PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2010

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

RE: Advice No. 10-003, Docket No. UE-___
In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon

Enclosed for filing by PacifiCorp dba Pacific Power are an original and 30 copies of the following proposed tariff pages associated with the Company's Tariff P.U.C. OR No. 35 applicable to electric service in the State of Oregon, together with the Pretrial Brief, supporting direct testimony and exhibits. The tariffs reflect an effective date of March 31, 2010. Provided on the enclosed CDs (3) are electronic versions of the testimony, exhibits and workpapers, in their original format when available.

Thirty-second Revision of Sheet No. B-1		Tariff Index Sheet
Eighth Revision of Sheet No.4	Schedule 4	Residential Service Delivery Service
Thirteenth Revision of Sheet No. 15-1	Schedule 15	Outdoor Area Lighting Service No New Service Delivery Service
Seventh Revision of Sheet No. 23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Fifth Revision of Sheet No. 28-1	Schedule 28	General Service – Large Nonresidential - Less than 1,000 kW Delivery Service
Fifth Revision of Sheet No. 30-1	Schedule 30	General Service-Large Nonresidential 201 KW to 999 KW Delivery Service
Ninth Revision of Sheet No. 41-1	Schedule 41	Agricultural Pumping Service Delivery Service
Seventh Revision of Sheet No. 47-1	Schedule 47	Large General Service/Partial Requirements Service – Nameplate Rating 1,000 kW and Over Delivery Service
Seventh Revision of Sheet No. 48-1	Schedule 48	Large General Service - 1,000 kW and Over Delivery Service
Fourteenth Revision of Sheet No. 50-1	Schedule 50	Mercury Vapor Street Lighting Service No New Service Delivery Service

Eighth Revision of Sheet No. 754	Schedule 754	Recreational Field Lighting Restricted Direct Access Delivery Service
Third Revision of Sheet No. 776R-1	Schedule 776R	Large General Service/Partial Requirements Service – Economic Replacement Service Rider Direct Access Delivery Service

It is respectfully requested that all data requests regarding this matter be addressed to:

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

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 300
Portland, OR 97232

Please address all communications related to this filing to:

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Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

A copy of this filing has been served on all parties to PacifiCorp's last general rate case proceeding, UE 210, as indicated on the attached certificate of service.

Very truly yours,

Andrea L. Kelly /js

Andrea L. Kelly
Vice President, Regulation

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE ____

In the Matter of PACIFICORP, dba PACIFIC POWER's Filing Of Revised Tariff Schedules for Electric Service in Oregon	**PACIFICORP'S PRETRIAL BRIEF**

I. INTRODUCTION

Pursuant to ORS 757.205 and ORS 757.220, PacifiCorp d.b.a Pacific Power ("PacifiCorp" or "Company"), is filing a general rate increase to revise its tariff schedules to adjust prices for its Oregon electric customers. The revised rates produce revenues necessary to sustain a stable, reliable, and low-cost power supply, while preserving the Company's ability to attract capital for future investments in system infrastructure. The Company files this brief in accordance with OAR 860-013-0075.

PacifiCorp is an electric company and public utility in the state of Oregon within the meaning of ORS 757.005, and is subject to the Public Utility Commission of Oregon's ("Commission") jurisdiction with respect to prices and terms of electric service to retail customers in Oregon. The Company provides electric service to approximately 580,000 retail customers in Oregon and approximately 1.7 million total retail customers in Washington, California, Idaho, Oregon, Utah, and Wyoming. PacifiCorp's principal place of business is Portland, Oregon.

Communications regarding this filing should be addressed to:

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In addition, PacifiCorp requests that all data requests be sent to the following:

By email (preferred): datarequest@pacificorp.com

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

II. CASE SUMMARY

This case is based upon a historical base period of 12-months ending June 2009, with normalizing and pro forma adjustments to calculate a calendar year 2011 future test period. The new rates will become effective no later than January 1, 2011, assuming application of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs. As such, the rate effective period aligns closely with the test period in this case.

