PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

September 15, 2010

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: Docket UM 1050
Petition of PacifiCorp Requesting Approval of Amendments to the Revised Protocol Allocation Methodology, Motion for a Protective Order and Waiver of Paper Service

PacifiCorp d/b/a Pacific Power (Company) submits for filing an original and five copies of its Petition, Direct Testimony and Exhibits in the above-referenced matter. Also enclosed are two CDs containing the confidential and non-confidential work papers supporting the testimony and exhibits.

Included with this filing is a motion for a protective order. The Commission previously issued a protective order in this docket for Phase 2. Since this time, the Commission's standard protective order has changed; therefore, the Company is requesting that the Commission issue its current standard protective order. Expedited consideration is requested.

Lastly, pursuant to OAR 860-013-0070(4), the Company waives paper service in this proceeding.

PacifiCorp respectfully requests that all data requests regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

Informal inquiries may be directed to Joelle Steward, Regulatory Manager at (503) 813-5542.

Sincerely,

Andrea Kelly /sak

Andrea L. Kelly
Vice President, Regulation

Enclosures

cc: Service List – UM 1050

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UM 1050, on the date indicated below by email and/or overnight delivery, addressed to said parties at his or her last-known address(es) indicated below.

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UM-1050

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DATED: September 15, 2010

Carrie Meyer
Coordinator, Administrative Services

Petition

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1050

In the Matter of the Application of PACIFICORP for an Investigation of Inter-Jurisdictional Issues	**PETITION FOR APPROVAL OF AMENDMENTS TO REVISED PROTOCOL ALLOCATION METHODOLOGY**

Pursuant to ORS 756.568 and OAR 860-013-0020, PacifiCorp (Pacific Power or Company) hereby submits its petition (Petition) to the Public Utility Commission of Oregon (Commission) requesting approval of amendments to the Revised Protocol allocation methodology previously approved by the Commission in Order No. 05-021 in this proceeding on January 12, 2005. In support of the Petition, Pacific Power states as follows:

1. Pacific Power is a division of PacifiCorp. PacifiCorp is an Oregon corporation that provides electric service to retail customers through its Pacific Power division in the states of California, Oregon, and Washington, and through its Rocky Mountain Power division in the states of Idaho, Utah, and Wyoming.

2. Pacific Power is a public utility in the state of Oregon under ORS 757.005 and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Oregon. The Company serves approximately 580,000 retail customers in Oregon. Pacific Power's principal place of business in Oregon is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232.

3. The Company respectfully requests that the Commission complete its review and issue an order with respect to this Petition no later than March 31, 2011, for the reasons discussed herein.

4. Communications regarding this filing should be addressed to:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232
Email: oregondockets@pacificorp.com

Ryan Flynn
Senior Legal Counsel
PacifiCorp
825 NE Multnomah Street, Suite 1800
Portland, Oregon 97232
Email: ryan.flynn@pacificorp.com

In addition, Pacific Power requests that all data requests regarding the Petition be sent to the following:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

Informal questions may be directed to Joelle Steward, Regulatory Manager, at (503) 813-5542.

I. BACKGROUND

5. PacifiCorp is a public utility pursuant to ORS 757.005. It provides retail electric service to more than 1.7 million customers in Oregon and five other western states. PacifiCorp owns substantial generation and transmission facilities. Augmented with wholesale power purchases and long-term transmission contracts, these facilities operate as a single system on an integrated basis to provide service to all customers in a cost-effective manner. PacifiCorp recovers costs of owning and operating its generation and transmission system in retail prices established from time to time in state regulatory proceedings.

6. In such state proceedings, it is customary to first determine what assets are deemed to be in the Company's rate base in the state conducting the proceeding. Then, because all of the Company's generation and transmission resources are deemed to be used to serve the Company's customers in all of its state jurisdictions, it is necessary to

determine what portion of the costs associated with each of the rate-based resources ought to be allocated to customers in the state for which prices are being established. If different state commissions make different decisions regarding what resources should be deemed to be in PacifiCorp's rate base or if different state commissions adopt different policies for allocating the costs of resources among states, the Company may not be afforded the opportunity to recover its full cost of providing electric service.

7. Each of PacifiCorp's state regulatory commissions has the ability to pursue policies that it believes are in the public interest in its state. However, it is also important for PacifiCorp to be able to make business decisions in an environment where differing state policies do not result in denying the Company a reasonable opportunity to recover its prudently incurred costs. This would create a disincentive for PacifiCorp to invest in its system.

8. Accordingly, in 2002, PacifiCorp filed applications in each of its six jurisdictions requesting the state commissions to investigate a number of important issues related to its status as a multi-jurisdictional utility and to endorse a process through which these issues can be considered by stakeholders, the Multi-State Process (MSP). In its application, the Company identified issues to be investigated, related primarily to the inter-jurisdictional allocation of prudently-incurred costs associated with investments in existing and new generation and transmission resources and how future policy scenarios including, but not limited to, direct access, sale or purchase of service territory or closure of a major industrial facility should be considered and implemented among the Company's state jurisdictions to allow PacifiCorp a reasonable opportunity to recover all of its prudently-incurred costs, among other things.

9. After approximately two years of discussions and negotiations, on September 29 and 30, 2003, PacifiCorp initiated proceedings in Utah, Oregon, Wyoming and Idaho seeking ratification of an Inter-jurisdictional Cost Allocation Protocol (Protocol) by the Public Service Commission of Utah, the Public Utility Commission of

Oregon, the Public Service Commission of Wyoming, and the Idaho Public Utilities Commission (collectively, the Commissions).

10. Thereafter, subsequent and substantial discussions occurred that resulted in the development of a Revised Protocol. The Revised Protocol was agreed to by the parties on June 28, 2004. The Revised Protocol seeks to allocate PacifiCorp's costs among its jurisdictional states in an equitable manner, ensures PacifiCorp plans and operates its generation and transmission system on a six-state integrated basis that achieves a least cost-least risk resource portfolio for customers, allows each state to independently establish its ratemaking policies and provides PacifiCorp with the opportunity to recover 100 percent of its prudently-incurred costs. The Revised Protocol was approved by the Public Utility Commission of Oregon on January 12, 2005.

II. REQUEST FOR APPROVAL OF AMENDMENTS TO THE REVISED PROTOCOL

11. Since the approval of the Revised Protocol, interested parties in Utah raised concerns that the continued use of the Revised Protocol may result in Utah-allocated revenue requirement that is higher when compared to revenue requirement allocated using the Rolled-In methodology than was anticipated by the Public Service Commission of Utah when it originally adopted the Revised Protocol. The Standing Committee and workgroups have been collaborating since September 2009 to come up with potential solutions acceptable to all parties in the context of the Revised Protocol allocation methodology, including the performance of various studies by the Company at the request of the Standing Committee.

12. In July 2010, the Standing Committee reached an agreement in principle to amend the Revised Protocol allocation methodology; such agreement will be known as the 2010 Protocol and is provided as Exhibit PPL/101 to the direct testimony of Ms. Andrea L. Kelly. If adopted, the 2010 Protocol will remain in effect for Company filings made through 2016. The amendments are intended to allow for greater movement to a

Rolled-In allocation methodology, while retaining a Hydro Endowment for the former Pacific Power & Light states of Oregon, California, Washington and part of Wyoming.

13. As further described in the attached direct testimony of Company witnesses Ms. Andrea L. Kelly, Vice President of Regulation; Mr. Steven R. McDougal, Director of Revenue Requirement; and Mr. Gregory N. Duvall, Director, Long-Range Planning and Net Power Costs, the 2010 Protocol continues to identify state resources based on cost responsibility and regional resources for the Hydro Endowment calculation. Besides using a Rolled-In allocation methodology as the starting point, a significant change relates to the Embedded Cost Differential (ECD). The scope of the ECD has been reduced and limited, using a comparison of embedded costs based on resources in place on the Company's system prior to 2005. The ECD calculation has been based on projected pre-2005 resource costs and the value allocated to each state is fixed and levelized over the term of the 2010 Protocol. For the duration of the 2010 Protocol a fixed dollar amount per year deviation would be applied to each state's revenue requirement under the Rolled-In allocation methodology. The deviation is composed of two parts; a situs adjustment associated with the surcharge imposed under the Klamath Hydroelectric Settlement Agreement to Oregon and California with a corresponding credit to the other states, and the fixed levelized ECD.

14. The requested amendments in the Revised Protocol allocation methodology result in a consistent and fair cost allocation method that assures the Company a reasonable opportunity to recover all of its prudently-incurred costs and supports further system investment. Adoption of the changes are just, reasonable and in the public interest.

III. PROPOSED COMMISSION PROCEEDING PROCESS

15. Given the significant discussions and analysis since November 2008 by interested parties, as described in Ms. Kelly's direct testimony, Pacific Power respectfully

requests that the Commission complete its review and issue an order with respect to this Petition no later than March 31, 2011. The Company also proposes that within 30 days of receipt of the date of this Petition, the Commission convene a prehearing conference to establish a schedule for further proceedings. In this context, the Company proposes the following illustrative schedule of milestones that would allow for discovery, rounds of testimony and hearings that would allow sufficient time for a comprehensive review:

Event	Date
PacifiCorp Petition, Testimony and Exhibits	September 15, 2010
Intervenor Testimony due	Early-December 2010
PacifiCorp Rebuttal Testimony due	Early-January 2011
Public Hearing	Late-January 2011
Briefs due	Mid-February 2011
Target Date for Commission Decision	March 31, 2011

IV. CONCLUSION

WHEREFORE, by this Petition, Pacific Power respectfully requests that the Commission issue an order approving the 2010 Protocol allocation methodology as described in the direct testimony of Company witnesses Ms. Kelly, Mr. McDougal, and Mr. Duvall no later than March 31, 2011.

DATED this 15th day of September 2010.

Respectfully submitted,

PACIFIC POWER

Ryan Flynn/SME

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Motion for Protective Order

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1050

In the Matter of the Application of PACIFICORP for an Investigation of Inter-Jurisdictional Issues	MOTION FOR PROTECTIVE ORDER Expedited Consideration Requested

Pursuant to ORCP 36(C)(7) and OAR 860-012-0035(1)(k), PacifiCorp d/b/a Pacific Power ("Company") moves for the expedited entry of the Public Utility Commission of Oregon's ("Commission") general protective order in this proceeding. The Company requests expedited consideration of this Motion to allow parties that execute the protective order to obtain prompt access to the confidential testimony filed in support of the Petition and to expedite any discovery in this proceeding. Good cause exists to issue a Protective Order to protect commercially sensitive and confidential business information related to the Company's Petition requesting approval of amendments to the Revised Protocol allocation methodology previously approved by the Commission in Order No. 05-021. In support of this Motion, the Company states:

1. The Commission previously found good cause to issue protective orders in this proceeding. *See Re Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket UM 1050, Order No. 03-638 (Oct. 31, 2003); Order No. 02-291 (Apr. 22, 2002). The Company's need for a protective order has not changed. However, the Commission's standard protective order has changed since the Commission last issued a protective order in this docket, so the Company is requesting that the Commission issue its current standard protective order.

2. The Commission's rules authorize PacifiCorp to seek reasonable restrictions on discovery of trade secrets and other confidential business information. *See* OAR 860-11-0000(3) (adopting Oregon Rules of Civil Procedure ("ORCP"); ORCP 36(C)(7) (providing protection against unrestricted discovery of "trade secrets or other confidential research, development, or commercial information"). *See also In re Investigation into the Cost of Providing Telecommunication Service*, Docket UM 351, Order No. 91-500 (1991) (recognizing that protective orders are a reasonable means to protect "the rights of a party to trade secrets and other confidential commercial information" and "to facilitate the communication of information between litigants").

3. The Company anticipates that parties to this docket may request proprietary cost data and models, commercially sensitive load and resource projections, confidential market analyses and business projections, and confidential information regarding contracts for the purchase or sale of electric power, power services, or fuel. This confidential business information is of significant commercial value, which could expose the Company to competitive injury if disclosure is unrestricted.

4. It is substantially likely that Staff and others in this proceeding will seek to discover a large amount of information held by PacifiCorp, including confidential business information. "The Commission's standard blanket protective order is designed to facilitate discovery in cases involving discovery of large numbers of documents." *See In re Portland Extended Area Service Region*, Docket UM 261, Order No. 91-958 (1991). Issuance of a protective order will facilitate the production of relevant information and expedite the discovery process.

5. The Company requests expedited consideration of this Motion to allow parties who execute the protective order to obtain prompt access to the confidential workpapers in support of the Company's Petition and to expedite any discovery in this proceeding.

For the foregoing reasons, PacifiCorp requests expedited entry of a standard Protective Order in this docket.

DATED this 15th day of September 2010.

Respectfully submitted,

PACIFIC POWER

Ryan Flynn /SAC

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Docket No. UM-1050
Exhibit PPL/100
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Andrea L. Kelly

September 2010

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Andrea L. Kelly, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, OR 97232. I am currently employed as a Vice President in Regulation.

Qualifications

Q. Please summarize your education and business experience.

A. I hold a Bachelor's degree in Economics from the University of Vermont and an MBA in Environmental and Natural Resource Management from the University of Washington. After graduate school, I joined the Staff of the Washington Utilities and Transportation Commission. In 1995, I became employed by PacifiCorp as a Senior Pricing Analyst in the Regulation Department and advanced through positions of increasing responsibility. From 1999 through 2005, I led major strategic projects at PacifiCorp including the Multi-State Process (MSP) and the regulatory approvals for the MidAmerican-PacifiCorp transaction. In March 2006, I was appointed as a Vice President in Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes, I have appeared as a witness on behalf of PacifiCorp in the states of California, Idaho, Oregon, Utah, Washington, and Wyoming.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. My direct testimony describes the process and approaches leading up to this filing of the proposed 2010 Protocol allocation methodology. Specifically, my direct testimony provides:

- a brief history of the MSP leading up to the adoption of the Revised Protocol;
- a brief history of the work of the Standing Committee workgroup since November 2008 that has culminated in this filing proposing limited amendments to the Revised Protocol;
- an overview of the proposed amendments to the Revised Protocol and the concerns that the amendments are designed to address;
- a discussion of the Company's view of the commission proceedings necessary to process this petition; and
- a discussion of the Company's view of processes necessary to ensure successful implementation of the 2010 Protocol through calendar year 2016 and beyond.

I also introduce the other two Company witnesses in this proceeding.

Q. Are you also sponsoring an exhibit to your testimony?

A. Yes. Exhibit PPL/101 presents the 2010 Protocol with all of its Appendices. Although I sponsor Appendix A, Company witness Mr. Steven R. McDougal sponsors the remaining Appendices.

Brief History of the Revised Protocol

Q. Please provide a brief history of the events that gave rise to the Revised Protocol.

A. In December 2000, the Company proposed to reorganize itself into six state distribution companies, a generation company and a service company. This

Structural Realignment Proposal (SRP) filing was in response to a number of external developments, including: (1) the lack of agreement among regulatory jurisdictions regarding the Company's inter-jurisdictional cost allocation process; (2) direct access initiatives in Oregon and elsewhere; (3) the need to provide independent control of transmission assets consistent with Federal Energy Regulatory Commission (FERC) expectations; (4) fundamental changes that occurred in wholesale power markets; and (5) increasingly divergent policy goals of various state commissions.

Q. What was the outcome of the SRP filings?

A. The SRP filings proved to be controversial - in large measure because of a concern that the proposed restructuring would result in a transfer of jurisdiction from state commissions to the FERC and the Securities and Exchange Commission. Ultimately, a number of parties and some state commissioners encouraged the Company to seek other means of resolving the Company's concerns that did not require a legal restructuring of the Company. The Company was strongly encouraged to initiate an informal process aimed at achieving consensus among interested parties regarding a number of important issues facing the Company. To that end, in March 2002, the Company made an additional set of state filings asking the state commissions to initiate investigations and endorse a collaborative process to address inter-jurisdictional issues facing PacifiCorp. These filings were broadly supported by the state commissions and gave rise to what became known as the MSP. Pending the MSP, the Company agreed to put the SRP filings on hold.

Q. What occurred in the MSP?

A. An initial organizing meeting was held in April 2002 in Boise, Idaho. At that first meeting, a schedule of future meetings and objectives for the process were established. A number of additional MSP meetings were held through July 2003, after which the Company made an additional filing with the states seeking ratification of a proposed solution, the Protocol. Additional discussions related to the Protocol continued through September 2004, which resulted in the Company supplementing its filings with the Revised Protocol. Through commission proceedings, the four state commissions of Utah, Oregon, Wyoming and Idaho issued orders adopting the Revised Protocol in late 2004 and early 2005. Utah's and Idaho's adoption of the Revised Protocol was accompanied by rate mitigation mechanisms tied to the difference between the revenue requirement calculated under the Revised Protocol allocation methodology and the revenue requirement calculated under the Rolled-In allocation methodology.

Q. Who participated in the MSP collaborative meetings?

A. All of the major meetings were attended in person by in excess of 50 individuals representing some 18 entities from the states of Utah, Oregon, Wyoming, Washington and Idaho. These included representatives of state commission policy staffs, advocacy staffs, industrial customers and consumer groups. A number of other people participated by telephone.

Q. How would you characterize the overall objectives of the Revised Protocol?

A. The objectives of the Revised Protocol include:

- allocating PacifiCorp's costs among its jurisdictional states in an equitable manner;
- ensuring PacifiCorp plans and operates its generation and transmission system on a six-state integrated basis in a manner that achieves a least cost-least risk resource portfolio for its customers;
- allowing each state to independently establish its ratemaking policies. Each state is encouraged to consider the impact its decisions have on other states served by PacifiCorp; and
- providing PacifiCorp a reasonable opportunity to recover 100 percent of its prudently incurred costs.

Q. Does the Revised Protocol contain provisions for continued dialogue among the states?

A. Yes. Section XIII.B of the Revised Protocol established the Standing Committee. While not abridging the integrity of commission decision-making processes within each respective state, the Standing Committee:

- monitors and discusses inter-jurisdictional allocation issues facing PacifiCorp and its customers;
- helps to organize and direct work group analysis of inter-jurisdictional allocation issues;
- ensures work group analysis is supported by sound technical analysis;
- shares views on possible amendments to the Revised Protocol, as they may arise;
- seeks consensual resolution of issues arising under the Revised Protocol;

- ensures wide dissemination of information regarding Standing Committee meeting locations and dates and information relating to its activities;
- ensures and encourages open participation in Standing Committee meetings by all interested persons; and,
- appoints the Standing Neutral to facilitate discussions among the states, to monitor issues and to assist the Standing Committee.

Recent Activities of the Standing Committee

Q. Please provide an overview of the recent activities of the Standing Committee that led up to this filing.

A. At the November 2008 Commissioners' Forum, an issue was raised by Utah related to the performance of the Revised Protocol as compared against the forecast results at the time the Revised Protocol had been adopted. At that meeting, MSP participants reviewed a chart comparing the MSP 2005 forecast with the original MSP 2004 forecast. The chart also provided comparisons to the Rolled-In allocation methodology both with and without the Utah rate mitigation measures. The chart raised concerns that Utah's expectations when adopting the Revised Protocol - near-term costs but long-term savings for Utah customers as compared to Rolled-In - were not projected to be fulfilled. In response to this concern, at the Standing Committee Annual Meeting held in November 2008, the Company agreed to undertake a new forecast of results under the Revised Protocol using updated information from the upcoming 2008 Integrated Resource Plan which was to be filed in March 2009. The results were to be completed in sufficient time to be presented at the next annual Commissioners' Forum. As discussed in detail in the direct testimony of Mr. McDougal, the preliminary results of these studies were provided to parties on August 17, 2009.

On August 27, 2009, the Standing Neutral sent a request to parties for any new issues to be considered by the Standing Committee in preparation for the annual meeting scheduled for December 9, 2009. On September 9, 2009, several Utah parties issued a notification to MSP participants of the following issue:

> "Given review of the Company's August 17, 2009, MSP Preliminary Study Results (2009 MSP Study) and the Public Service Commission of Utah's (PSCU) December 14, 2004, Report and Order in Docket No. 02-035-04, (MSP Order) the issue we raise is whether continued use of the revised protocol and rolled-in methods with rate mitigation measures is just and reasonable for PacifiCorp's Utah jurisdiction."

Q. What action did the Standing Committee take in response to this issue?

A. The Utah issue was first discussed by the Standing Committee at a meeting held on September 10, 2009. At the conclusion of the meeting, Utah parties were asked by the Standing Committee to develop a potential solution.

Q. What was the Utah parties' potential solution?

A. At the September 24, 2009 Standing Committee meeting, Utah parties proposed a strawman solution that would eliminate seasonal and regional resource categories, limit the state resource category to demand-side management programs and state portfolio standard resource costs, and apply allocation factors for system resources to the resources formerly addressed in the seasonal, regional and state resource categories. In a nutshell, the strawman solution described a move to a Rolled-In allocation methodology.

Q. What potential solutions were considered subsequently?

A. Over the next several months of Standing Committee meetings, participants considered the Utah parties' strawman solution, together with additional solution proposals offered for consideration by other MSP participants that focused on the elements of the Revised Protocol that could be analyzed as alternative considerations to address the Utah issue. At the direction of the Standing Committee, the Company provided quantitative analysis of the various proposals to aid the Standing Committee's deliberations and considerations.

