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September 16, 2013

Via Electronic Filing and U.S. Mail
Oregon Public Utility Commission
Attention Filing Center:
PO Box 1088
Salem, OR 97308-1088

RE: UM 1535 - AMENDED RESPONSE OF PORTLAND GENERAL ELECTRIC COMPANY

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and three copies of the **Amended Response of Portland General Electric Company** to Grays Harbor's Request for an Investigation. As indicated in PGE's Response to Grays Harbor's Objection, filed earlier today, PGE is filing this amended response to release information previously marked as confidential.

Please note that portions of PGE's Amended Response and Attachment F to the Response are confidential and subject to General Protective Order No. 11-097. Confidential portions of the Amended Response and Attachment F are being provided in a separately sealed envelope bearing the legend "CONFIDENTIAL."

This letter and the enclosed filing are being filed by electronic mail with the Filing Center and provided by electronic mail to all the parties on the UM 1535 service list.

Thank you in advance for your assistance.

Sincerely,

Douglas C. Tingey
Associate General Counsel

DCT: qal
Enclosures
cc: UM 1535 Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1535

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for Proposals for Capacity & Baseload Energy Resources	***AMENDED* RESPONSE OF PORTLAND GENERAL ELECTRIC TO GRAYS HARBOR REQUEST**

Portland General Electric Company ("PGE") requests that the Public Utility Commission of Oregon (Commission) deny the Request for Investigation ("Request for Investigation") of Grays Harbor Energy, LLC ("Grays Harbor") filed in UM 1535 on August 5, 2013 (Request).

Over the past three years PGE with the guidance of the Commission and participation of the stakeholders has engaged in a rigorous public process and an extensive review of PGE's RFPs. The Commission retained an Independent Evaluator (IE) and adopted safeguards to ensure the RFPS were designed and conducted fairly and that they provided no undue advantage to any bidder, including PGE. Under the auspices of impropriety, Grays Harbor is asking for an investigation. The allegations are shown false by publicly available information and further refuted when looking at the confidential information. There is therefore no need for further investigation. The Commission should re-affirm the integrity of this competitive bidding process that was carefully designed, extensively reviewed and monitored to ensure that the least cost, least risk resources were selected for PGE's customers.

The main issues raised by Grays Harbor in its Request for Investigation were previously considered by the Commission in UM 1535 and resolved in Order No. 12-215 (June 7, 2012). In addition, these allegations are similar to those raised in DR 46, filed by Troutdale Energy

Center, LLC ("TEC"). As PGE previously explained in its Reply to Northwest and Intermountain Power Producers Coalition (NIPPC) (February 22, 2013) and in its Reply to TEC's DR 46, the allegations are false. Without providing any evidence, Grays Harbor accuses PGE of a "possible campaign of intentional or unintentional misinformation toward the Commission and the RFP independent evaluator ("IE"), as well as potential misconduct relating to the CCTP transmission assumptions that may have been crucial to bid evaluation." *Request for Investigation* at 2. These brash allegations are baseless.[1] In this response, PGE will address them one more time for the record.

PGE Complied with the Commission's Competitive Bidding Guidelines

In connection with the RFP and bid evaluation (1) PGE's transmission assumptions were transparent, consistent and fully disclosed to the IE, Staff, Stakeholders and bidders; (2) The record developed in this proceedings (including part of the record that was submitted under the General Protective Order No 11-097 (Protective Order) issued by the Administrative Law Judge in this docket) demonstrates that PGE's scoring was consistent and accurately reflected the status of transmission for all bids, including bids submitted to utilize the Carty and Port Westward

[1] PGE notes that Grays Harbor, a bidder, is represented by the firm Davison Van Cleve, P.C., the same firm that also represents non-bidder Industrial Customers of Northwest Utilities ("ICNU") in this same docket. ICNU's counsel previously signed the Protective Order in this matter, agreed to be bound by its confidentiality requirements, and as a non-bidder signatory of the Protective Order, ICNU's counsel had access to confidential information not available to bidders. (UM 1535 Protective Order, Order No. 11 097, entered March 25, 2011; ICNU Protective Order signature page filed June 6, 2011. Two years later, in July 2013, ICNU's attorneys appeared on behalf of Grays Harbor in DR 46. PGE expressed concern that counsel was a signatory on the Protective Order with access to confidential non-bidder information, and therefore questioned the propriety of representing a bidder in DR 46. PGE's concern prompted Ms. Davison, Mr. Van Cleve and others from their firm, to remove their names from the Protective Order in UM 1535. (Letter and Protective Order signature page filed July 3, 2013.) With Grays Harbor's recent request for an investigation in UM 1535, the Davison Van Cleve firm now represents both a bidder and a non-bidder in the same matter, in which they previously signed the PUC Protective Order allowing them access to confidential information only available to non-bidders. Regardless of whether they have accessed the confidential non-bidder information over the past two years, their dual representation, together with agreeing to the protective order regarding confidential bidder information may raise the appearance of impropriety and may call into question the integrity of the RFP process.

sites; (3) Grays Harbor has selectively taken information out of context (ignoring information already in UM 1535 that shows otherwise) to weave a dark fairy tale of malfeasance that cannot withstand scrutiny; and (4) the investigation Grays Harbor requests is unnecessary because (a) the information that disproves these allegations is already available to the IE, Staff, and the Commission, (and could have been obtained by any stakeholder who signed the Protective Orders) and (b) additional review by the Commission and stakeholders will occur in the rate making process.

LEGAL STANDARD

The Commission has discretion under ORS 756.515 to initiate "an investigation of any matter relating to any public utility." Despite the Commission's broad authority, there is no precedent for the investigation requested by Grays Harbor which seeks to re-open a completed RFP. None of the cases cited by Grays Harbor re-opened a completed RFP. *Request for Investigation* at 12, 25, 28 (*citing* Re OPUC, Docket No. UM 1452, Order No. 10-304 (Aug. 9, 2010) (Commission investigated its own authority to impose price caps on a competitive bid option, concluding that Commission's price cap should be rescinded because it likely infringed on FERC's exclusive authority, resulting in the re-issue and extension of a pending RFP); Re Juniper, Docket No. UW 58, Order No. 98-177, 1998 Ore. PUC LEXIS 93 (Apr. 27, 1998) (Commission opened investigation to determine if utility was subject to jurisdiction and whether rates charged were unreasonable or unjustly discriminatory); Re US West, Docket No. UM 833, Order No. 97-043, 1997 Ore. PUC LEXIS 118 (Feb. 10, 1997) (Commission initiated investigation in response to utility's continued practice of imposing special construction charges in violation of four previous cease and desist orders)). Nor do the Commission's competitive bidding guidelines provide for such a post-hoc challenge by a non-winning bidder.

I. PGE's transmission assumptions were transparent

A. Cascade Crossing Transmission Project (CCTP)

PGE's Cascade Crossing Transmission Project team engaged Commission Staff and kept Staff and the Commission updated as they explored the Cascade Crossing Transmission Project (See Attachment A which was previously included in PGE's response to DR 46). Also, as required by the Commission in Order 10-457[2], which acknowledged PGE's 2009 Integrated Resource Plan ("IRP"), PGE provided updates on Cascade Crossing in the 2011 and 2012 updates to the 2009 IRP. Grays Harbor's accusation that PGE was "misleading the Commission about the status of CCTP throughout much of the RFP process" (*Request* at 7) is baseless.

In PGE's RFP for Power Supply Resources (Final Combined RFP), PGE acknowledged the constraints on transmission in the Northwest and notified bidders that the risks of each proposal would be updated based on developments in the transmission planning processes of the Bonneville Power Administration (BPA) and CCTP. The RFP stated that "The Pacific Northwest (PNW) transmission system currently has numerous constraints that can limit the firm delivery of power products for extended periods of time. The scoring process for this RFP assumes continuation of the status quo; however, PGE retains the right to adjust the delivery risk of each proposal based upon the progress of BPA's network open season process and the development of the proposed Cascade Crossing transmission line." *Final RFP* at 31.

[2] Order 10-457 at 20. The Commission stated "However, when developing an IRP, we always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages. We make this updating requirement explicit for the Cascade Crossing project because of the current uncertainty regarding equity participation and other key factors. We expect PGE to provide a thorough update of the Cascade Crossing benefit-cost analysis in its next IRP, with the understanding that Commission acknowledgment of the Company's next IRP will depend on the outcome of that updated analysis."

Grays Harbor's allegation that "PGE may have biased the RFP evaluation by improperly factoring less transmission risk for any own and operate resource option" (*Request* at 15) inverts the allegation NIPPC made even before the final RFP was issued. *See NIPPC Comments* at 16-18 (Feb. 22, 2012) (requesting that costs of Cascade Crossing be imputed to any bid using the Carty site). PGE's benchmark team actively pursued all commercially viable options to secure firm transmission rights for its Carty site. PGE's transmission options for the Carty site were fully disclosed during the RFP. As PGE's Reply Comments in UM 1535 explained:

> Indeed, PGE has submitted to BPA an interconnection request and a transmission service request sufficient to meet the needs of our proposed Carty energy facility. In other words, BPA transmission can be used to deliver energy from the proposed Carty benchmark resource. Therefore, the Cascade Crossing project is not the only transmission option.

PGE Reply Comments at 16 (Mar. 7, 2012). Thus, as early as March 2012, PGE had disclosed to everyone that it was pursuing dual transmission options in order to secure the best transmission rights for the Carty site.

PGE here addresses Grays Harbor's allegation that the timing of the announcement of the Memorandum of Understanding (MOU) between PGE and BPA "...strongly implicate PGE in a possible campaign of intentional or unintentional misinformation toward the Commission and the RFP Independent Evaluator ("IE"), as well as potential misconduct relating to the CCTP transmission assumptions that may have been crucial to bid evaluation." *Request for Investigation* at 2. There is no merit to this allegation. From the beginning and throughout its planning process, CCTP was proposed as an alternative to BPA's system. The MOU between PGE and BPA, which was entered into five months after the final short list was issued, had no role or impact to the RFP scoring or results, just like Cascade Crossing did not. In any event, if

PGE and BPA reach an agreement pursuant to the MOU, PGE will need to show that such agreement provides a better alternative on price and risk than the current BPA tariff. More importantly, the MOU's announcement did not impact scoring, nor did the Carty bid rely on CCTP or the MOU for firm transmission to PGE load, as further discussed below.

Because PGE's dual path to secure transmission was fully disclosed, Grays Harbor's suggestion that it "discovered through review of the Company's transmission service requests ("TSR") filed with BPA, PGE became very active beginning in 2010 and continuing through June 2013, requesting transmission capacity in BPA's system in an apparent attempt to possibly circumvent the need for the CCTP" (*Request* at 7) is disingenuous and disregards the record in UM 1535.

B. South of Allston

Grays Harbor's assertions regarding the South of Allston transmission project are similarly unfounded. Grays Harbor incorrectly asserts that if "The South of Allston transmission project was not built" that "Port Westward II ... [would] face a similar north to south transmission constraints as Grays Harbor." *Request for Investigation* at 8.

Grays Harbor, again, ignores the record in UM 1535. In PGE's Reply Comments from March 7, 2012, PGE explained:

> PGE does not need to make improvements to the South of Allston path to deliver energy from the Port Westward II benchmark resource. PGE included the South of Allston option in the IRP as a concept, not as a project that we were proposing to construct at this time. In describing this project, PGE stated, "At this point, this is a conceptual estimate" and indicated that "[w]e will provide the Commission an updated cost estimate and timeline in a future IRP filing as further studies and analysis are completed." 2009 IRP at 183-184. That the South of Allston project was conceptual is further demonstrated by the fact that it was not included in the IRP action plan.

PGE Reply Comments at 15.

PGE's Port Westward ("PWII") site bid did not rely on the construction of the South of Allston line for delivery of the energy from PWII on firm transmission. PGE PWII has firm transmission rights from BPA. The transmission for the PWII site is discussed at length in the IE Report and the IE concludes that "...we are pleased with both the process of the transmission evaluation for the transmission service request and for the accuracy of the findings." IE Report at 20-22.

C. The Commission has considered these arguments.

Grays Harbor offers no new information in its Request for Investigation. These same arguments were made by NIPPC and ultimately, the Commission ruled on them in Order No. 12-215. On the matter of allocation of transmission costs, the Commission stated:

> The issue in this proceeding is to ensure the fairness of the bidding process. PGE's claim that it does not need to build new transmission resources leaves its benchmark resources in the same position as the other possible resources proposed at the same (or nearby) sites with respect to transmission. This claim is consistent with PGE's IRP and this position does not affect the level playing field.
>
> At the June 5, 2012 Public Meeting it was made clear that the alternative to PGE's self-build transmission is the same for all parties - access to the Bonneville Power Administration's transmission system. Thus, the bid evaluation will be based on the same transmission costs for all similarly situated potential bidders.
>
> In its May 29, 2012 Staff Report, attached as Appendix A, Staff recommended the Commission approve the draft RFP with the condition that PGE provide additional information to the IE regarding the company's transmission assumptions. Given our disposition of this issue, the additional information is not required.

Order No. 12-215 at 3. Grays Harbor raises nothing new or materially different than the transmission issues previously raised in this docket by parties, and resolved by the Commission.

II. Confidential information available to the IE, Staff and Stakeholders support PGE's treatment of transmission for both sites as consistent with the guidelines and validates the Commission's ruling.

In addition to the disclosures made in UM 1535, PGE submitted, as part of the confidential information in its "technical specifications," information about the Carty site as well as the PWII site describing the transmission strategies. The information submitted included the following, which conclusively debunks Grays Harbor claims about the PGE's transmission assumptions:

For Carty Site:

Location in the IE website	File name	Attachment Number	Description
Carty Site Specification Documents	S-12-03-02_Carty_Transmission_Intercon n_Strategy_R0_Confidential_NDA 2	B	Document describing the dual approach to obtaining firm transmission from Carty Site to PGE Load
Carty Site Specification	S-12-03-05_Carty_Service_Agreement_fo r_NITS_R0_Confidential_NDA2	C	Transmission service request submitted to PGET for services on Cascade Crossing from Carty to PGE load
Carty Site Specification	S-12-03-06_Transmission_Reservation_74 611812_R0_Confidential_NDA2	D	Transmission service request submitted to BPAT for services on BPA system from Carty to PGE load for 450 MW
Carty Site Specification	S-12-03-07_Transmission_Reservation_76 829730_R0_Confidential_NDA2	E	Transmission service request submitted to BPAT for services on BPA system from Carty to PGE load for 50 MW
Bid Book/Bidder	102-6_Initial_Short_List_Notification_	F	Executed contract giving PGE the rights to step in EDPR[3] existing PTSA

[3]In the previous filing, this counterparty was mislabeled.

102/BidNumber06/d. Responses from seller/	Response_120512		for 475 MW of firm transmission on BPA transmission grid with automatic redirect rights.

The confidential information accessible to OPUC Staff, the IE, and stakeholders that signed the protective order is consistent with the publicly stated information in the IRP and the RFP process. PGE described in Attachment B, which was posted on the IE website as part of its technical specifications on April 26, 2012, prior to receipt of any bid, a strategy to pursue two (2) concurrent options to maintain queue positions in (a) CCTP (Attachment C) and (b) Bonneville Power Administration ("BPA") transmission process (Attachments D and E). This information contained in Attachments C, D, and E is confidential and proprietary information, and therefore was not available to any bidder.[4]

Further, during the timeframe afforded to all bidders to update their transmission information, the PGE Benchmark team submitted a fully executed agreement giving PGE the right to step into an existing Precedent Transmission Service Agreement (PTSA) and receive firm transmission rights on BPA transmission system from Carty to PGE Load (Confidential Attachment F). As a result, the final scores for bids utilizing the Carty site accurately reflect BPA transmission tariff costs and risks, based on existing firm contractual rights.