A. Return on Equity

PacifiCorp is forecast to earn a return on equity ("ROE") in Oregon of 3.8 percent for the test period. In this case, the Company seeks an ROE of 10.6 percent. This ROE is necessary to maintain the financial integrity of the Company, while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers. Significantly, the requested 10.6 percent ROE is at the low range of ROE recommended by the Company's cost of equity expert, Dr. Samuel C. Hadaway. This filing supports an overall price increase of $130.9 million, or 13.1 percent, required to produce the 10.6 percent ROE. Notwithstanding this increase, PacifiCorp's Oregon customers continue to benefit from some of the lowest electricity rates in the country.

B. New Investment is Primary Cost Driver

The Company's need for this rate increase is primarily driven by on-going new investments in the system required to provide safe, adequate and reliable service to customers in Oregon. This case includes investments in all facets of the system, including transmission, generation and distribution investment, all of which help to bolster reliability and improve power delivery. This filing includes an increase in Oregon-allocated net electric plant in service of more than $470 million over what was included in the Company's filing in the 2009 rate case in Docket UE 210 ("UE 210").

1. Transmission Investments

The most significant new investment in this case is the Populus to Terminal transmission line, which is the first segment to be constructed of the Company's Energy Gateway transmission plan. The Populus to Terminal transmission line will increase capacity of a key transmission path necessary to enhance reliability and transfer capability between the Company's east and west control areas, facilitate the delivery of power from wind projects, and provide greater flexibility and the opportunity to consider additional options regarding planned generation capacity additions.

2. Wind Generation Resources

This case also includes the addition of Dunlap I and McFadden Ridge I--two new wind generation resources which together add an additional 139.5 MW of cost-effective renewable resources to the Company's portfolio. The acquisition of the new wind generation resources is consistent with PacifiCorp's integrated resource planning ("IRP") process and commitments made during the MidAmerican Energy Holdings Company ("MEHC") acquisition of PacifiCorp.

3. Other New Additions

Other new additions in this case include generation investments for environmental improvements at the Dave Johnston Unit 3 power plant located in Wyoming; hydro investments to conform with relicensing agreements for the Lewis River and North Umpqua hydro systems; and on-going investments in other transmission projects and the Oregon distribution system.

4. Prudently Incurred/Used and Useful

All of the resources and investments included in rates by the Company for this case reflect prudently incurred costs for resources and investments that either are or will be used and useful for service to PacifiCorp's Oregon customers prior to the rate effective date of January 1, 2011. The Company is, however, proposing a separate tariff to recover the investment in the second phase of the Populus to Terminal transmission line (i.e., Populus substation to Ben Lomond substation), which is expected to be in service by December 31, 2010. Since the projected in-service date is only one day prior to the January 1, 2011 rate effective date for this case, the Company has separated the revenue requirement associated with this phase in the event the project completion is delayed. In the event of a delay beyond the expected December 31, 2010 in service date, the Company proposes that the separate tariff go into effect after January 1, once the Company has certified that the line is in service and used and useful. Although the construction is currently on schedule and no delay is expected, the Company is proposing this separate tariff out of an abundance of caution and to alleviate any concerns about the timing of this major resource addition, while also allowing timely inclusion in rates and timely cost recovery.

C. Klamath Hydroelectric Settlement Agreement ("KHSA")

The KHSA was executed on February 18, 2010 by thirty different parties, including PacifiCorp, the U.S. Department of the Interior, the states of Oregon and California and parties representing tribes, counties, irrigation districts, fisherman, environmentalists and other organizations. Consistent with Senate Bill 76 passed by the 2009 Oregon Legislature, the revenue requirement in this proceeding includes accelerated depreciation of the existing investment in the facilities and the costs of the relicensing and settlement process. Under the terms of the KHSA and Senate Bill 76, the Company will file an application with the Commission seeking review of the Company's decision to enter into the KHSA. As such, the merits of the KHSA will be considered by the Commission in a separate filing.

D. Mitigation Factors

In light of the current economic climate, PacifiCorp is keenly aware of the financial pressures faced by its customers. As such, the Company has taken several steps to mitigate the rate increase request.

