referred to as "yardstick competition" by which consumers can compare the rates and service offered by public and private utilities, and select their electric utility through elections.[13]

11. The creation of wholesale competition in Washington and the nation has its start with Congress' enactment of PURPA in 1978 to promote greater use of renewable energy and to force monopoly utilities to purchase power from innovative small and independent power producers.[14] The law's purpose was to diversify the supply of electric power by developing cost-effective non-utility resources.[15] Further Congressional statutes,

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11 RCW 54.48.020.

12 E.g., Tanner Elec. Coop. v. Puget Sound Power & Light Co., 128 Wash.2d 656, 659-664 (1995); Walla Walla Country Club v. Pacific Power & Light Co., Docket No. UE-143932, Order No. 03 at ¶¶ 7-8, 25, 34 (Jan. 15, 2016) affirmed Walla Walla Country Club v. Pacific Power & Light Co., Docket No. UE-143932, Order No. 05 (May 5, 2016) (The Commission rejected PacifiCorp's attempt to impose unlawful charges to prevent a customer from switching electric service to Columbia Rural Electric Association).

13 Showalter, M., Buying and Selling Electric Power in the Northwest, 1, 4 (2000).

14 See Fed. Energy Regulatory Comm'n v. Am. Elec. Power Serv. Ass'n, 461 U.S. 402, 404 (1983).

15 See Fed. Energy Regulatory Comm'n v. Mississippi, 456 U.S. 742, 750-51 (1982).

including the 1992 Energy Policy Act that created Exempt Wholesale Generators, as well as the Federal Regulatory Energy Commission ("FERC") policies and rules implementing non-discriminatory transmission access, market-based rates, and the promotion of competitive wholesale power have led to nearly half the generation in the United States being owned by non-utility independent producers.[16]

12. Robust regional generation surpluses and wholesale competition has helped keep Washington retail electric rates low. End use consumer rates would be higher without this robust market.[17] As explained by PSE, "[f]or a decade, these surpluses have enabled many utilities, including PSE, to use wholesale market purchases to meet load obligations with a high degree of confidence in the reliability of both physical supply and reasonable prices."[18] PSE explains that the energy surplus "has made it less expensive for utilities like Puget Sound Energy to meet its load needs by purchasing energy and capacity in the wholesale market rather than building new generating plants."[19] Essentially, Washington utilities have met their short-term energy and capacity needs with low cost market purchases,[20] which would likely not exist and cost more without a competitive power market in the West.

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16 Jim Lazar, The Regulatory Assistance Project, Electricity Regulation in the US: A Guide at 3.5 (2nd ed. 2016).

17 See e.g., Northwest Power and Conservation Council, Seventh Northwest Power Plan, at 2-4 (May 2016) ("Spot market prices for wholesale power continue to be quite low, due to increasing penetration of renewable resources with low variable operating costs and low natural gas prices, and do not provide an accurate representation of the avoided cost of new resources."); id. at 2-7 ("Increasingly, because of its low prices and apparent adequate supplies, natural gas-fired generation is displacing coal-fired generation.").

18 PSE 2015 IRP at G-4;

19 Id. at G-1.

20 Id.; see PacifiCorp 2015 IRP at 2 (PacifiCorp claims that the least cost and risk plan is to continue to meet its near term resource needs with market purchases).

13. An example of the lower costs produced by the market is PSE's large industrial customer retail access program. PSE's successful direct access program for large industrial customers has operated for about fifteen years and the associated savings have helped keep these businesses economically viable. Notably, none of the customers that left have wanted to return to cost of service regulation, and other industrial and commercial customers are seeking the same opportunities to purchase lower cost and renewable power from the market.

14. In contrast, Pacific Northwest utilities have a long history of developing costlier and riskier generation, including projects that exceeded initial cost estimates, were more expensive than comparable non-utility resources, underperformed, or required early closure or abandonment. All of the Northwest investor owned and many publicly owned utilities have their own unique stories of more expensive utility owned generation in which ratepayers would have been better served if the utility had entered into a long-term PPA, or at least tested the market with a competitive bidding process that would have allowed IPPs a fair opportunity to sell power at lower costs and risks.

15. The region's largest utility resource investment failures were the nuclear plant commitments made by Portland General Electric Company ("PGE"), PacifiCorp (as Pacific Light & Power),[21] Puget Sound Energy ("PSE") (as Puget Sound Power & Light),

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This ends up being a squeeze play on IPPs, as they are not permitted to "play" in the CAISO energy imbalance market (not being BAs), and yet, are cost-effective to PacifiCorp, when deeply discounted in one of the markets they can play in, i.e., spot market.

21 These comments refer to Pacific Power & Light Co. as PacifiCorp for the sake of convenience, because the comments refer to both Washington operations (which are under the name Pacific Power & Light Co.) and the company's other operations (which are under the name PacifiCorp, or sometimes Rocky Mountain Power).

Avista (as Washington Water Power), and, of course, the Washington Public Power Supply System ("WPPSS"). PGE's controversial Trojan plant was closed early for economic reasons, PSE, PGE, PacifiCorp and Avista's abandoned the Pebble Springs and Skagit plants, and, while five WPPSS plants were planned in the 1970s, only one was completed at a cost far more expensive than expected. WPPSS resulted in extreme financial difficulties and lapsed into the nation's second largest municipal bond default. Fortunately for shareholders, the investor owned utilities were allowed to recover nearly all the costs of these abandoned or shut down nuclear power plants courtesy of their ratepayers.[22]

16. The most recent example of the troubles associated with utility owned projects is PGE's ill-fated Carty Generating Station Unit 1. Despite significant opposition from industrial customers and IPPs, PGE selected a utility-owned bid over what customers and other bidders argued were lower cost and less risky bids offered by IPPs.[23] Customers and the IPPs proved to be correct as PGE estimates the total Carty capital costs to be in the range of $126 million and $146 million more than the $514 million original

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22 E.g., People's Org. for Wash. Energy Res. v. WUTC, 104 Wash.2d 798, 804 (Wash. 1985) ("the WUTC allowed Puget Power to ultimately recover, through rates, $47.5 million rather than Puget Power's full $53.5 million net investment [in Pebble Springs]. The part of the rate increase attributable to Pebble Springs increased the average residential customer's monthly billing by $1.12."); Gearhart v. Pub. Util. Comm'n of Or., 339 P.3d 904, 356 Or., 216 (Or. 2014) (the OPUC allowed a return of, but not a return on Trojan's costs and PGE's capital investment).

23 Ted Sickinger, Despite acrimony and accusations, PGE's bid process doesn't need investigating, regulators decide, THE OREGONIAN (Sep. 20, 2013), http://www.oregonlive.com/business/index.ssf/2013/09/explanation_of_portland_genera.html; Ted Sickinger, Construction halts at PGE's new gas plant in Boardman, THE OREGONIAN (Dec. 17, 2015), http://www.oregonlive.com/business/index.ssf/2015/12/construction_halts_at_pges_new.html.

estimate.[24] Ratepayers would not be at risk for any of these cost overruns if PGE had selected a lower cost and less risky PPA.

17. In addition to the nuclear plant miscalculations, PSE has its own examples of unfortunate utility owned resource options that proved unnecessarily expensive for ratepayers, as illustrated by the Lower Snake River wind project. PSE constructed the Lower Snake River project well in advance of need on a location that included four wind resource areas and includes enough acreage and wind potential for a 1,250 MW development.[25] Public Counsel and industrial customers argued that the 343 MW Lower Snake River 1 was built in advance of need, not cost effective, not used and useful, and imprudent.[26] WUTC staff also recommended reducing PSE's recovery on power costs, incentive pay, and federal income-tax issues associated with the project.[27]

18. The Commission concluded that PSE had constructed Lower Snake River 1 in advance of need, but found this decision prudent in light of the utility's renewable portfolio standard obligations.[28] However, if PSE had purchased a PPA, then it likely would not have needed to include PSE's $770 million investment in Lower Snake River 1 in rates so far before the power was needed.

19. Lower Snake River was originally permitted in 2009 for 1,432 MW of wind generation, the largest announced project in the nation at the time, and was to be

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24 Re PGE Application for Deferral of Incremental Revenue Requirement Associated with the Carty Generating Station, OPUC Docket No. UM 1791, PGE Application at 2 (July 29, 2016).

25 WUTC v. PSE, Docket Nos. UE-111048 and UG-111049 (consolidated), Order No. 08 at ¶ 378 (May 7, 2012).

26 Id. at ¶¶ 379, 385-87.

27 Id. at ¶¶ 300-329. The Commission received 778 public comments on PSE's rate increase proposal—733 opposed, three in favor, and 42 undecided.

28 WUTC v. PSE, Docket Nos. UE-111048 and UG-111049 (consolidated), Order No. 08 at ¶¶ 411, 418 (May 7, 2012).

implemented in phases.[29] Phase I included 149 turbines generating 343 MW of wind power at $70.62 per MWh, which is still a "cost-plus" figure based on costs initially placed in rate base without any real guarantee as to escalation of operations and maintenance or reduced performance over the project's lifetime. Because PSE significantly overestimated its need for renewable energy and transmission, PSE eventually sold off much of the wind site to PGE. Phase II of Lower Snake River was built as PGE's lower Tucannon 267 MW wind project, including 116 turbines that cost PGE's ratepayers approximately $525 million.[30] PSE appears to be repeating this regrettable history, as the assumed Washington wind in its draft 2017 IRP have capital costs of $2,018 per kilowatt ("kW"), as compared to PGE's draft 2016 IRP with has an assumption of $1,400 per kW,[31] and potentially lower costs in the market.

20. By way of contrast, in 2012 the Commission also approved as prudent Avista's 30-year PPA with Palouse Wind.[32] Palouse Wind's $62 per MWh bid was selected from Avista's RFP to build a 58 turbine project generating 104 MW in Whitman County.[33] Unlike Lower Snake River 1 and Tucannon, any Palouse Wind cost overruns could not

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29 Re CUP 012609 Lower Snake River Wind Energy Project, Hearing Examiner Decision (Nov. 25, 2009) available at: http://www.co.garfield.wa.us/planning/lower-snake-river-project.

30 Re PGE Request for General Rate Revision, OPUC Docket No. UE 283, Order No. 14-422 at 8 (Dec. 4, 2014); Re PGE Renewable Resources Automatic Adjustment Clause, OPUC Docket No. UE 288, Order No. 15-129 at 3 (Apr. 15, 2015).

31 Compare PSE 2017 IRP Advisory Group Presentation at 17 (Sept. 26, 2016) with PGE 2016 IRP Public Meeting Presentation at 123 (July 16, 2015).

32 WUTC v. Avista, Dockets Nos. UE-120436 and UG-120437 (consolidated), Order No. 09 at ¶¶ 87-329 (Dec. 26, 2012).

33 Avista 2013 IRP at 2-30, A-24; BUSINESS WIRE, First Wind Secures $210 Million Financing for Palouse Wind Project (Dec. 19, 2011) available at: http://www.businesswire.com/news/home/20111219005194/en/Wind-Secures-210-Million-Financing-Palouse-Wind.

be collected from ratepayers. Comparing PSE's contemporaneous cost-plus $70.62 per MWh price with Avista's fixed-price $62 per MWh price makes clear that PPAs can offer significant long-term savings to ratepayers in addition to greater flexibility and lower risk.

21. While Avista smartly entered into the Palouse PPA, this only occurred after that utility's original decision to construct, and then abandon, the Reardan Wind Project. Four years after the project commenced, but, luckily for ratepayers, before project construction had actually started, Avista reevaluated the estimated costs of the project and abandoned Reardan. The Commission ultimately authorized Avista to recover its share, about $2.5 million from customers.[34]

22. Meanwhile, PacifiCorp's recent utility owned resource decisions have proved costly to ratepayers. PacifiCorp's wind projects are a glaring example. Overall, PacifiCorp has systemically over-estimated the capacity factor of its 12 wind plants that began operating prior to 2010.[35] PacifiCorp used a "strategy of avoiding the" Oregon Public Utility Commission's competitive bidding guidelines, which resulted in the OPUC finding that "the poor capacity factor for Rolling Hills … project acquisition was not prudent."[36] In addition, both the Oregon and Washington commissions have found that PacifiCorp imprudently installed upgrades at its coal plants, resulting in cost increases for

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[34] Re Petition of Avista For an Accounting Order Authorizing Accounting Treatment, Docket No. UE-130536, Order 01 at 2 (May 17, 2013).

[35] Re NIPPC Petition for an Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182, NIPPC's Direct Testimony and Exhibits of William A. Monsen, NIPPC/100, Monsen/30-33 (Nov. 16, 2012) available at: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=12222.

[36] Re PacifiCorp, dba Pacific Power, 2009 Renewable Adjustment Clause Schedule 202, Docket No. UE 200, Order No. 08-548 at 19-20 (Nov. 14, 2008).

customers.[37] PacifiCorp's outage at its Hunter plant in 2000 ended up costing Oregon customers more than $130 million in power costs, plus paying for the utility's legal and other fees to litigate the case all the way to the Oregon Court of Appeals.[38]

23. In Washington's neighboring state, Idaho, there are additional examples of an investor-owned utility imposing substantial cost overruns at a utility-owned plant on its ratepayers. Shortly after placing its Bennett Mountain gas-fired power plant in service, Idaho Power Company experienced a $14 million capital expense above the initially committed cost of $60 million. The cost overrun resulted from a latent construction defect that manifested itself only after commercial operations had commenced.[39] Specifically, according to Idaho Power, a contractor engaged at the utility-owned site failed to install the bolts in the gas turbine's air inlet plenum in accordance with construction specifications.[40] The developer of the build-own-transfer project, and apparently Idaho Power, failed to detect the improper installation and a bolt ultimately dislodged, was ingested in the turbine, and caused extensive internal damage for a total of $14 million in cost overruns. These types of events are not uncommon at power plants,

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37 WUTC v. Pacific Power & Light Co., a division of PacifiCorp, Docket No. UE-152253, Order No. 08 at ¶ 116 (PacifiCorp "failed to meet its burden to demonstrate the prudence of its decision to install the SCR systems on Bridger Units 3 and 4."); Re PacifiCorp dba Pacific Power, Request for a General Rate Revision, OPUC Docket No. UE 246, Order No. 12-493 at 27-32 (Dec. 30, 2012).

38 Indus. Customers of N.W. Utils. v. Pub. Util. Comm'n of Or., 196 Or. App. 46 (Or. App. 2004).

39 Re NIPPC Petition for an Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182, NIPPC's Direct Testimony and Exhibits of William A. Monsen, NIPPC/100, Monsen/19-20 (Nov. 16, 2012) (discussing the same latent defect among a host of other cost overruns at utility-owned plants).

40 Re Idaho Power Co.'s Application for a Certificate of Public Convenience and Necessity for the Langley Gulch Power Plant, Idaho PUC Case No. IPC-E-09-03, Rebuttal Testimony of Vernon Porter at 4 (July 14, 2009), available at: http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE0903/company/20090702PORTER%20REBUTTAL.PDF.

but only in the case of a utility owned plant are the ratepayers' at risk of the cost overruns, increased insurance premiums and other consequences of such events.

2. The Commission Must Protect Customers By Eliminating Barriers to Competitive Markets and Ensuring Diverse Ownership of Generation Because Utilities Have an Inherent Ownership Bias

24. Basic realities of perverse regulatory incentives and pursuit of shareholder value motivate utilities to bias the resource procurement process in favor of their own resources over PPAs. The simple reason for this bias is that utility owned resources provide the company with an opportunity to grow the company though expanded stockholder equity investment, while PPAs are a pass through cost with no expanded shareholder investment opportunity. A rational utility exercising its fiduciary obligation to maximize company growth and shareholder profit will choose to own a capital asset rather than purchase power, even when the PPA is less risky and more economic for ratepayers. The choice is made even easier for utilities because, absent the rare prudence disallowance, utilities make capital investments on behalf of shareholders that are backed by ratepayer dollars.

25. The Commission has the statutory obligation to protect customers and to ensure that "[a]ll charges made, demanded or received by any" electric utility "shall be just, fair, reasonable and sufficient."[41] The Commission has broad authority to decide what is just, fair, reasonable and sufficient, and courts are reluctant to overturn those determinations.[42] This deference makes it all the more important to adopt rigorous rules to encourage competition and protect ratepayers.

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41 RCW 80.28.010(1); 80.28.020.

42 PacifiCorp v. WUTC, 376 P.3d 389, 398, 194 Wash. App. 571, 588 (2016).

26. The Commission's traditional approach to protecting ratepayers from utility bias has been to adopt RFP rules[43] and conduct prudence reviews.[44] Unless a utility is grossly negligent at the time in which the resource decision was made, most utility commissions are reluctant to disallow costs or engage in hindsight review; the WUTC has been no exception. The prudence review process does not protect against ratepayers against most cost overruns and risks of utility ownership. Aggressively protecting customers from utility mistakes can have other unintended negative consequences to captive customers because, if the prudence disallowance is significant enough to cause financial harm, then ratepayers may ultimately pay for the higher costs of capital.[45] While providing some protections to ratepayers, the current approach has failed to provide appropriate incentives to prevent the utilities from taking actions that benefit their principal constituency—management and shareholders—over their captive customers. The occasional prudence disallowance should not just be considered the "cost of doing the business" to ensure that power assets are utility owned.

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43 The Commission's rules on purchases of electricity from IPPs (or from utility-owned generation), WAC 480-107, are based on its statutory authority under RCW 80.01.040 and 80.04.160.

44 WUTC v. Puget Sound Power & Light, Dockets Nos. UE-920433, UE-920499, UE-921262, 19th Supplemental Order at 11, 37, 46-48 (Sept. 27, 1993); WUTC v. PSE, Dockets UE-090704 and UG-090705 (consolidated), Order 11 at ¶ 320 (Apr. 2, 2010); Re the WUTC Inquiry on Regulatory Treatment for Renewable Energy Resources, Docket No. UE-100849, Report and Policy Statement Concerning Acquisition of Renewable Resources by Investor Owned Utilities (Jan. 3, 2011).

45 For example, the nuclear power plant disasters of the 1980s may have been an example of "too big to fail" or "too big to regulate." PSE, PGE, PacifiCorp and Avista were all placed on credit watch due to the abandoned nuclear power plants. See Puget Power Will Seek End to Nuclear Project, THE NEW YORK TIMES (Aug. 31, 1983), http://www.nytimes.com/1983/08/31/business/puget-power-will-seek-end-to-nuclear-project.html. This may have been a reason that the Washington and Oregon commissions ultimately allowed the utilities to recover the majority of their costs.

27. The Northwest has a need for major new resources over the next decade, and the critical question is whether all these resources will be built and owned by utilities. PSE estimates that the region is transitioning from a winter surplus to a significant winter peak deficit of 3,110 MW in 2025.[46] While some of the shift from a surplus to a deficit is due to modest load growth, the major change will be the loss of 2,045 MW of generating capacity and approximately 1,750 aMW of annual energy production as several coal plants are shut down.[47] PSE itself forecasts a need to acquire approximately 275 MW of firm, dispatchable generation in the next 7 years.[48] PSE is not alone in the need for new resources.[49] Oregon recently doubled the size of its renewable portfolio standard and committed to a date certain to remove the costs of coal generation from rates, which will result in new resource construction.[50] Carbon regulation, up ticks in Washington's

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46 PSE 2015 IRP at G-2.

47 Id. at G-4 (Boardman (585 MW capacity) and Centralia Unit 1 (730 MW capacity) in 2020, and Centralia Unit 2 in 2025 (730 MW capacity)) This does not include the significant PacifiCorp coal plant retirements in Wyoming that could further reduce the energy and capacity situation in the Northwest.

48 PSE 2015 IRP at 1-2.

49 "PGE forecasts a need for significant new resource additions." PGE 2016 Draft IRP at 4.1. While PGE has not yet released its final action plan, PGE states that it will procure "renewables to meet RPS targets, an efficient [combined cycle combustion turbine] CCCT in 2021, and fills the remaining capacity need with generic capacity resources." Id. at 12.5.3 Avista forecasts a capacity deficit starting in 2020, and the acquisition of natural gas peakers in 2020 and 2027, and a combined cycle gas plant in 2026. Avista 2015 IRP at 1-2, 11-8.

50 SB 1547 §§ 1, 2; PacifiCorp testified to the Oregon Legislature in support of HB 4036 (subsequently reintroduced as SB 1547) that the Oregon RPS revisions "incents early action through its REC banking provision, which allows utilities and customers to benefit from recently extended federal tax credits. HB 4036 enables at least 225 MW of additional low-cost renewable procurement over the near-term." Hearing on HB 4036 Before the House Committee on Energy and Environment, Presentation of PacifiCorp VP Scott Bolton (Feb. 4, 2016). PacifiCorp also testified to the Oregon Commission that the bill would provide PacifiCorp "an opportunity to procure over 600 MW of low-cost renewable

renewable portfolio standard, and other requirements are only going to speed the transition from coal generation capacity to gas and renewables, which will trigger new resource construction in the Northwest.

28. Northwest utilities are looking to **own** all this new generation, rather than purchase the power from IPPs. For example, while PSE has relied for years upon the wholesale market to cost effectively meet its energy and capacity needs, PSE asserts in its latest IRP that wholesale markets are unreliable and continued reliance on purchased power will lead to increased curtailments.[51] Similarly, both PacifiCorp and PGE recently sought to secure new renewable energy targeted for utility ownership.[52] Wall Street understands the issue of why PGE's RFP was biased in favor of utility owned generation, explaining that PGE:

> [M]aintains a good deal of flexibility in driving RFP design [and] 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.

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resources over the near-term." OPUC Special Public Meeting, HB 4036 Preliminary Information Gathering (Jan. 29, 2016)

51 PSE 2015 IRP at G-1, G-2.

52 Re NIPPC Petition for Temporary Rulemaking and Investigation into PacifiCorp's 2016 RFP, OPUC Docket Nos. AR 598, UM 1771, NIPPC Petition at 1-2, 8-10 (Apr. 25, 2106); Re NIPPC Petition for Temporary Rulemaking and Investigation into PacifiCorp's 2016 RFP, OPUC Docket Nos. AR 598, UM 1771, Order No. 16-188 at 1-2 (May 19, 2016); Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, OPUC Docket No. UM 1773, NIPPC Comments at 1-4 (June 6, 2016); Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, OPUC Docket No. UM 1773, NIPPC Final Comments (July 27, 2016); Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, OPUC Docket No. UM 1773, Order No. 16-280 (July 29, 2016).

> 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.[53]

Ultimately, neither PGE nor PacifiCorp elected to proceed with any immediate acquisitions because they could not justify utility ownership at this time, but they are planning to acquire new renewables and build their capex in the near future.[54]

29. PacifiCorp has proven to be particularly aggressive in ensuring that it owns the majority of the generation that is used to serve load. An egregious example was the utility's theft of trade secrets that it used to build Currant Creek.[55] The Supreme Court of Utah recently affirmed a jury award of more than $133 million to compensate a developer for PacifiCorp's illegal actions mirroring a developer's bid in PacifiCorp's unsupervised RFP process, which resulted in PacifiCorp awarding itself the winning bid and building the power plant without the developer that originally proposed the project.[56] In May 2012, the Utah jury specifically found that PacifiCorp "willfully and maliciously misappropriated a trade secret from USA Power . . . ."[57]

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[53] See Portland General Electric Company Racing to the Finish Line, UBS INVESTMENT BANK (July 12, 2016).

[54] OPUC Public Meeting, PacifiCorp Presentation Re Ongoing Renewable and REC RFP at 32-33 (July 26, 2016) (PacifiCorp will assess renewable resource procurement opportunities in future RFPs and pursue bi-lateral renewable resource opportunities.) available at: http://oregonpuc.granicus.com/GeneratedAgendaViewer.php?view_id=1&clip_id=110; PGE 2016 Draft IRP at 4.1. and 12.1.

[55] Steven Oberbeck, Texas Company wins $134M from utility owner PacifiCorp, THE SALT LAKE TRIBUNE (May 23, 2012), http://archive.sltrib.com/story.php?ref=/sltrib/money/54163321-79/pacificorp-usa-power-jury.html.csp.

[56] USA Power, LLC v. PacifiCorp, 372 P.3d 629 (Utah 2016).

[57] Id. at 643.

3. The Commission Should Adopt New Rules to Protect Ratepayers from Utility Bias to Select Riskier and More Expensive Utility Owned Generation

30. NIPPC recommends the Commission significantly overhaul and revise its current competitive bidding rules which utilities are not required to follow. Essentially, Washington's rules are ineffective, mired in the past, and inadequate to ensure that utilities acquire the least cost and least risk generation that is needed to meet customer needs and environmental requirements in the early 21st Century.

31. Utilities should be required to conduct a fair and transparent RFP when they seek to acquire new major resources in which there is a possibility that they could build the generation or later acquire through a build-own-transfer arrangement.

32. Key elements to ensuring a fair process should start with requiring the utility to seek Commission approval of the RFP and Commission acknowledgment of the short list of projects that the utility plans to enter into final negotiations for and allowing stakeholders an opportunity to comment on both the RFP and shortlist. Other important requirements include retaining an IE and other independent experts, and ensuring that the utilities are not able to use their market power, informational advantage, self selected scoring methodologies, or other controls over the RFP process to bias the results. Finally, NIPPC recommends that the concept of "conflict of interest" bids used in other industries be incorporated into the Commission's rules so that there is a two stage bidding process in which all utility owned generation bids are made first, and then PPA bids are informed of the target price and provided an opportunity to beat it.

33. NIPPC cautions that any process that does not provide a firm cap on utility generation ownership, or that does not sever the conflict in making resource procurement decisions between utility shareholder profits and customer interests will be imperfect.

The proposed rules below are intended to structurally limit this bias, provide incentives for the utilities to make the best decisions for ratepayers, and empower the Commission to fulfill its role in ensuring that rates are fair, just, reasonable and sufficient.[58] In addition, while NIPPC refers to competitive procurement policies now in place in Idaho, Oregon and Washington, the proposed rules NIPPC offers here are distinctive and significant improvements from currently existing policies. While Oregon pioneered in the adoption of competitive bidding policies, its current policies have dramatically failed. Washington should learn from mistakes made in other jurisdictions.[59]

A. Utilities Should Be Required to Conduct a Commission Approved RFP Prior to Acquiring New Major Resources

34. The Commission's current rules require an RFP to be issued "no later than one hundred thirty-five days after the utility's integrated resource plan is due to be filed with the commission."[60] However, other provisions significantly limit the effectiveness of any "requirement" to conduct an RFP and even undermine the laudatory intent of the rules. Taken as a whole, the utilities are not required to conduct an RFP under the competitive bidding rules, which end up doing little to influence the actual process of resource procurement.

35. For example, the rules expressly "do not establish the sole procedures utilities must use to acquire new resources. Utilities may construct electric resources, operate

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58 See RCW 80.28.024 and 80.28.020.

59 While Oregon's guidelines have driven down the costs of new generation, only about 5% of the capacity acquired through Oregon's competitive bidding guidelines have been PPAs, and some of the resources acquired have been controversial and unnecessarily expensive. Without Oregon's guidelines, ratepayers would be paying for more expensive power, but considerable more savings could easily have been achieved with more rigorous rules.

60 WAC 480-107-015.

conservation programs, purchase power through negotiated contracts, or take other action to satisfy their public service obligations."[61] Moreover, the rules also explicitly "do not apply when a utility's integrated resource plan . . . does not need capacity within three years."[62] Even when an RFP is required, which means that the utility has stated it has a near-term resource need, the rules provide the Commission broad discretion to waive the RFP requirement.[63] In practice, routine waivers from the Commission have thwarted the effectiveness of a truly competitive bidding process.[64]

36. The Commission's bidding rules need a requirement that makes them compulsory when utilities acquire resources rather than merely providing another checkbox at the end of the IRP process. NIPPC therefore proposes the Commission require utilities to follow a Commission-supervised RFP whenever it seeks to acquire generation resources in excess of 50 MW of nameplate capacity[65] and certain energy storage[66] with a term of five years or more.[67]

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61 Id.

62 Id.

63 WAC 480-107-002(3) ("exceptions may be granted only if consistent with the public interest, the purposes underlying regulation, and applicable statutes.).

64 See e.g., Rulemaking for Integrated Resource Planning, WAC 480-100-238, WAC 480-90-238, and WAC 480-107, Docket No. UE-161024, Notice of Workshop and Opportunity to Comment at C.1 (Sept. 6, 2016); Re PSE Petition for Exemption from Filing Certain RFP Requirements under WAC 480-107-015(3)(b), Docket No. UE-160387, Order 01 (May 27, 2016) (waiving three RFP requirements for resource needs described in PSE's 2015 IRP).

65 NIPPC proposes 50 MW because it will capture some utility scale solar projects as well as smaller peaker plants. For example, Avista's IRP includes three planned peakers between 50 and 83 MW, and PGE is planning on a 50 MW new solar plant. Avista 2013 IRP at 8-8; James Cronin, PGE looks at utility-scale solar, additional natural gas capacity at Carty, PORTLAND BUSINESS JOURNAL (Sept. 1, 2016), http://www.bizjournals.com/portland/blog/sbo/2016/09/pge-looks-at-utility-scale-solar-additional.html?ana=RSS%26s=article_search.

37. The requirement to issue an RFP must also prevent utilities from disaggregating large projects. Without specificity on this point any competitive bidding rules may be easy to avoid. For example, PacifiCorp concurrently developed three Wyoming wind farms—Seven Mile Hill (99MW), Glenrock (99MW), and Rolling Hills (99MW) to avoid Oregon's 100 MW threshold for issuing an RFP.[68] PacifiCorp maintained that the three projects were in fact separate projects rather than one project developed in three phases, and argued that it did not need to comply with Oregon's policies. Oregon revised its policies to prevent a repetition of such gaming, which are instructive with respect to the level of specificity required to avoid strategic disaggregation.[69]

B. There Should Be a Two Staged RFP to Limit Utility Bias

38. To address the inherent conflict of interest between shareholder and customer interests that utility managers possess, NIPPC proposes a two step bidding process. First, all ownership bids will be evaluated. The best ownership score will be announced to the

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66 NIPPC recommends that an RFP be conducted for energy storage amounts of 20 MW or greater. Given that storage is so new, NIPPC welcomes further discussions about the appropriate size threshold for storage.

67 Potential exceptions could include an emergency or where there is a time- limited resource opportunity of unique value to customers, if an acknowledged IRP provides for an alternative acquisition, and acquisitions under the Public Utility Regulatory Policies Act.

68 Re PacifiCorp, dba Pacific Power, 2009 Renewable Adjustment Clause Schedule 202, OPUC Docket No. UE 200, Order No. 08-548 at 2, 19 (Nov. 14, 2008) (acknowledging "Pacific Power's strategy of avoiding the Commission's Major Resource acquisition Guidelines by developing 99 MW projects").

69 The OPUC considers small resources located on one parcel of land or on two or more adjacent parcels of land, or the generation equipment of any small resource within five miles of the generation equipment of any other small resource where construction has been performed by the same contractor, contract, or under multiple contracts entered into within two years of each other to be one major resource. Re NIPPC Petition for an Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182, Order No. 14-149 at Appendix A (Apr. 30, 2014).

bidders. Next, bids for PPAs should be provided with an opportunity to beat the ownership score.

39. NIPPC derived this proposal from bidding processes that occur in other situations where one of the bidders has an inherent conflict of interest. In other areas of the law, such as bankruptcy and corporate acquisitions, a "conflict-of-interest proposal" like that of a utility owned bid here requires special treatment. Both bankruptcy and company purchases/mergers include situations in which there is a risk that management or owners may have divided loyalties, which are explicitly recognized and formally protected against. This is accomplished by requiring the conflict-of-interest proposal be submitted first and then put out to be bid against competitive bids.

40. There are obvious conflicts when an entity with special knowledge (e.g., a majority shareholder or management) wants to purchase or merge with a public corporation. A way "to sanitize" the transaction from its inherent conflict between members of management that have had a conflict of interest with shareholders is to include a "go shop" clause. First, the insider transaction can be fully negotiated to definitive agreements and conditionally approved by the board. Once the "target" opportunity is made clear, then it is fully disclosed and there is a limited time period in which other offers have the opportunity to beat the target. If there are no better deals, then the insider's target offer can be accepted.

41. Bankruptcy proceedings use the concept of a "stalking horse offer," which can militate against potential conflicts of interest. When a company is bankrupt, a common approach is to have auction or bid, and sell to the highest bidder. The stalking horse offer is when a debtor tests the market in advance of an auction. For various reasons, the

debtor company often thinks it can get a better outcome by privately negotiating a transaction with a strategic or selected bidder, who may have a conflict of interest. If a stalking horse offer is negotiated, then other parties are encouraged to submit more favorable bids.

42. Similar measures can be taken in the utility competitive bidding approach, in which there could be a similar two stage bidding process in which the utility owned generation options provide the price to beat for power purchase agreement bids. The first stage of the RFP should have only utility owned generation options. After the determination of the lowest cost utility owned generation bid, the utility would then publish to all bidders the lowest cost price, including both a price score represented as a levelized price per year for different PPA or tolling agreement terms and any applicable non-price scores. That price is the standard to beat by non-utility owned generation bidders.[70]

43. This process can protect ratepayers and help obtain the least cost/risk generation because the utility will not know the price of the competing PPA bids at the time the utility owned bids are scored, thus making the bidding process more fair and transparent. As there will likely be multiple PPA bids, non-utility ownership bids will still have an incentive to propose the lowest cost. While non-price factors should be minimized, the total bid score will be based on both price and non-price factors to achieve the lowest cost and risk option. Finally, the utility will still engage in a negotiation process with the bidders on the short list, which will help ensure the legitimacy of all bids.

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70 To allow for a quick schedule to ensure that utility owned option bids do not become stale, PPA bidders will need to have completed most aspects of their bids, and then have a short period of time (about two weeks) to submit their bids.

C. There Should Be a Cost Cap on New Utility Generation at the Cost of the Winning Bid in an RFP

44. The Commission's competitive bidding process could reduce ratepayer exposure to cost overruns on utility owned generation with the simple addition of a cost cap. As mentioned above, PGE's estimated cost overruns on its Carty power plant project equal approximately 30 percent above the original bid price.[71] These kinds of exorbitant cost overruns reflect the precise problem that effective competitive bidding rules should address.

45. Additionally, the risk differentials between utility owned generation and PPAs is not accounted for in the Commission's process, which leads to ranking and selection skewed in favor of utility ownership. Unlike utilities, generators selling power under a PPA must manage their own risks throughout the term of the contract and account for those risks in the initial PPA price. The fact that risk is not otherwise addressed or accounted for in the RFP fails to include all risks of performance or non-performance in the RFP bid price. By implementing a cost-cap, the Commission can at least mitigate some of this unfair advantage by providing greater risk to the utility that ratepayers will not cover the costs, if the utility selects an owned asset that ends up being more expensive. Doing so would also encourage the utility to more accurately ensure that the costs of utility owned generation bids are not underestimated. Overall, this would incent more robust participation, which inevitably leads to lower priced bids.

