Peter J. Richardson (OSB No. 06668)
Gregory M. Adams (OSB No. 101779)
Richardson & O'Leary PLLC
515 N. 27th Street
P.O. Box 7218
Boise, Idaho 83702
Telephone: (208) 938-7901
Fax: (208) 938-7904
peter@richardsonandoleary.com
greg@richardsonandoleary.com

Attorneys for Northwest and Intermountain
Power Producers Coalition

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

In the Matter of PORTLAND GENERAL ELECTRIC Request for Proposals for Capacity Resources.	)	UM 1535 NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S COMMENTS

Pursuant to the scheduling order in this case issued on April 15, 2011, the Northwest and Intermountain Power Producers Coalition ("NIPPC") hereby files these comments on Portland General Electric's ("PGE's") Request for Proposals ("RFP") for Capacity Resources. NIPPC is a trade association whose members and associate members include independent power producers ("IPPs") active in the Pacific Northwest and Western energy markets.[1] Although these comments do not represent the views of any individual member company, NIPPC believes it is in

[1] NIPPC's members include Calpine, Capital Power Operations (USA) Inc., Constellation Energy Control & Dispatch, EverPower Renewables, Exergy Development Group, First Wind, Fort Chicago U.S. Power /Veresen Inc., Horizon Wind Energy, Invenergy LLC, Ridgeline Energy, Shell Energy North America, TransAlta Energy Marketing, Inc., and TransCanada.

a unique position to provide the Public Utility Commission of Oregon ("Commission") with a valuable perspective from the bidding community. As explained in more detail below, NIPPC is concerned that the RFP, as currently proposed, could be implemented to significantly advantage the self-built benchmark 200 megawatt ("MW") Port Westward Unit II project. NIPPC therefore respectfully requests that the Commission condition approval of the RFP upon PGE's agreement to implement several modifications.

I. Regulatory and Factual Background

A. The Oregon RFP Guidelines

The Commission's RFP Guidelines, and the related orders, require utilities to announce in their bi-annual integrated resource plans ("IRPs") all self-built benchmark resources they would submit into upcoming RFPs. Order Nos. 06-446, 07-002. This description and the IRP Action Plan should provide the potential bidders with an idea of what the RFP will seek, so that the bidders can begin preparing their projects which they will bid into the RFP. As the RFP approaches, the RFP Guidelines require the utility to retain an independent evaluator ("IE") in developing the RFP, and require the IE to submit its assessment of the draft RFP to the Commission. Guideline 7 calls for public comment and Commission review, as follows:

> The Commission will solicit public comment on the utility's final draft RFP, including the proposed minimum bidder requirements and bid scoring and evaluation criteria. Public comment and Commission review should focus on: (1) the alignment of the utility's RFP with its acknowledged IRP; (2) whether the RFP satisfies the Commission's competitive bidding guidelines; and (3) the overall fairness of the utility's proposed bidding process. After reviewing the RFP and the public comments, the Commission may approve the RFP with any conditions and modifications deemed necessary.

B. PGE's Capacity Resource Needs in the IRP

PGE's recently acknowledged 2009 IRP described a need for capacity resources to address peaking needs and integrate intermittent resources. PGE stated it would propose a 200 MW benchmark resource located at the Company's existing Port Westward Generating Project site. *PGE's 2009 IRP*, at p. 204. "The proposed benchmark capacity resource is a state‑of‑the‑art, highly efficient and environmentally responsible power plant consisting of multiple natural gas‑fired reciprocating engine‑generator sets and/or aero derivative combustion turbine generators and associated equipment in simple‑cycle operation." *Id.*

The IRP detailed the advantages of PGE's existing site, including the following

- a gas supply line from the KB Pipeline designed for two plants
- a gas pipeline connection to the NW Natural Mist Storage field that could be utilized as part of a combined fueling strategy for both plants
- the addition of a new PGE transmission line from Port Westward to Trojan, providing additional capacity to integrate Beaver to PGE load and retain existing BPA transmission capacity to allow delivery of power from a potential new resource located at Beaver
- an existing switchyard capable of being expanded to include connections to the capacity project and a Large Generator Interconnection Agreement in the process of being executed with PGE Transmission
- existing long‑term site leases that will be used for developing this benchmark site
- existing site certificate that can be amended more quickly at the existing site than for a green field site
- existing air quality permits, and wastewater permits that can be amended
- use of the existing staff, control room, water supply, gas supply, fire water, backup power, communications and security resulting in lower operating and development costs.

Id., at pp. 204-05.

,

The IRP Action Plan states PGE will pursue the following resources:

> 11. Flexible Capacity Resources. PGE requests acknowledgement of up to 200 MW of flexible capacity resources by year-end 2013 to fill a dual function of providing capacity to maintain supply reliability during peak demand periods and providing needed flexibility to address variable load requirements and increasing

levels of intermittent energy resources. PGE intends to submit a self-build alternative to be located near the existing Port Westward site.

12. Seasonal Capacity. PGE requests acknowledgement to acquire, via contracts, up to 131 MW of bi-seasonal, limited-duration peaking supply and 152 MW of winter-only peaking supply to maintain reliability and meet system contingencies during peak demand periods. These partially replace similar expiring peak seasonal contracts. In the event that we are unable to acquire bi-seasonal, limited-duration peaking supply resources, PGE would need to revisit our procurement plan and may need to consider additional year-round peaking resources as an alternative.

* * * *

14. Gas Transport. To meet the fueling requirements of the new energy and capacity resources in the proposed Action Plan, as well as to maintain portfolio flexibility, additional natural gas transport and/or storage is required. In this Action Plan, we recommend acquisition of 40,000 dekatherms per day of pipeline and/or storage for flexible capacity needs[.]

Id., at pp. 325-26.

PGE's IRP also described a need for another gas-fired resource – a 300-500 MW baseload energy facility – for which PGE would propose a benchmark combined cycle combustion plant called Carty Generating station, located near its Boardman plant and in service by year-end 2015. *Id.*, at pp. 205-06, 325. The IRP also discussed the advantages of that Carty benchmark resource's location at PGE's existing site. *Id.* at p. 205-06. The Commission conditionally acknowledged PGE's IRP in November 2010. Order No. 10-457. Prior to release of the RFP documents, the information in the IRP was the notice to the IPP community regarding the RFPs for gas-fired resources.

C. Public Release of RFP Documents in April 2011

In January 2011, PGE released its request for bids from potential IEs, which provided some additional details regarding the timing of the RFPs. It became apparent that PGE did not intend to hold a single RFP for gas-fired resources such that IPPs could bid to use the same site to build both the 200 MW flexible peaking resource and the 300-500 MW baseload resource.

The Commission selected Accion Group as the IE for PGE's three upcoming RFPs, and PGE subsequently released a first draft of the Capacity RFP on April 21, 2011. NIPPC reviewed that draft and a subsequent draft and has provided PGE with its preliminary comments and concerns. NIPPC has attached its prior letters distributed to all parties in this case on April 14, 2011, May 10, 2011, and May 20, 2011, as an Attachment to these Comments. On June 3, 2011, Accion Group filed its Assessment of the Draft RFP. While PGE and the IE have resolved some of NIPPC's concerns, NIPPC still has several serious concerns with the RFP's current design, which merit the Commission's attention and are discussed below.

II. Comments

A. NIPPC is concerned with PGE's expressed preference for a self-built 200 MW peaking plant and with the RFP's treatment of that benchmark.

NIPPC is very concerned that PGE has had an "informational" and timing advantage over IPPs in developing its own benchmark resource. Accion stated in its Assessment that it based its evaluation on the Commission's Guidelines and on criteria for a fair and transparent RFP process adopted by the Federal Energy Regulatory Commission ("FERC") in *Allegheny Energy Supply, LLC*, 108 FERC ¶ 61,082 (2004). *See Accion Group, Independent Evaluator Assessment of Portland General Electric's Draft 2011 RFP for Capacity Power Supply Resources*, p. 2 & n.2 (June 3, 2011) ("*Accion Group's Assessment of PGE RFP*"). NIPPC agrees that the FERC standards set forth in *Allegheny Energy Supply, LLC* can provide a useful reference to the Commission in application of Guideline 7's requirement to analyze "the overall fairness of the utility's proposed bidding process." As Accion states, the FERC decision provides the Commission with context for the industry understanding of a "fair" RFP design. Perhaps most importantly, FERC stated, "No party, particularly the affiliate, should have an informational advantage in any part of the solicitation process. The RFP and all relevant information about it should be released to all potential bidders at the same time." *Allegheny Energy Supply, LLC*, 108 FERC ¶ 61,082, at ¶ 23. This logical requirement would prevent one party from engaging in advanced permitting or development of its project with information not available to other bidders, such that the party could satisfy timing or other requirements of an RFP.

In this case, PGE's self-build team should have no informational advantage over IPP bidders in order for the RFP to be fair. It would be inherently unfair for those on the self build team to have had any information regarding the RFP and its requirements than the information made publicly available in the IRP. It would also be inherently unfair to design the criteria and requirements of the RFP such that they allow for the advanced design, permitting and development efforts of the self build benchmark to the exclusion of other resource options that could meet the needs identified in the IRP.

NIPPC's overarching concern in this RFP, however, is that PGE's self build benchmark has undoubtedly benefited from a head start in its development efforts, and from its ability to use the resources of the utility's rate-based assets potentially to the exclusion of IPPs. PGE filed the IRP, including descriptions of the upcoming resources PGE would seek, with the Commission on November 5, 2009 in Docket No. LC 48. PGE's development efforts for the benchmark were well advanced at that point. In November 2008, PGE began taking steps to amend its Site

Certificate with Oregon Department of Energy to allow for the peaking plant.[2] PGE also appears to have applied for an air quality permit with the Oregon Department of Environmental Quality in September 2009, which required very detailed explanation of the aero-derivative generating unit and plant operational characteristics.[3] Bidders were not afforded information necessary to take this advance opportunity to prepare their projects, or to use the existing rate-based facilities described in the IRP for their own bids.

