

**BEFORE THE WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION**

UE-161024

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

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

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

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,

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.

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),

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

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_pge_s_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

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

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

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,

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 through 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.

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 rules⁴³ 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.

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-see-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

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 "incentivizes 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.

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

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

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 capacity⁶⁵ and certain energy storage⁶⁶ with a term of five years or more.⁶⁷

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

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.

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

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.

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 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 thorough 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.

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.

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

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

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

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.

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

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

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 competitive bidding rules can offset.

⁹⁵ The OPUC considered, but rejected the use of bid adders to address utility ownership bias and risks in the RFP process. Re NIPPC Petition for an Investigation Regarding Competitive Bidding, 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

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 Required 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

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

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

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,

A handwritten signature in black ink that reads "Irion Sanger". The signature is written in a cursive style with a large, looped initial "I".

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