46. PacifiCorp's past IE, Boston Pacific, has stated that the problem with a utility bid "is that it is offered on a *cost-plus* basis while third-party bidders are required to

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[71] See U.S. SEC. AND EXCH. COMM., PGE Form 8-K Filing at 5 (Mar. 23, 2016). The difference between the PPA bid price and the actual Carty price is confidential.

guarantee their price and performance parameters."[72] Rather than accounting for the identified risk by modifying its evaluation of utility owned generation bids, Boston Pacific has "routinely requested that the Company to be held to its cost and performance projections in future rate cases should it be declared a winner."[73]

47. Accordingly, NIPPC proposes the costs included in rates for utility ownership options, including equipment procurement, construction supervision, internal and external legal, finance and accounting expense, construction bids and all similar items, shall be capped at the cost included in the bid used for comparative analysis in the RFP.[74]

48. NIPPC's proposal is generally consistent with the principles behind the Commission's existing competitive bidding rules. The current rules seek to protect against "unfair advantage" through the RFP process, but lack specific requirements or procedural mechanisms to do so. For example, the rules already preclude recovery "if any unfair advantage was given to any bidder."[75] Providing a cost cap would create a procedural mechanism to ferret out "unfair advantage." Likewise, the rules direct the Commission to "consider information obtained through these bidding procedures when it evaluates the performance of the utility in rate and other proceedings."[76] A cost cap would help the Commission influence utility performance to the benefit of both ratepayers and utilities.

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72 Re PacifiCorp Request for Approval of Final Draft 2011 All Source RFP, OPUC Docket No. UM 1540, Order No. 12-111, Appendix A at 15 (Mar. 27, 2012) (emphasis added).

73 Id.

74 NIPPC does not support a disallowance that would harm the financial integrity of the utility. That being said, NIPPC believes a cost cap that limits recovery to a utility's RFP bid price rather than its actual build price would provide adequate incentive to manage construction costs.

75 WAC 480-107-135(3).

76 WAC 480-107-001(2).

D. All RFPs that Could Result in Utility Owned Generation Should Include an IE and Financial Due Diligence Investigator

49. An IE and due diligence expert should be retained in conjunction with all RFPs in which the utility itself plans to bid. The current rules have an optional IE, but they require the party who requests it to pay for it if the utility does not choose to use one. WAC 480-107-035(6) provides: "When the utility, the utility's subsidiary or an affiliate submits a bid in response to an RFP, one or more competing bidders may request the commission to appoint an independent third party to assist commission staff in its review of the bid. Should the commission grant such a request, the fees charged by the independent third party will be paid by the party or parties requesting the independent review."

50. The inequity of this rule is staggering because it requires a bidder(s) to pay for procedural fairness. The Commission should strive to ensure procedural fairness as part of its normal routine rather than relying on parties to request it. The very existence of WAC 480-107-035(6) acknowledges the utilities' bias to build projects and effectively concedes the ineffectiveness of the WUTC competitive bidding rules to substantively protect bidders from the utilities' monopsony power.

51. To protect ratepayers from utility bias, an IE should be used in each RFP that allows any form of utility owned generation bid. The IE should ensure that the process is fair and transparent, including determining whether the pre-construction costs, pre-existing investments, transmission, real power losses, fuel supply (if applicable) and and financing provisions are entirely included in the bid cost used for comparative analysis for purposes of developing the initial short list of bids. The IE should be hired and

directly paid for by the Commission rather than individual (or even collective) bidders.[77] This IE should report to WUTC staff, and should be required to provide notes from all conversations with the utility and the full text of any written communications to ensure good faith and fair dealing with the utilities. This requirement would also ensure complete and thorough analysis in the IE report.

52. Finally, for each utility owned bid that makes it onto the final resource short list, the Commission should also oversee a financing due diligence by a highly qualified consultant. The intent of this requirement is to subject utility owned bids that may ultimately end up in a utility's rate base to the same type of deep due diligence to ensure the accuracy and complete inclusion of all costs and critical performance characteristics as well as adequate contingency reserves have been accounted for in fixed-price PPA bids to receive financing from major financial institutions. Prior to obtaining financing, bankers (which have their own, rather than ratepayer money, at stake) require an IPP bid to endure a through and exhaustive analysis of all assumptions, costs, and contract terms. Where there is a utility owned bid, the Commission and ultimately ratepayers are essentially acting as the banker approving the use of the utility's monopoly service rights and rate recovery rights. Thus, the utility owned project should be subjected to the same type of due diligence that any major IPP project must survive prior to acknowledging the utility owned bid submittal as reasonable in the RFP.

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[77] The IE and financing due diligence expert should be hired and paid for by the Commission because IEs hired and/or paid for by the utilities often see the utilities as their "clients." The costs, however, should be paid for by ratepayers (the ultimate beneficiaries) and/or the utilities (the reason we need the protections).

E. RFP Review and Acknowledgment

53. The Commission should require the utilities to obtain approval of their draft RFP before it is issued to bidders, and obtain acknowledgement of the final short list of bids for which the utility intends to negotiate a final resource procurement or PPA. This process will provide much needed oversight and supervision of a process that has inadequately protected customer interests.

i. The Utilities Should Obtain Approval of Their RFP

54. The current rules do not provide for meaningful review of the utilities' RFPs prior to issuance. Under the rules, "[u]tilities are encouraged to consult with commission staff during the development of the RFP", but are permitted "at their own discretion" to determine whether to "submit draft RFPs for staff review prior to formally submitting an RFP to the commission."[78] This procedural informality results in a general lack of involvement on the part of stakeholders and the Commission. Customers, bidders and other interested stakeholders should have the opportunity to comment on both the draft and the final RFPs prior to Commission approval.

55. Currently, the Commission relies upon utilities to provide notice that it intends to submit a bid, or allow its subsidiaries or affiliates to do so, and to indicate in the RFP how it "will not gain an unfair advantage over potential nonaffiliated competitors."[79] By allowing the utility to "ensure" that the RFP process is equitable, the Commission effectively delegates its authority to the very entities that are incentivized to abuse it. Bidders face unequal bargaining power and rely on the Commission for both procedural and substantive protection of the competitive market and ratepayers.

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[78] WAC 480-107-025.
[79] WAC 480-107-135(2).

56. WAC 480-107-015(3)(b) permits interested parties sixty days to submit written comments to the Commission on draft RFPs. Although the current RFP process is mainly directed by utilities, NIPPC proposes expanding the pre-RFP process to include meaningful Commission and stakeholder involvement. To that end, stakeholders and Commission staff would have the opportunity to make suggestions and then vet any responsive changes made by the utility before the Commission authorizes a proposed RFP. This will allow stakeholders the opportunity to identify any additional problems arising from clarification or changes the utilities make during the RFP process.

57. NIPPC recommends that the two rounds of public comment focus on whether the RFP: 1) meets the criteria set forth in the rules; 2) is consistent with the utilities' resource planning process; and 3) will be fair. Bidders vying for utility contracts are attuned to current market conditions and are uniquely positioned to identify anti-competitive behavior. The Commission could then modify the RFP, condition approval upon changes the Commission deems necessary, or extend the RFP review process, as necessary.

58. The requirement to obtain Commission approval prior to issuing an RFP can better ensure that the RFP limits utility bias, as well as provide the Commission and stakeholders an opportunity to prevent a utility from making poor resource decisions. For example, the OPUC requires that any approved RFP must be consistent with the utility's IRP. While it seems difficult to believe now, in 2006 PacifiCorp sought OPUC approval for an RFP to acquire up to 1,917 MW of new coal fired generation, including 840 MW to 915 MW of self-built generation.[80] The OPUC agreed with the arguments of its staff and customers and did not approve the RFP because it was inconsistent with the

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[80] Re PacifiCorp, dba Pacific Power & Light Co., Draft 2012 Request for Proposals, OPUC Docket No. UM 1208, Order No. 07-018 at 2-3 (Jan. 16, 2007).

Company's acknowledged IRP.[81] PacifiCorp went forward with the RFP, but ultimately concluded that it was not a good decision to build any new coal plants, thereby saving ratepayers hundreds of millions of dollars.

ii. The Commission Should Expand the Requirements for a Fair RFP

59. The Commission's competitive bidding rules have only minimal requirements to identify the resource need identified in the IRP. Currently the solicitation must, "explain general evaluation and ranking procedures the utility will use" and "specify any minimum criteria that bidders must satisfy" as well as "identify all security requirements and the rationale for them."[82] Unlike the wholesale energy markets, these requirements have not substantively changed since adopted in 1989.[83] The current rules include a reasonable list of project ranking criteria, which should be expanded to address the needs of a modern RFP.[84]

60. NIPPC therefore recommends that Commission provide structure and specificity that connects the specific need identified in a utility's IRP with that utility's

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81 Id. at 3, 7.

82 WAC 480-107-025.

83 Re Adopting Chapter 480-107 WAC Relating to Electric Companies -- Purchases of Electricity from QFs and IPPs and Purchases of Electrical Savings from Conservation Suppliers, Docket U-89-2814-R, General Order No. R-304, Appendix A at 5 (July 20, 1989).

84 WAC 480-107-035(2): "At a minimum, the ranking criteria must recognize resource cost, market-volatility risks, demand-side resource uncertainties, resource dispatchability, resource effect on system operation, credit and financial risks to the utility, the risks imposed on ratepayers, public policies regarding resource preference adopted by Washington state or the federal government and environmental effects including those associated with resources that emit carbon dioxide. The ranking criteria must recognize differences in relative amounts of risk inherent among different technologies, fuel sources, financing arrangements, and contract provisions. The ranking process must complement power acquisition goals identified in the utility's integrated resource plan."

corresponding RFP. A non-exhaustive list of some of the key information that should be reviewed to determine if the RFP is fair includes:

iii. Bidders Should Be Provided Details on Bid Scoring

61. The RFP should be designed so that bidders understand what sort of resource the utility wants in order to submit bids that meet these needs. Utilities do not always provide detailed scoring, but can provide vague scoring categories that make it hard for bidders to submit bids that meet their needs, unless they are provided sufficiently detailed scoring criteria and weighting. Instead, there should be a transparent bidding process that provides sufficient detailed scoring that will allow bidders to provide focused bids.[85]

62. In addition, bidders should be provided their scoring information for each bid at the end of the RFP. This will allow them an opportunity to verify the accuracy of how their bids were scored and understand how to prepare for future RFPs. Bidders should not, obviously, be provided the scoring of competitors.

iv. The RFP Approval Process Should Endeavor to Minimize or Eliminate Non-Price Factors

63. Non-price factors should be reduced to the maximum extent possible, and provided significantly less weight than price factors. Many non-price factors that utilities include in their bids can simply be eliminated and turned into minimum bid qualifications, and most others can be translated into adjustments to the bid price. Non-price factors are inherently subjective and provide a utility with far too much discretion to reject lower cost resources in favor of utility owned options that offer greater shareholder

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85 See Re PGE Request for Proposals for Capacity and Baseload Energy Resources, OPUC Docket No. UM 1535, Order No. 12-215 at 3 (June 7, 2012).

value. In NIPPC's experience, undue reliance on non-price factors can create a stilted weighting that also handicaps the IE from applying its largely quantitative analysis.[86]

v. The RFP Approval Process Should Ensure that All "Soft Costs" Are Included in the Price of the Utility Owned Resource

64. If construction overruns are akin to ratepayers handing the utility a blank check, then soft costs are handing over the ratepayers' debit card. Soft costs come from a variety of contexts and are anticipated, but not always accounted for in a utility's bid price and the true cost of the utility owned generation is hidden from ratepayers and the Commission. The non-technical soft costs associated with developing generation projects can be substantial and include: professional fees, transactional costs, permitting and other indirect corporate costs, inspection and interconnection labor, etc. And like other performance and regulatory risk, soft costs are managed by IPPs without passing on any risk to ratepayers. Because soft costs are inevitable, can potentially be sizeable, and are necessarily included in PPAs, they should be accounted for in utility bids as well.

65. Soft costs also add a perverse incentive for utilities to run up the bill when building projects. For example, a utility may prefer to slightly oversize projects under construction rather than build to meet its precise current need, which means that ratepayers are paying too much and effectively pre-paying for the utility's potential future plans. Worse yet, the utility can then use the benefits of its previous oversizing to outbid competition in its next RFP. The Commission must provide clarity and transparency around soft costs to establish equal footing between utility bids and PPAs.

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86 Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of Request for Proposals (RFP) Schedule; NIPPC Final Comments at 5-11 (July 27, 2016).

66. Finally, like non-price factors, soft costs could provide the opportunity for utilities to manipulate RFP ranking. For example, PacifiCorp's IE, Boston Pacific, has noted that even when PacifiCorp provided no self-build option, "the 'soft costs' or 'owners costs', which are added to the [engineering, procurement and construction] EPC costs to get the full cost of the project, are still not definite."[87] Thus, the Commission must address soft costs to ensure any hope of establishing truly competitive bidding. Soft costs should be rigorously reviewed by the IE and accounted for equitably between utility and non-utility bids.

vi. Additional Information Regarding Transmission

67. The treatment of transmission and integration costs in an RFP can be a significant barrier to fair treatment of PPA options and can be used to improperly justify utility ownership if PPAs are not treated equitably. An IE familiar with Northwest transmission markets should be retained, and the RFP approval and acknowledgement process should review the reasonableness of any transmission and integration requirements.

68. Transmission constraints and access are key considerations in utility resource planning. For example, both PSE and PacifiCorp allege significant transmission related issues that can limit what new generation is available.[88] PacifiCorp's last RFP to acquire resources to meet its Oregon and Washington renewable portfolio standard requirements explicitly required that "[b]id evaluations include transmission deliverability cost and third- party transmission wheeling costs, as applicable" and used a "transmission

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87 Re PacifiCorp Request for Approval of Final Draft 2011 All Source Request for Proposals, OPUC Docket No. UM 1540, Order No. 12-111, Appendix A at 15 (Mar. 27, 2012).

88 E.g., PSE 2015 IRP, I-3; PacifiCorp 2015 IRP at 47-61, 133-34.

deliverability analysis."[89] Available firm transmission could be withheld, requiring only flat market sales or otherwise withholding flexible transmission products, like dynamic scheduling.

69. NIPPC agrees that transmission and integration issues should be factors to consider when selecting new generation resources; however, the criteria and requirements can to bias the process in favor of utility owned generation.[90] For example, one way in which a utility can bias the results of an RFP is to allow its own generation special access to transmission resources, or impose unnecessarily burdensome requirements on PPAs.[91] Commission staff, customers, and impacted bidders should have the opportunity to review, comment, and request that the Commission remove any unfair transmission constraints.

vii. Additional Information Regarding Credit and Performance

70. NIPPC agrees that PPA bids should be required to meet minimum credit and performance guarantees, but onerous provisions can skew the results in favor of utility

89 OPUC Public Meeting, PacifiCorp Presentation Re Ongoing Renewable and REC RFP at 21-22 (July 26, 2016)

90 See e.g., Re PGE Request for Proposals for Capacity and Baseload Energy Resources, OPUC Docket No. UM 1535, Order No. 11-371 at 4-6 (Sept. 27, 2011); Re PGE Request for Proposals for Capacity and Baseload Energy Resources, OPUC Docket No. UM 1535, Order No. 12-215 at 2-4 (June 7, 2012); Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of Request for Proposals (RFP) Schedule; NIPPC Comments at 6-10 (June 6, 2016).

91 See, e.g., Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, OPUC Docket No. UM 1773, Order No. 16-280, Appendix A at 5-6 (July 29, 2016); PáTu v. PGE, 151 FERC ¶ 61,223, (2015) rehearing denied 154 FERC ¶ 61,167 (2016) (utility imposed unjust and unreasonable scheduling requirements on a QF while using less burdensome requirements for its own generation).

ownership projects. Ratepayers do not benefit from overly onerous requirements, especially if they are one-sided and provide an undue disadvantage against IPPs.

71. PGE's most recent RFP is illustrative of how, given the opportunity, a utility will inappropriately influence the results of an RFP based upon what appears to be credit worthiness. PGE's 2016 RPF included a pre-contractual bid bond requirement for 10 percent of the project price.[92] Several bidders submitted comments suggesting that the pre-contractual bid bond requirement imposed significant cost and risk to bidders, discriminates against small developers, and should be removed.[93] PGE initially agreed to adopt an unnamed bidder's recommendation and lowered the amount to $25/kW of the project's nameplate capacity rather than remove bid bond requirement. But, PGE never clarified when a developer might lose their bid bond. Thus, in the second round of comments NIPPC brought to light that without such clarification, PGE's bid bond could be used as leverage to obtain additional concessions during the final stages of negotiation. Ultimately, PGE dropped the requirement and stated it would rely on credit and collateral requirements to vet the creditworthiness of bidders.[94]

72. PGE's bid bond requirement brings to light an important issue: the IE should establish creditworthiness as a requirement to participating in the RFP rather than allowing utilities to make this determination as part of the bidding process. The

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92 Re PGE Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, OPUC Docket No. UM 1773, PGE RFP for Renewable Energy Resources at 17 (May 9, 2016).

93 Notably, one bidder insisted on remaining anonymous, calling itself an "Unnamed Bidder." This demonstrates the reluctance of bidders to push back against onerous and biased RFP requirements because of a fear of utility retaliation.

94 Re PGE Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, OPUC Docket No. UM 1773, PGE RFP for Renewable Energy Resources at 9, Attachment A at 18 (July 13, 2016).

Commission should not permit utilities to weed out smaller developers. Instead, IEs should rigorously review the reasonableness of all bids, including those submitted by the utility or its affiliates. PGE's RFP example also demonstrates how important the opportunity for two rounds of comment and review are to bidders.

viii. Proper Accounting for Resource Life Span

73. The RFP Rules should ensure that the entity that scores the utility ownership bids against the IPP bids accurately, or at least transparently, compares resources with varying life spans. This issue arises because a utility owned project is a longer-term obligation placed in rate base for 30-plus years, and the shorter-term PPA is typically for a shorter duration of 15-25 years. In addition, the significant costs of required capital replacements over a 30-year resource life may not be fully accounted for the utility owned bid, while the IPP will need to account for these costs in their fixed price bid. Generally speaking, the PPA option will typically be far less expensive to the ratepayer in the early years and the utility owned resource may decline in costs in its later years (if the utility owned generation costs and performs as advertised in those future years and rate-base depreciation exceeds the additions to rate-base due to capital replacements and repairs). This dichotomy raises two different issues relevant to an RFP evaluation.

74. First, because a utility owned resource is placed in rates for a period that is typically far in excess of the term of the PPA bids, the RFP that compares these two different resource types must conduct present value and/or levelization analysis in an attempt to compare bid prices between the two bid types. This analysis is inherently flawed since one type of bid (PPA) provides a known price for a known period of time, while the other (utility owned project) requires extensive assumptions to develop an

assumed price, including, at a minimum, escalation of future operations and maintenance charges prior to applying a discount factor to achieve a present value. Obviously, this is an area where major errors will be made in order to discount the unknown future costs of the utility owned plant in an attempt to compare its unknown cost to a fixed-price PPA bid. NIPPC submits that it is not really possible to accurately conduct this analysis.

75. Second, this issue highlights the even more important question of whether it is appropriate for utilities to be committing to generation commitments of 30-plus years at a time when the electric industry is undergoing major structural changes. As noted above, the IPP bid will typically be far less expensive in the early years of the resource life compared to the utility owned bid that will be placed in rate base, and the utility owned bid will become more valuable only if it performs as projected for the 30-plus years of the assumed rate-base period. However, at a time of impending carbon regulations at the state and federal levels and rapid changes in generation and storage technologies, the Commission should not allow the utilities to rely on projected benefits of a new generation resource that reach over 30 years into the future; ratepayers are better served by shorter commitments in the range of a 15-year to 25-year PPA.

76. At a minimum, if utility owned generation bids will continue to be scored against IPP bids, then NIPPC recommends that the impact of the assumed resource lifespan of the utility owned generation bids be transparently presented in the RFP evaluation. For each utility owned generation bid, the price score should be presented in a way that transparently demonstrates the impact of the present value analysis that is used to compare the present value or levelized costs of the utility owned bid to fixed price IPP bids. Such analysis must include, at a minimum, calculation of the annual levelized price

of the utility owned generation bid assuming different resource lifetimes for the bid for each five year interval extending from the shortest PPA term allowed to bid into the RFP to the proposed maximum period of evaluation of the utility owned generation bid. For example, with a 15-year minimum PPA bid and an assumption the utility owned generation bid will impose costs and benefits for 35 years, the analysis must present utility owned generation bid price scores with the assumption of resource lives of 15 to 35 years. This analysis, and the supporting data, will allow the parties to the RFP process to accurately understand the impact of lengthier life span of the utility owned generation bid, and will allow the Commission to determine if it is reasonable to assume that longer lifespan will both come to fruition at the projected costs and remain the best resource selection over that lengthy time frame, prior to committing ratepayers to the cradle-to-grave costs of that utility owned resource.

ix. Scoring Criteria Should Value the Unique Benefits of Portfolio Diversity and Protect Against the Risk of Cost Overruns, and Pre-construction Costs

77. The current energy market offers a barrage of challenges that require a balanced approach taking into consideration the impacts of different types of generation as well as between utility owned generation and market purchases. A healthy utility resource portfolio is one that displays a significant level of diversity. Just as diverse portfolio of different types of resources and resource technologies, so can diversity of types and duration of resource ownership. Customers benefit when resource ownership is diversified because it gives utilities and customers access to different types and durations of resources without committing excessively to any single resource or technology, as utility ownership requires.

78. Because traditional ratemaking naturally favors utility ownership, the Commission should explicitly encourage diverse ownership through its competitive bidding rules. Without explicit recognition, the state's electric consumers will not have access to the full range of resource alternatives and providers, but be forced to purchase all their power from a monoculture of utility owned generation for an excessive and costly amount of time.

79. As detailed above, utility ownership has unique risks and costs which simply do not occur with PPAs. For example, PPAs provide benefits to consumers by absorbing certain costs and risks that would otherwise be borne by customers if the utility were to own the resource for forty years. Risk and cost shifting onto a PPA sponsor occurs at bid and contract time, and is usually apparent on the face of the bid or contract. The specific advantages related to cost and risk mitigation should be a positive bidding factor for consideration when making resource decisions.[95]

80. While the Carty example provides a cautionary tale of cost overruns that could lead to PGE seeking to recover upwards of $150 million in additional costs, construction costs are only part of the problem. Ratepayers are also exposed to risk for pre-construction, engineering and installation costs. As project sizes increase with the economies of scale, so do these risks. Decades ago the cancellation of major projects and safety concerns associated with both nuclear and coal development exposed vulnerabilities to traditional prudence review. Cost of service regulation unnecessarily exposes ratepayers to risks that strong completive bidding rules can offset.

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95 The OPUC considered, but rejected the use of bid adders to address utility ownership bias and risks in the RFP process. <u>Re NIPPC Petition for an Investigation Regarding Competitive Bidding</u>, OPUC Docket No. UM 1182, Order No. 13-204 (June 10, 2013).

81. Moreover, PPAs offer a variety of unique benefits. Locking in long-term contracts allows utilities to capture the best energy price available on the market and hedges against fluctuating fuel prices. PPAs manage performance risk by guaranteeing utilities a certain amount of generation at a locked-in rate. But, as not all PPAs are long-term contracts, PPAs also offer tremendous flexibility in resource procurement. PPA present a very efficient way to add renewable energy and achieve sustainability compliance, which helps utilities avoid regulatory risk without acquiring land or dealing with siting issues. Finally, developers may be better positioned to take advantage of federal tax credits than entities with no taxable income. Thus, the Commission should encourage diversity of ownership to protect ratepayers from well-established performance and regulatory risk.

82. Recognizing diversity as positive criteria and the risks associated with utility owned generation in the bidding evaluation implicitly acknowledges that it is difficult if not impossible to quantify the relative value of risks and costs absorbed by a PPA when contrasted with utility resources. This is because the Commission cannot know precisely what future risks and costs might be imposed on utility customers from long-lived utility resources. For example, Duke Energy's Wyoming wind facilities had make changes and pay over $1 million in fines related to killing eagles under the Migratory Bird Treaty Act, costs that could not be passed on to ratepayers because the power sold through a PPA.[96]

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[96] See Alisa Opar, Duke Energy: Looking for Payback, AUDUBON (June 26, 2015), http://www.audubon.org/news/duke-energy-looking-payback. (indicating PacifiCorp was required to pay $2.5 million in fines for similar violations); see also INDIAN COUNTRY, Wind Power Co. to Pay $2.5 Million for Killing Golden Eagles, Other Protected Birds (Jan. 9, 2015), http://indiancountrytodaymedianetwork.com/2015/01/09/wind-power-co-pay-25-million-killing-golden-eagles-other-protected-birds-158633.

This makes it extremely difficult to fairly evaluate the true benefit of PPAs to customers at bid evaluation time without taking diversity explicitly into account.

83. Currently these risks and benefits are completely unaccounted for in the Commission's RFP process. The Commission should acknowledge the different advantages between utility owned projects and market purchases, and address these risks in the RFP scoring.

x. Utilities Should Be Requires to Obtain RFP Acknowledgement

84. The Commission's current rules provide far too little oversight of the selection of the bids, and NIPPC recommends that the Commission amend its rules to require the utility to seek the Commission's acknowledgement of its final short list of bids. Essentially, the current process is inadequate because it provides no meaningful Commission involvement in a utility's resource procurement decisions between the IRP and prudence review process.

85. Under the current rules, there is no express requirement for the Commission to actually review the utility's selection of bids until it is far too late to influence what resource the utility actually acquires. The current rules state that the "procedures and criteria the utility will use in its RFP to evaluate and rank proposal are subject to commission approval."[97] But the rules provide no mechanism for the Commission to review the utility's ranking of the bids until several months or years after the RFP when the utility seeks rate recovery for the winning bid.[98]

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[97] WAC 480-107-035(1).

[98] WAC 480-107-035(5); see also WAC 480-107-045(1) (stating *utility* must identify bidders that best meeting the selection criteria).

86. The RFP process must be revised to require the utility to obtain Commission acknowledgement of the final short list that is selected for final negotiations. Without requiring the utility to obtain short-list acknowledgement, there is no assurance whatsoever that the utility will actually conduct the RFP in the manner required by the Commission's acknowledgement of the RFP itself.

87. The flaws in the OPUC's original competitive bidding guidelines are instructive on the need to require the utility to file an application for approval of its final short list. In Oregon, a 2006 order provided comprehensive procedures for the RFP process, but the procedures provided the utilities with discretion as to whether they would file their short list of bidders for the OPUC's acknowledgment. Most recently and notably, PGE avoided the short-list acknowledgement process for its acquisition of the ill-fated Carty Generating Station.[99] After this and other abuses by Oregon utilities, the OPUC determined in 2014 to make acknowledgement of the short list of bidders a mandatory requirement.[100] The OPUC explained, "requiring utilities to file a shortlist acknowledgment application will promote transparency in the utility procurement process by providing an established, upfront opportunity for parties and bidders to voice concerns with the bidding process[,]" and will allow the OPUC "to timely review the IE's closing

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99 See Re PGE Application for Deferral of Incremental Revenue Requirement Associated with the Carty Generating Station, OPUC Docket No. UM 1791, PGE Application (July 29, 2016); Re PGE Request for Proposals for Capacity and Baseload Energy Resources, OPUC Docket No. UM 1535, Order No. 13-345 (Sept. 20, 2003); Re Troutdale Energy Center, LLC, Petition for Declaratory Ruling, OPUC Docket No. DR 46, Order No. 13-346 (Sept. 20, 2013) (representing two related requests for the OPUC to take preventive action prior to acquisition of Carty in the RFP).

100 Re NIPPC Petition for an Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182, Order No. 14-149 at 14 (Apr. 30, 2014).

report and address any issues the IE raises with the bidding process or the shortlist."[101] The OPUC concluded short-list review would "benefit[] ratepayers by helping ensure the utility selects the most competitive bids."[102]

88. Accordingly, NIPPC proposes an express requirement that the utility request Commission acknowledgement of the final short list. Acknowledgment of the RFP's final short list would have the same meaning as assigned to that term in and effect as IRP acknowledgment, which does not guarantee or prevent cost recovery. If the RFP allows affiliate bidding or allows utility owned generation bids, the IE would participate in the RFP acknowledgment proceeding, independently score all bids and select the initial and final shortlists to be included in a report for use in the acknowledgement proceeding.

89. If the final short list submitted to the Commission includes any utility owned bids, the highly qualified consulting firm should produce a comprehensive report on the cost and performance assumptions of the utility owned generation project and propose any necessary adjustments to the bid scoring. The utility shareholders should pay for the financing due diligence because the need for this added step is caused by the shareholder's choice to place a utility-owned resource on the final shortlist. As explained above, this due diligence step is imperative in order to ensure that the alleged costs supporting the bid upon which the utility would profit are indeed "bankable" assumptions. The requirement is merely an attempt to require similar treatment to PPA bids because the owners of the IPP projects would need to pay for the extensive due diligence review required for their own non-ratepayer financing. The highly qualified consultant will provide the final report of its analysis to the Commission, and will

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101 Id.

102 Id.

provide a copy to the utility and interested stakeholders in RFP process. The utility must explain in detail how the financing due diligence by the highly qualified consultant supports the utility's position that the project should remain on the final short list, particularly if the financing due diligence by the highly qualified consultant identified any flaws in the initial analysis of the utility owned generation bid that resulted in placement on the initial short list.

90. Additionally, acknowledgement of the final short list should be contingent upon the utility meeting a requirement of resource ownership diversity across its generation portfolio. Even the most well designed competitive bidding rules may fail to effectively mitigate against utility bias. To rectify this problem, the Commission should ensure that the RFP process is not systematically biased against diversity of ownership, including PPAs, tolling agreements, and PPAs or tolling agreements with the option for utility ownership after a specified term. For RFPs that result in the acquisition of multiple generation facilities or more than 100 MW of renewable energy, the utility should not be allowed to obtain acknowledgement if the RFP short list does not result in at least some level of ownership diversity. In addition, there should be a separate requirement that the Commission will not acknowledge an RFP short list that does not result in ownership diversity if the utility's RFPs over the last 10 years have not resulted in ownership diversity.

91. Finally, there may be circumstances where the IE's continued involvement in the final negotiations is necessary to ensure fairness of the process. For example, if the utility has exhibited a strong preference for utility ownership through its statements or conduct, bidders may need the assurance of an independent outside party to protect

against, or at least document for future rate recovery proceedings, any unfair self-dealing by the utility. The rules should provide that Commission Staff will make a recommendation about whether the Commission should require IE involvement through final resource selection at the time of acknowledgement of the utility's final shortlist of resources. Other parties, including bidders, should be allowed to request expanded IE involvement at that time.

III. CONCLUSION

92. NIPPC recognizes that it is asking for a significant expansion and revision of the Commission's competitive bidding rules. Washington utilities, however, are planning to make billions of dollars of new investment in utility owned generation in the near future. Ratepayers deserve to know that any utility owned generation is acquired at the least cost and risk. They also need to see the utilities' plans tested against IPPs who are prepared to compete to build and operate power resources at their own risk. It need be understood that sophisticated, credit worthy IPPs will only participate in RFPs they view as fair. It is simply impossible to achieve the least cost and risk resources if there is not a fair procurement process and if the utilities end up owning most or all of the new generation that is built to serve load and comply with environmental requirements.

Dated this 2nd day of November 2016.

Respectfully submitted,

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Of Attorneys for the Northwest and Intermountain Power Producers Coalition

Attachment B

Rulemaking for Integrated Resource Planning,
WAC 480-100-238, WAC 480-90-238, and WAC 480-107,
Docket No. UE-161024,
NIPPC Comments Regarding Proposed RFP Rules (Sept. 21, 2018)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

U-161024

In the Matter of	)	
	)	NORTHWEST AND INTERMOUNTAIN
Rulemaking for Integrated Resource	)	POWER PRODUCERS COALITION
Planning, WAC 480-100-238, WAC 480-90-	)	COMMENTS REGARDING PROPOSED
238, and WAC 480-107	)	RFP RULES
	)	
	)	

I. INTRODUCTION

1. The Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these comments regarding the Washington Utilities and Transportation Commission's (the "Commission" or "WUTC") draft rules related to competitive procurement for electric utilities (WAC 480-107). NIPPC appreciates this chance for comment on the draft rules, and also that the rules show some progress toward protecting customers from bias in the selection of generation resources toward utility-owned generation. As set out in more detail below, NIPPC continues to have significant concern about portions of the draft rules, and the Commission should adopt certain modifications to more completely level the playing field between utility-owned resources and third-party resources for the benefit of customers. Unfortunately, NIPPC does not believe the rules, if adopted as written, will result in meaningful, practical improvements. The rules require further work if they are to mitigate and manage the utilities' bias against entering into contracts for lower cost and lower risk independent power producer ("IPP") owned generation.

2. In these comments NIPPC provides: 1) responses to the questions posed by the WUTC in its August 24, 2018 Notice of Opportunity to File Written Comments; 2) general comments on

the proposed rules; and 3) a redlined version of the rules, showing the changes that should be adopted to more fully benefit customers and make the rules clearer. NIPPC's proposed changes are consistent with the Commission's mission, are necessary and appropriate based on past experience, and represent an implementation of competitive procurement for Washington utilities that would be fair for all parties, especially end-use consumers harmed by the current system.

3. NIPPC's November 2, 2016 comments in this docket set forth in detail the history surrounding competitive procurement rules at the WUTC. They also cover in detail the aspects of the current regulatory model that create a well-established bias for utilities to choose utility-owned generation to serve their loads rather than rely on third-party developers and power purchase agreements ("PPAs"). Those comments plead for the Commission to adopt strong rules regarding competitive procurement that ensure customers are benefitted by the protections offered by using IPPs to construct and operate required generation, and for the Commission to take meaningful steps to level the playing field for non-utility owners so that the Commission can be assured of a healthy diversity of generation resource options for the customers it protects.

4. NIPPC does not repeat those comments here, except to reiterate that absent strong rules regarding competitive procurement, Washington customers will be at risk as utilities continue to seek a return for their shareholders through maintaining an unnecessary and inappropriate monopoly over generation of electricity. The Commission should adopt rules that overcome utility bias in generation resource selection, and provide a greater likelihood that shareholders of IPPs, rather than captive utility ratepayers shoulder the risks associated with development, operation and management of generation facilities.

5. The draft rules reflect NIPPC's recommendations to improve the competitive bidding process by: 1) requiring a utility to hold a Commission-supervised request for proposal ("RFP") prior to acquiring 50 megawatts ("MWs") or more of new generation resources; 2) requiring a utility to retain an independent evaluator that should be more free from the editorial control of the utilities and thus better able to protect against utility bias; 3) providing stakeholders an opportunity to comment on both the draft and final RFPs, which must be approved by the Commission; and 4) adopting more specific RFP scoring and evaluation criteria to make the RFP more transparent to all bidders.