The IE Assessment explains that the self build team is blinded to the bids, but it also notes that PGE refused the IE's request to make the self build team known publicly. *Accion Group's Assessment of PGE RFP*, at pp. 4-5, 16. PGE's refusal to even share the names of those involved with the self-build team is troubling. Not only could IPPs inadvertently share information with the self build team which the self build team could use to its advantage, but PGE's secrecy also raises the question of what information the self build team possessed prior to release of the RFP in April 2011.

Under these circumstances, NIPPC believes it is imperative that specific efforts be

---

[2] The history of PGE's amendments to its Port Westward Site Certificates can be found online at the Oregon Department of Energy's website. *See* http://www.oregon.gov/ENERGY/SITING/PWG.shtml. Port Westward Unit II was initially intended and permitted to be a baseload natural gas-fired combustion turbine combined-cycle unit. PGE subsequently decided to alter the design to be a peaking gas plant that could integrate intermittent wind power. According to PGE's applications, in order to allow time to submit a request to amend the Site Certificate to authorize construction of Unit II as newly configured, PGE filed a request on November 7, 2008 for an extension of the deadline for completing construction of Unit II. It requested formal amendment allowing for the new configuration on September 18, 2009.

[3] PGE's draft permit and a DEQ report on the application can be found online at the following links, http://www.deq.state.or.us/nwr/permits/05-2606-P-09262010-AQ.pdf, http://www.deq.state.or.us/nwr/permits/05-2606-RR-09262010-AQ.pdf.

exercised by the IE, Commission Staff, and ultimately the Commission, to mitigate the clear cut indications of PGE's self-build bias. In particular, the RFP needs to be designed so as to allow for the maximum flexibility in the bids – including timing, technology, transmission, gas delivery, etc. – with a focus on meeting the actual needs of PGE and its customers rather than a predetermined set of criteria which the benchmark resource is now able to provide and which was not previously announced in the IRP.

B. NIPPC is concerned with the timing of this RFP.

1. A bid's ability to achieve an online date in 2013 should not be a precondition or scoring factor in any manner.

PGE's initial RFP documents appeared to list 2013 as a preferred online date which may impact a bid's ranking, but did not clearly define the ranking criteria. In response to NIPPC's May 10, 2011 letter expressing concern that this date seemed unnecessary given the ample peaking capacity currently available in the market, PGE changed the preferred online date to by the end of 2014. *PGE's Request for Proposals for Capacity Power Supply Resources*, p. 11 (May 23, 2011) ("*PGE's May 23, 2011 RFP*"). Yet the RFP still appears to reward a bid's ability to achieve a near-term online date as a non-price evaluation factor under the category titled "Project Development." The RFP states, "Plants that are already operating or are sufficiently advanced in construction may be deemed to earn the maximum possible score from this category." *Id.* at p. 21. PGE states it will also evaluate the status of equipment supply and engineering, procurement and construction agreements. *Id.* These criteria clearly advantage the self build project's advanced ability to develop and permit its project.

It is important to emphasize that these criteria are not tied to an actual pressing need for the flexible capacity resource sooner than 2014. There is no point in having a resource online and being billed to ratepayers sooner than it is truly needed. And possessing the ability to achieve an unnecessarily early online date should not increase the ranking of any bids to the potential detriment of bids that may otherwise offer a lower cost to ratepayers over the life of the plant. NIPPC suggests that there should be no evaluation criteria which result in higher ranks for resources that can achieve an online date prior to 2014 because no case was made in the IRP or elsewhere that the 200 MW resource must be available prior to 2014 to meet PGE's peaking needs.

2. PGE should allow adequate time for bidders to review the final RFP requirements prior to submitting bids.

The RFP schedule in this case seems condensed to the disadvantage of IPP bidders. *See PGE's May 23, 2011 RFP*, at p. 4. PGE first made its RFP available in any capacity on April 21, 2011, and it was missing many key elements at that point. PGE held the stakeholder and bidder workshops on May 11th and 12th. The schedule in the RFP calls for bids due September 2, 2011 – only a little over a month after PGE proposes releasing the final RFP to bidders on July 26, 2011. NIPPC does not intend to obstruct or delay this process, and has attempted to participate early. But bidders need at least six weeks after release of the final version of the RFP, so that they may adequately put together their bids. PGE's proposed schedule assumes that there will be no changes to the RFP, and assumes PGE can release the RFP the same day the Commission issues its order approving it. That is unrealistically optimistic because, as discussed below, the RFP is still missing several important items. NIPPC suggests that the RFP should provide at least 6 weeks from the date it is released in final version after the Commission's order, instead of rigidly adhering to a September 2, 2011 due date for bids.

3. The Capacity RFP should overlap with the Baseload Energy RFP to enable IPPs to bid a lower price to develop both the 200 MW Capacity resource and the Baseload Energy Resource on the same site.

PGE has issued a Capacity RFP requesting 200 MW of flexible year-round peaking capacity and plans to soon issue a Baseload Energy RFP for 300-500 MW of baseload energy. The logical resources in both RFPs are natural gas-fired plants – one a simple cycle plant and one a combined cycle plant. PGE commented extensively in its IRP regarding the advantages of developing two proposed benchmarks on or adjacent to its existing sites for Boardman and Port Westward. For the RFPs to be competitive, IPPs should also be allowed to achieve these economies of scale of using a single site to locate technology capable of meeting both requirements.

In a letter to PGE dated April 14, 2011, NIPPC requested that PGE adjust its RFP schedule to allow for a mechanism of PGE's choosing by which IPPs can take advantage of the likely economies of scale of using a single site. If IPPs could bid into both the Capacity RFP and the Baseload Energy RFP at the same time, or into a single gas resource RFP for Capacity and Baseload Energy resources, the IPPs could bid to use the same site for both resources and achieve economies of scale in construction and operations. This could include shared use of gas, water, interconnection, transmission, site leases/purchase, taxes, employees, and maintenance similar to the characteristics PGE credits to its two benchmark resources. If the RFPs were overlapping, IPPs may bid two prices into each of the RFPs – (1) a price in each RFP for a Capacity or Baseload Energy resource alone, and (2) separate (likely lower) prices for the Capacity and Baseload Energy resources if PGE were to select that IPP's bids in both RFPs.

This would allow for more competitive IPP bids, and should result in more cost-effective resources for ratepayers.

Shortly after NIPPC's April 14, 2011 letter, counsel for NIPPC understood from a discussion with PGE that PGE would be able to accommodate NIPPC's request. NIPPC did not raise the issue with subsequent letters or with the IE. Then, on June 2, 2011, PGE informed counsel for NIPPC that the overlap would not be sufficient to allow for any bidders other than those who make the short list in the Capacity RFP to bid a lower price into the Baseload Energy RFP in the event they win both RFPs and develop the same site for both resources. NIPPC submits that a more robust procurement will be achieved if all bidders into the Capacity RFP have this option.[4]

NIPPC suggests PGE should implement the adjustments necessary to the schedule to allow for the mechanism requested by NIPPC. NIPPC also suggests that the Capacity RFP should expressly state that bidders may provide a separate bid price that would be applicable if their projects are selected in both the Capacity and the Baseload Energy RFP.

C. NIPPC is concerned that the RFP's design will favor the self build benchmark if it is not modified and properly implemented.

The RFP contains provisions giving the benchmark resource a distinct advantage when considered in light of PGE's development efforts for the benchmark.

---

[4] Whether due to misunderstanding or miscommunication between PGE and NIPPC in April, or due to changed plans on PGE's part since that time, it is unfortunate that the IE has not had an opportunity to weigh in on this matter, but at least the Commission will now have an opportunity to address it.

1. The $45 million 230 kV Trojan line must be allocated to the self build bid price.

In its IRP, PGE discussed transmission constraints as a problem in developing any new resources, including the 200 MW year-round capacity resource being procured in this RFP. PGE stated, "To accomplish the delivery of this energy we have three options: 1) request transmission service from BPA, 2) request transmission service from a third ‑ party transmission provider for resources outside the northwest, or 3) provide the needed transmission service ourselves." *PGE's 2009 IRP*, at p. 168. PGE stated it was choosing to pursue "self build transmission" to solve this problem. *Id.* PGE stated:

> Our proposed South of Allston transmission project involves a new 230 kV line from Trojan that connects to the west side of our service territory. This third line from Trojan to PGE not only provides a significant increase in the transfer capacity of the South of Allston cutplane, but also would fully integrate the remaining Beaver capacity as well as fully integrate a potential new capacity resource. *Id.*, p. 169.

PGE stated this solution would significantly decrease PGE's need to purchase BPA point to point transmission. *Id.* at p. 170; *See id.* at p. 182-184 (providing further description of the Trojan line as well as a timeline for construction occurring in 2013).

In the cost of service study in PGE's 2009 general rate case, PGE allocated the costs of its $45 million 230 kV Trojan to Horizon line entirely as a capacity resource because PGE expects to use it to integrate a new 200 MW peaking resource. A highlighted copy of the applicable testimony (UE 215/PGE 1500, Kuns-Cody/5) is included with these comments as an enclosure to NIPPC's May 10, 2011 letter to PGE. It appears that the primary intent in planning and building the $45 million line will be for its use to bring the output of the 200 MW benchmark resource to load. While NIPPC is certainly sympathetic to PGE's preference to avoid relying on BPA for transmission, PGE's stated plans for its new transmission line can only be understood as further evidence, as if any were needed, of its plans to site its own capacity resource at Port Westward.