Q. When was the first opportunity to inform and update the Commissioners of the work of the Standing Committee to address the issue?

A. The Standing Committee convened a Commissioners' Forum in Portland, Oregon on April 6, 2010. At that meeting, the Standing Committee updated Commissioners generally on the activities of the Committee since the previous Commissioners' Forum in November 2008. The Commissioners were also presented with the Utah issue, together with a summarization of the analyses performed and potential solutions considered. A concern raised was that the Utah issue, if insufficiently addressed, could cause states to depart from a consistent method of cost allocation and impair integrated system planning. After some consideration of the issues and materials presented, the Commissioners directed the Standing Committee to continue progress on analyzing potential solutions to resolve the Utah issue and requested a follow-up meeting for the summer of 2010. In general, it was recognized that any solution would need to strike a balance between making progress toward fully Rolled-In allocations while maintaining a hydro endowment for Oregon and Wyoming.

Q. What was the progress of potential solutions prior to the next Commissioners' Forum?

A. The Standing Committee and participants met for an additional six meetings to continue the quantitative analyses of potential solutions to the Utah issue. As well as analyzing potential solutions, the Standing Committee and participants analyzed the potential impacts of not being able to achieve a resolution acceptable to all states. These studies, known as the control area structural separation and go-it-alone studies, were informative of the benefits of PacifiCorp continuing to operate as a single system. Progress since April 2010 was presented at the Commissioners' Forum held on June 13, 2010.

Q. What direction was received from Commissioners at the forum held on June 13, 2010?

A. At the Commissioners' Forum held on June 13, 2010, the Standing Committee updated Commissioners on the progress made since the previous meeting. The Commissioners expressed praise for the progress made and requested that the Standing Committee continue its efforts toward an acceptable resolution. An additional check-in meeting was targeted for July 2010.

After the check-in, the Standing Committee developed a summary of what the members heard as guidance from the Commissioners. The summary included the following key points:

1. All states prefer a consistent and fair cost allocation methodology that assures the Company a reasonable opportunity to recover its costs and support further system investment.

2. Utah prefers the Rolled-In allocation methodology, or results stated as a deviation from the Rolled-In allocation methodology as a viable solution alternative.

3. Oregon and Wyoming Standing Committee members have considered pre-2005 resource scenarios[1] as possible solution alternatives.

4. Both Wyoming and Oregon stressed that maintaining a hydro endowment is a critical component on any allocation methodology.

5. Utah stressed its benchmark methodology is Rolled-In and an allocation methodology should reflect Rolled-In +/- adjustments which are fixed for some future time period so as to avoid a repeat of not achieving expected forecasted results.

6. The Commissioners have agreed that the Standing Committee should work with the Company to develop an updated analysis based on Wyoming – 1 results which could be used to establish a fixed amount per year per state as a deviation from the Rolled-In allocation methodology and is net of the situs assignment of the Klamath surcharge. The results will be presented for all years of the study and be accompanied by a disk with working spreadsheets. Assessing whether the Wyoming - 1 achieves essentially a Rolled-In result could be viewed from the perspective of treating the Klamath Settlement as Rolled-In.

Q. What actions did the Standing Committee take based on this guidance?

A. Through additional conference calls and supporting analysis, the Standing Committee reached an agreement in principle that was presented on July 26, 2010 at a final Commissioners' Forum check-in conference call. The statement provided by the Standing Committee at that meeting stated:

"Standing Committee participants of the MSP process have tentatively reached an agreement in principle changing the Revised Protocol cost allocation methodology. The initial premise for this new agreement is a Rolled-In cost allocation methodology. The changed methodology continues to identify State Resources based on cost responsibility and Regional Resources for the Hydro Endowment calculation. Besides using Rolled-In as the starting point, a significant change relates to the Hydro Endowment quantified under the

[1] "Pre-2005 resource scenarios" refers to the set of resources included in the "All-Other" category of the Embedded Cost Differential calculation. This is discussed in more detail in the direct testimony of Mr. McDougal.

Embedded Cost Differential (ECD). The ECD will be reduced and limited using a comparison based on Pre-2005 Resources. It is proposed that for 2011 through 2016, the ECD calculation will be projected and a fixed dollar amount per year deviation from Rolled-In analysis would be applied. The deviation is composed of two parts; (1) a situs adjustment charge for the Klamath Surcharge to Oregon and California, with a corresponding credit to the other states, and (2) an adjustment to reflect the Hydro Endowment ECD.

State specific concerns continue to be evaluated and discussed. For instance: In Utah this cost allocation methodology produces results close to Rolled-In so a side agreement between the Company and Utah parties will allow Utah to utilize Rolled-In cost allocation methodology for its ratemaking purposes. Forecast accuracy also continues to be evaluated by the other states, Oregon in particular, and may result in state specific measures to address the forecast risk related to fluctuations, up or down. Wyoming parties have an interest in addressing a concern about the Revised Protocol definition of State Resources."

Q. What was the outcome of the Commissioners' Forum held on July 26, 2010?

A. At the Commissioners' Forum held on July 26, 2010, the Standing Committee updated Commissioners that the group had reached an agreement in principle. Commissioners were informed that the Company hoped to file a petition in each state by mid-September 2010 initiating limited amendments to the Revised Protocol that would implement the terms of the agreement in principle.

Overview of Proposed Amendments

Q. In summary, what key concerns do the proposed amendments endeavor to address?

A. As noted above, there were several overarching concerns expressed in the meetings:

- The need to move more toward a Rolled-In allocation methodology to reflect system operations while retaining the hydro endowment in some form.
- Volatility of results and unintended consequences of the ECD.
- Unpredictability of reliance on forecasts.

- Any solution must be fair to all states, and the Company must be afforded the opportunity to recover its prudently incurred costs.

Q. Are the amendments proposed by the Company and supported by the Standing Committee consistent with this agreement in principle?

A. Yes. The details are discussed in the direct testimony of Mr. McDougal.

Q. Do the amendments exclusively address the Utah issue?

A. No. The amendments also reflect an additional category of state resources called "state-specific initiatives". This addition includes emerging state-specific efforts to encourage investment in specific types of resources.

Q. Does this only include renewable resources?

A. No. The category does not limit the type of resource for which a state may seek to encourage investment.

Process for Commission Review of Petition

Q. What process does the Company propose for the Commission review of this Petition?

A. The Company is hopeful that the Commission will be able to complete its review of this Petition within a six-month timeframe. As discussed in the Company's direct testimony, significant analysis has been undertaken and reviewed by many parties since November 2008 as the Standing Committee considered its options. However, not all interested parties were able to participate in the Standing Committee efforts. As such, the Company proposes the following illustrative schedule of milestones that would allow for discovery, rounds of testimony and hearings that would allow sufficient time for a comprehensive record to be developed upon which the Commission may base its decision:

Event	Date
PacifiCorp Petition, Testimony and Exhibits	September 15, 2010
Intervenor Testimony due	Early-December 2010
PacifiCorp Rebuttal Testimony due	Early-January 2011
Public Hearing	Late-January 2011
Briefs due	Mid-February 2011
Target Date for Commission Decision	March 31, 2011

Q. Does the Company intend to continue dialogue with interested parties in each state during the proceedings?

A. Yes. As noted in the Standing Committee's statement, the Company intends to seek an agreement with Utah parties related to the use of the Rolled-In allocation methodology and to work with Oregon parties to address forecast risk. The Company will also work to address any additional concerns that arise during the proceedings. It will be imperative that any state-specific agreements do not undermine the intent of the 2010 Protocol to allow PacifiCorp the reasonable opportunity to recover 100 percent of its prudently incurred costs.

Processes subsequent to amendment adoption

Q. Assuming that the four state Commissions acknowledge the amendments and adopt the 2010 Protocol, what ongoing processes does the Company envision related to the 2010 Protocol?

A. As reflected in the 2010 Protocol, the Company is not proposing any changes to the ongoing Standing Committee function at this time. Although the elements of the 2010 Protocol are designed to minimize controversy and provide predictability through calendar year 2016, there are always emerging issues on which it is valuable for states to continue to engage in discussions.

Q. What does the Company envision as a process to address allocation issues post-2016?

A. The process would likely be similar to the one just followed. For example, the post-2016 issues would likely first be reviewed at the 2015 Standing Committee annual meeting. From that review, the Standing Committee would agree on appropriate next steps as far as issue identification and analysis. Standing Committee efforts would need to be designed to culminate in time for formal commission proceedings to occur with decisions well in advance of January 1, 2017. It is also possible that the states would agree to extend the terms of the 2010 Protocol to apply beyond calendar year 2016.

Introduction of Witnesses

Q. Please introduce the Company's other witnesses and provide a brief description of their testimony.

A. They are:

- Mr. Steven R. McDougal addresses the calculation and implementation of the 2010 Protocol allocation methodology and presents the revenue requirement analyses undertaken at the request of the Standing Committee, and
- Mr. Gregory N. Duvall presents the net power cost (NPC) studies used to support the 2010 Protocol revenue requirement analysis and to inform of the Standing Committee's consideration of options.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit PPL/101

Docket No. UM-1050
Exhibit PPL/101
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Andrea L. Kelly

2010 Protocol, including Appendices A to F

September 2010

2010 Protocol

I. Introduction

This 2010 PacifiCorp Inter-Jurisdictional Cost Allocation Protocol (2010 Protocol) is the result of continuing discussions that have occurred among representatives of PacifiCorp, Commission staff members and other interested parties from Utah, Oregon, Wyoming, and Idaho regarding issues arising from the previously adopted Revised Protocol, and the Company's status as a multi-jurisdictional utility.

PacifiCorp commits that it will continue to plan and operate its generation and transmission system on a six-State integrated basis in a manner that achieves a least cost/least risk Resource portfolio for its customers.

The 2010 Protocol describes regulatory policies, which, if utilized by all States for rate proceedings filed prior to January 1, 2017, should afford PacifiCorp a reasonable opportunity to recover all of its prudently incurred expenses and investments and earn its authorized rate of return. The assignment of a particular expense or investment, or allocation of a share of an expense or investment, to a State pursuant to the 2010 Protocol is not intended to, and should not, prejudge the prudence of those costs. Nothing in the 2010 Protocol shall abridge any State's right and/or obligation to establish fair, just and reasonable rates based upon the law of that State and the record established in rate proceedings conducted by that State. Parties who have supported the ratification of the 2010 Protocol do so in the belief that it will continue to achieve a solution to multistate issues that is in the public interest. However, a party's support of the 2010 Protocol is not intended in any manner to negate the necessary flexibility of the regulatory process to deal with changed or unforeseen circumstances, and a party's support of the 2010 Protocol will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude, in good faith, that the 2010 Protocol no longer produces results that are just, reasonable and in the public interest. Support of the 2010 Protocol shall not be deemed to constitute an acknowledgement by any party of the validity or invalidity of any particular method, theory or principle of regulation, cost recovery, cost of service or rate design and no party shall be deemed to have agreed that any particular method, theory or principle of regulation, cost recovery, cost of service or rate design employed in the 2010 Protocol is appropriate for resolving any other issues.

The 2010 Protocol describes how the costs and wholesale revenues associated with PacifiCorp's generation, transmission and distribution system will be assigned or allocated among its six-State jurisdictions for purposes of establishing its retail rates.

Definitions of terms that are capitalized in the 2010 Protocol are set forth in Appendix A.

A table identifying the allocation factor to be applied to each component of PacifiCorp's revenue requirement calculation is included as Appendix B.

The algebraic derivation of each allocation factor is contained in Appendix C.

A description and numeric example of how Special Contracts and related discounts will be reflected in rates is set forth in Appendix D.

The fixed and levelized Embedded Cost Differential (ECD) amounts, that will be included in filings made through December 31, 2016, are set forth in Appendix E.

Each State's allocated share of each Mid-Columbia Contract and the method for calculating the shares is set forth in Appendix F.

II. Proposed Effective Date

The 2010 Protocol will and apply to all PacifiCorp rate proceedings filed prior to January 1, 2017.

III. Classification of Resource Costs

All Resource Fixed Costs, Wholesale Contracts and Short-term Purchases and Sales will be classified as 75 percent Demand-Related and 25 percent Energy-Related. All costs associated with Non-Firm Purchases and Sales will be classified as 100 percent Energy-Related.

IV. Allocation of Resource Costs and Wholesale Revenues

Resources will be assigned to one of three categories for inter-jurisdictional cost allocation purposes:

A. Regional Resources,

B. State Resources, or

C. System Resources.

There are two types of Regional Resource and four types of State Resources. The remainder are System Resources which constitute the substantial majority of PacifiCorp's Resources. Costs associated with each category and type of Resource will be allocated on the following basis:

A. Regional Resources

Costs associated with Regional Resources will be assigned and allocated as follows:

1. Hydro-Endowment.

a. <u>Owned Hydro Embedded Cost Differential Adjustment.</u> The Owned Hydro Embedded Cost Differential Adjustment is calculated as follows:

- The Forecasted Embedded Costs – Hydro-Electric Resources, less the Forecasted Embedded Costs – Pre-2005 Resources, multiplied by the normalized MWh's of output from the Hydro-Electric Resources.
- The calculation is made using forecasted information contained in the Company's Baseline Study (finalized in March 2010) for calendar years 2011 through 2016.
- The forecasted differential is allocated on the DGP factor and the inverse amount is allocated on the SG factor to compute State specific amounts for calendar years 2011 through 2016.
- The net present value of the forecasted differential by State is set at a fixed dollar level that will be used for all PacifiCorp rate proceedings filed prior to January 1, 2017.

b. <u>Mid-Columbia Contract Embedded Cost Differential Adjustment.</u> The Mid-Columbia Contract Embedded Cost Differential Adjustment is calculated as follows:

- The Forecasted Mid-Columbia Contracts Costs, less the Forecasted Embedded Costs – Pre-2005 Resources, multiplied by the normalized MWh's of output from the Mid-Columbia Contracts (Mid-C less All Other).

- The calculation is made using forecasted information contained in the Company's Baseline Study (finalized in March 2010) for calendar years 2011 through 2016.
- The forecasted allocation of Mid-Columbia Contracts to each State is established pursuant to Appendix F. The forecasted Mid-Columbia differential is allocated on the MC factor and the inverse amount is allocated on the SG factor to compute State specific amounts for calendar years 2011 through 2016.
- The net present value of the forecasted differential by State is set at a fixed dollar level that will be used for all PacifiCorp rate proceedings filed prior to January 1, 2017.

The results of the Owned Hydro Embedded Cost Differential calculation and the Mid-Columbia Contract Embedded Cost Differential calculation are added together and a levelized annual value for the calendar years 2011 through 2016 time period is calculated. The levelized Hydro Endowment is fixed for purposes of ratemaking for that time period.

2. Klamath Hydroelectric Settlement Agreement (KHSA). As part of future ratemaking proceedings, the Company will include the full impact of the KHSA as a system cost in unadjusted results.

a. Klamath Dam Removal Surcharge Adjustment. The Klamath Dam Removal Surcharge is re-allocated to Oregon (92 percent) and California (8 percent) as follows:

- Each State's initial allocated share of the Klamath Dam Removal Surcharge is reversed and assigned to Oregon and California on a situs basis. The calculation is made using forecasted information contained in the Company's Baseline Study (finalized in March 2010) for calendar years 2011 through 2016.
- The net present value of the forecasted adjustment by State is set at a fixed dollar level that will be used for all PacifiCorp rate proceedings filed prior to January 1, 2017. The levelized annual value for the calendar years 2011 through 2016 time period will be used for purposes of ratemaking for that time period.

B. State Resources

Costs associated with the four types of State Resources will be assigned as follows:

1. <u>Demand-Side Management Programs:</u> Costs associated with Demand-Side Management Programs will be assigned on a situs basis to the State in which the investment is made. Benefits from these programs, in the form of reduced consumption and contribution to peak, will be reflected through time in the Load-Based Dynamic Allocation Factors.

2. Portfolio Standards: Costs associated with Resources acquired pursuant to a State Portfolio Standard, which exceed the costs PacifiCorp would have otherwise incurred, will be assigned on a situs basis to the State adopting the standard.

3. New Qualifying Facilities (QF) Contracts: Costs associated with any New QF Contract, which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources, will be assigned on a situs basis to the State approving such contract.

4. State-Specific Initiatives: Costs associated with Resources acquired pursuant to a State-specific initiative will be assigned on a situs basis to the State adopting the initiative. This includes the costs of incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, electric vehicle programs and the acquisition of renewable energy certificates.

C. System Resources

All Resources that are not Regional Resources or State Resources are System Resources. Generally, all Fixed Costs associated with System Resources and all costs incurred under Wholesale Contracts will be allocated based upon the SG Factor. Generally, all Variable Costs associated with System Resources will be allocated based upon the SE Factor. Revenues received by the Company pursuant to Wholesale Contracts will be allocated based upon the SG Factor. A complete description of the allocation factors to be utilized is set forth in Appendix B.

D. Load Growth

At the direction of the MSP Standing Committee, the Company and parties will continue to analyze and quantify potential cost shifts related to faster-growing States.[1] In addition, the MSP Standing Committee will track key factors including actual relative growth rates, forecast relative growth rates, costs of new Resources compared to costs of existing Resources, and other factors deemed relevant to any potential load growth-related issues.

V. Refunctionalization and Allocation of Transmission Costs and Revenues

If the Company is required to refunctionalize assets that are currently functionalized as "transmission" to "distribution", the cost responsibility for any such refunctionalized assets will be assigned to the State where they are located. Any refunctionalization will be implemented under the guidance of the MSP Standing Committee.

Costs associated with transmission assets, and firm wheeling expenses and revenues, will be classified as 75 percent Demand-Related, 25 percent Energy-Related and allocated among the States based upon the SG (System Generation) factor. Non-firm wheeling expenses and revenues will be allocated among the States based upon the SE Factor.

[1] This issue will be monitored through studies that compute the costs allocated to each State for two cases: (a) with currently projected load growth together with a least-cost, least-risk mix of Resource additions to meet that growth and (b) with the fastest-growing State growing at the average growth projected for the remaining States, again with a least-cost, least-risk mix of Resource additions.

<u>VI. Assignment of Distribution Costs</u>

All distribution-related expenses and investment that can be directly assigned will be directly assigned to the state where they are located. Those costs that cannot be directly assigned will be allocated among States consistent with the factors set forth in Appendix B.

<u>VII. Allocation of Administrative and General Costs</u>

Administrative and general costs, costs of General Plant and costs of Intangible Plant will be allocated among States consistent with the factors set forth in Appendix B.

<u>VIII. Allocation of Special Contracts</u>

Revenues associated with Special Contracts will be included in State revenues and loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors. Special Contracts may or may not include Customer Ancillary Service Contract attributes. In recognition that Special Contracts may take different forms, Appendix D provides a written description and numeric example of the regulatory treatment of Special Contracts and associated discounts.

<u>IX. Allocation of Gain or Loss from Sale of Resources or Transmission Assets</u>

Any loss or gain from the sale of a Resource (other than a Freed-Up Resource) or a transmission asset will be allocated among States based upon the allocation factor used to allocate the Fixed Costs of the Resource or the transmission asset at the time of its sale. Each Commission will determine the appropriate allocation of loss or gain allocated to that State as between State customers and PacifiCorp shareholders.

X. Implementation of Direct Access Programs

A. Allocation of Costs and Benefits of Freed-Up Resources

1. Loads lost to Direct Access – Where the Company is required to continue to plan for the load of Direct Access Customers, such load will be included in Load-Based Dynamic Allocation Factors for all Resources.
2. Loads of customers permanently choosing Direct Access or permanently opting out of New Resources – Where the Company is no longer required to plan for the load of customers who permanently choose direct access or permanently opt out of New Resources, such loads will be included in Load-Based Dynamic Allocation Factors for all Existing Resources but will not be included in Load-Based Dynamic Allocation Factors for New Resources acquired after the election to permanently choose Direct Access or opt out of New Resources. An effective date for this process will be established at such time as customers permanently choose Direct Access or opt out, and this process will be implemented under the guidance of the MSP Standing Committee.
3. In each State with Direct Access Customers, an additional step will take place for ratemaking purposes to establish a value or cost (which could include a transfer of Freed-Up Resources between customer classes within a State) resulting from the departure of the departing load; other States do not implement the second step.

B. Freed-Up Resource Sale Approval

Any proposed sale of a Freed-Up Resource for purposes of calculating transition charges or credits will be subject to applicable regulatory review and approval based upon a "no-harm" standard. States implementing Direct Access Programs that involve the sale of Freed-Up Resources will endeavor to propose a method for allocating the gain or loss on a sale to Direct Access Customers in a manner that satisfies the "no-harm" standard in respect to customers in the other States. The parties agree that they will not advocate a sale of Freed-Up Resources to be consummated if the proposed allocation of the gain or loss from the sale would cause the Company to distribute more than the total gain on a sale or recover less than the full amount of the total loss on a sale.

C. Allocation of Revenues and Costs from Direct Access Purchases and Sales

Revenues and costs from Direct Access Purchases and Sales will be assigned situs to the State where the Direct Access Customers are located and will not be included in Net Power Costs.