PGE's pursuit of multiple transmission options was a prudent business strategy that preserved the competitiveness of a site through a fast changing transmission landscape. PGE's strategy (which any other bidder could have employed) ultimately benefited customers.

[4] In this *Amended Response*, Attachments C, D, and E are no longer confidential.

For Port Westward II site:

Location in the IE website	File name	Attachment Number	Description
PWII Site Specification	S-10-03-00_Electric_Transmission_Interconnection_PW2_R0_Confidential_NDA2	Attachment G	Document describing the approach to obtaining firm transmission from PWII Site to PGE Load.
PWII Site Specification	S-10-03-01_PW2_BPA_PTP_14507_R0_Confidential_NDA2	Attachment H	Firm Point to Point transmission from Trojan to PGE load using existing BPA transmission rights
PWII Site Specification	S-10-03-05_PW2_NITS_46508_R0_Confidential_NDA2	Attachment I	Firm Transmission service rights from Trojan to PGE load using existing PGE transmission rights.

In Attachment G, submitted to the IE's website on April 26, 2012, prior to receipt of any bid, PGE described the transmission strategy for Port Westward II site as follows:

> PW2 capacity and energy will be dynamically delivered to PGE Load using Network Integration Transmission Service (NITS) capacity acquired under NITS Agreement No. 46508 between PGET and PGEM. In order to ensure sufficient NITS capability to deliver PW2 generation to load, PGEM will schedule its other resources interconnected at Trojan under its Bonneville Power Administration (BPAT) Long-term Firm Point-To-Point transmission service agreement No. 09TX- as necessary.

The final score for the PWII bid accurately reflected the Port Westward II transmission position with access to existing firm transmission rights. Existing firm transmission rights means that PWII is not subject to the challenges of a constrained I-5 corridor transmission path contrary to Grays Harbor's claims, nor is it dependent on the construction of the South of Alston transmission project.

III. Pricing assumptions used for scoring were transparent and accurate.

In its Request for Investigation, Grays Harbor makes many unsubstantiated allegations about improper pricing assumptions and concludes that "...An investigation is warranted now since it may uncover additional information related to improper CCTP and pricing assumptions which may well have led to a Company own and operate award which *did not* minimize resource cost and risk." (*Request* at 28). PGE's pricing assumptions were governed by the competitive bidding guidelines and were clearly defined in advance and consistently applied. General assumptions and scoring criteria were developed in conjunction with the IE (with the participation of stakeholders and bidders) and finalized prior to the receipt of bids. PGE then consistently applied these scoring criteria to all bids.

The IE independently validated the methodology PGE employed and determined the process was fair:

> The IE believes the evaluation of bids was conducted using the evaluation criteria and modeling agreed to by the IE, and was consistent with the outcome of the mock bid evaluation conducted before bids were received. The bids independently scored by the IE were easily reconciled with the scoring by PGE. The IE worked closely with PGE personnel in reviewing each bid and participated in the solicitation of additional information, as needed. In response to inquiries raised by certain bidders the IE conducted independent research and evaluation of the gas supply and transmission access available to bidders. When the short list was, finally, established, the IE agreed that the bids included represent the best value from all the bids received during the RFP process.
>
> The IE believes the RFP was conducted fairly, that all bidders were treated in the same manner and the resulting short list of bids is the product of the evaluation process that was developed by PGE with the participation of the IE being fairly employed. The IE believes the short list includes the bids that are the best value considering both price and non-price factors, from among all bids presented in the RFP.

Report of the Independent Evaluator at 38-39, OPUC Docket No. UM 1535 (Jan. 30, 2013).

With regard to the Carty bid, the IE stated: "The price and non-price scoring of the Carty Self-Build Project was performed using the models already developed by PGE that were finalized during the mock bid process. All base load energy bids were simulated using the AuroraXMP model to determine the appropriate dispatch costs and market value. These costs were combined with total fixed costs to calculate the real levelized $/MWh cost to market ratio." (*Id.* at 32).

Next PGE addresses Grays Harbor's wide-ranging claims of improper and inconsistent use of assumptions and scoring criteria in five broad categories:

A. Transmission assumptions of costs and risks associated with CCTP were not biased;
B. Assumptions of expected life of the asset and market price were appropriate;
C. There was no evidence of price uncertainty in the Company's announcements; and
D. Grays Harbor mischaracterizes the nature of transmission risks associated with the delivery of energy to customers.
E. Forward market pricing assumptions were available to bidders.

A. Transmission assumptions of costs and risks associated with CCTP were not biased.

In several places in its Request for Investigation, Grays Harbor claims that assumptions around CCTP may have biased the scoring in favor of the Carty site, for example:

> In considering CCTP as a part of the Company system for its own and operate bid, PGE may have biased the RFP evaluation by improperly factoring less transmission risk for any own and operate resource options.

Request for Investigation at 15.

> The figures and circumstances surrounding the RFP suggest that transmission scoring may have been seriously manipulated through use of CCTP in PGE's favor.

Request for Investigation at 18.

Contrary to Grays Harbor's unsubstantiated assertions, PGE did not "improperly factor[]less transmission risk for any own and operate resource options." (*Id.* at 15.) The scoring criteria did not assume that CCTP was built. Nor was there any consideration given to the overall benefit of CCTP had it been built. As a matter of fact, the RFP clearly stated that although Cascade Crossing is considered part of PGE's system, transmission risks would be updated based on new information.

> PGE retains the right to adjust the delivery risk of each proposal based upon the **progress of BPA's network open season** process and the **development of the proposed Cascade Crossing transmission line**." *Final Combined RFP* at 31 and repeated at 33 (emphasis added).

Therefore, Grays Harbor's assertion that PGE may have "biased the RFP evaluation by improperly factoring less transmission risk for any own and operate resource options" is not true. Further, as the confidential record included herein conclusively demonstrates, the final scoring for the Carty site included the matured transmission rights (existing BPA transmission) as submitted and were appropriately scored. Transmission scores on bids at Carty sites do not reflect any benefits nor risks associated with the proposed CCTP.

1. Transmission Price Scoring Assumptions

For clarity, PGE provided bidders with a list of the points of delivery that connect with various other transmission providers in the region. As part of that list, PGE identified Cascade Crossing as part of PGE's system. In addition, the RFP clearly stated that "Bid price scores will include all incremental costs to deliver, or sink, the energy from a scheduling POD on PGE's System to PGE's load." (*Id.* at 16). The distinction between "PGE load" and "PGE System" is well understood throughout the industry. PGE System is not the destination. The RFP made clear that the ultimate destination is "PGE's load" and therefore cost assumptions must reflect the cost of transmission to PGE load.

As instructed by the Commission in Order 12-215 (at page 3), PGE utilized BPA transmission service tariff rate for pricing for all bids (including all bids relying on CCTP), except those bids with projects directly interconnected to PGE load (which incurred no transmission service costs). Therefore, the statement that "Cascade Crossing is considered part of PGE's system" reflects the fact that interconnection onto CCTP is not interconnection to PGE load (i. e. the ultimate destination), rather it is only interconnection to PGE's system, and consequently the additional costs of transmission to PGE's load will be assessed. In other words, a bid submitted with an interconnection to CCTP was assessed the same transmission service tariff rate as a bid interconnecting to the BPA system. The concept of PGE's system was clear and consistently applied, and ensured that any project interconnected to CCTP could not gain an unfair advantage over those using BPA.

2. Transmission Non-Price Scoring

Grays Harbor also incorrectly speculates that the RFP evaluation "improperly factor[ed] less transmission risk for any own and operate resource options." *Request for Investigation* at 15. PGE's scoring took into consideration the transmission delivery risk as part of its non-price scoring criteria. The scoring criteria (see Attachment J) was disclosed to bidders as part of the RFP documents, and each bid was scored on its' individual progress toward obtaining a Large Generator Interconnection Agreement (LGIA) and an executed firm Transmission Service Agreement. The transmission delivery risk was assessed using information submitted by the bidder.

In total 95 Non-Price points (45 Non-Price points and 50 Non-Price points for transmission interconnection and transmission rights respectively) out of a possible 1,000 points (600 maximum Price Score and 400 maximum Non-Price Score) were allocated to transmission. These Non-Price scores for the transmission interconnection were assessed on a progressive scale based on the bid's status within the transmission planning process that the bidder identified.

For example, when allocating non-price score for a bid's interconnection status, a project which only has an interconnection request into BPA would not score as high as a project which has completed an interconnection facility study.

Similarly, the points associated with the transmission rights were allocated based on the bid's progression from submission of a valid transmission service request, which is the very first step to initiate the request for transmission service in the BPA process, to a fully executed transmission contract with the transmission provider. The points were consistently awarded to all bidders whether they were "owned and operated" or not.

B. Assumptions on expected life of the asset and market price were appropriate.

Grays Harbor alleges that PGE did not accurately score bids backed by existing resources. Although Grays Harbor offers no evidence in support of its allegation, it makes the following claim:

> Given PGE's complete silence on the interrelation of price scoring and asset life, questions must be asked about how the Company factored in asset life extensions for existing resources such as the Grays Harbor facility. Moreover, if PGE failed to properly evaluate (or evaluate at all) the actual run times and start figures for existing facilities, as appears to be the case, it would follow that the Company may also have unfairly handicapped existing resource bids in comparison to the future operational date of the Carty Plant. For example, retirement assumptions based simply on initial operation dates could have prejudiced the Company's evaluation, while maintenance provisions extending asset life may not have been factored in at all.

Request for Investigation at 9.

First, PGE has fully addressed the relation of price and asset life in the RFP. For instance, PGE describes the allocation of price factors as follows:

> The price score will be calculated as the ratio of the bid's projected total cost per MWh to forecast market prices using real-levelized or annuity methods (per Guideline 9a. of the Competitive Bidding Guidelines).

PGE's Final Combined Request for Proposal for Power Supply Resources at 29.

By clearly indicating that PGE was using a real levelized cost of energy, the scoring methodology by definition was based on the annuitized cost of the bid over the length of the life of the bid. Thus a "relation of price and asset life" exists. PGE was not silent about it. And as evidence that bidders, including Grays Harbor, fully understood that fact, all bidders that submitted Tolling Agreements or PPA clearly indicated the duration of each contract. In the case of projects offered for PGE ownership, PGE's expected life assumptions for combined cycle combustion turbines were consistent with the assumptions made in PGE's 2009 IRP as acknowledged by the Commission, which were thirty years from the commercial operation date.

Each bidder had the opportunity to include in its bid any "maintenance provisions extending asset life", and if included, such feature and the cost of the feature would have been evaluated in the bid scoring. It will be inconsistent with a competitive bidding process for PGE to assume facts that were not part of a bid and unilaterally extend the expected useful life of an asset, nor would PGE expect the IE and Commission to look favorably on this practice. And, as stated on page 10 of PGE's RFP "[t]he bids received will be evaluated and selected based on the information supplied by each Bidder in response to this RFP." PGE scored the bids based on the information bidders submitted. [redacted] The Competitive Bidding guidelines, and the previously IE-reviewed and accepted assumptions and methodology were consistently applied to all bids.

C. There was no evidence of price uncertainty in the Company's announcements

Grays Harbor asserts that:

> Calpine conclusively demonstrated a $76 to $91 million difference between what PGE and Abengoa have publicly disclosed as the costs of the Carty Plant. Docket No. DR 46, Comments of Calpine, Request for Investigation at 9. With such dramatic price uncertainty, coupled with the Company's possible long-acknowledged bias to self-select during the RFP process, an investigation seems abundantly merited. Simply put, pricing component issues raised specifically in relation to Grays Harbor bids could not have been accurately evaluated if confusion or indeterminacy existed over the actual pricing components of the Carty bid.

Request for Investigation at 11.

PGE followed the Commissions' guidance in providing the opportunity for third-parties to bid on the PGE-owned site. Order 11-371 at 6. As a result, PGE issued detailed technical specifications for bidders to bid an engineering, procurement and construction option on the Carty site. As such ABENGOA's contract only includes the cost of the scope of its work: procurement of the power-island, engineering, design and construction of the project. It did not include the cost of the scope of work identified as the responsibility of the owner (PGE) of the project: development costs, environmental mitigation, builder's risk insurance, permanent plant equipment and tools, and Allowance for Funds Used During Construction, just to name a few. What Calpine and Grays Harbor should have observed was that ABENGOA's press release spoke only to their scope of work and its cost, which is appropriately less than what PGE announced. PGE's press release spoke to the total cost of bringing the project on line for customers. The different numbers announced by PGE and ABENGOA were each accurate since they spoke to their respective scope of work, and not evidence of "dramatic price uncertainty", and Grays Harbor's suggestion to the contrary is meritless.

D. Grays Harbor mischaracterizes the nature of transmission risks associated with the delivery of energy to customers

In order to properly manage risks for customers, PGE in the RFP clearly spelled out the expectation of all bidders regarding transmission as a threshold issue. A bidder was required to submit a plan for firm transmission from its site to PGE load. Grays Harbor's score appropriately reflects the status of its submitted transmission plan, [redacted]

Grays Harbor notes that it shared with the IE a study it conducted ". . . finding that historical data indicated that energy from Grays Harbor would have reached PGE's system 99.71% of the time in 2012. Obviously, concerns related to I-5 Corridor upgrades should have been rendered moot (as they apparently were for Port Westward II)." *Request for Investigation* at 17. Grays Harbor seems to contend that a single year of data for 2012 should have "rendered moot" any transmission concerns, and suggests that PGE should have waived the threshold requirement for firm transmission service for Grays Harbor. As explained above, PGE did not waive or otherwise "render moot" transmission requirements for Port Westward II. Rather, PWII obtained firm transmission rights from BPA.

Grays Harbor's observation that, in 2012, 99.71% of the time energy from Grays Harbor would have reached PGE's system was cited by Grays Harbor as evidence that the I-5 Corridor constraint should be ignored. This contradicts years of study and statements by BPA identifying the I-5 Corridor as a constrained path. In fact, BPA has identified this path as constrained. (See Attachment K – BPA EIS). 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. Although PGE was not privy to the study Grays Harbor shared with the IE, PGE has monitored with a high level of interest and at times participated in the work BPA has undertaken in its study of the I-5 Corridor. The work identified to mitigate the constrain on the I-5 Corridor is neither cheap nor easy since it involves the permitting and construction of transmission assets through heavily populated areas. (See Attachment K – BPA EIS).

The fact that BPA has made significant investment in time and money to pursue upgrading this path is evidence of the gravity of the congestion. Contrary to Grays Harbor's claim that "concerns related to I-5 Corridor upgrades should have been rendered moot," PGE's threshold requirement for all bidders to submit a valid transmission plan was necessary. The RFP scoring accurately allocated non-price scores based on the bids progression towards obtaining firm transmission.

E. Forward market power forecast assumptions were available to bidders.

Grays Harbor contends that PGE failed to provide "details on market Power forecast assumptions . . . Consequently, it appears that no third party bidders were able to tailor their bids to reflect this indispensable component of RFP pricing evaluation." *Request for Investigation* at 8; *also id.* at 26-27. In PGE's 2009 IRP (and in the 2011 and 2012 updates), that was acknowledged by the Commission, PGE extensively discussed its power forecast assumptions. 2009 IRP Chap. 5 Fuels, at 75-91. Consistent with Guideline 9, PGE calculated the price score of each bid as the ratio of the bid's projected total cost per megawatt-hour to forward market prices.

IV. Grays Harbor's Request for an Investigation is Inappropriate.

The investigation requested by Grays Harbor is premature, contrary to the RFP process, and unwarranted as there is no evidence to support these unfounded accusations.