The ability to plan this line in advance of the RFP is an obvious logistical and cost advantage for the benchmark. PGE's initial, draft RFP released on April 21, 2011, expressed preference that bidders use a point of delivery that relied on the "status quo" of the existing transmission system and evaluated bids based on the cost to deliver to PGE's *system*. *PGE's Request for Proposals for Capacity Power Supply Resources*, pp. 12, 21-22 (April 21, 2011). NIPPC voiced concern with this language in the letter sent May 10, 2011, and requested confirmation that the $45 million Trojan line, since it is not built, is not itself part of the status quo and that its cost will be included in the price of the benchmark resource. The Capacity RFP filed with the Commission now states that the bids will be evaluated, in both the price and non-price criteria, based on the incremental costs to deliver to PGE's *load*. *PGE's May 23, 2011 RFP*, at pp. 12, 21. With regard to accounting for the cost of rate based, or future rate based assets, such as transmission, the IE stated that it "has worked with PGE to ensure that the evaluation process will capture all applicable costs and that bids will be scored fairly." *Accion Group's Assessment of PGE RFP*, at p. 11.[5] Obviously, no bidder but the self build benchmark team had the information or ability necessary to begin planning a $45 million new transmission

[5] It is useful to note in this context that in *Allegheny Energy Supply, LLC*, FERC stated that independent third party should eliminate characteristics that favor an affiliate, "e.g., the only acceptable interconnection point for a new nonaffiliated plant is at the affiliate's existing plant." 108 FERC ¶ 61,082, at ¶ 25. Accion should be commended for its stated commitment to ensure that all costs, including presumably the $45 million transmission line, are properly allocated to the cost of the benchmark.

line to avoid the need to secure point to point transmission services with BPA. Based on PGE's IRP and rate case filings, the proposed investment in the proposed new transmission line would not be warranted if the benchmark is not built. It cannot be overestimated that the only fair way to treat this $45 million investment is to allocate its cost to the benchmark's price.

NIPPC is also concerned that the RFP includes a requirement prior to execution of contracts, and as a non-price factor in bid evaluation, that the bids be able to provide a dynamic transfer, or real time pseudo tie to PGE's system if the project will be interconnected to a Balancing Authority ("BA") other than PGE's. *PGE's May 23, 2011 RFP*, at pp. 12, 22. This is one of the attributes that make up the non-price scoring category titled "Project Characteristics," which is allocated 15% of a bid's overall score. *Id.* at pp. 19, 22.[6] The benchmark resource need not confront this hurdle and will presumably receive a perfect score for this component because PGE chose to self build transmission to entirely avoid use of BPA's system. For IPPs without that luxury, however, a dynamic transfer may be difficult to establish with BPA or PacifiCorp without PGE's assistance. It would be unfortunate to decrease a bid's rank on account of its lack of establishment of a dynamic transfer when PGE did not make this requirement known until late April 2011, and when the dynamic transfer will be much easier to establish if PGE cooperates in its establishment.

NIPPC therefore suggests that the RFP requirement, and non-price factor, to establish a dynamic transfer be evaluated on the bidder's best efforts to establish a dynamic transfer or other

[6] The RFP documents do not specify whether dynamic transfer capability would be worth 0.1% or 14.99% under this non-price factor. As discussed below, further clarification of the percentages of an overall score allocated to each individual element are needed. The lack of transparency in the scoring value for all components – such as a dynamic transfer or direct interconnect to PGE – calls into question the fairness of the RFP.

cross BA arrangement. A bid's score should not be decreased prior to selection of the short list on account of failure to have established rights to a dynamic transfer. Should the bid reach the short list, NIPPC would expect PGE to recognize its value added in negotiating with the bidder's host BA to establish dynamic transfer, if necessary.

2. The RFP should not exclude or penalize IPPs unable to provide Gas Storage and Intraday Gas Scheduling without PGE's assistance.

PGE's RFP includes as bid pre-qualification proof of ability to provide "intraday" scheduling of gas supplies. It states:

> **Fuel Supply (where applicable)**
>
> Bidder must demonstrate physical and commercial access to fuel supplies and fuel transportation for the term of the contract proposed in its bid. Fuel transport and/or gas storage agreements used to support gas thermal bids submitted for Flexible Capacity must allow for intra-day nomination. *PGE's May 23, 2011 RFP*, at p. 18.

Gas transport and storage capabilities are also listed as components of the non-price element titled "Project Characteristics" worth 15% of overall score, but the RFP provides no more specification on how those criteria will be scored. *PGE's May 23, 2011 RFP*, at pp. 19, 22 (listing gas transport among "some of the characteristics that we will consider in our scoring").

Read strictly, the RFP appears to prevent a typical tolling arrangement whereby PGE would be responsible for providing fuel for operation of a plant to provide electric energy and capacity. NIPPC raised this issue in a letter dated May 20, 2011, and the IE has confirmed that "PGE's stated preference is for the bidder to provide firm fuel transportation for fuel, with either a tolling or non-tolling bid." *Accion Group's Memorandum Regarding NIPPC's Letters*, p. 4 (June 13, 2011). To NIPPC's knowledge, however, intraday gas scheduling is not feasible at this time in the Northwest without access to substantial gas storage facilities, which are scarce and under utility control. Indeed, in the excerpts of the IRP quoted above, PGE asserted it would need to use its existing gas storage and acquire additional gas storage to build and operate its benchmark. Other than existing plants that may bid into the RFP, the benchmark resource may well be the only bid that can meet this requirement, and it will do so thanks to existing rate-based assets. This is but another example – in addition to the new transmission line and the use of existing rate-based assets at the Port Westward site – of PGE attempting to use regulatory assets and proposed new utility projects financed by rate payers to advantage the becnhmark over IPP bids.

NIPPC believes that requiring IPPs to arrange for their own independent gas storage arrangements is asking for a different product than that described in the IRP. Given that gas storage is limited in the Northwest, bidders could reasonably expect that they would be bidding into an RFP for a typical tolling arrangement where PGE provided the gas, including storage and necessary delivery rights, while the IPP contracted to build and operate the electric generating plant. NIPPC notes also that PGE has provided a tolling agreement as Appendix H, which contains provisions in Section 7 allowing for an arrangement whereby PGE would deliver gas to the "Fuel Delivery Point," which is defined in the tolling agreement as the interconnection between the gas pipeline and meter station at the gas-fired power plant.[7] This seems entirely

[7] The tolling agreement allows for the option of PGE delivering to a separate "Fuel Receipt Point," from which the IPP would make arrangements to bring the gas to the Fuel Delivery Point at the plant. But the tolling agreement states that the provisions requiring the IPP to handle gas delivery "will be used only if the Fuel Receipt Point differs from the Fuel Delivery Point." *PGE's May 23, 2011 RFP*, Appendix H, p. 23, sec. 7.2(a). The entire section is captioned by a disclaimer stating that it may need to be modified to reflect the "actual fuel transportation

inconsistent with a gas storage precondition for the bids, and such a precondition may exclude bids that would otherwise provide ratepayers with a low cost option.

In short, NIPPC believes that, if the benchmark resource will use any existing or future rate-based assets of PGE's, such as storage facilities, etc., those resources should be made fully available to the IPP bidders on an equivalent basis. Furthermore, the RFP should expressly state on page 18 that no bids will fail the bidder pre-qualification criteria as a result of being unable to establish intraday gas scheduling without use of PGE's storage facilities under a tolling agreement. PGE's benchmark should not be able to use rate-based gas storage facilities to be the only project that can meet the RFP's preconditions.

3. The RFP should not exclude viable technology types.

PGE's RFP appears to exclude certain types of simple cycle combustion turbines unnecessarily. The RFP contains minimum capabilities for the 200 MW flexible peaking resource, including a "commercially viable generation technology" which is "AGC Ready" with a minimum ramp rate of 5 MW per minute. *PGE's May 23, 2011 RFP*, p. 17. However, the RFP also lists technologies it expects to be most likely to meet PGE's needs, and itemizes only "aero derivatives" as a type of simple cycle combustion unit. *Id.* at p. 1. Since the time PGE began its permitting of its self build option in 2009 employing an aero-derivative turbine, gas turbine manufacturers now offer a commercially viable generation technology which has the same capabilities as aero-derivatives but at a lower cost to rate payers. Recent models of frame

---

arrangements." *Id.* at p. 22. Likewise, the tolling agreement provides for an additional monthly payment to the IPP, called the "Variable Energy Charge," if the IPP moves the gas to the plant. *Id.* at p. 27, sec. 9.3.

unit simple cycle combustion turbines allow for equivalent performance useful for integrating intermittent resources, but at a lower cost than the aero-derivative turbines.[8]

PGE appears to be prohibiting the use of frame units, however. NIPPC understands that PGE made the pre-qualification section of the online bid form available to bidders and wrote those requirements to exclude use of frame unit simple cycle combustion turbines. The eligibility criteria state:

> **SECTION I. PRE-QUALIFICATION**
>
> **1. Eligible Technology** Simple Cycle Combustion Turbines [Aero derivatives] (Increments of 25 MW) Reciprocating Engine (Increments of 25 MW) Pumped Hydro Storage (Increments of 25 MW) Hydro based generation with pond capability (Increments of 25 MW) Compressed air with Simple Cycle Combustion Turbines (Increments of 25 MW) CCCT Duct Firing (Increments of 25 MW) Seasonal products only, not acceptable for flexible product.

This requirement was made available to bidders and was provided to NIPPC by a bidder. This requirement is not found in the RFP before the Commission for review, but appears to be how PGE plans to implement the RFP. This again is an example where PGE has tailored the RFP to favor its self build option without regard to its actual needs. NIPPC suggests that bidders did not have an adequate opportunity to petition PGE for acceptance of an alternative technology to those listed in this new eligibility criteria form, and that the Commission should expressly require PGE to agree that any technology that meets the dispatchability, ramp rate, or other

---

8 For example, NIPPC is aware of a simple cycle combustion frame unit now being produced by Siemens which has the capabilities described in PGE's RFP, and is currently in use by at least one utility. *See* http://www.energy.siemens.com/us/en/power-generation/gas-turbines/sgt6-5000f.htm#content=Description; http://www.greatriverenergy.com/makingelectricity/erps_fact_sheet.pdf. There may well be other examples or other technologies worthy of consideration because they deliver the functionality PGE seeks.

performance requirements should not be excluded from the bidding.[9]

The focus of the RFP should be in obtaining the lowest cost resource that will meet the utility's needs. "An RFP should not be written to exclude products that can appropriately fill the issuing company's objectives. This is particularly important if such exclusions tend to favor affiliates." *Allegheny Energy Supply, LLC*, 108 FERC ¶ 61,082, at ¶ 28. Based on PGE's IRP and its publicly available air quality permits, PGE has been planning to use an aero-derivative turbine if it uses a simple cycle combustion turbine for its benchmark. PGE's IRP did not state that the RFP would exclude frame units or any other technology types, and it would be unfortunate to deprive ratepayers of what may well prove to be a lower cost resource.