XI. Loss or Increase in Load

Any loss or increase in retail load occurring as a result of condemnation or municipalization, sale or acquisition of new service territory which involves less than five percent of system load, realignment of service territories, changes in economic conditions or gain or loss of large customers will be reflected in changes in Load-Based Dynamic Allocation Factors. The allocation of costs and benefits arising from merger, sale and acquisition transactions proposed by the Company involving more than five percent of system load will be dealt with on a case-by-case basis in the course of Commission approval proceedings.

XII. Commission Regulation of Resources

PacifiCorp shall plan and acquire new Resources on a system-wide least cost, least risk basis. Prudently incurred investments in Resources will be reflected in rates consistent with the laws and regulations in each State.

XIII. Sustainability of 2010 Protocol

A. Issues of Interpretation

If questions of interpretation of the 2010 Protocol arise during rate proceedings and/or audits of results of PacifiCorp's operations, parties will attempt to resolve them with reference to the intent of the parties who have supported the ratification of the 2010 Protocol.

B. MSP Standing Committee

1. The existing MSP Standing Committee will continue to be organized consisting of one member or delegate of each Commission. The chair of the MSP Standing Committee will be elected each year by the members of the Committee.
2. The MSP Standing Committee will appoint a Standing Neutral, at the Company's expense, to facilitate discussions among States, monitor issues and assist the MSP Standing Committee.
3. At least once during each calendar year, the Standing Neutral will convene a meeting of the MSP Standing Committee and interested parties from all States for the purpose of discussing and monitoring emerging inter-jurisdictional issues facing the Company and its customers. The meetings will be open to all interested parties.

4. The MSP Standing Committee will consider possible amendments to the 2010 Protocol that would be equitable to PacifiCorp customers in all States and to the Company. The MSP Standing Committee will have discretion to determine how best to encourage consensual resolution of issues arising under the 2010 Protocol. Its actions may include, but will not be limited to: a) appointing a committee of interested parties to study an issue and make recommendations, or b) retaining (at the Company's expense) one or more disinterested parties to make advisory findings on issues of fact arising under the 2010 Protocol.

5. The work of the MSP Standing Committee will be supported by sound technical analysis. A party supporting ratification of the 2010 Protocol will work in good faith to address issues being considered by the MSP Standing Committee.

C. 2010 Protocol Amendments

Proposed amendments to the 2010 Protocol will be submitted by PacifiCorp to each Commission for ratification. The 2010 Protocol will only be deemed to have been amended if each of the Commissions who have previously ratified the 2010 Protocol ratifies the amendment. PacifiCorp will not seek Commission ratification of any amendment to the 2010 Protocol unless and until it has provided interested parties with at least six months advance notice of its intent to do so and endeavored to obtain consensus regarding its proposed amendment. A party's initial support or acceptance of the 2010 Protocol will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude that the 2010 Protocol no longer produces just and reasonable results. Prior to departing from the terms of the 2010 Protocol, consistent with their legal obligations, Commissions and parties will endeavor to cause their concerns to be presented at meetings of the MSP Standing Committee and interested parties from all States in an attempt to achieve consensus on a proposed resolution of those concerns.

D. Interdependency among Commission Approvals

The 2010 Protocol has been developed by the parties as an integrated, inter-dependent, organic whole. Therefore, final ratification of the 2010 Protocol by any of the Commissions of Oregon, Utah, Wyoming and Idaho, is expressly conditioned upon similar ratification of the 2010 Protocol by the other mentioned Commissions, without any deletion or alteration of a material term, or the addition of other material terms or conditions. Upon any rejection of the 2010 Protocol, or any material deletion, alteration, or addition to its terms, by any one or more of the four Commissions, the Commissions who have previously conditionally adopted the 2010 Protocol shall initiate proceedings to determine whether they should reaffirm their prior ratification of the 2010 Protocol, notwithstanding the action of the other Commission or Commissions. The 2010 Protocol shall only be in effect for a State upon final ratification by its Commission. The Company will continue to bear the risk of inconsistent allocation methods among the States.

APPENDIX A

2010 Protocol - Appendix A

Defined Terms

For purposes of this 2010 Protocol, the following terms will have the following meanings:

"2010 Protocol" means this 2010 PacifiCorp Inter-Jurisdictional Cost Allocation Protocol.

"Baseline Study" means the calculation of the Company's projected revenue requirement for calendar years 2010 through 2019 and the corresponding inter-jurisdictional allocation. The Baseline Study was prepared in March 2010 and was designed to facilitate States' assessment of the ongoing reasonableness of the Revised Protocol.

"Coincident Peak" means the hour each month that the combined demand of all PacifiCorp retail customers is greatest. In States using an historic test period, Coincident Peak is based upon actual, metered load data. In States using future test periods, Coincident Peak is based upon forecasted loads.

"Company" means PacifiCorp.

"Commission" means a utility regulatory commission in a State.

"Comparable Resource" means Resources with similar capacity factors, start-up costs, and other output and operating characteristics.

"Customer Ancillary Service Contracts" means contracts between the Company and a retail customer pursuant to which the Company pays the customer for the right to curtail service so as to lower the costs of operating the Company's system.

"Demand-Related Costs" means capital and other Fixed Costs incurred by the Company in order to be prepared to meet the maximum demand imposed upon its system.

"Demand-Side Management Programs" means programs intended to reduce electricity use through activities or programs that promote electric energy efficiency or conservation, more efficient management of electric energy loads, or reductions in peak demand.

"Direct Access Customers" means retail electricity consumers located in PacifiCorp's service territory that either: a) purchase electricity directly from a supplier other than PacifiCorp pursuant to a Direct Access Program or b) elect to have all or a portion of the electricity they purchase from PacifiCorp priced based upon market prices rather than the Company's traditional cost-of-service rate. If a State implements a Direct Access Program pursuant to which Freed-Up Resources are transferred between customer classes, such transfers shall be considered Direct Access Purchases and Sales.

"Direct Access Program" means a law or regulation that permits retail consumers located in PacifiCorp's service territory to purchase electricity directly from a supplier other than PacifiCorp.

"Direct Access Purchases and Sales" means Wholesale Contracts and Short-Term Purchases and Sales entered into by PacifiCorp either to supply customers who have become Direct Access Customers or to dispose of Freed-Up Resources.

"Energy-Related Costs" means costs, such as fuel costs that vary with the amount of energy delivered by the Company to its customers during any hour plus any portion of Fixed Costs that have been deemed to have been incurred by the Company in order to meet its energy requirements.

"Existing Resources" means Resources whose costs were committed to prior to Direct Access Customers making an election to permanently forego being served by the Company at a cost-of-service rate.

"FERC" means the Federal Energy Regulatory Commission.

"Fixed Costs" means costs incurred by the Company that do not vary with the amount of energy delivered by the Company to its customers during any hour.

"Forecasted Embedded Costs – Hydro-Electric Resources" means PacifiCorp's total forecasted production costs contained in the Company's Baseline Study, for calendar years 2011 through 2016, expressed in dollars per MWh, associated with Hydro-Electric Resources as recorded in the FERC Accounts listed in Appendix E to the Revised Protocol.

"Forecasted Embedded Costs – Pre-2005 Resources" means PacifiCorp's total forecasted production costs of Pre-2005 Resources contained in the Company's Baseline Study, for calendar years 2011 through 2016, expressed in dollars per MWh, other than costs associated with Hydro-Electric Resources, and Mid-Columbia Contracts, as recorded in the FERC Accounts listed in Appendix E to the Revised Protocol.

"Forecasted Mid-Columbia Contract Costs" means the total forecasted net costs incurred by PacifiCorp contained in the Company's Baseline Study, for calendar years 2011 through 2016, expressed in dollars per MWh, under the Mid-Columbia Contracts.

"Freed-Up Resources" means Resources made available to the Company as a result of its customers becoming Direct Access Customers.

"General Plant" means capital investment included in FERC accounts 389 through 399.

"Grant County" means Public Utility District No. 2 of Grant County, Washington

"Hydro-Electric Resources" means Company-owned hydro-electric plants located in Oregon, Washington or California.

"Intangible Plant" means capital investment included in FERC accounts 301 through 303.

"Klamath Dam Removal Surcharge" means the tariffs collected from customers in California and Oregon for the purpose of providing funding to remove specific Klamath River dams, as detailed in the Klamath Hydroelectric Settlement Agreement.

"Klamath Hydroelectric Settlement Agreement" means the Klamath Hydroelectric Settlement Agreement executed on February 18, 2010 for the purpose of resolving specific FERC relicensing proceedings by establishing a process for potential facilities removal and operation of hydroelectric projects until that time.

"Load-Based Dynamic Allocation Factor" means an allocation factor that is calculated using States' monthly energy usage and/or States' contribution to monthly system Coincident Peak.

"Mid-Columbia Contracts" means the Power Sales Contract with Grant County dated May 22, 1956; the Power Sales Contract with Grant County dated June 22, 1959;the Priest Rapids Project Product Sales Contract with Grant County dated December 31, 2001; the Additional Products Sales Agreement with Grant County dated December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Grant County dated December 31, 2001; the Power Sales Contract with Douglas County PUD dated September 18, 1963; the Power Sales Contract with Chelan County PUD dated November 14, 1957 and all successor contracts thereto.

"Net Power Costs" means PacifiCorp's fuel and wheeling expenses and costs and revenues associated with Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales and Non-Firm Purchases and Sales.

"New QF Contracts" means Qualifying Facility Contracts that are entered into subsequent to September 15, 2010.

"New Resources" means Resources that are not Existing Resources as established pursuant to Paragraph XA2 of the Protocol.

"Non-Firm Purchases and Sales" means transactions at wholesale that are not Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales or Direct Access Purchases and Sales.

"Portfolio Standard" means a State law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d) Resources located in a particular geographic area.

"Pre-2005 Resources" means Resources (other than Mid-Columbia Contracts and Hydro-Electric Resources) that were part of the Company's integrated system prior to January 1, 2005.

"Qualifying Facility Contracts" means contracts to purchase the output of small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and regulations.

"Resources" means Company-owned and leased generating plants and mines, Wholesale Contracts, Seasonal Contracts, Short-Term Purchases and Sales and Non-firm Purchases and Sales.

"Short-Term Purchases and Sales" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.

"Special Contract" means a contract entered between PacifiCorp's and one of its retail customers with prices, term and conditions different from otherwise-applicable tariff rates. Special Contracts may provide for a discount to reflect Customer Ancillary Services Contract attributes.

"Special Contract Ancillary Service Discounts" means discounts from otherwise applicable rates provided for in Special Contracts.

"Standing Neutral" means an independent party, with experience in electric utility ratemaking, retained by the MSP Standing Committee to facilitate discussions among States, monitor issues and assist the MSP Standing Committee as required.

"State Resources" means Resources whose costs are assigned to a single State to accommodate State-specific policy preferences.

"System Resources" means Resources that are not Regional Resources, State Resources or Direct Access Purchases and Sales and whose associated costs and revenues are allocated among all States on a dynamic basis.

"State" means Utah, Oregon, Wyoming, Idaho, Washington or California.

"Variable Costs" means costs incurred by the Company that vary with the amount of energy delivered by the Company to its customers during any hour.

"Wholesale Contracts" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts.

APPENDIX B

2010 Protocol - Appendix B
Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Sales to Ultimate Customers			
440	Residential Sales		
		Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales		
		Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting		
		Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority		
		Direct assigned - Jurisdiction	S
448	Interdepartmental		
		Direct assigned - Jurisdiction	S
447	Sales for Resale		
		Direct assigned - Jurisdiction	S
		Non-Firm	SE
		Firm	SG
449	Provision for Rate Refund		
		Direct assigned - Jurisdiction	S
			SG
Other Electric Operating Revenues			
450	Forfeited Discounts & Interest		
		Direct assigned - Jurisdiction	S
451	Misc Electric Revenue		
		Direct assigned - Jurisdiction	S
		Other - Common	SO
454	Rent of Electric Property		
		Direct assigned - Jurisdiction	S
		Common	SG
		Other - Common	SO
456	Other Electric Revenue		
		Direct assigned - Jurisdiction	S
		Wheeling Non-firm, Other	SE
		Common	SO
		Wheeling - Firm, Other	SG
		Customer Related	CN
Miscellaneous Revenues			
41160	Gain on Sale of Utility Plant - CR		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
41170	Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
4118	Gain from Emission Allowances		
		SO2 Emission Allowance sales	SE
41181	Gain from Disposition of NOX Credits		
		NOX Emission Allowance sales	SE
421	(Gain) / Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
Miscellaneous Expenses			
4311	Interest on Customer Deposits		
		Utah Customer Service Deposits	CN
		Direct assigned - Jurisdiction	S
Steam Power Generation			
500, 502, 504-514	Operation Supervision & Engineering		
		Steam Plants	SG
501	Fuel Related		
		Steam Plants	SE
503	Steam From Other Sources		
		Steam Royalties	SE
Nuclear Power Generation			
517 - 532	Nuclear Power O&M		
		Nuclear Plants	SG
Hydraulic Power Generation			
535 - 545	Hydro O&M		
		Pacific Hydro	SG
		East Hydro	SG
Other Power Generation			
546, 548-554	Operation Super & Engineering		
		Other Production Plant	SG
547	Fuel		
		Other Fuel Expense	SE
Other Power Supply			
555	Purchased Power		
		Direct assigned - Jurisdiction	S
		Firm	SG
		Non-firm	SE
		100 MW Hydro Extension	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
556	System Control & Load Dispatch		
		Other Expenses	SG
557	Other Expenses		
		Direct assigned - Jurisdiction	S
		Other Expenses	SG
	2010 Protocol Adjustments		
		Hydro Endowment	S
		Klamath Dam Removal Surcharge	S
		Klamath Dam Removal Surcharge Re-allocation	S
TRANSMISSION EXPENSE			
560-564, 566-573	Transmission O&M		
		Transmission Plant	SG
565	Transmission of Electricity by Others		
		Firm Wheeling	SG
		Non-Firm Wheeling	SE
DISTRIBUTION EXPENSE			
580 - 598	Distribution O&M		
		Direct assigned - Jurisdiction	S
		Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE			
901 - 905	Customer Accounts O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE			
907 - 910	Customer Service O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
SALES EXPENSE			
911 - 916	Sales Expense O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
ADMINISTRATIVE & GEN EXPENSE			
920-935	Administrative & General Expense		
		Direct assigned - Jurisdiction	S
		Customer Related	CN
		General	SO
		FERC Regulatory Expense	SG
DEPRECIATION EXPENSE			
403SP	Steam Depreciation		
		Steam Plants	SG
403NP	Nuclear Depreciation		
		Nuclear Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
403HP	Hydro Depreciation		
		Pacific Hydro	SG
		East Hydro	SG
403OP	Other Production Depreciation		
		Other Production Plant	SG
403TP	Transmission Depreciation		
		Transmission Plant	SG
403	Distribution Depreciation Direct assigned - Jurisdiction		
		Land & Land Rights	S
		Structures	S
		Station Equipment	S
		Storage Battery Equipment	S
		Poles & Towers	S
		OH Conductors	S
		UG Conduit	S
		UG Conductor	S
		Line Trans	S
		Services	S
		Meters	S
		Inst Cust Prem	S
		Leased Property	S
		Street Lighting	S
403GP	General Depreciation		
		Distribution	S
		Steam Plants	SG
		Mining	SE
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
403MP	Mining Depreciation		
		Remaining Mining Plant	SE
AMORTIZATION EXPENSE			
404GP	Amort of LT Plant - Capital Lease Gen		
		Direct assigned - Jurisdiction	S
		General	SO
		Customer Related	CN
404SP	Amort of LT Plant - Cap Lease Steam		
		Steam Production Plant	SG
404IP	Amort of LT Plant - Intangible Plant		
		Distribution	S
		Production, Transmission	SG
		General	SO
		Mining Plant	SE
		Customer Related	CN

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
404MP	Amort of LT Plant - Mining Plant		
		Mining Plant	SE
404HP	Amortization of Other Electric Plant		
		Pacific Hydro	SG
		East Hydro	SG
405	Amortization of Other Electric Plant		
		Direct assigned - Jurisdiction	S
406	Amortization of Plant Acquisition Adj		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
407	Amort of Prop Losses, Unrec Plant, etc		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Trojan	TROJP
Taxes Other Than Income			
408	Taxes Other Than Income		
		Direct assigned - Jurisdiction	S
		Property	GPS
		System Taxes	SO
		Misc Energy	SE
		Misc Production	SG
DEFERRED ITC			
41140	Deferred Investment Tax Credit - Fed		
		ITC	DGU
41141	Deferred Investment Tax Credit - Idaho		
		ITC	DGU
Interest Expense			
427	Interest on Long-Term Debt		
		Direct assigned - Jurisdiction	S
		Interest Expense	SNP
428	Amortization of Debt Disc & Exp		
		Interest Expense	SNP
429	Amortization of Premium on Debt		
		Interest Expense	SNP
431	Other Interest Expense		
		Interest Expense	SNP
432	AFUDC - Borrowed		
		AFUDC	SNP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Interest & Dividends			
419	Interest & Dividends		
		Interest & Dividends	SNP
DEFERRED INCOME TAXES			
41010	Deferred Income Tax - Federal-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41011	Deferred Income Tax - State-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41110	Deferred Income Tax - Federal-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
41111	Deferred Income Tax - State-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP
SCHEDULE - M ADDITIONS			
SCHMAF	Additions - Flow Through		
		Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining related	SE
		General	SO
		Production / Transmission	SG
SCHMAT	Additions - Temporary		
		Direct assigned - Jurisdiction	S
		Contributions in aid of construction	CIAC
		Miscellaneous	SNP
		Trojan	TROJD
		Pacific Hydro	SG
		Mining Plant	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	SCHMDEXP
		Distribution	SNPD
		Production, Other	SGCT
SCHEDULE - M DEDUCTIONS			
SCHMDF	Deductions - Flow Through		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Pacific Hydro	SG
SCHMDP	Deductions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining Related	SE
		Miscellaneous	SNP
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
SCHMDT	Deductions - Temporary		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Miscellaneous	SNP
		Pacific Hydro	SG
		Mining related	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	TAXDEPR
		Distribution	SNPD
		Customer Related	CN
State Income Taxes			
40911	State Income Taxes		
		Income Before Taxes	IBT
40910		FIT True-up	S
40910		Wyoming Wind Tax Credit	SG
Steam Production Plant			
310 - 316			
		Steam Plants	SG
Nuclear Production Plant			
320-325			
		Nuclear Plant	SG
Hydraulic Plant			
330-336			
		Pacific Hydro	SG
		East Hydro	SG
Other Production Plant			
340-346			
		Other Production Plant	SG
TRANSMISSION PLANT			
350-359			
		Transmission Plant	SG
DISTRIBUTION PLANT			
360-373			
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT			
389 - 398			
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
399	Coal Mine		
		Remaining Mining Plant	SE
399L	WIDCO Capital Lease		
		WIDCO Capital Lease	SE
1011390	General Capital Leases		
		Direct assigned - Jurisdiction	S
		General	SO
		Generation / Transmission	SG
INTANGIBLE PLANT			
301	Organization		
		Direct assigned - Jurisdiction	S
302	Franchise & Consent		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
303	Miscellaneous Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
303	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
Rate Base Additions			
105	Plant Held For Future Use		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining Plant	SE
114	Electric Plant Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
115	Accum Provision for Asset Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
120	Nuclear Fuel		
		Nuclear Fuel	SE
124	Weatherization		
		Direct assigned - Jurisdiction	S
		General	SO
182W	Weatherization		
		Direct assigned - Jurisdiction	S
186W	Weatherization		
		Direct assigned - Jurisdiction	S
151	Fuel Stock		
		Steam Production Plant	SE
152	Fuel Stock - Undistributed		
		Steam Production Plant	SE
25316	DG&T Working Capital Deposit		
		Mining Plant	SE
25317	DG&T Working Capital Deposit		
		Mining Plant	SE
25319	Provo Working Capital Deposit		
		Mining Plant	SE
154	Materials and Supplies		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production - Common	SNPPS
		Hydro	SNPPH
		Distribution	SNPD
		Production, Other	SNPPO
163	Stores Expense Undistributed		
		General	SO
25318	Provo Working Capital Deposit		
		Provo Working Capital Deposit	SNPPS
165	Prepayments		
		Direct assigned - Jurisdiction	S
		Property Tax	GPS
		Production, Transmission	SG
		Mining	SE
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
182M	Misc Regulatory Assets		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production, Other	SGCT
186M	Misc Deferred Debits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
		Production - Common	SNPPS
Working Capital			
CWC	Cash Working Capital		
		Direct assigned - Jurisdiction	S
OWC		Other Working Capital	
131		Cash	SNP
135		Working Funds	SG
143		Other Accounts Receivable	SO
232		Accounts Payable	SO
232		Accounts Payable	SE
253		Deferred Hedge	SE
25330		Other Deferred Credits - Misc	SE
230		Other Deferred Credits - Misc	SE
Miscellaneous Rate Base			
18221	Unrec Plant & Reg Study Costs		
		Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
141	Notes Receivable		
		Employee Loans - Hunter Plant	SG
Rate Base Deductions			
235	Customer Service Deposits		
		Direct assigned - Jurisdiction	S
2281	Prov for Property Insurance		SO
2282	Prov for Injuries & Damages		SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
2283	Prov for Pensions and Benefits		SO
22841	Accum Misc Oper Prov-Black Lung		
		Mining	SE
22842	Accum Misc Oper Prov-Trojan		
		Trojan Plant	TROJD
254105	FAS 143 ARO Regulatory Liability		
		Trojan Plant	TROJP
230	Asset Retirement Obligation		
		Trojan Plant	TROJP
252	Customer Advances for Construction		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Customer Related	CN
25399	Other Deferred Credits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
254	Regulatory Liabilities		
		Regulatory Liabilities	SE
		Insurance Provision	SO
190	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
281	Accumulated Deferred Income Taxes		
		Production, Transmission	SG
282	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
283	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Production, Other	SGCT
		Property Tax	GPS
		Mining Plant	SE
255	Accumulated Investment Tax Credit		
		Direct assigned - Jurisdiction	S
		Investment Tax Credits	ITC84
		Investment Tax Credits	ITC85
		Investment Tax Credits	ITC86
		Investment Tax Credits	ITC88
		Investment Tax Credits	ITC89
		Investment Tax Credits	ITC90
		Investment Tax Credits	DGU
PRODUCTION PLANT ACCUM DEPRECIATION			
108SP	Steam Prod Plant Accumulated Depr		
		Steam Plants	SG
108NP	Nuclear Prod Plant Accumulated Depr		
		Nuclear Plant	SG
108HP	Hydraulic Prod Plant Accum Depr		
		Pacific Hydro	SG
		East Hydro	SG
108OP	Other Production Plant - Accum Depr		
		Other Production Plant	SG
TRANS PLANT ACCUM DEPR			
108TP	Transmission Plant Accumulated Depr		
		Transmission Plant	SG
DISTRIBUTION PLANT ACCUM DEPR			
108360 - 108373	Distribution Plant Accumulated Depr		
		Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT ACCUM DEPR			
108GP	General Plant Accumulated Depr		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
		Mining Plant	SE
		Customer Related	CN
108MP	Mining Plant Accumulated Depr.		
		Mining Plant	SE
108MP	Less Centralia Situs Depreciation		
		Direct assigned - Jurisdiction	S
1081390	Accum Depr - Capital Lease		
		General	SO
1081399	Accum Depr - Capital Lease		
		Direct assigned - Jurisdiction	S
ACCUM PROVISION FOR AMORTIZATION			
111SP	Accum Prov for Amort-Steam		
		Steam Plants	SG
111GP	Accum Prov for Amort-General		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
111HP	Accum Prov for Amort-Hydro		
		Pacific Hydro	SG
		East Hydro	SG
111IP	Accum Prov for Amort-Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		Production, Transmission	SG
		General	SO
		Mining	SE
		Customer Related	CN
111IP	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
111399	Accum Prov for Amort-Mining		
		Mining Plant	SE

APPENDIX C

2010 Protocol - Appendix C
Allocation Factors
Algebraic Derivations

September 15, 2010

Exhibit PPL/101
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Allocation Factors

PacifiCorp serves eight jurisdictions. Jurisdictions are represented by the index i = California, Idaho, Oregon, Utah, Washington, Eastern Wyoming, Western Wyoming, & FERC.

