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ADMITTED IN OREGON & WASHINGTON

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August 29, 2013

VIA ELECTRONIC FILING
AND FIRST CLASS MAIL
Public Utility Commission of Oregon
550 Capitol Street N.E., Suite 215
Salem, Oregon 97301-2551

Re: UM 1535 – In the Matter of Portland General Electric Company Request for Proposals for Capacity and Baseload Energy Resources

Dear Filing Center:

Attached for filing please find the original and three (3) copies of Troutdale Energy Center's Comments Regarding Grays Harbor Energy, LLC's Request for Investigation.

If you have any questions about this filing, please call me at (503) 224-3092.

Respectfully submitted,

Chad M. Stokes

Enclosures

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1535

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for Proposals for Capacity and Baseload Energy Resources.	TROUTDALE ENERGY CENTER'S COMMENTS REGARDING GRAYS HARBOR ENERGY, LLC'S REQUEST FOR INVESTIGATION

On August 5, 2013, Grays Harbor Energy, LLC ("Grays Harbor") requested that the Oregon Public Utilities Commission ("Commission") initiate an investigation into matters relating to Portland General Electric Company's ("PGE" or "Company") 2012 Capacity and Baseload Energy Resources Request for Proposals ("RFP"). Specifically, Grays Harbor raised concerns regarding transmission assumptions and bid pricing PGE used in the RFP and asked the Commission to investigate whether PGE failed to adhere to the Commission's RFP guidelines or whether PGE engaged in misconduct during the RFP process. Pursuant to Administrative Law Judge Grant's Memorandum dated August 16, 2013, Troutdale Energy Center, LLC ("TEC") submits these comments in support of Grays Harbor's request.

I. SUMMARY OF COMMENTS

TEC urges the Commission to grant Grays Harbor's request for investigation. In a separate docket, TEC has provided indisputable evidence to the Commission that PGE misled the Commission about the status of the Cascade Crossing Transmission Project ("Cascade Crossing Project"), that PGE violated several statutes and a direct Commission order in this docket, and identified improprieties in the evaluation modeling used by PGE and the Independent Evaluator to justify PGE's self-build resources.[1] PGE's response to TEC's claims in DR 46 and its response comments to Grays Harbor in this docket exemplify PGE's steady tactic in front of this Commission – provide volumes of ancillary information that fails to refute the fact that PGE has misused the Commission's RFP process to ensure the selection of PGE-owned resources. As part of that tactic, PGE relies heavily on the participation of the Independent Evaluator to validate its conduct. As explained more fully below, the Commission must question the reliability of PGE's Independent Evaluator (Accion), just as the Public Utilities Commission of Colorado is being advised to do by that commission's staff and ratepayer advocates. The Independent Evaluator's failure to follow the Commission's orders and evaluate bids in the manner the Commission expected has allowed PGE to further its self-build agenda through the RFP process under the Independent Evaluator's veil of legitimacy, without regard for determining the least-risk, least cost resource for ratepayers.

II. COMMENTS

A. INTRODUCTION

Like Grays Harbor, TEC was a bidder in the RFP process. TEC's project is configured as 450 MW base load energy and 200 MW flexible capacity plants located on the same site generating approximately $50 million in savings to ratepayers through economies of scale when compared to the total price of separate bids on different sites. TEC's project is located in PGE's service territory and will connect directly to PGE's load. TEC's project would not subject ratepayers to charges associated with proposed transmission projects, such as the Cascade Crossing Project or the South of Allston Transmission Project ("South of Allston Project") or escalating BPA transmission rates, a concern identified in PGE's IRP and recently validated by BPA's announced 11% increase in transmission rates. The transmission-related savings from

[1] *In re Troutdale Energy Center, LLC*, Docket DR 46 ("DR 46").

TEC's direct interconnection to the PGE system are substantial. PGE ratepayers would save approximately $750 million compared to projects requiring wheeling over BPA's transmission system.

Separate from this proceeding, TEC filed a Petition for Declaratory Ruling ("DR Petition") that raises similar, but distinct, issues from those raised by Grays Harbor.[2] TEC's DR Petition illustrates how PGE violated ORS 757.325(1), ORS 757.115 and ORS 757.105 and urges the Commission to make certain declarations with respect to PGE's ability to recover costs related to the Cascade Crossing Project, PGE's Port Westward Unit 2 Plant ("PW II Plant"), a PGE ownership option for a generator using the site adjacent to PGE's Boardman facility ("Carty Plant"), or any other PGE proposal to invest in transmission upgrades which serve the Carty Plant or the PW II Plant.

TEC initiated its DR Petition to illustrate how PGE violated Oregon law and RFP and IRP guidelines and to urge the Commission to conduct a review of PGE's $1.8 billion capital expenditure program now because of the unprecedented magnitude and interrelated nature of this program, and because the Commission's traditional, post-expenditure review is insufficient to protect ratepayers under current circumstances. Although TEC's DR Petition illustrates how PGE violated Oregon law and RFP and IRP guidelines, and challenges the validity of PGE's resource selection that resulted from the RFP process, TEC did not ask the Commission to make any declarations with respect to PGE's specific conduct in the RFP process. Now that Grays Harbor has raised the issue of PGE's conduct in the RFP process here, TEC will provide information to the Commission that should be helpful in addressing Grays Harbor's request.

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[2] DR 46, Amended Petition for Declaratory Ruling (June 10, 2013).

B. RFP GUIDELINES

RFP Guideline 5 required PGE to use an Independent Evaluator "to help ensure that all offers are treated fairly." RFP Guideline 9b required PGE to select a final short-list of bids that is based on the results of modeling the effect of a candidate resource on overall system costs and risks, and that the modeling must be consistent with the modeling and decision criteria used to develop the utility's acknowledged Integrated Resource Plan ("IRP"). RFP Guideline 10d directs the Independent Evaluator to independently score, not merely validate the scoring of, PGE's ownership options, taking into account all unique risks and advantages associated with those options. [3]

In establishing these guidelines, the Commission placed its faith in the Independent Evaluator to act on its behalf as an independent, third-party evaluator in order to ensure PGE procured the least-risk, least cost resources for ratepayers. Specifically, the Commission expected that the Independent Evaluator would investigate: (1) PGE's resource preferences which shaped the RFP requirements; (2) the detailed characteristics of PGE's self-build resources; and (3) the scoring of all bids including PGE's self-build resources and third party proposals. As described in more detail below, the Independent Evaluator fell short of its duty and enabled PGE to misuse the Commission's RFP process in pursuit of its self-serving capital expenditure program. As it has apparently done for other utilities, the Independent Evaluator failed to stop or question PGE's selective enforcement of its own RFP requirements for its self-build resources and the manipulation of the Commission's RFP process by crafting an RFP with self-serving requirements.

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[3] *In re Investigation Regarding Competitive Bidding*, Docket UM 1182, Order No. 06-446 (Aug. 10, 2006).

C. Transmission Issues[4]

1. *<u>PGE's Conduct in the RFP Process Was Inconsistent with PGE's Commission-Acknowledged IRP</u>*

In its 2009 IRP, PGE clearly stated its concerns about: (1) the transmission system in the Pacific Northwest becoming increasingly constrained; (2) PGE's heavy reliance on BPA transmission for energy deliverability; and (3) PGE's ability to meet energy needs and system reliability in this constrained environment. Based on those concerns, the IRP proposed two self-build transmission solutions: the Cascade Crossing Project (which could deliver energy from the Carty Plant to PGE load) and the South of Allston Project (which could deliver energy from the PW II Plant to PGE load).

Transmission was a significant concern for all parties in the RFP process because the transmission system in the Pacific Northwest is becoming increasingly constrained, as highlighted in PGE's 2009 IRP. Stakeholders therefore confronted PGE with questions on how it would allocate the costs of the proposed transmission solutions in its IRP to its benchmark bids. In the face of those questions, PGE abandoned the solutions it had proposed in its IRP. Now, after claiming the South of Allston Project is no longer needed and substantially revising the Cascade Crossing Project, PGE's plan is to deliver energy from the Carty Plant and the PWII Plant to PGE load primarily through BPA's transmission system. That plan directly contradicts the decision criteria used to develop PGE's Commissioned-acknowledged IRP and PGE's

[4] TEC's Amended Petition and Response to PGE's Comments in DR 46 already describe how PGE incorrectly evaluated bids in the RFP process by improperly assuming that the Cascade Crossing Project is a viable transmission project deemed to be part of the PGE system. These comments, therefore, are limited to the new issues raised by Grays Harbor and PGE's Response.

specific goal of reducing dependence on BPA due to reliability and cost risks.[5] PGE's conduct therefore undermines RFP Guideline 9b.

PGE's response to Grays Harbor reiterates the severity of the transmission constraints in the I-5 Corridor as identified by BPA and confirmed with years of study and statements. Relying on Attachment K included with PGE's comments, PGE states:

> This path is especially susceptible to congestion during the summer months when the State of California experiences periods of high electricity use creating a demand for power generated in the Northwest (including Canada). These summer months are also some of the months when PGE's load peaks. *** The work identified to mitigate the constraints on the I-5 Corridor is neither cheap nor easy since it involves permitting and construction of transmission assets through heavily populated areas.[6]

PGE's Response conveniently ignores the fact that the BPA transmission service PGE plans to use for the PW II Plant is also affected by those transmission constraints and, in fact, will only make those constraints worse by adding 200 MW of generation to the I-5 Corridor. This continued pattern of PGE selectively informing the Commission of certain facts and omitting other important facts, all in an effort to justify its self-build selection, is contrary to the guidelines the Commission established to create an open and transparent process to determine the least-risk, least cost resource for ratepayers.

The Independent Evaluator has been silent in reporting on how the PGE-identified transmission issues mentioned above impact the PW II Plant and how the PW II Plant impacts the I-5 constraints. PGE would have the Commission and stakeholders believe that the Independent Evaluator's silence on this issue implies there are no transmission problems associated with the PW II Plant even though PGE's Commission-acknowledged IRP and PGE's

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[5] Those cost risks were most recently reconfirmed when BPA announced an 11% transmission rate increase on July 30, 2013.

[6] Docket UM 1535, Response of Portland General Electric to Grays Harbor Request (Aug. 23, 2013) ("PGE's Response") at pp. 18-19.

Response clearly demonstrate otherwise. PGE's continued insistence that the Commission should re-affirm the integrity of the RFP process because it was "carefully designed, *extensively reviewed and monitored to ensure that the least cost, least risk resources were selected for PGE's customers*"[7] must be seen for what it is – PGE's manipulation of the process to pursue its self-serving capital expenditure program under a veil of legitimacy created by an Independent Evaluator who remains silent on the issues.

2. PGE's Selection of the PW II Plant is Inconsistent with the RFP Requirements

Early in this docket, the Commission supported PGE's contention that dynamic transfer transmission rights are "essential" for a flexible capacity resource and concurred that "a capacity resource can only provide the flexibility needed to integrate intermittent or variable energy resources if it is located in PGE's Balancing Authority or has dynamic transfer capability."[8] PGE incorporated that requirement into its RFP and, in the case of the Flexible Capacity resource proposals, required "rights to dynamically transfer the proposed nameplate equivalent of the resource being bid into PGE's load" and "the ability to operate the facility under automatic generation control (AGC)."[9] The RFP further provides:

> Confirmation of firm delivery capability or rights to transmit the proposed energy supply to PGE load (including confirmation of dynamic transfer capability) will be required prior to execution of any contracts in connection with this RFP.[10]

As originally conceived, the South of Allston Project would connect to the west side of PGE's service territory and allow full integration of a potential new capacity resource (the PW II Plant) and the remaining capacity that had not yet been integrated at PGE's existing 572 MW

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[7] PGE Response at p.1 (emphasis added).
[8] Docket UM 1535, Order No. 11-371 (Sept. 27, 2011) ("Order No. 11-371") at pp.4-5.
[9] Portland General Electric Co., Request For Proposals, Power Supply Resources (Jan. 25, 2012) ("PGE RFP") at p.16.
[10] PGE RFP at p.31.