4. The Commission should strongly encourage PGE to solicit IPPs to the build the 200 MW flexible capacity resource at PGE's site.

In commenting on PGE's IRP, NIPPC suggested that PGE should offer to allow IPPs to bid to the build the capacity and baseload energy resources at PGE's sites. *NIPPC's Response to Portland General Electric's Reply Comments*, Docket No. LC 48, p. 8 (September 1, 2010). PGE did not agree to do so at that time, and NIPPC recognizes that the Commission has expressed reluctance to require a utility to offer up its site. *See* Order No. 06-446, at pp. 5-6. In light of the distinct advantages PGE's site may have in this RFP, including transmission and gas

[9] The IE noted that "[a]n announcement was posted on the RFP website on May 27, 2011, inviting those who are interested in submitting a bid using a technology other than those identified in the RFP to provide information about the technology via the website no later than June 10, 2011." *Accion Group's Assessment of PGE RFP*, at pp. 3-4. PGE's announcement required bidders to submit information about the alternative technology by June 10, 2011, but PGE's May 27th announcement listed "Simple Cycle Combustion Turbines" as an eligible technology without further specification. *Id.* at p. 4. One could assume frame units were allowed at that time, and it is not surprising that no bidders asked to use frame units prior to June 10, 2011.

storage discussed above, NIPPC reiterates that it would be appropriate for the Commission to strongly encourage PGE to accept bids for IPPs to build at PGE's Port Westward site. Doing so would provide an appropriate check against the cost for which PGE projects it can build the resource. This would provide assurance to PGE's customers that the bid is truly competitive, and the ultimate price passed onto ratepayers is fair.

D. The RFP should not include imputed debt as a factor at any stage.

In Order No. 11-001, the Commission resolved its investigation in Docket No. UM 1276 into mechanisms to provide utilities with an incentive to overcome their self-build bias and enter into power purchase agreements ("PPAs"). In addition to foregone profit to the utility caused by PPAs, the Commission noted self build bias arose because "rating agencies may consider PPAs as long-term commitments that have debt-like obligations[,] . . . . which could negatively impact the credit ratios of a company." Order No. 11-001, at p. 2. In declining to adopt any of the proposed incentive mechanisms, the Commission stated:

> We do, however, take action to address the concerns raised about the self build bias. First, with regard to the debt imputation issue, we allow the utilities to raise the impact on this practice on credit ratings and earnings in individual rate proceedings. We believe that this issue is more appropriately addressed in the context of an overall examination of a utility's cost of capital. *Id.* at p. 6.

The Commission's RFP Guideline 9(c) states that consideration of imputed debt should be reserved for selection of final bids from the initial short list, and even then the Commission may require the utility to provide an advisory opinion from a ratings agency to support its position. There is no guarantee that a credit rating agency will impute debt to a PPA, even after an advisory opinion, and NIPPC understood the Commission to state in Order No. 11-001 that it does not want the possibility of debt imputation to affect the bidding process. Yet PGE's RFP states PGE will refine the initial short list to a final shortlist based upon factors which include imputed debt. *PGE's May 23, 2011 RFP*, at p. 24. NIPPC believes it is inappropriate for PGE to include this item in the RFP after the Commission recently stated that this consideration is now reserved for general rate cases. NIPPC suggests that the Commission should require PGE to remove this factor from the RFP.[10]

E. PGE should provide more specifics in the RFP before releasing the RFP to bidders.

1. The RFP should state the minimum performance assurance necessary to meet the Credit Requirements.

The Commission's RFP Guideline 6 requires PGE to provide "minimum bidder requirements for credit and capability." The RFP includes as a precondition that bidders should have "investment grade credit rating or provide acceptable performance assurance" in the form of a parental guarantee, a letter of credit and/or cash. *PGE's May 23, 2011 RFP*, at p. 16. The RFP states PGE "retains the right to adjust the bid price to include the cost to PGE of performance assurances if the bidder does not provide adequate performance assurance." *Id.* at p. 20. Credit evaluation is also a non-price factor worth 7.5% of the overall bid score, *id.* at pp. 19, 23, and the RFP allows PGE to further "refine performance assurance requirements" during the final shortlist determination, *id.* at p. 24. Security requirements can be quite large and can have a significant impact on the bid. To date, however, PGE has not explained what level of performance assurance is adequate, or how it will calculate the adequate level.

NIPPC raised this issue with PGE in its May 10, 2011 letter, and the IE has stated that

[10] Although the IE has opined on this matter in general terms, it may not have had adequate background on the Commission's order in the context of an investigation into overcoming self build bias that now allows PGE to overcome any *actual* imputed debt in that forum without compromising the bidding process.

PGE should describe the minimum performance assurance, at least in the form of a "standardized mechanism for determining security requirements." *Accion Group's Assessment of PGE RFP*, at pp. 8-9. The IE stated that it believes PGE "should provide a more robust description of credit support requirements that will be required during the term of each contract, before bids are accepted." *Id.* at p. 16. NIPPC agrees, and believes the standard should be clearly set forth in the RFP and the template contracts, consistent with the language in Guideline 6. The RFP should provide clarity on this point not only to allow IPPs to adequately evaluate the impact of the performance assurance requirement on their bids, but also to provide transparency to all stakeholders with regard to the RFP requirements prior to bid submittal and negotiations.

2. The RFP should provide further clarity on the 200 MW flexible resource's dispatchability factors.

NIPPC requested further clarification regarding the dispatchability of the 200 MW flexible resource in its letters sent on May 10, 2011 and May 20, 2011. The IE appears to agree. "Bidders have requested additional information including expected number of starts and typical intra-hour dispatch profile. While Accion and PGE agree that additional information should be provided, both parties are working to determine how much should be provided." *Accion Group's Assessment of PGE RFP*, at p. 6. PGE has now provided information regarding expected capacity factor and number of starts in a slide presentation and bidder question and answer sections on the website. *See Accion Group's Memorandum Regarding NIPPC's Letters*, p. 5 (June 13, 2011). The sections of the IE website cited by the IE, however, set forth a dispatch profile – with 344 starts and operation during 50% of the hours per year – that is far out of line with the resource PGE announced in the IRP because the capacity factor and starts per year are far in excess of what one would expect for a peaking plant used to integrate intermittent resources. NIPPC suggests that this recently disclosed description of PGE's preferred resource is yet another advantage to the benchmark not actually tied to PGE's needs.

Additionally, there has been no further clarification regarding how dispatchability factors will affect a bid's score. In describing the price factors of the score, the RFP states, "Additional dispatch costs will be included as part of the Price Factors of the Flexible Capacity bids." *PGE's May 23, 2011 RFP*, at p. 21. Also, the dispatchability of the facility is included as a non-price factor in the RFP under the category title "Power Product Characteristics." *See id*, at pp. 19, 23. NIPPC suggests that PGE's RFP should provide further clarity with regard to how a particular bid would receive a high score for these particular price and non-price factors.

3. The RFP's Evaluation Criteria should provide a greater level of specificity for the scoring value of individual characteristics of a bid.

The scoring criteria are of the utmost importance in selecting the lowest cost alternative that meets the utility's resource needs. The Commission's RFP Guideline 9 requires that the RFP's non-price scoring factors be tied to the needs identified in the IRP Action Plan. Also, the FERC decision cited by the IE noted the importance of transparent scoring criteria in RFPs containing a utility-ownership option. Specifically, "all criteria should be specific and detailed so that all bidders can effectively respond to the RFP. Clear evaluation criteria will ensure that the RFP does not give an advantage to the affiliate." *Allegheny Energy Supply, LLC*, 108 FERC ¶ 61,082, at ¶30. All scoring criteria should be shared with all bidders and stakeholders in the RFP.

But PGE's RFP does not provide enough detail because it only provides scoring percentages for broad categories featuring several project attributes. *PGE's May 23, 2011 RFP*, at p. 19. For example, the non-price bid scoring category for "Project Characteristics" is worth 15% of a overall score and includes interconnection, transmission rights, and gas transport and storage. *Id.* There is no indication if a bid with more favorable transmission rights will be favored over one with more favorable gas transport and storage. The non-price criteria – which make up 40% of the score in this RFP – will always be inherently subjective, and maximum clarity on the value allocated to each individual attribute would make the process more transparent and more objective.[11]

The IE described the evaluation of non-price factors as follows:

> Development experience, transmission, fuel supply, unit flexibility, and credit are all valuable components that should be considered when procuring capacity products. In Accion's review with PGE, Accion discussed suggestions regarding weightings on specific components and PGE was open to suggestions with a desire to create the most appropriate final scorecard. The detailed scorecard explaining the details of each individual attributes has been reviewed but will likely be adjusted as the mock bid process is conducted to ensure that balanced weightings are given for each component. *Accion Group's Assessment of PGE RFP*, at p. 13.

The IE appears to agree with PGE that the level of detail provided in the version of the RFP before the Commission is adequate "without providing too much detail so as to provide opportunities for gaming the process." *Id.* at p. 11. It is not clear how a bidder would game the process without misrepresenting the characteristics of its bid and being potentially in breach of the contract it may enter into with PGE. NIPPC believes that the benefits of transparency would outweigh the risk that a bidder may devise a way to game the process. In NIPPC's view, it is

---

[11] Further, many of these criteria are also preconditions for bidder pre-qualification, which should eliminate some of the import and need for these subjective categories to be weighted heavily in the scoring process. *Id.* at pp. 16-18.

PGE that is attempting to game the RFP process. Any attempt for an individual bidder to somehow advantage itself pales in comparison to the attempted over-reach of the RFP's sponsor. NIPPC respectfully suggests the Commission should require that the final RFP released for bidding include the completed final scorecard for all attributes.

III. Conclusion

With these Comments, NIPPC respectfully urges the Commission to approve PGE's Capacity RFP conditioned upon adoption of the suggested changes contained herein.