The following assumptions are made in the factor derivations:

It is assumed that the 12CP (j=1 to 12) method is used in defining the System Capacity (“SC”).

It is assumed that twelve months (j=1 to 12) method is used in defining the System Energy (“SE”).

In defining the System Generation (“SG”) factor, the weighting of 75 percent System Capacity, 25 percent System Energy is assumed to continue.

While it is agreed that the peak loads & input energy should be temperature adjusted, no decision has been made upon the methodology to do these adjustments.

System Capacity Factor (“SC”)

$$SCi = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i	=	**System Capacity Factor** for jurisdiction i.
TAP_{ij}	=	Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

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System Energy Factor (“SE”)

$$SEi = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAE_{ij}}$$

where:

SE_i	=	**System Energy Factor** for jurisdiction i.
$TAEi_j$	=	Temperature Adjusted Input Energy of jurisdiction i in month j.

System Generation Factor (“SG”)

$$SG_i = .75 * SC_i + .25 * SE_i$$

where:

SG_i	=	**System Generation Factor** for jurisdiction i.
SC_i	=	System Capacity for jurisdiction i.
SE_i	=	System Energy for jurisdiction i.

Mid-C Factor (“MC”)

$$MC_i = \frac{WMCE_i}{\sum_{i=1}^{i=8} WMCE_i}$$

where:

MCi = **Mid-C Factor** for jurisdiction i.

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$$WMCE_i = E^*_{ipr} + (E_{rr} * \mathrm{SGi}) + (E_{wa} * WWA_i) + (E_w * \mathrm{SGi})$$ Weighted Mid-C Contracts annual energy generation

where:

$E^*_{ipr} = E_{ipr}$ If i is Oregon, otherwise

$E^*_{ipr} = 0$

$E_{ipr} =$ Annual Energy generation of Priest Rapids.

.

$E_{rr} =$ Annual Energy generation of Rocky Reach.
$E_{wa} =$ Annual Energy generation of Wanapum.
$E_w =$ Annual Energy generation of Wells.

$$WWA_i = \frac{SG^*_i}{\sum_{i=1}^{i=8} SG^*_i}$$ Weighted Wanapum Energy

where:

$SG^*_i = SG_i$ if i is Washington or Oregon jurisdiction, otherwise

$SG^*_i = 0.$

$SG_i =$ System Generation for jurisdiction i.

Division Generation - Pacific Factor ("DGP")

$$DGP_i = \frac{SG^*_i}{\sum_{i=1}^{i=8} SG^*_i}$$

where:

$DGP_i =$ **Division Generation - Pacific Factor** for jurisdiction i.

$SG_i^* = SG_i$ if i is a Pacific jurisdiction, otherwise

$SG_i^* = 0.$

SG_i = System Generation for jurisdiction i.

Division Generation - Utah Factor ("DGU")

$$DGU_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGU_i = **Division Generation - Utah Factor** for jurisdiction i.

$SG_i^* = SG_i$ if i is a Utah jurisdiction, otherwise

$SG_i^* = 0.$

SG_i = System Generation for jurisdiction i.

System Net Plant Production - Steam Factor ("SNPPS")

$$SNPPS_i = \frac{SG_i * (PPS - ADPPS)}{(PPS - ADPPS)}$$

where:

$SNPPS_i$	=	**System Net Plant - Steam Factor** for jurisdiction i.
SG_i	=	System Generation for jurisdiction i.
.		
PPS	=	Steam Production Plant.
$ADPPS$	=	Accumulated Depreciation Steam Production Plant.

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System Net Plant Production - Hydro Factor ("SNPPH")

$$SNPPH_i = \frac{SG_i * (PPHE - ADPPHE) + SG_i * (PPHRP - ADPPHRP)}{(PPH - ADPPH)}$$

where:

$SNPPH_i$	=	**System Net Plant - Hydro Factor** for jurisdiction i.
SG_i	=	System Generation for jurisdiction i.
$PPHE$	=	Hydro Production Plant – East.
$ADPPHE$	=	Accumulated Depreciation & Amortization Hydro Production Plant - East.
$PPHRP$	=	Hydro Production Plant - Pacific.
$ADPPHRP$	=	Accumulated Depreciation & Amortization Hydro Production Plant - Pacific.
PPH	=	Hydro Production Plant.
$ADPPH$	=	Accumulated Depreciation & Amortization Hydro Production Plant.

System Net Plant - Distribution Factor ("SNPD")

$$SNPD_i = \frac{PD_i - ADPD_i}{(PD - ADPD)}$$

where:

$SNPD_i$	=	**System Net Plant - Distribution Factor** for jurisdiction i.
PD_i	=	Distribution Plant - for jurisdiction i.
$ADPD_i$	=	Accumulated Depreciation Distribution Plant - for jurisdiction i.
PD	=	Distribution Plant.
$ADPD$	=	Accumulated Depreciation Distribution Plant.

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System Gross Plant - System Factor (“GPS”)

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{i=8} (PP_i + PT_i + PD_i + PG_i + PI_i)}$$

$GP\text{-}S_i$ = **Gross Plant - System Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.

System Net Plant Factor (“SNP”)

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i}{\sum_{i=1}^{i=8} (PP_i + PT_i + PD_i + PG_i + PI_i - ADPPi - ADPT_i - ADPD_i - ADPG_i - ADPI_i)}$$

SNP_i = **System Net Plant Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.
$ADPP_i$ = Accumulated Depreciation Production Plant for jurisdiction i.
$ADPT_i$ = Accumulated Depreciation Transmission Plant for jurisdiction i.
$ADPD_i$ = Accumulated Depreciation Distribution Plant for jurisdiction i.
$ADPG_i$ = Accumulated Depreciation General Plant for jurisdiction i.
$ADPI_i$ = Accumulated Depreciation Intangible Plant for jurisdiction i.

Exhibit PPL/101
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System Overhead - Gross Factor ("SO")

$$SOG_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PP_i - PP_{o}i - PI_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

SOG_i	=	**System Overhead - Gross Factor** for jurisdiction i.
PP_i	=	Gross Production Plant for jurisdiction i.
PT_i	=	Gross Transmission Plant for jurisdiction i.
PD_i	=	Gross Distribution Plant for jurisdiction i.
PG_i	=	Gross General Plant for jurisdiction i.
PI_i	=	Gross Intangible Plant for jurisdiction i.
PP_{oi}	=	Gross Production Plant for jurisdiction i allocated on a SO factor.
PT_{oi}	=	Gross Transmission Plant for jurisdiction i allocated on a SO factor
PD_{oi}	=	Gross Distribution Plant for jurisdiction i allocated on a SO factor
PG_{oi}	=	Gross General Plant for jurisdiction i allocated on a SO factor
PI_{oi}	=	Gross Intangible Plant for jurisdiction i allocated on a SO factor

Income Before Taxes Factor ("IBT")

$$IBT_i = \frac{TIBT_i}{\sum_{i=1}^{i=8} TIBT_i}$$

$IBTi$	=	**Income before Taxes Factor** for jurisdiction i.
$TIBTi$	=	Total Income before Taxes for jurisdiction i.

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Bad Debt Expense Factor ("BADDEBT")

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{i=8} ACCT904_i}$$

$BADDEBT_i$	=	**Bad Debt Expense Factor** for jurisdiction i.
$ACCT904i$	=	Balance in Account 904 for jurisdiction i.

Customer Number Factor ("CN")

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{i=8} CUST_i}$$

where:

CN_i	=	**Customer Number Factor** for jurisdiction i.
$CUST_i$	=	Total Electric Customers for jurisdiction i.

Contributions in Aid of Construction ("CIAC")

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{i=8} CIACNA_i}$$

where:

$CIAC_i$	=	**Contributions in Aid of Construction Factor** for jurisdiction i.
$CIACNA_i$	=	Contributions in Aid of Construction – Net additions for jurisdiction i.

Exhibit PPL/101
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Schedule M - Deductions ("SCHMD")

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^{i=8} DEPRC_i}$$

where:

$SCHMD_i$	=	**Schedule M - Deductions (SCHMD) Factor** for jurisdiction i.
$DEPRC_i$	=	Depreciation in Accounts 403.1 - 403.9 for jurisdiction i.

Trojan Plant ("TROJP")

$$TROJP_i = \frac{ACCT18222_i}{\sum_{i=1}^{i=8} ACCT18222_i}$$

where:

$TROJP_i$	=	**Trojan Plant (TROJP) Factor** for jurisdiction i.
$ACCT18222_i$	=	Allocated Adjusted Balance in Account 182.22 for jurisdiction i.

Trojan Decommissioning ("TROJD")

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{i=8} ACCT22842_i}$$

where:

$TROJD_i$	=	**Trojan Decommissioning (TROJD) Factor** for jurisdiction i.
$ACCT22842_i$	=	Allocated Adjusted Balance in Account 228.42 for jurisdiction i.

Tax Depreciation ("TAXDEPR")

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{i=8} TAXDEPRA_i}$$

where:

$TAXDEPR_i$	=	**Tax Depreciation (TAXDEPR) Factor** for jurisdiction i.
$TAXDEPRA_i$	=	Tax Depreciation allocated to jurisdiction i.

(Tax Depreciation is allocated based on functional pre merger and post merger splits of plant using Divisional and System allocations from above. Each jurisdiction's total allocated portion of Tax depreciation is determined by its total allocated ratio of these functional pre and post merger splits to the total Company Tax Depreciation.)

Deferred Tax Expense ("DITEXP")

$$DITEXP_i = \frac{DITEXPA_i}{\sum_{i=1}^{i=8} DITEXPA_i}$$

where:

$DITEXP_i$	=	**Deferred Tax Expense (DITEXP) Factor** for jurisdiction i.
$DITEXPA_i$	=	Deferred Tax Expense allocated to jurisdiction i.

(Deferred Tax Expense is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

<u>Deferred Tax Balance ("DITBAL")</u>

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{i=8} DITBALA_i}$$

where:

$DITBAL_i$	=	**Deferred Tax Balance (DITBAL) Factor** for jurisdiction i.
$DITBALA_i$	=	Deferred Tax Balance allocated to jurisdiction i.

(Deferred Tax Balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

Exhibit PPL/101
Kelly/48

APPENDIX D

2010 Protocol - Appendix D
Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes Special Contracts without identifiable Ancillary Service Contract attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1

Special Contracts with Ancillary Service Contract Attributes

For allocation purposes Special Contracts with Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Ancillary Service Contract rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Service attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Service Contract attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2

Buy-through of Economic Curtailment

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

2010 Protocol - Appendix D - Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

Line		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Special Contract Customer Revenue		$ 16,000,000		$ 16,000,000	
17	Discount for Ancillary Services				-	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service**					
49						
50	**Cost of Service**					
51	Energy Cost	SE2	$ 498,000,000	$ 166,148,347	$ 248,777,480	$ 83,074,173
52	Demand Related Costs	SG2	$ 998,000,000	$ 334,058,577	$ 496,912,134	$ 167,029,289
53	Sum of Cost		$ 1,496,000,000	$ 500,206,924	$ 745,689,614	$ 250,103,462
54						
55	**Revenues**					
56	Special Contract Revenue	Situs	$ 16,000,000		$ 16,000,000	
57	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,206,924**	**$ 729,689,614**	**$ 250,103,462**

2010 Protocol - Appendix D - Table 2
Interruptible Contract With Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Tariff Equivalent Revenue		$ 20,000,000		$ 20,000,000	
17	Ancillary Service Discount for 75 MW X 500 Hours of Economic Curtailment				$ (4,000,000)	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service & Ancillary Service Contract**					
49						
50	**Cost of Service**					
51	Energy Cost	SE1	$ 498,000,000	$ 166,000,000	$ 249,000,000	$ 83,000,000
52	Demand Related Costs	SG1	$ 998,000,000	$ 332,666,667	$ 499,000,000	$ 166,333,333
53	Ancillary Service Contract - Economic Curtailment (Demand)	SG1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
54	Ancillary Service Contract - Economic Curtailment (Energy)	SE1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
55	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
56						
57	**Revenues**					
58	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
59	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**

APPENDIX E

2010 Protocol - Appendix E
6 Year Levelized ECD Hydro Endowment Fixed Dollar Proposal
Revenue Requirement ($000)

2011	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

2012	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

2013	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

2014	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

2015	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

2016	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

6 Year NPV 2011-2016 @ 7.36%	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(3)	5,008	54,194	(6,064)	(34,278)	(4,601)	(13,932)	(330)
ECD Hydro	(0)	**(106)**	**(32,298)**	(3,511)	29,414	3,939	2,281	281
Total	(3)			**(9,575)**	**(4,864)**	**(662)**	**(11,650)**	**(49)**

APPENDIX F

2010 Protocol - Appendix F
Methodology for Determining Mid-C (MC) Factor

Energy for each Mid-C contract is allocated as follows to determine the MC factor.

- Priest Rapids energy is assigned 100% to Oregon.

- Rocky Reach energy is allocated on the SG factor.

- Wanapum energy is assigned to Oregon and Washington based upon each state's respective share of the SG factor.
  - Wanapum energy assigned to Oregon = Oregon SG / (total Oregon and Washington SG).
  - Wanapum energy assigned to Washington = Washington SG / (total Oregon and Washington SG).

- Wells energy is allocated on the SG factor.

- The Grant replacement contracts begin at the time the Priest Rapids contract terminates. The energy from these contracts is assigned to Oregon through October 31, 2009.

- Effective November 1, 2009, the date the Wanapum contract expires, the Grant replacement contract energy is divided into two pieces based on PacifiCorp's share of the nameplate of Priest Rapids and Wanapum as shown in the following calculation:

	Nameplate Capacity MW	PacifiCorp's Share - %	PacifiCorp's Share of Nameplate - MW	PacifiCorp's Share of Nameplate - %
Priest Rapids	789	13.9%	110	41.35%
Wanapum	831	18.7%	155	58.65%
	1,620		265	100.00%

- The Priest Rapids portion of the Grant County replacement contracts is 41.35%. The energy associated with the Grant County replacement contracts for Priest Rapids is assigned 100% to Oregon.

- The Wanapum portion of the Grant County replacement contracts is 58.65%. The energy associated with the Grant County replacement contracts for Wanapum is assigned to Washington based on the ratio of the Washington SG factor to the sum of the Oregon and Washington SG factors. The remaining energy from the Wanapum portion is assigned to Oregon.

After all of the energy from the Mid-Columbia Contracts has been assigned or allocated to each State, then the MC factor is created by dividing each State's energy by the total energy associated with the Mid-Columbia Contracts. The MC factor is used to allocate the Mid-Columbia Contract embedded cost differential to each State.

2010 Protocol - Appendix F
Allocation of Each Mid-Columbia Contract

Factors Used to Allocate Mid C Energy to Jurisdictions / Calculation of Mid C Factor

2005

Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.80%		1.80%		
Oregon	100.00%	28.86%	76.94%	28.86%	100.00%	76.94%
Washington		8.65%	23.06%	8.65%	0.00%	23.06%
Utah		41.93%		41.93%		
Idaho		5.85%		5.85%		
Wyoming		12.91%		12.91%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

MWh

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,658		4,749			10,407	0.54%
Oregon	567,559	90,829	596,498	76,238	-	-	1,331,125	69.27%
Washington		27,222	178,772	22,849			228,842	11.91%
Utah		131,984		110,783			242,767	12.63%
Idaho		18,426		15,466			33,892	1.76%
Wyoming		40,636		34,108			74,744	3.89%
	567,559	314,754	775,270	264,193	-	-	1,921,777	100.00%

2007

Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.73%		1.73%		
Oregon	100.00%	27.56%	76.68%	27.56%	100.00%	76.68%
Washington		8.38%	23.32%	8.38%	0.00%	23.32%
Utah		44.13%		44.13%		
Idaho		5.59%		5.59%		
Wyoming		12.61%		12.61%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

MWh

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,457		4,581			10,038	0.52%
Oregon	-	86,746	594,444	72,811	564,683	-	1,318,684	68.72%
Washington		26,388	180,826	22,149			229,363	11.95%
Utah		138,899		116,587			255,486	13.31%
Idaho		17,582		14,758			32,340	1.69%
Wyoming		39,682		33,308			72,990	3.80%
	-	314,754	775,270	264,193	564,683	-	1,918,900	100.00%

2011

Percent

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/
California		1.65%		1.65%		
Oregon	100.00%	26.13%	76.18%	26.13%	100.00%	76.18%
Washington		8.17%	23.82%	8.17%	0.00%	23.82%
Utah		46.96%		46.96%		
Idaho		5.20%		5.20%		
Wyoming		11.90%		11.90%		
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

MWh

Mid C Contracts	Priest Rapids 1/	Rocky Reach 2/	Wanapum 3/	Wells 4/	Priest Grant Replacement 5/	Wanapum Grant Replacement 5/	Total Mid-C	MC Factor %
California		5,200		4,365			9,565	0.65%
Oregon	-	82,231	-	69,021	372,327	402,325	925,904	62.59%
Washington		25,708	-	21,579	-	125,776	173,064	11.70%
Utah		147,810		124,066			271,876	18.38%
Idaho		16,353		13,726			30,079	2.03%
Wyoming		37,452		31,436			68,887	4.66%
	-	314,754	-	264,193	372,327	528,101	1,479,375	100.00%

(1) Priest Rapids Power Sales Agreement with Grant County dated May 2, 1956
(2) Rocky Reach Power Sales Agreement with Chelan County dated November 14, 1957
(3) Wanapum Power Sales Agreement with Grant County dated June 22, 1959
(4) Wells Power Sales Agreement with Douglas County dated September 18, 1963
(5) Priest Rapids Project Product Sales Agreement with Grant County dated December 31, 2001
The Additional Product Sales Agreement with Grant County dated December 31, 2001
The Priest Rapids Reasonable Portion Power Sales Agreement with Grant County dated December 31, 2001

Docket No. UM-1050
Exhibit PPL/200
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Steven R. McDougal

September 2010

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Steven R. McDougal, and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111. I am currently employed as the director of revenue requirement.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a Master of Accountancy degree from Brigham Young University with an emphasis in Management Advisory Services in 1983 and a Bachelor of Science degree in Accounting from Brigham Young University in 1982. In addition to my formal education, I have also attended various educational, professional, and electric industry-related seminars. I have been employed by PacifiCorp or its predecessor companies since 1983. My experience at PacifiCorp includes various positions within regulation, finance, resource planning, and internal audit.