6. NIPPC recommends that the rules be further revised to include meaningful provisions that will address utility bias. These include:

- Requiring a two-stage process for RFPs where a utility-owned resource is bid, with the price scores of the utility-ownership options made available prior to the bidding for the power purchase agreement options;
- Include a due diligence review of utility-ownership bids as one of the independent evaluator's ("IE") duties, to help ensure utility-ownership bids are fairly priced and evaluated equivalently with third-party bids;
- If a utility-ownership bid is proposed for inclusion on the shortlist of the RFP for final negotiations, subjecting the utility's resource short list to an acknowledgement proceeding that has the same effect as integrated resource plan ("IRP") acknowledgment;
- If the utility owned asset is the winning bid, imposing a cap on the costs included in rates;
- Requiring that utilities' return on utility-owned generation be built into the price and collected on a per-MWh basis, in order to put these projects on equal footing with PPAs;
- Removing language that could be interpreted as making the RFP process just one of many options utilities can use to acquire new resources;
- Including a cost-based threshold for when storage projects require an RFP;
- Relieving the utility and ratepayers of the costs of an IE when there is no utility ownership bid in response to an RFP;
- Expanding the IE's duties to include managing, rather than just evaluating the RFP;
- Having the IE be paid by the Commission, and reimbursed, and having the IE be managed by the Commission Staff;

- Requiring the utility to release the winning bid score to customers, the public, and bidders;
- Making clear that utilities cannot make RFPs overly prescriptive by mandating generation technologies, or locations without a statutory mandate or other regulatory requirement;
- Requiring that utility-owned transmission assets be made available for use by third-party bidders;
- Revising the rules to prevent project disaggregation by utilities in order to avoid the thresholds;
- Modifying the definition of subsidiary to be based on ownership alone, rather than ability to control the related company;
- Encouraging utilities to consult with all interested parties during the development of the RFP;
- Using an RFP process to select the IE;
- Requiring a Commission-approved PPA and other transaction documents, so that bids can be submitted and evaluated on a level playing field;
- Keeping the current rule language that the RFP rules do not override any utility's Public Utility Regulatory Policies Act ("PURPA") responsibilities;
- Requiring the RFP to specify interconnection requirements; and
- Not setting the threshold for distribution system projects at $10 million, but conducting a further process to refine the methods that should be used to determine when an RFP is needed.

II. COMMENTS ON UTC's SPECIFIC QUESTIONS

A. Is the language in the draft rule at WAC 480-107-015 sufficient to require an all-source RFP for most resource needs, while allowing sufficient flexibility in the process to allow limited scope RFPs when they are most useful?

7. Draft WAC 480-107-015 requires that a utility "must solicit bids for its resource needs identified during the IRP process." It also requires that it "must accept bids for a variety of energy resources" that can meet the needs identified in the IRP, and that this includes conservation and efficiency, demand response, energy storage, qualifying facilities, power from independent power producers, and potentially utility- or utility affiliate-owned resources. The

rule then goes on to explain the circumstances under which an RFP is required, and provides certain exceptions for when that process can be avoided by a utility.

8. This portion of the rule is clear that utilities must solicit bids to meet their resource needs, and also that an RFP is required, except for certain enumerated circumstances. It also makes clear that the utility must look at all resources that can meet its identified needs. In instances where the identified resource need is specifically for renewable resources, the rule is drafted in a way that allows for an RFP to be limited in scope to reflect that requirement.

9. NIPPC supports this level of clarity in the rules, but has concerns with some of the language used to describe certain of the exceptions to the RFP, which are described below in paragraph 20.

10. NIPPC also notes that there is highly problematic language in the proposed version of WAC 480-107-001 that seems to undermine, or cause confusion about the required nature of the obligation to solicit bids and use RFPs. The proposed version of that rule states: "The rules in this chapter do not establish the sole procedures utilities may use to acquire new resources." Taken at face value, this sentence as drafted could be interpreted to mean that nothing in the rules is mandatory and, instead, that the rules are just one option for the procedures utilities may use to acquire resources. The proposed edit to this sentence (turning "must" into "may") contributes to this unfortunate potential interpretation. The prior version of the rules indicated that utilities *must* abide by the procedures, and that there could in fact be other requirements placed upon a resource acquisition. To ensure that the RFP requirement is mandatory, unless an exemption applies or a waiver is granted, this sentence should be left as it was in the prior rules, or removed altogether.

11. Additionally, WAC 480-107-035(7) states that the "utility may reject all project proposals if it finds that no proposal adequately serves ratepayers' interest." Although the rule specifies that a utility that makes this decision will have its finding reviewed in the utility's relevant cost recovery proceeding, this provision still substantially undercuts the idea that the RFP process should be the primary method through which utilities select and then acquire resources. Instead of simply allowing utilities to make that decision, and proceed without an RFP, the rules should make clear that utilities must use the RFP process to acquire resources, unless they obtain a waiver from the rules.

B. In WAC 480-107-035(3) the draft contains the term net benefits. Language around this concept has been evolving recently. Would using a different phrase, such as costs and benefits, or impacts, be clearer?

12. The proposed version of WAC 480-107-035(3) uses the term "net benefits" in describing one of the criteria that the utility must evaluate with respect to project bids received, along with other factors like risk, state energy policy, resiliency, reliability, etc. The term "net benefits" is used in RCW 80.12.010(1) in establishing the standard to be met when there is a change in utility ownership. It is therefore likely that the Commission will most often interpret this phrase in the context of proposed mergers or acquisitions of a utility. Because the considerations and issues that arise in the context of a change of utility ownership are potentially quite different than the considerations at play during an RFP for a new resource, NIPPC believes it is not advisable to use the same wording in this rule.

13. As used in the draft rules, NIPPC assumes that the purpose of the phrase is to require utilities to consider both costs and benefits that may be associated with resources that are bid in response to an RFP. Simply using that language would likely be clearer, and accomplish the

same purposes without forcing the Commission to consider impacts to these rules from how it interprets the net benefits standard in other contexts.

C. RFP timing: "Is there a way to ensure long-lead time technologies have an equal opportunity to meet resource needs anticipated ten years out without requiring RFPs at such an early stage?"

14. NIPPC does not believe that the rules should require accommodation for extremely long lead time resources by requiring an RFP when a resource need is 10 years out because such acquisitions will be rare, and may result in unnecessary RFPs and vendor fatigue. In today's market, most generation technologies will have lead times of three years or less, with notable exceptions where transmission availability, permitting or other issues may exist (e.g., hydropower licensing or pump storage licensing, certain conservation resources, etc.). Because longer lead time resources are likely to be the exception, NIPPC does not believe that they should cause the rules to require accommodation for 10-year lead times. Most project sponsors would not wish to wait 10 years between the commitment to sell and the final acquisition of the resource and therefore would be unlikely to bid into an RFP with a 10-year lead time to full acquisition.

15. NIPPC, however, agrees that the current process may not provide long lead time resources with a fair opportunity to compete in RFPs. The Commission should attempt to address the issue by using market purchases to fill the utility's need prior to the acquisition of the long lead time resource. If a long lead time resource is shown to be the least cost and least risk resource, then the utility should analyze whether it can meet its need in the shorter term with market purchases. Market resources should be used to fill in the time between the stated date for a resource need and the date the long lead time resource can be made available.

It is important to keep in mind that integrated resource plans that identify specific capacity, energy and renewable needs by a specific date are as much an art as a science. A retrospective review of even the best utility planning shows that the only certain aspect of resource planning is that the specific needs and timing will be wrong. There should be some flexibility in the planning and RFP process to account for the fact that the specific forecasted need and timing will differ from what is actually needed, which supports allowing for the delay of an ultimate resource acquisition in some circumstances to provide long lead time resources an opportunity to compete.

D. Thresholds for exemption. In the proposed draft language for WAC 480-107-015(3) there are thresholds and circumstances that would exempt utilities from issuing an RFP without requesting an exemption.

1. Are the thresholds proposed appropriate?

16. WAC 480-107-015(4)[1] sets 50 megawatts ("MW") as a capacity threshold for when an RFP is required. NIPPC supports this threshold with respect to electric generation, and strongly opposes raising it any higher than this amount. NIPPC understands this rule as requiring an RFP when the utility needs to acquire a resource to meet a capacity, energy or renewable resource need with a nameplate capacity resource greater than 50 MW. This represents a significant resource, and one which implicates all the concerns about utility bias towards owning generating assets. Additionally, raising the threshold higher than this would add to NIPPC's concerns about utilities seeking to disaggregate projects into smaller "projects" to avoid the requirements of the rule.

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[1] Although the WUTC's question about exemptions refers to WAC 480-107-015(3), NIPPC assumes the reference was meant to refer to -015(4), which addresses the exemptions.

17. The threshold for storage resources, however, should be lower than 50 MW. Storage resources, on a per-MW basis, are much costlier than generating resources, and therefore a storage project well below the 50 MW of capacity threshold would likely implicate the same concerns about utility bias in the selection process that apply to electric generators 50 MW and above. Additionally, storage technologies are rapidly developing and dynamic, and thus an RFP process serves an important purpose with respect to storage by allowing customers to benefit from exposure to new technologies and proposals that can be provided in response to future RFPs.

18. NIPPC recommends that an RFP be performed based on the cost of the storage resource. Setting a specific number in the rules would be difficult given the declining costs of storage and the difficulty in revising rules. While it will be impossible to perfectly estimate the cost of new storage prior to the issuance of an RFP, utilities frequently provide estimates in their IRPs and when setting avoided costs for conservation and qualifying facilities selling power under the Public Utility Regulatory Policies Act. Thus, NIPPC recommends that an RFP for storage be conducted when the estimated cost for storage in an IRP is the same as the estimated lowest cost 50 MW capacity resource in the IRP.

2. Are there other circumstances appropriate to qualify for exemption from the rule?

19. The Commission should identify specific and narrow circumstances under which utilities should be able to be exempted from an RFP for a resource that otherwise fits the size and characteristics threshold. The Draft Rules would allow an exemption based on the Commission's generic rule allowing exemption from any rule, which uses the nebulous and

potentially broad "public interest" and "undue hardship" standard.[2] NIPPC maintains that exceptions be narrower and only when: 1) there is an emergency; and 2) a time limited opportunity to acquire a resource of unique value to the utility's customers. In addition, if the Commission expands its current acknowledgement process to be more rigorous like Oregon's, then an additional exemption may be warranted where an alternative acquisition methodology was proposed in the IRP and explicitly acknowledged in the IRP.[3] These are the requirements in Oregon, which allowed exceptions in limited circumstances, including PacifiCorp's fire sale acquisition of the Chehalis gas plant and Portland General Electric Company's recent decision to enter into capacity contracts with Bonneville Power Administration rather than build a new gas generation unit at its ill-fated Carty location.

20. Additionally, as referenced above in paragraph 9, NIPPC is concerned that some of the language used in WAC 480-107-015(4) is unclear. Specifically, the rules state that an RFP is not required if the utility's "identified resource need will be acquired under an existing tariff." Neither the Commission's notice, nor the rules provide further clarity on what is intended by this provision. If the intent is for utilities to be exempted from the RFP requirements in instances where they already have an expectation of having a resource need met through an existing tariff, then it is unclear why the utility would have projected a resource need in its IRP process. Further, NIPPC is unsure of what types of resources the utilities receive through existing tariffs that would be large enough to rise above the thresholds that otherwise require the submission of an RFP. NIPPC recommends that this language be dropped as it appears unnecessary, and could create an unintended incentive for utilities to acquire resources via tariff revisions rather than go

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2 Existing WAC 480-07-110(2)(c).

3 OAR 860-089-0100(3).

through the RFP process that is intended to protect customers. In the event that the Commission elects to keep the language, NIPPC requests that (at least informally) the Commission explain what type of resource acquisitions this is intended to allow.

3. What other types of resources would benefit from a threshold?

21. For the reasons described above, the Commission should adopt a cost-based threshold for purposes of determining when an RFP is required in order to acquire a storage facility.

E. Whether RFPs should be required for Delivery System /Distribution planning.

22. NIPPC generally supports competitive bidding where investment in the utility system is required, but recognizes that unique circumstances may exist in the case of the delivery system, as compared to generation. The $10 million threshold referenced is ill-suited to support robust competition for distributed resources. NIPPC recommends that the Commission use a different methodology to determine when the need for a distribution RFP should be conducted. This could include: 1) a cost-to-capacity metric ($/MW); and 2) an approach based on the capacity needs of the grid and the ability for distributed resources to meet that need. The Commission should better investigate these options, via a workshop or additional comments, to determine the appropriate measure for delivery system planning RFPs.

F. Reliance upon the market, and whether the rules should use the Northwest Power and Conservation Council's resource adequacy assessment as a third-party assessment of resource adequacy.

1. Are there other third-party sources that would be more appropriate to reference?

2. Are there other methods that are easier, more transparent, or more accurate than relying on third-party analysis?

23. NIPPC supports the use of the Northwest Power and Conservation Council's resource adequacy assessment or another independent third-party analysis. In NIPPC's experience, utility forecasts and assessments can, even if unconsciously, be biased in favor of the utility's preferred

outcome. In a rate case, Staff and intervenors have an opportunity to vet, challenge and obtain Commission resolution over disputed forecasts and assessments. The IRP and RFP process is different and there is limited opportunity for review and resolution of disputed issues, and warrants reliance upon independent analysis as much as possible to avoid even the appearance of bias.

G. Independent Evaluator. The draft rule WAC 480-107-AAA requires the use of an independent evaluator under certain circumstances.

1. Does this section identify the proper circumstances or are there other circumstances under which an independent evaluator should be required?

24. NIPPC believes this section properly identifies where an independent evaluator should be required because it ties to the 50 MW; however, a separate threshold of 20 MW for storage projects should be included in this section as well, for the reasons described above.

2. Is there value in requiring an independent evaluator for large projects when a utility will not be bidding? If so, is a 50 megawatt resource need an appropriate threshold?

25. There is not sufficient value to require an IE for large projects when there is no utility ownership option in the RFP. The regulatory model incentivizes utilities to own their own generation assets and IEs provide the kind of transparency that makes it more difficult for utilities to tip the scale during resource procurement. If a utility will not be bidding and will not accept build own transfer bids that result in utility ownership, then the costs associated with an IE are not warranted.

26. While IEs arguably provide some nominal value in all RFPs, their primary purpose is to ensure utilities fairly compete in their own RFPs. In certain instances, therefore, the costs should be avoided. It is entirely appropriate for the rule to provide two different RFP paths based upon

whether a utility is bidding for a resource. NIPPC has suggested language in the redline to provide for these two different paths.

27. The Commission's primary tool for protecting competitive markets and limiting utility bias has been its prudency review, which has failed to stop expensive and unnecessary utility owned projects from the nuclear power debacles of the 1980s to PacifiCorp's Wyoming 99 MW Rolling Hills project and Puget Sound Energy's Lower Snake River wind farm. The competitive bidding rules are not designed to be pre-approval or replace the rate case, but to provide an initial check or tool to address the utilities' bias to own resources. Thus, the fundamental justification for going through the regulatory burden, overseeing utility actions, and the expense of an RFP is because of a concern that the utilities will make the economically rational choice of choosing the interests of their shareholders over ratepayers.[4]

28. When there are no incentives for the utility to choose its own generation assets, then there is less need to burden ratepayers with additional costs of policing the utilities' actions to ensure that they do not favor certain bids. Simply put, when the utilities do not have a bias to select any particular outcome, then we should entrust them to make the right decision without the cost and burden of an RFP, and review that choice in a rate case.

29. Allowing exemptions for market purchases and PPAs is consistent with both the utilities' and the Commission's common practice. PSE, PacifiCorp, and Avista routinely enter into short-

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[4] The Commission should be concerned by any claims that this bias does not exist or is irrelevant. NIPPC does not doubt that the majority of utility managers take seriously their responsibility to meet their statutory duty to make decisions with the ratepayers' best interests at heart. However, even the most conscientious of utility managers will need to act scrupulously to avoid both this real explicit and implicit bias.

term firm contracts in the market, amounting to hundreds of megawatts.[5] In the aggregate these transactions are similar to new major resource acquisitions, but raise no utility-ownership issues, and are not subjected to additional scrutiny of a formal RFP.

30. PacifiCorp's 2016 and 2017 RFPs provide a clear example as to why this kind of exemption is appropriate. PacifiCorp's most recent solar RFPs did not allow utility-ownership.[6] This meant that the RFP can proceed on a more level playing field and does need the formal monitoring by an IE. PacifiCorp has now entered into significant long-term solar PPAs. This option allowed PacifiCorp to move more quickly and test the market, without going through traditional RFP steps. Common sense tells us that an RFP that does not include utility ownership need not go through additional scrutiny designed to mitigate that same bias.

31. NIPPC also recognizes that IEs provide value beyond the primary role of mitigating utility bias, but that value must be weighed against the rising costs attributed to IE involvement. The IE's oversight, review and documentation of the process may help inform later prudence reviews. Simply put, the prudence review should be significantly easier with the IE's help. In addition to better policing the utilities' actions, the assistance of a third-party evaluator can also serve to inform and improve the utilities' decision-making process.

32. These benefits, however, come at a cost, burden and complexity for both ratepayers and the Commission, which cannot be justified where there is no risk that the utility will own the new generation assets. The costs associated with using a worthwhile IE, however, should not be

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5 See e.g., PacifiCorp 2017 IRP, OPUC Docket No. LC 67, PacifiCorp's IRP at 2 (Apr. 4, 2017) (forecasting PacifiCorp's front office transactions from 273 – 1,575 MW over the planning horizon).

6 PacifiCorp's 2017 Solar RFP at 1-2 (Nov. 15, 2017), available at http://www.pacificorp.com/sup/rfps.html (not accepting bids for either build and transfers and not submitting a benchmark bid).

unnecessarily imposed upon ratepayers. Staff and ratepayers have reviewed the prudence of utility decisions, and can continue to do so on non-ownership acquisitions without the benefit of an IE.

33. Finally, it should be noted that a primary beneficiary of using an IE when there is no utility ownership option is not ratepayers, but the utility. The use of IE provides greater certainty to the utility that the utilities' ultimate selection will be reviewed as reasonable and prudent. If a utility wants the greater cost recovery associated with including an IE when they are not needed to mitigate utility bias, then utility shareholders, and not ratepayers should pay for their costs.

3. Does this subsection provide enough specificity concerning the independent evaluator's role, or is additional rule language needed?

34. NIPPC supports the requirements in the rules for the use of an IE, but this role should be expanded, including: 1) managing rather than evaluating the RFP; 2) being paid by the Commission and not the utilities; and 3) being managed by Staff and not the utilities.

35. The IE should take on a larger role in the RFP process, and should be put in charge of managing the entire RFP process. This would protect customers by eliminating opportunities for the utility to influence the RFP process in ways that could be inconsistent with the neutrality that the IE is intended to provide, and take advantage of the neutral party to perform those duties where bias can be imposed. Because the IE has the expertise to solicit and review bids for resources, the IE should be allowed to take all of these steps in order to eliminate the potential for utility bias in how the RFP process is run.

36. Other states and commissions have adopted this approach of having the IE take on a more comprehensive role with respect to RFPs, administering the process to help ensure fairness and a lack of bias throughout. For example, in implementing a state program for competitive procurement of renewable energy, the North Carolina Utilities Commission recently developed

rules related to an Independent Administrator that was to assist in the selection of resources. Under those rules, the IE is called an Independent Administrator ("IA") and their duties are expansive, and include developing a methodology to ensure equitable review of utility-owned and IPP bids, receiving and transmitting proposals, evaluating proposals, monitoring post-proposal negotiations, and providing a certification to the Commission of program compliance.[7] A role like this makes sense for the IA, and that the rules should make clear that the IA role is to manage the RFP process.

37. NIPPC appreciates the provisions in the draft rule that make it clear that the IPP does not need to pay for the costs of the IE. NIPPC recommends, however, that the Commission directly hire and pay for these costs. The rules also contain problematic and unnecessary provisions that substantially undermine the benefits associated with the use of an IE. The rules state that the "independent evaluator will *contract with* and be *paid by* the utility."[8] These provisions contrast with the purposes of an IE to be "independent" and watch out for utility bias. It is implausible to assume that an IE is wholly independent when that individual or firm has a contract with, and is paid by the utility. This approach is unnecessary, and NIPPC requests that the Commission adopt changes that provide that the Commission can contract with and pay the IE. The Commission could then require the utility to reimburse it for such payments, and allow the utility to then collect those costs in rates (as long as the RFP includes the possibility of utility ownership—utility shareholders should pay for the IE if utility ownership is not possible).

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7 See North Carolina Administrative Code, R8-71(d)(5), available at https://www.ncuc.net/ncrules/Chapter08.pdf, and adopted in that Commission's Nov. 6, 2017 Order in Docket No. E-100, SUB 150, *In the Matter of Rulemaking Proceeding to Implement G.S. 62-110.8*).

8 Proposed WAC 480-107-AAA (3).

38. The rules also state that the utility "will also manage the contract terms with the independent evaluator." Again, this could be done by Commission Staff, and aid the independence of the IE.

4. Should the Commission require that the independent evaluator be certified or accredited? If yes, provide specific qualifications the independent evaluator should possess.

39. The independent evaluator should be qualified to perform the work, have relevant experience, and be reviewed to ensure independence and competence. If the individual or firm meets these criteria, then NIPPC does not believe it is necessary for them to have any specific required certification or accreditation. However, the IE should have the demonstrated ability to police utility bias, and any process by which the IE is selected should specifically inquire into their views about the purpose of the RFP, how they would or have addressed the problem of utility bias, and how they intend to prevent it in any Washington RFP. NIPPC has reviewed the IE solicitations by utilities, and some of them appear designed to ensure that a weak IE, or even one biased against PPA bids was selected.

H. IE Report. "[W]e recognize that a two-step reporting process will increase the cost and length of the independent evaluator's review. Could the Commission require the reconciliation process to occur prior to the issuance of a single final report and still ensure that the evaluator's work is free from outside influence?"

40. NIPPC strongly supports the two-step reporting process. The extra time that would be required from the two-step process should be modest, and is well worth the additional transparency that is added to the IE's review and the reconciliation process with the utility. Issuing a single report, after the reconciliation process is completed, would provide no insight into the extent of the differences between the IE's initial independent view, and the outcome of the reconciliation process with the utility. Conversely, the two-step approach would create a

record and justification for how and why the IE's views changed, if they did, during the reconciliation process. And, under circumstances where a party was disappointed with the final report's conclusions, having a clear articulation of the changes in view that may have occurred, and a description of why, would give valuable insight.

I. Conservation RFP provisions.

41. NIPPC does not have comments on this question.

J. Procurement Outside of an RFP: Utilities often have opportunities to procure low-cost resources that are owned by entities that typically will not bid their resources into an investor-owned utility RFP, but will enter into contracts with the IOUs. These types of opportunities can also require the construction of complex components that do not lend themselves to a bid in an RFP. Contracts such as these require proactive behavior from the investor-owned utility outside of the RFP. How can the Commission ensure that utilities are pursuing these low cost opportunities available outside of an RFP? How can this idea be incorporated in rule?

42. NIPPC is somewhat confused by this question, as it is not clear exactly what types of physical resources are being referenced. If there is not opportunity or risk of utility ownership, then the utility should be free to procure resources outside of an RFP. If a utility is procuring a utility owned resource greater than 50 MW for generation or 20 MW for storage, then NIPPC maintains that the RFP process should apply, as it is calculated to solicit the resources that are available to serve that need. If, in some circumstance, the utility is aware of a unique opportunity, then it should seek a waiver from the rules for a time limited opportunity. It would seem more likely that in crafting a rule to capture this circumstance, the Commission could inadvertently open the door to a very subjective and difficult to monitor exception that utilities may attempt to use for a variety of resources and conditions. Even if flawed, the RFP process has the potential to better ensure a competitive market for generation and achieve the least cost and least risk resource for consumers.

K. Evaluation Transparency: Proposed draft rule 480-107-025(4) requires RFPs to "include a sample evaluation rubric that quantifies the weight each criterion will be given during the project ranking procedure." What are the implications of this language?

43. NIPPC recommends that the draft rule require more transparency as to the scoring criteria for bidders. The more detailed the scoring criteria, the better, because it will allow IPPs to prepare bids that match the utilities actual needs and requirements, rather than some secret end result that only the utility owned asset can satisfy.

44. Transparency as to the scoring criteria is a fundamental element of a fair solicitation process, and it is even more important in an RFP where the utility is likely to have a self-interested utility-ownership option against which the independent power producer bids will be evaluated. For example, in discussing its competitive bidding rules, the Federal Energy Regulatory Commission ("FERC") has explained: "No party, particularly the affiliate, should have an informational advantage in any part of the solicitation process. The RFP and all relevant information about it should be released to all potential bidders at the same time."[9] "[A]ll criteria should be specific and detailed so that all bidders can effectively respond to the RFP. Clear evaluation criteria will ensure that the RFP does not give an advantage to the affiliate."[10]

45. This logical requirement would prevent one party from engaging in advanced permitting or development of its project with information not available to other bidders, such that the party could satisfy timing or other requirements of an RFP. It would likewise prevent one party with an informational advantage from compiling numerous different project characteristics in a manner that will achieve the greatest score.

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[9] Allegheny Energy Supply, LLC, 108 FERC ¶ 61,082, P.23 (2004).

[10] Id. at P.30.

46. To illustrate the problem as applied to likely Washington RFPs, the utility will necessarily have a detailed understanding of the objective and subjective criteria that will receive a high score because the utility designs the RFP and solicits the resource. However, if the scoring criteria are not objective and subject to self-scoring by the independent bidders, the process cannot be fair because those bidders cannot structure their projects and their bid submittal in a way to meet the utility's needs, as reflected in its scoring criteria. Yet the proposed rule would appear to allow the utility to only furnish bidders with a "sample evaluation rubric" that is likely to amount to nothing more than scoring percentages for broad categories featuring several project attributes. The rule should require very specific and detailed scoring criteria for price and non-price criteria and eliminate the use of any subjective criteria.

47. The RFPs in Oregon have experienced a long-running problem with utilities providing only vague and subjective scoring criteria, especially with regard to so-called non-price criteria, such as the quality of transmission rights, the level of experience of the development team, and the credit supporting the bid. These vague criteria and the lack of transparency were undermining the integrity of the entire process. In response, the OPUC recently adopted rules that substantially remove the ability of the utility to game the process with vague scoring criteria.[11] In effect, these rules require the RFP to either convert the project characteristic at issue to a minimum bidding requirement or to characterize the non-price scoring criteria with a level of objective specificity that allows the bidder to self-score the bid.

48. Utilities sometimes argue that providing detailed scoring criteria to the bidders will allow the bidders to "game" the process in some way. This is an ironic claim because the utility often

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[11] Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources, OPUC Docket No. AR 600, Order No. 18-324 at 12-13 (Aug. 30, 2018) (adopting OAR 860-089-0400).

possesses this detailed bid scoring criteria when it assembles its own bid, and would thus be the only bidder able to game the process. In any event, in proceedings where NIPPC has participated, no utility has ever demonstrated how a bidder would game the process without misrepresenting the characteristics of its bid and being potentially in breach of the contract it may enter into with the utility. NIPPC believes that the benefits of transparency would outweigh the risk that a bidder may devise a way to game the process.

49. On a related topic, NIPPC supports the proposal in the rule to provide the bidders with their confidential bid score after the solicitation closes, but also believes that added transparency of providing the winning bid price to all bidders provides necessary transparency and another backstop to keep the utility honest. Specifically, the Commission should also require the utility to release the winning bid score to customers, the public and bidders.

L. Two-stage bidding process. Please discuss advantages and disadvantages of NIPPC's proposed approach of a two-stage bidding process, including whether the bidding structure proposed creates asymmetrical bidding opportunities between IPPs that offer power purchase agreements and those offering to sell their generation. How should the sequence of bid offers be designed if the IPP is offering two differently structured offers for the same project, one that is PPA and one that is a contract with transfer of ownership?

50. The two-stage bidding structure proposed by NIPPC contains significant advantages for ratepayers by more fully mitigating against the well-established utility bias toward utility-owned generation resources, and the acceptance of development risk by captive ratepayers. The two-stage process would ensure that a utility only builds and owns a resource in instances where that represents the best option available in the market. Although NIPPC's proposal definitely differs from the historical practice of the Commission, NIPPC asks that the Commission consider the following questions about the proposal:

- How would this process impact customers?

- Would such a provision be effective at ensuring least-cost resources are built to serve customers?
- Would the process prevent utilities from building resources when doing so is in the best interests of customers?
- Would the process further the Commission's goals and aid in the implementation of its duties?
- Would the process be unfair to utilities?

51. NIPPC asserts that a reasoned consideration of each of these questions would show that the two-step process is superior in terms of customer protection, ensuring low-cost resources are built, and more fully mitigating utility bias, while presenting no unfairness to utilities or hinderance to their building of resources when doing so is in the best interests of customers.

52. Contrary to the concerns of the utilities, the process would not mean that an IPP would automatically win the process. If a utility can truly build a project that is superior than what is available in the market, then its bid will win. Additionally, the process will not negatively affect pricing of the bids or result in IPPs submitting bids just below the utility's estimate because they will all know that they are competing against each other, and will thus continue to have every incentive to offer as low of a cost as is reasonable. The process could narrow the number of projects that an IE and the utility must evaluate because projects will only be bid if they are believed to be superior to the project offered by the utility.

53. As described more fully in NIPPC's November 2016 comments in this docket, NIPPC also emphasizes that this two-step process is not novel. In fact, in other industries and circumstances where a party has a conflict of interest, such as in bankruptcy proceedings or

corporate acquisitions, this process is commonly used to ensure against bias.[12] This process makes eminent sense in circumstances where utilities are proposing to build resources for customers, because there is an established conflict of interests between the utilities' understandable desire to produce returns for shareholders from the resource, and their charge to benefit customers through providing reliable service at the lowest reasonable costs.

54. The second part of the Commission's question above asks how the two-stage process would work in the case where an IPP offers two differently structured offers for the same project—one that is a PPA, and one that is a contract with transfer of ownership to the utility. This situation would seem to be handled appropriately through simply applying the rules as proposed by NIPPC. Because the structure involving transfer of ownership to the utility would result in utility ownership, it should be bid as part of the first-stage. And, if it were selected as the winner of the first stage, the second stage would determine if another project bid would be superior. In that second stage, the project could be also bid under a PPA structure, to determine if this structure provided any benefits that made it superior to the first-offered model, and to also compare the PPA structure to other bids that were provided during round two.

M. Resource Need Definition: "Should the proposed definition of Resource Need above include specific resource needs that should be subject to competitive bidding? If so, what should be included in that list?"

55. The proposed definition of "Resource Need" should be specific to the type of resource needs of the utility but should not be so prescriptive that it identifies a single generation technology or geographic location. In other words, NIPPC agrees that it is appropriate to issue an RFP for energy (e.g., up to a 200 aMW block of year-round baseload energy), an RFP for capacity (e.g., up to a 200 MW of dispatchable capacity during peak load periods or other

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12 See NIPPC Comments at ¶ 39.

specified times), or an RFP for renewable energy (e.g., up to a 200 aMW block of energy plus bundled Washington-qualified renewable energy certificates). However, NIPPC opposes overly prescriptive RFPs that would bar submission of bids from new or alternative generation technologies to meet the identified resource need or for a specified geographic location absent a statutory or regulatory mandate.

56. For example, PacifiCorp recently proposed a Wyoming wind-only RFP, which barred bids from solar facilities, facilities using battery or other storage, and even wind bids located outside of a narrow geographic area in Wyoming. Coincidentally, PacifiCorp's self-build option was a wind facility located in Wyoming plus an expensive self-build transmission line in Wyoming will amount to a massive addition to rate base. The resource need was low-cost renewable energy—not just Wyoming wind in a specific location. If a non-wind renewable facility outside of Wyoming could supply that resource need at lower cost and lower risk than the wind facility and transmission located in Wyoming, the RFP was eventually required to accept such bids. Not surprisingly, the Oregon Commission declined to acknowledge the short-list that emerged from PacifiCorp's Wyoming Wind RFP, explaining: "We simply cannot conclude at this time that the narrow shortlist from PacifiCorp's RFP—a packaged bundle of mostly company-owned Wyoming wind resources connected to a single transmission line—clearly represents the renewable resource portfolio offering the best combination of cost and risk for PacifiCorp customers."[13] In the end, all evidence to date shows that PacifiCorp's Wyoming Wind RFP is resulting in very low cost resource acquisitions and an excellent deal for ratepayers, but we will be unable to determine if it was the best result.

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13 Re PacifiCorp, dba Pacific Power, 2017R Request for Proposals, OPUC Docket No. UM 1845, Order No. 18-178 at 10 (May 23, 2018).

57. In sum, overly prescriptive RFPs that mandate generation technologies or locations could deprive ratepayers of potentially lower cost and lower risk resources. This point should be added to the definition of "Resource Need" in the rules.

N. Certain PURPA Rules Should Be Kept in the RFP Rules

58. The draft rules propose to remove the PURPA rules from the RFP rules and NIPPC is not opposed in principle to having two sets of PUPRA and RFP rules. NIPPC understands that the RFP rules will keep WAC 480-107-101, which states that if there is any conflict between the Commission's rules and PURPA, that PURPA governs. NIPPC supports keeping this provision in the RFP rules.

III. OTHER COMMENTS ON RFP RULES AND PROCESS

59. In addition to the above responses to the Commission's questions, NIPPC offers the following comments on the use of RFPs and the proposed rules more generally.

A. Cost Caps and Approach to Rate of Return Ratemaking for Generation Resources

60. NIPPC continues to be very concerned about the established utility bias to select utility-owned resources as the method to meet resource needs. That bias has played out again and again in the state, and harms customers by forcing them to accept development risks that they do not have to bear. It also undermines the vitality of the energy markets that are critical to ensuring the health of the industry, and the availability of low-cost resources for customers. The Commission should do more than is described in the proposed rules to more fundamentally address the problem.

61. NIPPC proposes that the Commission institute caps on the costs of utility owned resources that can be included in rates. The Idaho Commission recently found that such limits can be warranted, recently ordering that PacifiCorp will not be able to recover any costs over and

above the utility's projected costs of a major resource addition for which it sought a Certificate of Public Convenience and Necessity.[14] The Idaho Commission reasoned that this was warranted because the utility specifically argued that the project was needed in order to produce an economic benefit for customers (and not needed in the near-term to meet loads). Although most projects built by utilities are likely needed to meet resource needs in the nearer term, once a utility goes through an RFP project, and chooses *its* project above other projects, it is doing so because it is estimating an economic benefit to customers from that project. It is therefore appropriate to have the utility bear the risk that its project turns out to not provide that benefit, and remove that risk from customers. After all, if the utility does not want to bear that risk, it does not have to, and could always choose to fulfill a resource need through a PPA, and have a third-party bear that risk.

62. If the Commission is not interested in a simple and clear cost cap because of concerns regarding regulatory pre-approval (or disapproval), then there are less significant (and effective) alternatives. Instead of capping a utility's cost recovery to the price of the bid it provides for an RFP, the Commission could make clear that it will cap cost recovery at the cost of the next highest bid. This would still allow recovery of some cost overruns, if deemed prudent, but would prevent customers from being harmed by a utility's decision to forego the price certainties that would have been available if they had chosen the next highest bid. Another option would be to impose an assumption that any costs above utility's self-build estimate are presumptively

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[14] See Re Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for New Wind and Transmission Facilities, Idaho Public Utilities Commission Case No. PAC-E-17-07, Order No. 34139 (Sept. 6, 2018).

imprudent. The Commission could allow the utility to rebut this presumption, but the utility should be required to provide clear and convincing evidence of a lack of imprudence.