A. Grays Harbor's end-run around the RFP process should be denied.

Though the Commission has discretion to open an investigation, the RFP process does not provide disappointed bidders the right to contest the outcome. The Commission, Staff and stakeholders spent several years developing the guidelines for the RFP process. As the Commission recognized, the "competitive bidding guidelines require a robust and lengthy process that reflects the value of public input and review of a utility's resource procurement action. An integral part of those guidelines is the mandated use of an independent consultant - the IE – to help prepare the RFP and ensure that all bids are treated fairly." Order 13-056.

In addition, the final draft RFP that is under attack by Grays Harbor was approved by the Commission prior to release by PGE in Order 12-215 consistent with Competitive Bidding Guideline 7.

Here, the competitive bidding guidelines were followed, the Commission approved the draft final RFP, the IE played an integral role, and the result should be respected. The Competitive Bidding Guidelines do not provide an avenue for a non-winning bidder to challenge the completed process.

B. The scoring methodology was fully developed and refined with the broad participation of the IE, Staff, Stakeholders and bidders.

At a cost of nearly $800,000 to PGE's customers, the IE fully participated in the RFP process.[3] As the IE states at page 18 of its report "[i]n addition to the collaboration between the IE/PGE, the bidders and stakeholders also participated and provided feedback through the public process." The IE further elaborated about the process:

> One of the roles of the IE in this RFP is to ensure fair and appropriate evaluation of all Bids. Because of the complexity of the products sought in this RFP, the process of ensuring fairness and appropriateness began well before the RFP was ever issued.
>
> * * *
>
> Of primary importance to bidders, the IE and PGE personnel invested considerable time and effort to construct an evaluation model and process that was fair and thorough. *Final Report of the Independent Evaluator* at 12 and 38, respectively.

The RFP process was fully developed and fairly implemented. The elongation of the RFP via an investigation not contemplated by the RFP process would be wasteful.

C. All information for scoring was, and is, available.

All the information that was used for the scoring of bids was available to the IE, Staff and non-bidding intervenors, and remains available to the Commission in the custody of the IE. In a competition, competitors should not have access to each other's information.

D. The Final Short List bids represent the least cost low risk resources for customers.

The Competitive Bidding guidelines requires the IE to;

> … independently score the utility's Benchmark Resource … and all or a sample of the bids to determine whether the selections for the initial and final short-lists

[3] Cost estimate as of March 2013 filing in Docket UM 1532. Costs included are for both the combined energy and capacity RFP and the renewable RFP.

> are reasonable" when the IOU includes a benchmark resource. See RFP Guideline 10.d. The IE attested to the consistent evaluation of all bids. The IE believes the evaluation of bids was conducted using the evaluation criteria and modeling agreed to by the IE, and was consistent with the outcome of the mock bid evaluation conducted before bids were received. The bids independently scored by the IE were easily reconciled with the scoring by PGE. The IE worked closely with PGE personnel in reviewing each bid and participated in the solicitation of additional information, as needed. In response to inquiries raised by certain bidders the IE conducted independent research and evaluation of the gas supply and transmission access available to bidders. When the short list was, finally, established, the IE agreed that the bids included represent the best value from all the bids received during the RFP process.

Final Report of the Independent Evaluator at 38-39.

The IE goes on to say:

> The IE believes the RFP was conducted fairly, that all bidders were treated in the same manner and the resulting short list of bids is the product of the evaluation process that was developed by PGE with the participation of the IE being fairly employed. The IE believes the short list includes the bids that are the best value considering both price and non-price factors, from among all bids presented in the RFP.

Final Report of the Independent Evaluator at 39.

E. In addition to the RFP process, the Commission has another opportunity to review the results of the RFP during ratemaking.

In Order No. 13-056 of this docket, the Commission rejected NIPPC's request for an investigation based on similar arguments. The Commission reiterated the well-known principles of rate-making - PGE will bear the burden of showing the prudence of its decision making. The Commission also stated that the "extensive record in this proceeding" will assist at rate making. From the order at page 2:

> PGE will ultimately bear the consequence of its final resource decision when it later seeks rate recovery. PGE will be required to show that its decision to proceed with any selected resource was prudent, and any investment found to be unreasonable will be subject to full or partial disallowance. The extensive record in this proceeding, including reports from the IE, information provided by PGE,

> and filings by Staff and other parties, will assist the Commission and other parties in that future ratemaking review.

Id. at 2. The Commission's ratemaking process will provide stakeholders with yet another opportunity for the RFP process to be reevaluated, making further investigation at this time unnecessary.

F. Reckless allegations of securities law violation.

Grays Harbor, without basis, asserts that "PGE may have apprised investors weeks before the announcement of the Carty selection of a potential $2 billion to be added to the rate base in the next few years . . ." *Request for Investigation* at 11. This assertion amounts to a spurious accusation of securities fraud. PGE made timely disclosures in its 8-K filing with the SEC of all material information. (PGE 8-K filed June 3, 2013.)

V. Conclusion

PGE has conducted a fair and transparent RFP under the watchful eyes of the IE, with robust participation by Staff, Stakeholders, including Grays Harbor's trade group, and bidders. PGE followed and met the requirements of the Commission's competitive bidding guidelines. The IE's final report correctly concluded that "PGE personnel went to great lengths to treat all bidders equally and without bias." *Final Report of the Independent Evaluator* at 38. In its Request for Investigation, Grays Harbor has made allegations with no supporting evidence and disregarded contrary evidence in the voluminous record that has been developed in this proceeding and related proceedings. The Commission should deny Grays Harbor's Request for an Investigation and in doing so reaffirm the integrity of the Commission-defined RFP process.

DATED this 16th day of September, 2013.

Respectfully submitted,

PORTLAND GENERAL ELECTRIC

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ATTACHMENT A

Year	Source	Quote or Discussion	Page
2004	*Order No. 04-375* (Acknowledgement Order from LC 33)	The Commission ordered the following in Order No. 04-375: • PGE must initiate discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region. • PGE must include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to PGE at a reasonable price. • PGE must demonstrate that it has made reasonable efforts to acquire, retain or option cost effective transmission capacity over the Cascades before issuing its next RFP.	p. 10-11

2005	*PGE 2002 IRP Final Action Plan Update, March 23, 2006 (LC 33)*	• PGE engages the Oregon State University (OSU) Engineering department to 1) examine transmission flows and identify system upgrades for relieving the congested flow-gates at the South of Allston cutplane; and 2) ascertain the feasibility of building a new transmission line from the McNary area to PGE's service territory in Salem.
		• The new line would require an upgrade to the Round Butte-Bethel line and allow for increased transmission capacity across the Cascades. This potential expansion was known as "**Southern Crossing**."
		• Phase I of the OSU study was completed in 2005, with work to continue in 2006.
		• **<u>Initial Reasoning in Support of Southern Crossing</u>**:
		  ○ Southern Crossing could "provide additional transmission capacity form Eastern Oregon to the Willamette Valley."
		  ○ Southern Crossing would offer "the potential to use existing transmission corridors and rights-of-way, reducing such obstacles as permitting and securing easements."
		  ○ Southern Crossing would be in line "with other BPA and regional initiatives to increase east-to-west transmission efficiency and capacity."
			p. 15-17

Year	Source	Quote or Discussion	Page
2007	*PGE's 2007 Integrated Resource Plan (LC 43) filed June 29, 2007*	• Studies to determine the technical feasibility of Southern Crossing are now complete and the project has been deemed technically viable. (Models indicate that power flows would occur at the desired level and direction.) • Regional transmission planning shows that Southern Crossing offers a high benefit and is synergistic with other regional transmission projects. • Economic evaluations of Southern Crossing are on-going. • Talks with the joint BPA/Northwest Power and Conservation Council and their Wind Integration Action Plan reveal that Southern Crossing may play a significant role in PGE and other parties having access to new supply sources like wind. • Talks with BPA and others to develop transmission options will continue.	p. 153-54
2008	*Order No. 08-246 (LC 43)*	• 2007 IRP not acknowledged and PGE to refile within 18 months • Southern Crossing listed in PGE's portfolio as a preferred resource strategy and PGE intends to continue to evaluate the Southern Crossing project and actively work with BPA and others in the region to develop capacity.	p. 2
2008	*PGE 2009 Integrated Resource Plan (LC 48)*	• **<u>January 18, 2008</u>** – PGE initiated the WECC Project Rating Review Process for Cascade Crossing with notification to the WECC Coordination Committee (PCC) and Technical Studies Subcommittee (TSS). • **<u>March 20, 2008</u>** – PGE-solicited technical studies review group began activities • **<u>August 15, 2008</u>** - PGE gives WECC notice of intent to undergo the Project Rating Review and Regional Planning Process simultaneously.	p. 187-88

Year	Source	Quote or Discussion	Page
2009	*PGE 2009 Integrated Resource Plan (LC 48)*	• Cascade Crossing is a new Cross-Cascades line that would connect our Coyote Springs and Boardman plants directly to PGE, as well as allowing the full integration of a new energy resource near Boardman and new wind generation resources along the line corridor. • The Cascade Crossing and South of Allston projects result in a marked reduction in the amount of BPA transmission needed to deliver energy from our resources.	p. 170
		• PGE and Idaho Power Company sign a MOU to coordinate planning and development activities for Idaho's Boardman-Hemingway Project and Cascade Crossing.	p. 178
		• WECC Regional Planning Process through TCWG to be conducted for Cascade Crossing and other transmission projects.	p.178
		• Provides a list of objectives and benefits Cascade Crossing should help PGE and the region meet	p. 185
		• PGE's transmission department (PGET) initially began studying Cascade Crossing in response to 1,260 MW of requests for service submitted by PGE merchant transmission (PGEM) under PGE's OATT.	p.186
		• PGE seeks accepted WECC path rating for Cascade Crossing in the single-circuit configuration, but expects to convert to double-circuit configuration in Phase 2 study.	p.186
		• History and detailed background of Cascade Crossing, as well as the estimated cost of a single-circuit vs. a double-circuit configuration • **<u>May 2009</u>** - PGE completes the WECC Regional Planning Process and submits the Comprehensive Progress Report to WECC for a 60-day review (p. 188)	pp. 184-202

Year	Source	Quote or Discussion	Page
2009	*PGE 2009 Integrated Resource Plan - Addendum(LC 48)*	In addition, we still recommend moving forward with new transmission facilities to link generation resources on the east side of the Cascades to PGE's load centers on the west side. The new transmission ("Cascade Crossing") will enable continued reliable delivery of energy from existing and potential future thermal generation. It is also targeted to reach areas where renewable resources are expected to be built, thereby increasing our access to energy which can be used to meet future RPS requirement.	p. 2
		• Finally, the Action Plan includes new transmission facilities ("Cascade Crossing") to link existing and potential future generation resources on the east side of the Cascades to PGE's load centers on the west side. • The new transmission is also targeted to reach areas where further renewable resources are expected to be built, thereby increasing access to green energy supply that will be needed to meet future RPS requirements.	p. 111
		• We also seek acknowledgement of the design, siting and construction of a 500 kV double-circuit transmission line, Cascade Crossing, to enable us to deliver power from significant existing and new resources east of the Cascades, subject to certain milestones and participation agreements.	p.112
		• Cascade Crossing discussion	p. 128-129
2010	*Order No. 10-457* (Acknowledgement Order from LC 48)	The Commission acknowledged the development of the Cascade Crossing transmission project and required PGE to include an updated benefit-cost analysis of the project in its next IRP. For the updated analysis, PGE was to update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.	p. 20 (Full discussion p. 17-20)

Year	Source	Quote or Discussion	Page
	PGE 2011 Integrated Resource Plan Update (LC 48)	**<u>May 2010</u>** • PGE filed a Notice of Intent (NOI) with the Energy Facilities Siting Council (EFSC). The U.S. Forest Service published a Notice of Intent in the Federal Register announcing the initiation of a federal Environmental Impact Statement process for Cascade Crossing.	p.68

2011	*PGE 2011 Integrated Resource Plan Update (LC 48)*	• This includes updates on the status of:
		  o Project permitting - conducting field surveys to assess the environmental and cultural impacts of the line and we are actively engaged with state and federal agencies and developing the necessary
		  o Route surveying
		  o Coordinated planning
		  o WECC Path Rating Process
		  o Capital expenditures and the economic analysis.
		  o The Northern Tier Transmission Group (NTTG) and the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) continue to proclaim Cascade Crossing a critical component of regional transmission planning.	

		• **<u>April 2011</u>** - PGE received a Project Order from ODOE. • **<u>October 5, 2011</u>** – Obama administration names Cascade Crossing as one of seven transmission projects that will help enhance the transmission capacity and reliability across the country. • **Q1 2012** – Submit draft Application for Site Certificate to ODOE • **Q4 2012** – draft federal EIS anticipated.	p. 70

Year	Source	Quote or Discussion	Page
2012	*PGE 2012 Integrated Resource Plan Update (LC 48)*	• Status Update on Cascade Crossing - PGE continuing to work with other utilities to coordinate transmission planning related to the Cascade Crossing Transmission Project. • PGE is contractually unable to discuss or disclose details being discuss with third parties. Yet, PGE expects to provide the Commission with an update on Cascade Crossing in 2013.	p.18
January 15, 2013	*OPUC Public Meeting – Presentation on 2012 IRP Update filed on Nov. 21, 2012 (LC 48)*	PGE and BPA have announced a Memorandum of Understanding to pursue modifications to the Cascade Crossing Transmission Project The modifications would benefit the region's grid while eliminating about 101 miles of the project, reducing land acquisition, construction and environmental impacts and resulting mitigation costs PGE would invest in construction of the line and other grid enhancements and/or exchange certain assets with BP A In return, PGE anticipates receiving up to 2,600 MW of transmission capacity This capacity would be staged to come on-line in phases as needed, both before and after the original estimated 2017 in-service date Specific contract terms are still under discussion PGE will include a detailed update of the modifications to the project as well as an updated timeline in its 2013 IRP	p. 17

ATTACHMENT B

DRAFT

APPENDIX S
ATTACHMENT 12
EXHIBIT 03
ANNEX 02

ELECTRIC TRANSMISSION INTERCONNECTION

CARTY GENERATING STATION

PORTLAND GENERAL ELECTRIC

2012

REQUEST FOR PROPOSAL

NO.	DATE	REVISION	BY	CHK'D	APPROVALS	
0	25Apr12	Issued for RFP				

Carty Site Specification: Transmission

Overall Strategy:

General description of the strategy:

- **What:** The Carty Generating Facility (Carty) will interconnect to Bonneville Power Administration (BPA) at the BPA Slatt Substation pursuant to Interconnection Request No. G0380 (464 MW) and Interconnection Request No. G0457 (36 MW). Both Interconnection Requests have progressed to the Facilities Study stage of BPA's Large Generating Interconnection Procedures. Portland General Electric – Power Operations (PGEM) has submitted Transmission Service Requests to BPA for long-term firm transmission service in order to schedule and deliver Carty capacity and energy from Slatt to BPAT.PGE (Transmission Service Request Nos. 74611812 and 76829730). The requests are in BPA's queue awaiting BPA's next Network Open Season (NOS). Additionally, PGEM submitted requests to Portland General Electric Transmission (PGET) for interconnection and transmission service on Cascade Crossing.
- **When:** May 1, 2014 – Likely to be modified to May 1, 2015 during the NOS process.
- **Who:** BPAT
- **Where:** BPAT – Slatt to BPAT.PGE
- **Duration and Quantity:**
  - Interconnection Rights
    - BPAT – 500 MW, 10 years from date of execution of LGIA, with automatic renewals
    - PGET – 525 MW, 10 years from date of execution of LGIA, with automatic renewals
  - Transmission Rights
    - BPAT PTP requests totaling 500 MW, 5 years of service, includes roll-over rights.
    - PGET NITS request for 450 MW, Carty is designated as a network resource effective 1/1/2015 until 1/1/2025; and can be redesignated for a longer period of time.