Q. What are your responsibilities as director of revenue requirement?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings or revenue requirement, assuring that the inter-jurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the Company operates.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony before the Public Service Commission of Utah, the Washington Utilities and Transportation Commission, the California Public

Utilities Commission, the Idaho Public Utilities Commission, the Public Service Commission of Wyoming, and the Utah State Tax Commission.

Purpose of Direct Testimony

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony addresses the calculation and implementation of the 2010 Protocol allocation methodology. Specifically, I provide direct testimony on the following:

- calculation of the Company's projected revenue requirement for calendar years 2010 through 2019 and the corresponding inter-jurisdictional allocation (Baseline Study);
- a review of historical results using the Revised Protocol;
- changes between the Revised Protocol and 2010 Protocol, including changes in allocation factors, the calculation of the Embedded Cost Differential (ECD), the fixed allocation adjustments for each state, and treatment of costs related to the Klamath Hydroelectric Settlement Agreement (KHSA);
- information to be included the Company's future results of operations reports and rate cases related to the 2010 Protocol and the calculation of the ECD;
- changes to the following appendices included with the direct testimony of Ms. Andrea L. Kelly: 1) Appendix B – Allocation Factor Applied to each Component for Revenue Requirement; 2) Appendix C – Allocation factor – Algebraic Definitions; 3) Appendix D – Special Contracts; 4) Appendix E – 6-Year Levelized Fixed Dollar Embedded Cost Differential Hydro Endowment; and 5) Appendix F – Methodology for Determining Mid-C (MC) Factor; and

- allocation of State resources associated with: 1) Demand-Side Management Programs; 2) Portfolio Standards; 3) State-specific Initiatives; and 4) New QF Contracts.

Baseline Study

Q. Why did the Company prepare the Baseline Study?

A. As described by Ms. Kelly, the Company prepared the Baseline Study at the request of the Multi-State Process (MSP) Standing Committee. The purpose of the study was to compute a current projection of revenue requirement for calendar years 2010 through 2019 and produce the inter-jurisdictional allocation according to the Revised Protocol, Rolled-In, and Modified Accord allocation methodologies. The study was designed to facilitate MSP participants' assessment of the ongoing reasonableness of Revised Protocol to determine if modifications were needed. The focus of the Baseline Study was to create a tool that could be used to compare current expectations of the future on varying allocation methodologies. The Baseline Study is not intended to precisely predict annual revenue requirement through calendar year 2019 and does not serve to predict future rate setting proceedings or price changes in any state. Rather, it serves to model differing allocation assumptions and is used as an analytical tool to assess the impact of those assumptions on the states served by the Company.

The purpose of the Company's baseline study was described using the following language circulated to MSP participants:

> "These attachments represent the Company's best efforts to provide reasonable draft projections of the differences in allocation methodologies over the 10-year study horizon. Emphasis was put on forecasting items that are treated differently and would create differences

> between the allocation methodologies used. Less time was spent on items that are treated the same in the various allocation methodologies, since this would not impact the comparisons between allocation methodologies. As such, the focus of the analysis was on the relative differences between allocation methodologies, as opposed to the absolute level of total company revenue requirement."

Q. Please describe how the Company produced the Baseline Study.

A. Study preparation began in mid-2009. Projected revenue requirement was based on actual 2008 costs which were escalated through the study time horizon to reflect inflation and expected changes in the Company's resource base consistent with the 2008 Integrated Resource Plan (IRP). System net power costs (NPC) were computed consistent with these assumptions as described in the direct testimony of Mr. Gregory N. Duvall. Jurisdictional allocation factors were calculated for each year of the study using the forecast load from the Company's February 2009 load forecast. Jurisdictional revenue requirement was then calculated according to Revised Protocol and compared to the allocation methodology preferred by each state prior to adoption of Revised Protocol, either Rolled-In or Modified Accord. Preliminary results of the study were provided to MSP participants on August 17, 2009.

Q. Why were the August 2009 results considered preliminary?

A. The August 17, 2009 study was considered a draft by the Company and was provided to MSP participants in order to vet the modeling of assumptions and the resulting revenue requirement. The results were also considered preliminary because of the treatment of the Klamath hydro project. At this stage in the process the KHSA had not yet been finalized; consequently, the preliminary study assumed that Klamath would be relicensed and included cost assumptions based on the best information available at that time. After circulating the preliminary results in August 2009, the Company solicited feedback from the MSP participants in workgroup meetings. As described by Ms. Kelly, several Utah parties subsequently issued a notification to MSP participants questioning the continued used of Revised Protocol. The Company gathered input from MSP participants, continued to refine the revenue requirement modeling, and awaited finalization of the KHSA in order to produce the final Baseline Study.

Q. When was the Baseline Study finalized?

A. Once the KHSA was finalized, the Company incorporated it and other feedback from MSP participants into the revenue requirement modeling, and the Baseline Study was finalized and shared with MSP participants in March 2010.

Q. What were the results of the Baseline Study?

A. Exhibit PPL/201 provides the results of the Baseline Study. Revenue requirement using Revised Protocol for each state is compared to the allocation methodology used by that state prior to adoption of Revised Protocol, either Rolled-In or Modified Accord.

Q. Was the Baseline Study compared to the study performed in 2004 supporting Revised Protocol (the 2004 Study)?

A. Yes. The relative differences by state between Revised Protocol and Rolled-In or Modified Accord in the Baseline Study were compared to the relative differences between the same allocation methodologies used in the Company's 2004 Study. The results are shown in Exhibit PPL/201. This comparison spurred continued discussion among the MSP participants regarding whether Revised Protocol will perform as originally expected based on updated expectations of the future.

Q. Were there any additional analyses performed based on the Baseline Study results?

A. Yes. At the request of the Standing Committee, the Company performed alternative studies related to varying wholesale market prices, the value of operating as a single integrated system, and the impact of load growth.

Q. Please describe the study related to wholesale market prices.

A. The Standing Committee requested a study to test the potential impact on each jurisdiction under Revised Protocol with a given change in wholesale market prices, one using high market prices and one using low market prices. The direct testimony of Mr. Duvall describes the corresponding calculation of NPC and I incorporated his revised NPC results into the revenue requirement model. A summary of the results is provided in Exhibit PPL/202.

Q. Please describe the studies performed on the value of the single integrated system.

A. Two studies, a structural separation study and go-it-alone analysis, were completed to estimate the benefits of the Company continuing to plan and operate as a single integrated system. The direct testimony of Mr. Duvall describes each of these studies in greater detail along with the calculation of the impact on NPC in each scenario. The results of these studies are provided in the direct testimony of Mr. Duvall.

Q. Please describe the load growth study.

A. An additional study was conducted to estimate the impact of load growth on the various jurisdictions. The study began with the baseline study. Load growth was then adjusted in Utah and Wyoming, the two fastest growing jurisdictions, to a level consistent with other states. Using the revised load data, the following three changes were made to the revenue requirement calculation: 1) NPC were updated, as described in the direct testimony of Mr. Duvall; 2) jurisdictional demand and energy used to compute inter-jurisdictional allocation factors were updated; and 3) rate base and operation and maintenance costs were updated to be consistent with the change in loads and resources. The results of the study for both Revised Protocol and Rolled-In are included in Exhibit PPL/203. The net impact of the change to the dynamic allocation factors and net power costs was an allocation of 103 percent of the incremental cost of load growth to Utah and Wyoming, the fastest growing states. The slower growing states all receive a slight benefit from the load growth because of the reallocation of fixed costs.

The load growth study showed that the dynamic allocation factors utilized under a Rolled-In allocation methodology protect individual states from bearing the cost of load growth in other states. This study showed that currently load growth is not an issue and is not expected to be an issue in the future. On the contrary, Revised Protocol was shown to have a great deal of volatility related to the calculation of the ECD and is therefore not a singularly effective protection mechanism against load growth.

Historical Results

Q. Did the Company compare historical results utilizing Revised Protocol to the 2004 Study?

A. Yes. An analysis was prepared to help the MSP participants better understand how the Revised Protocol has performed historically. The results of this analysis are shown in Exhibit PPL/204. This analysis shows there is a great deal of volatility in the Revised Protocol results, driven mainly by the ECD calculation. As a result, considerable analysis was done on various options to the ECD resulting in the changes described later in my testimony.

2010 Protocol

Q. Please describe the major differences between the 2010 Protocol and the Revised Protocol.

A. The 2010 Protocol is a simplified version of the Revised Protocol that is intended to reduce unintended variation in the allocation of actual revenue requirement as compared to the forecasts used in the 2004 Study and the Baseline Study. The specific changes to Revised Protocol incorporated into the 2010 Protocol are identified below.

- **Factor Changes:** Similar to Revised Protocol, the 2010 Protocol is based on an initial Rolled-In allocation of system costs. Resources classified as seasonal for Revised Protocol (including simple cycle combustion turbines and the Cholla Unit 4/APS exchange) will no longer be uniquely allocated, but will follow a Rolled-In allocation. Consequently, the allocation of system costs, prior to the application of the ECD and KHSA deviations, is the same as the Rolled-In allocation methodology.

- **<u>ECD Changes:</u>** The scope of the ECD has been modified in the 2010 Protocol, specifically related to Qualifying Facility (QF) contracts and the "All Other" generation resources category. All QF contracts entered into prior to September 15, 2010, are considered system resources in the 2010 Protocol and will not be considered as part of the ECD calculation. New QF contracts will also be considered system resources unless deemed to be priced greater than comparable resources. The embedded cost of "All Other" generation resources includes only resources that were part of the Company's integrated system prior to 2005.

The ECD calculation, prior to levelization, was done using forecasted information from the Baseline study, using the following three sections from the Revised Protocol ECD calculation:

<u>Company Owned Hydro - West:</u> This section was calculated the same as under Revised Protocol.

<u>Mid-C Contracts:</u> This section was calculated the same as currently used in all Company filings. The Grant Reasonable contract is included as an offset to the Mid-C contract costs.

<u>Generation Costs – Pre-2005 Resources ("All Other" Generation):</u> This section was calculated the same as in Revised Protocol with the exception that the calculation of the embedded cost of "All Other" resources only included costs and MWh associated with pre-2005 resources.

- **<u>ECD Levelization:</u>** The value of the modified 2010 Protocol ECD is calculated for each state in the Baseline Study, levelized, and fixed for all rate cases filed through December 31, 2016, rather than allowed to float with each rate case or other regulatory filing.
- **<u>Klamath Costs:</u>** All costs related to the KHSA are initially allocated to all states in unadjusted results. The depreciation expense associated with Klamath assets will be adjusted on January 1, 2011, in order to fully depreciate these assets by December 31, 2019. The system allocation of Klamath costs is consistent with the benefits of the hydro output under the Rolled-In allocation methodology. As part of the 2010 Protocol agreement, an adjustment is made to reverse the initial system allocation of the KHSA surcharge expected to be paid for by Oregon and California customers and situs assigns it to those states based on the amounts stipulated in the KHSA. This re-allocation of costs is consistent with the reallocation of hydro benefits accomplished through the ECD component of the 2010 Protocol. The surcharge included in the Baseline Study is levelized and fixed for the period 2011 through 2016 and included in the 2010 Protocol at the levelized amount.

Q. Why is the scope of the ECD limited to only pre-2005 resources in the "All Other" generation resource category?

A. During the MSP meetings, the costs of "All Other" generation were identified as one of the components causing variability in the Revised Protocol ECD calculation. Several options were studied for the "All Other" generation cost component, including using pre-1989 resources to correspond with the date of the original merger, using pre-2005 resources to align with the adoption of Revised Protocol, or continuing to base the “All Other” resources on current assets. The MSP participants agreed that since the ECD compares legacy hydro resources to “All Other” generation, using pre-2005 would provide a consistent calculation, and would exclude new resources acquired which may cause significant impacts on the calculation. The list of pre-2005 resources is provided as Exhibit PPL/205.

Q. What are the costs related to the KHSA and why is an adjustment necessary to re-allocate the KHSA surcharge?

A. Since the 2010 Protocol uses Rolled-In allocation as the baseline, it was decided that the KHSA costs will initially be system allocated. This is consistent with the treatment of costs for other system resources under Rolled-In, and is consistent with the benefit of the Klamath resources which are allocated to all jurisdictions under Rolled In. However, consistent with the ECD calculation which re-allocates the hydro costs and benefits to Pacific Power states, an adjustment will be made to the KHSA surcharge to undo the system allocation and directly assign the amount of the surcharge borne by California and Oregon through respective tariff riders in those states. This re-allocation does not revoke the right of parties in any jurisdiction to review the KHSA costs for prudency.

Q. Please explain how the ECD and KHSA surcharge will be levelized and fixed for the period 2011 through 2016.

A. The starting point for the levelized ECD and KHSA calculation is the annual amounts included in Exhibit PPL/206. The annual amounts were levelized using the 2008 IRP discount rate to come up with the six year net present value shown on the bottom of Exhibit PPL/207. Annual levelized amounts were then developed that result in the same net present value by jurisdiction over the six year period from 2011 to 2016.

Q. Please illustrate the revenue requirement difference between the 2010 Protocol and Revised Protocol.

A. The difference between results using the 2010 Protocol and Revised Protocol are shown on Exhibit PPL/208. This exhibit shows, for each jurisdiction, the revenue requirement difference from changing to 2010 Protocol.

Future Reporting

Q. What information will the Company provide in its results of operations reports and rate cases related to allocation methodologies?

A. Subject to the approval of the Company's application, jurisdictional revenue requirement in future results of operations reports and rate cases will be calculated using the 2010 Protocol allocation methodology. In addition, all historical results of operations filed by the Company will include a calculation of the 2010 Protocol ECD using historical data. This will be provided for informational purposes for states to track the information over time. The Company proposes to no longer provide reports or comparisons using any other allocation methodologies.

MSP Appendix Modifications

Q. Please describe the changes to Appendix B – Allocation Factor Applied to each Component for Revenue Requirement.

A. Appendix B has been updated to remove allocation factors related to seasonal resources and the Cholla resource which are no longer used in 2010 Protocol.

The changes to Appendix B also include general cleanup and housekeeping, such as removing factor combinations no longer used and adding new factor combinations since Revised Protocol was originally developed.

Q. Please describe the changes to Appendix C – Allocation factor – Algebraic Derivations.

A. Derivations of factors related to seasonal resources and the Cholla Unit 4/APS exchange which are no longer used in 2010 Protocol have been removed. The income before tax factor has been removed, and state income taxes will be calculated using the statutory state effective tax rate, consistent with the methodology used to calculate state income taxes associated with rate changes in rate cases in all states. This change is necessary because of the volatility of calculating results for a single jurisdiction.

Q. Please describe the changes to Appendix D – Special Contracts.

A. This document remains unchanged, other than now labeling the document as "2010 Protocol". The appendix has two options for special contracts designed to provide consistency between the allocation of revenues, costs and benefits derived from adjusting allocation factors. Under option 1, the costs of a program are embedded in the tariff price, resulting in the jurisdiction approving the contract absorbing the full cost of the program, similar to demand-side management (DSM) costs. Since the costs are absorbed by the jurisdiction approving the contract, it also receives the benefits associated with the program through reduced allocation factors. Under option 2, the contract costs are separately identified and allocated to all states. Since the costs are allocated to all states and not to a specific jurisdiction, the monthly load used to calculate allocation factors is calculated assuming no curtailment occurs.

Q. Please describe the changes to Appendix E – 6-Year Levelized Fixed Dollar Embedded Cost Differential Hydro Endowment.

A. This document has been re-crafted to reflect the ECD from the 2010 Protocol and therefore replaces in its entirety, rather than changing Appendix E from the Revised Protocol. Under the 2010 Protocol, the ECD amount has been levelized and is set at a fixed amount. The ECD page has been updated to show the amounts that will be included in filings made through December 31, 2016.

Q. Please describe the changes to Appendix F – Methodology for Determining Mid-C (MC) Factor.

A. This document remains unchanged, other than now labeling the document as "2010 Protocol". The MC factor is utilized in the Baseline Study to compute the allocation of the projected ECD. However, because the ECD is fixed by year and by state in the 2010 Protocol, this factor will not be directly utilized in filings made prior to December 31, 2016.

State Resources

Q. How will State Resources be allocated in 2010 Protocol?

A. As mentioned above, state resources included: 1) Demand-Side Management Programs; 2) Portfolio Standards; 3) State-specific Initiatives; and 4) New QF Contracts. There is no change in the allocation of State resources, which continue to be situs allocated per the 2010 Protocol.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit PPL/201

Docket No. UM-1050
Exhibit PPL/201
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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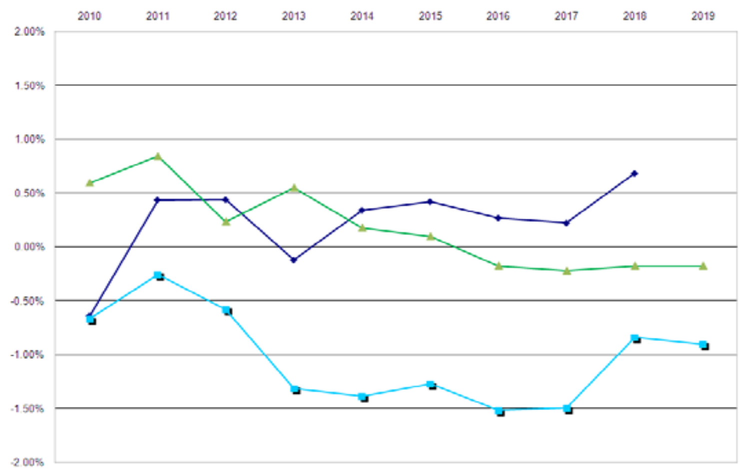
Exhibit Accompanying Direct Testimony of Steven R. McDougal

Baseline Study and 2004 Study Comparison

September 2010

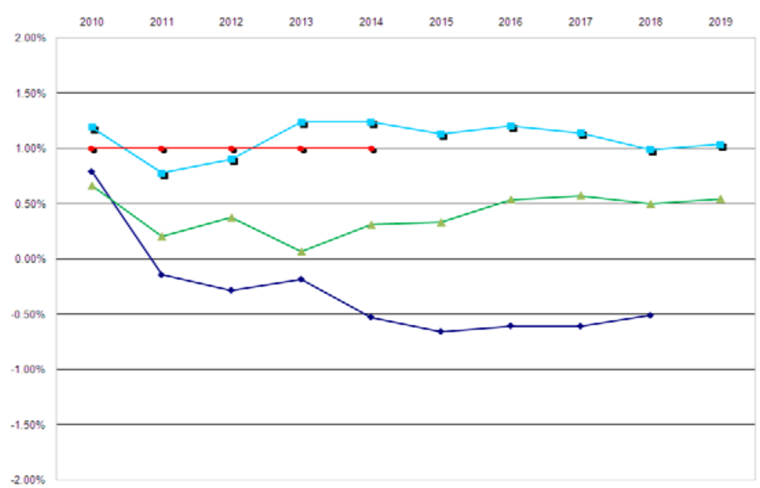
Multi-State Process (MSP)
2010 MSP Study Final Results

Oregon

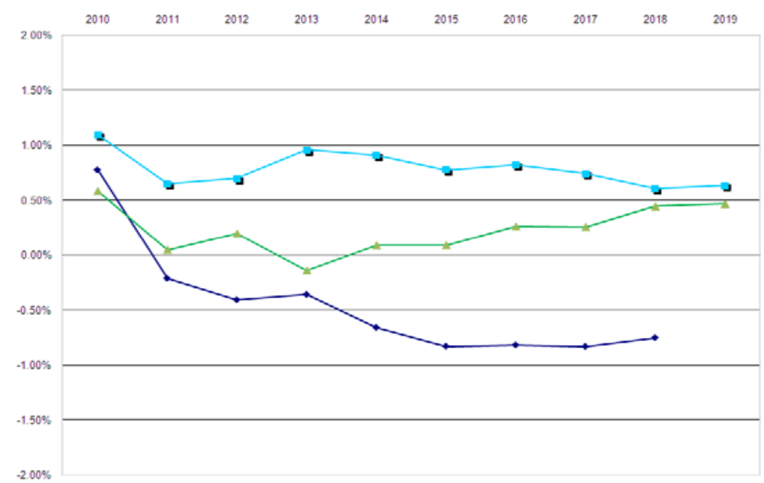


Wyoming

Utah



Idaho



2004 MSP Study

2005 MSP Study

2010 MSP Study Final

Exhibit PPL/202

Docket No. UM-1050
Exhibit PPL/202
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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High and Low Market Price Studies

September 2010

Multi-State Process (MSP)
2010 MSP Study Final - High Market Price and Low Market Price Sensitivity