63. NIPPC also proposes that when a utility bids a utility-owned project, and that project wins an RFP, the Commission should require the utility to collect its regulated return on that investment through building it into the fixed price of the resource, which could be collected on a per-MWh basis. This approach would be in contrast to the current practice of allowing utilities to add net plant costs into rate base, and then including them in the total utility rate base upon which the utility is allowed to earn its authorized return when setting rates. This current approach has led to too easy of a path for utilities to recover a return on costs that are really cost overruns, or slippage on projects that they may have chosen in order to benefit shareholders. Making the regulated return part of the fixed price of a resource would instead place cost control incentives on the utilities that they currently may not have, and would also ensure that utility-owned resource pricing is put on a comparable basis to a PPA bid from an IPP, which builds its (often lower) return into the fixed bid.

B. Use of Utility Assets to Provide Power Generation

64. Any decision by a utility not to allow bidders access to its utility-owned facilities or assets is harmful to customers and should be considered *per se* imprudence. Utilities have historically used their informational advantage in advance of solicitations to position themselves to prevail. Additionally, NIPPC's understanding is that utilities generally recover as operating expenses in rates the costs of their site, transmission rights, and other development costs, even if the utility-owned bid is not successful in the solicitation and is never placed in service for recovery as used and useful plant. NIPPC maintains that it is wholly unsupportable for ratepayers to be required to bear the costs of utility resources, but not be entitled to receive bids

from IPPs that can provide the utility with power for those customers that may rely on those assets customers are already paying for. The rules should thus clarify utilities' obligation to make utility-owned resources and rights available to third party bidders into an RFP process. Utility-owned facilities or assets do not include those facilities or assets to which the utility has the right of access or control under an agreement that is contingent upon regulatory approval of the utility's application to own that facility or asset.

65. Allowing bidders access to the same utility-owned transmission resources as the benchmark bid will result in lower cost proposals. NIPPC and customer advocates have pointed out numerous examples where utilities have used their utility-owned facilities and access to transmission to favor their benchmark bids or otherwise ensure that a utility-owned bid wins.[15] Customers should not pay for any utility asset that is not used to their own benefit.

66. This issue will become of greater significance as the region's limited transmission assets and rights may serve to significantly limit the number and diversity of bidders of low cost and less risky generation that cannot access transmission to reach utility loads. A utility's transmission holdings that are recovered in rates or are being reserved for future use to transmit power to sell to its ratepayers (who will pay for them at that time) should be made available to bidders into the RFP. Utilities have a much wider portfolio of transmission resources and

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[15] Re PGE Request for Proposals for Capacity and Baseload Resources, OPUC Docket No. UM 1535, NIPPC's Comments at 18-19 (Feb. 22, 2012) (asking the Commission to require PGE to provide granularity regarding the scoring criteria because PGE's proposed scoring criteria had scoring percentages for broad categories containing several project attributes); Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of Request for Proposals (RFP) Schedule, OPUC Docket No. UM 1773, Order No. 16-280 at Appendix A at 5 (July 29, 2016); Re Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182, Order No. 06-446 at 5-6 (Aug. 10, 2006); Re PGE Request for Proposals for Capacity Resources, OPUC Docket No. UM 1535, Order No. 11-371 at 5-6 (Sept. 27, 2011).

reservations to benefit its ratepayers by ensuring that ratepayers have access to the least cost and least risk generation resources bid into the RFP. Any existing transmission reservations or transmission reservations in deferral status, in queue or optioned by a utility should be assumed to be available to the resource selected in any RFP.

67. If the Commission were not inclined to make this a hard and fast rule, it would be reasonable for the rules to provide that if the utility proposes a cost-plus utility-owned bid to compete against fixed-price competitive bids, and it determines that it will not make utility-owned resources available to other bidders, then the utility must explain why it would not be in the best interest of its customers to do so. This would at least encourage the utility to make rate-payer funded transmission available for use by competitors who may be able to supply the utility's customers with a lower, fixed-price product than the utility-owned cost-plus product.

68. This is the approach recently taken by the Oregon Commission, which was consistent with its historic approach of encouraging rather than requiring a utility to offer its assets to be used by third party bidders.[16] The Oregon Commission explained that: "We believe that the use of utility owned resources by third parties to develop additional or better, more efficient bids will help facilitate the objective of more and better proposal options."[17] The Oregon rules did impose a requirement that the utility explain what utility owned assets will be used and why it did or did not offer the benchmark or utility owned resources to third party bidders. Specifically, the rules require "that a filed analysis of the decision be provided to the Commission at the time of RFP

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16 Re PGE Request for Proposals for Capacity Resources, OPUC Docket No. UM 1535, Order No. 11-371 at 6 (Sept. 27, 2011) (The Oregon Commission stated the decision to open up its site to third party bidders was a prudence decision, but directed PGE to consider other recent utility decisions that opened up their sites. This caused PGE to decide to offer up its site to bidders).

17 Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources, OPUC AR 600, Order No. 18-324 at 10 (Aug. 30, 2018)

development, as well in a subsequent prudence determination."[18] PSE's recent RFP in which that utility agreed to allow its transmission assets be used by third party bidders is an excellent example of what should be done in RFPs. PSE's decision should be commended, but the rules should require this from all utilities in the future.

69. As described above, though, the Commission should just take the next step and clarify that any other action is per se imprudent. Therefore, the Commission's rules should require utilities to offer up ratepayer-funded assets to bidders in order to obtain cost recovery for utility-owned assets.

C. Further Definition to Prevent Disaggregation of Projects

70. The proposed rules provide that the bidding requirements would not apply where "the utility's identified resource need of capacity less than 50 MW." Proposed WAC 480-107-015(4)(a). NIPPC recommends that the rule should more definitively proscribe a utility from evading the bidding requirements by rate-basing multiple facilities that fall just below the 50-MW capacity limit.

71. For example, in Oregon, the RFP Guidelines previously applied to resources of 100 MW or greater capacity, until PacifiCorp intentionally evaded the Guideline through its rate-based acquisition of multiple wind farms in Wyoming just below the capacity limit. Specifically, PacifiCorp avoided the previous Oregon RFP Guidelines for its Rolling Hills and Glenrock projects, which were sized at 99 MW each and separated by one mile, and also avoided the Guidelines by breaking apart one project into "two" 99 MW projects (Rolling Hills and Glenrock).[19] The Oregon Commission determined that its rule needed "to be modified to address

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18 Id. at 11.

19 Re PacifiCorp 2009 Renewable Adjustment Clause, OPUC Docket No. UE 200, Order No. 08-548, pp. 3, 6, 19-22 (Nov. 14, 2008).

the problem of a utility sizing projects to avoid competitive bidding requirements" and to "clarify when multiple small projects should be considered a major resource."[20] The Oregon Commission's competitive bidding guidelines used the following criteria:

> A utility must issue an RFP for all Major Resource acquisitions identified in its last acknowledged IRP. Major Resources are resources with durations greater than 5 years and quantities greater than 100 MW. If multiple small generating resources total more than 100 MW and meet the following criteria, then there is a rebuttable presumption that the multiple small resources are a single Major Resource and the competitive bidding guidelines apply:
>
> > a. The small resources are located on one parcel of land or on two or more adjacent parcels of land, or the generation equipment of any small resource is within five miles of the generation equipment of any other small resource; and
> >
> > b. Construction of the resources is performed by the same contractor, or under the same contract, or under multiple contracts entered into within two years of each other.
>
> A single area of land is considered one parcel even if there is an intervening public or railroad right of way.
>
> The utility bears the burden of rebutting this presumption. If multiple small resources meet these criteria, but the utility believes that other factors show that each resource is separate and distinct, then the utility may request that the Commission find that the resources do not qualify as a single Major Resource. If the utility proceeds without making this request and without following the competitive bidding guidelines, then the utility may attempt to rebut the presumption that it should have followed the guidelines when the utility seeks recovery of the costs of the resource in rates.[21]

72. In the case of utility-owned resources where the utility has the incentive to avoid the rules, NIPPC recommends that the Washington rules should adopt similar criteria to specify when multiple small facilities that exceed 50 MW are subject to the bidding requirements in the

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20 Re Public Utility Commission of Oregon, Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182(1), Order No. 11-340, at 5 (Sept. 1, 2011).

21 Re Public Utility Commission of Oregon, Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182(1), Order No. 12-007, at Appendix A (Jan. 10, 2012).

rules to avoid the same issues that arose in Oregon before the loophole was removed there. NIPPC has provided proposed revisions to the Washington rules submitted with these comments.

D. Addition of Due Diligence to IE's Duties

73. Because an IE's duties are to ensure an appropriate comparison is made between utility-owned projects and those bid by other third parties, it is critical that all projects be subjected to the same type of due diligence review. This ensures that all project costs and assumptions are equally supportable, and have been subjected to similar scrutiny. It is often assumed by regulators that the IE conducts a full analysis of the assumptions regarding the utility owned "bid". But typically, the IE does not perform this task and instead monitors the process to merely ensure that it is run consistent with its stated requirements (which are determined by the utility).

74. NIPPC proposes to introduce a due diligence review of the utility-owned bids on the shortlist that is commensurate with the type of "project-finance due diligence" that is regularly conducted to obtain third-party financing for an independent power producer's facility. Because utility-owned projects are usually not project financed, they escape the type of due diligence review that IPP projects must go through in order to get financing. Thus, NIPPC proposes that the IE's job duties in the rule be expanded to clearly include due diligence review of utility-owned projects bid in response to an RFP. Without this, utility-owned resources that have less certainty with respect to costs, risks, and feasibility will be compared to IPP projects that undergo a strict test of each of these items. The Commission should ensure that the IE has a broad enough scope to allow them to do a true "apples to apples" comparison of all of the projects bid in response to an RFP. NIPPC specifically proposes the following language:

> For each bid with utility ownership on the final short list of potentially winning bids, the IE must conduct a project-finance due diligence

evaluation of the type utilized by financing institutions for purposes of securing financing from reputable financing entities prior to extending project financing for major generation facilities.

75. NIPPC's proposal is based on the assumption that bankers and other financers typically retain independent firms to evaluate the viability of projects seeking financing commitments from commercial lenders. This is a commonly accepted idea in all types of business that obtain project financing. For example, when lending money to purchase a home, a bank will hire a third party to conduct market analysis to make sure they are not lending money that is clearly in excess of market value. A home inspector may also be retained to review the house and whether there are underground oil tanks. When hiring a builder to construct a new home or make improvements, a lawyer may be retained to review the construction agreement. These are the types of actions that someone who is investing their own money may take.

76. Investors require a far more thorough and rigorous analysis when lending money to construct electric generation resources for independent power producers securing project financing. A PPA bidder will develop and tender a bid that includes a confidential pro-forma accounting of project costs, revenues and returns. The bank will want every input to this income statement reviewed to determine whether the numbers are supported, whether they match the terms of the various contracts, the risk around the inputs, and steps taken to hedge that risk. The risk around each will be assessed and valued. A review will also ensure that all permits have been obtained, that the counter parties have the requisite experience to construct the facility, wind and solar profiles and cost assumptions are reasonable, etc. The draft power purchase agreement will be reviewed to ensure that the lenders understand how much the generator will be paid, how much power they will be paid for, and all the other risks, benefits and potential liabilities. Based upon the financial and engineering due-diligence review, the bank will decide

whether to lend money to the project, how much of the total project cost they are willing to lend, and what interest rate they will demand.

77. Some large developers that balance sheet finance their projects may not separately retain an independent consultant to conduct this due diligence. However, they often have internal staff that conduct a similar rigorous internal review of the proposed project pro-forma, often throughout the development process, because they also are putting their own private capital at risk, not ratepayer money.

78. Utility ownership bids are not vetted with the same project due diligence because their financing has the ultimate back stop of ratepayers. While the Commission conducts prudence reviews, too large of disallowance will harm the utility's cost of capital, which ultimately increase rates. Because they provide essential service (electricity), utilities are generally considered "too big to fail."

79. Any active participant or IE in the energy industry should know exactly what is contemplated by this proposed language. The level of due diligence that occurs during project financing is well known and there are firms that offer this type of due diligence review for third-party lenders. The language plainly requires that the review conducted be "of the type utilized by financing institutions for the purpose of securing financing." If a proposed IE is not aware of the type of due diligence that IPPs must go through to obtain project financing from a third-party lender, then that IE has no business advising this Commission on whether the utility's ownership bids have the same level of assurances of cost and performance as the IPP bids. The Commission should adopt NIPPC's proposed language into the final rule to ensure that utility-owned bids are not placed in rate base without first passing the same type of scrutiny as IPP bids for PPA options.

80. Finally, there is no reason to require bids that do not have an ownership option to go through this due diligence. As mentioned above, independent power producers typically perform this type of due diligence because they, unlike utilities, need to stand behind their bid price. Additionally, their bids are offered on a fixed price basis, not cost plus. To counter the inherent bias present in the regulatory model, it is entirely appropriate to treat utility-owned bids differently than PPAs, and only require the IE to separately perform this due diligence on projects on the short-list that the utility could own.

E. Requiring Acknowledgment of Shortlist when Utility Bid is Included.

81. The Commission's rules should be modified to provide more oversight over the selection of resources under an RFP by requiring utilities to submit the short list to the Commission for acknowledgment when the short list contains a utility-owned project. This process is necessary to address the fact that there is otherwise no meaningful Commission involvement in the utility's resource procurement decisions between the RFP process and the prudence review process, which normally occurs in a rate case. By that time, the Commission's review is too late to actually influence the decision that the utility makes about resource procurement. The Commission's acknowledgment process would also ensure that the utility followed the RFP process and the relevant criteria.

82. Such a requirement, however, would not constitute pre-approval or guarantee favorable ratemaking treatment. Oregon's process is illustrative, and the Oregon Commission has similarly concluded that it does not have the ability to pre-approve or pre-disapprove any utility decisions on prudence or other matters. In fact, the Oregon Commission does not even believe that it can bind a future Commission. In Oregon, the utility always has the burden of proving that it acted prudently, and (as part of that) bears the initial burden of producing evidence to

support prudence. When a utility follows the competitive bidding policies, then it has met its initial burden of producing evidence that it acted prudently and a party must then produce evidence of imprudence. From a legal perspective, the utility retains the overall burden of proof, but complying with the competitive bidding requirements merely provides the benefit of making it easier for the utility to provide evidence of prudence.[22] Thus, in Washington, a determination that the utility followed or did not follow the competitive bidding rules would impact the evidentiary process, but not make a prudency determination.

F. Access to Confidential Information in RFPs by Lawyers Not Representing Specific Developers.

83. Representatives of non-bidding parties should be provided access to confidential material in utility RFPs, even if they represent bidders on other matters. In Oregon RFPs, the utilities have recently attempted (and failed) to restrict access to confidential information to only Staff and ratepayer advocates. The primary purpose of these restrictions is not to protect confidential material, but to ensure that those that can best police the utilities and understand the tricks they employ to ensure that utility owned assets win (NIPPC's representatives) are unable to meaningfully participate in an RFP. NIPPC urges the Commission to adopt Oregon's rule and policy of allowing non-bidding parties access to confidential material.[23]

84. To be clear, NIPPC's position is only that legal counsel for organizations with a legitimate non-commercial interest in the RFP like customer groups, renewable energy advocates

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22 Re PacifiCorp 2009 Renewable Adjustment Clause, OPUC Docket No. UE 200, Order No. 08-548 at 19 (Nov. 14, 2008).

23 See Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Resources, OPUC Docket No. AR 600, Order No. 18-324, Appendix A at 9 (Aug. 30, 2018) (setting forth rule OAR 860-089-0550 regarding protected information).

and NIPPC be allowed to access this confidential material. This would not include individual companies, for profit organizations, and non-lawyer representatives.

85. The Oregon Commission has a longstanding policy of allowing broad access to confidential RFP information to non-bidders, including organizations that may include bidders and attorneys who represent bidders on other unrelated matters. In a 2006 competitive bidding investigation, PacifiCorp raised concerns about the disclosure of detailed bid scoring and evaluation to non-bidding parties, and explained that "parties may include entities that could use this information to the commercial disadvantage of bidders or the utility."[24] Staff and Renewable Northwest Project ("RNP"), a renewable energy advocacy group that would likely have members who are bidders, opposed PacifiCorp's proposal. The Commission agreed "with RNP and Staff that non-bidding parties should have access to this information and have written the guideline accordingly."[25] There have been no problems with disclosures or inappropriate use of confidential material from utility RFPs.

86. This year the Oregon utilities suddenly re-raised the issue of access to confidential material by non-bidders. In a recent PacifiCorp RFP and in the Oregon Commission's competitive bidding rulemaking, efforts were made to eliminate access to non-bidding parties, even under protective order to limit the ability of stakeholders to review and the OPUC to evaluate the reasonableness of RFPs. The utilities' proposals would have prevented all of NIPPC's current attorneys to review confidential material, and any new counsel would not likely be familiar with NIPPC's interests and needs nor have the requisite knowledge of the rules, policies and/or competitive solicitations to provide competent legal advice.

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24 Re Commission Investigation Regarding Competitive Bidding, OPUC Docket No. UM 1182, Order No. 06-446 at 14-15 (Aug. 10, 2006).

25 Id. at 14.

87. The Oregon Commission agreed with NIPPC and revised PacifiCorp's protective order "to more specifically address NIPPC's concerns. The language is revised to limit only persons (including attorneys) that are involved in PacifiCorp's 2017R or 2017S RFPs. This will limit attorneys that represent current bidders in the 2017R or 2017S RFP process, but does not extend to attorneys that represent bidders on unrelated matters."[26] The Oregon Commission also agreed with NIPPC in the generic competitive bidding rulemaking that it would:

> not automatically eliminate access to protected information to a class of parties. We trust in the professional standards of the energy bar in Oregon, and expect all parties, individuals, and organizations trusted with protected information to strictly adhere to the letter and spirit of our protective orders. It is our conclusion that in practice, this has occurred and will continue to occur. However, this trust can and will be revoked if professional standards break down and information is disclosed improperly.[27]

88. The Washington Commission should reach the same conclusion and adopt Oregon's rule allowing broad access to confidential RFP material, unless they represent bidders in the RFP.

G. Definition of "Subsidiary" is Too Loose

89. The proposed rules offer a change to the definition of "subsidiary." This is an important definition to get right, because whether a company that bids in response to an RFP is a subsidiary or affiliate of a utility determines the level of scrutiny that is applied to the bid. Unfortunately, the proposed language excludes any company of which the utility owns more than five percent from being considered a subsidiary, so long as the utility "does not control" that company. "Control" could likely be interpreted as owning more than 50% of the voting power of a company. Thus, a utility could potentially have a major ownership interest in another company

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[26] Re PacifiCorp, dba Pacific Power Application for Approval of Final Draft 2017R RFP, OPUC Docket No. UM 1845, Order No. 18-080 at 3 (March 8, 2018).

[27] Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources, OPUC Docket No. AR 600, Order No. 18-324 at 14.

(such as 45%), but claim that it is not a “subsidiary” because it does not “control” the company. This would clearly be contrary to the intent of rules, which are to protect against utility bias in selecting resources from which the utility will earn a return for shareholders. Any significant ownership percentage in another developer raises the same issues of utility bias that warrant these rules in the first instance, and thus for the purposes of these rules, subsidiary should be considered based on ownership percentage alone.

H. Consultation During the RFP Process

90. The rules provide that “Utilities are encouraged to consult with commission staff during the development of the RFP.” NIPPC urges the Commission to modify the rules to make clear that utilities are encouraged to consult with other interested parties as well. Such consultation and discussion helps ensure a common understanding of a utility’s intent, approach, and goals, and would help avoid unnecessary miscommunications and disputes.

91. A significant problem in many RFPs has been that there were unmentioned requirements in the RFP that were not known by many of the bidders until after the RFP had been released,[28] or even after bids were received.[29]

92. NIPPC also requests that the rules make clear that parties have discovery rights with respect to the RFP process. This is a necessary tool to ensure that parties have access to communications between an IE and other parties, and to ensure that the Commission’s rules are

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28 For example, PGE’s RFP that selected its Carty gas plant that was ultimately $150 million over budget included a controversial gas storage requirement that was known to only PGE prior to the issuance of the RFP, which meant that only PGE could win the RFP in the end.

29 Only a limited number of resources could potentially compete in PacifiCorp’s recent Wyoming wind RFP; however, a much greater number of resources submitted bids, apparently unaware that they did not have a chance to become the winning bid. PacifiCorp ultimately may have acquired the least cost and least risk resource, but bidders should have been aware the requirements well in advance of the RFP.

followed. NIPPC recognizes that discovery will, of course, be subjected to appropriate confidentiality provisions and certain limitations on disclosure of competitive information.

I. Choosing the Independent Evaluator

93. The draft rules state that the utility recommends the IE to the Commission, after consultation with the Staff and appropriate stakeholders. NIPPC requests that the Commission modify this language to provide that the Staff make the recommendation instead. This gives the Staff greater influence over the selection of the IE, aids the IE's independence from the utility, and would also be consistent with the approach taken by the Oregon PUC in its recent rulemaking.[30]

94. NIPPC also recommends that the selection of the IE be done through an RFP, upon which interested stakeholders could comment. This would ensure that a broad pool of candidates is considered, and that the parties have a chance to comment on the types of qualifications that would be necessary to ensure independence, competence, and qualification of the IE. NIPPC has proposed rule language based on Oregon's process for engaging an IE which allows the process to be controlled by Staff and the IE selection made by the Commission and not the utility.

J. Removal of Provisions Regarding Utility Bias

95. The proposed deletions from WAC 480-107-135(2) and (3) seem to unnecessarily lessen the rules' focus on eliminating utility bias in resource selection. For example, the draft rules propose to remove the utility's requirement to articulate in the RFP how it will avoid unfair advantage in the RFP process. NIPPC recommends that these provisions be left in the rule, and is unsure why they were proposed to be deleted.

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30 See Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources, OPUC Docket No. AR 600, Order No. 18-324, adopting OAR 860-089-0200.

K. Use of Commission-Approved PPA and Transaction Documents

96. NIPPC recommends that the Commission review and approve any PPA and associated transaction documents for use in response to RFPs. In NIPPC's experience, the PPA documents can include onerous provisions that in and of themselves preclude PPA bids or steer the results toward a utility ownership option. For example, in PGE's recent Oregon RFP, that utility included language in its RFP PPAs that was objected to by the IE, Staff and stakeholders. PGE removed much of the language during the RFP approval process, and the Oregon Commission directed PGE to remove additional language that biased the results against PPA options.[31]

L. The Rules Should Limit the Ability to Use Interconnection Issues to Bias RFPs

97. The rules should specifically address how interconnection plays a role in the RFP process. In other states, RFPs have significantly limited the number of available projects by either outright excluding them, or including draconian scoring criteria that effectively precluded otherwise low cost and low risk projects in favor of utility owned resources that were further along the interconnection process. NIPPC recommends that the rules specify that a bidder need not have an interconnection agreement prior to completion of the formal RFP process.

98. Overly burdensome interconnection timelines will prevent otherwise viable projects from being considered in an RFP. This is particularly true when it is unknown when the next RFP will be issued, and developers may need to expedite their preparations to bid into an otherwise unforeseen RFP. The interconnection process in the Northwest, even when moving perfectly, can be cumbersome and time consuming, and it is not uncommon for there to be significant delays completely outside of the control of the developer. This may be especially true for studies

[31] Re PGE 2018 Request for Proposals for Renewable Resources, Oregon Docket No. UM 1934, Order No. 18-171 at 3-4 (May 21, 2018).

conducted by utilities that are not subject to FERC's interconnection jurisdiction, like BPA. Projects that are further along in the interconnection process will be able to produce a more refined bid and can be reflected in the negotiated price, but the process itself will should not structurally discriminate against any particular project.

M. Redlines Provided to Commission:

99. Attached to these comments are NIPPC's redlines to the proposed rules, reflecting the changes described in these comments and other modifications that NIPPC proposes.

IV. CONCLUSION

100. NIPPC requests that the Commission consider these above comments, and make the changes to the proposed rules in order to more fully protect customers, and ensure a level playing field between utility-owned resources and independent power producers by issuing rules that are effective at mitigating utility bias towards utility-owned resources.

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Dated this 21st day of September 2018.

Respectfully submitted,

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Of Attorneys for the Northwest and Intermountain Power Producers Coalition

Chapter 480-107 WAC

WAC 480-107-001 Purpose and scope. (1) The rules in this chapter are intended to provide an opportunity to minimize long-term energy costs and risks, complement the integrated resource planning process, and establish a fair, objective, and transparent competitive bidding process. The rules in this chapter require utilities to solicit bids, rank project proposals, and identify any bidders that meet the minimum selection criteria, except in circumstances beyond the scope of these rules or explicitly exempted from these rules.

Deleted: The rules in this chapter do not establish the sole procedures utilities may use to acquire new resources. Utilities may construct electric resources, operate conservation and efficiency resource programs, purchase power through negotiated contracts, or take other action to satisfy their public service obligations.

(2) The commission will consider the information obtained through these bidding procedures when it evaluates the performance of the utility in rate and other proceedings.

(3) To the extent of any conflict between these rules and the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA), Title II, sections 201 and 210, and related regulations promulgated by the Federal Energy Regulatory Commission (FERC) in 18 C.F.R. Part 292, PURPA and those related rules control.

WAC 480-107-002 Application of rules. (1) The rules in this chapter apply to any utility that is subject to the commission's jurisdiction under RCW 80.04.010 and chapter 80.28 RCW.

(2) Any affected person may ask the commission to review the interpretation or application of these rules by a utility or customer by making an informal complaint under WAC 480-07-910, Informal complaints, or by filing a formal complaint under WAC 480-07-370, Pleading—General.

(3) The commission may grant an exemption from the provisions of any rule in this chapter in the same manner and consistent with the standards and according to the procedures set forth in WAC 480-07-110 Exceptions from and modifications to the rules in this chapter; special rules. However, a utility must comply with the requirements regarding requests for proposals in these rules unless there is an emergency, such as a human-caused or natural catastrophe resulting from an unusual or unexpected event, that requires the utility to take immediate action; or there is a time-limited opportunity to acquire a resource of unique value to the utility's customers.

WAC 480-107-004 Additional requirements. (1) These rules do not relieve any utility from any of its duties and obligations under the laws of the state of Washington.

(2) The commission retains its authority to impose additional or

different requirements on any utility in appropriate circumstances, consistent with the requirements of law.

WAC 480-107-006 Severability. If any provision of this chapter or its application to any person or circumstance is held invalid, the remainder of the chapter or the application of the provision to other persons or circumstances is not affected.

WAC 480-107-007 Definitions. "Affiliate" means a person or corporation that meets the definition of an "affiliated interest" in RCW 80.16.010.

"Commission" means the Washington utilities and transportation commission.

"Conservation and efficiency resources" has the same meaning as defined by WAC 480-100-238(2).

"Conservation supplier" means a third-party supplier or utility affiliate that provides equipment or services that save capacity or energy.

"Generating facilities" means plant and other equipment used to produce electricity purchased through contracts entered into under these rules.

"Independent Administrator" means a third party, not affiliated with the utility, that manages and administers the request for proposal, and provides an evaluation of the utility's evaluation, selection criteria, and related analyses of all project bids and project proposals discussed in this chapter received in response to a request for proposal.

Deleted: evaluator

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"Independent power producer" means a non-utility entity that develops or owns generating facilities or portions thereof that are not qualifying facilities as defined in WAC 480-106-xxx.

"Integrated resource plan" or **"IRP"** means the filing made every two years by a utility in accordance with WAC 480-100-238 Integrated resource planning.

"Project developer" or **"bidder"** means an individual, association, corporation, or other legal entity that can enter into a contract with the utility to supply a resource need.

"Project proposal" or **"bid"** means a project developer's document containing a description of a project and other information in response to the requirements set forth in a request for proposal.

"Qualifying facilities" means generating facilities that meet the criteria specified by the FERC in 18 C.F.R. Part 292 Subpart B as described in WAC 480-106.

"Request for proposals" or **"RFP"** means the documents describing a utility's solicitation of bids for delivering a resource need.

"Resource need" has the same meaning as defined by WAC 480-100-238(2).

"Resource supplier" means a third-party supplier or utility affiliate that provides equipment or services that serve a resource need.

"Subsidiary" means any company in which the utility owns directly or indirectly five percent or more of the voting securities, and that may enter a power or conservation contract with that electric utility.

"Utility" means an electrical company as defined by RCW 80.04.010.

Deleted: A company is not a subsidiary if the utility can demonstrate that it does not control that company.

WAC 480-107-015 The solicitation process. (1) The utility must solicit bids for its resource needs identified during the IRP process. It must accept bids for a variety of energy resources which may have the potential to fill the identified needs including: electrical savings associated with conservation and efficiency resources; demand response; energy storage; electricity from qualifying facilities; electricity from independent power producers; and, at the utility's election, electricity from utility subsidiaries, and other electric utilities, whether or not such electricity includes ownership of property.

(2) A utility may participate in the bidding process as a resource supplier, or may allow a subsidiary or affiliate to participate in the bidding process as a resource supplier, pursuant to conditions described in WAC 480-107-135 Conditions for purchase of resources from a utility's subsidiary or affiliate and WAC 480-107-AAA Independent Administrator for Large Resource Need or Utility or Affiliate Bid.

(3) The solicitation process in this section is required whenever a utility's most recently acknowledged integrated resource plan demonstrates that the utility has a resource need within 3 years.

(4) Utilities are exempt from the RFP requirement under this section under the following circumstances:

(a) The utility's identified resource need of capacity is less than

(b) 50 megawatts, or provides no option of utility ownership of a resource; or, in the case of a resource need for energy storage, the resource in the utility's IRP is forecast to cost less than the estimated lowest cost of any 50 megawatt capacity resource in the IRP. The utility plans to satisfy the remainder of its identified resource need for capacity with short-term market purchases so long as sufficient regional adequacy to support these forecasted market purchases has been identified by the Northwest Power and Conservation Council in their latest published power supply

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adequacy assessment over the entire period of the utility's resource need or the next five years, whichever period is shorter;

(c) The utility's identified resource needs are for conservation and efficiency resources and the utility has previously issued an RFP in accordance with WAC 480-107-065;

(d)

Deleted: <#>The utility's identified resource need is for a distribution system or local transmission resources project estimated to cost less than $10 million; or
<#>The utility's identified resource need will be acquired under an existing tariff.…

(5) A project less than 50 megawatts requires an RFP if it is part of multiple projects that in aggregate provide the utility with more than 50 megawatts of capacity, the generation equipment of any one of these resources is within five miles of the generation equipment of any of these resources, and construction of these resources is performed under the same contract or within two years of each other. A utility may request that the Commission find that resources presumed to be aggregated as described in this section should not be considered in the aggregate, but bears the burden of rebutting the presumption that the acquisition is subject to these rules by showing each resource is separate and distinct. If the utility proceeds with a resource acquisition where the project meets the aggregation criteria without utilizing the RFP requirements of this rule, then the utility will be required to rebut the presumption that it should have followed the

guidelines when the utility seeks cost recovery of the resource in rates.

(6) A utility must submit to the commission a proposed RFP and accompanying documentation no later than one hundred thirty-five days after the utility's integrated resource plan is due to be filed with the commission. Interested persons will have sixty days from the RFP's filing date to submit written comments to the commission on the RFP. The commission will approve, approve with conditions, or suspend the RFP within thirty days after the close of the comment period.

(7) Utilities are encouraged to consult with commission staff and other interested parties during the development of the RFP. Utilities may submit draft RFPs for staff review prior to formally submitting a proposed RFP to the commission.

(8) A utility must solicit bids for resource needs within thirty days of a commission order approving the RFP, with or without conditions, as applicable. To solicit bids, a utility must post a copy of the RFP on the utility's public web site and place notices in relevant industry publications. The utility must maintain a list of potential vendors and communicate to those vendors when an RFP is issued.

(9) The utility must ensure that all bids remain sealed until the expiration of the solicitation period specified in the RFP.

(10) A utility may issue RFPs more frequently than required by this rule.

(11) Any person interested in receiving commission notice of utility proposed RFP filings may place their name on the IRP listserv on the commission's website.

WAC 480-107-025 Contents of the solicitation. (1) The RFP must identify the resource need, including any specific attributes or characteristics the utility is soliciting, such as the amount and duration of power, the avoided cost identified in the integrated resource plan, the type of technology necessary to meet a compliance requirement, and any additional information necessary for potential bidders to make a complete bid.

(2) The RFP must document that the size and operational attributes of the resource need requested are consistent with the range of estimated new resource needs identified in the utility's integrated resource plan.

(3) The RFP must allow any resources that meet a portion of the amount or a subset of the characteristics or attributes of the resource need to bid, including unbundled renewable energy credits for a renewable resource need, or conservation and efficiency resources for a capacity need.

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(4) The RFP must clearly explain the specific ranking procedures and assumptions that the utility will use in accordance with WAC 480-107-035 Project ranking procedure. The RFP must include a sample evaluation rubric that quantifies the weight each criterion will be given during the project ranking procedure. The RFP must also specify any minimum criteria and qualifications that bidders must satisfy to be eligible for consideration in the ranking procedure. The RFP must specify how any scores for non-price criteria will be assigned, and this scoring must be objective and reasonably subject to self-scoring analysis by bidders. Non-price score criteria that seek to identify minimum thresholds for a successful bid and that may be converted into minimum bidder requirements must be converted into minimum bidder requirements.

(5) The utility's RFP submittal must declare if the utility or an affiliate is allowed to bid into the RFP.

(6) The RFP must specify the timing of process including the solicitation period, the ranking period, and the expected selection period.

(7) The RFP must identify all financial security requirements and the rationale for such requirements.

(8) The RFP must identify utility-owned transmission assets that could be used by bidders to assist in meeting the resource need, and allow the use of such assets to be included in bids.

(9) The RFP must contain a Commission-approved power purchase agreement and associated transaction documents that contain terms and conditions that bidders may utilize in issuing a response to the RFP.

(10) The RFP may not limit bids to specific generation technologies or specific locations, or require an interconnection agreement prior to completion of the RFP process.

WAC 480-107-AAA Independent Administrator for Large Resource Need or Utility or Affiliate Bid. (1) If required to solicit bids under WAC 480- 107-015(3), a utility must engage the services of an independent evaluator to oversee the solicitation process if:

(a) The resource need is greater than 50 megawatts, or in the case of energy storage, the need is greater than the threshold in WAC 480-107-015(4)(a); and (b)(i) The utility, its subsidiary, or an affiliate is allowed to submit a bid; or (ii) The solicitation may result in acquisition of a resource that the utility will own at some point during the resource's operation.

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(2) The commission staff, after consulting with the utility and the appropriate stakeholders, must recommend an independent administrator for approval by the commission. In seeking qualified candidates for independent administrators, a request for candidates' proposals must be utilized, and staff will evaluate candidates' independence, proposed costs, experience and competence.