List of Supporting documents:

- BPAT Point-To-Point Transmission Service:
  - Transmission Service Request – 74611812 (450 MW)
  - Transmission Service Request – 76829730 (50 MW)
- PGET Service Agreement for Network Integration Transmission Service:
  - Network Integration Transmission Service Agreement No. 46508
- PGET LGIA

- Interconnection Facilities Study Agreement (Request No. 08-030)
- Interconnection Request No. 12-049 – Good Faith Estimate of Time and Cost and Tender System Impact Study Agreements

ATTACHMENT C

DRAFT

APPENDIX S
ATTACHMENT 12
EXHIBIT 03
ANNEX 05

CARTY SERVICE AGREEMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE

CARTY GENERATING STATION

PORTLAND GENERAL ELECTRIC

2012

REQUEST FOR PROPOSAL

NO.	DATE	REVISION	BY	CHK'D	APPROVALS	
0	25Apr12	Issued for RFP				

Service Agreement For Network Integration Transmission Service

1.0 This Service Agreement, dated as of **January 18, 2002**, is entered into by and between Portland General Electric Company, Transmission and Reliability Services Department ("PGE" or the "Transmission Provider") and Portland General Electric Company (the "Transmission Customer").

2.0 The Network Customer has been determined by the Transmission Provider to have a valid request for Network Integration Service under the Company's Network Integration Transmission Service Tariff (Tariff).

3.0 The Network Customer has provided to the Transmission Provider an application deposit in the amount of **$2,506,627**, which will be applied to charges for service under this Agreement in accordance with the provisions of Section 29.2 of the Tariff.

4.0 Service under this Agreement shall commence on the later of: (1) **January 1, 2002**, or (2) the date on which construction of any new facilities necessary to provide the service are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on Customer's 90-day minimum notice.

5.0 The Transmission Provider agrees to provide and the Network Customer agrees to take and pay for Network Integration Service in accordance with the provisions of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Portland General Electric Company
Transmission and Reliability Services Department
121 SW Salmon Street, 3WTC0506
Portland, Oregon 97204
Attn: Frank Afranji, Director; Transmission & Reliability Services
Telephone: 503-464-7033
FAX: 503-464-8178

Network Customer:

Portland General Electric Company
121 SW Salmon Street, 3WTCBR06
Portland, Oregon 97204
Contact: Jerry L. Thale
Telephone: 503-464-7041
FAX: 503-464-2605

7.0 The following documents are incorporated herein and made a part of this Agreement: (a) The Transmission Provider's Open Access Transmission Tariff; (b) Appendix A, which is the Network Customer's application for network integration service (as required by Section 29.2 of this Tariff); and (c) Appendix B, which is the Network Operating Agreement entered into between the Network Customer and the Transmission Provider.

8.0 The Network Customer's Network Resources are:
As specified in the Network Application. (Appendix A)

9.0 The Network Customer's Network Loads are
As specified in the Network Application. (Appendix A)

10.0 The Network Customer's Owned Transmission Facilities are **N/A.** Compensation from the Transmission Provider to the Network Customer for the use of these facilities will be determined by the following: **N/A.**

11.0 Network Customer shall by no later than **December 31** of each year provide the annual load and resource information updates required by Section 31.6, or such successor Section of the Tariff.

12.0 Network Customer shall complete installation of the following equipment as required by Section 29.3 or such successor Section of the Tariff prior to commencement of service hereunder [describe equipment]. **N/A.**

13.0 If a System Impact Study or a Facilities Study (collectively or separately, "Studies") was undertaken based on Network Customers request for Network Integration Transmission Service, and the Studies indicate the need for Direct Assignment Facilities or Network Upgrades (collectively "Facilities") to be constructed for service to Network Customer then the following provisions shall apply: **N/A.**

13.1 Network Customer shall pay to Transmission Provider $ **N/A,** which represents the Transmission Provider's good faith estimate of the Network Customer's share of the cost of the Facilities. This amount shall be revised to the actual cost of the Facilities upon completion and placement of the Facilities in commercial service. Payment terms for this amount shall be **N/A.** The obligation to pay this amount shall be independent of any other term or duration of service under this agreement. In addition, Network Customer shall annually pay $ **N/A,** which is Transmission Provider's good faith estimate of the annual operation and maintenance costs of Network Customer's share of the Facilities. This annual amount shall be revised based upon actual experience with the operation and maintenance of the Facilities.

13.2 The Facilities are expected to be completed by **N/A.** If the Transmission Provider is unable to complete the Facilities, the provisions of Section 20 or such successor Section of the Tariff shall apply.

13.3 The Network Customer shall provide the following as security for the cost of the Facilities: This security shall be provided by the Network Customer by **N/A.**

14.0 Should Network Customer fail to respond to Load Shedding or Curtailment procedures as provided in the Tariff or Operating Agreement, Network Customer shall pay Transmission Provider one hundred (100.0) mills per kilowatt-hour for all energy used, that should have been Curtailed or shed. In addition, Network Customer shall indemnify, defend, and save the Transmission Provider harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees on trial and appeal and all other obligations of Transmission Provider or to third parties arising our of or resulting from the Network Customer's failure to Load Shed or Curtail.

15.0 Credit Agreement. Service under this Service Agreement is subject to Transmission Customer complying with the credit review and support procedures as set forth below.

15.1 Definitions

15.1.1 "Credit Rating" shall mean, with respect to a party on any date of determination, the lower of the ratings issued or maintained by Moody's and S&P with respect to such party's long-term senior unsecured, unsubordinated debt obligations not supported by third party credit enhancement (or current corporate credit rating), or if such party is a financial institution, its long-term, unsecured, unsubordinated deposits.

15.1.2 "Letter of Credit" means one or more irrevocable, transferable standby letters of credit from a major U.S. commercial bank or U.S. branch of a major foreign commercial bank, with such bank having assets of at least $10 billion (U.S. Dollars) and a Credit Rating of at least A+ from S&P or A1 from Moody's.

15.1.3 "Moody's" means Moody's Investor Services, Inc. or its successor.

15.1.4 "Performance Assurance" means collateral in the form of either cash, or Letters of Credit naming the Transmission Provider as the beneficiary.

15.1.5 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill Companies, Inc.) or its successor.

15.2 Transmission Customer agrees to provide the following information, as scheduled, unless Transmission Provider waives such requirement in writing:

15.2.1 On a yearly basis, a copy of the most recent audited financial statements, no later than 120 days after the end of each fiscal year.

15.2.2 Unaudited quarterly statements certified by the Chief Financial Officer of the Transmission Customer, no later than 60 days after the end of the first three quarters of each fiscal year. In certifying the unaudited quarterly statements the CFO of the Transmission customer shall submit a Certificate stating that such unaudited financial statements fairly represent the financial condition and the results of the operations of the Transmission Customer for the period indicated and are prepared in accordance with generally accepted accounting principles.

15.2.3 A list of Transmission Customer's Affiliates, including parent and subsidiaries, if applicable.

15.2.4 Such other documents, as the Transmission Provider shall reasonably request in connection with this service contemplated.

15.3 As security for the payment of amounts due under this Service Agreement, Transmission Customer agrees to provide the following if requested by the Transmission Provider:

15.3.1 In the event Transmission Customer maintains a Credit Rating of at least BBB- by S&P or BAA3 Moody's, without negative implications, additional security may not be required.

15.3.2 In the event Transmission Customer maintains a Credit Rating less than BBB- by S&P or Baa3 by Moody's, has negative implications, or does not maintain a Credit Rating, it agrees:

15.3.2.1 To provide a Letter of Credit. The Letter of Credit shall be in favor and acceptable to Transmission Provider; or

15.3.2.2 provide cash prepayment.

All security provided shall be in the amount at least equal to six- (6) month's service under the Transmission Service Agreement.

16.0 Network Customer shall pay the following rates and charges:

Monthly Demand Charge: **as per the Tariff Part III, Section 34.**

Redispatch Charge: **None.**

Ancillary Charges:

(1) The charges for Scheduling, System Control and Dispatch Service are provided pursuant to the Tariff, Schedule 1.

(2) The charges for Reactive Supply and Voltage Control from Generation Sources Service are provided pursuant to the Tariff, Schedule 2.

(3) The Transmission Customer is self-providing Ancillary Services other than those above.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

TRANSMISSION PROVIDER:

By : Frank Afranji JRS
Frank Afranji, Director

03-21-02
Date

Network Customer:

By: LM
(Title)

04/09/02
Date

ATTACHMENT D

DRAFT

APPENDIX S
ATTACHMENT 12
EXHIBIT 03
ANNEX 06

TRANSMISSION RESERVATION DETAIL 74611812

CARTY GENERATING STATION

PORTLAND GENERAL ELECTRIC

2012

REQUEST FOR PROPOSAL

NO.	DATE	REVISION	BY	CHK'D	APPROVALS	
0	25Apr12	Issued for RFP				

Transmission Reservation Detail 74611812 STUDY

Seller	Source Sink	POR POD	Request Type	Start	Stop	MW Req	MW Grant	Bid Price	Offer Price	Ceiling Price	Price Unit
BPAT	SLATT500 PGE_CNTGS	SLATT BPAT.PGE	ORIGINAL	2014-05-01 00:00 PD	2019-05-01 00:00 PD	450		1312.0000		1312.0000	$/MW-MONTH
Path:											

Service Code	Increment	Class	Type	Period	Window	Subclass
LTF-YEARLY PTP	YEARLY	FIRM	POINT_TO_POINT	FULL_PERIOD	EXTENDED	

Preconfirmed: No	Competing: No	Negotiated: No	Nerc Priority: 7	Affiliate: No

Reservation Profile

Start Date	Stop Date	MW Req	MW Grant	MWH	Bid Price	Offer Price
2014-05-01 00:00 PD	2019-05-01 00:00 PD	450		19720800.00	1312.00	
			Profile Total:	19720800.00		

Times		References	
Queued	2010-08-24 12:29:46 PD	Deal	
Updated	2010-09-10 08:02:26 PD	Sale	96095
Response		Posting	
		Request	
Impacted	0	Reassigned	
Last Customer Action	2010-08-24 12:29:46 PD	Seller	
Last Seller Action	2010-09-10 08:02:26 PD	Related	

Comments	
Status	
Seller	
Provider	
Customer	

Provisions	
Status Notification	
Anc-Service-Link	

Customer: PGEM		Seller: BPAT	
Name	Jamieson_J	Name	BPAT_WEBTRANS
Phone	503-464-7399	Phone	
Fax	503-464-7608	Fax	
E-mail	john.jamieson@pgn.com	E-mail	

ATTACHMENT E

DRAFT

APPENDIX S
ATTACHMENT 12
EXHIBIT 03
ANNEX 07

TRANSMISSION RESERVATION DETAIL 76829730

CARTY GENERATING STATION

PORTLAND GENERAL ELECTRIC

2012

REQUEST FOR PROPOSAL

NO.	DATE	REVISION	BY	CHK'D	APPROVALS	
0	25Apr12	Issued for RFP				

Transmission Reservation Detail 76829730 QUEUED

Seller	Source Sink	POR POD	Request Type	Start	Stop	MW Req	MW Grant	Bid Price	Offer Price	Ceiling Price	Price Unit
BPAT	SLATT500 PGE_CNTGS	SLATT BPAT.PGE	ORIGINAL	2015-01-01 00:00 PS	2020-01-01 00:00 PS	50		1298.0000		1298.0000	$/MW-MONTH
Path:											

Service Code	Increment	Class	Type	Period	Window	Subclass
LTF-YEARLY PTP	YEARLY	FIRM	POINT_TO_POINT	FULL_PERIOD	EXTENDED	

Preconfirmed: No	**Competing:** No	**Negotiated:** No	**Nerc Priority:** 7	**Affiliate:** No

Reservation Profile

Start Date	Stop Date	MW Req	MW Grant	MWH	Bid Price	Offer Price
2015-01-01 00:00 PS	2020-01-01 00:00 PS	50		2191200.00	1298.00	
			Profile Total:	2191200.00		

Times		References	
Queued	2012-04-20 08:54:15 PD	Deal	
Updated	2012-04-20 08:54:15 PD	Sale	96095
Response		Posting	
		Request	
Impacted	0	Reassigned	
Last Customer Action	2012-04-20 08:54:15 PD	Seller	
Related			

Comments	
Status	
Seller	
Provider	
Customer	

Provisions	
Status Notification	
Anc-Service-Link	

Customer: PGEM		Seller: BPAT	
Name	Morton_J	Name	
Phone	503-464-7305	Phone	
Fax	503-464-2605	Fax	
E-mail	john.morton@pgn.com	E-mail	

NON-CONFIDENTIAL

ATTACHMENT F

(pages 1 -2)

Portland General Electric

Date: December 5, 2012

To: PGE Bid Evaluation Team
From: Jaisen Mody on behalf of bid team 102-6
Subject: Initial Short List Notification – Updated Information for Evaluation

Bidder: 102
Bid No: 6

The purpose of this memorandum is to respond to the notification we received from you on November 20, 2012.

In the notification, you requested additional information on the items listed below. Please find our responses below each item.

- *Transmission* - Explanations of transmission evaluations can be found in the section "Criteria Used for Scoring Qualified Bids" in the RFP. As stated the RFP, PGE may adjust the delivery risk of external PODs based upon the progress of BPA's open season process and the development of the proposed Cascade Crossing transmission line at the time of the determination of the short lists. As further described therein, bids which do not provide for firm delivery capability or rights to transmit the proposed energy supply to PGE's load or satisfactory evidence of steps taken to perfect the rights to use PGE's Cascade Crossing Transmission Project may be excluded from the final short list. Please provide any new information relating to your transmission efforts.

  Bid Team 102-6 Response: PGE originally submitted a transmission plan for the Carty Site that included a transmission service request to be evaluated during BPA's next Network Open Season. Please accept the attached executed agreement as an enhancement to the Carty Site's current transmission plan. Below is a summary of the attributes to be added to the Carty Site's transmission plan:

  - Transmission capacity with a POR of Slatt and POD of BPAT.PGE
  - Precedent Transmission Service Agreement (PTSA) to be converted to a Firm Transmission Service Agreement upon energization of BPA's Big Eddy-Knight upgrade. (350 MW)
  - Deferred Transmission Service Agreement based on an associated PTSA (145 MW)
  - Service Commencement date based on the later of January 1, 2015 or the Big Eddy-Knight upgrade energization.

- Service can be deferred until January 1, 2016 to match Carty Site testing and operational dates.

In summary, this Agreement provides PGE with rights to 495MW of firm transmission from BPA Slatt to BPAT.PGE after the energization of BPA's Big Eddy-Knight project, which is expected to be completed by 1/1/15.

- *Security for Performance Requirements* – PGE will perform a detailed credit risk evaluation of all shortlist bidders, and will refine performance assurance requirements during this stage. However, performance assurance will only be required at the execution of an agreement with a successful bidder. Please provide any new information that relating to your credit profile.

Bid Team 102-6 Response: Our credit profile has not changed since our bid was submitted.

- *Dynamic Transfer* - For bidders submitting proposals into the Flexible Capacity RFP, PGE will perform due diligence with respect to ascertaining the existence of dynamic transfer capability (DTC). You are requested to provide proof of DTC from the resource bid to PGE's load. For the Flexible Capacity resource bids, no definitive agreement will be signed unless and until the shortlisted bidder(s) can satisfy this requirement.

Bid Team 102-6 Response: Not applicable for our Baseload Energy bid.

If you have any questions regarding our bid or the above information please let us know.