RESPECTFULLY SUBMITTED this 22nd day of June, 2011.

RICHARDSON & O'LEARY PLLC

____
Gregory M. Adams (OSB No. 101779)
Attorneys for Northwest and Intermountain
Power Producers Coalition

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 22nd day of June, 2011, a true and correct copy of the within and foregoing **NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S COMMENTS** was served as shown to:

G. Catriona McCracken CITIZEN'S UTILITY BOARD OF OREGON catriona@oregoncub.org	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Gordon Feighner Robert Jenks CITIZEN'S UTILITY BOARD OF OREGON gordon@oregoncub.org	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
S. Bradley Van Cleve Irion Sanger Davison Van Cleve las@dvclaw.com	___ Hand Delivery ___U.S. Mail, postage pre-paid ___Facsimile _X_ Electronic Mail
Erik Colville OREGON PUBLIC UTILITY COMM. erik.colville@state.or.us	__ Hand Delivery __U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
John W. Stephens Esler Stephens & Buckley stephens@eslerstephens.com	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Megan Walseth Decker Jimmy Lindsay Renewable Northwest Project megan@rnp.org jimmy@rnp.org	___ Hand Delivery ___U.S. Mail, postage pre-paid ___ Facsimile _X_ Electronic Mail
Michael Early Industrial Customers of NW Utilities 333 SW Taylor Ste 400 Portland OR 97204 mearly@icnu.org	__ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail

Wendy Gerlitz Northwest Energy Coalition wendy@nwenergy.org	__ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Randy Dahlgren V. Denise Saunders Portland General Electric pge.opuc.filings@pgn.com denise.saunders@pgn.com	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Janet L Prewitt Assistant AG Department of Justice janet.prewitt@doj.state.or.us	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Matt Krumenauer Vijay A Satyal Oregon Department of Energy matt.krumenauer@state.or.us vijay.a.satyal@state.or.us	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
J Laurence Cable Richard Lorenz Cable Huston Benedict et al lcable@cablehuston.com rlorenz@cablehuston.com	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Stephanie S Andrus Department of Justice Stephanie.andrus@state.or.us	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail
Donald W Schoenbeck Regulatory & CoGeneration Services Inc dws@r-c-s-inc.com	___ Hand Delivery ___U.S. Mail, postage pre-paid __ Facsimile _X_ Electronic Mail

Chuck Sides
Tepper LLC
chucksides@mgoregon.com

___ Hand Delivery
___U.S. Mail, postage pre-paid
__ Facsimile
_X_ Electronic Mail

Signed______ ____________
Gregory M. Adams

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1535

In the Matter of PORTLAND GENERAL ELECTRIC Request for Proposals for Capacity Resources

NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S

ATTACHMENT 1

June 22, 2011

RICHARDSON & O'LEARY
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

April 14, 2011

Via Electronic Mail

V. Denise Saunders
Assistant General Counsel
Portland General Electric Company
121 S.W. Salmon Street, IWTC1301
Portland, Oregon 97204
Telephone: 541-752-9060
Facsimile: 503-464-2220
denise.saunders@pgn.com

Re: NIPPC's Concern with the Timing of PGE's Thermal RFPs

Ms. Saunders:

I write to express a concern of the Northwest and Intermountain Power Producers Coalition (NIPPC) regarding the timing of Portland General Electric Company's (PGE's) upcoming requests for proposals (RFPs) for gas-fired resources.

PGE has made Independent Power Producers (IPPs) aware of the benchmark resources in its RFPs from the 2009 integrated resource plan (IRP). The IRP (pages 203 to 206) described three benchmarks:

(1) Port Westward Unit 2 – 200 MW simple cycle natural gas plant at the Port Westward Unit 1 site
(2) Carty Generating Station – 300-500 MW combined cycle combustion turbine natural gas plant adjacent to Boardman
(3) Wind Farm – 330-385 MW—online for Oregon's 2015 RPS target

The IRP did not describe the online date projected for the gas-fired resources or the timing of any of the RFPs, but it extensively discussed the benefits of citing the benchmark gas plants at sites where or near PGE already operates the existing Port Westward unit and the Boardman plant.

At Port Westward, the described benefits included shared gas supply lines designed for two plants, expansion (rather than new construction) of the existing switchyard for interconnection, existing site leases, existing permits allowing for a second unit, common facilities, and existing site access by rail, water, and paved roads (pages 204 to 205).

PGE also stated that Carty's location near Boardman would benefit from the existing 500 kV line to Boardman, existing water rights for Boardman, and existing access roads and rail spur to Boardman (pages 205 to 206). The IRP also highlighted the potential to share common facilities with Boardman, including "potable water, sanitary sewage, fire water, internet and microwave connections, standby electric power, and others" (page 206).

PGE has now made public the plans for sequencing of the RFPs. In the RFP to retain an Independent Evaluator, PGE described the sequencing on pages 4 and 9. *See* http://www.portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/docs/jan2011_rfp.pdf (attached). PGE states that the Capacity RFP (Port Westward II Benchmark) will be released for bidding on May 17, 2011, with bidder responses due June 28, 2011, and an online date "in the 2013 timeframe." PGE states that the Baseload Energy RFP (Carty Benchmark) will be released for bidding January 3, 2012, with bidder responses due February 14, 2012, and an online date "by year end 2015."

It appears from this schedule that PGE does not envision the bidder selection timeframe for the Capacity RFP to precisely overlap with that from the Baseload Energy RFP. NIPPC believes, however, that PGE should adjust this schedule to allow for some mechanism by which IPPs can take advantage of the economies of scale of using a single site in the same manner that PGE proposed to do so in its RFP. If IPPs could bid into both the Capacity and the Baseload Energy RFP at the same time, or into a single gas resource RFP for Capacity and Baseload Energy resources, the IPPs could bid to use the same site for both resources and achieve economies of scale in construction and operations. This could include shared use of gas, water, interconnection, transmission, site leases/purchase, taxes, employees, and maintenance. This would allow for more competitive IPP bids, and should result in more cost-effective resources for ratepayers.

In other words, NIPPC believes that IPPs should be provided with the opportunity to bid a price whereby they would bid into both RFPs using the same site for both the Capacity and the Energy resource. If the RFPs were overlapping, IPPs may bid two prices into each of the RFPs – (1) one price for a Capacity or Baseload Energy resource alone, and (2) separate (likely lower) prices for the Capacity and Baseload Energy resources if PGE were to select that IPP's bids in both RFPs so that the IPP could take advantage of the economies of scale of a single site. If the RFPs do not overlap temporally, IPPs cannot attempt to bid to use the same site and achieve the advantages of the economies of scale described by PGE in its IRP.

Our request may not require a major modification of the proposal in the Independent Evaluator RFP document because PGE stated that PGE anticipated "issuing the Baseload Energy RFP prior to the conclusion of the Capacity and Renewable RFPs." Because the timing the RFPs was not discussed in PGE's IRP, NIPPC does not feel that it has had the chance to raise this point earlier. We hope by raising the issue at this time, PGE can make the appropriate adjustments prior to completing the draft RFPs.

Thank you for your consideration of this matter. If you have any questions, please contact me.

Very truly yours,

Gregory M. Adams
Richardson and O'Leary, PLLC
Attorneys for the Northwest and Intermountain
Power Producers Coalition

Attachments:	Excerpts of Independent Evaluator RFP, February 8, 2011
cc:	UM 1534 and UM 1535 Service Lists (e-mail only)

I. INTRODUCTION

A. Purpose

Portland General Electric Company ("PGE") is seeking proposals from qualified entities ("Proposers") interested in serving as an Independent Evaluator ("IE") to assist PGE in conducting and evaluating bids in response to multiple requests for proposals for new electric generation supply to be initiated by PGE in 2011 ("2011 RFPs").

The purpose of this solicitation ("IE-RFP") is to assist the Oregon Public Utility Commission ("OPUC") Staff in recommending an IE for the OPUC's approval for the 2011 RFPs. The IE will participate in each 2011 RFP to ensure that the 2011 RFPs are conducted fairly and properly and that bids thereto are evaluated consistently. The IE must be independent of PGE and potential bidders, and also be experienced and competent to perform all IE functions identified in the OPUC Competitive Bidding Guidelines, attached to this IE-RFP as Attachment C. PGE will contract directly with the OPUC-selected IE pursuant to the PGE Professional Services Agreement, included as Attachment B to this IE-RFP.

B. Background

PGE will be seeking to acquire capacity and energy resources through up to three 2011 RFPs. These 2011 RFPs may run concurrently or sequentially as further described below. One 2011 RFP will address the capacity actions ("Capacity RFP") identified in PGE's 2009 Integrated Resource Plan ("2009 IRP"). PGE will be seeking the following three products in the Capacity RFP: (1) approximately 200 MW of year-round flexible capacity available in the 2013 time frame to fill a dual function of providing capacity for maintaining supply reliability during peak demand periods and for providing needed flexibility to address variable load requirements and increasing levels of intermittent energy resources; (2) approximately 200 MW of bi-seasonal, limited-duration peaking supply in the 2013 time frame; and (3) approximately 150 MW of winter-only peaking supply to maintain reliability and meet system contingencies during peak demand periods in the 2013 time frame. PGE intends to submit a self-build alternative in the Capacity RFP.

The second RFP will address the renewable energy actions acknowledged in PGE's 2009 IRP ("Renewable RFP"). PGE will be seeking up to 122 MWa of renewable energy resources that meet the requirements of Oregon's Renewable Energy Standard to be in service in the 2015 time frame. PGE intends to submit a self-build option in the Renewable RFP.

For the third RFP, PGE will be seeking a high-efficiency, combined-cycle natural gas plant ("CCCT") of approximately 300 to 500 MW to be in service by year end 2015 at the earliest ("Baseload Energy RFP"). PGE intends to submit a self-build alternative in the Baseload Energy RFP.

PGE anticipates that the timing of the RFPs will overlap. PGE anticipates issuing the Capacity and Renewable RFPs first and issuing the Baseload Energy RFP prior to the conclusion of the Capacity and Renewable RFPs. Alternatively, the Capacity and Renewable RFPs may run concurrently.