(3) The independent administrator will manage the RFP process, and contract with and be paid by the commission. The utility shall reimburse the commission for the costs incurred, and will be allowed to recover such costs through rates in the case where a utility bid was provided in response to the RFP. The commission staff will also manage the contract terms with the independent administrator.

(4) The independent administrator will, at a minimum:

(a) Ensure that the RFP process is conducted fairly and properly;

(b) Verify that the utility's inputs and assumptions including capacity factors are reasonable;

(c) Evaluate the unique risks of each bid;

(d) When the RFP allows bidding by the issuing electric company or an affiliate of the company, or includes resource ownership options for the electric company, the independent administrator must independently score the affiliate bids and bids with

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ownership characteristics or options, if any, and all or a sample of the remaining bids; and

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(e) For each bid with utility ownership that is included on the final short list of potentially winning bids, conduct a project-finance due diligence evaluation of the type utilized by financing institutions for purposes of securing financing from reputable financing entities prior to extending project financing for major generation facilities and complete a comprehensive report on the cost and performance assumptions in the bid and propose any necessary adjustments to the bid scoring and whether the bid should remain on the short list for final negotiations as a result of the conclusions of the report.

(5) The independent administrator will provide an initial report to the commission at the conclusion of the process, before reconciling project rankings with the utility, and a final report after reconciling project rankings with the utility in accordance with WAC 480-107-035(4) Project ranking procedure.

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(a) No stakeholder, including the utility or staff, shall have any editorial control over the independent administrator's initial report.

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(b) The final report should not differ significantly from the initial report and must explain any significant ranking differences and why the independent administrator and the utility were, or were not, able to reconcile the differences.

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(c) The utility, staff, and stakeholders may file responses to the final report with the commission.

(6) The utility, staff, and stakeholders shall have discovery rights with respect to the RFP process, as limited by any applicable protective order, and in accordance with WAC 480-07-400 and 480-07-405. Protected information will be provided to the Commission, the independent administrator, and non-bidding parties as appropriate under the terms of the protective order. Information shared under the terms of a protective order may be used in RFP review and approval, final short list acknowledgement, and cost recovery proceedings.

(7) The utility must give the independent administrator full access to examine and test the utility's production cost and risk models and any other model or data that is necessary for the independent administrator to complete its work.

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WAC 480-107-035 Project ranking procedure. (1) The commission must approve the procedures and criteria the utility will use in its RFP to evaluate and rank project proposals.

(2) At a minimum, the ranking criteria must recognize resource cost, market-volatility risks, demand-side resource uncertainties, resource dispatchability, resource effect on system operation, credit and financial risks to the utility, the risks imposed on ratepayers, public policies regarding resource preference adopted by Washington state or the federal government, environmental effects including those associated with resources that emit carbon dioxide, resiliency attributes, and reliability costs and benefits. The ranking criteria must recognize differences in relative amounts of risk inherent among different technologies, fuel sources, financing arrangements, contract provisions, and be consistent with the avoided cost methodology developed in the utility's most recently acknowledged integrated resource plan.

(3) The utility must evaluate project bids that meet only a portion of the resource need in conjunction with other proposals in developing the lowest reasonable cost portfolio. The utility must consider the value of any additional benefits, or costs that are not directly related to the specific need requested.

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(4) The utility and, when applicable, the independent administrator will each score and produce a ranking of the qualifying bids following

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the RFP ranking criteria and methodology.

(5) If the utility or an affiliate bids into the RFP or the RFP may result in utility ownership of the winning resource, then all bids involving utility or affiliate ownership will be first submitted and evaluated. The best score and price will then be announced to the bidders, and a second round of responses to the RFP will be conducted to determine if any independent power producer bids receive a better score than the utility- or affiliate-owned bid.

(6) Within five days after the sealed project proposals have been opened for ranking, the utility must make available for public inspection on the utility's website a summary of each project proposal.

(7) The utility may reject any project proposal that does not specify, as part of the bid, the costs of complying with environmental laws, rules, and regulations in effect at the time of the bid.

(8) The utility may reject all project proposals if it finds that no proposal adequately serves ratepayers' interests. The commission will review, as appropriate, such a finding together with evidence filed in support of any acquisition in the utility's relevant general rate case or other cost recovery proceeding. This provision does not relieve a utility of its requirements under these rules to receive bids for, and

utilize the required RFP processes before obtaining resources that meet the thresholds specified in these rules.

(9) After the process is concluded, the utility will provide access to each bidder to its own confidential scoring information.

(10) Within five days after executing an agreement for acquisition of a resource or determining that all proposals or bids will be rejected, the utility must make available for public inspection on the utility's website a final detailed ranking of results for all proposals, and the details of the winning bid pricing and scores.

WAC 480-107-045 Pricing and contracting procedures. (1) Once project proposals are ranked in accordance with WAC 480-107-035 Project ranking procedure, the utility must identify the bidders that best meet the selection criteria and that are expected to produce the relevant attributes as defined by that portion of the resource need to which the project proposal is directed.

(2) The project proposal's price, pricing structure, and terms are subject to negotiation.

WAC 480-107-065 Acquisition of conservation and efficiency resources. (1) A conservation and efficiency resource supplier may participate in the bidding process for any resource need. A utility or a utility subsidiary may participate as a conservation supplier, on conditions described in WAC 480-107-135 Conditions for purchase of resources from a utility's subsidiary or affiliate.

(2) All conservation and efficiency measures included in a project proposal must produce savings that can be reliably measured or estimated with accepted engineering, statistical, or meter-based methods.

(3) A utility must acquire conservation and efficiency resources through a competitive procurement process. A utility must use one of the following options:

(a) Option 1. A utility achieves at least thirty-three percent of the utility's conservation and efficiency resource program savings each biennium through competitively procured programs;

(b) Option 2. A utility solicits competitive proposals for each conservation and efficiency resource program in the portfolio at least every six years; or

(c) Option 3. A utility develops a competitive procurement framework in consultation with their conservation advisory group, as described in WAC 480-109-110 Conservation advisory group. If a utility develops a competitive procurement framework:

(i) The framework must define the minimum proportion of the utility’s budgeted conservation and efficiency resource programs that must be submitted for competitive bidding over a specified time frame;

(ii) The utility must document that the framework was supported by the advisory group;

(iii) The framework must be filed as an appendix to each biennial conservation plan, as described in WAC 480-109-120 Conservation planning and reporting; and

(iv) The first competitive procurement framework for conservation and efficiency may be filed with the 2020-2021 biennial conservation plan.

WAC 480-107-075 Contract finalization. (1) Unless otherwise prohibited by law, a utility may decide whether to enter into a final contract with any project bidder that meets the selection criteria of the RFP. Any bidder may petition the commission to review a utility's decision not to enter into a final contract.

(2) Except upon a showing of good cause, the utility must request that the Commission acknowledge the utility’s short list of resources for final negotiations when any utility-owned generating facility is

included in such list, and the utility must include the independent administrator’s comprehensive report described in WAC 480-007-AAA(4)(e) with its application for approval of the authorization to engage in final negotiations with the short list of bids.

(3) Any project bidder and utility may negotiate changes to the selected project proposal for the purpose of finalizing a particular contract consistent with the provisions of this chapter.

(4) The utility may sign contracts for any appropriate time period specified in a selected project proposal for up to a twenty-year term. The utility may sign longer-term contracts if such provisions are specified in the utility's RFP.

(5) If material changes are made to the project proposal after project ranking, including material price changes, the utility must suspend contract finalization with that party and rerank, and have the independent administrator rerank when applicable, projects according to the revised project proposal. If the material changes cause the revised project proposal to rank lower than projects not originally selected, the utility must instead pursue contract finalization with the next ranked project.

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WAC 480-107-135 Conditions for purchase of resources from a utility, a utility's subsidiary or affiliate. (1) The utility, its subsidiary, or affiliate may participate in the utility's bidding process, and the utility may solicit bids that will result in the utility owning the resource at some point during its operation. In these circumstances, the solicitation and bidding process will be subject to additional scrutiny by an independent administrator, pursuant to WAC 480-107-AAA Independent administrator for large resource need or utility or affiliate bid, and the commission to ensure that no unfair advantage is given to the utility, its subsidiary, its affiliate, or any bid that might result in the utility owning the resource.

(2) A utility, its subsidiaries or affiliates may not submit a bid or accept bids that will result in the utility owning the resource at some point during its operation unless the utility provides notice this may occur in the RFP. The utility must indicate in its RFP how it will ensure that the utility-owned resource, or the resource of its subsidiary or affiliate, through association with the utility, will not gain an unfair advantage over bids for a resource that will be owned and operated by an independent power producer during its operation.

(3) A utility must not disclose the contents of an RFP or competing

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project proposals to its own personnel involved in developing the utility's bid, or to any subsidiary or affiliate prior to such information being made public. The utility must include in the RFP and notice the methods used to assure that inappropriate information is tightly controlled and not communicated internally or with affiliates or subsidiaries.

(4) If a utility provides a bid in response to an RFP, it must include its requested regulated return in the total project costs, and that such return will be collected on a per-megawatt hour basis similar to cost recovery provided for with respect to power purchase agreements with independent power producers.

(5) If a project owned by the utility, affiliate, or subsidiary is the winning bid, the Commission will allow to be included in rates only the costs that were included in the bid used for comparative analysis in the RFP.

WAC 480-107-145 Filings—Investigations. (1) The commission retains the right to examine project proposals as originally submitted by potential developers. The utility must keep all documents supplied by project bidders or on their behalf, and all documents created by the utility relating to each bid, for at least seven years from the close of the bidding process, or the conclusion of the utility's general rate

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case, including any time period allowed for reconsideration or appeal, in which the fully-developed project was reviewed for prudence, whichever is later.

(2) The utility must file with the commission within 30 days of the conclusion of any resource RFP process a summary report of responses including, at a minimum:

(a) Specific reasons for any project rejected under WAC 480-107-035(6) Project ranking procedure.

(b) Number of bids received, categorized by technology type;

(c) Size of bids received, categorized by technology type;

(d) Number of projects received, categorized by technology type;

(e) Size of projects received, categorized by technology type; and

(f) Median and average bid price categorized by technology type. Categorization should be broad enough to limit the need for confidential designation whenever practical.

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WAC 480-107-999 Adoption by reference. In this chapter, the commission adopts by reference all or portions of regulations and standards identified in subsection (1) of this section. The publication, effective date, reference within this chapter, and availability of the resources are as follows:

(1) Pacific Northwest Power Supply Adequacy Assessment as published by the Northwest Power and Conservation Council.

(a) The commission adopts the Pacific Northwest Power Supply Adequacy Assessment for 2023 published in 2018.

(b) This publication is referenced in WAC 480-107-015.

(c) Copies of Pacific Northwest Power Supply Adequacy Assessment for 2023 are available from the Northwest Power and Conservation Council at https://www.nwcouncil.org/energy/energy-topics/resource-adequacy/pacific-northwest-power-supplyadequacy-assessment-for-2023.

Attachment C

Rulemaking for Integrated Resource Planning,
WAC 480-100-238, WAC 480-90-238, and WAC 480-107,
Docket No. UE-161024,
NIPPC Reply Comments Regarding Proposed RFP Rules
(Oct. 26, 2018)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

U-161024

In the Matter of Rulemaking for Integrated Resource Planning, WAC 480-100-238, WAC 480-90-238, and WAC 480-107	)))))))	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION REPLY COMMENTS REGARDING PROPOSED RFP RULES

I. INTRODUCTION

1. In accordance with the Washington Utilities and Transportation Commission's (the "Commission" or "WUTC"), October 11, 2018 Notice in this docket, Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these Reply Comments regarding the Commission's draft rules related to competitive procurement for electric utilities (WAC 480-107).

2. In these comments NIPPC provides: 1) responses to the new questions posed by the WUTC in its October 11, 2018 Notice of Opportunity to File Written Reply Comments; and 2) responses to comments from certain other parties in this proceeding.

II. COMMENTS ON UTC's SPECIFIC QUESTIONS

1) Independent Evaluator Requirement.

3. The Commission requested feedback on a new proposal, designed to encourage the use of an Independent Evaluator ("IE"). Under this proposal, the Commission would allow a utility to shorten the ninety-day process between when a utility files a proposed RFP with the Commission and when the Commission approves the RFP, to a process where there is a thirty-day comment

period, and the Commission would approve the RFP at its next regularly scheduled open meeting following the comment period. This process would occur so long as the utility has obtained the services of an IE for the RFP, and its retention of the IE was early enough to allow the IE to participate in the formulation of the RFP. The Commission asked specific questions about this proposal, which NIPPC addresses below.

a. Does the incentive of a shortened regulatory approval process for the RFP encourage the use of an IE?

4. NIPPC does not support using a shortened period of review as an "incentive" to encourage a utility to use the services of an IE. The purpose of retaining an IE should be to help ensure that an RFP process is fair, well-analyzed, and that it is designed to ensure the best resource options for meeting customers' needs. In NIPPC's view, these reasons justify *requiring* electric utilities to use the services of an IE under the circumstances where the thresholds in the rules are met, and there is no need to encourage the utilities to do what the rules should require.

5. The final rules should ensure that the IE is used as an important to tool to design fair and beneficial RFPs, and that stakeholders have an opportunity to review and comment on any draft RFPs. NIPPC values this opportunity for review, and it is a necessary and appropriate part of the Commission's implementation of its duties to protect customers. It would be counter-productive to determine that if a utility uses one tool for the protection of customers (an IE), that the other tool (review of the RFP) should be diminished in a material way. NIPPC believes that a thirty-day comment period is too short to ensure that parties have a chance to conduct meaningful review, discuss with their findings with their principals or members, conduct any necessary research or investigation, and develop effective and clear comments for the Commission's review.

b. Does the use of an IE adequately assure sufficient review of the RFP considering the tradeoff in the length of the stakeholder comment period?

6. Although the use of an IE helps assure a fair and effective RFP, it is not a given that it will always do so. The Commission should not see the IE as the "be all and end all" solution to designing a fair and transparent RFP. Even with the best and most professional IE, it is vital that the Commission's review process allow interested stakeholders an opportunity to review and provide comments to the Commission. It will serve no one's interests to have a rule that truncates review of the RFP due simply to the fact that an IE was utilized. As described above, the Commission should take reasonable steps to ensuring fair and efficient RFP processes in its rules, and this should include a requirement to utilize an IE *and* an adequate review and comment period by interested stakeholders and Commission Staff.

7. If the Commission is inclined to shorten the ninety-day review period, NIPPC recommends that the Commission take the approach recently adopted by the Public Utility Commission of Oregon in its competitive bidding rules. Those rules allow for an eighty-day review period, and allow a party to request to extend the period for an additional thirty days upon a showing of good cause.[1]

2) Role of the Independent Evaluator.

8. The Commission states in its Notice that the rule requirements regarding use of an IE will be the minimum requirements a utility must meet, and that a utility may contract for more in-depth involvement by an IE at its discretion. In light of this, the Commission asks what parties

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[1] OAR 860-089-0250(6).

envision is the proper role of an IE under the rules. The Commission asks parties to consider the following questions, which are each followed by NIPPC's response.

a. How deeply should the IE be involved in the development of the RFP? Should an IE independently score all bids, a sampling of bids, or only bids resulting in utility ownership?

9. NIPPC first points out that it does not believe it is practical to expect a utility to treat the rules regarding the use of IEs as only a minimum, and then voluntarily go above and beyond the requirements in expanding an IE's role beyond what is required. To the contrary, the Commission should bear in mind that the purpose of an IE is to assist in overseeing the utility's actions, and provide a second opinion as to the utility's analysis and conclusions. Likely in all cases, the Commission should expect that the level of involvement demanded by the rules will be the level of involvement that an IE will have.

10. NIPPC does not see any valid reason why the IE should not be given an expansive role in the development of the RFP. A qualified IE has the expertise to develop and manage an entire RFP process, and this process would be superior to having a utility run the process in terms of providing protection to customers, and ensuring a truly even field for independent power producers that want to compete for the opportunity to provide low-cost, low-risk resources to customers.

11. The IE should certainly do more than independently score only a sampling of bids. In other Commission processes, sampling is generally used where there is so much data that a review of all data is not practical. NIPPC does not anticipate that this would be the case when it comes to RFP responses. And, a sample would mean that one or more projects would go unreviewed by an IE, meaning that these projects would be measured against projects that likely were subject to a very different level of scrutiny, and may have a much more robust record of

their associated review. This would seem to introduce the potential for unfairness into the RFP process by potentially resulting in "apples to oranges" comparisons between certain bids.

12. If a utility project has bid into an RFP, then the IE should independently score that bid. And, because other projects will be competing against that bid, they too should be evaluated by the IE to ensure that the IE can directly compare those projects with the one(s) bid by the utility.

b. How should the IE be involved in communication between the utility and bidders?

13. The communications between the utility and bidders are of major importance within an RFP process. After all, it is these communications where a utility seeks additional information, provides responses to questions a bidder may have, and potentially starts to judge a project. Because all of these factors ultimately conclude with a utility's assessment of an individual bid, the IE should be heavily involved in these communications. To the extent that these communications are done by email, it is easy enough to copy the IE on all communications. And, where such communications are by phone, or through in-person meetings, it is also easy to include an IE either in person or by phone. These safeguards help ensure the fairness and integrity of an RFP process, and the Commission should require them.

c. Should there be a requirement that the IE document and file all communications with the Commission?

14. The IE should be allowed, as described above, to participate in and monitor all communications between the utility and the bidders. Such communications should be knowable by parties to the case, and therefore appropriate and reasonable documentation of such communications, such as notes, summaries, etc., should be subject to production.

d. In situations where there is a direct conflict between the IE and the utility should additional process be proscribed?

15. The purpose of the IE is to help ensure a fair and effective RFP process. In the event that there is a direct conflict between the IE and the utility, this would indeed be cause for concern, or at least further investigation. In such cases, NIPPC believes there would be good cause to ensure that sufficient review and discovery could occur. NIPPC recommends that parties be allowed to request up to thirty additional days for review during the course of RFP proceedings, for good cause shown. A direct conflict between the IE and the utility should be sufficient cause, if the dispute is material and relevant to an important issue in the process.

3) Conservation RFP.

16. NIPPC does not have comments regarding this question.

4) Market Purchases Resource Adequacy Exemption.

17. On the topic of resource adequacy, and the rules' proposed reliance on the Northwest Power and Conservation Council's resource adequacy assessment, the Commission notes that during the workshop, stakeholders suggested adding additional language. This additional language would limit the degree of reliance on the market a utility may have in order to qualify for the automatic exemption provided in the rules. The Commission asks:

a. If this idea were to be incorporated into rule, what level of reliance on the market would be reasonable?

b. Should the degree of reliance be tied to a separate metric? If so, what metric should be used?

c. Should an RFP be required for firm resources whenever there is significant market risk?

d. This section also uses the undefined term "short-term market purchases." Please provide comments on the following proposed definition: "Purchases of energy or capacity on the spot or forward market contracted for a term less than four years."

18. NIPPC recommends that the rules should not overly proscribe or limit the amount of reliance upon the market that is reasonable. Generally, Pacific Northwest markets are robust, and they may become significantly more so as regional transmission markets develop. However, NIPPC supports an RFP for firm resources when there is a significant market risk. Finally, NIPPC does not believe the rules need to include a definition for short-term market purchases because that term can change over time. If the Commission intends to include a definition in the rules, then the proposed definition is currently reasonable ("Purchases of energy or capacity on the spot or forward market contracted for a term less than four years.").

5) RFP Transparency.

19. In its Notice, the Commission cites comments that Public Counsel provided, which would modify the rules to regarding transparency in the RFP's evaluation rubric. Staff added one additional edit, such that the rules would read: "The RFP must include a sample evaluation rubric that either quantifies the weight each criterion will be given during the project ranking procedure or provides a detailed explanation of the aspects of each criterion specifically identified that would result in the bid receiving higher priority." Regarding this suggestion, the Commission asks:

a. Is this language sufficient to elicit the transparency stakeholder's desire in an RFP? Is this language reasonably flexible?

b. Will this requirement result in the utility being tied to and limited to criterion established prior to review of the bids that does not fit or account for the complexity of the evaluation of actual bids?

c. Should instead the utility be required to establish contemporaneous documentation of its criterion prior to receipt of bids and provide its contemporaneous reasoning for any changes to its criterion?

20. NIPPC generally supports the proposal regarding scoring criteria by Public Counsel, as modified by Commission Staff. As noted in earlier comments, NIPPC believes the Commission would be well-justified to apply an even more prescriptive set of criteria to limit the use of subjective scoring criteria that can undermine the process. Specifically, NIPPC continues to believe that the Commission would be justified in barring the use of non-price scoring criteria unless the utility can demonstrate those criteria cannot be converted to minimum bidder criteria in the RFP, as the Oregon Public Utility Commission recently did in its RFP rulemaking.[2] However, NIPPC nevertheless supports the Public Counsel proposal as modified by Staff given the apparent consensus around this definition.

21. As NIPPC's prior comments have explained, transparency of the scoring process and scoring criteria is a fundamental element to any fair bidding process.[3] The problem is most significant in the case of so-called "non-price" scoring criteria, such as the quality of the development team, permitting status, credit evaluation, status of interconnection and transmission. Unlike a price per unit of energy or capacity delivered, scoring criteria for these non-price elements of a bid can be inherently subjective. Yet it is common for a utility to allocate 20 to 40 percent of the bids' individual scores to these non-price attributes. Providing transparency as to the scoring criteria would assure the bidders that all bids will be evaluated according to the same metric, as opposed to some ad hoc, subjective analysis by the utility's evaluation team. It will also limit the ability of the utility to arbitrarily boost the score of its preferred utility-ownership bid. Further, transparency early in the process will allow interested

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[2] See NIPPC's Comments at 19-21 (Sept. 21, 2018) (citing Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources, OPUC Docket No. AR 600, Order No. 18-324 at 12-13 (Aug. 30, 2018) (adopting OAR 860-089-0400).

[3] See Id.

stakeholders to comment upon and possibly achieve a change to the utility's initially proposed scoring weights where a change in the utility's proposed weights is justified.

22. The Public Counsel's proposal, as modified by Staff, will provide added transparency to Washington RFPs. NIPPC understands the proposal to require that the RFP include a detailed description of the score card that will be used to evaluate the bids received in the RFP, including a detailed description of the characteristics that will result in a high score. Assuming that is the case, NIPPC supports the proposal. An example of this type of score card information is attached, as Attachment A, to these comments for reference, from the recent Portland General Electric Company's ("PGE") 2018 Renewable RFP.[4] The PGE 2018 Renewable RFP was not subjected to the full requirements of the recently adopted Oregon administrative rules referenced above, but it provides a good example of an adequately transparent scoring explanation in the case where the utility is allowed to heavily weight the non-price criteria.

23. As can be seen in the PGE RFP document, the scoring criteria are transparently presented in a table that sets forth the relative weight of each price and non-price characteristic.[5] In this case, the price score was worth 600 total points and the various non-price categories were worth a total of 400 points, which consisted of the following subcategories: 100 points allocated to Project Development criteria, 130 points allocated to Project Physical Characteristics, 120 points allocated to Project Performance Certainty, and 50 points allocated to Credit Evaluation. The PGE RFP document also contains a detailed explanation of the specific characteristics that will result in a full allocation of the available points for specific non-price sub-categories.[6] This type

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4 Also available online at: https://www.portlandgeneralrfp2018.com/documents/ (last accessed Oct. 24, 2018).

5 Attachment A, PGE's 2018 Renewable RFP, Appendix H at 8.

6 Id. at 11-17.

of transparency is essential to provide bidders the assurance that the evaluation is being conducted objectively and equally across all bids. There is no valid reason for a utility to fail to use the same score card for each bid or to withhold this type of information from the bidders and stakeholders.

24. The specific information relevant to each RFP will likely change from one RFP to the next. Therefore, NIPPC does not propose use of a uniform score card that might apply to all solicitations. Instead, the utility's proposed score card and explanations should be made available for public comment and revisions by the Commission before the individual RFP is released for bidding.

25. NIPPC opposes any changes to the scoring criteria once the RFP is released to bidders. The question here suggests that the scoring criteria established prior to review of the bids may not account for the complexity of the evaluation of actual bids, and thus may need to be changed during the bidding process. However, it is hard to understand how the criteria relevant to the bids could be unknown at the time of the solicitation. On the other hand, any change to the scoring criteria after receipt of bids would severely undermine the integrity of the process for the reasons discussed above. If the utility can modify the scoring criteria during the process, the RFP becomes a moving target for the bidders, who will be left to assume that the utility will change the criteria to ensure the utility-owned bids will score higher and win the solicitation.

26. In sum, NIPPC recommends using the language proposed by Public Counsel as modified by Staff for purposes of developing a rule related to the scoring criteria.

III. COMMENTS ON OTHER PARTIES' COMMENTS

1) NIPPC's Two-Stage Bidding Process Is Superior to PacifiCorp's Proposal

27. In NIPPC's prior comments, we demonstrated that a two-stage bidding process is standard practice in bidding procedures across different industries where one bidder is an interested party with decision-making authority in the process.[7] PacifiCorp has made a proposal that is not a two-stage process and would provide none of the benefits of the NIPPC proposal.

28. NIPPC's proposal is simple: first the utility determines the best utility-owned bids; second, the utility makes the details regarding the winning utility-owned bid known as the price-to-beat by the independent power producer bids. NIPPC provided examples of bankruptcy and corporate acquisitions and mergers where an interested party that is also a decision-maker in the process must conduct a two-stage process to ensure that it does not engage in preferential evaluation of its own bid. In those cases, the two-stage process is intended to protect the interest of third parties who will be affected by the transaction – in the case of corporate law, the two-stage process for management's acquisition of the corporation protects shareholders; in bankruptcy, the stalking horse bid protects the creditors of the bankrupt company. Similarly, here, the utility's ratepayers are protected by the proposed requirement to evaluate utility ownership options first and allow independent power producers to bid against the best utility-ownership offer. Given that a two-stage process is used in other commercial contexts to protect against self-dealing, the Commission should also use such a process to protect against utility self-dealing.

29. In written comments and at the workshop on November 2, 2018, PacifiCorp stated that it proposed an alternative form of a two-stage bidding process. However, PacifiCorp only

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[7] See NIPPC's Comments at 21-23 (Sept. 21, 2018).

proposes that the utility-owned bids be received first, not that the winning utility-owned bid be made known to the independent bidders to provide the price-to-beat for those bids for an independent-ownership structure.[8] Under PacifiCorp's proposal, the utility bids are sealed until after receiving the independent-ownership bids, but the process does not include any type of stalking horse offer or utility "price-to-beat" phase as NIPPC proposed. PacifiCorp's proposed restriction (sealing the utility-owned bids) would certainly be necessary to prevent the utility from potentially altering bids in the case where all the bids were evaluated in a single phase. But PacifiCorp's proposed single-phase restriction is not equivalent to the processes used in other contexts to prevent a self-interested party from influencing the solicitation to its advantage. The two-stage bidding process provides the type of transparency and protections that have been required in other commercial contexts where a self-interested party is involved in the evaluation of the transaction. It is not at all clear why the investor-owned utility industry is any different.

30. PacifiCorp argued at the workshop that NIPPC's proposal will encourage independent-ownership bids that are not commercially viable – colorfully suggesting the winning bid will be submitted by "three guys in an Avis." However, this perceived problem is unfounded because the RFP will contain other restrictions that would prevent commercially unviable bids from prevailing. The RFP would typically contain certain minimum bidding qualifications, and the resulting power purchase agreement would contain significant creditworthiness guarantees or security requirements to support damages for non-performance. Thus, while PacifiCorp's concern about "three guys in an Avis" was amusing, the other requirements of the RFP would prevent three guys in an Avis from prevailing in any PacifiCorp RFP unless they possessed requisite financial backing, development expertise, and a viable plan to perform on the bid.

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[8] PacifiCorp's Comments at 11 (Sept. 21, 2018).

31. NIPPC notes that while bidding criteria are appropriate for the above-described reasons, it is important to ensure that they are flexible enough to allow creative competitive options to succeed in the RFP process. Experienced development teams, though sometimes small, have brought multiple gigawatts of power generation capacity successfully online in the Western Interconnection in recent decades, including gas, hydro, wind, and solar, some of which was a result of winning utility RFPs and for single multi-hundred MW projects. The ability of these developers to participate in RFP processes should be encouraged, as it ensures that a full array of competitive options are made available to benefit ratepayers.

32. The utilities have also complained that the two-stage bidding proposal will unfairly disadvantage utility-ownership bids. That complaint incorrectly assumes that the Commission's objective is to ensure the utility's shareholders are entitled to own and profit from generation assets. Despite the lack of such a right, investor-owned utilities in the Northwest have historically enjoyed substantial advantage in the generation market for decades. Instead of perpetuating the utilities' generation monopoly, the Commission is instead responsible for ensuring the that the bidding process results in the least-cost, least-risk resource for the utility's captive ratepayers. The utility has an obvious and inherent incentive to engage in self-dealing to ensure that any RFP for a generation resource results in the new resource being placed in the utility's rate base where it can provide long-term profits to the utility's shareholders. That incentive is little different from the incentives that two-staged processes were developed to prevent in other contexts, such as bankruptcy and corporate law. If the utility-owned bids are the lowest cost bids, then the utility and the ratepayers will still end up with the same result under the two-stage process. However, the two-stage process gives the ratepayers the opportunity to

possibly obtain a lower cost resource by subjecting the self-interested utility-ownership bid to the market to see if any qualified bidder can beat the price with a commercially viable offer.

33. In sum, while PacifiCorp's proposal to seal utility-owned bids would be necessary in an RFP with single-phase evaluation of all bids, NIPPC maintains that the Commission should adopt the two-stage process to protect against utility self-dealing and provide the lowest cost resource to ratepayers.

2) Discussion Regarding IE Costs

34. There was discussion at the Commission workshop regarding the costs of IE participation in RFPs. In Oregon's recently concluded competitive bidding rulemaking, the Oregon Public Utility Commission Staff provided an analysis of the IE costs. Staff's comments are attached to this document, for the Commission's reference, as Attachment B.[9]

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[9] Also available at https://edocs.puc.state.or.us/efdocs/HAC/ar600hac11732.pdf (last accessed Oct. 24, 2018).

Dated this 26th day of October 2018.

Respectfully submitted,

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Of Attorneys for the Northwest and Intermountain Power Producers Coalition

Attachment A

PGE's 2018 RENEWABLE RFP-APPENDIX H

SCORING PROCEDURES

APPENDIX H

SCORING PROCEDURES

Overview

Appendix H details the RFP's Price and Non-Price Scoring components, which all bids will be subject to. The maximum possible price score will be 600 points, and the maximum possible non-price score will be 400 points. The maximum overall offer score a bid may receive is 1,000 total points. This 60/40 weighting of the price and non-price scores provides a balance between cost and risk, similar to that in the 2016 IRP, and consistent with past Commission-approved RFP processes. Appendix H also provides additional description on PGE's portfolio analysis methodology.

Price Scoring

Price accounts for 60% of the maximum overall offer score, or a maximum of 600 points out of 1,000 total. The price score will be determined by the ratio of the offer's projected total cost to its total benefits using real-levelized, or annuity methods, per Guideline 9a of Order No. 14-149 (Oregon Competitive Bidding Guidelines). The price scoring will incorporate benefits of expected energy value, capacity value, and flexibility value associated with each offer.

Price Scoring Ratio

Following the quantification of offer costs and benefits, including any necessary offer price adjustments (as outlined in the RFP main document section 8.5), each offer's component cost and benefits will be converted to a cost-to-benefit price score ratio. Real-levelized offer costs, divided by the equivalent real-levelized benefits value (incorporating energy, capacity, and flexibility benefits) will be the basis for the offer's price ratio.

Score Allocation

Once price ratios have been calculated for all offers, PGE will allocate price scoring points on a scaled basis, with 600 points allocated to the offer with the lowest (best) price ratio. The point allocation system is illustrated in the tables below, which are populated with fictitious cost-to-benefit and price scores for the sole purpose of illustrating the score allocation method.

Table 1. - Illustrative Scoring Example - Cost-to-Benefit Score

Cost-to-Benefit Ratio (%)	Price Score
75%	378
50%	528
80%	348
91%	282
60%	468
38%	600
88%	300
42%	576
101%	222

Table 2 - Illustrative Scoring Example - Price Ratio to Price Score

	Price Ratio	Price Score
Lowest (Best)	38 %	600
Highest	101%	222
Average	69.4%	411
Ratio Highest/Lowest	2.66	2.70

The lowest price ratio offer will receive the highest amount of points possible. All other offers will receive a scaled score, out of the 600 possible points, depending on their relative scores compared to the best score:

The lowest offer with a 38% price ratio will receive 600 points;

Any offer at or above a 138% price ratio will receive 0 points; and

An offer with a 75.0% price ratio will receive:

600-[600*(75%-38%)]

= 600-(600*37%)

= 600-222

= 378

Determination of the Energy Value

An offer's energy value reflects the value of energy generated throughout the offer's economic life or term. Energy value for the duration of the offer's term is expressed on a present-value basis and included in the denominator of an offer's cost to benefit price score ratio. The energy value will be based on the offer's simulated dispatch and the projected revenue associated with PGE's hourly market price forecast. The methodology used to create the hourly market price forecast is further described in Exhibit C, the 2016 IRP and the 2016 IRP Update.

Determination of Capacity Benefits

An offer's capacity benefit reflects PGE's need to acquire new, physical capacity resources due to the offer's estimated system capacity value. PGE is facing a capacity deficit, and requires capacity products, to otherwise displace the need to contract with or construct new peaking generating facilities. The capacity benefit will be included in the denominator of the offers cost to benefit price score ratio.

An offer's capacity benefit will be calculated as the product of the offer's capacity value and the avoided capacity cost. The product's capacity value will be calculated annually using the Renewable Energy Capacity Planning (RECAP) model. RECAP is described in Chapter 5 of the 2016 IRP. The model has been updated to accurately reflect the assumptions included in PGE's 2016 IRP Update filed in March 2018. The offer's capacity value will be expressed as the quantity of avoided simple-cycle combustion turbine (SCCT) needed to meet PGE's long-term capacity targets. The avoided capacity cost will be based on a per kilowatt, real-levelized cost (net of wholesale revenues) of a simple-cycle combustion turbine (SCCT). The assumed costs and performance of the SCCT are consistent with 2016 IRP capital costs and performance metrics (described in Chapter 7) operated under the updated reference case gas and wholesale power prices. The product of the offer's annual capacity value and levelized avoided capacity cost constitute the offers annual capacity benefit. Capacity benefit for the duration of the offer's term is expressed on a present value basis and included in the denominator of the price score ratio.