1. Cost of Capital

First, as noted above, the Company has moderated the increase to its requested cost of capital notwithstanding the current challenges in the financial markets. The requested

10.6 percent ROE in this filing is at the low range of 10.5 percent to 11.0 percent recommended by the Company's cost of equity expert, Dr. Samuel C. Hadaway. The ROE in this case is consistent with the ROE authorized for the Company by the Public Service Commission of Utah on February 18, 2010 after a fully litigated rate case.[1]

In addition, the Company was successful in securing favorable interest rates for recent bond issuances. These favorable interest rates directly benefit customers by reducing the Company's cost of long-term debt in the capital structure.

2. Operation and Maintenance Costs

The Company also continues to proactively and aggressively control operations and maintenance ("O&M") and administrative and general ("A&G") expenses ("OMAG"). As a result of the Company's cost-control efforts, the Oregon-allocated OMAG costs in this case are only 2.6 percent higher than what the Company included in UE 210. The Company was able to keep overall expenses low by aggressively pursuing efficiency gains that have allowed the Company to largely offset the O&M expense for new generation. Contributing to this on-going low level of OMAG expense is the Company's decision to hold flat the number of full-time equivalent employees ("FTEs") since UE 210, with the exception of a small number FTEs related to new generation facilities.

III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 17 witnesses:

Richard Patrick "Pat" Reiten, President, Pacific Power, provides the Company's policy testimony.

[1] *See* Public Service Commission of Utah's Report and Order on Revenue Requirement, Cost of Service and Spread of Rates, Docket No. 09-035-23 (Issued February 18, 2010).

Dr. Samuel C. Hadaway, Principal, FINANCO, Inc. testifies concerning the Company's cost of equity. His evidence demonstrates that the current cost of common equity for the Company is in the range of 10.5 percent to 11.00 percent.

Bruce N. Williams, Vice President and Treasurer, describes the calculation of PacifiCorp's capital structure, cost of debt and preferred stock.

John A. Cupparo, Vice President, Transmission, demonstrates that the addition of the Populus to Terminal transmission line will be beneficial to customers as part of the overall long-term transmission plan, Energy Gateway.

Darrell T. Gerrard, Vice President, Transmission System Planning, provides additional details and technical information on the Company's decision to build the Populus to Terminal line.

Dean S. Brockbank, Vice President and General Counsel, explains the relicensing and settlement process for the KHSA and demonstrates that these costs are prudent expenditures.

Chad A. Teply, Vice President, Resource Development and Construction, provides the justification and description of the environmental improvements to Dave Johnston Unit 3.

Stefan A. Bird, Vice President, Commercial and Trading, demonstrates the prudent acquisition of the Dunlap I wind resource.

Mark R. Tallman, Vice President, Renewable Resource Development, demonstrates the prudent acquisition of the McFadden Ridge I wind resource.

Gregory N. Duvall, Director, Long Range Planning and Net Power Costs, presents the Company's load forecast and describes how it was developed.

R. Bryce Dalley, Manager, Revenue Requirement, presents the Company's overall revenue requirement based on the test period and allocation factors.

Erich D. Wilson, Director, Human Resources, presents an overview of compensation and benefit plans and supports the costs related to these areas included in the test period.

Norman K. Ross, Tax Director, explains how the Company calculates property taxes and explains why this method results in an accurate forecast of property taxes.

Nancy K. Kent, Managing Director, Risk & Insurance, Corporate Security and Information Technology, explains the Company's proposal related to insurance coverage beginning in 2011.

Barbara C. Coughlin, Director, Customer & Regulatory Liaison, explains the process for providing electric service request estimates and what would be required if the Company is not able to recover the costs for customer-cancelled projects in general rates.

C. Craig Paice, Regulatory Consultant, Cost of Service, presents the Company's marginal cost of service study.

William R. Griffith, Director, Pricing, Cost of Service and Regulatory Operations, presents the Company's proposed rate spread, rate design and tariffs.

Pursuant to OAR 860-013-075(b), attached as Exhibit A is the summary setting forth the information required to be filed in connection with applications for general rate increases.

IV. CONCLUSION

The Company requests the Commission issue an order approving the proposed rate changes and tariffs described herein.