III. PGE'S ESTIMATED 2011 RFPs SCHEDULE TIMELINE

Schedule 1 - assumes the RFPs would occur sequentially

- PGE submits final draft 2011 RFPs to OPUC for approval
  - RFP1 - March 18, 2011
  - RFP2 - July 6, 2011
  - RFP3 – October 24, 2011

- PGE issues 2011 RFPs (up to 60 days after final draft 2011 RFP is filed)
  - RFP1- May 17, 2011
  - RFP2 - September 6, 2011
  - RFP3 – January 3, 2012

- Bidder responses due six weeks from issuance
  - RFP1- June 28, 2011
  - RFP2 - October 18, 2011
  - RFP3 - February 14, 2012

Schedule 2 - assumes RFPs 1 and 2 begin simultaneously, followed by RFP 3

- PGE submits final draft 2011 RFPs to OPUC for approval
  - RFP1 - March 18, 2011
  - RFP2 - March 18, 2011
  - RFP3 - October 24, 2011

- PGE issues 2011 RFPs (up to 60 days after final draft 2011 RFP is filed)
  - RFP1- May 17, 2011
  - RFP2 - May 17, 2011
  - RFP3 – January 3, 2012

- Bidder responses due six weeks from issuance
  - RFP1- June 28, 2011
  - RFP2 - June 28, 2011
  - RFP3 - February 14, 2012

- Minimum of 8 weeks from date Bidder responses due – PGE's initial short list is complete

- TBD – OPUC consideration of acknowledgment of PGE's final short-list of bids (if requested by PGE)

RICHARDSON & O'LEARY
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

May 10, 2011

Via Electronic Mail

V. Denise Saunders
Assistant General Counsel
Portland General Electric Company
121 S.W. Salmon Street, IWTC1301
Portland, Oregon 97204
Telephone: 541-752-9060
Facsimile: 503-464-2220
denise.saunders@pgn.com

Re: NIPPC's Comments on the Draft Capacity Request for Proposals dated April 21, 2011

Ms. Saunders:

I write to provide written feedback from the Northwest and Intermountain Power Producers Coalition (NIPPC) regarding matters of concern NIPPC has with Portland General Electric Company's (PGE's) Draft Capacity request for proposals ("RFP") dated April 21, 2011. We have conducted a preliminary review of the Draft RFP and want to express some initial concerns. In general, NIPPC is concerned that the Draft RFP appears to be incomplete in several respects. Please do not consider any matter not addressed to be a matter upon which NIPPC may not later provide suggested changes. We appreciated the opportunity to discuss these issues with PGE yesterday prior to circulating this letter publicly and look forward to working collaboratively in this RFP process. We hope PGE will be willing to incorporate the recommendations provided in this letter to provide for a more robust and fully transparent procurement process.

Timing of the Online Date for the 200 MW Year-Round Flexible Capacity Resource

NIPPC is concerned that the Draft RFP does not describe how a bid's offered online date may impact the bid's overall rank. The Draft RFP on page 12 lists online dates as preferred before 2014, but no earlier than 2013 and no later than 2015. Nowhere, however, does the Draft RFP describe how a project's ability to come online in the "preferred" timeframe during 2013 will impact that bid's overall score. The Draft RFP should explain the calculus of how an inability to be online before 2014 will impact the bid's score. In this context, it is worth noting that there appears to be ample peaking capacity available in the market during the 2014 timeframe, and that an online date in 2013 may not have a significant impact on the value of the resource. If the online date is going to be a minimal factor in the overall evaluation and scoring of the bids, PGE should make that known to all bidders so that bidders with viable projects do not materially compromise their bid to achieve an online date that is largely immaterial to the needs of the utility and its ratepayers, as well as the final scoring of the bids.

Transmission and Point of Delivery Issues

The Draft RFP states on page 22 with regard to point of delivery, "The scoring process for this RFP assumes continuation of the status quo." NIPPC understands, however, from testimony in PGE's 2009 general rate case that PGE allocated the costs of its $45 million upgrade to the South of Allston project for the 230 kV Trojan to Horizon line entirely as a capacity resource for cost-allocation purposes because PGE expects to use it to integrate a new 200 MW peaking resource. I have enclosed a highlighted copy of the applicable testimony (UE 215/PGE 1500, Kuns-Cody/5). That 200 MW peaking resource appears to be PGE's benchmark Port Westward Unit 2 in this RFP, which is described in PGE's 2009 Integrated Resource Plan. It does not appear, therefore, that PGE's benchmark will be relying upon the status quo.

NIPPC would like confirmation of the following:

(1) The Port Westward Unit 2 benchmark has reserved or plans to use 200 MW of capacity on the new the Trojan to Horizon line; and

(2) PGE will increase the costs of the benchmark for purposes of RFP evaluation to account for the cost of that 200 MW of increased transmission capacity that enables the benchmark resource.

Credit and Bidder Qualifications

NIPPC is concerned that the Draft RFP (pages 17-18) does not fully explain the necessary credit requirements, which will obviously impact Independent Power Producers ("IPPs'") bids. The Draft RFP states, "Typically contracts will only be awarded to Bidders that have at a minimum, investment grade credit rating or provide acceptable performance assurance." The Bidder may alternatively "provide performance assurance in the form of a parental guarantee, a letter of credit and/or cash, based on the Bidder's and/or Guarantor's credit profile and the amount of expected financial exposure related to the bid." This boiler-plate language does not provide bidders with any indication of what amount they may be required to post. The Draft RFP should expressly state the minimum provisions bidders can expect, so that they can incorporate that requirement into their bids.

Scheduling Practices and Qualifications

The Draft RFP states on page 18 that a bidder must provide documentation, satisfactory to PGE, that it is able "schedule" the power to PGE and "operate under industry standards." But there are many scheduling practices, and the RFP provides no guidance on which practice PGE prefers.

For projects interconnecting directly to PGE's system, we believe that PGE should spell out the scheduling requirements and responsibilities of the IPP project and PGE.

We understand from our conversation yesterday that PGE's requirement on page 19 that the 200 MW year-round capacity product be "AGC Ready" means that the bidder must be able to establish that it will provide a dynamic transfer, or pseudo tie if it is interconnected to a Balancing Authority (BA) other than PGE's. A dynamic transfer will be difficult to establish with Bonneville Power Administration ("BPA") and PacifiCorp. These elements are beyond the control of the bidder, but considerably easier to effectuate between cooperating Balancing Authority Areas (BAAs). NIPPC therefore requests that any RFP requirement to establish a dynamic transfer be evaluated on the bidder's best efforts to establish a dynamic transfer or other cross BA arrangement. Should the bid reach the short list, we would expect PGE to recognize its value added in negotiating with the bidder's host BA to establish dynamic transfer, if necessary.

Price Factors

The Draft RFP provides a description of the different criteria by which PGE and the independent evaluator will score the price factors. Among the factors, the Draft RFP states on page 21, "Additional dispatch costs will be included as part of the Price Factors of the Flexible Capacity bids." This factor is based on a project's ability to provide "reliability based dispatch required to follow load or wind deviations," as well as "economic dispatch." The Draft RFP also describes the requirements in very general terms on page 28 in a sample term sheet, which merely states the preferred available capacity is between 50 MW per hour and 100 MW per hour.

However, the description of scoring criteria should be more complete with regard how a particular bid would receive a high score for this particular price factor. Without more detail, it is difficult for IPP bidders to factor this requirement into their price. In this context, PGE should note that the BPA will balance any deviations less than 20 MW for resources within its Balancing Authority Area. Incremental shifts of 20 MW or less in dispatchability of IPP bids in BPA's authority, therefore, may not negatively impact a bid. The same may be true for other BAAs.

Also, the table that should describe all of the evaluation criteria on page 20, is not even available in this draft. That missing table makes it impossible to complete an evaluatation of the Draft RFP.

Imputed Debt

In Order No. 11-001, the Commission noted that the possibility that credit rating entities might impute debt equivalency amounts from PPAs to a utility's balance sheet, but stated that it would "allow the utilities to raise the impact on this practice on credit ratings and earnings in individual rate proceedings. We believe that this issue is more appropriately addressed in the context of an overall examination of a utility's cost of capital." There is no guarantee that a credit rating agency will impute debt to a PPA, and it seems clear to NIPPC that the Commission does not want the possibility of debt imputation to affect the bidding process.[1]

Yet the Draft RFP states on page 25 that PGE will refine the initial short list to a final shortlist based upon factors which include imputed debt. NIPPC believes it is inappropriate for PGE to include this item in the RFP after the Commission recently stated that this consideration is now reserved for general rate cases.

Confidentiality Agreement

NIPPC also has a concern with the confidentiality agreement, which is Appendix J to the Draft RFP. In defining "Confidential Information" protected by the agreement, the draft agreement states that "oral information that is not confirmed as Confidential Information in writing within two (2) business days of disclosure to the Receiving Party shall not be considered Confidential Information under this Agreement[.]" Because the same clause requires that such Confidential Information must be "designated in writing or stamped as 'confidential,'" an email confirmation that oral communications were confidential appears to be inadequate.

Two days will often be an inadequate amount of time to document and deliver oral communications that bidders wish to keep confidential. NIPPC understands that RFPs typically provide the designating party four to five business days, if they require the bidder to provide the other party with written confirmation of oral confidential information. NIPPC requests that PGE consider extending the two-day period to a four or five business day requirement.

Conclusion

As you can tell from our comments, NIPPC's fundamental concern is with transparency of the scoring criteria. We believe that the scoring criteria should be designed to select the bid that best fits the resources PGE actually needs. We also believe it is essential that all bidders know those criteria and the percentage weight given to each individual scoring factor so that they can design their bids to best meet the needs of PGE and its ratepayers. If the bidders do not explicitly know the relative weight of each scoring factor, the bidders will not be providing bids designed to provide PGE with the resources it needs, and the entire process will be flawed.

Thank you for your consideration of this matter. If you have any questions, please contact me.