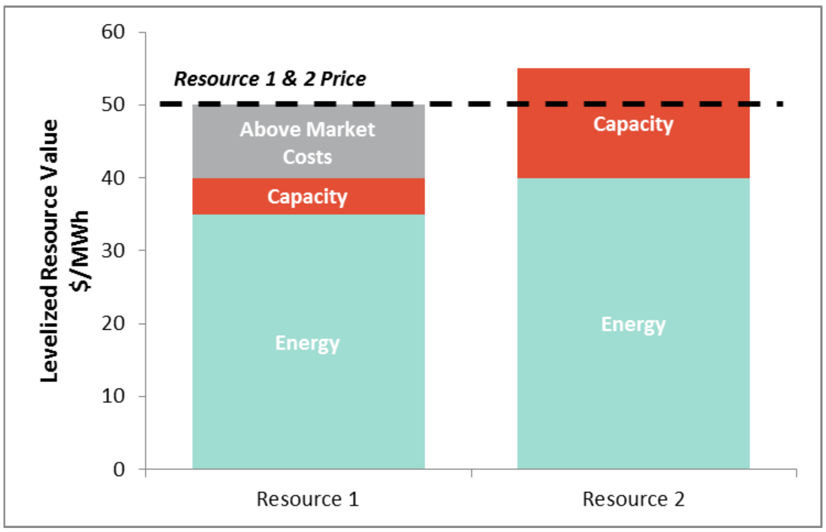
Determination of Flexibility Benefits

The flexibility value associated with an offer reflects any additional value that the offer may bring to PGE's generation portfolio due to its ability to ramp, respond to forecast errors, and/or provide ancillary services that is not captured by its energy value. PGE approximates flexibility benefits using the Resource Optimization Model (ROM), which the Company relied on in the 2016 IRP to quantify flexibility value associated with energy storage systems and the costs due to flexibility challenges (i.e., integration costs) associated with variable renewable resources. An offer's flexibility benefit is calculated using a methodology further explained in Example B. The flexibility benefit for the duration of the offer's term is expressed on a present value basis and is included in the denominator of the offer's cost-to-benefit price score ratio.

Price Screen

The cost-containment screen will be unique for each resource evaluated by PGE. The screen will be elevated for resources that provide more value to PGE customers due to the resource's geographic diversity. For this reason it is possible that a lower priced resource does not pass the economic screen, while a higher priced resource passes the economic screen due to increased resource value (e.g., higher capacity contribution, more valuable energy production profile or higher flexibility value). For example, Figure 1 illustrates a possible application of the proposed cost-containment screen. Resource **1** and Resource 2 have the same resource pricing. However, Resource 1's levelized cost exceeds the resource's energy, capacity and flexibility value. The resource is found to have above-market costs on a real-levelized forecasted basis and does not pass the economic screen. Resource 2 passes the economic screen as its resource value exceeds the resource cost.

Figure 1: Example of cost containment screen



It is PGE's expectation that the most economically competitive resources are capable of passing the proposed cost-containment screen. Table 3 provides an example of the applicable economic screen for generic 100 MW renewable resources.

Table 3: Example energy and capacity values for generic 100 MW resources*

	Gorge Wind ($/MWh)	Solar ($/MWh)	MT Wind ($/MWh)
Energy Value	$ 44.47	$ 38.70	$ 44.05
Capacity Value	$ 6.73	$ 8.15	$ 12.72
Total	**$ 51.20**	**$ 46.85**	**$ 56.78**

*Generic wind and solar resources are not considered dispatchable and therefore do not include flexible value.

Were these generic IRP resources to be evaluated within the RFP, the resources would only pass the cost-containment screen if priced below the total resource value. Importantly, each actual resource offered into the RFP will be screened against its unique resource value (not a generic threshold).

Non-Price Scoring

Non-Price accounts for 40% of the maximum overall offer score, or a maximum of 400 points out of 1,000 total. The non-price scoring will capture elements of the offers that are not easily captured in the price scoring. This is consistent with the RFP Guidelines, specifically 9a. The four main areas of focus are Development Criteria, Physical Characteristics, Performance Certainty, and Credit. See attached Exhibit A for the detailed Non-Price Scoring Rubric.

Portfolio Analysis

Portfolio modeling will provide PGE with additional information regarding the cost and risk profile of all offers considered. Portfolio analysis methods, consistent with the 2016 IRP, will demonstrate how resources perform together, on a cost and risk basis, due to their specific size, term, portfolio capacity value, and portfolio flexibility value.

Portfolio Construction

Portfolio analysis begins with the assembly of portfolios evaluating many different unique combinations of resources. The candidate portfolios will be developed through multiple techniques including 1) portfolio size optimization, 2) portfolio net-cost optimization, 3) cost-screened permutations, and 4) additional analyst selected portfolios (if necessary). The specific methodologies used to construct portfolios are described in further detail in Exhibit D.

Each portfolio will include sufficient resources to meet the RFP targeted capacity need in each year. The unique portfolio capacity value for each portfolio will be calculated using the IRP's RECAP methodology. The portfolio capacity calculation will recognize the resources' capacity diversity included in each portfolio. The RECAP model is described in Chapter 5 of the 2016 IRP. Any portfolio whose capacity contribution does not meet the RFP capacity target will also include a specified fill resource ('fill'). Including a fill resource ensures the portfolio incorporates the total cost necessary to meet the RFP capacity target in each year of the analysis. The specified fill resource will be sized to fulfill the resource target in each year of the analysis.

The specified fill resource will have cost and performance characteristics comparable to the average cost and performance of new resources of like product type offered into the RFP.

Portfolio Analysis

Portfolio analysis will test combinations of resources across multiple futures. The futures will evaluate portfolio exposure to multiple scenarios of gas prices, carbon costs, and hydro conditions. The futures are discussed in Exhibit C. For each portfolio, the relevant resources' variable costs and energy benefits will be calculated recognizing AURORA results under 27 economic and hydro futures. The variable net income for each resource will be reported annually for all futures. The AURORA dispatch simulation is described in Exhibit C.

A unique portfolio flexibility value will be calculated using the portfolio flexibility tool. The portfolio flexibility calculation will recognize the flexibility diversity included in each portfolio. The portfolio flexibility calculation is further detailed in Exhibit B.

For each portfolio, the portfolio flexibility value and the relevant resources' net incomes will be subtracted from the relevant resources' fixed costs to calculate the portfolio's total net cost for each future.

For each portfolio, the total present value net cost for years 2019 through 2050 under each future will be calculated to estimate the cost impact of the additions on the PGE system. This expected cost impact will be measured as the total portfolio net present value of revenue requirement (NPVRR) under reference case conditions. Portfolio risk will be evaluated using the standard deviation of future results. Portfolios will be ranked according to a blended cost and risk metric based 50% on reference case expected cost and 50% based upon the standard deviation of portfolio costs. In addition, portfolio risk will be characterized using additional IRP risk metrics including severity, variability, and durability as described in the 2016 IRP Chapter 11.

Portfolio results will be stress tested under multiple resource targets and qualifying facility planning scenarios. Specifically, PGE will test a 2018 through 2040 planning horizon sensitivity in addition to a 2018 through 2050 base planning horizon.

Portfolio analysis performance will be based on the inclusion of specific offers across multiple top-performing portfolios. Those resources that appear most frequently in top-performing portfolios are those that best reduce cost and economic risks. However, non-price factors are not evaluated or considered in portfolio analysis.

Exhibit A – Scoring Criteria

Exhibit A - 2018 RFP Scorecard Template

Summary

Bid Number:		Fill In	
Summary	**Max Score**	**Bid Score**	**Description**
1. Price Scoring	600		
2. Project Development Criteria	100	0	Includes Development team experience, Permitting, Project Finance, Cost Certainty
3. Project Physical Characteristics	130	0	Interconnection, Transmission rights, Resource Certainty (production assessment), Engineering Reliability
4. Project Performance Certainty	120	0	Firmness of Energy, Scheduling, Technological maturity, Online date, Contractual elements
5. Credit Evaluation	50	0	Score based on counterparty's ratio and debt rating
Total Score	1,000	0	

Exhibit A - 2018 RFP Scorecard Template

Thresholds

Bid Number:		Required at Bid Submittal or Short List	Yes	No
1. Proposal satisfies minimum bid quantity and duration criteria:				
Size and Term	Minimum size of 10 MW with minimum 20 year duration.	Submittal		
Qualifying Product	Projects must include all associated Renewable Energy Credits (RECs) and all environmental attributes.	Submittal		
Registered Product	Bidder will be responsible for ensuring RECs are established in WREGIS.	Submittal		
2. Proposal satisfies minimum development criteria				
Site Control	Title, executed lease or executed option agreement for a minimum of 80% of site, with 100% required two weeks prior to final short list.	Submittal and Short list		
Permitting	Refer to attached permitting table attached.	Final Short list		
Project Financing	Demonstrated ability to internally finance project or evidence of good faith commitment from financing institution/financial backer prior to final short listing.	Final Short list		
Equipment costs estimates - PPA	OEM Supply agreements or quote. LTSA quote optional.	Submittal		
Equipment costs estimates - Utility Ownership	OEM and APA+EPC/BOT bid quote. LTSA quote optional.	Submittal		
Tax Credit Eligibility	New Wind projects must include PTC Opinion from qualified accounting firm for PTC eligibility. Solar projects claiming ITC eligibility must demonstrate plan to receive the credit.	Submittal		
3. Proposal satisfies minimum physical characteristics criteria				
Interconnection	Executed System Impact Study Agreement.	Submittal		
Interconnection	Completed Interconnection Facilities Study	Final Short list		
Off System Bidders - BPA Transmission:	Already have long term firm service, PTSA for long term firm service, or CF bridge service agreement transitioning to long-term firm within three years upon near-term, viable upgrades. Alternatively, the project is included in BPA's currently active TSEP process or has requested and been accepted for Individual Study.	Submittal		

Off System Bidders - BPA Transmission:	Has transmission study schedule that allows transmission service commitments by December 31, 2018. For bidders relying on the TSR Study and Expansion Process (TSEP) or Individual Study Process, transmission service commitments will be deemed demonstrated by completion of phase four (Record of Decision issued) or completion of the facilities study respectively.	Final Short list		
On System Bidders - PGE Transmission	Already have service or granted facility plan with approved construction plan targeting completion at least six months prior to COD.	Submittal		
Resource certainty - Historical Data Requirements:	Wind/Solar/Hydro resources must provide a minimum 3-years of data and include an output study from verifiable third-party. Geothermal proposals must have feasibility report completed, based on a year or more of test data from full diameter production wells. Biomass/biogas proposals must come with long-range fuel supply plan with identified, established suppliers and transportation options.	Submittal		
4. Proposal satisfies minimum performance certainty criteria				
Quality of Power	Must be at a minimum unit contingent agreement associated with an identified resource.	Submittal		
Power Scheduling	Off-system resources: Must be integrated by third-party balancing services delivered to PGE using hourly schedules. On-system resources: Must be designated Network Resources.	Submittal		
Technological acceptability - Utility Ownership	Major equipment manufacturer must be on attached preferred vendor list.	Submittal		
Online Date	Online on or before December 31, 2021.	Submittal		
Contractual requirements	Proposed contractual structure, redline or otherwise, must contain provisions related to: Liability Caps, Indemnification, Default/Termination Rights, Performance Guarantees, Remedies for non-performance, and Security/Collateral.	Submittal		
5. Proposal satisfies minimum credit threshold criteria				
Security requirements	PGE will only award contracts to Bidders that have, at a minimum, investment grade credit rating (or with investment-grade guarantors) and can prove that they can provide acceptable performance assurance at time of execution. Investment grade as rated by S&P, Moody's, DBRS and/or Fitch, requires ratings at a minimum must be BBB-, Baa3, BBB low, or BBB- respectively.	Submittal		

Exhibit A - 2018 RFP Scorecard Template

Development Criteria

Development Criteria	Score	Weight	Total	Scoring Rules
2. Project Development Criteria Max Score = 100			100	Measures likelihood that project to support proposal will be placed into commercial service on time and on budget
2. Project already in service	0	14	0	Use the following scoring rules for projects that are already in operation: Operating plants should be given a score of 5 points, however this score can be reduced by 1 point if the plant has experienced extended outages, shutdowns or closures during the asset life. For scoring product development from portfolios use the following rules: (1) If product mostly supplied from a specific plant, use that plant for scoring (2) If product supplied from several plants, use the average score from all plants.
For projects not in service proceed with questions below, otherwise go to Section 3				
2.a Permitting status (see permitting attachment)	2	10	20	2 = All project permits and Site Certificate approved.
				1 = Major permits approved
				0 = Permit process underway, all permits timely acquired consistent with identified thresholds
2.b Experience of Project Team	2	5	10	2 = Successfully developed multiple similar projects in WECC delivered on time without material facility unplanned outages within first year.
				1 = Successfully developed multiple similar projects in US.
				0 = Successfully developed similar project in US.
2.c Project Financing	1	10	10	1 = Project can be internally financed by developer. Alternatively, project has financing agreement (e.g. primary lender, and tax equity as appropriate) with credible funding source with joint commitment to proceed.
				0 = PGE bid award needed to obtain financing (e.g. lender commitment contingent on bid award)
2.d Site Control: Including all rights required for project including access to the project site, easements and resources rights appropriate for the project	1	15	15	1 = Title/Executed lease or options for a minimum of 100% of site
				0 = Title/Executed lease or options for a minimum of 80% of site
2.e Cost Certainty - equipment	3	5	15	2 = Pricing guarantee for identified major equipment in addition to executable agreement for prime movers (e.g. turbines, panels)
				1 = Executable agreement for prime mover (e.g. turbines, panels)
				0 = OEM quotes for prime mover (e.g. turbines, panels)
				+1 for LTSA or other long-term service quote
All proposals regardless of current online status				
2.f Cost Certainty – Value of Extension	2	10	20	2 = Allows contract extension at original contract price or purchase option at book value or allows for continued operation at cost for benefit of customers
				1 = Allows contract extension at price certain or purchase option at known price
				0 = Allows for no rights for contract extension or purchase option. Alternatively allows for contract extension or purchase

				option at unknown price (e.g. fair market value)
For ownership proposals regardless of current online status				
2.g Cost Certainty - Milestone payments	1	10	10	1 = Payments at, or under PGE suggested milestone schedule (i.e. payments total less than actual completion percentage prior to completion)
				0 = Payments match with PGE suggested milestones
				-1 = Payments front loaded relative to proposed schedule of values and milestone payment schedule
For PPA proposals regardless of current online status				
2.h Cost Certainty – Pricing Structure	0	5	0	2 = Contract price does not escalate and does not include capacity payment
				1 = Contract price escalating at known and committed escalation rate and does not include capacity payment
				0 = Contract price escalating at market based escalator (e.g. historical CPI) or does include capacity payment

Exhibit A - 2018 RFP Scorecard Template
Physical Characteristics

Physical Characteristics	Score	Weight	Total	Scoring Rules
3. Physical Characteristics Max Score = 130			130	Measures project specific physical attributes for each offer. For scoring physical characteristics from portfolios use the following rules: (1) If product primarily supplied from a specific plant, use that plant for scoring; (2) If product supplied from several plants, use the average score from all plants.
3.a Interconnection Rights	5	10	50	5 = Executed LGIA or project in operation.
				4= Tendered LGIA, in Negotiations.
				3 = Executed optional Engineering and Procurement Agreement (E and P) or procurement agreement for long-lead interconnection items if applicable.
				2 = Completed Interconnection Facilities Study (must be completed prior to final short list).
				1 = Completed Interconnection System Impact Study.
				0=Executed System Impact Study Agreement.
3.b.1 Long Term Firm Transmission Rights on BPA's transmission	4	10	40	4 = Existing long-term firm rights to BPAT.PGE POD.
				3 = Existing long-term firm rights confirmed by transmission provider to be redirectable to PGE's system.
				2 = Executed PTSA for existing firm transmission to BPAT.PGE POD.
				1 = PTSA agreement executed for identified upgrades. PTSA contains offer of conditional firm-bridge service that converts to long-term service upon completion of upgrades. Facility upgrades to be completed no later than three years after COD.
				0 = Project included in the currently active round of TSEP or has requested and been accepted for Individual Study.
3.b.2 Long Term Firm Transmission Rights on PGE's Transmission	0	10	0	4 = Executed Interconnection Agreement with Network Resource Integration Service or existing long-term firm rights.
				2 = Tendered Interconnection Agreement with Network Resource Integration Service or executed Construction Agreement.
				1 = Completed Facility Study.
				0 = Completed System Impact Study.
3.c Projects Subject to BPA Oversupply Management Protocol	0	-10	0	1 = Project subject to BPA Oversupply Management Protocol.
				0 = Project not subject to BPA Oversupply Management Protocol.
3.d Remedial Action Scheme Projects Subject to (RAS)	1	10	10	1 = PGE able to use resource as a credit for its obligation to support AC intertie RAS.
				0 = No RAS.
3.e Engineering Reliability	5	2	10	For all project types (maximum of 5 points)
				1 = PGE is able to influence in maintenance and availability

				decisions impacting reliability (0 if no influence). 2 = The experience and expertise of O&M operator (<5 years=0, 5-9 years=1, >10 years=2). 1 = The owner and/or operator is supported by local or centralized engineering staff (0 otherwise). 1 = The seller has an established relationship with prime mover vendor including vendor support through a service agreement (<5 years=0, 5-9 years=.5, >10 years=1).	
Resource Specific Issues					
3.f Resource Certainty	**Wind/Solar/Hydro Resources**				Select Resource type for 4.a
	4	5	20	4 = 7+ years data. 3 = 6-years data. 2 = 5-years data. 1 = 4-years data. 0 = 3-years data (threshold). 2 = Wind project is a staged build-out of an adjacent project (assumes adjacent project has at least 7 years' wind data and the adjacent project has a similar wind microclimate to the original project).	
	Geothermal Resource				
	0	20	0	1 = Production and injections wells for the project drilled and completed. 0 = Feasibility report completed, based on >1 year of test data from full diameter production wells.	
	Biomass/Biogas – Project Fuel Supply				
	0	5	0	4 = Firm access to multiple fuel sources for 100% or greater of need, with ability to store fuel on site and options for fuel transportation. 3 = Firm access to multiple fuel sources for 100% or greater of need. 2 = Have executed long-term fuel supply contract for minimum of 60% of need with ability to store fuel on site and options for fuel transportation. 1 = Have executed long-term fuel supply contract for minimum of 60% of need with plan for remaining need. 0 = Have fuel supply plan with identified, established suppliers and transportation options.	

Exhibit A - 2018 RFP Scorecard Template

Performance Certainty

Performance Certainty	Score	Weight	Total	Scoring Rules
4. Performance Certainty Max Score = 120			120	Measures project specific commercial and delivery attributes for each offer.
4.a Quality of Power - Firmness of Energy	2	10	20	2 = Backed by physical resources or system with resupply obligation for curtailments or outages including make whole provisions for bundled RECs.
				1 = Backed by physical resources or system with finite resupply obligation for curtailments or outages including finite make whole provisions for bundled RECs.
				0 = Finite resupply obligation without make whole provisions for RECs.
4.b Quality of Power - Scheduling Period Commitment	2	5	10	2 = Weekly or greater in scheduling.
				1 = Pre-schedule.
				0 = Hourly.
4.c Online Date	2	10	20	0 = prior to 12/31/2019.
				2 = After 12/31/2019 and prior to 12/31/2020.
				1 = After 12/31/2020.
4.d Guarantee Available Factor	2	5	10	2 = Minimum mechanical availability agreement of 97% or greater for any two out of three calendar years on a rolling basis.
				0 = No stated minimum mechanical availability commitment.
4.e Liability Cap Contractual Terms and Conditions Redlines	6	2	12	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.
4.f Indemnification Contractual Terms and Conditions	6	2	12	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or

				cost.
4.g Default & Termination Contractual Terms and Conditions	6	2	12	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.
4.h Security and Collateral Contractual Terms and Conditions	6	2	12	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.
4.i Performance Guarantees and Remedies of Non-Performance Contractual Terms and Conditions	6	2	12	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.

Exhibit A - 2018 RFP Scorecard Template

Credit

Credit	Score	Weight	Total	Scoring Rules	
5. Credit Evaluation Max Score = 50			50	**Score based on Bidder, not Guarantor**	
5.a PGE ratio analysis score	10	2	20	10=Credit score of 10	5=Credit score of 5
				9=Credit score of 9	4=Credit score of 4
				8=Credit score of 8	3=Credit score of 3
				7=Credit score of 7	2=Credit score of 2
				6=Credit score of 6	1=Credit score of 1
5.b Bond Rating	10	2	20	10=Aaa/AAA	
				8=Aa/AA	
				6=A/A	
				4=Baa/BBB	
				2=Baa-/BBB-	
				0=Below BBB- or not rated	
5.c Tangible Net Worth	10	0.5	5	10 >1,000mm	5=600mm-501mm
				9= 1000mm-901mm	4=500mm-401mm
				8= 900mm-801mm	3=400mm-301mm
				7= 800mm-701mm	2=300mm-101mm
				6= 700mm-601mm	1= <100mm
5.d Corporate Structure	5	1	5	5=Publicly Traded	
				4=Publicly Traded subsidiary	
				3=Private Corporation	
				2=Private LLC	
				1=Sole Proprietorship/Partnership	

Permitting Timing Guidelines

Permits (if applicable to the specific project)	Wind	Solar	Geothermal	Hydro / Pumped Storage	Biomass
Detailed Plan for Obtaining All Major Permits (w/schedule)	Bid	Bid	Bid	Bid	Bid
State/local siting permit (e.g. site certificate, conditional use permit)	Award	Award	Award	Bid	Award
Federal siting permit (e.g. NEPA Record of Decision for construction*, FERC License or final EIS from FERC) **This does not include NEPA for an Eagle Take Permit*	Award	Award	Award	Bid	Award
Air quality permit (e.g. ACDP)	N/A	N/A	N/A	N/A	Award
FCC permit	Award	Award	Award	Award	Award
FAA permits	CP	Award	N/A	Award	Award
Airspace and Obstacle Evaluation Analysis	Bid	N/A	N/A	N/A	N/A
Water rights	N/A	N/A	Award	Bid	Award
Wastewater discharge permit (e.g. NPDES, WPCF)	N/A	Award	Award	N/A	Award
Construction Permits (NPDES - 1200 C, etc.)	Award	Award	Award	Award	Award
Removal Fill Permits (DSL and Corp)	Award	Award	Award	Award	Award
Eagle surveys finished or nearly finished	Bid	Bid	Bid	Bid	Bid
Federal ESA surveys completed	Bid	Bid	Bid	Bid	Bid
Cultural Resources Surveys	Bid	Bid	Bid	Bid	Bid
Tribal coordination (Traditional Use Studies. Traditional Cultural Properties)	Bid	Bid	Bid	Bid	Bid
Misc: Dikes, Scenic Areas, Local Requirements	Award	Award	Award	Award	Award

Key:					
Bid - Approved by bid submittal date					
Award - Approved by bid award date					
CP - Approved as a condition precedent in the definitive agreement(s)					
N/A - Not applicable					

2018 Renewable RFP - Major Permit Identification by Technology

Wind	Solar	Geothermal	Hydro / Pumped Storage	Biomass
Federal and State and Local Permitting	Federal and State and Local Permitting	Federal and State and Local Permitting	Federal and State and Local Permitting	Federal and State and Local Permitting
		Water Rights	Water Rights	Air Permit
		Wastewater Permit	Construction Permits	Water Rights
			Removal Fill Permits, if appropriate	Wastewater Permit

Local permits include Conditional Use Permit and Zoning Permit

2018 Renewable RFP Major Equipment Preferred Vendors

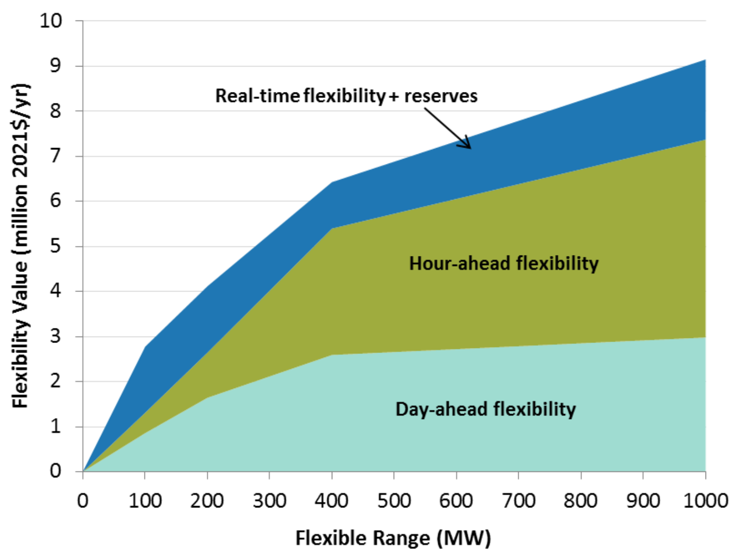
Substation Main Power Transformer	GSU Pad-mount Transformers	Photovoltaic Inverters	Photovoltaic Modules	Wind Turbine Generators
ABB, Varennes, Canada shop	ABB	SMA	JA Solar	General Electric
ABB, St. Louis, Missouri shop	CG Power Systems USA	Power Electronics	Trina Solar	Siemens Gamesa
ABB, Bad Honnef, Germany shop	General Electric	TMEIC	Jinko	Vestas
ABB, South Boston, Virginia shop	Cooper Power Systems	Eaton	Canadian Solar	Nordex/Acciona
HICO, ChangWon, South Korea shop	Siemens	General Electric	Hanwha Q-Cells	
Hyundai, Montgomery, Alabama shop	Pacific Crest Transformers	ABB	First Solar	
Hyundai, Ulsan, South Korea shop			Sunpower	
Smit, Nijimegen, The Netherlands shop			Kyocera	
SPX Waukesha, Waukesha, Wisconsin shop			LG	
EFACEC, Arroteia, Portugal shop			REC	
Siemens, Guanajuato, Mexico shop				
GE Prolec, Monterrey, Mexico shop				
Shihlin, Taipei, Taiwan shop				

Exhibit B – Flexibility

B.1 Flexibility value functions

In preparation for the evaluation of offers, PGE conducted a series of simulations with the ROM tool to isolate the flexibility benefits of perfectly flexible products available in various time frames (day-ahead, hour-ahead, and real-time[1]) and at various sizes (100MW, 200MW, 400MW, and 600MW) in a 2021 test year. For each simulation, the resource operational value was calculated as the annual operational cost difference between the PGE resource fleet with the perfectly flexible resource and the PGE resource fleet without the perfectly flexible resource. The flexibility value was isolated by subtracting the market revenues that the resource was capable of providing if it had dispatched to market in all hours from the total operational value obtained by optimizing its dispatch in coordination with the PGE resource fleet. This exercise yielded a set of functions that could be used to approximate the flexibility value associated with each offer in each stage according to its "flexible range" – the portion of the resource capacity that could be approximated as perfectly flexible in each stage. These functions are shown in the figure below.

Figure 1. Flexibility value functions by stage and size



The annual flexibility values shown in the above figure were allocated to each season based on the seasonal distributions of the flexibility values identified by

[1] Real-time flexibility was bundled with the ability to provide load following, regulation, spinning, and non-spinning reserves, since the incremental value of these ancillary services was found to be relatively small.

ROM. The resulting allocation factors, which are summarized in the table below, were used to obtain monthly flexibility values by stage and flexible range.

Table 3. Flexibility value seasonal allocation factors

Stage	Q1	Q2	Q3	Q4
Day-ahead flexibility	25%	34%	30%	10%
Hour-ahead flexibility	19%	34%	33%	13%
Real-time flexibility + reserves	27%	23%	39%	12%

Flexibility values were assumed to escalate at inflation through the analysis horizon.

B.2 Flexible ranges

For each offer, flexible ranges are calculated for the day-ahead, hour-ahead, and real-time stages based on the operating characteristics of the resource. The flexible range calculation is conducted on a monthly basis over the full duration of the resource in the PGE portfolio. This calculation depends on whether the offer reflects an energy-limited or non-energy-limited resource. Energy-limited resources are those with a fixed amount of energy that much be used over a stated length of time – in other words, they behave like hydro resources. Non-energy-limited resources are all other resources that do not have this energy-driven constraint – they behave more like thermal resources.

B.3 Energy-limited

In the flexibility evaluation, each energy-limited resource is characterized by its minimum (p_m^{min}), maximum (p_m^{max}), and average (p_m^{avg}) dispatch level by month throughout the resource duration. Flexible ranges may also be limited by a fixed amount in each stage (f_k). In month m and stage k, the flexible range for an energy-limited resource is:

$$\min\left[2\left(p_m^{max} - p_m^{avg}\right), 2\left(p_m^{avg} - p_m^{min}\right), f_k\right]$$

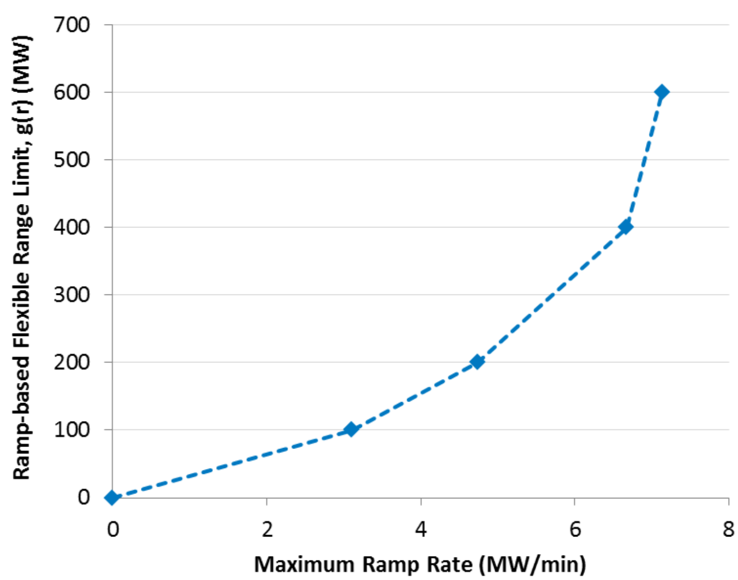
B.4 Non-energy-limited

Non-energy-limited resources are characterized in the flexibility evaluation by their monthly maximum output (p_m^{max}), minimum output (p_m^{min}), availability in each stage (a_{km}), ability to be re-comitted in each stage (c_k), ability to redispatch in each stage (d_k), and maximum ramp rate (r). The availability in a given month is defined as the fraction of hours that the resource is committed (i.e., has non-zero output) in that month in the AURORA dispatch simulation. If a resource can be re-committed and redispatched in a given stage, then its flexible range reflects the full capacity range between its minimum and maximum output regardless of its availability. However, if the commitment is fixed in a given stage (due to fuel or operational constraints) but the resource can be redispatched, then the flexibility range is scaled by the availability in order to reflect the probability that the resource has been committed in a prior stage. The flexibility range is also limited by a function, $g(r)$, of the maximum ramp rate, which is discussed further below. In month m and stage k, the flexible range for a non-energy-limited resource is:

$$\min\left[d_k\left(p_m^{max} - p_m^{min}\right)\left[c_k + (1 - c_k)a_{km}\right], g(r)\right]$$

The ramp rate-based function, $g(r)$, limits the flexible range based on the ramping capability of the resource. In the day-ahead and hour-ahead stages, this function was determined by calculating the ramping capability needed to meet 95% of all ramps experienced by the perfectly flexible resource in the ROM simulation. Because units ramp between hourly schedules over the last 10 minutes of each hour and the first 10 minutes of the following hour, the function assumes that the resource must be capable of meeting simulated hourly ramps over a 20-minute period. The resulting function is shown below.

Figure 2. Ramp-based flexible ramp limit, *g(r)*, for day-ahead and hour-ahead stages



The ramp-based limit on the flexible range for real-time flexibility and reserves is equal to 10 minutes times the MW/min ramp rate to reflect the approximate time scale of modeled subhourly dispatch needs and reserve requirements.

B.5 Portfolio flexibility values

The flexibility value in the portfolio modeling stage is calculated using the same methodology and the same flexibility value functions used to evaluate specific resources. In this exercise, the flexible range in each month associated with the portfolio is the sum of the flexible ranges of the component resources in the corresponding month. Because the flexibility functions are sub-linear, the monthly portfolio flexibility value is less than the sum of the monthly flexibility values of the component resources. This approach therefore captures the declining marginal value of flexible resources in PGE's resource portfolio, a phenomenon identified in the energy storage evaluation and discussed in Chapter 8 of the 2016 IRP. Within the portfolio flexibility value assessment, PGE will recognize the flexibility value effects of the bilateral capacity agreements executed by PGE in Q1 2018 and described in the 2016 IRP Update.

Exhibit C – Aurora Dispatch

As discussed in PGE's 2016 IRP, AURORAxmp allows PGE to perform fundamental analysis of the western power markets under various assumptions and test the performance of candidate resource portfolios in those environments. PGE uses the net present value of revenue requirements (NPVRR) to summarize the expected cost of portfolios. The NPVRR includes the fixed and variable costs associated with operating the respective resources, as well as the net market revenue or expense associated with net sales or purchases in the portfolio. PGE evaluates portfolio risk according to two primary categories:

1. Reliability risk: Serves as a threshold for portfolio design; and,
2. Deterministic risk: Referred to above as "futures."

To evaluate the variable benefits of the candidate resources in the bilateral capacity acquisition initiative, PGE used AURORAxmp consistent with the Integrated Resource Plan (IRP) methodology. This methodology includes:

1) Western Electric Coordination Council (WECC) Capacity Expansion
2) Generate Market Power Prices
3) Compute the "Value" of all candidate resources

WECC Capacity Expansion: PGE used the three capacity plans developed under various carbon price futures in the 2016 IRP. PGE used Wood McKenzie's database for information regarding the existing resources in WECC. It was not necessary to execute new long-term capacity expansion studies as long-term market fundamentals have not moved significantly enough to justify the effort required to perform long-term studies.

Market Power Prices*:* Using the applicable WECC capacity plan, hourly Mid-Columbia power price curves until year 2050 under 27 various futures were generated. The futures were designed to study impacts of three factors on power pricing: carbon pricing, natural gas pricing, and regional hydro availability. More detail for each factor is shown below.

Carbon pricing: PGE used three carbon price estimates: zero carbon prices, reference carbon prices, and high carbon prices. Consistent with the IRP, PGE used Synapse's forecasts for the reference and high carbon pricing.

Natural Gas pricing: PGE used three natural gas pricing scenarios: Low, reference and high. Consistent with the 2016 IRP Update data source assumptions, the trading curve was used until 2021 for all three scenarios.

Regional hydro availability: PGE used three regional hydro scenarios: low, reference and high. The reference case value is the average of historical hydro estimates provided by Wood Mackenzie. For low and high values, consistent with the 2016 IRP Update, PGE adjusted forecasted hydro volumes by ten percent.

PGE simulated all combinations of carbon price, gas price and regional hydro availability scenarios to create 27 futures.

Exhibit D – Portfolio Construction

Candidate portfolios will consist of executable combinations of all offers. The total resources selected must meet the energy target identified in Commission Order No. 18-044. PGE will optimize portfolio selection with the following two-step processes:

1. Select the starter resource. There will be an optimal candidate portfolio based on each resource.
2. Use the Excel solver to select additional resources to add to the starter resource. Excel will select resources under different optimization routines such as minimizing the deviation from the target MWa energy addition in 2021 or total net costs.