Beaver power plant. In choosing to no longer pursue a direct interconnection to its service territory for the PW II Plant, PGE has admitted that it will now be required to utilize BPA transmission for that benchmark bid and that "PGE PWII has firm transmission rights from BPA."[11]

PGE's Response again hides a critical fact from the Commission – that BPA does not offer a firm dynamic transfer product that conveys the "dynamic transfer right" PGE required in its RFP. BPA's dynamic transfer product is allocated on an "as available" basis and on a day-ahead schedule with BPA transmission service requests.[12] Not only can BPA deny a request for dynamic transfer, but BPA can reduce the allocation of dynamic transfer and the associated ramp rate at any time due to BPA system conditions.

BPA's existing dynamic transfer product does not meet the needs of a peaking plant in a constrained corridor, such as the I-5 Corridor where the PW II Plant is located. These "as available" and day-ahead scheduling conditions completely negate any dispatch capabilities associated with PGE's fuel supply requirements (namely "no notice" fuel scheduling) that PGE has consistently explained are necessary for reliability.

Here, too, the Independent Evaluator was silent in reporting how PGE's selection of the PW II Plant using BPA transmission satisfies the RFP's requirement for dynamic transfer capability. The Independent Evaluator made absolutely no comment on dynamic transfer capability in the closing report other than the statement that "PGE should not consider this component in the initial scoring of Bids…."[13]

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[11] PGE's Response at p.7.
[12] *BPA Dynamic Transfer Operating and Scheduling Requirements*, *Version* 3 at pp.6, 9 and 10, attached hereto as Exhibit A (emphasis added).
[13] UM 1535, Report of the Independent Evaluator (Jan. 30, 2013) ("Final IE Report") at p.13.

By ignoring the industry-wide acknowledged constraint in delivering energy from the PW II Plant to PGE load and the dynamic transfer capability issue, the Independent Evaluator was also able to ignore the Commission's directive to investigate the issue of cost allocation for the South of Allston Project. The Independent Evaluator sidestepped that responsibility by relying on PGE's conclusion that because the PW II Plant could be fully deliverable through additional reliance on BPA without that upgrade, the costs of the South of Allston line should not be included in its evaluation of that project. The Independent Evaluator's conclusion on this issue raises more questions than it answers, and the Commission should be concerned that the Independent Evaluator enabled PGE to undermine RFP Guideline 5 by not treating all bids fairly.

D. RFP EVALUATION CRITERIA

Grays Harbor correctly asserts that the Independent Evaluator was unable to ensure evaluative fairness as required by the RFP Guidelines. TEC agrees that the RFP process is littered with examples where the Independent Evaluator, at the direction of PGE, evaluated bids in a manner designed to ensure that only PGE ownership options could be chosen and prevented selection of the least-risk, least cost resources. Below are two examples.

1. Fuel Supply Plan

PGE's treatment of bidders' fuel supply plans demonstrates PGE's efforts to weaken bids competing with its Benchmark Resources or other ownership options. PGE, working with NW Natural Gas Company ("NW Natural"), made it impossible for some independent bidders, and very costly for others, to meet unjustifiable and unprecedented fuel supply standards set in the Capacity RFP. The end result is that PGE passed over lower-cost alternatives to PGE's PW II

Plant and PGE ratepayers will be saddled with the long term purchase of 1 Bcf of storage for a 200 MW peaking facility, which is approximately five times more than is reasonably needed.

PGE required potential resources responding to the Capacity RFP to have fuel supply arrangements that can provide "no-notice" intraday service. Such service refers to the ability of the power plant to access fuel without giving notice through pre-defined scheduling procedures with a natural gas pipeline in order to provide flexibility to turn the plant on and off to meet intraday changes in electricity demand. PGE's requirement – "no-notice" intraday service – is not a service available on an interstate pipeline in the Pacific Northwest. Natural gas pipelines in the Pacific Northwest have long provided flexibility for peaking plants in the region through scheduling and true-up mechanisms. Despite this fact, however, through a unique and mutually-beneficial natural gas storage arrangement with NW Natural, PGE developed this concept and convinced the Independent Evaluator that all bidders must meet this requirement.

The only long-term contract for new natural gas storage services available to bidders in the RFP is through NW Natural's Mist Storage Facility expansion (the "Emerald" expansion). To justify the development of the Emerald expansion, NW Natural needed to secure an anchor tenant with a minimum requirement of 1 Bcf of natural gas storage, [14] much more than would be reasonably required for a 200 MW peaking plant.[15]

Other than PGE's desire to move forward with its self-build option and disregard the least-risk, least cost resource for ratepayers, there is no basis for requiring the fuel plan PGE required. Peaking plants run less than 25% of the time and utilities in the Pacific Northwest recognize it is unnecessary to procure expensive firm transportation contracts for such

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[14] Indeed, NW Natural has now used its contract with PGE as the basis for continuing to pursue a site certificate from the Energy Facility Siting Council.

[15] A reasonable natural gas storage requirement for a 200 MW peaking facility should be around 150 – 200 million cubic feet.

generators. For example, PGE's existing Beaver and Coyote Springs plants utilize on-site liquid fuel storage to provide fuel supply redundancy. Similarly, a recent IRP from Puget Sound Energy called for 221 MW of new peaking generation after finding that such facilities equipped with oil back up and a sufficient amount of interruptible natural gas pipeline capacity are the most cost-effective and reliable peaking resources.[16]

In fact, TEC put forward an alternative fuel supply plan utilizing interruptible transportation with on-site dual fuel capability in the form of liquid fuel storage. This fuel option, if utilized by PGE in the RFP process, would save ratepayers $300 million[17] compared to the pre-defined options PGE sought. While PGE originally indicated that it would consider bids with an on-site fuel storage option, it unilaterally changed its mind when it began evaluating bids and took the position that on-site fuel storage was not desirable.[18]

The Independent Evaluator supported PGE's "no-notice" requirement that ensured both a self-build selection and an economic windfall for PGE and NW Natural. The Independent Evaluator offered that support even though his own investigation turned up no reasonable basis for PGE to impose that requirement. In the fall of 2012, during the evaluation of the bids, it became apparent to PGE and the Independent Evaluator that PGE's mandated fuel plan requirements resulted in bids that could not be compared to PGE's PW II Plant self-build option. Despite this glaring indication that the design and implementation of PGE's RFP requirements maintained a self-build bias, it took a TEC filing and ensuing Commission order directing the

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[16] Puget Sound Energy, 2013 Integrated Resource Plan (May 30, 2013), portions of which are attached hereto as Exhibit B.

[17] The $300 million is a comparison of the costs of firm transportation and gas storage compared with interruptible transportation and on-site liquid fuel.

[18] PGE and the IE answered Questions 104 and 113 in January and February 2012, that provided: (1) "[b]ack up fuel on site will receive additional points for firmness of fuel delivery" and (2) "[t]he requirement for intra-day scheduling is for the flexible capacity plant to dispatch intra-day, without being restricted by the day-ahead gas procurement decisions" and that "[a]s long as the on-site stored fuel allows for the autonomous dispatch of the Flexible Capacity resource for its fuel capacity and for any 24 hour period on a no notice basis, the RFP scoring will consider it to have met the intra-day fueling requirement."

Independent Evaluator to review these requirements to finally force the Independent Evaluator into action.

More than a year after PGE's draft RFP first included the "no-notice" requirements, the Independent Evaluator finally contacted natural gas pipelines in the Pacific Northwest to learn about PGE's desired service. As stated in the Independent Evaluator's final report, the pipelines informed the Independent Evaluator that they do not offer "no-notice" intraday service. However, the pipelines stated that they do offer scheduling and true up mechanisms that provide the level of service needed for peaking facilities. The Independent Evaluator learned that "[i]f a project on the GTN pipeline was to win the RFP, it is expected that the necessary services could be procured to meet the needs of the capacity RFP even though not all of those services are currently in place." The Independent Evaluator received the same information from Northwest pipeline.

After learning about the service pipelines offer, and rather than grapple with whether PGE has an actual need for "no-notice" intraday service or whether alternatives could provide an equivalent balance of risks and benefits, the Independent Evaluator proceeded to simply assign different levels of expensive firm transportation to bids under three pre-defined scenarios, rendering those bids less competitive.

2. Combined Sites

Another example of PGE's manipulation of the Commission's RFP process and the Independent Evaluator's silence is the complete disregard for the Commission's directive to consider bids that combine proposals for the Capacity RFP and the Energy RFP on the same site. In Order No. 11-371, the Commission combined PGE's requests for a baseload and flexible capacity resource into a single docket for the express purpose of allowing "bidders to offer to build capacity and energy resources at a single site to take advantage of economies of scale."[19] PGE's overly restrictive interpretation of the Flexible Capacity Fuel Plan prequalification requirements and scoring criteria apparently resulted in the failure to properly evaluate and consider the potential benefits of combining capacity and energy RFP bids on one site.

In lock-step with PGE, the Independent Evaluator's final report makes no mention of bids combining proposals on the same site. TEC's combined capacity and energy RFP bid would have saved rate payers $50 million in constructions costs when compared to the total price of the separate, individual bids.

E. THE COMMISSION SHOULD NOT RELY ON THE PARTICPATION OF THE INDEPENDENT EVALUATOR TO JUSTIFY PGE'S CONDUCT

PGE's response to the concerns TEC raised in DR 46 and that Grays Harbor raises in this docket rely heavily on PGE's hope that the Commission will ignore these concerns because the RFP process involved the Commission's retention of an Independent Evaluator. As part of its final report, the Independent Evaluator declared that the RFP process was conducted in a "fair and transparent" and "fair and unbiased manner."[20] Coincidentally, the same Independent Evaluator (Accion) made those same conclusions in a recent RFP process conducted by the Black Hills/Colorado Electric Utility Company, LP ("Black Hills") in Colorado, concluding that the RFP was "conducted fairly and without bias" and was a "fair and objective process." That conclusion in the Black Hills RFP, however, is now under scrutiny by the Colorado Office of Consumer Counsel (the state's ratepayer advocate) and the Staff of the Colorado Public Utilities Commission, which last week filed comments illustrating oversights and omissions in Accion's RFP evaluation. The Colorado Office of Consumer Counsel report claims that Accion's "evaluation appears to be focused on modeling and analysis of the bids and not of the issues that

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[19] Order No. 11-371 at p.2.
[20] Final IE Report at p.2.

lead to the perception of a rigged bid….”[21] This Commission, too, should take a hard look at the Independent Evaluator’s conduct, which enabled PGE to arrive at a predetermined outcome in the same way it apparently enabled Black Hills to arrive at a predetermined outcome.