DATED: March 1, 2010.

Jordan A. White JB

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Attorneys for PacifiCorp

Exhibit A

Summary of Requested Electric General Rate Increase

Oregon Allocated

Filed March 1, 2010

(A)	Total Revenues collected under proposed rates:	$851,528,408
(B)	Revenue change requested:	
	Total:	$130,924,178
	Net of credits from federal agencies:	$130,924,178
(C)	Percentage change of requested increase:	
	Total %:	13.1%
	Net of credits from federal agencies:	13.1%
(D)	Test period:	Calendar year 2011
(E)	Requested return on capital:	8.38%
	Requested return on equity:	10.6%
(F)	Rate base in filing:	$3,315,956,804
(G)	Results of operation:	
	Utility operating income, before proposed change:	$200,242,619
	Utility operating income, after proposed change:	$277,891,439
(H)	Effect of rate change on each customer class:	
	• Residential -	13.3%
	• Small General Service (Schedule 23) -	13.3%
	• General Service 31-200 kW (Schedule 28) -	13.3%
	• General Service 201-999 kW (Schedule 30) -	13.3%
	• Large General Service >= 1,000 kW (Schedule 48) -	13.3%
	• Agriculture Pumping Service (Schedule 41) -	13.3%
	• Street lighting -	0.0%

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UE 210, 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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DATED: March 1, 2010

Ariel Son
Coordinator, Administrative Services

Exhibit PPL(/100
Richard P. Reiten

Docket No. UE-
Exhibit PPL/100
Witness: Richard P. Reiten

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Richard P. Reiten

March 2010

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

A. My name is Richard Patrick "Pat" Reiten. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am President of Pacific Power.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a bachelor's degree in political science with an emphasis in economics from the University of Washington and completed executive training at the Wharton School of Business, University of Pennsylvania. Prior to joining PacifiCorp in September 2006, I was president and chief executive officer of PNGC Power, an energy cooperative located in Portland, Oregon, that provides power management services to electric distribution utilities serving parts of seven Western states. I was appointed to that position in May 2002. I joined PNGC Power in 1993, advancing through positions of increasing responsibility. Prior to PNGC Power, I served as an aide to U.S. Sen. Mark O. Hatfield, handling issues associated with the U.S. Senate Energy and Natural Resources Committee. I also was an official in several different capacities at the U.S. Department of Interior, including deputy director of the U.S. Bureau of Land Management.

Purpose of Testimony

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

A. My testimony provides an overview of the Company's request for an increase in its base electric rates, describes the major factors driving the need for the rate increase, and discusses actions taken by the Company to mitigate the rate increase. Finally, my testimony introduces the other witnesses providing testimony on behalf of PacifiCorp.

Summary of PacifiCorp's Rate Increase Request

Q. Please summarize PacifiCorp's rate increase request.

A. PacifiCorp is requesting an increase to its base electric rates in Oregon. Based on the evidence provided in the direct testimony of Company witness Mr. R. Bryce Dalley, PacifiCorp is currently forecast to earn a return on equity ("ROE") in Oregon of 3.8 percent for the test period. This filing supports an overall price increase of $130.9 million, or 13.1 percent, required to produce the 10.6 percent ROE requested by the Company, which is necessary to maintain the financial integrity of the Company. As I discuss later in my testimony, the requested 10.6 percent ROE is at the low end of the range of the current cost of common equity for the Company as demonstrated in evidence proffered by cost of equity expert, Dr. Samuel C. Hadaway.

Q. Upon what test year is the rate increase request based?

A. As described in the testimony of Mr. Dalley, the test year for this filing is the 12-months ending December 31, 2011.

Q. What is the primary factor driving the need for an overall rate increase?

A. As a regulated utility, PacifiCorp has a duty and an obligation to provide safe, adequate and reliable service to customers in its Oregon service territory while balancing cost, risk and state energy policy objectives. The Company's need for this rate increase is primarily driven by on-going new investments in the system.

As described in the testimony of Mr. Dalley, the Company continues to make significant investments to serve its customers. This filing includes an increase in Oregon-allocated net electric plant in service of more than $470 million over what was included in the Company's filing in the 2009 rate case in Docket UE 210 ("UE 210").