CONFIDENTIAL – Subject to
General Protective Order No. 11-097

Attachment F

(pages 3 - 21)

ATTACHMENT G

APPENDIX S
ATTACHMENT 10
EXHIBIT 3

ELECTRIC TRANSMISSION INTERCONNECTION

PORTLAND GENERAL ELECTRIC

2012

REQUEST FOR PROPOSAL

DRAFT

NO.	DATE	REVISION	BY	CHK'D	APPROVALS	
0	20Apr12	Issued for RFP				

PW2 Site Specification: Transmission

Overall Strategy:

General description of the strategy:

- PW2 will interconnect to Portland General Electric Company (PGE) at the PGE Trojan Substation utilizing existing generation lead capacity acquired pursuant to the 200 MW Large Generator Interconnection Agreement (LGIA), Service Agreement No. 07-025, dated June 16, 2009 between Portland General Electric Transmission (PGET) and Portland General Electric – Power Operations (PGEM). PGEM subsequently submitted Interconnection Request No. 11-041 to PGET for an additional 25 MW of interconnection capacity on April 19, 2011. PGET is currently conducting a System Impact Study of Interconnection Request No. 11-041. PW2 capacity and energy will be dynamically delivered to PGE Load using Network Integration Transmission Service (NITS) capacity acquired under NITS Agreement No. 46508 between PGET and PGEM. In order to ensure sufficient NITS capability to deliver PW2 generation to load, PGEM will schedule its other resources interconnected at Trojan under its Bonneville Power Administration (BPAT) Long-term Firm Point-To-Point transmission service agreement No. 09TX- as necessary.
- Transmission providers: PGET and BPAT
- Path: PGET – Trojan to PGE; BPAT – Trojan to BPAT.PGE
- Duration and Quantity:
    - Interconnection Rights
        - PGET LGIA
            - Service Agreement No. 07-025 for 200 MW expiring in 2019 with automatic renewal rights.
            - Interconnection Request No. 11-041 for 25 MW– in process; will expire 10 years from execution of LGIA with automatic renewal rights.
    - Transmission Rights
        - BPAT Service Agreement from Trojan to BPAT.PGE expires 1/1/2015 00:00 and includes roll-over rights. Transmission capacity is sufficient to accommodate 225 MW of PW2 generation capacity from Trojan.

- PGET NITS Agreement. PW2 is currently designated as a 220 MW network resource under this agreement effective 12/1/2013 until 1/1/2015 and can be redesignated for a longer period of time.

List of Supporting documents:

- BPAT Service Agreement for Point-To-Point Transmission Service:
  - Service Agreement - No. 09TX-14507, Exhibit A, Table 1
  - Transmission Service Request, Assign Ref – 73540912

- PGET Service Agreement for Network Integration Transmission Service:
  - Network Integration Transmission Service Agreement No. 46508

- PGET LGIA
  - Service Agreement No. 07-025, as amended
  - Interconnection Request No. 11-041 – in process

DRAFT

ATTACHMENT H

Service Agreement No. 09TX-14507

SERVICE AGREEMENT
for
POINT-TO-POINT
TRANSMISSION SERVICE
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
PORTLAND GENERAL ELECTRIC COMPANY

1. This Service Agreement is entered into by and between the Bonneville Power Administration Transmission Services (Transmission Provider) and Portland General Electric Company (Transmission Customer).

2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Point-to-Point (PTP) Transmission Service under the Transmission Provider's Open Access Transmission Tariff (Tariff).

3. The Transmission Customer has provided to the Transmission Provider a deposit, if applicable, unless such deposit has been waived by the Transmission Provider, for Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff.

4. Service under this Service Agreement for a transaction shall commence on the later of (1) the Service Commencement Date as specified by the Transmission Customer in a subsequent request for transmission service or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed. This Service Agreement shall terminate on such date as mutually agreed upon by the Parties.

5. The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit D.

7. The Tariff, Exhibit A (Transmission Service Request), Exhibit B (Direct Assignment and Use-of-Facilities Charges), Exhibit C (Ancillary Service Charges), Exhibit D (Notices), and Exhibit E (Creditworthiness and Prepayment) are incorporated herein and made a part hereof. Capitalized terms not defined in this Service Agreement are defined in the Tariff.

8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

10. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(i) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

11. Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), as amended or supplemented, which provides, among other things, that the Transmission Customer will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Service Agreement the same as if the specific language had been written into the Service Agreement, except that Indian Tribes and tribal organizations may apply Indian preference to the extent permitted by Federal law.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PORTLAND GENERAL ELECTRIC COMPANY	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: [signature]	By: Craig Hardin
Name: JAMES F. LOBDELL *(Print / Type)*	Name: Craig Hardin *(Print / Type)*
Title: VICE PRESIDENT	Title: Transmission Account Executive
Date: DECEMBER 8, 2009.	Date: December 8, 2009

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PGE Approved By:	
Business Terms	[initials]
Credit	KG
Legal	[initials]
Risk Mgt.	JB

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

TABLE 1
TRANSMISSION SERVICE REQUEST

The Assign Ref is: 73540912

1. **TERM OF TRANSACTION**
Service Commencement Date: at 0000 hours on January 1, 2010.
Termination Date: at 0000 hours on January 1, 2015.

2. **DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER AND MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED (RESERVED CAPACITY)**

Contract POR (Source)	Reservation - Scheduling (POR)	POR Balancing Authority	Contract POD (Sink)	Reservation - Scheduling (POD)	POD Balancing Authority	Reserved Capacity (MW)
TROJAN230	TROJAN	PGE[1]	PGE_CNTGS	BPAT.PGE	PGE	531

PGE's Contiguous Points of Delivery (PODs) consist of Forest Grove Substation (115 kV), D. R. Keeler Substation (230 kV), McLoughlin Substation (230 kV), Pearl Substation (230 kV), and Rivergate Substation (230 kV); and are subject to the transmission Provider's Contiguous Point(s) of Delivery Business Practice, as revised or replaced.

3. **POINT OF RECEIPT**

TROJAN SWITCHING STATION

Location: the points in Portland General Electric Company's Trojan Switching Station, where the 230 kV facilities of the Transmission Provider and Portland General Electric Company are connected;

Voltage: 230 kV;

Metering: Quantity as scheduled.

[1] Portland General Electric Company.

4. POINT OF DELIVERY

PGE Contiguous:

(a) **FOREST GROVE 115 kV**

Location: the point in the Transmission Provider's Forest Grove Substation where the 115 kV facilities of the Transmission Provider and Portland General Electric Company are connected;

Voltage: 115 kV;

Metering: in the Transmission Provider's Forest Grove Substation, in the Transmission Customer's 115 kV circuit over which such Electric Power flows;

Exception: this POD has been added on a temporary basis and Transmission Provider assumes no responsibility for permanently maintaining service to this point. This POD may be terminated by Transmission Provider upon 3 years' written notice to the Transmission Customer if Transmission Provider determines facilities (those facilities from Keeler 230 kV Substation to Forest Grove 115 kV Substation or back-up facilities from Carlton 230 kV Substation to Forest Grove 115 kV Substation) must be upgraded to accommodate the Transmission Customer's load served from Forest Grove Substation. Upon such notice of termination, the Parties will commence good faith negotiations for new commercial arrangements appropriate to the new plan of service. This POD may be terminated by the Transmission Customer upon 3 months' prior written notice to Transmission Provider if the Transmission Customer chooses not to use such service, or upon mutual agreement.

(b) **D. R. KEELER 230 kV**

Location: the point in the Transmission Provider's D. R. Keeler Substation where the 230 kV facilities of the Transmission Provider and Portland General Electric Company are connected;

Voltage: 230 kV;

Metering: in the Transmission Provider's D. R. Keeler Substation, in the 230 kV circuit over which such Electric Power flows.

(c) **MCLOUGHLIN 230 kV**

Location: the points in Portland General Electric Company's McLoughlin Substation where the 230 kV facilities of the Transmission Provider and Portland General Electric Company are connected;

Voltage: 230 kV;

Metering: in the Transmission Provider's McLoughlin Substation, in the 230 kV circuit over which such Electric Power flows.

(d) **PEARL 230 kV**

Location: the point in the Transmission Provider's Pearl Substation where the 230 kV facilities of the Transmission Provider and Portland General Electric Company are connected;

Voltage: 230 kV;

Metering: in the Transmission Provider's Pearl Substation, in the 230 kV circuit over which such Electric Power flows.

(e) **RIVERGATE 230 kV**

Location: the point adjacent to Portland General Electric Company's Rivergate Substation on structure 8/2 of the Transmission Provider's Ross-Rivergate 230 kV line where the facilities of the Transmission Provider and Portland General Electric Company are connected;

Voltage: 230 kV;

Metering: in the Transmission Customer's Rivergate Substation, in the 230 kV circuit over which such Electric Power flows;

Exception: there shall be no adjustment for losses between the POD and the point of metering.

5. DESIGNATION OF PARTY SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Portland General Electric Company.

6. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

None.

7. **SERVICE AGREEMENT CHARGES**
Service under this Service Agreement will be subject to some combination of the charges detailed below and in Exhibits B and C. The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.

(a) **Transmission Charge**
PTP-10 Rate Schedule or successor rate schedules.

(1) **Reservation Fee**
Not Applicable.

(2) **Short Distance Discount (SDD)**
Not Applicable.

(b) **System Impact and/or Facilities Study Charge(s)**
System Impact and/or Facilities Study Charges are not required for service under this Assign Ref.

8. **OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT**

(a) Notwithstanding section 7.3 of the Tariff, i) if the Transmission Customer fails to pay any monthly invoice for transmission services by the due date, and does not correct such failure of payment within 30 calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, the Transmission Provider may notify the Transmission Customer that it plans to terminate services in 30 days; and ii) in the event of a billing dispute, if the Transmission Customer fails to meet the requirements for continuation of service the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in 30 days.

(b) During any outage involving the loss of station service, Transmission Customer will provide backup station service from an alternate resource. Transmission Customer will reserve and e-Tag such service for Coyote Springs Substation, Garrison Substation, Slatt Substation, or Trojan Substation, as needed.

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ATTACHMENT I

Service Agreement For Network Integration Transmission Service

1.0 This Service Agreement, dated as of **January 18, 2002**, is entered into by and between Portland General Electric Company, Transmission and Reliability Services Department ("PGE" or the "Transmission Provider") and Portland General Electric Company (the "Transmission Customer").

2.0 The Network Customer has been determined by the Transmission Provider to have a valid request for Network Integration Service under the Company's Network Integration Transmission Service Tariff (Tariff).

3.0 The Network Customer has provided to the Transmission Provider an application deposit in the amount of **$2,506,627**, which will be applied to charges for service under this Agreement in accordance with the provisions of Section 29.2 of the Tariff.

4.0 Service under this Agreement shall commence on the later of: (1) **January 1, 2002**, or (2) the date on which construction of any new facilities necessary to provide the service are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on Customer's 90-day minimum notice.

5.0 The Transmission Provider agrees to provide and the Network Customer agrees to take and pay for Network Integration Service in accordance with the provisions of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Portland General Electric Company
Transmission and Reliability Services Department
121 SW Salmon Street, 3WTC0506
Portland, Oregon 97204
Attn: Frank Afranji, Director; Transmission & Reliability Services
Telephone: 503-464-7033
FAX: 503-464-8178

Network Customer:

Portland General Electric Company
121 SW Salmon Street, 3WTCBR06
Portland, Oregon 97204
Contact: Jerry L. Thale
Telephone: 503-464-7041
FAX: 503-464-2605

7.0 The following documents are incorporated herein and made a part of this Agreement: (a) The Transmission Provider's Open Access Transmission Tariff; (b) Appendix A, which is the Network Customer's application for network integration service (as required by Section 29.2 of this Tariff); and (c) Appendix B, which is the Network Operating Agreement entered into between the Network Customer and the Transmission Provider.

8.0 The Network Customer's Network Resources are:
As specified in the Network Application. (Appendix A)

9.0 The Network Customer's Network Loads are
As specified in the Network Application. (Appendix A)

10.0 The Network Customer's Owned Transmission Facilities are **N/A.** Compensation from the Transmission Provider to the Network Customer for the use of these facilities will be determined by the following: **N/A**.

11.0 Network Customer shall by no later than **December 31** of each year provide the annual load and resource information updates required by Section 31.6, or such successor Section of the Tariff.

12.0 Network Customer shall complete installation of the following equipment as required by Section 29.3 or such successor Section of the Tariff prior to commencement of service hereunder [describe equipment]. **N/A**.

13.0 If a System Impact Study or a Facilities Study (collectively or separately, "Studies") was undertaken based on Network Customers request for Network Integration Transmission Service, and the Studies indicate the need for Direct Assignment Facilities or Network Upgrades (collectively "Facilities") to be constructed for service to Network Customer then the following provisions shall apply: **N/A**.

13.1 Network Customer shall pay to Transmission Provider $ **N/A**, which represents the Transmission Provider's good faith estimate of the Network Customer's share of the cost of the Facilities. This amount shall be revised to the actual cost of the Facilities upon completion and placement of the Facilities in commercial service. Payment terms for this amount shall be **N/A**. The obligation to pay this amount shall be independent of any other term or duration of service under this agreement. In addition, Network Customer shall annually pay $ **N/A**, which is Transmission Provider's good faith estimate of the annual operation and maintenance costs of Network Customer's share of the Facilities. This annual amount shall be revised based upon actual experience with the operation and maintenance of the Facilities.

13.2 The Facilities are expected to be completed by **N/A**. If the Transmission Provider is unable to complete the Facilities, the provisions of Section 20 or such successor Section of the Tariff shall apply.

13.3 The Network Customer shall provide the following as security for the cost of the Facilities: This security shall be provided by the Network Customer by **N/A**.

14.0 Should Network Customer fail to respond to Load Shedding or Curtailment procedures as provided in the Tariff or Operating Agreement, Network Customer shall pay Transmission Provider one hundred (100.0) mills per kilowatt-hour for all energy used, that should have been Curtailed or shed. In addition, Network Customer shall indemnify, defend, and save the Transmission Provider harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees on trial and appeal and all other obligations of Transmission Provider or to third parties arising our of or resulting from the Network Customer's failure to Load Shed or Curtail.

15.0 Credit Agreement. Service under this Service Agreement is subject to Transmission Customer complying with the credit review and support procedures as set forth below.

15.1 Definitions

15.1.1 "Credit Rating" shall mean, with respect to a party on any date of determination, the lower of the ratings issued or maintained by Moody's and S&P with respect to such party's long-term senior unsecured, unsubordinated debt obligations not supported by third party credit enhancement (or current corporate credit rating), or if such party is a financial institution, its long-term, unsecured, unsubordinated deposits.

15.1.2 "Letter of Credit" means one or more irrevocable, transferable standby letters of credit from a major U.S. commercial bank or U.S. branch of a major foreign commercial bank, with such bank having assets of at least $10 billion (U.S. Dollars) and a Credit Rating of at least A+ from S&P or A1 from Moody's.

15.1.3 "Moody's" means Moody's Investor Services, Inc. or its successor.

15.1.4 "Performance Assurance" means collateral in the form of either cash, or Letters of Credit naming the Transmission Provider as the beneficiary.

15.1.5 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill Companies, Inc.) or its successor.

15.2 Transmission Customer agrees to provide the following information, as scheduled, unless Transmission Provider waives such requirement in writing:

15.2.1 On a yearly basis, a copy of the most recent audited financial statements, no later than 120 days after the end of each fiscal year.

15.2.2 Unaudited quarterly statements certified by the Chief Financial Officer of the Transmission Customer, no later than 60 days after the end of the first three quarters of each fiscal year. In certifying the unaudited quarterly statements the CFO of the Transmission customer shall submit a Certificate stating that such unaudited financial statements fairly represent the financial condition and the results of the operations of the Transmission Customer for the period indicated and are prepared in accordance with generally accepted accounting principles.