The first optimization routine consists of an optimization problem to minimize the difference (delta) between a portfolio's total energy and the energy target in 2021. The optimized portfolio under the first optimization routine will be calculated using the following formula:

$$f(\underline{x}) = \left| TG_t - \sum_{i=1}^{n} E_{t,i} \cdot \underline{x} \right|$$

$$\min_{\underline{x}} f(\underline{x})$$

$$s.t.\ \underline{x}\ is\ binary$$

where:

$\underline{x}$: A binary vector representing resource selection in a portfolio
(0 represents exclusion, and 1 represents inclusion)
$E_{t,i}$: Energy of the resource *i* for the year *t*
TG_t : Energy target of the year *t*
t : Year 2021
i : Resource index

The second optimization routine set up an objective function to minimize a portfolio's total present value net cost. The optimized portfolio under the second optimization routine will be calculated using the following formula:

$$f(\underline{x}, y_t) = \sum_t^T P_t \cdot \{TC_{t,i} \cdot \underline{x} + F_t . y_t\}$$

$$\min_{\underline{x},\, y_t} f(\underline{x}, y_t)$$

$$s.t.\ \underline{x}\ is\ binary$$

$$\text{and}\ \ \underline{x} \cdot E_{t,i} + y_t \geq TG_t$$

where:

$\underline{x}$: A binary vector representing resource selection in a portfolio

(0 represents exclusion, and 1 represents inclusion)

y_t : Amount of the fill resource needed for the year *t*

$TC_{t,i}$: Total net cost of the resource *i* for the year *t*

TG_t : Energy target of the year *t*

$E_{t,i}$: Energy of the resource *i* for the year *t*

F_t : The fill resource's total net cost

(standardized by the fill resource's name plate capacity)

P_t : Present value factor

t : The beginning of the period

T: The end of the period

To supplement the optimized portfolios, PGE will also develop all possible portfolio permutations with total energy ranging from 75MWa to 125MWa in 2021 and will advance the top 50th percentile of these portfolios to portfolio evaluation. Performance in the 50th percentile screen will be measured on the basis of present value net cost, with the top portfolios achieving the lowest present value net cost.

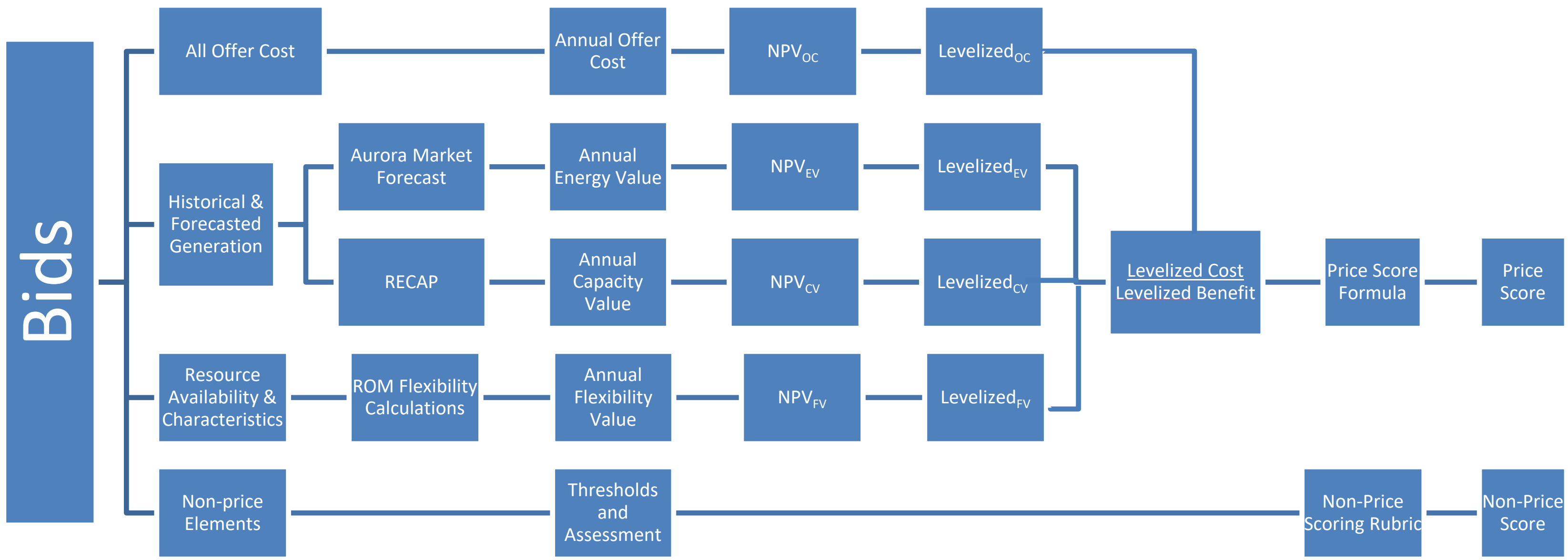
Portfolio Term and Size Normalization

For portfolio analysis, resources will be term and size normalized to match the energy target identified:

- To term normalize for resources with shorter duration (e.g. PPA for 20 years), we will fill with the real levelized cost of an appropriate specific resource of like size for the remaining planning horizon.
- To size normalize, any difference in size between the offers' total energy and the targeted energy need will be effectively filled in by the remaining specific fill resource.
- The specific resource used to size and term normalize reflects the cost and performance of new resources informed by the initial short list.

Filling with costs associated with new resources will correctly account for the risks associated with the energy target identified in Commission Order No. 18-044. We will calculate a total portfolio cost based on the AURORA dispatch of the candidate portfolios across futures including the reference case of carbon price, natural gas price, and hydro availability. In addition, we will calculate risk as the standard of deviation of the total portfolio present value net cost of candidate portfolios across the futures. Candidate portfolios will be ranked in order of increasing costs and risks. After the initial analysis, portfolio results will be stress-tested under multiple energy targets and qualifying facility planning scenarios.

Exhibit E – Scoring Process Flow



Attachment B

STAFF'S INITIAL COMMENTS FROM PUBLIC UTILITY COMMISSION OF OREGON DOCKET NO. AR 600

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 600

In the Matter of Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources.	STAFF'S INITIAL COMMENTS

I. INTRODUCTION

The Public Utility Commission of Oregon Staff (Staff) submits these initial comments in this docket. These initial comments are limited in scope and are intended to respond to a Commission request that Staff provide analysis relating to independent evaluator (IE) costs during the public comment period.[1] Staff plans to file additional comments prior to the close of the public comment period on June 15, 2018.

II. BACKGROUND

Prior to issuing notice of the proposed rulemaking, the Commission indicated that "we wish to see more data and information from Staff regarding IE costs in a variety of scenarios. As discussed in the [March 6, 2018] workshop, we believe that part of the rationale for the proposal to allow exemption from the IE retention requirement in the case of an RFP that does not contemplate electric company ownership of resources is cost savings. We expect Staff to provide analysis to us during the public comment portion of this proceeding on IE costs."[2]

Accordingly, Staff issued information requests to determine the historic cost of IEs in procurements conducted under the Commission's Competitive Bidding Guidelines. In response, two of the Joint Utilities were able to provide total IE costs for ten requests for proposals (RFPs).

[1] See Order No. 18-087, available at: http://apps.puc.state.or.us/orders/2018ords/18-087.pdf.
[2] Order No. 18-087.

Staff's analysis is discussed below. Additional cost information may be included in additional comments filed by Staff.

II. Summary Analysis

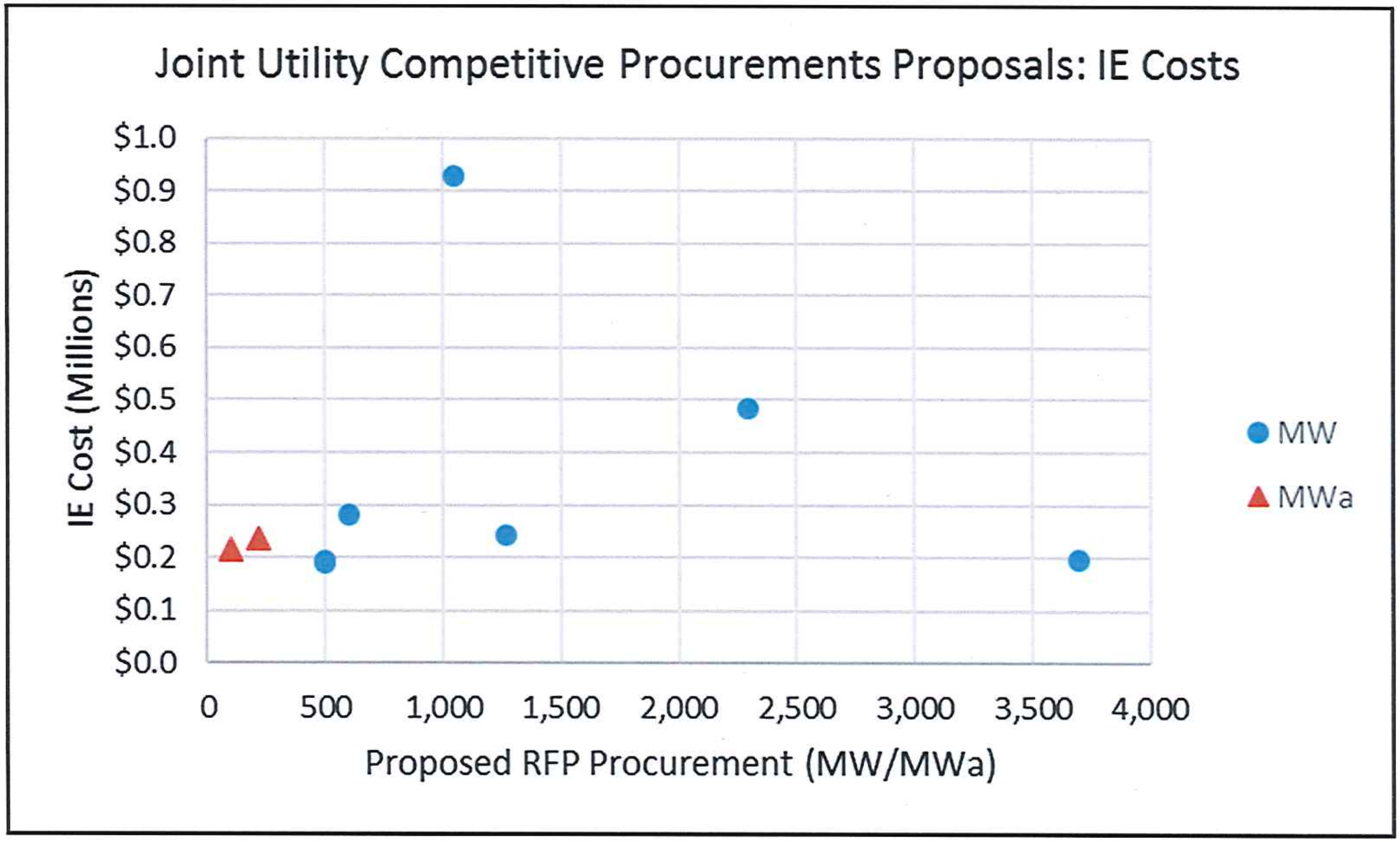
Staff reviewed cost data provided for ten RFPs that involved the services of an IE. The RFPs have issue dates ranging from 2007 to 2018. Of the ten RFPs, six of the RFPs were exclusively for renewable energy sources. Staff notes that the IE costs associated with the procurement of the Carty Generating Station (PGE's 2012 Power Supply Resources RFP) were combined with the IE costs associated with PGE's 2012 Renewable RFP as the same IE was used for both RFPs. For the purposes of this analysis, the total IE cost for the two RFPs are treated as one procurement. The total reported cost of an IE's services for the nine RFPs, without taking into account what has been recovered through customer rates, ranges from $190,000 to $929,000. The average IE cost of all the RFPs, with the inclusion of the RFP associated with Carty, is $329,000. Without including the Carty RFP, the average IE costs of the eight RFPs is $254,000. As seen in Table 1 and Table 2 below, the relationship between procurement size and IE cost is not direct. The RFP with the largest-issued procurement size had the lowest IE costs of the nine RFPs under review. To note, the three renewable RFPs are reported in average megawatts. These three procurements were calls for renewable resources in general. It would be inappropriate to convert the average megawatts to a nameplate capacity relating to any one given renewable resource type. For detail beyond the summaries in the tables below. see the attached utility responses to the related information requests.[3, 4]

[3] PGE's response to OPUC Information Request No. 001, Attachment A.
[4] PacifiCorp's response to OPUC Information Request No. 001, Attachment B.

Table 1: Joint Utility IE Cost Summary

Project	1	2	3	4	5	6	7	8	9	10
Type	Thrm	RE	RE	RE	Thrm	Thrm	Thrm	RE	RE	RE
Size	2290 MW	218 MWa	500 MW	500 MW	3700 MW	597 MW	1050 MW	101 MWa	100 MWa	1270 MW
Year	2007	2008	2008	2009	2009	2012	2012	2012	2016	2017
IE Cost	$0.5 M	$0.2 M	$0.2 M	$0.2 M	$0.2 M	$0.3 M	$0.9 M		$0.2 M	$0.2 M

Table 2: Joint Utlitity Competitive Procurements: Independent Evaluator Costs



III. Cost Drivers for Independent Evaluator Work

Staff has considered the various factors that can affect IE cost. As noted above, the size of the procurement does not appear to be a defining factor. However, there are other factors that can drive IE costs up or down. The type of procurement, for example, whether the resource is base load or renewable, can have variable impact on IE costs. Base load resource procurement often entails specific unit comparisons through complex modeling. Renewable resource procurement, specifically solar energy resources, require additional analysis related to distribution infrastructure. The complexity of the RFP design process, and the degree to which an IE is involved in that process, can lead to more or less material for an IE to review and evaluate before an RFP is approved. The number of proposals received in response to an RFP will affect the amount of time the IE will need to spend in review. The degree to which the IE needs to interact with bidders can affect the costs involved. Similarly, the amount of time the IE may need to be available to engage with the Commission or to be available during contract negotiations can affect the cost associated with a procurement. Finally, Staff notes that the IE's responsibility in relation to high-end modeling, involves at a minimum, analysis and review of the production-cost and transmission modeling inputs and outputs. In some instances, the IE may need to run its own modeling in addition to reviewing the utility's model input and output, which can further increase IE costs.

This concludes Staff's Initial Comments.

Dated at Salem, Oregon, this 13th of June 2018.

Thomas Familia
Senior Utility Analyst
Energy Resources & Planning

AR 600 PGE Response to OPUC IR 001
AR 600 Attachment A

RFP	2018 Renewable RFP	2016 Renewable RFP	2012 Power Supply Resources RFP	2012 Renewable RFP	2008 Renewable RFP
i) RFP Name;	Portland General Electric Company Request for Proposals Renewable Energy Resources	Portland General Electric Company Request for Proposals Renewable Energy Resources	Portland General Electric Company Request for Proposals Power Supply Resources	Portland General Electric Company Request for Proposals Renewable Energy Resources	Portland General Electric Company Request for Proposals Renewable Energy Resources
ii) RFP Issue Date;	Not Yet Issued	Not Issued	June 8, 2012	October 1, 2012	April 23, 2008
iii) Associated OPUC Docket Number;	UM 1934	UM 1773	UM 1535	UM 1613	UM 1345
iv.a) Procurement size (MW), if identified in the RFP	100 MWa	100 MWa	200 MW flexible, year-round capacity resources, 200 MW of bi-seasonal capacity contracts, 150 winter peaking capacity contracts and/or 300-500 MW CCCT Targeted	101 MWa	218 MWa
iv.b) Resource size acquired, if any, based on final result of RFP process;	0 MWa	0 MWa	220 MW Reciprocating Engine, 440 MW CCCT	98 MWa	0 MWa
v) Type of generation asset sought in the RFP;	RPS Eligible Renewable Resources	RPS Eligible Renewable Resources	SCCT; Reciprocating engines; Pumped storage hydro; Hydro with pond capability; Energy storage; CCCT	RPS Eligible Renewable Resources	RPS Eligible Renewable Resources
vi) Name of independent Evaluator selected and approved by the Commission;	Bates White	Accion Group	Accion Group		Accion Group
vii) Description of how Independent Evaluator services were to be compensated by Company under its contract;	Time and Materials	Time and Materials	Time and Materials		Time and Materials
viii) Total Cost to compensate Independent Evaluator;	Ongoing	$214,293	$928,718		$233,658
ix) Amount of total cost to compensate Independent Evaluator recovered through customer rates.	$0	$0	$430,152		$233,658

Oregon Independent Evaluator(s) Summary
PacifiCorp - Request for Proposals for Generation Resources
As at May 11, 2018

subpart (i)	*subpart (ii)*	*subpart (iii)*	*subpart (iv)*	*subpart (v)*	*subpart (vi)*	*subpart (vii)*	*subpart (viii)*
Request for Proposals (RFP) Name	**RFP Issue Date**	**Public Service Commission of Oregon (OPUC) Docket Number**	**Procurement Size (megawatts (MW))** [1]	**Type of Generation Resource(s) Sought**	**Name of Independent Evaluator (IE)**	**How IE was compensated by PacifiCorp**	**IE Total Cost**
2012 RFP	5-Apr-07	UM-1208 / UM-1285	2012 - 600 MW to 940 MW 2013- 750 MW 2014 - 250 MW to 600 MW	All resources accepted including benchmark bids; tied to PacifiCorp's 2004 Integrated Resource Plan (IRP)	Boston Pacific, Company, Inc. (RFP review) Accion Group (RFQ review)	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	Accion Group: $190,398 Boston Pacific Company, Inc.: $292,979
2008 All Source RFP (re-issued in 2010 as All Source RFP)	2-Oct-08 (re-issued 2-Dec-09)	UM-1360	2012 - 1,300 MW 2016 - 2,400 MW	Base Load and Intermediate Load generating assets sold via Asset Purchase and Sale Agreements (APSA), Tolling Service Agreements (TSA) and purchases of existing assets] represents nearly 6,500 MW	Boston Pacific, Company, Inc. (RFP review) Accion Group (RFQ review)	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$195,395
2008R-1 Renewables RFP	6-Oct-08	UM-1368	500 MW of system-wind renewable resources (~5,000 MW offered)	Renewables (wind) via Build-Own-Transfer (BOT), Power Purchase Agrements (PPA), and 50 percent BOT / 50 percent PPA	Boston Pacific, Company, Inc.	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$190,341
2009 RFP for Supply-side Renewable Resources (Expedited Treatment Requested)	9-Jul-09	UM-1429	Up to 2,000 MW by 2013	All renewable resource types	Boston Pacific, Company, Inc.	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$192,583
2016 All-Source	4-Apr-12	UM-1540	Up to 597 MW Baseload	All-source / No benchmark. Currant Creek Site included	Boston Pacific, Company, Inc.	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 in Docket UM-1182	$282,113
2017R RFP	27-Sep-17	UM-1845	1,270 MW	Wind resources only	Bates White Economic Consulting (formally Boston Pacific Company, Inc.)	IEs were contracted to provide oversight of the RFP consistent with the competitive bidding guidelines in OPUC Order 06-446 and OPUC Order 14-149 in Docket UM-1182	$243,184

Notes:

(1) Procurement size (MW), if identified in RFP, and size required, if any, based on final results of RFP process

Attachment D

Rulemaking for Integrated Resource Planning,
WAC 480-100-238, WAC 480-90-238, and WAC 480-107,
Docket No. UE-161024,
NIPPC Additional Comments Regarding Proposed Revised RFP Rules
(Jan. 31, 2019)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

U-161024

In the Matter of	)	
	)	NORTHWEST AND INTERMOUNTAIN
Rulemaking for Integrated Resource	)	POWER PRODUCERS COALITION
Planning, WAC 480-100-238, WAC 480-90-	)	ADDITIONAL COMMENTS REGARDING
238, and WAC 480-107	)	PROPOSED REVISED RFP RULES
	)	
	)	

I. INTRODUCTION

1. In accordance with the Washington Utilities and Transportation Commission's (the "Commission" or "WUTC"), December 31, 2018 Notice in this docket, Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these additional comments on the revised draft rule related to competitive procurement for electric utilities (WAC 480-107).

2. In these comments NIPPC provides limited and discrete comments on only the new sections in the latest informal draft request for proposal ("RFP") rules. NIPPC has participated in workshops, meetings and submitted three rounds of formal RFP comments in this proceeding. NIPPC continues to support its original recommendations in support of and in opposition to specific rule language, but in the interests of brevity does not repeat them herein.

3. NIPPC supports many of the changes in the Commission's new and most recent version of the draft rules, especially the requirement that utility-owned transmission assets be used for the benefit of ratepayers, the improvements to how bids are scored, and the increased participation by the independent evaluator provided for in the rules. In the end, however, NIPPC remains concerned that the changes will be insufficient to allow lower-cost and less risky independent power producer-owned generation an opportunity to fairly bid into Commission-

approved RFPs, and urges the Commission to adopt the complete recommendations in its earlier comments.

II. NIPPC ADDITIONAL COMMENTS

1) Improvements in the Draft Rules

4. NIPPC identifies the following new provisions in the draft RFP that will improve the competitive bidding process:

- **WAC 480-107-015 The solicitation process**. The original proposed draft rules encouraged the utilities to consult with Commission staff during the development of the RFP, but the current draft encourages the utilities to also consult with stakeholders, which is an improvement recommended by NIPPC.
- **WAC 480-107-025 Contents of the solicitation**. The current draft rule includes a number of improvements, many of which were recommended by NIPPC. These include converting non-price score criteria into minimum bidder requirements, strengthening the requirements for the RFP to provide a detailed explanation of the scoring criteria, additional requirements regarding utility affiliate bidding, and, most importantly, a requirement that "[t]he RFP must identify utility-owned transmission assets that are made available by the utility to be used by bidders to assist in meeting the resource need, and allow the use of such assets to be included in bids." NIPPC, however, recommends an improvement to the new language regarding a utility's requirement to include in the RFP "a detailed explanation of the aspects of each criterion specifically identified that would result in the bid receiving higher priority." In its current form, this information is optional because it can be substituted by a sample evaluation. NIPPC recommends that the final rules make this detailed explanation a requirement.

- **WAC 480-107-AAA Independent Evaluator for Significant Resource Needs or Utility or Affiliate Bid.** While NIPPC continues to believe that the Independent Evaluator should run the entire RFP, the current draft rules include some significant improvements. These include the Independent Evaluator participating in the design of the RFP, being available to the Commission, providing notes and communications, verifying the utility's inputs and assumptions, and assessing whether the utility's scoring and shortlists are reasonable.

III. COMMENTS ON OTHER PARTIES' COMMENTS

5. National Grid submitted comments on November 2, 2018 proposing a new exception to the RFP exemptions to address the unique circumstances of long lead time resources, including pumped storage. Specifically, National Grid proposes a "reverse RFP" that would allow a utility to address the challenges of valuing the energy and capacity for these types of resources.

6. NIPPC believes the rules should be agnostic about the specific types of resources that can be bid into an RFP, which sometimes means accounting for the unique difficulties in valuing the energy and capacity benefits of different resource types. As there is no specific proposal at this time, however, NIPPC does not have a final position on any reverse RFP framework. NIPPC believes the idea is worthy of additional exploration, however, and recommends that either National Grid or the Commission propose specific rules on the topic, and provide an additional opportunity for stakeholders to submit comments on the proposal.

IV. CONCLUSION

7. For the reasons explained in these and earlier comments, NIPPC recommends that the Commission significantly modify its current RFP rules to more comprehensively address the ways in which lower-cost, less risky independent power producer projects are prevented from fair participation in utility resource RFPs. NIPPC acknowledges the improvements to the Commission's rules that have been made through this process, and offers further modifications, as described above, without reiterating its stated preferred positions from its earlier comments.

Dated this 31st day of January 2019.

Respectfully submitted,

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Of Attorneys for the Northwest and Intermountain Power Producers Coalition

Attachment E

NIPPC Comments to Oregon Pub. Utility Comm'n on SB 978 (April 20, 2018)

April 20, 2018

Via Email

Chair Megan Decker
Commissioner Steve Bloom
Oregon Public Utility Commission
201 High St SE, Suite 100
Salem, Oregon 97301

RE: Senate Bill 978 Comments

Dear Commissioners:

The Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these comments in response to the Oregon Public Utility Commission (the "Commission" or "OPUC") notice requesting specific feedback on its Senate Bill ("SB") 978 process. The Commission must submit a report to the Legislature describing how developing industry trends, technologies, and policy drivers impact the existing electricity regulatory system and may suggest changes to accommodate developing industry trends or support new policy objectives. NIPPC understands that the Commission's report will identify changes to the existing regulatory structure recommended by stakeholders, and will either develop plans to implement these changes or recommend changes in law so the Legislature can implement these changes. NIPPC urges the Commission to support the changes proposed by NIPPC and other independent power producers when making its report. At a minimum, the Commission should identify all of the changes proposed by stakeholders, and explain how they could either be implemented under the Commission's current enabling statutes or identify legislative changes that would be necessary to implement the changes. This kind of clarity will be crucial for the Legislature.

The Commission notice specifically requests stakeholders: 1) summarize the Commission's current responsibility (i.e., its legal mandate) in 100 words or less; and 2) identify public policy objectives promoted/impeded by the Commission's current system for regulated investor owned utilities ("IOUs"). Stakeholders may also address: 3) the primary obligations/benefits the current regulatory system creates for one or more of the following participants: utilities, cost-of-service customers, direct access customers, and the OPUC; and 4) the actions/behaviors the current system encourages from those same groups.

Each of these gets at the central question underlying the SB 978 process: what do we need IOUs to do that only regulated monopolies can do? The regulatory compact assumes monopolies are needed to perform a particular function for society, which only the monopoly can perform. Because the American economic system is built around competition, government authorized monopolies are typically only allowed to exist to protect essential industries. IOUs allow a certain amount of public control over the electric system, which is essential to our society, but IOUs should only exist to do what only they can uniquely do. When discussing the proper role of IOUs, it is important to remember that monopolies do not have customers, but rather have captive ratepayers. Customers can freely choose who they want to buy their products and services from while ratepayers lack choice.

Most of the country has answered SB 978's central question by unscrambling monopoly dominance in electricity generation. Oregon has wrestled with the breakdown of the vertically integrated utility since PURPA began forcing competition into the electric generation sector forty years ago. Since that time, most of the country has passed

Oregon by. Now is the time to take affirmative action and figure out Oregon's direction for the future. NIPPC does not want to weaken Oregon utilities or promote changes that would put utilities at risk. Oregon needs strong utilities because at least the distribution system will remain a monopoly in need of investment. But utilities must align their interests with the 21st century. Amid changing realities in the power sector, we must ask: what do we still need these monopolies to do?

Q1. The Commission's Current Responsibilities

The Commission is primarily responsible for:

> Ensuring that regulated utilities offer safe, reliable and non-discriminatory energy service at fair, just and reasonable rates that provide utilities an opportunity earn a reasonable rate of return.

The Commission's responsibilities also extend beyond its core regulatory responsibilities to include competition, environmental regulation and broader energy policy. Regarding to competitive markets and independent power producers, NIPPC adds that the Commission is also responsible for:

> Promoting the development of competitive market and providing customer market choices by stimulating competition, alleviating monopoly market power, functionally separating or divesting utility generation assets, providing retail consumers with access to competitive electricity options,[1] promoting the development of a diverse array of permanently sustainable, [2] non-utility owned and community based energy resources, [3] and increasing the marketability and creating a uniform institutional climate for independent power producers. [4]

As the citations above demonstrate, the Commission has responsibilities related to competitive markets and non-utility power providers that are specifically enumerated in Oregon law. This should be no surprise, as the Commission is the most important state agency regulating the energy sector.

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1 ORS 757.646(1); Senate Bill 1149 Recitals.
2 ORS 469.010(2)(a).
3 ORS 469A.210; ORS 758.515.
4 ORS 758.515.

These statutory responsibilities fall into two non-exclusive groups. One, the Legislature has directed the OPUC to use competition and to allow market choices to ensure that consumer rates and services are fair, just, reasonable and non-discriminatory. For example, the Legislature has concluded that the best way to achieve the goal of fair, just and reasonable rates is to provide customers with competitive electricity options by stimulating competition. As the administrative agency implementing the Legislature's mandate, the Commission should not question or take action to prevent consumers from having competitive electricity options, but does have the discretion to decide the best way to achieve the goal providing consumers these options and to adjust or refine its policies where most retail consumers do not have meaningful competitive electricity options. Similarly, the Legislature has determined that the Commission must require utilities to use competitive procurement processes that allow for diverse ownership of generation. This requirement was primarily imposed by the Legislature because it believes that the best way to achieve fair, just and reasonable rates is to require the utilities to acquire new generation in a specific, proscribed manner. Thus, the Legislature has directed the OPUC to use competition and market choices to implement its mandate to ensure that consumer rates and services are fair, just, reasonable and non-discriminatory.

Oregon law also specifically directs the Commission to independently consider the interests of independent power producers. While NIPPC believes that the interests of customers and non-utility generators are generally consistent, because competition drives down costs for consumers, the Legislature requires the Commission to consider the separate and unique interests of non-utility providers. For example, federal and Oregon Public Utility Regulatory Policies Act ("PURPA") laws require competition in the utility generation market in large part to benefit customers. These statutes were also passed to diversify the ownership and type of generation resources in and of themselves. Oregon's PURPA specifically states that Oregon's state policy is to:

> (a) Increase the marketability of electric energy produced by qualifying facilities located throughout the state for *the benefit of Oregon's citizens*; and
> (b) Create a settled and uniform institutional climate for the *qualifying facilities* in Oregon.[5]

Avoided cost rates must also be "just and reasonable to the electric consumers of the electric utility, the *qualifying facility* and in the public interest."[6] Thus, Oregon's PURPA establishes a policy, that the Commission cannot ignore, seeking to support non-utility owned generation for the benefit of all Oregon's citizens as well as qualifying facilities themselves. As the primary Oregon administrative agency charged with implementing PURPA, it is incumbent upon the Commission to ensure these policies are implemented.

NIPPC urges the Commission to recognize the Legislature's direction when defining the current Oregon regulatory system, recommending administrative and legislative changes to accommodate developing industry trends, and supporting new policy objectives in a manner that does not compromise affordable rates, safety, or reliable service.

Q2. The Public Policy Objectives that Are Promoted and Impeded by the Commission's Current System for Regulating IOUs

Despite legislative mandates and administrative policies in support of competition and customer options, the Commission's fundamental system for regulating IOUs is based on a *de facto* regulatory compact where utilities are obligated to offer safe and reliable service and allowed the opportunity to recover costs plus an authorized rate of return; in exchange, the Commission acts as an economic regulator to ensure utilities provide adequate service at fair, just and reasonable prices.

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5 ORS 758.515(3) (emphasis added).
6 ORS 758.515(2) (emphasis added).

This regulatory compact provides utilities an economic incentive to invest, build and own physical distribution, transmission, and generation assets because this is how they obtain a profit for their shareholders. In the first part of the 20th century, this incentive had a positive impact on society and consumers with the practical result being the modern electrical system. Utilities should be commended for electrifying the nation. The utility business model that promoted utility ownership and construction of physical assets created a safe, reliable, and affordable electric and natural system.

Nevertheless, energy generation has changed dramatically over the last few decades bringing major changes in regulatory policy and creating independent non-utility owned electric generators that can sell electricity to utilities and end use consumers alike. In the natural gas and electric sectors in much of the United States, the load-serving utility is no longer vertically integrated or its role as the sole owner of generation resources has been significantly limited. This has resulted in significant cost savings for consumers with lower environmental costs, but these changes have not reached Oregon's electric IOUs. While the public policy objectives of ensuring that IOUs remain healthy and able to earn returns are being met, the current regulatory model does not allow customers to make energy choices, does not foster the development of new technologies, is poorly suited to cost effectively meet Oregon's broader public policy goals likely addressing climate change, and will not keep rates affordable going forward.

A. Public Policy Objectives Promoted by the Current System

1. Incentive to Favor Utility-Owned Capital Investments Over Other Potential Solutions

There is little doubt that the current regulatory system favors utility-owned investment. Yet, even after a lengthy discussion of traditional ratemaking incentives and the Averch-Johnson effect, the utilities refuse to acknowledge the magnitude of this incentive. As described above, the traditional opportunity to earn a profit on capital investments has served the public interest well by ensuring sizable investments were consistently available to expand our electric systems. Because electricity generation is no longer a natural monopoly, however, our electric system may not need large IOU investments in generation going forward. Allowing utilities to over-invest capital in generation assets instead of relying on the market will increasingly distort the market and ensure ratepayers pay too much. And as long as rate-based capital investments remain the principle source of revenue generation for utilities, doubt and bias will be prominent in every utility resource selection process. The Commission should therefore make reasonable adjustments to the regulatory compact to mitigate the self-build bias and prevent utilities from over investing capital in generation assets. The Commission should exercise its statutory authority to protect customers from vertical and horizontal monopoly power by facilitating and protecting wholesale markets. Organized power markets bring savings to customers and opportunities for generation to compete.

Although many of the votes taken during the March stakeholder meeting highlighted differences between the utilities and the rest of the parties, this issue was a particularly stark example. This vote tally received uniform consensus among both the utility and non-utility stakeholders—where the two groups were also in total disagreement. While all of the non-utility stakeholders recognized an overwhelming incentive, none of the utility stakeholders did. The utilities seemed merely willing to concede there is *an* incentive that favors utility-owned capital investments, but could not agree that it was strong enough to favor utility ownership *over* other potential solutions.

This distinction is contrary to the Commission's own findings in past dockets[7] and is not helpful in moving along the SB 978 process.

2. Obligation to Offer Reliable and Safe Service to All Customers

Unlike the incentive to favor capital investments, the main tenet of the current regulatory model—that utilities are obligated to offer safe and reliable service in exchange for the opportunity to recover costs plus an authorized rate of return—enjoyed complete unanimity at the March meeting. Interestingly, this was the only issue without any dissent. Every person present agreed that the current system obligates utilities to produce reliable and safe service in exchange for the ability to make a profit. This is generally a commendable aspect of the system and should be retained. But, reasonable adjustments are needed to avoid the problems associated with overbuilding and utility decisions to procure riskier and more expensive generation assets.

By focusing on large capital-intensive generation assets, utilities may lose focus on distribution assets, new technologies, and other opportunities that will be costly in the end. State goals, and those of utility customers, are increasingly out of alignment with the current regulatory system's goals. Utilities need to invest in distribution rather than generation to modernize the grid. Ignoring distributed generation may ultimately undermine system reliability and safety.