Q. What major new investments are included in this filing?

A. This case includes investments in all facets of the system, including transmission, generation and distribution investment, all of which help to bolster reliability and improve power delivery.

The most significant new investment in this case is the Populus to Terminal transmission line. This is the first segment to be constructed of the Company's Energy Gateway transmission plan. The need for the Populus to Terminal transmission line was identified through PacifiCorp's integrated resource planning process and captured as a commitment during the MidAmerican Energy Holdings Company ("MEHC") acquisition of PacifiCorp, approved by the Public Utility Commission of Oregon ("Commission") in Order No. 06-082. Commitment 34 calls for transmission system infrastructure improvements to increase capacity of a key transmission path to enhance reliability and transfer capability between the Company's east and west control areas, to facilitate the delivery of power from wind projects, and to provide greater flexibility and the opportunity to consider additional options regarding planned generation capacity additions. In the Commission's recent acknowledgement of the Company's 2008 Integrated Resource Plan, the

Commission adopted the Staff recommendation, which noted that the detailed analysis of the proposed segment showed that the overall benefits of this addition for Oregon customers outweighed the costs. The Populus to Terminal transmission line and its relation to the Energy Gateway transmission expansion project are described in detail in the testimony of Company witnesses Mr. John A. Cupparo and Mr. Darrell T. Gerrard.

The new generation resources included in this filing are the Dunlap I and McFadden Ridge I wind resources, which together add an additional 139.5 MW of cost-effective renewable resources to the Company's portfolio. These resources are described in the testimony of Company witnesses Mr. Stefan A. Bird and Mr. Mark R. Tallman, respectively. This filing also includes generation investments for environmental improvements at the Dave Johnston Unit 3 power plant located in Wyoming. Company witness Mr. Chad A. Teply explains the nature of the investment and the environmental regulations governing the decision.

In addition to the major plant additions, the filing includes investments in hydro plant to conform with the relicensing agreements for the Lewis River and North Umpqua hydro systems and on-going investment in the Oregon distribution system.

Q. Is the Company proposing to reflect impacts of the Klamath Hydroelectric Settlement Agreement ("KHSA") in this rate case?

A. Yes. The KHSA was executed on February 18, 2010 by thirty different parties, including PacifiCorp, the U.S. Department of the Interior, the states of Oregon and California and parties representing tribes, counties, irrigation districts, fisherman, environmentalists and other organizations. Consistent with Senate Bill 76 passed by the 2009 Oregon Legislature, the revenue requirement in this proceeding includes accelerated depreciation of the existing investment in the facilities and the costs of the relicensing and settlement process. Mr. Dalley includes the accelerated depreciation in his testimony and Company witness Mr. Dean S. Brockbank demonstrates the prudence of the costs incurred by PacifiCorp related to the relicensing and settlement process that ultimately led to the KHSA.

Under the terms of the KHSA and Senate Bill 76, the Company will file an application with the Commission seeking review of the Company's decision to enter into the KHSA. As such, the merits of the KHSA will be considered by the Commission in a separate filing.

Q. Are increases associated with net power costs part of the increase requested in this case?

A. No. The Company is filing a separate Transition Adjustment Mechanism to recover increases in net power costs. In accordance with the Transition Adjustment Mechanism, rate changes related to net power costs will also have an effective date of January 1, 2011.

Q. Are the cost increases facing the Company unique in the industry?

A. No. Other utilities are facing the same types of cost pressures. As such, even with the price increase proposed in this case, PacifiCorp's prices will remain competitive when measured against other utilities within the state.

Q. Has the Company taken any actions to mitigate the rate increase requested in this case?

A. Yes. The Company has taken several steps to mitigate the rate increase request. First, the Company has moderated the increase to its requested cost of capital notwithstanding persistent challenges in the financial markets. In his direct testimony, Company witness Dr. Hadaway determines that the cost of common equity for the Company is currently in the range of 10.5 percent to 11.0 percent. The Company has proposed that the Commission authorize rates based on an ROE at the lower end of that range, 10.6 percent. This ROE is consistent with the ROE that was authorized for the Company by the Utah Public Service Commission on February 18, 2010.[1] The Utah decision resulted from a fully litigated rate case.