First, the Independent Evaluator failed to properly and fairly evaluate the impact of transmission issues on PGE’s PW II Plant. The South of Alston cut-plane is widely considered one of the most constrained transmission paths in the Pacific Northwest. This fact is illustrated in Appendix K of PGE’s Response. Given these widely known facts, it is unclear why the Independent Evaluator allowed PGE’s evaluation team to claim Grays Harbor’s plant would not be deliverable to load until the I-5 corridor upgrade was in service in 2018 while also claiming that the PW II Plant was deliverable in 2015.

Moreover, despite the inability of the PW II Plant to meet the flexible capacity requirements of the RFP (in the absence of the South of Allston Project), the Independent Evaluator was silent on that issue and failed to identify the fact that the PW II Plant would not have the dynamic transfer capability PGE required of other bidders.

Second, the Independent Evaluator failed to fairly evaluate PGE’s fuel plan requirements. Numerous parties attempted to address fuel supply plan concerns throughout the RFP process, and the Commission directed the Independent Evaluator to investigate those concerns. The Independent Evaluator, however, simply enforced PGE’s desired outcome without independently reviewing the basis for that outcome. As one of the most important requirements in the RFP, which TEC and other third-party bidders spent a considerable amount of time trying to satisfy, it is impossible to reconcile how this requirement remained unchallenged by the Independent

[21] The comments from the Colorado commission’s staff, the Colorado Office of Consumer Council, and portions of a related article in MW Daily are attached hereto as Exhibit C.

Evaluator for so long during the RFP process without questioning the reliability of the Independent Evaluator.

Even more troubling is the Independent Evaluator's actions in response to Commission Order No. 12-398, which directed the Independent Evaluator to report any detrimental impact gas storage issues had on the RFP and PGE's ability to solicit competitive bids.[22] According to the Independent Evaluator, one bidder offered a facility with dual fuel capability and on-site liquid fuel storage to provide fuel supply redundancy. PGE and the Independent Evaluator determined that such alternative proposals were a "significant divergence from the desired product, had substantial environmental and regulatory risks, and did not offer enough supplemental value to warrant further consideration." Dual fuel capability with on-site liquid fuel storage would save $300 million compared to the expensive pre-defined gas storage options PGE imposed on bidders. Despite $300 million in potential savings, and the Commission requirement to report any detrimental impact the gas storage issue had on the RFP process and PGE's ability to solicit competitive bids, the Independent Evaluator determined that no further comment was necessary.

III. CONCLUSION

Despite what the Commission intended would take place in the RFP process, the Independent Evaluator knowingly or unknowingly enabled PGE to implement a multitude of self-serving requirements in the RFP process. The independent ideas and proposals from other bidders created lower risk and lower cost solutions, which, had they been considered, would have yielded the Commission's desired result of the least-risk, lowest cost resources for ratepayers. TEC urges the Commission to open an investigation into these matters and to

[22] UM 1535, Order No. 12-398 (Oct. 23, 2012) at p.3.

determine how PGE was able to use the Commission's process in a manner that is completely contrary to the Commission's goal for having such a process in the first place.

Dated this 29th day of August 2013.

Respectfully submitted,

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Of Attorneys for the
Troutdale Energy Center, LLC

EXHIBIT A

Dynamic Transfer Operating and Scheduling Requirements, Version 3

Effective: 11/13/12

Version 3 of this Business Practice updates the process for submitting Dynamic Transfer[1] Capacity from sending notification by fax to sending the notification by email in step H.1.a and H.1.c.

[1]A term that refers to methods by which the control response to load or generation is assigned, on a real-time basis from the Balancing Authority to which such load or generation is electrically interconnected (native Balancing Authority) to another Balancing Authority (attaining Balancing Authority) or other controlling entity on a real-time basis. This includes Pseudo-Ties, Dynamic Schedules, and dynamic arrangements within the BPA Balancing Authority Area.

A. Introduction

1. The Dynamic Transfer Operating and Scheduling Business Practice combines two existing business practices, the Dynamic Schedules Business Practice and the Remote Resources and Remote Loads Business Practice. These business practices are being consolidated into one business practice to update technical and operational requirements needed to effect dynamic transfers on Bonneville Power Administration's (BPA) system.
2. This business practice sets forth the technical and communication requirements for a Customer[1] to use BPA's transmission system for Dynamic Transfers. Entities desiring to effect Dynamic Transfers on BPA's system must use firm transmission rights and must either (1) have had their use of Dynamic Transfer approved by BPA as of the date of this business practice or (2) request Dynamic Transfer Capability[2] pursuant to the Requesting Dynamic Transfers – Pilot Business Practice or its successor.
3. This business practice may require some Customers to upgrade their telemetry for projects that are dynamically transferred. BPA understands that this may take Customers some time to accomplish. BPA will work with its Customers to help them comply with these requirements. BPA encourages Customers to contact their Account Executive if they have questions or concerns about how this business practice may impact them.

B. Eligibility Criteria

1. New requests for Dynamic Transfer are subject to BPA's Requesting Access to Dynamic Transfer Capability – Pilot business practice or its successor.
2. The Dynamic Transfer Entity[3] must have executed a Dynamic Transfer Agreement[4], or equivalent agreement, and other agreements as appropriate, with BPA, prior to implementation of a Dynamic Transfer that involves the use of BPA's transmission system or the use of non-Federal transmission within BPA's Balancing Authority Area.
3. Each Balancing Authority involved in a Dynamic Transfer must have executed a Dynamic Transfer Operating Agreement, or equivalent agreement.
4. The Dynamic Transfer Entity may only effect Dynamic Transfers on BPA's transmission system with firm transmission rights.

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[1]Any customer taking service under Use of Facilities (UFT), Formula Power Transmission (FPT), Integration of Resources (IR), Part II or Part III of the OATT.
[2]The capability of the transmission system to accommodate continuous ramping of a resource (s) over a pre-determined range, such that the control of the electrical output of such resources(s) can be varied from moment to moment by an entity other than the host utility/host Balancing Authority Area operator.
[3]A load, generator, generation provider, Transmission Customer, (Customer), or other party that is using BPA transmission to effect a Dynamic Transfer.
[4]An agreement between BPA and an Applicant that sets forth the requirements for use of Dynamic Transfer Capability on BPA's system.

5. The Dynamic Transfer Entity that requires a Dynamic Transfer shall be operating within a Balancing Authority Area recognized by the WECC.
6. The Dynamic Transfer Entity must coordinate with its Balancing Authority, BPA, and any other impacted Balancing Authorities to ensure that procedures are in place and appropriate agreements executed to facilitate the desired Dynamic Transfer.
7. The Dynamic Transfer Entity and all involved Balancing Authorities must comply with WECC and NERC (or successor organizations) standards and policies.

C. Telemetering

1. Telemetry requirements for implementation of a Dynamic Transfer into, out of, or through BPA's Balancing Authority Area are described below:
   a. BPA must test and approve in advance all systems necessary, as determined by BPA, to effect a Dynamic Transfer for each Dynamic Transfer Entity that desires to engage in a Dynamic Transfer.
   b. The Dynamic Transfer Entity will provide BPA a telemetry signal corresponding to each Dynamic Transfer e-Tag representing the Dynamic Transfer. BPA will determine where the appropriate signal will emanate from. This is the Dynamic Transfer Request Signal[1].
   c. The Dynamic Transfer Request Signal will be updated at least once every four seconds and will conform to ICCP requirements, or equivalent requirements as determined by BPA, for data format, accuracy, and reliability consistent with BPA' AGC[2] cycle time and anti-aliasing filtering.
   d. If the desired Dynamic Transfer sources or sinks in BPA's Balancing Authority Area, BPA will send a Dynamic Transfer Return Signal[3] to the Dynamic Transfer Entity in response to the Dynamic Transfer Entity's Dynamic Transfer Request Signal described above. The Dynamic Transfer Return Signal will be based on the actual response to the Dynamic Transfer Entity's Dynamic Transfer Request Signal. The Dynamic Transfer Return Signal will be the official Dynamic Transfer.

[1]The telemetry signal provided by the Customer or other applicable Entity that corresponds to each Dynamic Transfer e-Tag representing the Dynamic Transfer.
[2]Automated Generation Control
[3]The return telemetry signal that BPA sends to the Customer or other applicable Entity, which is the response to the Dynamic Transfer Request Signal.

e. BPA will provide a Dynamic Transfer Limit Signal[1] to the Dynamic Transfer Entity continuously in real-time. This Dynamic Transfer Limit Signal will indicate the maximum allowable Dynamic Transfer. The Dynamic Transfer Entity shall adhere to this Dynamic Transfer Limit Signal.

f. If BPA's Balancing Authority Area is an intermediary Balancing Authority Area between the native and attaining Balancing Authorities (the native and attaining Balancing Authorities can be the same Balancing Authority or two different Balancing Authorities), the Dynamic Transfer Entity will arrange for either the native or attaining Balancing Authority to provide BPA with a real-time telemetry signal that represents the amount of power being Dynamically Transferred through BPA's Balancing Authority Area. This signal will be the official Dynamic Transfer and will conform to the same requirements described in step C.1.d above.

g. Latency time is measured from the attaining Balancing Authority metering point to inclusion of the BPA Dynamic Transfer Return Signal in the same attaining Balancing Authority's ACE calculator and shall be no greater than 20 seconds.

h. BPA will provide a Ramp Rate Limit Signal[2] to the Dynamic Transfer Entity continuously in real-time, which indicates the maximum ramp rate in MW per minute allowed for the Dynamic Transfer. As described further in step J.1, BPA may reduce the allowable ramp rate to maintain system reliability. The Dynamic Transfer Entity shall adhere to this limit.

i. If the Dynamic Transfer Request Signal emanates from a Balancing Authority Area other than BPA's Balancing Authority Area, that Balancing Authority Area shall provide to BPA, upon request, documentation showing in detail the method of anti-aliasing and frequency cutoff it will be using to implement a Dynamic Transfer Request Signal. As required in step B.3, the Dynamic Transfer Entity is responsible for ensuring the appropriate arrangements with the applicable Balancing Authority Area to comply with this requirement.

j. If there is a communication failure such that one or more of the requirements in steps C.1.b-h is not met, the Dynamic Transfer Entity shall immediately contact BPA Dispatch. BPA shall hold the Dynamic Transfer Limit Signal(s) at the last good value until appropriate communication is restored.

k. All costs incurred by BPA to install telemetry for a Dynamic Transfer will be the responsibility of the Dynamic Transfer Entity requesting such service. Such costs may include, without limitation, cost of system studies performed to determine the transmission impacts of the requested Dynamic Transfer request, costs for labor, software

[1] The telemetry signal communicated by BPA to the Customer or other applicable Entity to limit or reduce the Dynamic Transfer.

[2] The real-time telemetry signal sent by BPA to the Customer or other applicable Entity to communicate the current maximum MW/minute ramp rate limit.

for AGC, communication equipment, and costs to upgrade both the Dynamic Transfer Entity and BPA's facilities. The Dynamic Transfer Entity is responsible for ongoing maintenance costs of its own equipment. BPA Transmission Service will maintain its own equipment.

l. If a Dynamic Transfer sources from multiple Points of Receipt (PORs) and/or sinks to multiple Points of Delivery (PODs), then BPA reserves the right to require the Dynamic Transfer Entity to provide a separate official Dynamic Transfer for each POR[1]/POD[2] combination. This applies to any Dynamic Transfer into, out of, or through the BPA Balancing Authority Area and is necessary so that BPA can determine the impact of the Dynamic Transfer on the FCRTS[3].