15.2.3 A list of Transmission Customer's Affiliates, including parent and subsidiaries, if applicable.

15.2.4 Such other documents, as the Transmission Provider shall reasonably request in connection with this service contemplated.

15.3 As security for the payment of amounts due under this Service Agreement, Transmission Customer agrees to provide the following if requested by the Transmission Provider:

15.3.1 In the event Transmission Customer maintains a Credit Rating of at least BBB- by S&P or BAA3 Moody's, without negative implications, additional security may not be required.

15.3.2 In the event Transmission Customer maintains a Credit Rating less than BBB- by S&P or Baa3 by Moody's, has negative implications, or does not maintain a Credit Rating, it agrees:

15.3.2.1 To provide a Letter of Credit. The Letter of Credit shall be in favor and acceptable to Transmission Provider; or

15.3.2.2 provide cash prepayment.

All security provided shall be in the amount at least equal to six- (6) month's service under the Transmission Service Agreement.

16.0 Network Customer shall pay the following rates and charges:

Monthly Demand Charge: **as per the Tariff Part III, Section 34.**

Redispatch Charge: **None.**

Ancillary Charges:

(1) The charges for Scheduling, System Control and Dispatch Service are provided pursuant to the Tariff, Schedule 1.

(2) The charges for Reactive Supply and Voltage Control from Generation Sources Service are provided pursuant to the Tariff, Schedule 2.

(3) The Transmission Customer is self-providing Ancillary Services other than those above.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

TRANSMISSION PROVIDER:

By : Frank Afranji JRS
Frank Afranji, Director

03-21-02
Date

Network Customer:

By: Mary K Turner LM
(Title)

04/09/02
Date

Attachment J

Bid Scoring Catagories	Max Score	% of Total Score	Description	Individual Catagories	Maximum Scoring Weights	
Price Score	600	60%	Includes fixed and variable bid costs compared to a market price: • For Flexible Capacity Bids, variable costs incorporates: o Cost to comply with PGE's reliability-based dispatch signals o Energy-based market dispatch • Seasonal Capacity bids variable cost will only include cost related to market dispatch • Baseload Energy bids variable cost will only include cost related to market dispatch	The price score will be calculated as the ratio of the bid's projected total cost per MWh to forecast market prices using real-levelized or annuity methods (per Guideline 9a. of the Competitive Bidding Guidelines). See also 'Price Factor' in PGE's 2012 Request for Porpopsals - Power Supply Resources	600	
Project Development Criteria	50	5%	Includes development team experience, permitting	Project already in service	50	Projects in Service
				Permitting status (emissions, makeup water, waste discharge, land use, zoning)	15	Projects not in Service in Development
				Experience of Project Team	7.5	
				Project Financing	17.5	
				Site Control: Including all rights required for project including access to the project site, easements and resources rights appropriate for the project	10	
Project Characteristics	150	15%	Interconnection, Transmission rights, Gas transport and storage	Resource Base Diversity	5	
				Resource Adequacy Considerations	5	
				Interconnection Rights	45	
				Transmission Rights: Long Term Firm Transmission Rights to PGE's System	50	
				Natural Gas Point of Delivery	45	
Power Product Characteristics	125	12.50%	Flexibility of unit, length of contract and firmness of energy	Quality of Power	15	
				GAF / Liquidated Damages	10	
				Length of contract commitment	35	
				Flexibility of Assets used to back bids	60	
				Amount (in MWs per hour) of contract commitment	5	
Credit Evaluation (PPA)	75	7.50%	Collateral requirement, credit threshold, cross default	Credit Rating	15	Credit Evaluation will be based on proposed structure
				PGE propriatary financial scoring based on liquidity ratios, profitability ratios, leverage ratios and financial statement audit quality. The scores and weight given to each of the input will be consistent with PGE Credit Risk Management internal procedures.	60	
Credit Evaluation (Equity)			This is only used for equity bids for projects still in construction. Score is based on counterparty's ratio and debt rating (mutually exclusive with 5. Credit Evaluation (PPA))	PGE ratio analysis score	25	
				Bond Rating	25	
				Net Tangible Worth	15	
				Liquidity	5	
				Corporate Structure	5	
Total	1,000	100%			1,000	

Attachment K

Chapter 1 Purpose of and Need for Action

Words in **bold** and acronyms are defined in Chapter 32, Glossary and Acronyms.

Bonneville Power Administration (BPA) is proposing to build a 500-kilovolt (kV) lattice-steel tower transmission line that would run about 70 miles from a new 500-kV substation near Castle Rock, Washington to a new 500-kV substation near Troutdale, Oregon. The proposed transmission line and substations would increase the electrical capacity and transfer capability of BPA's transmission system in this area. BPA is considering four action alternatives (each with several options) that include transmission line routes, three sites for the proposed substation near Castle Rock, and one site for the proposed substation near Troutdale (see Map 1-1). This proposed action is referred to as the I-5 Corridor Reinforcement Project (I-5 project or project).

This chapter provides background information about BPA, its transmission system, and causes of congestion on this system, including local **load** growth, existing contractual obligations, and new requests for use of BPA's system. This chapter describes the need for BPA to increase the electrical capacity and **transfer capability** of its transmission system to respond to the increasing congestion on this system and growing system reliability concerns. This chapter also identifies the purposes that BPA is attempting to achieve in meeting this need, potential transmission system benefits from BPA's proposal, and the agencies involved in development of this environmental impact statement (EIS). Finally, the chapter provides a summary of the public scoping process conducted for the EIS, and information about the scope and organization of this EIS.

For proposed actions with the potential to affect the environment, BPA is required by the National Environmental Policy Act (NEPA) to identify, evaluate, and consider potential environmental consequences of the proposed action and reasonable alternatives before taking action, and to inform decision-makers and the public of these alternatives and their consequences. BPA prepared this draft environmental impact statement in accordance with NEPA, to address the proposed action to build the I-5 project.

1.1 Background

1.1.1 About BPA

BPA is a not-for-profit federal agency based in the Pacific Northwest. Although BPA is part of the United States (U.S.) Department of Energy (DOE), it is self-funded and covers its costs by selling its products and services. BPA markets wholesale electrical power from 31 federal hydroelectric projects in the Columbia River Basin, one nonfederal nuclear plant and several other small nonfederal power plants. The dams are owned and operated by the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (BOR). About one-third of the electric power used in the Northwest comes from BPA. BPA also owns, operates, and maintains about three fourths of the high-voltage (500-, 345-, 230- and 115-kV) transmission lines in its service territory. BPA's service territory includes Idaho, Oregon, Washington, western Montana, and small parts of California, eastern Montana, Nevada, Utah, and Wyoming.

BPA has an obligation to ensure that it has sufficient capability to serve its customers through a safe and reliable transmission system. The Federal Columbia River Transmission Act directs BPA to construct improvements, additions, and replacements to its transmission system that the BPA Administrator determines are necessary to provide service to BPA's customers, maintain electrical stability and reliability, and integrate and transmit power (16 U.S.C. § 838b).

1.1.2 BPA's Transmission System

BPA owns and operates more than 15,000 circuit miles of high-voltage transmission lines in the Pacific Northwest. BPA's transmission system moves most of the Northwest's high-voltage power from facilities that generate the power to customers in the Northwest. Besides the transmission system within the Northwest, BPA has large interregional transmission lines that connect to Canada, California, the Southwest and eastern Montana. BPA's lines carry electricity from federal and nonfederal generating resources to be used within and outside the Northwest.

1.1.2.1 Load Growth, Limited System Capacity, and Congestion

In southwest Washington and northwest Oregon, BPA's system primarily includes high-voltage transmission lines connected through substations to local utilities and generating facilities (see Map 1-2). Local utility customers served by BPA's transmission system include Clark Public Utilities, Cowlitz Public Utility District (PUD), PacifiCorp, and Portland General Electric (PGE).

The Portland, Oregon-Vancouver, Washington metropolitan area (metro area) is the major electric load center in northwest Oregon and southwest Washington. High concentrations of residential, commercial, and industrial loads are served by hydroelectric dams on the Columbia River, **thermal plants** along the Interstate-5 (I-5) corridor west of the Cascade Mountains and a few others in Canada, and wind turbines operating east of the Cascades in Washington and Oregon. Electricity flows from these generating resources to the metro area and beyond over BPA's and other utilities' high- and low-voltage (less than 115-kV) transmission lines throughout the West.

Utilities monitor these lines (or paths) to make sure that the transmission system is functioning safely and reliably. In and around the metro area, the high voltage lines together are known as the South of Allston (SOA) path. Allston is a BPA substation in northern Oregon, across the Columbia River from Longview, Washington (see Map 1-2). When all lines within this path are in service, that is, functioning and available with no outages for maintenance or emergencies, the SOA path can be operated within a range (in **megawatts** [MW]) called the path's system operating limit.

For the last 10 years, BPA studies have shown that this path has become more congested because of higher loads. BPA built the last major high-voltage line in the I-5 corridor area over 40 years ago. Over that same period, the population has grown from about 1 million to more than 2.2 million (Sprague and Picha 2010).

Higher loads create congestion because of the way electrons flow on a transmission line or path. The higher the loads in different areas, the more the power flows to these areas, and depending on the available line or path capacity, the line can become congested and physically unable to reliably accommodate the need for power to flow. The path is like an interstate highway, the higher the loads (or traffic) the more the path becomes crowded or congested.

Transmission lines can also be affected by surrounding air temperatures. Transmission lines are designed to operate up to a maximum temperature that includes a safety buffer so that the lines will not sag into objects on or near the right-of-way. In summer, higher air temperatures can cause conductors to expand and stretch, which increases the sag of the conductors. During these times, lines can reach their maximum operating limit quicker. This decreases the amount of power that could have been carried over the lines (reduced capacity) had the surrounding temperatures been cooler.

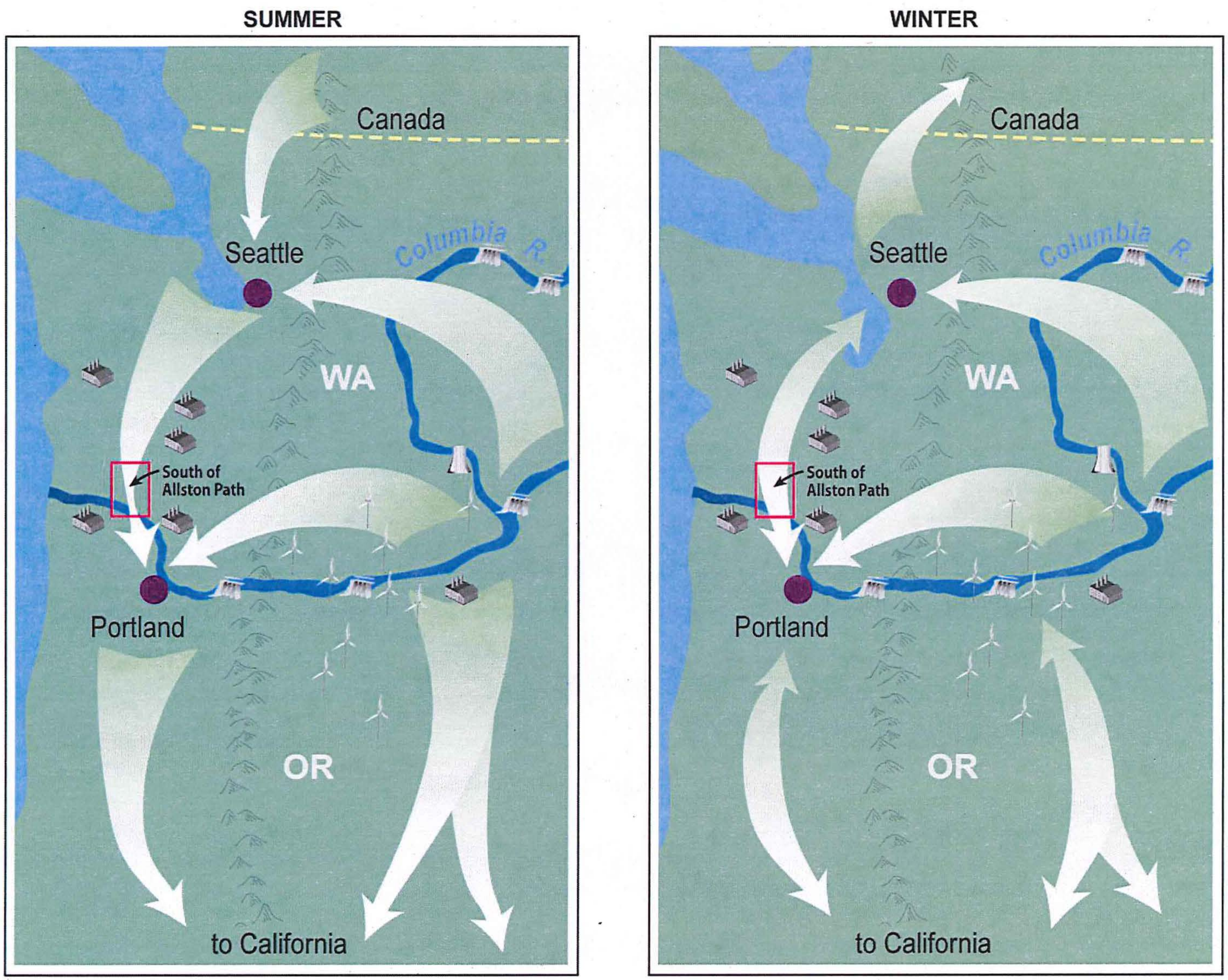
In the past, electrical use in the metro area peaked in the winter, often when a winter storm boosted the need for electric heat. Now, as new homes and commercial buildings are constructed, most have installed air conditioning, and that has increased the demand for energy in the summer. In general, peak electricity use in summer is about equal to winter peak levels.

Power flows in a different pattern in winter than it does in summer, using different transmission paths with different capacities (see Figure 1-1). In winter, power use is greater in the Northwest and Canada. This demand causes power to flow primarily from generation sources east of the Cascades to load centers in the west. Transmission system capacity is adequate to accommodate this flow. In summer, however, power use is concentrated in the Northwest and California, which causes power to primarily flow from north to south (see Figure 1-1). The north-to-south transmission capacity available in summer on the SOA path is about half of the system capacity in winter from east-to-west. This creates a system bottleneck for the summer pattern.

In summary, because of a variety of factors—including growing summer peak loads, new power plants that have interconnected to BPA's transmission system north of the SOA path, and, to a lesser extent, power transfers from Canada through the Northwest to load centers south of the metro area—the SOA path has become congested during the summer months.

With the current forecasts for load growth (up to 2 percent per year), BPA's analysis indicates that by spring 2016 the existing transmission system's capacity will likely be reached, which, in the absence of other measures, could require BPA to reduce power deliveries and this compromises the reliability of the transmission system to serve loads (see Section 1.1.2.2, Reliability and **Non-Wires Measures**).

Figure 1-1 Typical Power Flows (Winter and summer flows vary depending on generation and load patterns)



1.1.2.2 Reliability and Non-Wires Measures

Mandatory reliability standards and principles of good utility practice prohibit BPA from operating the transmission system beyond its capacity. Operating in this manner could **overload** the system and create **voltage** instability, potentially leading to **brownouts** or **blackouts**. When BPA determines that capacity on a particular path is insufficient to meet demand under certain conditions, BPA relies on non-wires measures to the extent possible to help maintain system reliability and maximize use of the existing system facilities before building a new transmission line. For the SOA path, BPA and other utilities have developed a non-wires measure called a remedial action scheme (RAS) that is carried out when needed. RAS uses a high-speed automatic control system designed to protect the transmission system in the event of an unexpected outage of a critical transmission facility. If such an outage occurs, the RAS is activated and rapidly disconnects (or "drops") selected generation in the Northwest and Canada to reduce the flow of power and avoid overloading the lines that remain in service.