---

[1] We recognize your interpretation that the Commission, by not incorporating its stated preference into its 2006 Competitive Guidelines, justifies your incorporation of debt equity into the RFP evaluation. Perhaps the Commission will use the conclusion of Phase One in the UM 1182 docket as an opportunity to resolve any confusion.

Very truly yours,

Gregory M. Adams
Richardson and O'Leary, PLLC
Attorneys for the Northwest and Intermountain
Power Producers Coalition

Attachments:	PGE's UE 215 Testimony regarding transmission upgrades
cc:	Robert Kahn, Northwest and Intermountain Power Producers Coalition UM 1535 Service List

II. Marginal Cost of Service Study and Ratespread

Q. Briefly describe the purpose of a Marginal Cost of Service Study.

A. Since the mid-1970s, Oregon utilities have developed marginal cost studies for a number of purposes. In this case, PGE uses its Marginal Cost of Service Study to guide the allocation of the generation, distribution, and customer service (separately, Metering, Billing, and Other Consumer Service) functional revenue requirements in the rate spread process. The results of the distribution and customer service portions of this study are summarized in Table 8 of PGE Exhibit 1505. The generation portion is summarized in PGE Exhibit 1504.

Q. What other functional revenue requirement categories do you allocate besides those mentioned above?

A. Because the Ancillary Services revenue requirement is split out from generation, we allocate it in the same manner as we do generation. We also allocate the transmission revenue requirement in accordance with the generation allocation. These two functional categories combined with the five categories above complete the seven functional categories specified in Senate Bill 1149 enacted in 2002.

Q. Why do you allocate transmission revenue requirements in the same manner as you do generation?

A. Generally, we have previously allocated transmission revenue requirements on a peak load basis. The 1992 NARUC Cost Allocation Manual lends support to this on page 128: "For purposes of a marginal cost study, investment in the transmission system is generally assumed to be driven by increments in system peak load."

However, in this docket, we allocate transmission revenue requirements consistent with long-term generation marginal costs. We do so because PGE's 2009 Integrated Resource

Plan (IRP) proposes two large transmission projects, Cascade Crossing and South of Allston that interconnect existing PGE generation resources as well as new gas and wind resources.

Q. Please describe the analysis you performed regarding the allocation of these two transmission projects.

A. We first designated the South of Allston project entirely as capacity because it will integrate a new peaking resource of up to 200 MW as well as integrate the Beaver capacity of 181 MW that is not integrated from the Port Westward to Trojan line. The Cascade Crossing project will integrate Boardman, Coyote, a new 450 MW combined cycle baseload gas plant, and approximately 600 MW of new wind resources. Consistent with our generation marginal cost study, we designate all but the wind resources as 31% capacity, 69% energy. We designate the wind resources as 100% energy. We then allocate the nameplate capacity of all the existing and proposed resources in the manner described above. The result for the two transmission projects is an allocation of approximately 35% to capacity and 65% to energy.

Q. Did you allocate the two projects on the basis of capital expenditures?

A. Yes. We used the same capacity/energy designations for each generation resource above to allocate the estimated $45 million South of Allston project costs and the estimated $823 million (both projects in 2009 dollars) Cascade Crossing project costs. The result of this allocation was approximately 24% to capacity and 76% to energy. The Pricing work papers contain the two aforementioned analyses.

Q. How do these two analyses support the transmission allocation based on generation?

A. We used the generation cost allocation for transmission revenue requirements because the simple average of these two analyses approximates the test period generation cost allocation of 31% capacity/69% energy. The details of the two analyses are contained in the Pricing work papers.

Q. Do you allocate other cost categories to the individual rate schedules?

A. Yes. We allocate franchise fees and OPUC fees on a current revenue basis and Trojan decommissioning on a busbar energy basis. We allocate Schedule 129 Long-Term Transition Adjustment to Schedule 85 and 89 customers on an energy basis, and finally, we allocate uncollectible expense based on historical incidence for the years 2006-2008. This latter category was previously not specifically allocated, but was treated as a revenue sensitive cost, and was therefore implicitly allocated to schedules on a revenue basis. All allocations are presented in PGE Exhibit 1504.

Q. Do you propose any form of rate mitigation or other deviation from using marginal cost to spread the revenue requirements?

A. No, however, we employ the Customer Impact Offset (CIO) after spreading the revenue requirements in order to temper the rate impacts to certain schedules. Specifically, we limit the rate increase to two times the average increase for Schedules 38, 47, 49, and 93. We further limit the subsidy to no more than 9.5 cents/kWh. For our major cost of service rate schedules (7, 32, 83, 85, and 89) we limit the increase to 1.25 times the average increase. Additionally, before calculating the increase limit discussed above, we set a floor such that no rate schedule receives a decrease. When allocating the CIO we do not propose any surcharges for schedules 7, 32, and 83 because for these schedules we propose increases that are above the average increase. We further discuss the CIO later in this testimony.

Q. Could you please provide a brief history of how PGE has previously estimated its marginal cost of generation?

A. Prior to this docket, PGE has used the same short-run marginal cost methodology since UM 827 (1997). PGE stated at that time the following:

> PGE's Avoided Cost Study, which was approved by the Commission and became effective on December 18, 1996, serves as the foundation for determining marginal generation costs. In this study, the combined effect of a significant reserve margin in the 11-state WSCC and an increasingly vibrant market for electricity was observed to drive the cost of short-term firm power below the cost of a new, long-term generating resource and below the fully allocated cost of existing resources. We expect this trend, and its effect on short-term prices, to remain for the foreseeable future. Moreover, this trend has significantly reduced the cost of capacity, which is reflected now primarily through the differential between on-peak and off-peak energy prices.

Q. Please continue.

A. When we filed UE 115 in 2000 we used the same short-run methodology. At that time we did not contemplate new generation resources, in particular given that the UE 115 docket was largely about restructuring to accommodate direct access and portfolio options consistent with the requirements contained in Senate Bill 1149. At that time no one objected to the short-run marginal cost approach and we subsequently settled on a generation allocation methodology. This methodology specified historical resource shares of existing assets accompanied by allocations of BPA Subscription Power as part of a resource stacking methodology.

In UE 180, which we filed in March of 2006, we proposed once again the same marginal cost methodology, thereby eliminating the historical generation allocations stipulated to in UE 115. In UE 180, the methodology was opposed solely by ICNU in its direct testimony. Prior to PGE filing its rebuttal testimony, parties settled ratespread and rate design issues. The outcome of this settlement was the adoption of the PGE proposed marginal cost and generation allocation methodology.

Q. Please describe the positions of parties in UE 197.

A. In UE 197, PGE proposed the same short-run marginal cost of generation methodology as in the prior dockets. ICNU raised issues with this methodology relating to the lack of consideration of capacity costs and reliability planning. Staff in Staff Exhibit 600 stated that they recommend adoption of PGE's marginal cost study because it provides reasonable results. However, on page 6, line 18 to page 7, line 2 Staff stated the following: "regarding production marginal costs it seems reasonable to use potential new electrical generating plants as the basis for capacity and energy costs instead of relying exclusively on wholesale market energy prices." Staff in Staff Exhibit 1200 then stated a preference to use the generation marginal cost as filed by PGE in its direct testimony. CUB in their surrebuttal testimony supported using the short-run methodology proposed by PGE in its direct testimony.

Q. What methodology do you propose in this docket?

A. We propose a long-run generation methodology that explicitly takes into account the cost of marginal generation capacity and long-run marginal energy costs. This marginal cost methodology is consistent with our IRP that identifies a need for capacity resources for both the winter and summer periods. This methodology is similar to the long-run methodology we proposed as an alternative in our UE 197 Rebuttal testimony. It is also the methodology we proposed during the UM 1415 workshops.

Q. Please describe the steps you used to develop the long-run generation allocation methodology.

A. The generation marginal cost analysis involves the following inputs and steps:

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a combined cycle combustion turbine (CCCT) used for baseload purposes.

2. From this analysis, separately estimate the capacity and energy components as follows:
   a) Estimate the marginal cost of future capacity as the fixed cost of a simple cycle combustion turbine (SCCT).
   b) Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
   c) To the SCCT capacity costs add 12% reserve requirements consistent with PGE's 2009 IRP.
3. Finally, express these capacity and energy values in real levelized terms. PGE Exhibit 1504 presents the summary of these long-run marginal capacity and energy cost calculations. PGE Exhibit 1504 also presents the results of how the generation revenue requirement is spread to the rate schedules.

Q. How did you calculate the 2011 test-period marginal capacity costs?

A. We multiplied the real levelized annual capacity cost described above by the projected 2011 test-period peak hour load. This peak hour load is projected to occur in January.

Q. How did you allocate the marginal capacity costs to each rate schedule?

A. We allocated the total 2011 test period marginal capacity costs described above on the basis of each schedules' relative contribution to the monthly peak hours contained in the months of January, July, August, and December (4-CP).

Q. Why did you choose these four monthly peaks?

A. We chose these four months because they are the months with the highest peaks consistent with the periods identified as capacity deficient in the 2009 IRP. We additionally chose these months because for each of the past ten years PGE's highest annual peak hour occurred during one of these four months.

Q. How did you estimate the marginal energy costs?

A. We used both the long-run real levelized marginal energy cost derived from our analysis described above and the projected fully allocated cost of a generic wind farm as identified in the IRP.

Q. Please describe how you determined the proportion of marginal energy costs attributable to the CCCT and the generic wind farm.

A. We used the proportion of new gas and renewable resources proposed for the year 2020 as identified on page 320 of the IRP. This resulted in an attribution of 58% of marginal energy costs to the energy costs of a CCCT as defined above, and 42% to the fully allocated costs of a generic wind farm.

Q. What is the source of your long-term gas price forecast?

A. We used the long-term gas price forecast contained in our IRP for the Sumas and AECO hubs. We equally weighted the projected burnertip prices from these two hubs.

Q. Did you include the projected costs of carbon dioxide compliance in your analysis?

A. Yes. We include compliance costs of $30.00 per short ton (real levelized 2009$) consistent with the environmental assumptions in the IRP.