D. E-Tagging Dynamic Transfers

1. Each Dynamic Transfer shall be electronically e-tagged in accordance with current NERC and WECC requirements and related BPA procedures.
2. The Dynamic Transfer Entity must arrange with BPA to have Real Time Operations Dispatch and Scheduling system Accounts established for each Dynamic Transfer request. This must be arranged during a regular Business Day[4] and be completed prior to the Preschedule day.
3. E-Tags for a Dynamic Transfer must be submitted when the transmission demand set aside in the Transmission Profile[5] for a Dynamic Transfer is reserved. The dynamic capacity reserved shall be deemed as used.
4. The e-Tag requirements for a Dynamic Transfer are specified in BPA's Scheduling Transmission Service business practice, as may be replaced or revised, and must also include the following:

[1]Point of Receipt is an interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available by the Delivering Party; An OASIS field on a TSR that is the scheduling POR.
[2]Point of Delivery is a point on the The Transmission Provider's Transmission System where capacity and energy transmitted by the Provider will be made availabe to the Receiving Part; An OASIS field on a TSR that is the scheduling POD.
[3]Federal Columbia River Transmission System
[4]Any weekday (Monday through Friday) that is not a United States Federal Holiday.
[5]The maximum amount of fim reserved capacity set aside to cover the Energy Profile. The data on the e-Tag related to the hourly Transmission Demand.

a. Transaction type “DYNAMIC” is required for Dynamic Schedules.

b. Transaction type “PSEUDO-TIE” is required for Pseudo-Tie[1] transactions.

c. Expected average Energy Profile[2] delivered during the hour.

d. Adjustment after the hour will use the integrated official Dynamic Transfer.

e. The Dynamic Transfer Entity responsible for tagging Dynamic Transfers must ensure the e-Tag is updated for the next scheduling hour and future hours when:

   i. The average Energy Profile on the e-Tag deviates from the hourly average Energy Profile, as described in NERC Standard INT-004-2 (as may be replaced or modified);

   ii. Requested by a Reliability Coordinator or BPA.

5. Real-time pro rata curtailments of transmission capacity that is being used to effect a Dynamic Transfer will be calculated based upon the actual Dynamic Transfer Return Signal at the time of the curtailment. The resulting Dynamic Transfer Capacity curtailment will be communicated via the Dynamic Transfer Limit Signal and via the revised e-Tag from BPA indicating the new maximum allowable Dynamic Transfer Capacity use.

6. If BPA limits the Dynamically Transferred electrical power injected by the Dynamic Transfer Entity at a particular POR, then the Dynamic Transfer Entity will reduce the generation of its resources sourcing the Dynamic Transfer at the specific POR. The resulting change in the Dynamic Transfer Entity’s official Dynamic Transfer will be used to assess the Dynamic Transfer Entity’s compliance with the limit. Failure to comply with any Dynamic Transfer limit shall be subject to the Failure to Comply[3] Penalty consistent with BPA’s Failure to Comply Business Practice, as may be replaced or revised.

E. Transmission Requirements Using Federal Columbia River Transmission System (FCRTS) Capacity

1. If the Dynamic Transfer Entity is using FCRTS Reserved Capacity for Dynamic Transfers, the following transmission requirements shall apply:

[1] A telemetered reading, or value that is updated in real time, that represents generation or load assigned dynamically between control areas and used as a tie line flow in the affected control areas’ AGC/ACE equation, but for which no physical control area tie actually exists. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.
[2] The data on the e-Tag related to the hourly interchange schedule.
[3] The consequences of non-compliance as defined in the Failure to Comply Business Practice in effect at the time.

a. The Dynamic Transfer Entity may allocate all or part of its reserved capacity to its allowed Dynamic Transfer amount.

b. The Dynamic Transfer Entity may allocate any remaining reserved capacity to standard (i.e. non-Dynamic Transfer) transmission usage.

c. The Dynamic Transfer Entity must have adequate reserved capacity in the Transmission Profile for the Dynamic Transfer.

d. Population of the Energy Profile shall occur electronically using the official Dynamic Transfer after the fact based on the integrated number within 15 minutes after the end of the hour.

e. Each Dynamic Transfer will be for only one direction over a path. The portion of reserved capacity that has been reserved for Dynamic Transfer purposes in the Transmission Profile cannot be redirected, resold, or reassigned.

f. All reserved capacity for a Dynamic Transfer in the Transmission Profile whether or not called on, will be included in the Dynamic Transfer Entity's usage for purposes of determining whether there has been an Unauthorized Increase.

F. Transmission Requirements Not Using Federal Columbia River Transmission System (FCRTS) Capacity

1. This section applies to any Dynamic Transfer Entity that wishes to effect a Dynamic Transfer in or through BPA's Balancing Authority Area on non-FCRTS transmission. The following transmission requirements shall apply:

   a. The Dynamic Transfer Entity must demonstrate that it has firm transmission capacity across BPA's Balancing Authority Area or on a path where BPA is the path operator for its Dynamic Transfer by setting aside reserved capacity in the Transmission Profile for the non-FCRTS path used.

   b. The official Dynamic Transfer integrated over the hour will be used for interchange accounting purposes.

G. California-Oregon Intertie (COI) Dynamic Transfer Preschedule Methodology

1. If the total aggregated Dynamic Transfers requested on the COI exceeds the available Dynamic Transfer capacity, BPA will allocate during Preschedule the available Dynamic Transfer capacity equally to all eligible Dynamic Transfer Entities requesting Dynamic Transfers.

2. If a Dynamic Transfer Entity does not request its full allocation of capacity, the Dynamic Transfer capacity will be allocated to those Dynamic Transfer Entities that did not receive their full request.

3. The maximum Dynamic Transfer capacity that a Dynamic Transfer Entity can request is limited to the lesser of:
    a. The amount of Dynamic Transfer capacity the Dynamic Transfer Entity has been certified to schedule by the California Independent System Operator (CAISO), or
    b. The total Dynamic Transfer capacity allocation that BPA has granted to the Dynamic Transfer Entity, or
    c. The capacity available for Dynamic Transfers on other paths that must also be crossed, or
    d. Other factors limiting Dynamic Transfers.

H. Scheduling Procedures for Dynamic Transfers using COI

1. Dynamic Transfer Entities that want to use their firm Reserved Capacity for a Dynamic Transfer over the COI must follow the procedures described below:
    a. The Dynamic Transfer Entity must notify BPA's Preschedule by 08:00:00 PPT[1] of the WECC Preschedule day of the amount of Dynamic Transfer capacity it wants to use. Such notification must be made by email to BPATPreschedule@bpa.gov. The email should include the account number, transmission path, MW of Dynamic Transfer capacity for each hour of the Preschedule period, and day total.
    b. The amount of Dynamic Transfer capacity requested must be entered for each hour or the requested amount will be assumed zero, and the Dynamic Transfer Entity will have no allocation for that hour.
    c. Notification of the Dynamic Transfer Entity's allocation of Dynamic Transfer capacity shall be provided by email to the Dynamic Transfer Entity no later than 09:45:00 PPT. The Dynamic Transfer capacity allocation will not change after this time.
    d. The Dynamic Transfer Entity will then modify its Dynamic Transfer capacity amount by e-Tag to be equal to or less than its Dynamic Transfer capacity allocation. The Dynamic Transfer Entity must submit its final prescheduled Dynamic Transfer to BPA no later than one hour after the close of the California final Day-Ahead Market for the California-Oregon Intertie (COI). Preschedule staff will check the Dynamic Transfer capacity accounts by close of Preschedule to ensure that each account is not greater than the allocated amount of Dynamic Transfer. If the Dynamic Transfer Entity exceeds its Dynamic Transfer capacity allocation, BPA's Preschedule staff shall reduce the schedule and notify the Dynamic Transfer Entity.

[1] Pacific Prevailing Time

e. The Dynamic Transfer Entity can decrease its Dynamic Transfer capacity accounts as needed in real-time twenty minutes prior to the hour of delivery, but the account must contain only the Dynamic Transfer capacity needed to meet the Dynamic Transfer Entity's obligation in the CAISO market or other COI transaction as represented by valid e-Tags.

I. Limitations on Dynamic Transfer

1. A Dynamic Schedule[1] will be allowed to move from zero MW to the BPA determined maximum allowed MW for a Dynamic Transfer within the Operating Hour[2] in one direction over the path.
2. A Pseudo Tie will be allowed to move within a BPA assigned bandwidth around the estimated usage shown on the Type-Pseudo-Tie e-Tag within the Operating Hour in one direction over the path.
3. The Transmission Profile shall not be exceeded during the hour of flow -this applies to both Dynamic Schedules and Pseudo Ties.
4. BPA may limit or freeze a Dynamic Transfer (including ramp rates) into, out of or through BPA's Balancing Authority Area at any time if the reliability of the FCRTS or associated interconnection is threatened where the Dynamic Transfer is a contributing factor to the problem being encountered -even if no other transactions or ATC[3] are curtailed. In more serious cases, BPA may also have to curtail ATC to maintain reliability.
5. Examples of when BPA may take action to limit or freeze a Dynamic Transfer include, but not limited to:
   a. staying within acceptable limits during real-time operations;
   b. performing acceptably after contingencies; and
   c. effecting restoration after loss of system elements.
6. The Dynamic Transfer limit will be the lower of the reliability limit or the Transmission Profile on the e-Tag. Failure to comply with any Dynamic Transfer limit shall be subject to the Failure to Comply Penalty consistent with BPA's Failure to Comply Business Practice, as may be replaced or revised.
7. BPA is the path operator of the northern portion of the COI. BPA is also the Balancing Authority in which the northern portion of the COI is located.

[1]A telemetered reading or value that is updated in real time and used as a schedule in the Automatic Generation Control (AGC) and the Area Control Error (ACE) equation and the integrated value of which is treated as a schedule for interchange accounting.
[2]The current hour. Also defined as the Clock Hour.
[3]Available Transfer Capability

8. Each Dynamic Transfer over the COI must be monitored and operated through BPA's Balancing Authority Area without regard to whose transmission rights are used.

9. Dynamic Transfer schedules are limited to 200 MW in aggregate during 0600 to 2200 every day and 550 MW during 2200 to 0600 every day over the California-Oregon Intertie (COI).

    a. If the total aggregated Dynamic Transfer schedules requested exceeds the available Dynamic Transfer capacity, BPA Transmission Services will allocate, during Preschedule, the available Dynamic Schedule capacity equally to all Entities submitting Dynamic Schedules utilizing the COI.

10. Dynamic Schedules over the Northern Intertie are limited to 300 MW in aggregate.

11. Dynamic Transfers are not allowed over the DC Intertie at this time.

J. Dynamic Transfer Ramp Rate

1. BPA may establish a maximum ramp rate limitation for each Dynamic Transfer and may lower the maximum ramp rate due to system conditions.
2. Failure to follow Ramp Rate Limit Signal will be subject to a Failure to Comply Penalty consistent with BPA's Failure to Comply business practice, as may be replaced or revised.

K. Load & Resource One-Day Forecast Requirements

1. Load and resource forecasts are necessary to allow BPA to plan the Transmission System, determine the usage of constrained transmission paths for the calculation of ATC and Available Flowgate[1] Capability and to determine curtailment priority.
2. Dynamic Transfer Entities with loads outside the BPA Balancing Authority Area, which are served with a resource dynamically transferred using transmission in BPA's Balancing Authority Area, must submit or arrange to have submitted one-day forecasts for the use of that resource for each POR/POD combination for each hour of the following delivery day.