The Commission should therefore use its authority over rate regulation to stimulate (not simulate) competition and bring the system's goals back into alignment. The Commission's broadest authority is its rate authority. Utilities are allowed an opportunity to recover their costs of service plus an authorized rate of return, but the Commission sets that rate. The current regulatory system encourages low rates by

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[7] Re Investigation Regarding Performance-Based Ratemaking Mechanisms to Address Potential Build-vs.-Buy Bias, Docket No. UM 1275, Order No. 11-001 (Jan. 3, 2011) ("self-build bias").

allowing OPUC Staff, and intervenors the opportunity to challenge proposed rate increases in an adjudicatory process. It also encumbers low rates, however, due to the regulatory lag this process brings. Prudent utilities are encouraged to try to over-recover in their rate cases and then drive down costs to increase their profits. On the other hand, utilities typically do not pass along savings until a subsequent rate case has occurred. This dichotomy theoretically benefits customers by encouraging utilities to manage their costs, but it also protects utilities from their mistakes.

In the end the Commission's regulatory tool box of carrots and sticks is inadequate. The Commission cannot sufficiently penalize utilities for their mistakes because the Commission must also protect utility credit ratings. If the Commission sets a rate of return low enough to damage a utility's credit rating, it will increase the costs of capital for that utility, which effectively raises its customer's rates. This makes rate regulation increasingly difficult for the Commission and insulates utilities from receiving what are effectively market signals. The only way to truly protect customers is for the Commission to use its rate regulation authority to bolster competitive energy markets in Oregon and provide customers with more choices.

B. Public Policy Objectives Impeded by the Current System

1. The Current System Does Not Make Energy Choices Accessible to All Customers While Minimizing Cost Shifting

The votes taken during the March stakeholder meeting on customer choice again set the utilities at the opposite end of the spectrum from the rest of the stakeholders. While the utilities argued that the current system makes energy choices accessible to all customers, the rest of the stakeholders vehemently disagreed. While ratepayers may be able to choose between normal or "green" service, they are still forced to buy their power from a monopoly provider that may not reflect their values and limits the "green" options.

A brief recap of customer choice in Oregon underscores the frustrations from non-utility stakeholders on this issue.

The Oregon Legislature sought to bring a fully competitive electricity market to Oregon nearly two decades ago, but the Commission's policies are hampering progress on that front. The express goal of SB 1149 is to provide *all* retail electric consumers access to the competitive market. This vision is consistent with modern buyers' expectations. While restructuring efforts in California no doubt affected the Commission's view on the appropriate speed with which restructuring should occur in Oregon, the overall lack of progress is not consistent with Oregon law and unnecessarily constrains customers. Residential customers are still not eligible for direct access and often feel constrained by their utility when it comes to options for rooftop solar, net metering, etc. Business customers have not fared much better. According to OPUC statistics, less than twenty percent of eligible (i.e., non-residential) customers are currently participating in direct access programs.

The current level of customer choice is abysmal considering that since 1999, SB 1149 required PacifiCorp and PGE to give all business customers the option to buy directly from electricity service suppliers ("ESS"). In 2005, Portland General Electric Company ("PGE") established a five-year cost of service opt-out program that has had moderate participation.[8] In 2012, the Commission directed PacifiCorp to establish a similar five-year opt-out program.[9] PacifiCorp's program, which was approved by the Commission in 2015, requires direct access customers to pay ten years of charges (rather than five) over its five-year opt-out period. These charges have been under

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8 Re Stephen Forbes Cooper, LLC, Docket No. UM 1206, Order No. 05-1250 at Attachment A at 8 (Dec. 14, 2005).

9 Re Investigation of Issues Relating to Direct Access, Docket No. UM 1587, Order No. 12-500 (Dec. 30, 2012).

judicial review since 2016 and are an impermissible barrier to direct access.[10] PGE has recently signaled a desire to adjust its own opt-out program to more closely mirror PacifiCorp's. If PGE's direct access participation rates were as low as PacifiCorp's, then perhaps as little as 7% of both utilities' eligible customers would be able to participate in the Commission's direct access program. The Commission may argue that these harsh eligibility requirements are shielding customers from cost shifting, but customers can be adequately protected with higher participation rates that do not preclude Oregon businesses from taking advantage of lower energy prices and building new renewable energy projects.

In 2014, the Oregon Legislature passed another bill, HB 4126, directing the Commission to consider allowing non-residential customers access to purchase power from a voluntary renewable energy tariff ("VRET"). Unfortunately, this bill has not done much better under the Commission's processes. Many businesses have expressed the desire to purchase exclusively renewable energy, but utilities have not yet met this demand.[11] The Commission responded to HB 4126 by directing its Staff to establish conditions to allow VRETs and asked the utilities to file generic VRETs for consideration.[12] The utilities declined to offer VRETs, however, claiming the Commission's conditions were too onerous. The Commission ultimately closed its docket without finding justification to approve VRETs were in the public interest.[13]

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10 Re PacifiCorp 2016 Transition Adjustment Mechanism, Docket No. UE 296, Appeal Notice (Mar. 11, 2016) (certifying decision for the Court of Appeals, Appellate Court No. A161359)

11 See e.g., Re Voluntary Renewable Energy Tariffs for Non-residential Customers, Docket No. UM 1690, NIPPC and Facebook Comments (Dec. 10, 2015).

12 Docket No. UM 1690, Order No. 15-405 (Dec. 15, 2015).

13 Docket No. UM 1690, Order No. 16-251 (July 5, 2016).

PacifiCorp has subsequently offered something similar to VRET[14] and PGE very recently requested the Commission reopen its VRET proceeding to consider its own filing.[15]

On the other hand, other states have been welcoming new direct access customers in recent years. In 2016, New Mexico approved a Green Energy Rider (Rate No. 36B) for renewable customers that limits charges associated with existing facilities.[16] Utah and Washington both approved special contracts to allow large customers like Facebook and Microsoft to part ways with their cost-of-service counterparts.[17] In 2017 Nevada issued a declaratory order after only a number of months confirming that new customers like Google should not pay that state's stranded cost charges.[18] Conversely, the Commission has moved cautiously in this arena and its own expedited process began over a year ago.[19] In short, customer choice in Oregon to date has been *in spite of* the Commission and utilities rather than because of them. The Commission should make reasonable changes to its direct access rules to allow more meaningful participation and to effectuate the goals expressly stated in both SB 1149 and HB 4126.

Finally, NIPPC reiterates that regulatory changes that provide customers more competitive options will have limited applicability or use by some customers, especially low-income residential customers. It is a core principle for NIPPC that customers with the ability to directly access the market not harm the remaining captive customers.

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14 Advice No. ADV 386, Advice No. 16-012 (Sept. 27, 2016).

15 Docket No. UM 1690, PGE's Petition to Amend Order No. 16-251 (Apr. 13, 2018).

16 PSCNM Docket No. 16-00191-UT (Aug. 17, 2016).

17 Re Rocky Mountain Power's Proposed Electric Service Schedule No. 34, Renewable Energy Tariff, PSCU Docket Nos. 16-035-T09, Order (Aug. 18, 2016), Re Application of Rocky Mountain Power for Approval of a Renewable Energy Services Contract between Rocky Mountain Power and Facebook, Inc. Pursuant to Tariff Electric Service Schedule 34, 16-035-27, Order (Aug. 29, 2016); WUTC vs. PSE, Docket No. UE-161123, Order 06 (July 13, 2017)

18 PUCN Docket No. 17-04019 (Sept. 8, 2017).

19 See e.g., Docket No. UM 1837, AR 614 process, available at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=20777.

NIPPC is confident, however, that captive customers can be protected while providing meaningful market options to all customers.

2. The Current System Does Not Utilize Competition as a Tool to Make the System More Affordable

As discussed above, competition has been codified in law and Commission policy and has changed the electric industry, but the current regulatory system fails to fully utilize competition to make the system more affordable.

This issue led to a fruitful discussion at the March stakeholder meeting as votes highlighted different views on the proper role for competition and its untapped potential to drive down costs. Customer groups explained that even though competition is being severely under-utilized, it is still being used as a tool to make the system more affordable. Customers were clear that they did not believe that there was any true competition during utility resource acquisitions, but they also agreed that simply allowing some amount of competition into the process very likely drives down the prices utilities are ultimately able to award themselves. The customers group also pointed out that even though utilities win 95% of their own requests for proposals, the 5% they did not win technically also makes the system "more" affordable. Conversely, the generators group were quick to point out that the current regulatory system is doing very little to utilize the competition, which means it is actually *not* utilizing competition. Thus, customers and generators are in alignment that the system should be changed to allow competitive forces to truly lower costs. The Commission should make reasonable changes to allow for more than *de minimis* competition and ensure true diversity of ownership in electricity generation exists.

3. The Current System Does Not Balance Risks with Pursuing New Versus Embedded Technologies

The overwhelming majority of stakeholders at the March meeting agree that the current system is not capable of balancing risks associated with new technologies. The current system hinders risk by prioritizing cost without considering other economic factors. For example, the current system encourages utilities to procure old, established technologies over new technologies that could ultimately end up being less expensive over the long term. Unfortunately, this kind of problem is difficult to overcome in the regulated world. Indeed, we might still all have rotary phones if telephone service were still regulated.

This is why SB 978 mandates the Commission think creatively and consider policy drivers like distributed energy resources and improved distribution controls, transportation electrification, increased carbon output recognition and regional transmission markets. The current regulatory system is not designed to promote these kinds of projects, but each of them could serve an important part of achieving out state's goals. For example, utilities have not shown much inclination to offer distributed energy resources, but (as with telephone service) new options could flourish if the Commission were to allow more competition in that space. There is no need to await specific statutory direction or undergo a multi-year proceeding: the Commission should find new ways to combine public and private investment to meet Oregon's legislative goals today.

4. The Current System Does Authorize the Commission to Act as an Environmental Regulator, but the Commission May Not Agree

The utilities and most of the generators and service providers agree that the Commission can act as an environmental regulator as well as an economic regulator. As with the issue of competition and promoting non-utility generation ownership, Oregon law directs the Commission to consider environmental impacts when making decisions.

As mentioned above, PURPA mandates the Commission to implement policies to encourage renewable energy for the benefit of all Oregonians. The Legislature has also found that community based renewable energy projects are "an essential elements of this state's energy future" and directed the Commission adopt rules and policies to ensure that at least 8% of the aggregate electrical capacity of all electric companies include community-based projects.[20] The Commission considers environmental issues like the cost of carbon in integrated resource plans and how to best meet renewable portfolio standard requirements, but has been hesitant to consider broader environmental factors as part of its public interest inquiry.

5. The Current System Does Promote Social Justice, But the Commission Could Do More to Encourage Meaningful Participation

The equity, environmental justice, and environmentalists all believe that the current system does not do enough to promote environmental, social and economic justice, while members of the customer, generation and service providers and utility groups were more divided on this issue. NIPPC believes many elements of the current electrical system have successfully promoted equity and justice concerns. NIPPC agrees with Pacific Power Vice President Scott Bolton, who stated that the system addresses equity concerns because utilities provide essential services in their communities that often look a lot like social service agencies. For example, electric utilities are required by law to provide low-cost and reliable power to all consumers on a non-discriminatory basis regardless of class, race, and gender. In addition to the basic and universal obligation to service, other examples include directing ratepayer funding from the public purpose charge toward schools, utility programs designed to protect low income customers, etc. NIPPC recognizes, however, that the Commission could do

[20] ORS 469A.210.

more to promote meaningful involvement from different stakeholder groups without expanding its primary mission or statutory directives. For example, access to intervenor funding could be expanded.

Q3. Primary Obligations and Benefits Created by the Current System

A. Utilities

The utilities primary obligation is to provide service to all customers in its service area in exchange for the opportunity to earn a return on its rates. Providing reliable service is no small task and utilities play a vital role in our society. Utilities are more than adequately compensated for this obligation by being awarded a monopoly and receiving economic protection from the Commission. While utilities are not guaranteed to earn a profit, it is generally a very lucrative business, and utilities typically earn returns at or above those for businesses with commensurate risk profiles.

B. Cost-of-Service Customers

The primary obligation of cost-of-service customers is to pay their bill and purchase their power from their monopoly utility. Cost-of-service customers are not allowed to shop around or buy power from any other providers. The primary benefit to cost-of-service customers is that the Commission works to ensure they get safe and reliable service from their utilities at fair, just and reasonable rates. These captive consumers are permitted to participate in the regulatory processes at the Commission; however, the processes are not typically suited for ordinary customer participation.

C. Direct Access Customers

Direct access customers represent an extreme minority in Oregon. The primary obligation of direct access customers is to ensure that normal cost-of-service customers are not harmed by unwarranted cost shifts when they (direct access customers) leave their monopoly utility. This typically comes in the form of a very large, multi-year transition fee that direct access customers must pay for the privilege of changing electricity service providers. The main benefit for direct access customers is freedom of choice. Direct access customers are free to negotiate better rates or different service arrangements from the wholesale market. For example, Nike recently announced that is left its regulated utility in order to purchase 100% renewable energy for its facilities. In the end, industrial and large commercial customers want more control and certainty over their power supply to lower their costs and meet other corporate goals, including purchasing renewable energy. The desire to lower power costs and access renewable energy is a priority in boardrooms throughout the United States, including Oregon.

The mere existence of direct access also benefits Oregon as a whole, including cost-of-service customers. Retail wheeling allows the state to maintain existing industries and attract new businesses. Competition from non-utility power suppliers also makes utilities operate more efficiently and strengthen wholesale power markets, which drives down power costs for all customers.

D. OPUC

The Commission's primary obligation is to regulate in the public interest and balance the interests of utility shareholders and customers. The Commission must also implement Oregon law as directed by the legislature. The main benefit for the Commission is that it is the most powerful and important energy regulatory agency in the state. The Commission gets the opportunity to shape energy policy throughout the region and make key decisions affecting utilities. The Commission effectively gets to determine issues like whether IOUs or independent power producers own electric generation resources and whether the state will be able meet its carbon reduction goals in a cost effective manner.

Q4. Primary Actions and Behaviors Encouraged by the Current System

The current regulatory system focuses on litigation to set public policy and make economic decisions rather than relying upon the market and customer choice. A more effective system would be to allow the government to establish rules and set public policy goals, and then let market participants figure out how to best achieve those goals within the rules. Using litigation rather than simply leveraging market forces to achieve our goals has left the current regulatory system unnecessarily adversarial and slow to react to market changes. The best way to achieve the modern 21st century electric system is to get rid of lawyers and middlemen, and empower innovators and dreamers.

A. Utilities

The current system forces utilities to choose between its shareholders and the public interest. Because utilities have a fiduciary duty to their shareholders, it is economically rational for utilities to act to secure the highest return on their investments possible. Because the regulatory system is so litigious, utilities employ large legal teams to participate in Commission proceedings. These legal teams are entirely paid for by ratepayers.

B. Cost-of-service Customers

The current system generally positions cost-of-service customers against direct access customers and utilities. While cost-of-service customers are busy paying their bills and perhaps working with their utility to resolve billing disputes or better represent their values, an individual cost-of-service customer would not typically be aware of any Commission proceedings, direct access customers, or opportunities to leave their monopoly utility. Thanks to the Oregon Legislature, ratepayer advocates are able to intervene into any Commission proceeding as a matter of law. Ratepayer advocates also employ their own legal team, and receive funding from a portion of the rates paid by ratepayers, but do not have access to fully fund their legal team like the utilities do. Thus, ratepayer advocates face a resource disadvantage when participating before the Commission.

C. Direct Access Customers

Conversely, direct access customers are acutely aware of cost-of-service customers; direct access customers must ensure they can afford to leave their utility monopoly and that means helping remaining cost-of-service customers whether their departure. Direct access customers in Oregon are most likely either: 1) currently paying transition fees because they have recently left their utility; 2) currently wishing the Commission would make direct access more accessible because they want to leave their utility; or 3) already left their utility and committed to paying transition fees. Depending on where a direct access customer (or potential direct access customer) is in its transition process, its actions and behaviors vary greatly. Direct access customers may need an attorney to negotiate a power purchase agreement, or may belong to trade groups that hire attorneys to participate in Commission proceedings on their behalf, but a single direct access customer is unlikely to participate directly in Commission dockets.

D. OPUC

The Commission's interpretation of the current regulatory system encourages it to protect monopoly utilities from competition and not to consider how utility actions impact other stakeholders besides customers. For example, although the Commission may be inclined to protect the environment or help advance electric transportation, it is unlikely to take any action that would bring about those kinds of changes without the clear legal authority to do so. Even in the cases where the Commission has the clear legal authority to take action, like with direct access, the Commission may still be reticent to act in any way that could cause economic harm to its regulated utilities.

Overall, NIPPC appreciates the opportunity to comment regarding how the Commission can best meet Oregon's policy goals of ensuring that customers receive safe and reliable service and affordable rates in a manner consistent with the state's energy policy.

Sincerely,

Robert D. Kahn

Robert Kahn

Irion Sanger

Irion A. Sanger

Sidney Villanueva

Sidney Villanueva

cc: Julie Peacock

Attachment F

NIPPC Comments to Oregon Pub. Utility Comm’n on SB 978 (July 10, 2018)

July 10, 2018

Via Email

Chair Megan Decker
Commissioner Steve Bloom
Commissioner Letha Tawney
Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, Oregon 97301

RE: Senate Bill 978 Comments

Dear Commissioners:

The Northwest and Intermountain Power Producers Coalition ("NIPPC") submits these comments in response to the Oregon Public Utility Commission (the "Commission" or "OPUC") notice requesting that stakeholders provide their priorities regarding the Commission's upcoming Senate Bill ("SB") 978 report ("Report") to the Legislature.

The Commission needs to look at the world as it can and should be, and not just as it is today. The Commission's Report should outline a 21st Century vision of the electricity system and utility regulation rather than just describe the trends challenging the over 100-year old utility business model and regulatory construct. SB 978 offers a matchless opportunity re-shape Oregon energy policy to better reflect the state's policy priorities starting with decarbonizing the power sector at the least cost and least risk to consumers.

The following comments represent NIPPC's second set of formal written comments. NIPPC's April 20 comments, which: 1) summarized of the Commission's current regulatory responsibilities; 2) explained the public policy objectives promoted and impeded by the current system for regulation of investor owned utilities ("IOUs"); 3) identified the primary obligations and benefits for utilities, cost-of service and direct access customers and the Commission; and 4) descried the actions and behaviors the current system encourages from utilities, cost-of-service and direct access customers, and the Commission are not repeated here.[1]

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[1] NIPPC's SB 978 Comments (April 20, 2018) (Available at: https://www.puc.state.or.us/Renewable%20Energy/NIPPC-Comments.pdf).

NIPPC continues to maintain, however, that the guiding principle of regulatory innovation should address the question: what can regulated monopolies uniquely do? NIPPC believes IOUs serve a central role ensuring reliable, non-discriminatory access to electricity at fair, just, sufficient and reasonable rates. Today, the IOUs' role, which justifies monopoly status should be limited to investment in and operation of the distribution and transmission grid.

The electricity generation sector is no longer a natural monopoly. This reality is recognized in Federal law and most of the country. The IOUs' monopsony entitlement and obsession with owning generation assets, while consistent with the utility shareholders' economic interest, runs contrary to the ratepayer interests. The IOU exercise of their monopolistic prerogatives increases the cost of electricity thwarts innovation and impedes the state's energy policy goals of de-carbonization, diversification of resource ownership and rural economic development.

Oregonians are hamstrung by today's dated approach to utility regulation. Regrettably, prior Commissions failed to fully and fairly implement the Legislature's statutory directives expressed in SB 1149. While other elements of that ground-breaking legislation were adopted,[2] the law's core vision of a competitive electricity market has not been realized. This Commission in responding to SB 978 can now shift to a regulatory model centered on market competition, choice and innovation.

Twenty years after its passage, SB 1149 is more relevant than ever. For example, the provision of direct access for commercial and industrial customers is of pressing interest. Businesses of all sizes currently in the state, and others considering relocating to Oregon, are eager to avoid cost-of-service rates and to shift to carbon-free electricity sources offered by the market at affordable prices. This change can be achieved without disadvantaging ratepayers.

Returning to the vision set by SB 1149 would set the pace for other needed modification of the status quo regulatory structure. The Commission can get ahead of changes, which have already occurred and are expected to accelerate in the near future. If the Commission fails to adopt a roadmap for the future, it risks being disintermediated by technological changes, economic inventiveness, consumer frustration and piecemeal legislative initiatives. This outcome needs be avoided given the Commission's exceptional expertise and its position to drive de-carbonization of the energy economy at the lowest cost to all power consumers.

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[2] The public purpose charge to fund conservation, renewable energy, low income weatherization, housing and schools has been fully implemented with great success. SB 1149 removed conservation from the utilities and allowed the creation of the Energy Trust of Oregon ("ETO"), which now manages conservation and energy efficiency. This was done because utilities have a financial interest in under investing in conservation. Oregon's approach to conservation, lead by the ETO, may now be the best in the nation.

Therefore, with the eyes of the Legislature upon it, the Commission needs to take this opportunity to describe a reconfigured utility system that meets Oregon's future needs. The Commission's Report should make substantive recommendations for administrative and legislative changes that will enable Oregonians to live and conduct business in an energy economy that is more innovative, cleaner, and cost effective.

Specifically, NIPPC urges the Commission to craft a Report to the Legislature which:

- Describes the current energy regulatory model in Oregon, including its obligations and benefits to stakeholders, regulatory incentives, and the primary public policy objectives that are advanced by the Commission's actions under the current regulatory model;

- Summarizes all of the changes to the regulatory model proposed by participating stakeholders;

- Explains which stakeholders' specific recommendations can be achieved through administrative action and what those actions would be, or if new statutory authority is needed, and what kinds of legislative changes would be required;

- Proposes changes to the existing regulatory system and incentives that benefit customers and the public generally, including plans to administratively implement these changes and make recommendations to the Legislature to implement any changes to the regulatory system to meet the current and future challenges in the energy economy.

1. The Market, Subject to Commission Oversight and a Utility Backstop, Should Meet the Utilities' Future Generation Requirements

NIPPC's primary recommendation is to remove the perverse incentive of the IOUs to build and own generation resources. The Commission can achieve this with or without legislative action, in directing the IOUs to rely upon the market to meet long-term power requirements. Such a policy would lower capital costs to ratepayers by tapping into robust competition amongst independent power producers ("IPPs") and the unprecedented innovation in renewable generation, storage and distributed generation they bring to the power sector. Repositioning the utilities' role in resource acquisition as called for in the original SB 978[3] will do more than protect ratepayer interests, it will economically and rapidly advance Oregon's move to a decarbonized energy economy.

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[3] SB 978, available at: https://olis.leg.state.or.us/liz/2017R1/Downloads/MeasureDocument/SB978/Introduced.

In a "market first" future, the Commission would continue to review and acknowledge the IOUs' least cost and least risk plans, allowing the IOUs to retain ownership of their existing generation assets. The Commission would then oversee competitive procurements where IPPs exclusively compete against one another to ensure that ratepayers obtain the best deal.[4] Only in extraordinary circumstances could the IOUs petition the Commission to endorse their acquisition of capacity—either to maintain system reliability in exigent circumstances or secure a "deal" if a resource is well below market value.

Simply put, with Carty[5] as "Exhibit One," it is time to end the utilities' monopoly over generation capacity, and allow a competitive market to provide these services at lower cost and less risk.

2. Commercial and Industrial Customers Should Be Allowed the Freedom to Choose Their Power Supplier to Increase Renewable Acquisitions and Lower Power Costs for All Customers

The Commission's Report should outline how the benefits of direct access can be achieved either through administrative action or, where required, legislative initiative. NIPPC does not believe additional statutory changes are necessary and the Commission only needs to fully implement existing law; however, NIPPC would support legislative changes if the Commission concludes that current law is inadequate to allow commercial and industrial customers to exercise true retail choice.

SB 1149 sought to provide commercial and industrial consumers with market access in order to boost economic competitiveness leading to increased investment and commensurate job creation. The Oregon Legislature found that "all Oregon retail electricity consumers should be provided fair, non-discriminatory access to competitive electricity options,"[6] and that "retail electricity consumers that want and have the technical capability should be allowed, either on their own or through aggregation, to take advantage of competitive electricity markets as soon as is practicable." NIPPC does not believe "as soon as practicable" should take two decades to effectuate.

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4 History has demonstrated that fair competition cannot occur when the utility has an economic interest in selecting its own generation assets.

5 Despite strong opposition from industrial customers and independent power producers, PGE selected Carty, a utility owned resource, instead of lower cost and less risky non-utility owned generation. Carty is at least $150 million over budget, and PGE will surely seek to recover those amounts, *plus a return*, if PGE cannot recover the overage from the original contractor's insurance companies.

6 Under SB 1149, only commercial and industrial customers have direct access to independent electricity service suppliers and residential customers can select a portfolio rate options (green power, time of use rates, etc.).

The Commission's Report should address the pursuit of direct access driven by commercial and industrial businesses seeking to lower costs and carbon emissions. This Commission can correct for lost time by facing down the utilities' undue exercise of market power, which is patently in conflict with state law (SB 1149).

Independently owned energy companies (electricity service suppliers) are also currently prevented from fully bringing their creativity and innovation into the energy economy, which drives up costs and reduces service quality. The frequently cited analogy has real merit: few envisioned a world of smart phones prior to the forced divestiture of Ma Bell. Thankfully, Americans are generations removed from "choices" that were limited to a gray, black or pink landline phone. It was innovation, freed from obsolete monopoly regulation, which opened a world of new possibilities. A restructured energy economy, which unleashes competition, will surely yield similar results.

The Report should explain that direct access benefits all customers by allowing the state to retain existing industries, attract new businesses, and strengthen wholesale power markets, which drive down power costs for all customers. It allows customers who have goals to secure carbon-free resources above and beyond the existing renewable portfolio standard if that is a corporate objective, thereby advancing meaningful and lower cost de-carbonization. Now is the time to facilitate progress, which the Commission needs to pursue promptly.

3. The Commission Should Protect Qualifying Facilities

The Oregon Commission has generally adopted fair and balanced policies to manage the role of qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act ("PURPA"). These policies brought modest levels of non-utility renewable energy development at no additional cost to ratepayers. Regrettably, the Commission has undermined its own policy by allowing PacifiCorp to nearly completely escape its obligation to purchase power under PURPA. Portland General Electric Company ("PGE") has aggravated the situation by aggressively deploying abusive tactics to stonewall IPP generation. Except for small projects, the Commission's goal should be to make PURPA irrelevant by fostering a truly competitive market. Unless and until that becomes a reality, PURPA will be a primary route by which competitive power options are foisted upon the IOUs.

NIPPC recommends the Commission's Report begin by honestly taking stock of how, despite its oversight, utilities have successfully prevented Oregon from achieving the legislative policy of creating a "settled and uniform institutional climate for" and to "increase the marketability of" Oregon Qualifying Facilities ("QFs").[7]

[7] ORS 758.515.

The Commission should also implement the 8% community renewables mandate, which was not implemented when it was only a "goal" and has been ignored now that it is a mandate.[8] In terms of legislative changes, the Commission should at a minimum recommend that the current statutory goals supporting the development of QFs be turned into mandates.

NIPPC recognizes that the process of setting rates for retail and PURPA is more art than science. The overall result, rather than each step of the process, reflects on how successful a regulatory agency is at implementing the law. Oregon's process for setting PURPA avoided costs is broken, as illustrated by dozens of QFs seeking Commission protection from PGE's efforts to put its competitors out of business. Similarly, there is no reasonable rate setting methodology that can justify PacifiCorp setting its avoided cost rates so low as to keep QFs from selling it power, while at the same time the company seeks to acquire over 1,000 megawatts of new wind generation and associated new transmission to wheel its new wind capacity to its load. PURPA rates should reflect the obvious economic reality where the all-in costs of Wyoming wind plus new transmission are more expensive than eastern Oregon solar or irrigation districts' small hydro.

4. A Northwest Regional Transmission Organization Should Be Created

The Northwest is in dire need of a regional transmission organization. The success of the Energy Imbalance Market suggests that the region is ready to take the next step towards a modern regulatory framework for transmission access. The Commission has long advocated for the creation of an independent regional transmission organization to optimize transmission service and investment, better integrate renewables and lower costs to consumers. What is not readily recognized is how utilities like PacifiCorp and PGE use the status quo to discriminate against IPPs in the competitive procurement process and prevent QFs from wheeling power to load.

In the Northwest, there is often sufficient available transmission from a reliability and electrical engineering perspective, but an outdated contract path transmission reservation system artificially constrains the operation of the transmission grid. The contract path system locks in existing patterns of generation dispatch ensuring market access for the traditional generation resources while blocking access of cheap, clean new generation. Having to move renewable energy generation from the sunny, windy and hydroelectric rich parts of the region to loads often requires transmission rights across multiple providers; these "rate pancakes" increase the cost of new resources. An independent regional transmission organization would mitigate many of these obstacles.

While Oregon has limited ability to influence transmission decisions due in part to the Bonneville Power Administration's control of 75% of the region's transmission and the Federal Energy Regulatory Commission overarching authority over transmission

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[8] ORS 469A.210.

policy, it needs to amplify its voice. The Commission can prevent the utilities from deploying their transmission assets (whether on their own or on Bonneville's grid) to restrict competition. The Commission can also exert pressure and provide incentives for utilities to create or join an independent regional transmission organization. The Commission's Report to the Legislature should clearly identify the need for a regional transmission organization and recommend administrative and legislative changes that would lay the groundwork for truly open and optimized transmission access.

5. Equity and Justice

The traditional regulatory model brought electrification and non-discriminatory access to Oregon, but not all voices have been involved in regulatory discussions and decision making. Electric service has been a powerful tool to promote equity and prosperity justice for all consumers whatever their economic status or residency. The present moment brings the prospect of genuine competition and innovation, which would benefit all ratepayers. Meanwhile, standing pat carries risks in harming the environment and reducing equity and social justice.

NIPPC recognizes regulatory and economic changes create risks, and that some customer groups are better positioned to benefit from a transition to a less carbon intensive, more efficient and innovative energy economy. Special care must be taken to ensure that all customers benefit from industry changes, including economically disadvantaged and other underserved communities. NIPPC does not presume to know the best ways to address the concerns highlighted by the SB 978 equity and social justice stakeholders, but more voices need to be heard and acknowledged and their interests protected. Some immediate changes NIPPC could support include providing the Commission more authority to better serve compromised customer groups and at-risk communities; the ability to approve low-income tariffs; and more inclusive pathways to receive intervenor funding so that social equity and environmental justice perspectives are better represented in the regulatory process.

The Commission's goal must be for all customers to benefit from change, and to break out of the mindset that ensuring adequate protection for all customers means that we should be afraid of innovative regulation that can enhance and diversify the energy economy of the next century. For example, PacifiCorp's remaining cost-of-service customers can be adequately protected if more than 5% of eligible large non-residential customers are provided a meaningful opportunity to select direct access.[9] All customers can and should benefit from innovation in regulation and development.

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9 Oregon commercial and industrial customers are eligible for direct access. Only 4.7% of the PacifiCorp's eligible customers are on direct access and only 17% of PGE's eligible customers are on direct access.
https://www.puc.state.or.us/electric_restruc/statrpt/2017/June_2017_Status_Report.pdf

6. The Commission's Mission Statement and Goals Should Be Expanded

NIPPC is convinced the Commission's existing statutory authority is expansive enough to advance innovation across the broad energy economy, including utility competitors, the wholesale market, and the environment. However, if the Commission concludes otherwise, then it should make recommendations to change its enabling statutes. The late 19th Century model was created for a time when state regulatory authority was focused on encouraging capital investment, marshaling low prices, and supporting utilities so they could deliver reliable service. This model is not well suited to the modern world. With utility shareholder interest diverging from ratepayer needs and plentiful capital available to IPPs, the Commission is on the spot. The SB 978 process has highlighted how Commission decisions impact economic development, whether Oregon meets its carbon reduction goals and ratepayers pay more for electricity than necessary. The Commission's regulatory footprint has dramatically expanded to encompass whole industries and areas of energy law and policy that did not exist more than 100 years ago.

Again, the Commission can either lead a holistic conception of its mission statement or react to events and more piecemeal direction from the Legislature. There have been numerous statutes passed that require the Commission to consider and protect the wholesale and retail markets, protect small scale and community based renewable resources, allow natural gas utilities to invest and profit from emission reductions, allow above market and non-cost effective transportation electrification investments, ensure that low income communities benefits from community solar, etc. If the Commission does not act now to establish itself as the forum for thoughtful development of regulatory policy, then the legislature will continue to propose and pass ad-hoc legislation directed to the Commission and its activities. While that is the job of a legislature, the Commission's work can be frustrated when legislative changes do not include a Commission input. SB 978 gives the Commission the opportunity to be heard first.

Specifically, NIPPC recommends the Commission's mission be expanded to include an explicit commitment to environmental protection beginning with carbon reduction, and enhancement of a healthy economy by driving the cost of power and associated emissions as low as possible. The Commission should be enabled to achieve these goals by stimulating innovation and promoting competition.

7. The Commission's Regulatory Powers Should Be Expanded

While NIPPC believes additional statutory authority is unnecessary, to remove any doubt, the Commission should request additional direction to ensure adequate competition in the electricity generation sector, promote innovation, and implement direct access. Specific legislation the Commission should support, if it does not believe it has the statutory authority now includes:

- Expanding the Commission mission statement;
- Preventing utility ownership of new generation assets;
- Requiring utilities to join an independent regional transmission organization or system operator;
- Requiring utilities to allow third-party providers to use their generation, transmission and distribution assets to ensure that the least cost and least risk resources are acquired;[10]
- Regulating carbon emissions by electric utilities;
- Ensuring that wholesale and retail competition in the electricity sector is achieved;
- More fully implementing direct access, including ensuring that the utilities no longer acquire or plan on serving direct access customers and new loads that have never been served;
- Creating a statutory requirement, rather than a policy or goal, to increase the marketability of QFs and to create a uniform institutional climate for QF development, including specific protections for QFs to prevent utility abuses; and
- Increasing equity, potentially through low income tariffs, and intervenor funding for equity and social justice organizations.

8. Conclusion

NIPPC appreciates the opportunity to submit written comments to help shape the Commission's Report. The Commission, after superbly managing the SB 978 stakeholder process, will most certainly capture stakeholders' positions in its Report. Next, regardless of whether the Commission supports or opposes any specific recommendations, the Commission should definitively explain whether they can be achieved through administrative processes or if new statutory authority is required.

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[10] This is consistent with the Commission's current regulatory authority. The Oregon Legislature has already explicitly granted electricity service suppliers with the statutory right to access and use the utilities' distribution and transmission system. ORS 757.632 and 757.637. Congress has also explicitly granted independent power producers non-discriminatory access to back up power and interconnections, and (without explicit statutory authority) the Federal Energy Regulatory Commission requires utilities to provide equal non-discriminatory access to the IOUs transmission assets.

Finally, the Commission should think big and be bold. The current regulatory model that worked well for its time, but must now adapt to a new world so that the energy economy can less expensively achieve state and federal goals related to power supply, environmental and climate goals, equity, reliability, accessibility and affordability. It is time to rely upon innovation and competition in the power sector. The notion that the Commission's regulatory regime exists to simulate competition could not be more inadequate. The Commission needs to seize this golden opportunity and lay out a vision for how to do its job better for the benefit of Oregonians and the environment that makes the state so special.

Sincerely,

Robert D. Kahn

Robert Kahn

Irion Sanger

Irion A. Sanger

cc: Jason Eisdorfer
Julie Peacock