Q. What is the fully allocated cost of a generic wind farm as specified in the IRP?

A. On page 118 of the draft IRP issued September 4, 2009, a fully allocated wind farm is estimated at $93.62/MWh in real levelized 2011 dollars.

Q. Did you modify this real levelized figure for purposes of the marginal cost study?

A. Yes. Because of the two large transmission projects proposed in our IRP, we removed the wheeling portion of estimated costs to be consistent with how we modeled the fully allocated costs of a CCCT and the capacity costs of a SCCT. This results in a real levelized marginal energy cost for wind of $85.69/MWh.

Q. How did you shape these energy costs into hourly values?

A. We shaped the weighted marginal energy costs described above into hourly intervals based on the energy price shaping from PGE's production cost model, Monet.

Q. How did you estimate each rate schedule's marginal energy cost?

A. We performed the following steps to calculate the 2011 hourly load profile and marginal energy cost of each rate schedule:

1. For each schedule and each month, calculate a typical weekday, Saturday, and Sunday load shape using 2008 hourly load profiles.
2. Use these day-type hourly profiles and the projected monthly peak hour loads to shape each schedule's monthly test-period load forecast into hourly values.
3. By hour, sum each schedule's loads from 2 above and compare these hourly sums to the hourly system load forecast. Assign hourly differences between the two quantities on the basis of each schedules monthly standard deviation of hourly shaped loads in 2 above. These standard deviations are differentiated by weekday, Saturday, and Sunday.
4. Multiply each schedule's shaped hourly load forecast by the corresponding hourly long-term energy cost described above.

Q. How does this projection of hourly interval loads compare to the monthly load forecast submitted in this docket?

A. The energy values by schedule match precisely. However, by inserting the projected monthly peak hour loads to smoothed hourly loads, the monthly peak load hours and the hourly loads immediately proximate to the peak load hours can sometimes appear to be somewhat less than smooth. Nevertheless, the hourly interval data yields a more granular basis to allocate the marginal cost of energy relative to simply using monthly energy values and monthly loads. It furthermore is responsive to those parties in the UM 1415 workshops that stated a preference for hourly marginal energy cost estimation.

Q. Did you use the shaped hourly loads for any purpose other than for the marginal cost of energy?

A. Yes. We used the hourly loads to calculate the annual non-coincident peak load factors for the individual rate schedules. With one exception, Schedule 38, we used the calculated load factors because they provided reasonable values relative to what we have used in previous dockets. For Schedule 38 we imposed a non-coincident peak load factor of 20%, consistent with past practice. This 20% load factor approximates the load factor that results in comparable monthly bills for both Schedules 38 and 83.

Q. Please summarize how you calculate marginal distribution costs.

A. We separately calculate marginal distribution costs for subtransmission, substations, distribution feeders (backbone facilities and local facilities), line transformers and services, and meters.

Q. How do you calculate the marginal unit costs of subtransmission and substations?

A. We calculate subtransmission and substation marginal unit costs by first summing growth-related projected capital expenditures over the five-year period 2010-2014. We then annualize these capital expenditures and divide by the growth in system non-coincident peak. Customers served at subtransmission voltage are not included in the substation calculation because they supply their own substation.

Q. How do you calculate the marginal unit feeder costs?

A. We estimate distribution feeder unit costs in the following manner:

1. Perform an analysis that places customers on the distribution feeder from which they are currently served.
2. Eliminate any distribution feeders from which we cannot obtain customer information, and which do not conform to "typical" standards. Examples of these "non-typical" feeders are feeders serving customers at 4 kV, or network feeders that serve downtown core areas.
3. Perform an inventory of the wire types and sizes for each feeder. Standardize these wire types and sizes to current specifications and then calculate the cost of rebuilding these feeders in today's dollars.
4. Segregate the wire types and sizes into mainline feeders and taplines. Mainline feeders are typically capable of carrying larger loads and are generally closer to the substations from which they originate. Taplines are typically capable of carrying smaller loads and can be remote from substations.
5. For each feeder, allocate the mainline cost responsibility of each rate schedule based on the rate schedule's proportionate contribution to non-coincident peak (NCP). Calculate a unit cost per kW by totaling the feeder cost responsibilities and dividing by the sum of each schedule's NCP.
6. For each feeder, allocate the tapline cost responsibility of each rate schedule based on the rate schedules proportionate design demand (distribution design standard peak load). Calculate a unit cost per kW for both poly and single phase customers by totaling the feeder cost responsibilities and dividing by the sum of each schedule's design demand.
7. Annualize the mainline and tapline unit costs by applying an economic carrying charge.

8. Separately estimate the unit costs of customers greater than 4 MW who are typically on dedicated distribution feeders. Calculate these marginal unit costs (per customer) as the average distance between the substation and the customer-owned facilities. Because new customers on dedicated circuits typically have a redundant feeder, multiply this average distance by two, resulting in a per-customer average of 10,800 feet of dedicated feeders. Finally, apply the annual carrying charge to annualize the cost per customer.

9. Separately estimate the per customer cost of customers served at subtransmission voltage by first calculating the average distance from the point at which subtransmission voltage customers connect into the subtransmission system from their substation and then multiplying this average distance by the current cost per wire mile. These estimated costs are then annualized.

Q. Please describe any other considerations in calculating unit feeder costs.

A. Currently, many municipalities require undergrounding of taplines within subdivisions and commercial areas. We therefore used the current cost of underground facilities exclusively in our marginal feeder tapline cost calculations.

Q. How do you calculate marginal transformer and service costs?

A. We calculate each schedule's marginal transformer and service costs by estimating the cost of providing the average customer within a class with a service lateral and a line transformer (secondary delivery voltage only). We also include the service design costs and any wire costs not captured in the feeder portion of the study. For smaller customers, such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer in order to appropriately calculate their service and transformer costs. Table 4 of PGE Exhibit 1505 summarizes these marginal transformer and service costs by schedule.

RICHARDSON & O'LEARY
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

May 20, 2011

Via Electronic Mail

V. Denise Saunders
Assistant General Counsel
Portland General Electric Company
121 S.W. Salmon Street, IWTC1301
Portland, Oregon 97204
Telephone: 541-752-9060
Facsimile: 503-464-2220
denise.saunders@pgn.com

Re: NIPPC's Comments regarding issues discussed at the bidders' workshop

Ms. Saunders:

I write to provide additional written feedback from the Northwest and Intermountain Power Producers Coalition (NIPPC) regarding matters of concern NIPPC has with Portland General Electric Company's (PGE's) Draft Capacity request for proposals ("RFP"), which have come to our attention since our letter to you dated May 10, 2011. We hope PGE will be willing to fully incorporate the recommendations provided in this letter so as to provide for a more robust and fully transparent procurement process.

After further review of the most recent Draft RFP available on the RFP website, NIPPC is very concerned with the RFP's requirements for gas transport. This is a new, added dimension to the RFP which first surfaced at the bidders' conference. PGE's new request of bidders is untenable in its own right and underscores concerns NIPPC has stated previously.

It is our understanding that a typical RFP for a gas peaking resource, such as the 200 MW year-round flexible peaking resource in this RFP, would essentially seek independent power producers' (IPPs) bids for a tolling agreement. Under the terms of these types of agreements, the IPP would own and operate the electric generating facility per the utility's dispatch orders. While the IPP may provide for an interconnection agreement to a gas line, the utility would handle all arrangements with the gas transport. This makes sense because utilities such as PGE already own substantial rate-based assets, such as gas storage facilities, that can lower the ratepayers' incremental cost of supplying the new generation facility with fuel.

The current version of the Draft RFP, however, would require that IPP bidders prove they can provide "intraday" scheduling of gas supplies for the 200 MW year-round flexible generation facility they bid. The May 5, 2011 version of the Draft RFP states on page 19:

> Bidder must demonstrate physical and commercial access to fuel supplies and fuel transportation for the term of the contract proposed in its bid. Fuel transport and/or gas storage agreements used to support gas thermal bids submitted for Flexible Capacity must allow for intra-day nomination.

It is our understanding that PGE confirmed at the bidders' workshop that it expects the IPPs to bid projects that would provide for intraday gas transport capabilities. Apparently, IPPs will not be able to use any of PGE's resources or assistance in the provision of fuel for their projects. Presumably, this will not allow for a tolling agreement, and will require the bidders to take on the risk of fuel price volatility for the entire term of the agreement.

Beyond being out of the ordinary from what NIPPC expects to see in an RFP, this requirement raises several questions regarding the benchmark Port Westward Unit II resource. It is our understanding that intraday gas scheduling is not feasible at this time in the Northwest without access to substantial storage facilities. We would like confirmation that the benchmark will not use any of PGE's existing rate-based assets to supply gas, and will be making separate and independent arrangements for its own fuel supply so that the costs of supplying intraday fuel deliveries to the benchmark resource may be properly allocated to its bid price. If the benchmark resource will use any existing rate-based assets of PGE's, such as storage facilities, etc., those resources must either be made fully available to the IPP bidders on an equivalent basis, or be fully allocated to the benchmark resource's bid price.

The gas transport requirement also underscores some of the earlier comments that we have made. Specifically, the cost of intraday gas transport capability will vary significantly based upon the level of flexibility PGE will require for the 200 MW resource. At this point, we are not aware of the facility's expected capacity factor, or the expected number of starts per day. This information needs to be provided to bidders as soon as possible.

In addition to the concern regarding the benchmark discussed above, we again request some additional specificity on the following items we believe are truly essential for IPPs to accurately compose their bids with regard to the 200 MW year-round flexible resource:

(1) Expected capacity factor;

(2) Expected number of starts per day;

(3) Performance Assurance PGE will require as cash or a letter of credit for bidders not providing a parental guarantee or otherwise meeting the minimum credit requirements.

Thank you for your consideration of this matter. If you have any questions, please contact me.

Very truly yours,

Gregory M. Adams
Richardson and O'Leary, PLLC
Attorneys for the Northwest and Intermountain
Power Producers Coalition

cc: UM 1535 Service List
Independent Evaluator, Accion Group