[1]Flowgate (Cutplane): Transmission lines and facilities owned by BPA on a constrained portion of BPA's internal network transmission grid or transmission lines and facilities owned by BPA and one or more neighboring transmission providers that are interconnected and the separately owned facilities are operated in parallel in a coordinated manner, and each of the owners has an agreed upon allocated share of the transfer capability.

3. Forecasts are to be provided on the prescheduled day in accordance with the Pre-schedule ancillary services window. Forecasts may be updated in accordance with the real-time window.
4. If multiple days are being prescheduled, then hourly load forecasts for all days being pre-scheduled must be submitted.
5. BPA will treat these one-day forecasts as the equivalent of transmission usage for purposes of ATC, curtailment, and Energy Imbalance[1] calculations.
6. Forecasts will be submitted consistent with the scheduling provisions of the Dynamic Transfer Entity's transmission contract and may not exceed transmission contract demand.

L. Additional Information

Policy Reference

This Business Practice implements BPA' policies relating to operating and scheduling requirements for dynamic transfers on the Federal Columbia River Transmission System.

Related Business Practices

- Requesting Access to Dynamic Transfer Capability – Pilot
- On Demand Resource[2] Scheduling
- Redispatch and Curtailment Procedures[3]
- Requesting Transmission Service
- Scheduling Transmission Service
- Failure to Comply

[1] Difference occurring between hourly scheduled amount and hourly metered (actually-delivered) amount associated with transmission to a load located in BPA's Balancing Authority Area or from a generation resource located within BPA's Balancing Authority Area.
[2] a. A resource located within BPA's Balancing Authority Area; b. An arrangement with a neighboring Balancing Authority that allows the delivery of power on BPA's system to or from a neighboring system; or c. A Demand Response Resource capable of meeting the technical requirements for an On Demand Resource.
[3] Measures taken to relieve transmission system overloads and therefore manage loading on the transmission system to within the Operating Transfer Capability (OTC).

- Unauthorized Increase Charge[1]

Version History

Version 3	11/13/12 Version 3 of this Business Practice updates the process for submitting Dynamic Transfer Capacity from sending notification by fax to sending the notification by email in step H.1.a and H.1.c.
Version 2	02/22/12 Included the Dynamic Schedule Limits Bulletin incorporated as steps I.8-10. The incorporation moves all associated information from the Bulletin into one document.
Version 1	11/01/10 Posted for customer comment through 12/17/10 02/20/11 Posted again for customer comment 02/03/11 through 02/18/11. Added 3 to the Introduction and removed the second paragraph from the introduction.

[1]Transmission Customers taking Point-to-Point Transmission Service under the PTP, IS, and IM Rate Schedules shall be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD). Transmission Customers taking Network Integration Transmission Service under the NT Rate Schedule shall be assessed the UIC if their Actual Customer-Served Load (CSL) is less than their Declared CSL. BPA-TS will notify a Transmission Customer that is subject to a UIC once BPA-TS has verified the UIC amount.

EXHIBIT B

2013 Integrated Resource Plan

CHAPTERS 1-7

May 30, 2013

PSE.com

PUGET SOUND ENERGY

Exhibit B
Page 1 of 5

Electric plan resource additions

Figure 1-4 summarizes changes to the electric resource portfolio in terms of peak hour capacity. This plan is the "integrated resource planning solution."[4] It reflects the lowest reasonable cost portfolio of resources that meets the projected capacity, energy, and renewable resource needs described above. Except for demand-side resources, which significantly reduce risk, most of the other resources show the same risk profile. The resource plan reflects the expectation that Colstrip will continue to be a least-cost resource in the portfolio. In this IRP, we have chosen to reflect gas storage for generation fuel as part of the electric resource plan. While gas storage is not a "supply-side resource" for generation (and therefore not required to be addressed by the IRP rule), it is important to highlight this aspect of the company's resource plan.

Figure 1-4
Electric Resource Plan, Cumulative Nameplate Capacity of Resource Additions

	2017	2023	2027	2033
Demand-Side Resources (MW)	327	800	887	1,007
Wind (MW)	0	300	500	600
Peakers (CT in MW)	221	442	1,327	2,212
Transmission Renewals (MW)	1,141	1,407	1,407	1,567
Gas Storage (MDth/day Gas)	100	100	100	150

Demand-side resources (DSR)

This plan – like prior plans – includes acquiring conservation to levels such that much of what is available will be acquired. That is, significant changes in avoided cost had little impact on how much could be acquired cost effectively. PSE's analysis indicates that although current market power prices are low, accelerating acquisition of DSR continues to be a least-cost strategy.

[4] *Chapter 2 includes a detailed explanation of the reasoning that supports each individual element of the resource plan.*

Renewable resources

Timing of renewable resource additions is driven by requirements of RCW 19.285. PSE's analysis shows that while additional wind is not a least-cost resource, we anticipate remaining comfortably below the revenue requirement compliance mechanism included in the law. PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law through 2022.

Peakers appear more cost effective than combined-cycle plants.

This finding holds as long as the peakers are equipped with oil back-up and a sufficient amount of interruptible natural gas pipeline capacity is available for fuel delivery. This should certainly be the case for the first few additions, but adding several hundred MW of new peakers may over-tax the natural gas infrastructure. Should peakers require firm pipeline capacity, some level of combined-cycle combustion turbine (CCCT) plants may be found to be cost effective.

Transmission contract renewals backed by market purchases appear cost effective.

In the short to intermediate term, transmission contract renewals do appear least cost. These contracts only need to be renewed for 5-year terms to preserve PSE's unilateral roll-over rights in the future. If and when Unit 1 of TransAlta's Centralia coal plant retires in 2020, regional resource adequacy is expected to decline abruptly. Unless replacement generation is developed, it is unlikely that heavy reliance on short-term markets over firm transmission will continue to be a viable resource strategy. There also may be concerns about longer-term generation plant closures in the California market; this could reduce the Northwest region's ability to import power from that region, as has been done traditionally for decades. The action plan below states PSE will file an update to the 2013 IRP later this year to focus specifically on this issue.

MW of peakers in the plan. The gas-fired MW additions in the plan reflect the Base Scenario and demand forecast. Demand forecasts significantly influenced the amount of peakers added across scenarios. As Figure 2-2 shows, under Colstrip Case 1, the Base Scenario added 2,212 MW of peakers; the Low (load and gas price) scenario added 1,327 MW, and the High (load and gas price) scenario added 3,096 MW. The high and low demand forecasts reflected in these scenarios represent the extremes of future macroeconomic conditions analyzed. When the time comes to make actual acquisitions, PSE will adjust the amount to reflect prevailing conditions. Figure 2-2 also shows how Colstrip's presence or absence impacts the amount of peakers included in the portfolio; however, since Colstrip is expected to remain a cost-effective resource, load forecast variability is the focus here.

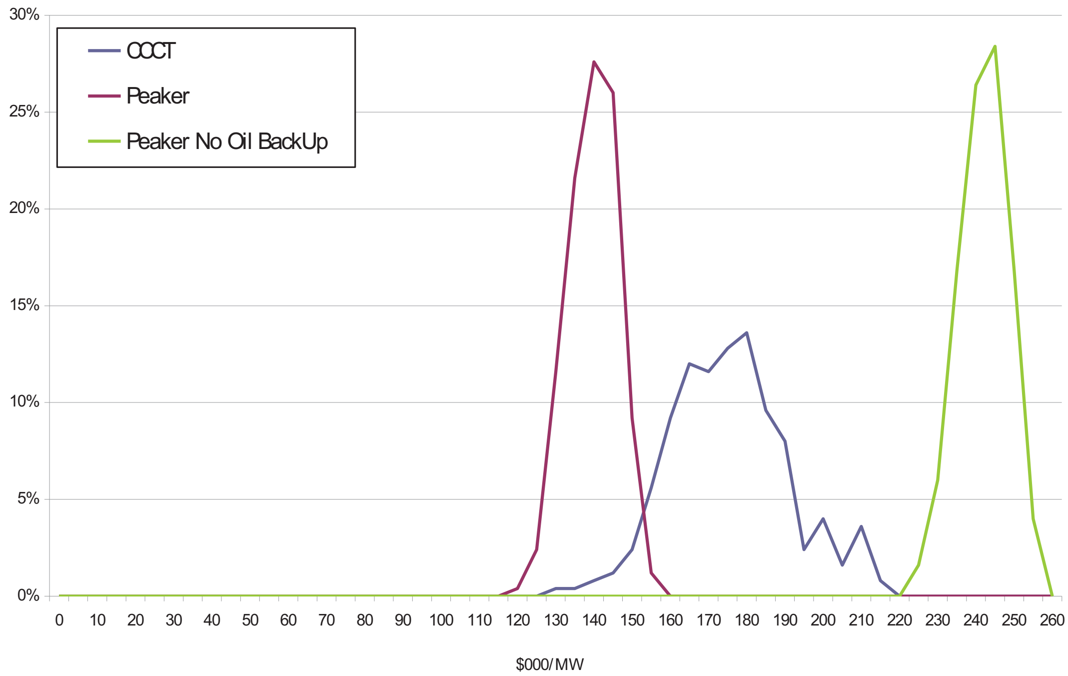
Significance of oil back-up. The new gas-fired peakers included in the resource plan are assumed to be equipped with oil back-up. These plants would turn first to interruptible pipeline capacity for natural gas fuel, but if gas supply was unavailable, up to two days of fuel oil stored onsite could be used to run the plant. Major barriers to siting back-up oil supplies do not appear to be a problem at this time, but if this did become an issue, peakers without back-up fuel may not remain cost effective compared to CCCT plants.

Figure 2-9 shows the results of the net cost per kW market risk analysis from a 250-draw Monte Carlo simulation, as described more fully in Chapter 5. The chart illustrates a probability density function of the net cost/MW for a CT with oil back-up, a CCCT, and a CT without oil back-up, where the horizontal axis is the net cost [7] and the vertical axis is the probability of that net cost occurring from the Monte Carlo simulation. Figure 2-9 demonstrates that gas-fired peakers without back-up oil supply would be significantly more expensive on a net dollars per MW basis than a CCCT plant. This net cost analysis is helpful to understand the relative importance of the cost distributions of the three different plants, but is not a substitute for portfolio analysis. PSE's full portfolio analysis also takes into consideration the timing and size of capacity needs—CCCT plants are lumpier than CTs, so the smaller CT without oil back-up could still lead to a lower overall portfolio cost than a CCCT.

[7] *Net Cost = Fixed Costs – (Market Price-Variable Cost)*MWh of dispatch.*

Figure 2-9

Comparison of Net Cost Distribution: CCCT and Peakers



Reliance on interruptible pipeline capacity. Interruptible pipeline capacity is a key factor in the economic advantage that peakers with oil back-up have over CCCT plants. Firm pipeline capacity guarantees the right to transport a given quantity of gas; it requires a fixed payment whether or not the capacity is used. Cheaper, intermittent service can be purchased through the market for interruptible pipeline capacity. This makes it a good fit for peaking plants, which run only when needed. If sufficient interruptible gas supplies are not available, or if two days of oil back-up is not available (or sufficient to meet reliability needs), it may be necessary to turn to firm pipeline capacity. Should this happen, the added cost of equipping peakers with oil back-up would not make sense, and CCCT plants may become more economic to operate than peakers.