RAS has been used for many years to preserve the reliability of the SOA path. During the summer, as loading increases on the SOA path, successively higher levels of RAS are engaged, and greater amounts of generation are dropped as needed. Using RAS in this manner, however, has some undesirable consequences. BPA has had to prepare to drop up to 2700 MW of generation in the event of a critical outage on this path. To continue to serve the demand if generation is dropped, replacement power, if available, must be found and delivered over alternate paths. Even if replacement power is available, it may be difficult to deliver the replacement power due to constraints on the alternate paths. If replacement power cannot be found or delivered to serve the demand, this could lead to **load curtailments**, particularly in the metro area. As the projected gap between SOA capacity and demand grows, the likelihood of curtailments will increase as well. Furthermore, as the economy and population in the metro area continue to grow, using RAS will become more difficult and less effective.

Providing a high level of system reliability, and avoiding load curtailments, has become even more important in the Pacific Northwest in recent years as new industries that rely on steady, uninterrupted power have come to the area. In the past, Northwest industries, such as lumber mills and aluminum plants, could adjust to short power interruptions and sometimes received a special power rate for their flexibility. Today, high-quality (non-interruptible) power is critical to high-tech manufacturing of products, such as microchips. Power disruptions can ruin products in these plants, and plant operators can only tolerate fluctuations within a narrow range.

In addition to RAS, for the past 2 years BPA has been investigating the feasibility of using other possible non-wires measures to help maintain reliability of the SOA path. To determine how non-wires could help alleviate power flows on the SOA path, BPA contracted with Energy and Environmental Economics, Inc. (E3) to conduct non-wires studies (see inset box). The studies determined that non-wires measures could not eliminate the need for a new line. (See Section 4.7.1, Non-Wires Alternative, for a discussion of the consideration of non-wires measures in meeting the need for the project.) However, the studies did find that upgrades at BPA's Pearl Substation could potentially defer the need for a new line for reliability purposes by about 2 years beyond spring 2016 (when the existing transmission system's capacity is likely to be reached). In addition, the studies found that **generation redispatch** may be able to provide an additional deferral of up to about 4 years. Generation redispatch would turn off large generators located north of the metro area, while turning on generators located south of the metro area to reduce power flow on the SOA path. The E3 study did not consider the new commercial demand for transmission service over the SOA path discussed in Section 1.1.2.3, Existing Obligations and New Requests for Transmission Service.

Because of the potential for generation redispatch to help address reliability of the SOA path, BPA is continuing to separately evaluate the operational feasibility of generation redispatch, and whether contracts with regional generators would be cost effective.

If BPA finds that generation redispatch measures are cost effective and commercially and operationally feasible, those measures, along with upgrades at BPA's Pearl Substation, could be separately and independently implemented to maintain system reliability in the I-5 project area. This could delay the date a new line would need to be operational to satisfy reliability needs by 2 to 6 years.

Non-Wires Studies

BPA contracted with Energy and Environmental Economics, Inc. (E3) to conduct a screening study of possible non-wires measures for the I-5 project. The study focused on measures to address the reliability need for the project. E3 completed the Phase I study in January 2011 (see I-5 project website). The study identified four possible non-wires measures, estimated impacts to the SOA path, and determined that non-wires could potentially provide a short-term deferral of the energization date for the I-5 transmission line, but *could not* provide a long-term solution for future overloads on the SOA path. In April 2011, BPA convened the Non-Wires Round Table, a technical forum of non-BPA experts capable of providing external review of non-wires measures being considered as alternatives to transmission projects. The Round Table evaluated the E3 report and recommended a Phase II study be prepared to examine the implementation feasibility of the non-wires measures for a short-term I-5 project deferral. The Phase II study was completed in December 2011 (see I-5 project website) and concluded that upgrades at BPA's Pearl Substation and generation redispatch were the measures that showed the most potential for a short-term deferral of the I-5 project. The study also acknowledged the need for BPA to evaluate operational challenges that generation redispatch would create and the uncertainty as to whether commercial agreements with regional generators would be achievable and cost effective.

1.1.2.3 Existing Obligations and New Requests for Transmission Service

BPA has adopted an Open Access Transmission Tariff (OATT) for its transmission system. BPA follows the open access tariff as a matter of national policy. The tariff defines the terms and conditions of transmission services offered by BPA. This tariff, which is generally consistent with the Federal Energy Regulatory Commission's (FERC) **pro forma open access tariff**, has procedures that provide access to BPA's transmission system for all eligible customers, consistent with all BPA requirements (including the availability or development of sufficient transmission capacity) and subject to an environmental review under NEPA. More information about the tariff is available on BPA's Transmission Services website: http://www.transmission.bpa.gov/business/ts_tariff/.

For many years even before BPA adopted its OATT, BPA provided access to its transmission system to both federal and nonfederal power generators. As a result, BPA and other utilities currently have existing contracts with several power generators (including wind generators and power marketers) in Canada, the Pacific Northwest east and west of the Cascades, and surrounding states to move power across BPA's transmission system. Much of the available capacity for firm transmission service that remains on BPA's transmission system is already under contract.

At the present time, BPA, PacifiCorp, and PGE are the entities that have allocated capacity on the SOA path. PGE and PacifiCorp likely use their allocations to meet their customers' needs for power. BPA's share of that capacity is provided to BPA's **firm transmission service** customers (see inset box). Because of BPA's obligations to serve loads and provide firm capacity on this path, BPA cannot provide firm transmission service to other customers at certain times of the year, because the path has reached the limit of its capacity. Accordingly, BPA can only offer **conditional firm** or **non-firm** service to these other customers at this time (see inset box).

Firm transmission service is more expensive to users of the system, but it is more desirable because the capacity is available to the power generator or marketer at any time when it is needed, but subject to outages. Non-firm customers, on the other hand, pay less for power, knowing that their power could be first to be interrupted in an emergency or outage.

Firm, Conditional, and Non-Firm Transmission Service

Firm transmission service is reserved and/or scheduled for a specific term (usually a year or longer) that is of the same priority as BPA's use of the transmission system.

Conditional firm transmission service is long-term transmission service that BPA may be able to provide when there is not enough firm transmission service, but conditional firm service has constraints that give BPA additional curtailment rights. Conditional firm service has a lower priority than firm service, but is a higher priority than non-firm service.

Non-firm transmission service is not guaranteed to be available and is only available after commitments for firm and conditional firm service have been met.

BPA has received new requests from other utilities and power generators for long-term firm transmission service on the SOA path. Under its OATT, BPA maintains a request queue for long-term, firm transmission service. By the mid 2000s, this queue had become overloaded with requests, and BPA became aware that many requests were speculative. In March 2008, to help manage the queue and identify the new transmission infrastructure that would be needed to provide service that customers had requested, BPA began its first Network Open Season (NOS) process. During this NOS process, utilities and power generators were given the opportunity to submit requests for use of BPA's transmission system to transmit their power. More information about the NOS process is available at BPA's Transmission Services website: http://www.transmission.bpa.gov/customer_forums/open_season/default.cfm.

During the 2008 NOS process, and the subsequent 2009 and 2010 NOS processes, BPA identified firm transmission service requests that would use the SOA path. BPA has no more firm capacity available on the SOA path to accommodate these new requests to transfer power (see Section 1.1.2.1, Load Growth, Limited System Capacity, and Congestion).

In spring 2011, BPA announced its plans to delay the next NOS to conduct a regional discussion on more effective ways to meet the transmission needs of the Northwest and to ensure BPA's policies support those needs. This delay will not affect BPA's work to serve requests received in the 2008, 2009 and 2010 open seasons.

1.1.3 Planning for Transmission Additions in the I-5 Corridor

Load growth and transmission service requests have combined to increase flows on the SOA transmission path to levels that the path cannot accommodate without adding transmission capacity. BPA has taken several steps to reduce congestion on the transmission system without building new lines. BPA has upgraded many facilities to maximize the use of existing transmission lines. To allow new generation facilities to move power on the transmission system, BPA initiated operational procedures such as RAS to maximize usage of the transmission system rather than building new substations and transmission lines (see Section 1.1.2.2, Reliability and Non-Wires Measures). However, increasing RAS and other operational procedures does not create additional capacity on the system and cannot effectively mitigate the stresses on the system without causing other problems.

Under its OATT, BPA must investigate actions it could take, including adding infrastructure, to provide access to the transmission system in response to requests for service.

Accordingly, BPA studied the transmission system in the area and identified where the system needed reinforcements to meet forecasted load growth. BPA's studies found that if an additional transmission line is not built in this area, continued congestion will jeopardize transmission system reliability and, eventually, lead to power interruptions or blackouts in the area. Based on these results, combined with planning studies that began in late 2006 and continued through 2007, BPA developed a plan that included a major infrastructure addition in this area.

In conducting its studies and undertaking transmission planning, BPA follows the reliability standards established by the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) (see inset boxes). NERC, the national electric reliability organization, and WECC, the regional reliability organization, help coordinate the operation and planning of the bulk transmission system throughout the region. Electric utilities are required to meet the standards of both organizations when planning new facilities.

BPA also sought review of the I-5 project through WECC's Project Coordination process (formerly known as the Regional Planning Project Review, or "Regional Review," process). The Project Coordination process is part of the initial development phase of a project. BPA coordinated the review through ColumbiaGrid (see inset box) and worked with other utilities and interested parties throughout the Northwest in developing the project.

During the Project Coordination process, BPA shared study results and alternate plans of service with other Northwest utilities. This provided other utilities with an opportunity to review and comment on BPA's plans with the goal of developing the best plan of service with respect to regional benefits and impacts. The Project Coordination process concluded in March 2008 with regional approval for the project.

About the North American Electric Reliability Corporation

NERC is an organization that has been delegated the responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.

NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is subject to oversight by FERC and governmental authorities in Canada.

As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. More information is available on NERC's website: http://www.nerc.com (NERC 2010). BPA is required by law to comply with these reliability standards.

About the Western Electricity Coordinating Council

WECC is the regional entity responsible for coordinating and promoting bulk electric system reliability in the West. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states.

In addition to coordinating system reliability, WECC ensures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in its bylaws.

Membership in WECC is open to all entities with an interest in the operation of the bulk electric system in the West. All meetings are open and anyone may participate in WECC's standards development process. More information is available on WECC's website: http://www.wecc.biz/ (WECC 2009).

About ColumbiaGrid

ColumbiaGrid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. The corporation itself does not own transmission, but its members and the parties to its agreements own and operate an extensive network of transmission facilities. Northwest members include BPA, Avista Corporation, Puget Sound Energy, Snohomish PUD, Tacoma Power, Chelan PUD, Grant PUD, and Seattle City Light.

ColumbiaGrid has substantive responsibilities for transmission planning, reliability, the Open-Access Same-Time Information System (OASIS), and other development services. These tasks are defined and funded through agreements with members and other participants. Development of these agreements is carried out in a public process with broad participation. More information about ColumbiaGrid is available on its website: http://www.columbiagrid.org/ (ColumbiaGrid 2009).

1.2 Need for Action

BPA needs to increase the electrical capacity and transfer capability of its 500-kV transmission system between the Castle Rock area in Washington and the Troutdale, Oregon area, in response to growing local demand for electricity and firm transmission requests that BPA has received to move power across this portion of its system.

A new 500-kV transmission line would increase the 500-kV transmission capacity in the southwest Washington/northwest Oregon area and allow BPA to provide for local load growth, maintain reliable power, and accommodate requests for long-term, firm transmission service. These new facilities would eliminate a transmission capacity constraint for this area, provide an additional electrical pathway, and increase system capacity (see Section 1.4, Transmission System Benefits, for other transmission system benefits related to a new line). Continuing to use BPA's existing transmission system in this area without a new transmission line would eventually cause BPA's transmission system to become overloaded at certain times of the year.

1.3 Purposes

In meeting the need for action, BPA will attempt to achieve the following purposes:

- Use ratepayer funds responsibly and efficiently.
- Minimize impacts to the natural and human environment.
- Maintain BPA transmission system reliability and performance.
- Meet BPA's statutory and contractual obligations.

1.4 Transmission System Benefits

In addition to meeting the need for the project (see Section 1.2, Need for Action), the project would have several benefits for operation of BPA's transmission system. The proposed new line and substations would help redistribute the flow of power, which would generally increase the capacity of the region's transmission system. Reinforcing the transmission system would also provide the transmission flexibility required to bring more renewable wind power from the east to population centers along the I-5 corridor.

In addition, the project would allow BPA to schedule outages on existing lines, which is necessary to perform critical maintenance. Because the existing system is so heavily used, it is difficult for BPA to schedule these outages to work on equipment. If critical maintenance is deferred, the reliability of the equipment is jeopardized. Reinforcing the transmission system with another line in this area would considerably improve BPA's ability to perform needed maintenance safely and keep the system functioning reliably.

This project would also reduce overall transmission system **line losses** and reduce BPA's reliance on RAS. Although RAS has provided a means to maximize the use of existing transmission facilities, as demands on the system grow, RAS is becoming more complex yet less effective at mitigating system problems. Reducing reliance on RAS by reinforcing the transmission system would help promote greater reliability for this area. All of these additional benefits would make the transmission system more efficient and reliable.

1.5 Agency Roles

1.5.1 Lead and Cooperating Agencies

BPA is the lead agency responsible for preparing this EIS under NEPA. BPA will use the EIS, along with comments from the public, other stakeholders and interested and affected agencies, to inform the following BPA decisions:

- Whether to build a new 500-kV transmission line to meet the need.
- If the decision is to build a transmission line, which route would be constructed to a new substation near Troutdale, Oregon, and which substation site near Castle Rock, Washington would be constructed at the north end of the line.

The Council on Environmental Quality (CEQ) regulations implementing NEPA allow for the designation of other federal, state, and local agencies and Indian Tribes as cooperating agencies for an EIS where appropriate.

The Corps is a cooperating agency in this process. The Corps' role is primarily to implement the requirements of the federal Clean Water Act (33 CFR) and Section 10 of the Rivers and Harbor Act of 1899 (33 U.S. C. 403). This role includes reviewing and making permit decisions on proposals, such as this project, that may require discharge of dredged or fill material into waters of the U.S., and work within navigable waters of the U.S. The Corps assists with identification of appropriate mitigation under these statutes. The Corps will use the EIS to help meet the requirements for the ongoing Clean Water Act Section 404(b)(1) alternatives analysis process. Under the Section 404(b)(1) Guidelines developed by the Environmental Protection Agency, the Corps may only permit discharges of dredged or fill material into waters of the U.S. that represent the least environmentally damaging practicable alternative, so long as the alternative does not have other significant adverse environmental consequences (see Section 27.10, Clean Water Act).

In furtherance of existing cooperative agreements between BPA and the states of Washington and Oregon, the Washington Energy Facility Site Evaluation Council (EFSEC) and the Oregon Department of Energy (ODOE) are participating in preparation of this EIS as cooperating agencies under NEPA. Among other things, these state agencies are assisting BPA in the environmental evaluation of transmission line routes, developing possible mitigation measures, and identifying state interests that should be addressed in the EIS.

Clark and Cowlitz counties are also cooperating agencies in this process. They are providing knowledge, information, and expertise to BPA about their respective jurisdictions.

1.5.2 Other Agencies That May Use this EIS

Chapter 27 of this EIS identifies other federal agencies that may have permitting, review, or other approval responsibilities related to certain aspects of the project. Certain state, regional, and local agencies also may use all or part of this EIS to fulfill their applicable environmental review requirements for any actions they may need to take for the proposed project (see Chapter 27, Consultation, Review, and Permit Requirements; Chapter 28, Consistency with State Substantive Standards; and Appendix A, Washington Department of Natural Resources Lands Analysis).