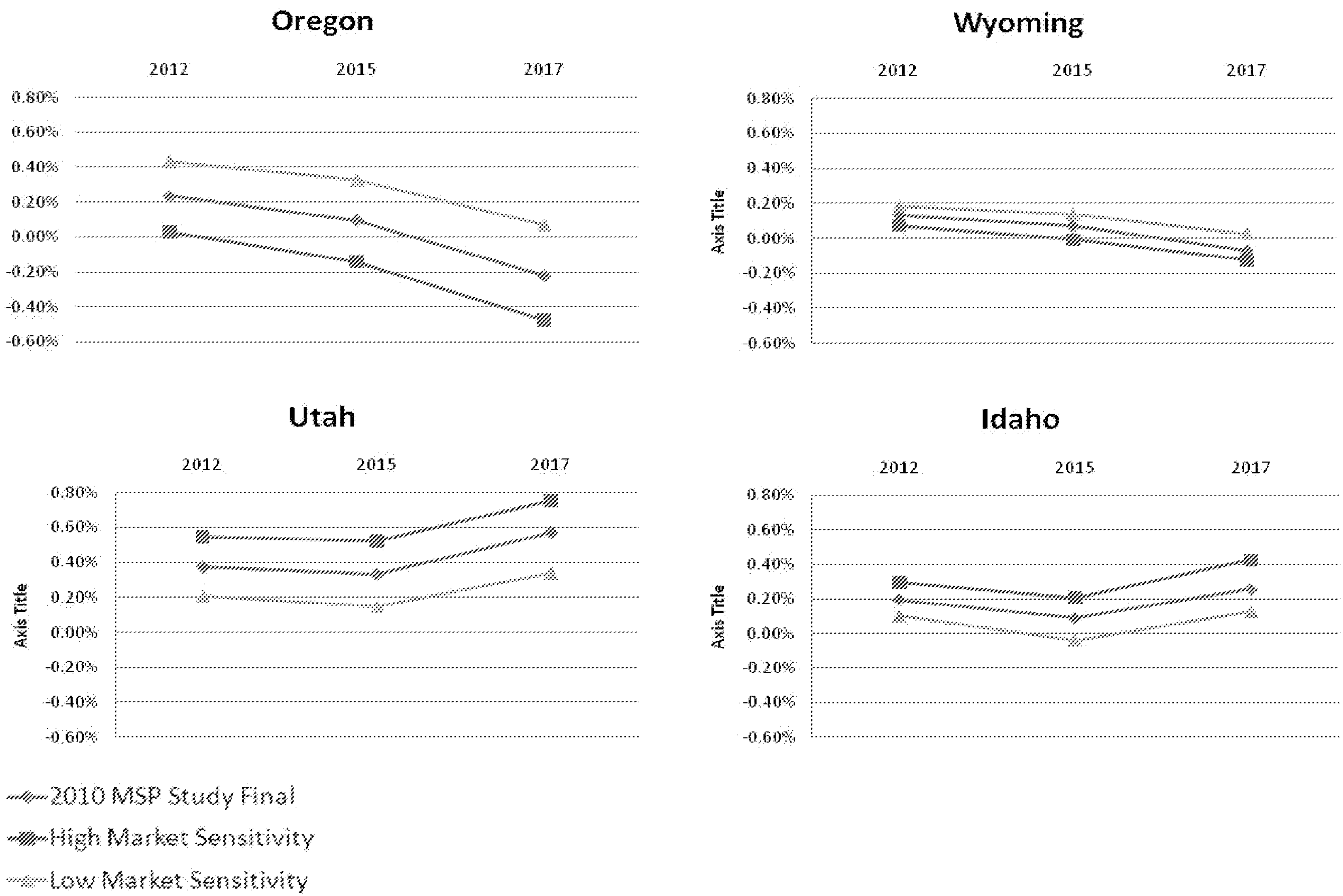

Exhibit PPL/202
McDougal/1

Exhibit PPL/203

Docket No. UM-1050
Exhibit PPL/203
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Load Growth Study

September 2010

Multi-State Process (MSP)
Percentage of Load Growth Allocated by State - 2011 through 2019

	2011-2019 (9-Year) 2010 NPV @ 7.36%	2011	2012	2013	2014	2015	2016	2017	2018	2019
Revised Protocol										
% of Load Growth										
California	-0.10%	-0.17%	-0.28%	0.11%	-0.14%	-0.02%	0.01%	-0.06%	-0.22%	-0.21%
Oregon	-1.63%	-2.90%	-4.46%	1.23%	-2.17%	-0.61%	-0.17%	-1.11%	-3.12%	-2.95%
Washington	-0.48%	-0.89%	-1.33%	0.36%	-0.64%	-0.17%	-0.03%	-0.31%	-0.92%	-0.87%
Utah	**70.56%**	**73.06%**	**74.07%**	**67.68%**	**71.37%**	**69.78%**	**69.08%**	**69.76%**	**71.71%**	**71.71%**
Idaho	-0.46%	-0.88%	-1.21%	0.22%	-0.66%	-0.32%	-0.06%	-0.26%	-0.77%	-0.76%
Wyoming	**32.13%**	**31.83%**	**33.31%**	**30.38%**	**32.30%**	**31.36%**	**31.17%**	**31.99%**	**33.38%**	**33.13%**
Sum of UT and WY Load Growth States	**102.69%**	**104.89%**	**107.38%**	**98.06%**	**103.66%**	**101.14%**	**100.25%**	**101.75%**	**105.09%**	**104.85%**

	2011-2019 (9-Year) 2010 NPV @ 7.36%	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rolled-In										
% of Load Growth										
California	-0.09%	-0.19%	-0.30%	0.12%	-0.13%	-0.01%	0.03%	-0.04%	-0.20%	-0.19%
Oregon	-1.48%	-3.25%	-4.66%	1.31%	-2.17%	-0.55%	0.12%	-0.83%	-2.87%	-2.73%
Washington	-0.45%	-0.98%	-1.40%	0.37%	-0.65%	-0.17%	0.03%	-0.25%	-0.87%	-0.83%
Utah	**70.03%**	**73.13%**	**73.97%**	**67.38%**	**71.06%**	**69.42%**	**68.36%**	**69.05%**	**71.00%**	**71.03%**
Idaho	-0.49%	-0.90%	-1.21%	0.17%	-0.68%	-0.34%	-0.12%	-0.32%	-0.80%	-0.78%
Wyoming	**32.52%**	**32.26%**	**33.68%**	**30.64%**	**32.62%**	**31.67%**	**31.59%**	**32.42%**	**33.79%**	**33.56%**
Sum of UT and WY Load Growth States	**102.54%**	**105.39%**	**107.66%**	**98.02%**	**103.68%**	**101.09%**	**99.95%**	**101.47%**	**104.80%**	**104.59%**

Exhibit PPL/204

Docket No. UM-1050
Exhibit PPL/204
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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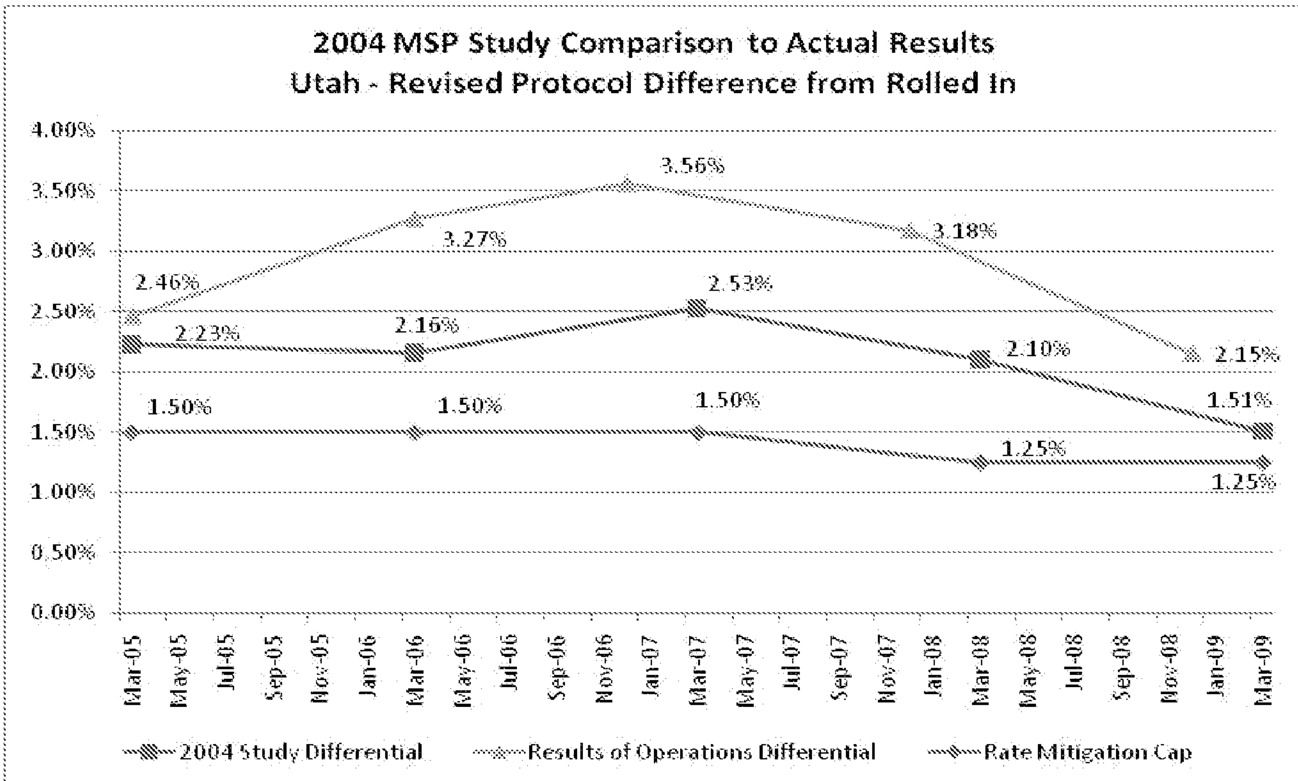
Exhibit Accompanying Direct Testimony of Steven R. McDougal

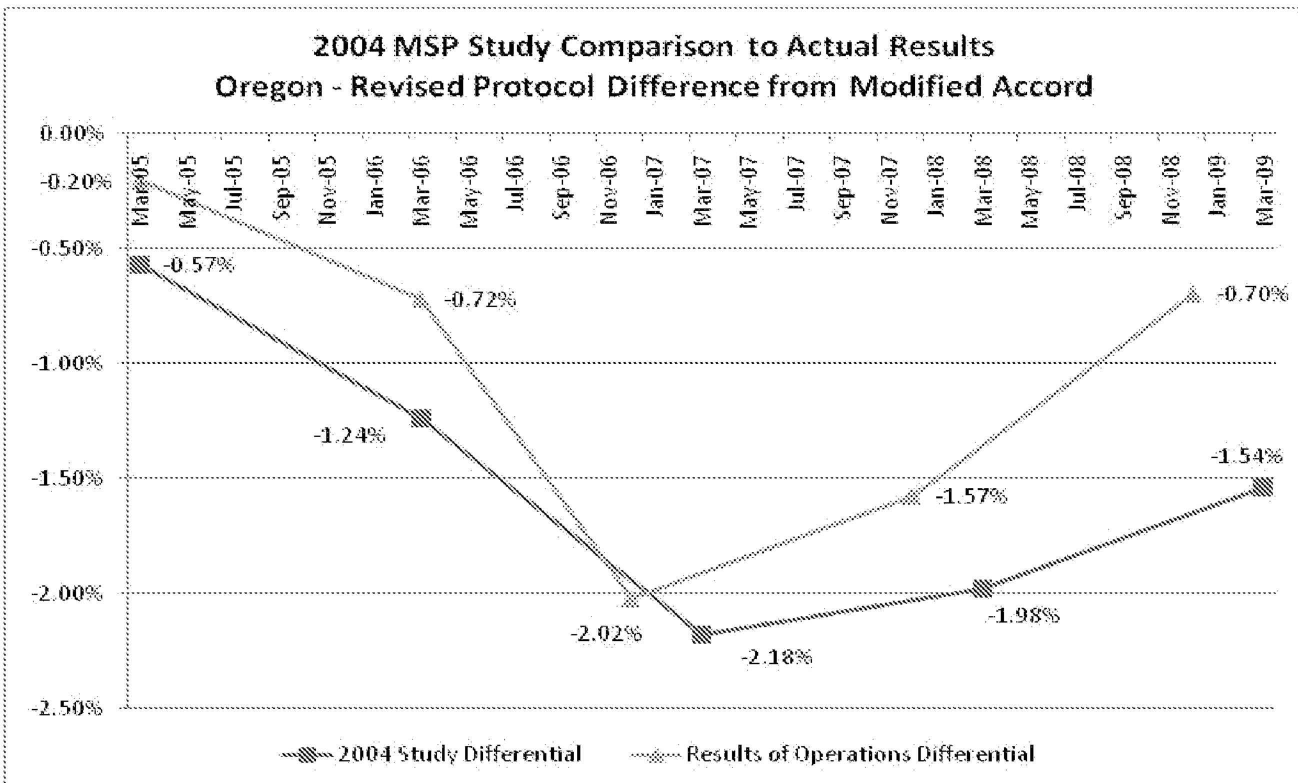
Revised Protocol Historical Analysis

September 2010

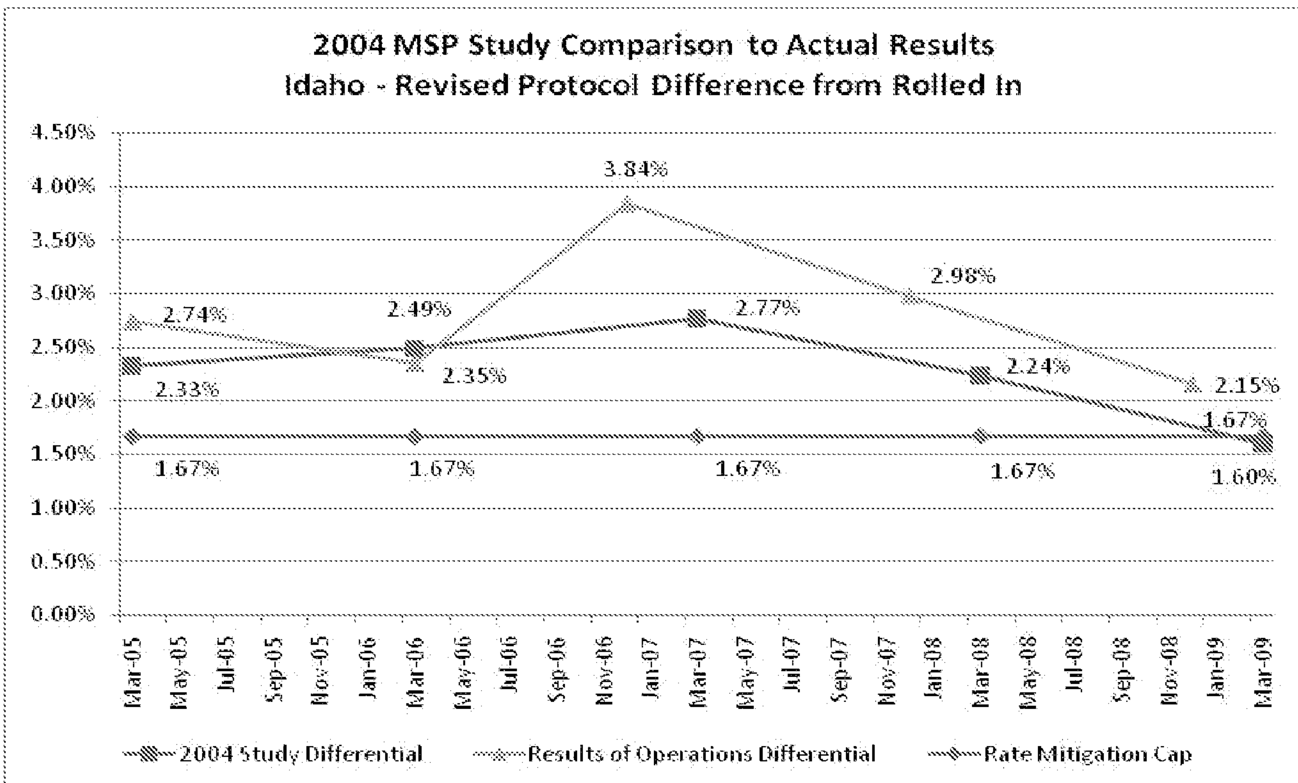
Multi-State Process (MSP)
2004 MSP Study Comparison to Actual Results - By State



Multi-State Process (MSP)
2004 MSP Study Comparison to Actual Results - By State



Multi-State Process (MSP)
2004 MSP Study Comparison to Actual Results - By State



Multi-State Process (MSP)
2004 MSP Study Comparison to Actual Results - By State

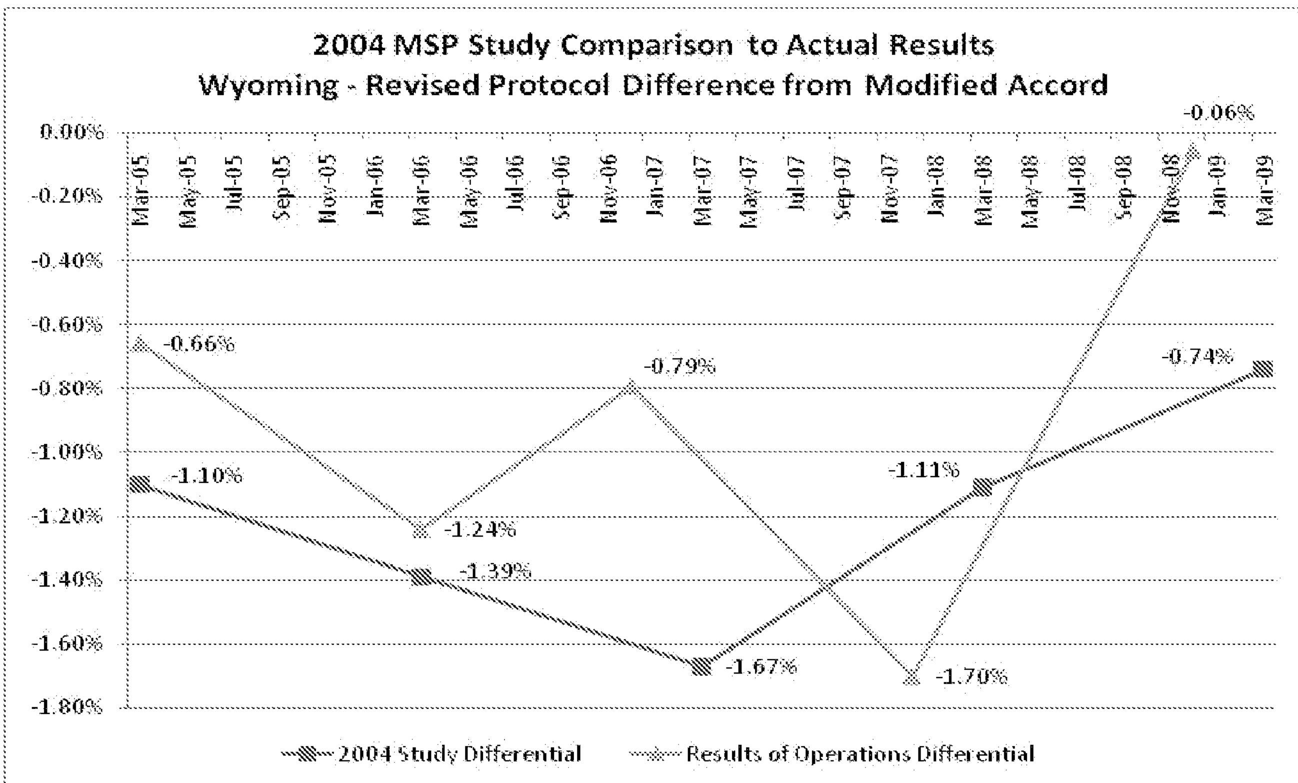


Exhibit PPL/205

Docket No. UM-1050
Exhibit PPL/205
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Steven R. McDougal

List of Pre-2005 Reources

September 2010

Multi-State Process (MSP)
2010 Protocol - Pre-2005 Resources
Resources Included in Embedded Cost Differential (ECD)
All Other $/MWh Calculation

Pre-2005 Resources
BPA and Hermiston Purchase Power Contracts
Blundell (23 MW)
Carbon
Dave Johnston
Foote Creek I
Gadsby 1, 2, 3
Gadsby 4, 5, 6
Hunter
Huntington
Jim Bridger
Naughton
Wyodak
Camas
Colstrip
Craig
Hayden
Cholla
East Hydro
Little Mountain
Hermiston

Exhibit PPL/206

Docket No. UM-1050
Exhibit PPL/206
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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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2010 Protocol Embedded Cost Differential by Year

September 2010

Multi-State Process (MSP)
2010 MSP Study
Fixed Dollar Proposal
Revenue Requirement ($000)

2011	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,065	11,308	(1,327)	(7,169)	(971)	(2,839)	(67)
ECD Hydro	0	123	(12,469)	129	9,222	1,249	1,659	87
Total	(1)			(1,198)	2,053	278	(1,181)	19

2012	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,060	11,396	(1,313)	(7,193)	(958)	(2,921)	(72)
ECD Hydro	(0)	(70)	(5,876)	(1,044)	6,028	803	100	60
Total	(1)			(2,357)	(1,165)	(155)	(2,821)	(12)

2013	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,059	11,466	(1,293)	(7,224)	(982)	(2,955)	(72)
ECD Hydro	(0)	199	(1,635)	134	(67)	(9)	1,379	(1)
Total	(1)			(1,160)	(7,291)	(991)	(1,576)	(72)