EXHIBIT C

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

DOCKET NO. 13A-0407E

IN THE MATTER OF THE APPLICATION OF BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP FOR APPROVAL OF WIND SOLICITATION.

STAFF COMMENTS

2013 WIND BID RFP – BID EVALUATION REPORT

August 23, 2013

Executive Summary:

On April 23, 2013, Black Hills/Colorado Electric Utility Company, LP (Black Hills or the Company) filed an Application for Approval of a Wind Solicitation (Application). The Commission, in Decision No. C13-0582-I, found that "Black Hills has the discretion to solicit bids outside of the ERP approval process but also that, until the Commission issues a ruling on the merits the Application, the Company's actions enjoy no presumption of prudence." The Commission set the application for hearing and referred the matter to an Administrative Law Judge (ALJ) for an initial decision.

The Company issued the Wind Solicitation Request for Proposal (RFP) on May 10, 2013 with bids due June 14, 2013. While 31 entities had registered interest, only two entities submitted bids with one being a non-regulated affiliate of Black Hills. Because the response was not robust, the Company asked the Independent Auditor (IA) to survey the entities who had earlier expressed interest to determine whether a second opportunity to bid under a modified RFP would potentially produce more bids. Ultimately the Company on July 2, 2013 provided a second opportunity to bid or refresh bids on or before July 17, 2013 with a lowered bid fee. The Company received four additional bids.

Staff believes that the bidding process implemented by the Company and overseen by the IA afforded all interested bidders a fair and non-discriminatory opportunity to bid. Further, Staff does not take exception to the calculated Present Value of Revenue Requirement (PVRR) for each of the bids for 30 MW or less wind generation. While Staff agrees that the Black Hills IPP non-regulated affiliate bid (BH-IPP) is projected to provide the least PVRR, Staff determined that the bid identified as Bidder A, 25 year PPA (A-PPA), provides the highest overall customer value.

The factors which led Staff to recommendation to select the Bidder A, 25 year PPA bid follow:

- The A-PPA bid is for delivery of 29.75 MW of wind generation with a capacity factor of 47.90%. The BH-IPP project is for delivery of 29.25 MW with a capacity factor of 32.97%. Effectively, the A-PPA bid is 48% larger than the BH-IPP bid.
- The A-PPA will produce, on the average, 125,881 MWh and RECs annually, while the BH-IPP will produce 84,479 MWh and RECs. The A-PPA will produce an estimated 3,120,805 MWh and RECs over the life of the contract, while the BH-IPP will produce 1,689,581 MWh and RECs.
- The A-PPA project will avoid 49,933 tons of CO_2 annually, while the BH-IPP project will avoid 33,792 tons.
- The cost difference between the two bids of $4.98 million over 20 years is *de minimis* relative to a total system PVRR of over $2 billion.
- Black Hills will need to acquire additional wind generation in the future to comply with the Renewable Energy Standard (RES), and future wind projects may not enjoy the benefit of a Production Tax Credit. As a result, Black Hills should take advantage of the bid that provides the highest production at a reasonable cost.

Staff recommends that the Commission order Black Hills to proceed with contract negotiations for a 25 year Purchase Power Agreement (PPA) with Bidder A.

Introduction:

Provided herein are Staff's comments on the Black Hills Bid Evaluation report and the Independent Auditor's Report pursuant to Commission Decision No. R13-0830-I. The Commission, in Decision No. C13-0582-I, provided the Company with authority to proceed with the proposed RFP process to accommodate the provisions of the American Taxpayer Relief Act of 2012, signed into law on January 2, 2013. The law extended the Federal Production Tax Credit (PTC) for wind resources beginning construction before January 1, 2014. The Commission found that the limited extension of the federal PTC creates a narrow window to receive, evaluate, and select bids for wind resources in time to allow developers to meet the construction deadline.

Staff relied heavily on the Independent Auditor (IA) to ensure a fair and reasonable bid solicitation. In addition, Staff relied on the Company's resource planning model results as verified by the IA. Staff chose not to replicate the work conducted by the Company and verified by the IA in modeling and estimating the PVRR for each of the bids considered. Staff utilized the results provided by the Company to investigate and quantify a number of additional benefits that should be recognized, particularly with respect to energy productivity, term of contract offered, the contribution toward compliance with the RES, and consideration of other externalities.

Staff, by its evaluation, provides the Commission with an alternative valuation which identifies additional factors that Staff believes should be considered in determining the wind resource bid that offers the most value to Black Hills customers.

Staff did rely partially on the PVRR values calculated by the Company. However, when Staff considered a wider range of benefits, it reached a completely different conclusion as to which bid provides the most value to customers.

Black Hills RFP Process & Evaluation:

Due to timing and the urgency of this proceeding, modeling assumptions and the optimum quantity of wind to be acquired was not vetted or approved by the Commission prior to the issuance of the RFP, or for that matter prior to the development of recommendations by the Company or others. In fact, the expedited nature of the proceeding eliminated the opportunity for a thoughtful analysis of how much wind should be acquired.

It appears that Black Hills chose a strategy to acquire only up to 30 MW pursuant to the exemptions provided in Rule 3615(a)(III) assuming it would minimize opposition, and filed its application accordingly. The Commission, pursuant to Rule 1206(b), issued notice of the Company's application. Although some bidders and parties have expressed interest that this acquisition allow larger bids, the application and notice limit the bids to no more than 30 MW. While the Company could amend its application to accept larger wind projects, Rule 1309 would require new notice thus jeopardizing the ability to acquire wind resources that could take advantage of the PTC.

The Company issued the Wind Solicitation Request for Proposal (RFP) on May 10, 2013 with bids due June 14, 2013. While 31 entities had registered interest, only two entities submitted bids with one being a non-regulated affiliate of Black Hills. Because the response was not robust, the Company asked the Independent Auditor (IA) to survey the entities who had earlier expressed interest to determine whether a second opportunity to bid under a modified RFP would potentially produce more bids. Ultimately the Company on July 2, 2013 provided a second opportunity to bid or refresh bids on or before July 17, 2013 with a lowered bid fee. Black Hills should be commended for these efforts to provide every reasonable opportunity for interested parties to respond to the solicitation.

Although Staff believes the solicitation was fair, there is one specific RFP provision that is at issue in this proceeding; it is the requirement for bidders to have a Large Generator Interconnection Agreement (LGIA) in place at the time of bid submission. Only the BH-IPP bid conformed to this requirement; the other bidders provided transmission paths and injection capabilities, but were unable to provide LGIAs in the short period provided. In the case of the initial RFP offering, bids were due five weeks after issuance of the RFP. The reopened RFP offering period provided a two week period to provide or refresh bids. The expectation that the work to prepare an interconnection requests, perform analysis of requests by utilities, prepare responses back to the applicants, and execution of a final LGIA in such a short timeframe is unreasonable. It is important to remember that this requirement has not yet been vetted or approved by the Commission. Notwithstanding, the Company received five bids that it evaluated regardless of the absence of LGIAs.

The Company has reported in its *2013 Wind Bid RFP Bid Evaluation Report* that the BH-IPP 20 year PPA bid provided the least cost PVRR and recommended that the Commission authorize negotiations leading to a final contract. While Staff does not dispute the least cost PVRR determination, it believes that one of the other bids provides customers much better overall value and in the long term additional savings.

Staff Bid Evaluation:

As indicated above, Staff relies on and accepts the IA's finding that the RFP was conducted fairly and without bias for or against any Bidder. In addition, Staff does not dispute the Black Hills determinations of least cost PVRR results presented *2013 Wind Bid RFP Bid Evaluation Report, Table 2 – Bid Terms and PVRR*, nor does it dispute the bid information provided in *Table 3 PTC Wind Bid Summary*. In fact, the tables provided a starting point for Staff's evaluation of the bids.

It is important to understand that wind generation is primarily an energy resource, not a capacity resource. Considering that the typical wind resource in Colorado provides, on the average, about 12.5% of nameplate capacity during period of peak usage, the 29.75 MW acquisition under consideration in this proceeding will provide less than 4 MW of capacity. As a result, the evaluation of wind bids should include not only the estimated cost to the customer, but also should consider the amount of clean energy a project will produce and the term of the bid; whether the bid provides certainty long term, and whether the bid provide the additional benefit of location diversity; whether the bid furthers Black Hills' compliance with the RES; and last whether the bid provides other externality benefits such as additional emissions avoidance or a lower environmental footprint.

It is Staff's opinion that this evaluation can be narrowed down to the bids of the Black Hills non-regulated affiliate (BH-IPP) and the next least cost PVRR bid which is identified as Bidder A, 25 year PPA (A-PPA). The BH-IPP bid is the lowest PVRR bid and the A-PPA bid is the next lowest NPRR bid that has the attributes of high capacity factor, location diversity, and longer contract terms.

Energy Production

Critical in determining the value of a wind resource is its ability to generate clean energy and the associated Renewable Energy Credits (REC). The A-PPA bid is for delivery of 29.75 MW of wind generation with a capacity factor of 47.90%. The BH-IPP project is for delivery of 29.25 MW with a capacity factor of 32.97%. Effectively, the A-PPA bid is 48% larger than the BH-IPP bid. One could think of the BH-IPP as being able to produce an amount typically provided by a 20 MW facility in the better wind regimes in Colorado such as where the A-PPA project is sited.

The calculation of production from each of the two bids is a simple matter. The production is estimated as the nameplate capacity multiplied by the Capacity Factor multiplied by 8,760 hours (the number of hours in a year). The estimated production from the two bids follow:

Project Descriptor	Abrev.	Nameplate (MW)	Capacity Factor	Term (years)	Annual Production (MWh)	Contract Term Prod. (MWh)
Bidder A, 25 year PPA	(A-PPA)	29.75	47.9%	25	124,832	3,120,805
Bidder B, 20 year PPA	(BH-IPP)	29.25	32.97%	20	84,479	1,689,581

The above shows that the Bidder A, 25 year PPA (A-PPA) bid will produce roughly 48% more clean energy annually than the Bidder B, 20 year PPA (BH-IPP) bid. In addition, the A-PPA being 5 years longer provides certainty for capture of 85% more PTC wind generation than the BH-IPP bid.

Location Diversity

Most generation system planners believe that wind generation location diversity will lead to lower integration costs since geographic diverse wind facilities are unlikely to experience coincident wind patterns (e.g., coincident increases or decreases in wind, or weather fronts). Currently all of Black Hills wind is located at Busch Ranch which is Southeast of Pueblo. The non-regulated affiliate of the Company is proposing to expand this same wind property with its BH-IPP bid. The A-PPA bid is located in Northeastern Colorado. Staff believes that bid A-PPA could decrease cost to ratepayers due to increased location diversity through lower renewable energy integration costs which include less gas generation cycling, less gas nomination penalties, less need for transmission upgrades, and less wind curtailment.

The Company's Wind and Solar Integration Study provided in the ERP proceeding clearly identified that by 2021, the Company will see increased system costs for renewable energy integration that could be mitigated by additional renewable energy injection points and transmission upgrades. Further the Western Wind and Solar Integration Study[1] used as a peer review study has cautioned against build out in single or same geographic location, and study findings include:

- Geographic diversity, extreme events and overall variability are mitigated when wind and solar generation is aggregated over a wide area.
- The spatial diversity here is relatively poor, and the incremental reserve requirement is higher.
- Aggregating diverse renewable resources over larger geographic areas reduces the overall variability of the renewables.