Before Washington state agencies can take action to authorize use of state-managed lands or issue permits, they must comply with the requirements of the Washington State Environmental Policy Act (SEPA), Chapter 43.21C Revised Code of Washington (RCW). BPA is coordinating with the state of Washington so that environmental issues relevant to the Washington state agencies and their SEPA needs are addressed to the fullest extent practicable in BPA's NEPA process. These agencies will use relevant information from this EIS to help fulfill their SEPA requirements for their actions related to the project.

Oregon does not have a similar SEPA process, but ODOE and other agencies will review the EIS to ensure that their relevant environmental issues are addressed in the EIS.

1.6 Public Involvement and Major Issues

Early in the development of this EIS, BPA solicited comments from the public; Tribes; federal, state, regional, and local agencies; interest groups; and others to help determine what issues should be studied in this EIS. Because these issues help define the scope of the EIS, this process is called "scoping." As the I-5 project has developed, there have been many opportunities for public involvement and participation to continue.

1.6.1 EIS Scoping Outreach

During the scoping period for the EIS, BPA used several ways to request comments.

BPA published a Notice of Intent to prepare an EIS for the project in the Federal Register in October 2009 (74 Federal Register 52482, October 13, 2009). The scoping period was originally scheduled to close November 23, 2009. On November 18, 2009, in response to requests for more time to submit comments, BPA extended the comment period to December 14, 2009.

BPA notified more than 9,500 landowners within a 500-foot (either side of existing BPA rights-of-way) to 1-mile buffer or study area (greater in some areas) under consideration by BPA engineers for siting a new transmission line, substations, and access roads. BPA also notified other interested individuals, Tribes, elected officials, organizations, and agencies. The notification packet included a letter announcing the project and scoping period, a project fact sheet, project map, comment form, and return envelope. A separate letter and Permission to Enter Property (PEP) form was sent to landowners with property within the notification buffers described above. BPA also posted information, including interactive maps, on the project website: http://www.bpa.gov/go/i5. The website also had an electronic comment form allowing the public to submit comments online.

BPA sent a press release to local media, and placed paid ads in the following newspapers about the scoping period and public scoping meetings:

- Battle Ground Reflector – October 13 and October 18, 2009
- Camas-Washougal Post-Record – October 13 and October 21, 2009
- The Columbian – October 14, October 18 and October 26, 2009
- Gresham Outlook – October 14 and October 28, 2009

- Longview Daily News – October 13 and October 18, 2009
- The Oregonian – October 14 and October 28, 2009

BPA invited comments through a variety of methods, including online, through a dedicated voice messaging system, comment forms mailed or faxed, and written and verbal comments collected at the public scoping meetings. BPA posted all comments it received on the project website.

1.6.2 Public Scoping Meetings

BPA held a series of six open house-style public scoping meetings at six different locations (see Table 1-1).

Table 1-1 Public Scoping Meetings

Meeting Date	Meeting Location	Meeting Attendance[1]
October 27, 2009	Amboy, WA	547
October 28, 2009	Vancouver, WA – Clark College	465
October 29, 2009	Longview, WA	614
November 3, 2009	Camas, WA	480
November 5, 2009	Gresham, OR	47
November 7, 2009	Vancouver, WA – Hazel Dell	344

Note:
1. This column reflects the number of people who signed the meeting sign-in form. Some members of the public declined to sign the form.

Each meeting featured eight stations with topic-specific project information and BPA staff available to answer questions. Maps were available to help landowners locate their property in relation to the notification buffers and multiple transmission line route segments that BPA had identified as part of the buffers. BPA staff recorded verbal public comments in their notes and also on flip charts positioned at each station. A comment station also provided members of the public an opportunity to complete a comment form.

1.6.3 EIS Scoping Comment Summary

Over 2,500 people attended the public scoping meetings. Each meeting was summarized, and meeting summaries were posted to the project website the next work day after each meeting. People expressed opinions about a wide range of issues for BPA to consider, including the following:

- Project purpose and need
- Project decision-making process
- Public involvement
- Regulatory obligations, coordination, and documentation
- Draft EIS approach and content
- Transmission tower, substation, and line design and transmission rights-of-way

- Undergrounding lines
- Transmission technology
- Transmission line and access road construction
- Access road siting and rights-of-way
- Nuisance, safety, and maintenance issues
- Project monitoring and mitigation
- Route segments and alternatives
- Threatened, endangered, and sensitive plant and animal species, and wildlife and wildlife habitat
- Socioeconomics, including cost to landowners, eminent domain and compensation, and environmental justice
- Quality of life issues
- Health and safety including noise and **electric and magnetic field** (EMF) effects
- Aesthetics
- Cumulative impacts
- Existing and planned land uses
- Transportation
- Recreation
- Mining
- Surface and ground water resources, wetlands, and floodplains
- Native and non-native vegetation
- Air quality and climate
- Cultural and historic resources
- Geology and soils

This is a partial list of issues identified from the comments received. All comments received were logged in and forwarded to resource specialists to consider when preparing their environmental impact analyses for the EIS, and to engineers to consider as they continued working on the preliminary project design.

Over 3,000 communications and over 7,000 individual comments were received during the scoping period. A summary of the comments received during the scoping period is available on the project website: http://www.bpa.gov/corporate/i-5-eis/documents/I-5_ScopingSummary.pdf.

BPA continued to take comments on the project after the scoping period ended and will take comments throughout the environmental process. Additional summaries of comments received after the scoping period ended are available on the project website.

1.6.4 Post-Scoping BPA Public Meetings

In August and September, 2010, BPA hosted additional public meetings to present updated project information (see Table 1-2):

Table 1-2 Post-Scoping Public Meetings

Meeting Date	Meeting Location	Meeting Attendance[1]
August 30, 2010	Castle Rock, WA	225
August 31, 2010	Vancouver, WA – Skyview High School	110
September 8, 2010	Amboy, WA	275
September 12, 2010	Camas, WA	130

Note:
1. This column reflects the number of people who signed the meeting sign-in form. Some members of the public declined to sign the form.

BPA sent a press release to local media, and placed paid ads in the following newspapers about the meetings:

- Battle Ground Reflector – August 25, September 1, and September 8, 2010
- Camas-Washougal Post-Record – August 24, August 31, and September 7, 2010
- The Columbian – August 22, August 29, and September 5, 2010
- Longview Daily News – August 22, August 29, and September 5, 2010
- The Oregonian – August 22 and September 5, 2010

BPA also provided project updates and additional opportunities for public input at the following listening sessions:

- On November 3, 2010, BPA hosted a meeting for property owners along a small portion of Segment F where additional field work and modifications to the proposed design caused the notification buffer to be expanded in this area. Expansion of the notification buffer involved 29 new land parcels. Twenty-three people attended this meeting.
- On December 8, 2011, BPA presented a brief project update and took public comment at the Battle Ground Community Center. About 300 people attended this meeting. Thirty-seven people provided verbal comment.

1.6.5 Post Scoping Outreach and Public Comments

In addition to BPA's public meetings, BPA staff attended meetings organized by elected officials, neighborhood groups, community organizations, and others. BPA staff also held meetings with federal, state and local agencies; representatives of Tribes with interests in the area; and other interested parties and individuals. From the scoping period until the release of the draft EIS, BPA continued to update the project website with new information and interactive maps; mailed out frequent project updates and posted them on the website; attended local service club, civic group and neighborhood meetings as requested (or as resources allowed); provided information at local farmers' markets, fairs, community events, and local libraries; and continued to collect comments (see inset box). All BPA's post-scoping public outreach materials for the proposed project are available on the project website: http://www.bpa.gov/corporate/i-5eis/documents/cfm.

Comments received from the close of the scoping period to the release of the draft EIS are contained in supplemental comment reports posted on the project website. The issues included in these comments are similar to those received during scoping (see Section 1.6.3, EIS Scoping Comment Summary). These comments were also used by BPA staff in their engineering and environmental work.

1.7 Issues Outside the Scope of the I-5 Project or this EIS

Most issues raised during the scoping process are considered to be within the scope of the project and are addressed in this EIS. However, a few issues are considered to be either beyond the scope of this EIS or are outside the scope of the project. Issues outside the scope of this EIS are not addressed further in this EIS. Issues outside the scope of the project are not considered in the evaluation of the project itself, but may be further addressed in other EIS chapters (e.g., Chapter 26, Cumulative Impacts).

1.7.1 Regional Generation Development

Some comments received during scoping asked that BPA undertake a programmatic review of all energy generation projects, including new and proposed wind development that may occur throughout the region related to any increased capacity on BPA's transmission system. Generation projects are not proposed, constructed, or operated by BPA. Instead they are proposed and undertaken by private entities and their siting and development is controlled by state or local jurisdictions and other regulating entities. BPA's role is typically limited to deciding whether to interconnect these proposed projects, in compliance with its OATT, after an evaluation of the environmental effects of the proposed interconnection is done under NEPA. As a result, BPA does not have a region-wide program or plan related to wind or other generation projects, and does not dictate or direct where these projects are proposed.

Furthermore, decisions by BPA on whether to interconnect a particular proposed generation project to its transmission system are made independently of a decision on whether to construct the project. More specifically, a decision to interconnect any generation project is not dependent on construction of this transmission line. This transmission line is being proposed to respond to increasing load growth, requests for transmission service from a variety of existing and proposed generation sources, as well as from entities seeking to move their electrical power from one point to another. These requests are already in BPA's queue for transmission service. A decision to proceed with the I-5 project would not be dependent on decisions related to interconnection of any new or proposed generation development projects in the region.

Therefore, new and proposed generation development projects are not considered to be within the scope of the project analyzed in this EIS. However, to the extent that the potential environmental impacts of any reasonably foreseeable new or proposed generation projects in the vicinity of the I-5 project are cumulatively added to the potential environmental impacts of the project, these impacts are discussed and considered in the cumulative analysis in this EIS (see Chapter 26, Cumulative Impacts).

Additional Public Participation Opportunities

Direct mail, email and phone contacts

The I-5 project is one of the largest public involvement efforts BPA has undertaken. Since announcing the project in 2009, BPA has mailed, emailed, met, and spoken with thousands of interested stakeholders. Our mailing list includes more than 11,000 addresses and more than 2,400 email addresses. The project team has sent 11 mailings (available on the project website: www.bpa.gov/goto/i5), and hosted 12 public meetings attended by more than 4,000 people (see Sections 1.6.2, Public Scoping Meetings, and 1.6.4, Post-Scoping BPA Public Meetings).

Local media

Regular local media outlets, such as newspapers and TV stations, have helped us share news and inform the region about project developments and key issues. On several occasions, BPA contacted the media to share elements of the environmental review and other project developments. A BPA representative also was interviewed by staff of the website Couv.com and answered questions about the project and its environmental review. Couv.com is a local website that focuses on issues affecting Vancouver and Clark County, Washington.

Developing newsletters

Using the feedback we received from a survey at our August 2010 public meetings, we learned that most people wanted to receive project information through print and email updates. Project staff then developed a newsletter to provide updates and address key questions and concerns raised by community members and leaders. Between October 2010 and June 2012, BPA mailed seven newsletters that provided new project information and schedule updates; results of exploring suggested changes to the project; and contact information for questions, comments or summaries of public meetings and comments.

Public comment helped shape this Draft EIS

The agency has responded to public comments about this project. We heard many suggestions about alternatives for BPA to consider; these are discussed in Chapter 4 (see Section 4.7, Alternatives Considered but Eliminated from Detailed Study). Comments also shaped our evaluation of the project's potential affect on communities in general, and in specific geographic areas. Because people requested more detail and a web-based mapping tool, we created an interactive map, available on our website for the public to use to see how the project would affect their communities. This and other materials available on the website helped address questions from thousands of property owners and interested citizens.

Additional offers to meet

Given the level of interest in the project, BPA extended several offers, through meetings and mailings, to attend group meetings to discuss the project and answer as many questions as possible. Staff attended meetings with local community groups, rotary clubs, cities, counties, neighborhoods and citizen groups. Clark & Cowlitz County Farm Forestry Association hosted a meeting in September 2010 to discuss how BPA would address access and security issues along newly constructed roads, how BPA would value timber lands, and how future crops would be factored into the value calculation. BPA staff attended to answer questions and listen. In November 2010, Clark and Cowlitz county commissioners hosted a public meeting to hear why BPA is no longer considering options to Pearl Substation in Oregon. BPA Administrator Steve Wright attended and answered a wide range of questions.

Citizen group formation and engagement

Several citizen groups formed since BPA announced the project. BPA began attending meetings organized by groups as early as November 2009. These groups created and maintained their own websites and outreach lists, held meetings and rallies, and purchased or posted hundreds of signs throughout Clark and Cowlitz counties (including billboard space) to share their views. Members or their boards had opportunities to speak with BPA transmission executives and the BPA Administrator about their concerns and ideas. BPA attended and spoke at more than 14 meetings, rallies or community events hosted or organized by citizens. The largest was held at Prairie High School in Battle Ground (between 800 and 1,000 participants). We also attended meetings at other schools, libraries and fire stations.

We will continue our public involvement efforts throughout the life of the project.

1.7.2 Regional Transmission Development

Some comments received during scoping asked that BPA undertake a programmatic review of all of its proposed transmission infrastructure projects in the region. Transmission infrastructure projects are proposed by BPA on a project-specific basis when needed to address various transmission reliability and service issues on portions of BPA's transmission system. Increases in capacity that may occur on BPA's existing transmission system from proposed BPA improvements would be in response to existing requests for transmission service, rather than designed to provide significant additional, unsubscribed capacity. While there may be synergies among the various proposed BPA transmission infrastructure projects in the region, no project is wholly dependent on any other project for its viability or success. Other proposed BPA transmission infrastructure projects in the region are therefore outside of the scope of the I-5 project. Nonetheless, any reasonably foreseeable transmission infrastructure projects with cumulatively additive environmental impacts to the I-5 project are discussed and considered in the cumulative analysis in this EIS (see Chapter 26, Cumulative Impacts).

1.8 Organization of this EIS

The remainder of this EIS is organized as follows:

- Chapter 2 describes how BPA system planners, engineers and other specialists developed potential routes for the transmission line and sites for the new substations. It includes a summary of the route segments that make up the action alternatives.
- Chapter 3 describes the transmission components that make up the project, and construction and maintenance requirements. It also includes mitigation measures that are included as part of the project.
- Chapter 4 describes the action alternatives, the No Action Alternative, and alternatives eliminated from detailed consideration.
- Chapters 5 through25 describe, for each resource, the existing environment that could be affected by the project, environmental consequences of the action alternatives and the No Action Alternative, and mitigation measures that could be used to minimize impacts to resources.
- Chapter 26 discusses cumulative impacts.
- Chapter 27 discusses the permits and other approvals that must be obtained to implement the project.
- Chapter 28 discusses the project's consistency with state substantive standards.
- Chapters 29 through 32 list the references used, individuals who helped prepare the EIS, the individuals, agencies, and organizations notified of the availability of this EIS, and a glossary.
- Chapter 33 contains the document index.
- Supporting technical information is provided in appendices or referenced on the project website: http://www.bpa.gov/go/i5.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **AMENDED RESPONSE OF PORTLAND GENERAL ELECTRIC COMPANY** to be served by electronic mail and by First Class U.S. Mail, postage prepaid and properly addressed, to those parties on the attached service list for OPUC Docket UM 1535. **The Confidential portions of the Amended Response and Attachment F have been provided to those parties who have signed General Protective Order** No. **11-097.**

Dated at Portland, Oregon, this 16TH day of September, 2013.

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