2014	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,063	11,573	(1,267)	(7,319)	(990)	(2,988)	(72)
ECD Hydro	(0)	(116)	(6,019)	(1,157)	6,467	875	(114)	63
Total	(1)			(2,424)	(852)	(115)	(3,103)	(8)

2015	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,063	11,640	(1,253)	(7,383)	(982)	(3,018)	(69)
ECD Hydro	0	(97)	(5,895)	(1,104)	6,198	825	15	58
Total	(1)			(2,357)	(1,184)	(157)	(3,003)	(11)

2016	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,694	(1,243)	(7,407)	(977)	(3,061)	(69)
ECD Hydro	(0)	(254)	(8,577)	(1,820)	9,855	1,300	(596)	92
Total	(1)			(3,063)	2,448	323	(3,658)	23

6 Year NPV 2011-2016 @ 7.36%	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(3)	5,008	54,194	(6,064)	(34,278)	(4,601)	(13,932)	(330)
ECD Hydro	(0)	(106)	(32,298)	(3,511)	29,414	3,939	2,281	281
Total	(3)			(9,575)	(4,864)	(662)	(11,650)	(49)

Exhibit PPL/207

Docket No. UM-1050
Exhibit PPL/207
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Steven R. McDougal

2010 Protocol Embedded Cost Differential (Levelized)

September 2010

Multi-State Process (MSP)
2010 MSP Study
6 Year Levelized Average Hydro Endowment Fixed Dollar Proposal
Revenue Requirement ($000)

2011	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

2012	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(1)	1,062	11,496	(1,286)	(7,272)	(976)	(2,955)	(70)
ECD Hydro	(0)	**(23)**	**(6,851)**	(745)	6,240	836	484	60
Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

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Total	(1)			**(2,031)**	**(1,032)**	**(140)**	**(2,471)**	**(10)**

6 Year NPV 2011-2016 @ 7.36%	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
Klamath Surcharge Situs	(3)	5,008	54,194	(6,064)	(34,278)	(4,601)	(13,932)	(330)
ECD Hydro	(0)	**(106)**	**(32,298)**	(3,511)	29,414	3,939	2,281	281
Total	(3)			**(9,575)**	**(4,864)**	**(662)**	**(11,650)**	**(49)**

Exhibit PPL/208

Docket No. UM-1050
Exhibit PPL/208
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Steven R. McDougal

Compare 2010 Protocol to MSP Study Final (Revised Protocol)

September 2010

Multi-State Process (MSP)
2010 Protocol Difference from Revised Protocol

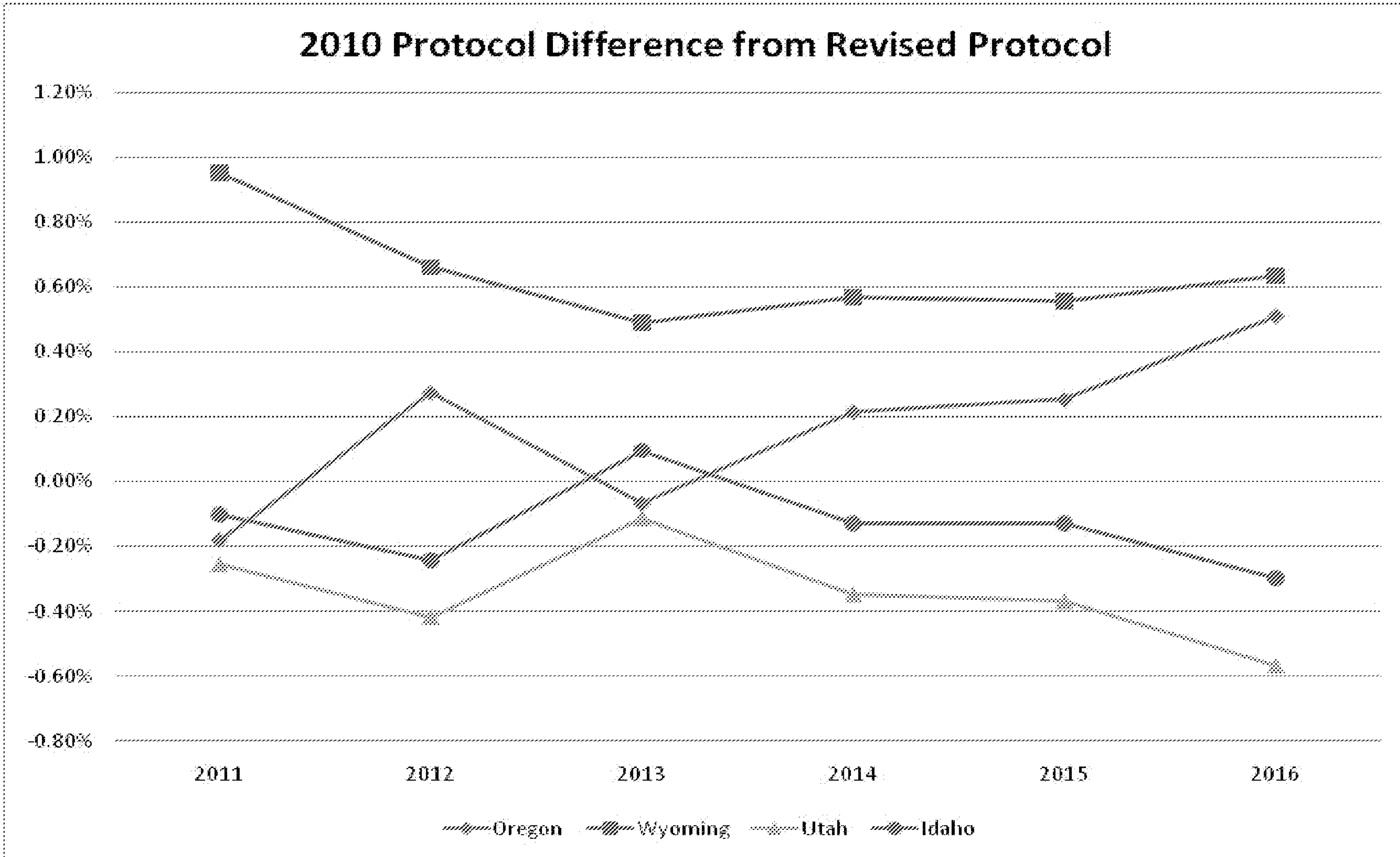


Exhibit PPL/208
McDougal/1

Docket No. UM-1050
Exhibit PPL/300
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

September 2010

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Director, Long-Range Planning and Net Power Costs.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process (MSP). Currently, I direct the work of the integrated resource planning group, the load forecasting group, the net power cost group, and the renewable compliance area.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. I present the net power cost (NPC) study used to support the 2010 Protocol revenue requirement analyses that is presented in the testimony of Mr. Steven R. McDougal. In addition, I present the NPC studies that were conducted to test the sensitivity of high and low market prices, the studies that were conducted to estimate the increased NPC that the Company would incur if there were structural separation by balancing areas, and the study that was used to develop the NPC and resource changes associated with the load growth study. I also present an analysis estimating the increased generation-related costs the Company would incur if each jurisdiction were to go-it-alone. The structural separation study and the go-it-alone study were conducted to provide a rough estimate of cost savings that may arise from continuing to plan and operate as a single integrated system. Finally, I present the NPC results associated with the load growth study. All studies except the go-it-alone study were conducted using the Company's Generation and Regulation Initiative Decision Tool (GRID) model.

2010 Protocol NPC Study

Q. Why did the Company prepare the 2010 Protocol NPC study?

A. The Company prepared the 2010 Protocol NPC study (Base NPC Study) at the request of the Standing Committee. The purpose of the study was to compute a current projection of total company NPC to support revenue requirement analysis as presented in the testimony of Mr. McDougal. The Standing Committee requested that the Company update its NPC study to reflect the most recent information available at the time.

Q. What input data did the Company use to conduct the Base NPC Study?

A. The Company used the 2008 Integrated Resource Plan (IRP) preferred portfolio, along with (i) the Company's February 2009 load forecast, (ii) June 2009 Official Forward Price Curves, and (iii) updated information of new and existing contracts as of August 2009. Input assumptions for the Klamath River operations and dam removal schedule were taken from the Klamath Hydroelectric Settlement Agreement (KHSA) dated February 18, 2010.

Market Price Sensitivity Studies

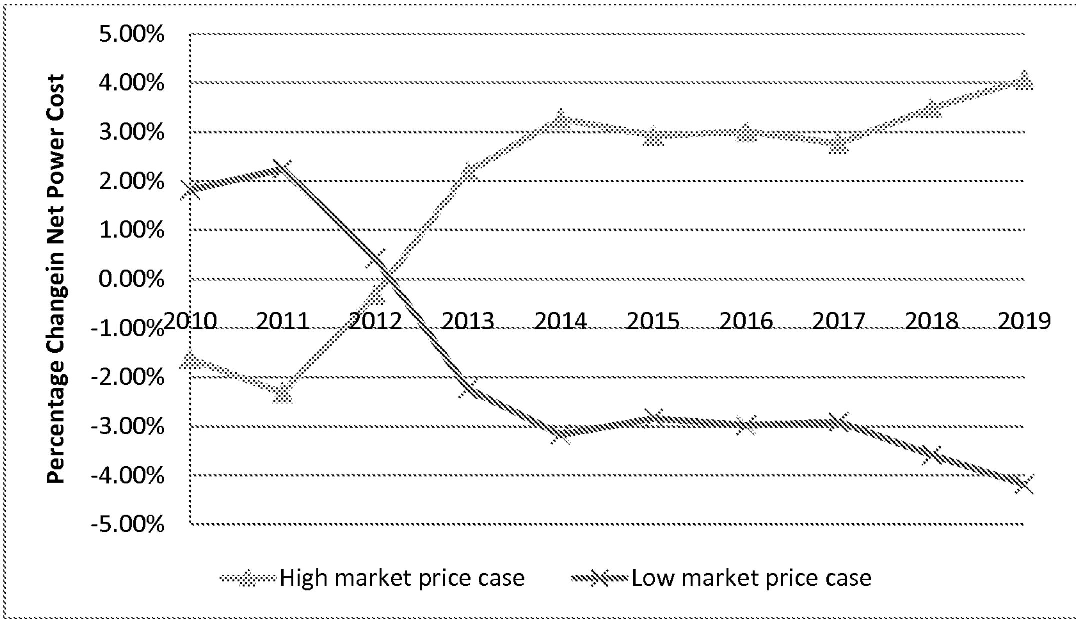
Q. Why did the Company perform market price sensitivity studies?

A. Wholesale power and gas market prices are volatile and unpredictable and have the potential to affect each jurisdiction differently under the Revised Protocol. To test this, the Company was requested by the Standing Committee to run a high and a low market price sensitivity study and report the results of those studies.

Q. What assumptions were used for the high and low market price studies?

A. For the NPC studies supporting the high and low market price sensitivity analyses, the Company increased or decreased market prices by 20 percent, respectively. An annual summary of the base, high and low market prices at California Oregon Border (COB) and Palo Verde (PV) for electricity and at Rocky Opal for natural gas are provided in Exhibit PPL/301. Chart 1 below shows the impact of the high and low market prices on net power cost, presented as percentage changes in NPC from the Base NPC Study.

Chart 1
High and Low Price Studies Compared to Base NPC Study



Structural Separation Studies and Go-It-Alone Analysis

Q. Why did the Company perform the structural separation studies and the go-it-alone analysis?

A. The Company was requested to perform structural separation studies and the go-it-alone analysis by the Standing Committee as a means of estimating the cost savings that may arise from continuing to plan and operate as a single integrated system. These studies are highly assumption driven and should not be relied upon other than for the purpose they are used for in the MSP. The structural separation studies assume that Pacific Power and Rocky Mountain Power would become separate entities and operate on a balancing area basis, and the go-it-alone study assumes that each state jurisdiction would become a separate entity. In the case of structural separation, it was assumed that the current system-wide planning is sufficient to cover the resource needs of both balancing areas, rather than as a single, integrated power system as is currently done. However, the balancing areas were assumed to operate on their own. In the case of the go-it-alone analysis, the jurisdictional entities would need to plan and operate on their own because the significant differences in the jurisdictional non-coincidental peaks as compared with the coincidental peaks of the system that are used in the Company's planning.

Q. What assumptions were made to perform the structural separation studies?

A. The Company currently operates in two balancing areas, east and west. The structural separation studies disconnect the transfer between the two balancing areas. Loads and resources were assigned to each balancing area based on their physical location. The Company has a small number of exchanges under which power is received by the Company in one balancing area and returned to the Company in the other balancing area. For purposes of the structural separation studies, the Company assumed these cross-balancing area exchanges would be terminated, and therefore they were not included in either balancing area. A list of major assumptions to NPC studies for the structural separation analysis is provided in Exhibit PPL/302. The studies were performed on calendar years 2012, 2015 and 2017 based on changes in the Company's transmission additions that impact the modeling topologies.

Q. What are the limitations of the structural separation NPC study results?

A. As previously mentioned, the structural separation study results are a highly assumption-driven assessment of a balancing area structural separation model. The assignment of resources and the modeling of a balancing area structural separation are based on one set of assumptions. It is not advocated by any party including the Company and is provided solely for informational purposes. The balancing area split of generation and transmission resources does not reflect the pre-1989 merger assignment of resources between Pacific Power and the former Utah Power. This study does not analyze the potential costs of refinancing, additional workforce and other costs associated with changing the operation of a single integrated system that serves each of California, Idaho, Oregon, Utah, Washington and Wyoming to a control area structural separated system. Neither does the analysis evaluate what resources changes might occur under a balancing area structurally separated system.

Q. What were the results of the structural separation studies?

A. The structural separation studies for calendar years 2012, 2015 and 2017 indicate that the total NPC for the combined east and west balancing areas would be higher than the Base NPC Study by about 3 percent as shown in Table 1 below. Assuming a level of NPC at $1.5 billion, the dollar increased ranged from $37 million to $45 million.

Table 1
Combined East and West Studies Compared to Base NPC Study

2012	2.50%
2015	3.68%
2017	3.02%

Q. Has the Company updated its structural separation studies to incorporate the KHSA?

A. Yes. The Company updated the studies that were previously provided to the Standing Committee. The results presented in Table 1 above are from the updated studies, and are consistent with what the Company has previously provided, which indicated significant savings operating the system as a whole.

Q. Please describe the go-it-alone analysis.

A. The go-it-alone analysis quantifies the difference between the total amount of peak load that would need to be met on a state-by-state basis and the amount of peak load that would need to be met with the continuation of integrated system resource planning. The loss of diversity that would occur if each jurisdiction were to go-it-alone would directly translate into an increased need for generating resources, and therefore increased costs. For this analysis, the increased resource requirements were priced at the 2008 IRP costs of new combined cycle combustion turbines.

Q. What are the limitations of the go-it-alone NPC study results?

A. Like the structural separation study, the go-it-alone study is a highly assumption driven assessment of a state separation model. It is not advocated by any party including the Company and is provided solely for informational purposes. This study does not analyze the potential costs of refinancing, additional workforce and other costs associated with changing the operation of a single integrated system that serves each of California, Idaho, Oregon, Utah, Washington and Wyoming to a six-state separated system. The study also does not evaluate the impact of the resource dispatching under a six-state separated system.

Q. What were the results of the go-it-alone analysis?

A. If each jurisdiction were required to plan to meet their own peak loads, the additional costs incurred to acquire the necessary additional resources could be approximately $270 million each year. The results of the analysis are provided in Exhibit PPL/303.

Q. Why was GRID not used to prepare the go-it-alone study?

A. Modeling each jurisdiction in GRID would require assumptions on resource and transmission assignment, as well as assumptions on each jurisdiction's access to wholesale markets. In the Company's view, creating a set of assumptions on these issues that would prove reasonably acceptable to all jurisdictions would be impractical at this time. The Company believes that the analysis performed reasonably captures the increased cost that would be incurred if each jurisdiction needed to plan for itself.

Load Growth Analysis

Q. Why did the Company perform the load growth analysis?

A. The Company was requested to perform load growth analysis by the Standing Committee as a means of evaluating whether the slower-growing states unfairly subsidize the faster-growing states.

Q. How is the NPC calculated for the load growth analysis?

A. The first step is to identify which states are growing relatively faster than the rest of the states, which are Utah and Wyoming in the current study. The growth rate of these two states during the study period from calendar year 2010 through calendar year 2019 was adjusted down to match the average growth rate of load in the rest of the states. Then the 2008 IRP resource portfolio was modified to remove resource additions that would no longer be needed due to the reduced system load.

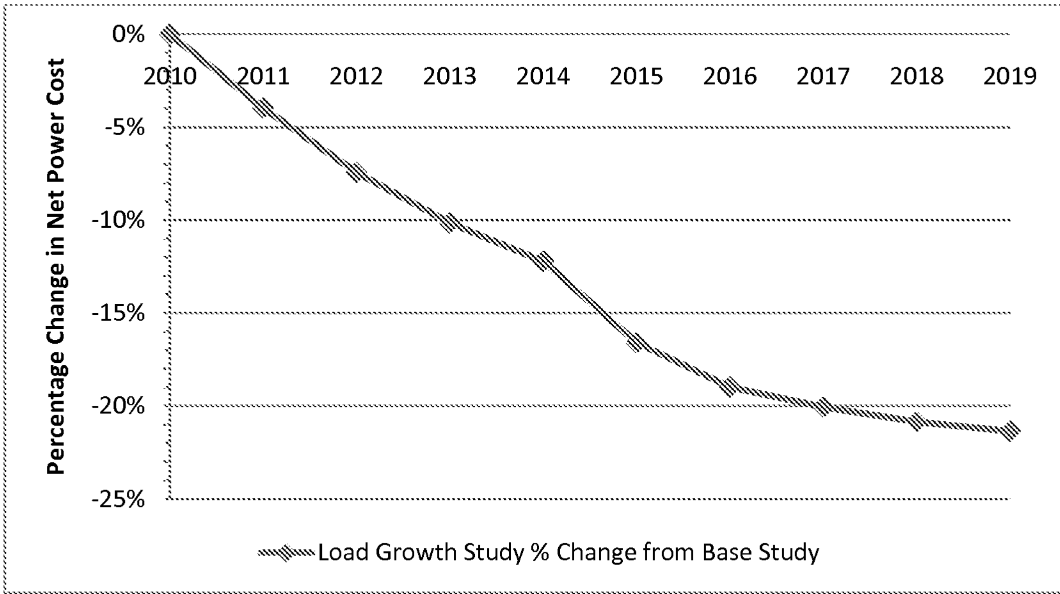
Q. How was the 2008 IRP resource portfolio modified as a result of the changes in load growth?

A. First, the load and resource balance was updated from the 2008 IRP to reflect the reduction in system peak load assumed for Utah and Wyoming. Next, the resource additions in the east balancing area were reduced to maintain a minimum of a 12 percent planning reserve margin. Several planned east resources included in the 2008 IRP were removed, including the East CCCT (CCCT F 2x1, Utah North), the East thermal PPA, the East Aero and the East Geothermal. Planned east wind resources and demand side management assumptions were not changed. Front office transactions in the load growth resource portfolio were reduced. Exhibit PPL/304 illustrates the changes to the 2008 IRP preferred portfolio as a result of the reduction in Utah and Wyoming load.

Q. What is the impact of the reduced load?

A. By the end of the study period, through calendar year 2019, the total Company NPC decreases by approximately 21 percent as compared to the Base NPC Study. The results of the analysis are provided in Chart 2 below. The overall revenue requirement impact of the reduced load, including the change to NPC and the corresponding change fixed costs related to resource additions that would no longer be required, is reflected in the revenue requirement study that is addressed by Mr. McDougal.