Bidder A provides the recommended location diversity that the BH-IPP bid fails to provide. Although the Company has a preference for the Busch Ranch development, the peer studies strongly suggest that increased transmission costs may be offset by lower integration costs attributable to location diversity.

Compliance with the RES

The Company has indicated in its current 2013 RES Compliance Plan that it will need to acquire additional renewable resources in order to comply with the RES beginning in 2016. As a result, it is important to understand that any wind generation acquired through this application will impact future wind acquisitions that will be required. Considering that the primary purpose of this expedited proceeding is to capture wind projects that can exploit the PTC, it is very shortsighted to consider only the relative customer impact of the two proposals. The A-PPA bid provides a 48% higher annual contribution of RECs for compliance with the RES as compared to the BH-IPP bid.

[1] Western Wind and Solar Integration Study, May 2010, Prepared for NREL by GE Energy, Prepared under Subcontract No. AAM-8-77557-01, Subcontract Report NREL/SR-550-47434, page 93, 248 and 331.

The PTC is available for ten years, starting at $22 per MWh in year one and escalates with the rate of inflation. All of the bidders presumably considered the PTC in developing their wind proposals. Considering that there is no certainty at all that the PTC will be further extended, it is reasonable to assume that the next tranche of wind bids will be offered at significantly higher cost. It is important to realize that the A-PPA bid will provide 85% more production using PTC priced wind than the BH-IPP proposal.

Avoided Emissions:

Since every MWh of wind generation displaces a MWH of gas-fired generation, it should be obvious that high capacity factor wind resources reduce green-house gas emission more than lower capacity resources. Since the average modern combined-cycle gas generation produces approximately 0.4 tons of carbon dioxide (CO_2) for every MWh generated, one can calculate roughly the amount of CO_2 emissions avoided for each of the bids. The A-PPA bid will avoid approximately 50,000 tons of CO_2 each year. The BH-IPP bid will avoid approximately 34,000 tons of CO_2 each year. The A-PPA bid will avoid approximately 1,248,000 tons of CO_2 over the life of the contract. The BH-IPP bid will avoid approximately 676,000 tons of CO_2 over the life of the contract.

Environmental Impact

High capacity factor wind energy resources provide for high-density wind production. The higher annual production per MW installed, the lower the number of wind generation turbines required. This reduces the amount of land required for wind turbines and number of construction deployments. To provide a means of comparison, the same production of energy from 120 MW of wind located at Busch Ranch could be provided by roughly 80 MW of wind located in areas such as that proposed for the A-PPA bid. Simply stated wind generation located where capacity factors near 50% can be achieved requires a 50% smaller environmental footprint and should be valued accordingly.

Conclusion & Recommendation

Staff does not dispute that the PVRR over a twenty year period for the Bidder A 25 year PPA is $4.98 million higher than the Black Hills non-regulated affiliate bid to expand Busch Ranch, but the A-PPA bids offers the additional benefits of 48% higher annual energy production, 48% higher annual contribution toward RES compliance, 48% higher annual CO2 avoidance, 85% higher benefits over the term of the contract, location diversity, and a smaller environmental impact. These additional benefits far outweigh the *de minimis* difference in PVRR. A summary of the PVRR and the other factors considered by Staff are provided as Appendix A.

Staff recommends that the Commission order Black Hills to proceed with negotiations for a final contract for the Bidder A, 25 year PPA.

2013 American Tax Relief Act (ATRA) Wind Bids		
	Bidder A 25 Year PPA	BH-IPP Busch Ranch II
MW	29.75	29.25
Capacity Factor	47.90%	32.97%
Contract Term (Years)	25	20
20 Year PVRR (millions)	$2,007.64	$2,002.66
Contract Expected RECs	3,120,805	1,689,581
Production Tax Credit Benefit - Contract	$ 30,767,939	$20,821,918
Annual REC per MW Installed	4,196	2,888
Annual RECs for Compliance	124,832	84,479
Contract RECs for Compliance	3,120,805	1,689,581
Avoided CO2 Emissions (1)		
Annual (lbs CO2)	49,933	33,792
Annual CO2/Tons	58,359	39,494
Contract CO2/Tons	1,248,322	675,832
Project Location	NE Colorado	Busch Ranch
Developer Wind Portfolio (MW)	3,900	30

(1) Emissions calculated based on modern combustion turbine which produces roughly 0.4 tons of CO_2 for every MWh generated

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

PROCEEDING NO. 13A-0407E

IN THE MATTER OF THE APPLICATION OF BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP. FOR APPROVAL OF WIND SOLICITATION

THE COLORADO OFFICE OF CONSUMER COUNSEL'S COMMENTS ON THE FINAL REPORT OF THE INDEPENDENT EVALUATOR
(Public Version)

Pursuant to Decision No. R13-0830-I, the Colorado Office of Consumer Counsel ("OCC") submits its comments on the Final Report of the Independent Evaluator ("IE's Report").

The Commission and the parties selected Accion Group, Inc. to serve as the Independent Evaluator ("IE") for the Black Hills/Colorado Electric Utility Company, LP ("Black Hills") 2013 Request for Proposals ("RFP") for 30 MW of wind power. The IE submitted its Report on August 13, 2013. The OCC's comments regarding the report are provided below. The OCC also provided testimony in this proceeding on August 16, 2013, which also addresses some aspects of the IE's Report.

The OCC cited many problems with the Black Hills solicitation in its testimony. These include the small 30 MW size of the bid, the initial $10,000 bid fee, and the stated preference for an existing LGIA. Black Hills also failed to initially explain their net economic benefits charge, proposed to use a 10-year evaluation period, and then ignored this when the bid from the Black Hills affiliate didn't meet the requirement. The OCC appreciates the IE's efforts to survey potential bidders who decided not to submit a bid on why they did not submit a bid. The result was that some bidders believed that the RFP was rigged to be won by a Black Hills affiliate. The

IE acknowledged this on page 29, "There exists a perception on the part of some that the result of the RFP was predetermined, and the Affiliate would be deemed the winner." The result was a low response – initially only two bidders submitted, but on the second round a total of three bidders participated.

It is therefore surprising that the IE gave the Black Hills RFP a glowing recommendation. The IE report on p. 28 states, "We believe the Company conducted the RFP fairly and without bias towards or against any Bidder or type of generation acceptable under the terms of the 2013 Wind RFP. We are satisfied that Black Hills adhered to the established RFP protocols and consistently demonstrated its commitment to a fair and objective process." There is not even a hint of qualification in the IE overall conclusion. This is surprising given that the IE report provides three pages of reported problems with the RFP. Our only explanation is that the problems started prior to the IE's entry into the process.

That is, it appears that Black Hills decided on the 30 MW size, the $10,000 bid fee, the LGIA preference, and the net economic benefits test prior to IE's involvement. The IE appears to be saying that once all those bad decisions had been made, that Black Hills RFP was run fairly. The IE hints at the same frustration that everyone has: that Black Hills limited the RFP to 30 MW instead of taking the maximum amount of capacity that it could in order to take advantage of the Production Tax Credit (PTC) before it expires at the end of 2013 and before the 1.25 times multiplier for Renewable Energy Credits (RECs) for wind expires on January 1, 2015 pursuant to Senate Bill 252. The IE's evaluation appears to be focused on modeling and analysis of the bids and not of the issues that lead to the perception of a rigged bid, the poor response, the high costs of bids and the low number of RECs obtained.

Black Hills Shortage of RECs and Another Potential 30 MW Solicitation

The IE makes an insightful comment, but it provides only a hint of what might be forthcoming. Page 16 of the IE's Report states, "Given Black Hill's projected shortage of RECs, it is expected that additional renewable procurement will need to take place in the near future. With the expiration of the Federal PTC program, future bids may be substantially higher than bids that reflect the receipt of the PTC." It appears that Black Hills current 30 MW RFP will provide only sufficient RECs to meet Black Hills RES requirement through 2015 with banking and the 1.25 multiplier. As the IE hints, Black Hills will likely not meet their 2016 RES requirement. Thus, Black Hills may be setting themselves up for another 30 MW solicitation in a couple of years. If Black Hills does issue another 30 MW solicitation, it is likely to have a similar response and problems as this RFP.

Regulation Charges

The IE addresses regulation charges starting on page 23 of the IE's report. It appears that the IE worked with Black Hills to develop the regulation charges. These regulation charges appear to be developed by reading the tariffs. The IE's Report states on page 24, "Whenever regulation services are provided by an outside entity, there must also be in place a transmission service contract with that entity." This interpretation appears to be the crux of the issue.

First, the IE should have required Black Hills to provide the imputed transmission and regulation charges (or schedules) to potential bidders before the bids were due. This would have allowed potential bidders to have known in advance what regulation charges Black Hills would add onto their bid. Potential bidders should also have known in advance what regulation charges were going to be assessed to their key competitor, Black Hills IPP, which is directly connected to the Black Hills transmission system. This would have provided potential bidders with more information with which to make the best bid that they could.

If the IE had required Black Hills to spell out regulation charges in advance, not only would bidders have been better able to address them, but parties such as the OCC and Staff could have provided early feedback as well. Instead, this was an issue that came up at the last minute when there was not time to resolve it. This issue didn't come up until the release of Black Hills bid evaluation report on August 2, 2013. There was time for only one discovery request to address this prior to the time when testimony was due. This issue should have been resolved long before the bids were submitted. Instead OCC was scrambling to gain an understanding of this complex issue.

The table below summarizes the transmission charges and the regulation charges assessed on the bids that were received.[1]

	Transmission from Developer	Black Hills Regulation Adder (with PSCo Transmission)
Bidder A	$13.29	$8.88
Black Hills IPP	$0.00	$12.92
Bidder C	$12.07	$9.37

The fact that the regulation charges that Black Hills assigned to Bidders A and C are nearly the same magnitude as their transmission charge should have thrown up red flags for everybody, particularly the IE. A cursory review of the transmission and regulation tariffs shows that regulation should cost only a small fraction of transmission costs.

[1] Regulation charges are from Appendix 3 of the IE's Report. Both transmission and regulation charges are shown in Table 4 of the Black Hills 2013 Wind Bid RFP Wind Evaluation Report, August 2, 2013.

This is a complex issue. But, the IE appears to have tried to interpret this only by reading the tariffs and business practices. The IE's report does not provide any indication that they independently contacted anybody at Public Service or Western Area Power Authority (Western) in order to understand the regulation charges.

OCC attempted to investigate this issue with Public Service before filing its Answer Testimony. OCC received a call back from Robert (Bob) Stanton, PSCo's control center manager, on Friday morning, August 16 with testimony due at noon.   He said that OCC was correct that if wind originates in Western's balancing area, then Western needs to provide regulation. Western is generally Tri-State's balancing authority and provides regulation when Tri-State provides transmission. He said that the other option is BASOT which will be discussed below.

OCC also received a call back from Gerry Stellern, Public Service transmission planning manager, on Tuesday, August 20th. Mr. Stellern stated that regulation can certainly be provided without transmission. He said that Black Hills is the best example because Public Service provides regulation service to Black Hills but does not charge them for transmission. BASOT is one term used for this, but Balancing Authority Ancillary Services is the term used in the Public Service transmission tariffs. This is ancillary services provided to entities who are in Public Service's balancing authority but who do not take transmission service from them, like Black Hills.

Balancing Authority Ancillary Services are discussed in Section IV starting on page 86 of Public Service's Open Access Transmission Tariffs available at http://www.xcelenergy.com/staticfiles/xe/Corporate/OATT%5b1%5d.pdf. Page 101 of this tariff states:

> "Service by Public Service Company of Colorado: The Transmission Customer ***or*** [Balancing Authority] Ancillary Service Customer shall purchase Regulation and Frequency Response Service in the following amounts:" (Emphasis added).

And then it lists the prices for regulation service. The "or" in the above statement indicates that services are indeed provided to those who do not take transmission service from Public Service, such as Black Hills or the wind bidders.

[redacted]

There has not been time for the OCC to fully resolve this complex issue of regulation charges. But, it appears that the approach used by Black Hills and the IE of charging twice for transmission is not correct.

Access to the IE

Due to Commission Rule 3612(d), the OCC had essentially no access to IE. The Rule states that "[a]ll parties to the resource plan other than the utility are restricted from initiating contacts with the independent evaluator. Therefore the OCC was not allowed to email or phone the IE to raise and discuss problems and concerns or to suggest that the IE investigate certain aspects of the RFP. On the two occasions that the OCC met with the IE in person (meetings were initiated by the IE), the IE appeared to welcome comments from the OCC. But once the IE left the room, the OCC was not allowed to email or phone the IE with comments. The OCC would have more confidence in the IE's independence, analysis and conclusions if the OCC had been able to work with the IE throughout the bid evaluation. To the contrary, Black Hill was not restricted from initiating contact with the IE and therefore the IE was only able to get the perspective of the utility. The OCC recommends that in the future, the OCC have full access to the IE.

Comments by Chris Neil, Rate/Financial Analyst for the OCC.

Respectfully submitted this 23rd day of August 2013.

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CERTIFICATE OF SERVICE
13A-0407E

This is to certify that on this 23rd day of August 2013, I have filed **THE COLORADO OFFICE OF CONSUMER COUNSEL'S COMMENTS ON THE FINAL REPORT OF THE INDEPENDENT EVALUATOR (public version)** via the Commission's E-Filing system to the following:

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Tuesday, August 27, 2013

Lessons learned evident with ERCOT heat wave

ANALYSIS A combination of lessons learned, better weather and conservation measures helped the Electric Reliability Council of Texas power through a heat wave earlier this summer that at one point threatened to set a new peak demand record, market participants said.

Some ERCOT observers said participants appear to be shifting from real-time deals into the day-ahead market to avoid the volatility of price spikes. Real-time prices surpassed the day-ahead in 2011, but that trend shifted this year as real-time prices remained steady and below the day-ahead market as the heat wave struck.

ERCOT system load reached 67,180 MW on August 7, 2013, setting the highest demand peak so far in 2013. While demand was high with temperatures in the 90s to low 100s across the state

(continued on page 13)

Capacity markets facing challenges: FERC staff

MARKETS Capacity markets operated by independent system operators in the East are facing new challenges in light of changing state and federal policies as well as an evolving resource mix, staff at the Federal Energy Regulatory Commission said in a report Friday.

The report also outlines a number of possible steps ISOs could take to address emerging issues, including creating new, more granular definitions for the types of capacity products in those markets. The report came in advance of a FERC technical conference scheduled for September on capacity markets in ISO New England, New York Independent System Operator and PJM Interconnection, which is expected to include plenty of discussion over these issues.

(continued on page 14)

BC Hydro details plans to meet rising demand

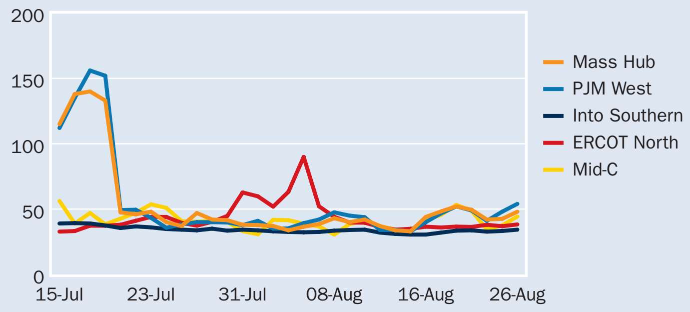
SUPPLY BC Hydro plans to build a 1,100-MW dam, increase capacity at two existing hydroelectric facilities by about 800-MW and buy power off the wholesale market to meet rising demand, according to the utility's draft integrated resource plan.

BC Hydro, which serves nearly all of British Columbia, sees little potential in exporting renewable and clean power to the US, according to the draft IRP, released Friday. BC Hydro estimates that average spot power prices will range from about $25/MWh to $40/MWh at the Mid-Columbia trading hub over the next two decades.

Also, potential renewable exports face competition from less expensive resources in the US, the draft IRP said. "BC Hydro concludes ... that there are no suitable market opportunities that warrant the development of new, additional clean or renewable resources for the purpose of exporting electricity for the

(continued on page 16)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Aug 27 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	50.50	56.46	27.76	29.29
NYISO	40.71	58.38	27.06	33.12
PJM	43.71	51.95	24.50	26.44
MISO	52.60	63.69	22.62	26.79
ERCOT	37.12	48.52	22.87	23.01
CAISO	48.43	52.02	33.14	34.89

Note: Lows and highs for each ISO are for various hubs and zones. A full listing of average LMPs are availible for the hubs and zones inside this issue.

Day-ahead bilateral indexes and spark spreads for Aug 27

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	48.00	12698	21.54	17.76	10.20	2.64	-8.70
N.Y. Zone-A	44.00	12506	19.37	15.85	8.82	1.78	-8.78
PJM/MISO							
PJM West	54.00	15820	30.11	26.69	19.87	13.04	2.80
Indiana Hub	54.00	14714	28.31	24.64	17.30	9.96	-1.05
Southeast & Central							
Southern, Into	34.25	9689	9.51	5.97	-1.10	-8.17	-18.78
ERCOT, North	38.27	11005	13.93	10.45	3.50	-3.46	-13.89
West							
Mid-C	44.27	13436	21.21	17.91	11.32	4.73	-5.16
SP15	50.75	13606	24.64	20.91	13.45	5.99	-5.20

Note: All indexes are on-peak. Spark spreads are reported in ($) and Marginal heat rates in (Btu/kWh). A full listing of bilateral indexes and marginal heat rates are inside this issue.

Inside this Issue

NEWS

Bias claimed in Black Hills Energy solicitation

Black Hills Energy's wind solicitation may have been slanted toward a utility affiliate that was selected to build a 30-MW wind farm in Colorado, according to a group of independent power producers and the state's ratepayer advocate.

Further, Colorado Public Service Commission staff believes another bidder provided the best offer, and the PUC should direct Black Hills to negotiate a power purchase agreement with that bidder, staff said in comments filed Friday. That bidder's name and terms of the proposal are confidential.

Black Hills issued its request for proposals for up to 30 MW of wind in early May to take advantage of the federal production tax credit. Thirty five parties registered to bid, but only two, including Black Hills IPP, made offers at the June 14 deadline. The utility extended the deadline to mid-July and received four more offers.

Earlier this month, Black Hills asked the PUC for permission to pay $33.25/MWh to Black Hills IPP under a 20-year PPA that includes a 2.5% annual price escalator. Two PPAs that were not accepted ranged from $26.95/MWh to $40.30/MWh, Black Hills said. The winning proposal had the highest score in economic and noneconomic analyses, the utility said. The Black Hills IPP offer was the only proposal that had a large generation interconnection agreement in place, according to the utility.

The proposal would expand the existing 29-MW Busch Ranch wind farm about 30 miles south of Pueblo. The project is jointly owned by the utility and AltaGas Renewable Energy Colorado.

Accion Group, the independent evaluator for the RFP, said that Black Hills "conducted a fair RFP and that it acted appropriately when evaluating bids," in an August 13 report to the PUC.

However, based on a survey of registered bidders, Accion Group said that some potential bidders thought the solicitation was biased. "A recurring theme heard by the IE was that, notwithstanding efforts to make the RFP attractive to bidders, Black Hills' affiliate had an insurmountable advantage," Accion Group said.

Black Hills IPP had a site advantage over other bidders, Accion Group said. "The IE is unable to ignore the reality of the situation where one site – Busch Ranch – had an advantage because of the ability to directly connect to the Black Hills transmission system, while supplies from other sites would incur the cost of wheeling," Accion Group said. "As with real estate sales, location is everything when it comes to siting, and location was a significant factor with this RFP."

The results of the RFP may stifle future solicitations, according to the Colorado Independent Energy Association. "The actions of BHE in selecting its affiliate's project may lead to continued reduced interest in future BHE RFPs; and as a result BHE ratepayers will see reduced benefits of competition in terms of pricing and risk allocation," the IPP trade association said in comments filed Friday with the PUC.

CIEA contends that project risk from the wind farm will flow to the utility's parent company, Black Hills Corp. "For BHE customers, all risk and liability, and all construction, operation, fuel, hedging, consumer rates and risks flow to the same upstream parent company," CIEA said.

The Colorado Office of Consumer Counsel, which believes the PUC should reject the RFP results, believes Accion Group's report may have missed key issues. "The IE's evaluation appears to be focused on modeling and analysis of the bids and not of the issues that lead to the perception of a rigged bid, the poor response, the high costs of bids and the low number of [renewable energy credits] obtained," the ratepayer watchdog agency said Friday.

Despite interconnecting directly to Black Hills' system, PUC staff believes that another bid presents a better offer and should be pursued, partly because it provides greater geographic diversity, according to Friday comments. The other offer is connected to a planned wind farm in northeast Colorado with a 48% capacity factor, compared with a 33% capacity factor for the Busch Ranch project, staff said.

Also, under the Black Hills proposal, it will need to acquire additional wind generation in 2016 to meet Colorado's renewable energy standard, which climbs to 30% by 2020. "Black Hills will need to acquire additional wind generation in the future to comply with the [RES], and future wind projects may not enjoy the benefit of a production tax credit," staff said. "As a result, Black Hills should take advantage of the bid that provides the highest production at a reasonable cost."

Colorado limits resource acquisitions outside of a utility's resource planning process to 30 MW. However, Black Hills received low-cost offers for more than 30 MW and would be willing to consider them if the PUC agreed that they should be explored, the utility said. CIEA is urging the PUC to consider directing the utility to review the larger offers.

— Ethan Howland

FPL details reasons for pursuing nuclear units

The fuel diversity and fuel-cost savings that two new nuclear units would provide make it very likely Florida Power & Light will commit to building Turkey Point units 6 and 7 soon after the Nuclear Regulatory Commission issues combined construction and operation licenses in late 2014 or early 2015, Florida Power & Light said Monday.

Peter Robbins, FPL's nuclear spokesman, said all the considerations that will be part of the utility's ultimately decision whether to build the two-unit, 2,200-MW project point toward proceeding with the project, which is expected to cost between $12 billion and $18 billion.

Among other things, Robbins said, FPL expects to need new baseload capacity the nuclear units would provide by the early 2020s. Also, the units would provide needed diversity to FPL's generation fleet, which has become increasingly dependent on natural gas-fired units in recent years and will become more so in coming years.

Further, the spokesman said, FPL's very conservative estimates for natural gas and nuclear fuel prices suggest that utility customers

CERTIFICATE OF SERVICE

I hereby certify that I caused to be served the foregoing ***Troutdale Energy Center's Comments Regarding Grays Harbor Energy, LLC's Request for Investigation*** in UM 1535 via electronic mail and, where paper service is not waived, via postage-paid first class mail upon the following parties of record:

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Dated in Portland, Oregon, this 29th day of August 2013.

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