Chart 2
Load Growth Study Compared to Base NPC Study



Q. Does this conclude your direct testimony?

A. Yes.

Exhibit PPL/301

Docket No. UM-1050
Exhibit PPL/301
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

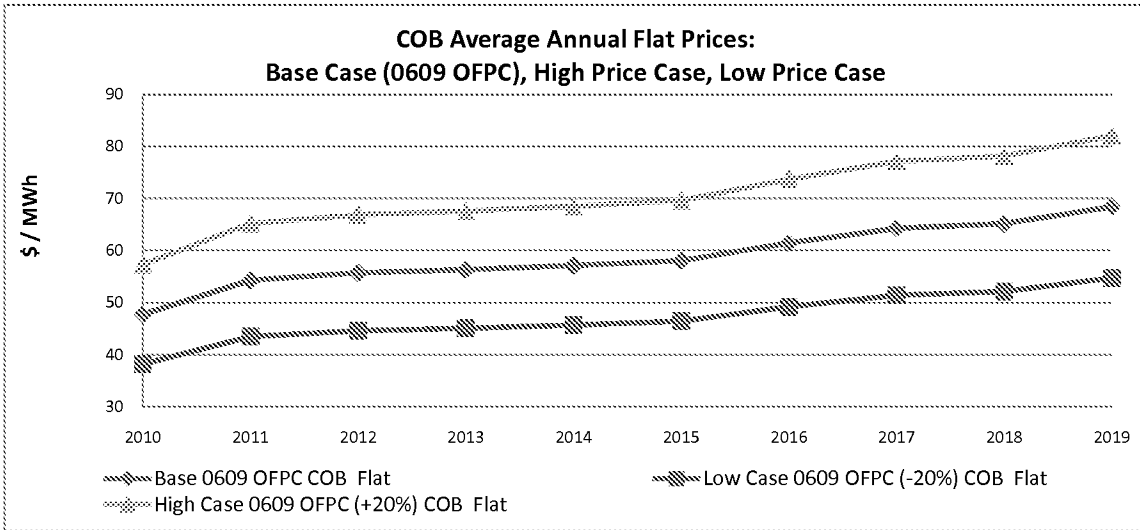
PACIFICORP

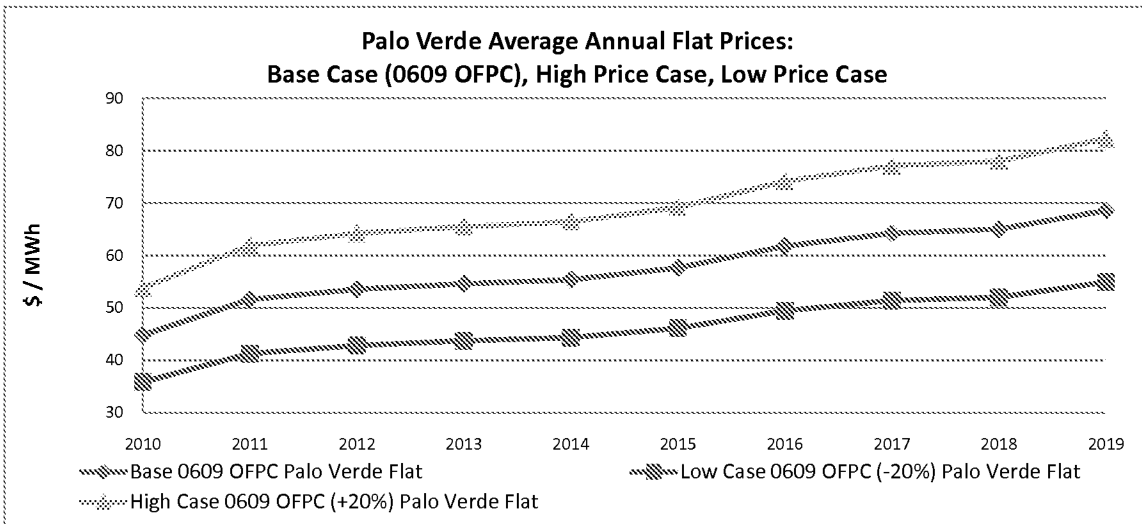
Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Annual Summary of Base, High and Low Market Prices at COB, Palo Verde, and Rocky Opal

September 2010

Multi-State Process (MSP)
Annual Summary of Base, High and Low Market Prices at COB, Palo Verde, and Rocky Opal





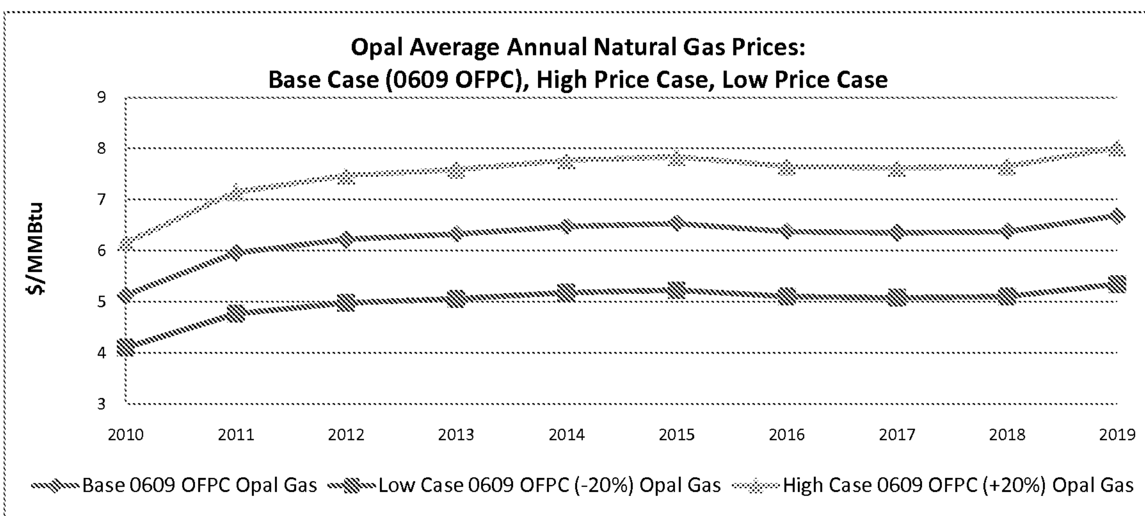


Exhibit PPL/302

Docket No. UM-1050
Exhibit PPL/302
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Net Power Cost Assumptions for Structural Separation

September 2010

Multi-State Process (MSP)
Net Power Cost Assumptions for Structural Separation

East Balancing Area (East)

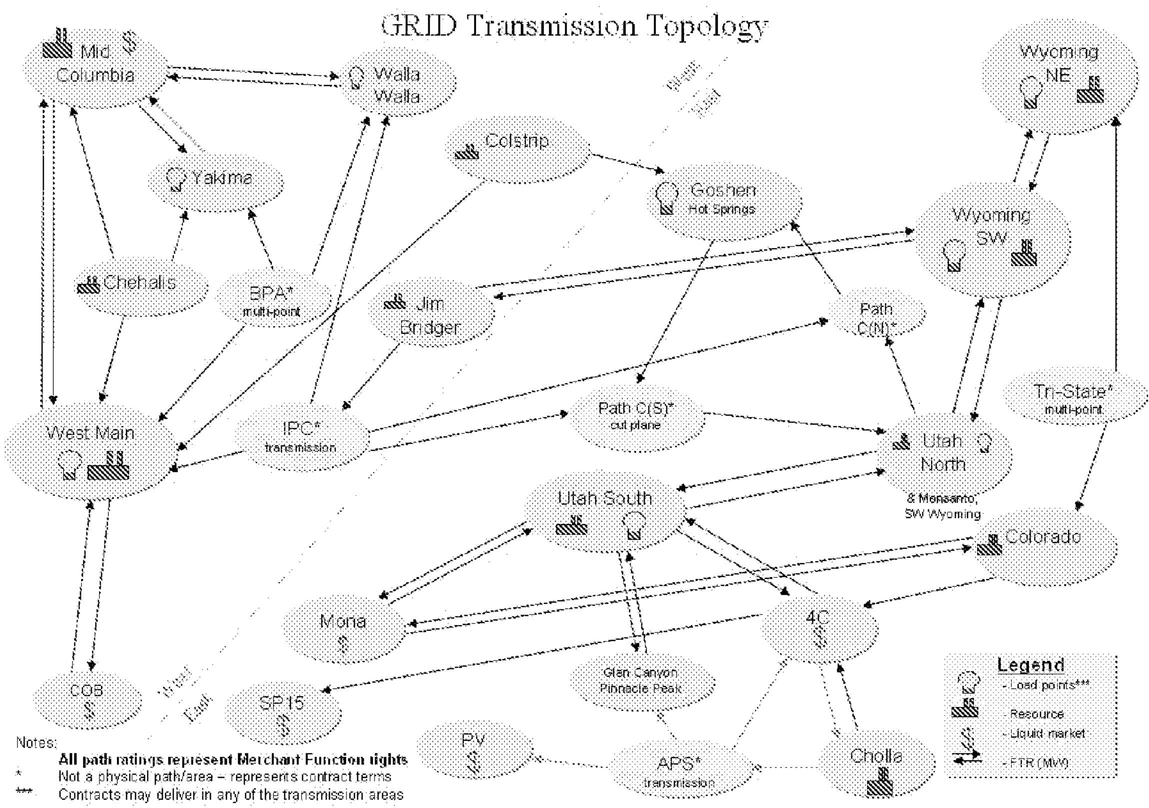
The Rocky Mountain Power jurisdictions of Idaho, Utah and Wyoming will be assigned to the East balancing area.

West Balancing Area (West)

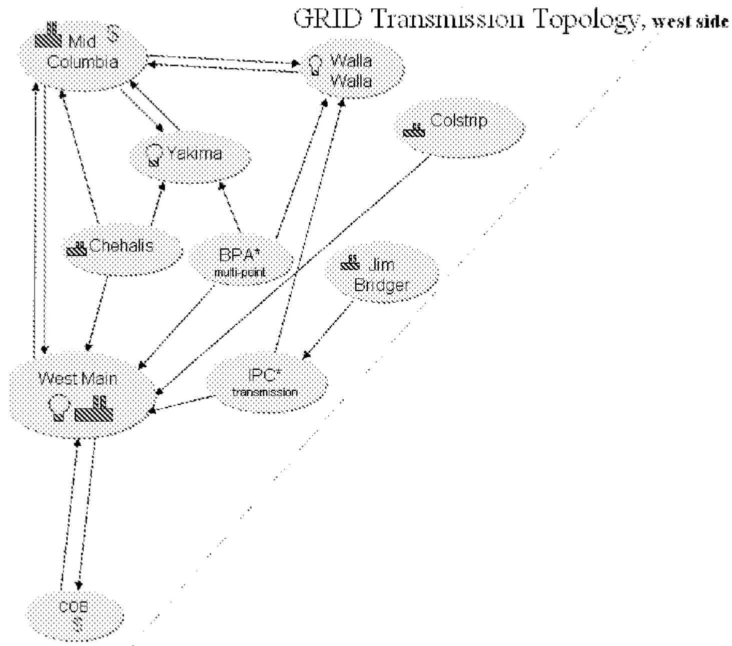
The Pacific Power jurisdictions of California, Oregon and Washington will be assigned to the West balancing area.

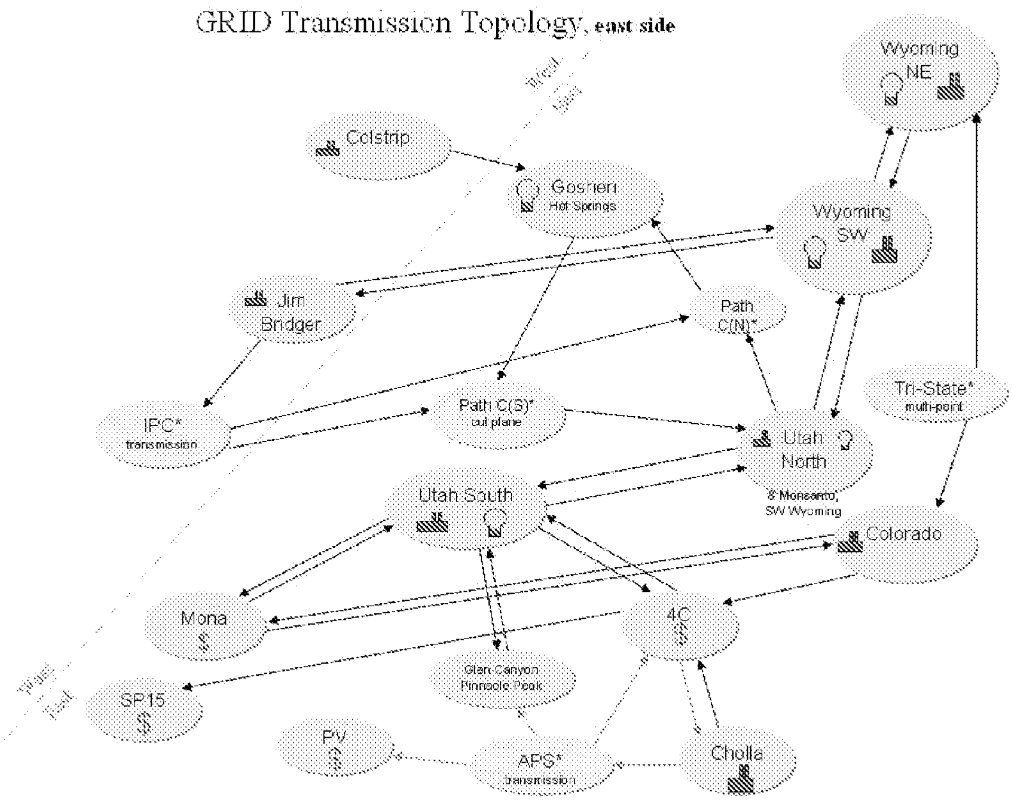
Topology

The total system has 26 transmission areas, which include load centers, market hubs, location of generation resources, and transmission rights that the Company holds. Below is the transmission topology for the total system.



Based on the transmission rights for the Company's share of the Colstrip and Jim Bridger plants, below are the transmission topologies for the East and West.





Wheeling expenses are included in either the East or West, based on the location of the points of receipts and deliveries.

Load

Load in the East includes the load in the states of Idaho, Utah and Wyoming. Load in the West includes the load in the states of California, Oregon and Washington.

Generation and Transmission Resources

All generation resources will be assigned either to the East or West depending on their physical locations, except the Jim Bridger and Colstrip plants that are shared between East and West based on transmission connections.

Jim Bridger and Colstrip Plants

In accordance with the wheeling contract with the Idaho Power Company, approximately 95.8% of the Company's share of the Jim Bridger plant capacity is included in the West, and the remainder is assumed to be transmitted to the East.

In accordance with the wheeling contract with the Bonneville Power Administration, the Company's right to the transmission capacity from the Colstrip plant is 156 megawatts, of which 70 megawatts is to the West. As a result, the Company's share of the capacity of the Colstrip plant is pro-rated based on the 70:86 split between the East and West.

Wholesale Contracts with Third Parties

All contracts that are entirely delivered to either the west side or east side of the system will be included in either the East or West, including all qualifying facilities. For the purposes of this study, cross balancing area contracts have been excluded.

Transfers Between Balancing Areas

This study will assume that there is no ability to transfer between the balancing areas.

Exhibit PPL/303

Docket No. UM-1050
Exhibit PPL/303
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Go-It-Alone Summary

September 2010

Multi-State Process (MSP)
Go-It-Alone Summary
MSP Analysis - Impact of Resource Planning on a Jurisdictional Basis versus System Basis

Additional Capacity between Jurisdictional Non-coincidental Annual Peak and Jurisdictional Contribution to System Coincidental Annual Peak (%)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OR	22.0%	17.4%	17.0%	17.9%	17.7%	17.9%	18.0%	18.2%	18.4%	18.5%
WA	11.8%	10.8%	7.4%	10.4%	9.4%	9.1%	8.7%	8.5%	5.1%	8.0%
CA	11.2%	10.7%	9.1%	8.7%	12.7%	12.2%	10.8%	8.2%	9.8%	9.1%
UT	3.1%	3.1%	3.3%	3.0%	2.9%	2.9%	3.4%	3.0%	3.0%	3.1%
ID	13.5%	12.8%	12.6%	11.9%	11.1%	9.6%	8.5%	8.3%	8.1%	7.9%
WY	6.0%	5.6%	7.0%	4.5%	4.6%	3.5%	2.5%	2.5%	1.9%	1.3%

Additional Resource Cost (Fixed O&M per PPA + Fuel Expense)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OR	*CCCT*	$ 143,306,014	$ 128,492,566	$ 132,643,825	$ 143,210,315	$ 146,111,166	$ 148,994,433	$ 147,714,923	$ 150,452,719	$ 154,587,673	$ 162,746,375
WA	*CCCT*	$ 25,714,184	$ 26,406,993	$ 19,762,590	$ 27,685,049	$ 25,804,836	$ 25,241,410	$ 24,158,983	$ 24,155,253	$ 15,039,072	$ 24,339,302
CA	*CCCT*	$ 4,911,698	$ 5,474,621	$ 5,024,387	$ 4,785,070	$ 6,974,280	$ 7,011,503	$ 6,212,310	$ 4,831,051	$ 5,945,680	$ 5,812,371
UT	*CCCT*	$ 38,707,471	$ 43,665,658	$ 50,973,135	$ 48,588,144	$ 48,652,659	$ 50,627,191	$ 60,258,884	$ 53,801,508	$ 56,033,914	$ 60,573,576
ID	*CCCT*	$ 25,244,003	$ 26,942,640	$ 27,890,961	$ 27,718,069	$ 27,658,703	$ 24,976,081	$ 22,429,696	$ 22,193,122	$ 22,073,966	$ 22,539,005
WY	*CCCT*	$ 21,036,669	$ 22,297,358	$ 29,814,475	$ 20,543,980	$ 22,326,905	$ 17,888,274	$ 13,390,863	$ 13,450,377	$ 10,867,183	$ 8,099,955
		$ 258,920,040	$ 253,279,836	$ 266,109,374	$ 272,530,628	$ 277,528,549	$ 274,738,892	$ 274,165,658	$ 268,884,029	$ 264,547,488	$ 284,110,583

Exhibit PPL/304

Docket No. UM-1050
Exhibit PPL/304
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

Load Growth Portfolio Summary

September 2010

Multi-State Process (MSP)
Load Growth Portfolio Summary

2008 IRP Preferred Portfolio (2008 IRP, Executive Summary, page 6)

	Resource	Capacity, MW									
		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
East											
	CCCT F 2x1, Utah North	-	-	-	-	-	570	-	-	-	-
	IC Aero SCCT	-	-	-	-	-	-	-	261	-	-
	East Power Purchase Agreement	-	-	-	200	-	-	-	-	-	-
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-
	Geothermal	-	-	-	-	35	-	-	-	-	-
	Wind [1/]	99	249	-	100	100	100	150	100	100	50
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4
	DSM, Class 1 Utah Cool Keeper Load Control	25	50	40	30	10	10	10	10	10	10
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*
	DSM, Class 2	42	51	49	52	55	55	56	56	58	59
	Front Office Transactions	75	50	150	394	493	200	202	228	717	800
West											
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-
	Swift Hydro Upgrades [2/]	-	-	-	25	25	25	-	-	-	-
	Wind	45	20	200	-	-	-	-	-	-	-
	Combined Heat & Power	1	1	1	1	2	2	2	2	2	2
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1
	DSM, Class 1	*	*	*	*	*	*	*	*	*	*
	DSM, Class 2	35	36	39	39	38	39	39	39	39	29
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582

Total Planned Resources	332	517	587	1725	1619	1762	1207	1402	1224	1541
Planning Margin -										
East	13.7%	12.3%	12.3%	12.3%	12.3%	12.2%	12.3%	12.3%	12.3%	12.3%
West	14.6%	11.5%	11.5%	11.5%	11.6%	11.7%	11.6%	11.7%	11.6%	11.6%
System	14.0%	12.1%	12.1%	12.1%	12.1%	12.1%	12.1%	12.1%	12.1%	12.1%

2008 IRP Preferred Portfolio - Adjusted to Maintain Planning Margin

	Resource	Capacity, MW									
		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
East											
	CCCT F 2x1, Utah North	-	-	-	-	-					
	IC Aero SCCT	-	-	-	-	-	-	-			
	East Power Purchase Agreement	-	-	-							
	Coal Plant Turbine Upgrades	3	44	33	25	2	14	-	8	-	-
	Geothermal	-	-	-	-						
	Wind [1/]	99	249	-	100	100	100	150	100	100	50
	Combined Heat & Power	2	2	2	3	3	3	4	4	4	4
	Distributed Standby Generation	4	4	4	4	4	4	4	4	4	4
	DSM, Class 1 Utah Cool Keeper Load Control	25	50	40	30	10	10	10	10	10	10
	DSM, Class 1, Other	*	*	*	*	*	*	*	*	*	*
	DSM, Class 2	42	51	49	52	55	55	56	56	58	59
	Front Office Transactions	75	50	-	175	175	225	75	175	550	525
West											
	Coal Plant Turbine Upgrades	-	9	9	12	12	-	-	-	-	-
	Swift Hydro Upgrades [2/]	-	-	-	25	25	25	-	-	-	-
	Wind	45	20	200	-	-	-	-	-	-	-
	Combined Heat & Power	1	1	1	1	2	2	2	2	2	2
	Distributed Standby Generation	1	1	1	1	1	1	1	1	1	1
	DSM, Class 1	*	*	*	*	*	*	*	*	*	*
	DSM, Class 2	35	36	39	39	38	39	39	39	39	29
	Front Office Transactions	-	-	59	839	839	739	739	689	289	582

Total Planned Resources	332	517	437	1306	1266	1217	1080	1088	1057	1266
Planning Margin -										
East	13.7%	12.8%	12.0%	12.0%	12.1%	12.2%	12.2%	12.0%	12.1%	12.1%
West	14.6%	11.5%	11.5%	11.5%	11.6%	11.7%	11.6%	11.7%	11.6%	11.6%
System	14.0%	12.4%	11.8%	11.9%	11.9%	12.0%	12.0%	11.9%	12.0%	12.0%

[1/] The 99 MW amount in 2009 is the High Plains project; the 249 MW in 2010 includes the 99 MW Three Buttes wind PPA.
[2/] The Swift 1 hydro updates are shown in the year they enter into commercial service
* Up to 120 MW of additional cost-effective Class 1 DSM programs (100 MW east, 30 MW west) to be identified through competitive Requests for Proposals and phased in as appropriate from 2009-2018. Firm market purchases (3rd quarter products) would be reduced by roughly comparable amounts.