In addition, the Company has been successful in securing favorable interest rates for recent bond issuances. This is discussed in the direct testimony of Company witness Mr. Bruce N. Williams. These favorable interest rates directly benefit customers by reducing the Company's cost of long-term debt in the capital structure.

The Company also continues to proactively and aggressively control operations and maintenance ("O&M") and administrative and general ("A&G") expenses (together "OMAG"). As a result of the Company's cost-control efforts, the Oregon-allocated OMAG costs in this case are only 2.6 percent higher than what the Company included in UE 210. This is in line with Global Insights

[1] *See* Public Service Commission of Utah's Report and Order on Revenue Requirement, Cost of Service and Spread of Rates, Docket No. 09-035-23 (Issued February 18, 2010).

inflation increase over this period, notwithstanding the new plant additions in the case and the associated incremental O&M expense. The Company has been able to keep overall expenses low by aggressively pursuing efficiency gains that have allowed the Company to largely offset the O&M expense for new generation.

Contributing to this on-going low level of OMAG expense is the Company's decision to hold flat the number of full-time equivalent employees ("FTEs") since UE 210, with the exception of a small number FTEs related to new generation facilities.

Q. **Has the Company taken any actions to address issues contested by Commission Staff and other parties in UE 210, in order to further mitigate impacts on customers?**

A. Yes. One of the most significant areas of controversy in UE 210 was the removal of approximately $116.6 million in Oregon-allocated capital additions forecast to be completed during the 2010 test year. Commission Staff removed these capital additions arguing that these projects were not used and useful under Oregon Revised Statute 757.355. While the Company disagrees with this new interpretation of the statute by Commission Staff and believes it is inconsistent with Commission precedent, for the purpose of minimizing controversy in this case and mitigating impacts to customers, the Company has included plant in service through only December 31, 2010, rather than through December 31, 2011, which is the future test period and the rate effective period. Mr. Dalley discusses this in more detail in his testimony.

Q, Has the Company implemented any other "lessons learned" from prior proceedings?

A. Yes. First, the Company has included testimony in this initial filing to provide better information in several areas where supplemental testimony was required in UE 210 or where adjustments were proposed in UE 210. This includes testimony from Company witnesses:

- Gregory N. Duvall explaining how the Company develops the load and sales forecasts.
- R. Bryce Dalley explaining the selection of the historic base period, the development of allocation factors and compliance with the Revised Protocol inter-jurisdictional allocation methodology.
- C. Craig Paice discussing the development of class loads.
- William R. Griffith demonstrating how the proposed rate spread reflects cost of service and describing how the forecast test year billing determinants are developed.

In addition, the testimony of Company witness Mr. Norman K. Ross, explains the method used by the Company to estimate property taxes, which takes into account the complexities of multiple state assumptions. The testimony of Company witness Ms. Barbara A. Coughlin explains the process for providing electric service request estimates and what the implication would be if the Company is not able to recover the costs in general rates for customer-cancelled projects.

Second, the Company is proposing a separate tariff to recover the investment in the second phase of the Populus to Terminal transmission line (i.e., Populus substation to Ben Lomond substation), which is expected to be in service by December 31, 2010. Since the projected in-service date is only one day prior to the January 1, 2011 rate effective date for this case, the Company has separated the revenue requirement associated with this phase in the event the project completion is delayed. In the event of a delay beyond the expected December 31, 2010 in-service date, the Company proposes that the separate tariff go into effect after January 1, once the Company has certified that the line is in service and used and useful. Although the construction is currently on schedule and no delay is expected, the Company is proposing this separate tariff out of an abundance of caution and to alleviate any concerns about the timing of this major resource addition, while also allowing timely cost recovery for the Company. This proposed tariff is described in more detail in the testimony of Company witness Mr. William R. Griffith.

Introduction of Witnesses

Q. Please list the Company witnesses and provide a brief description of their testimony.

A. **Dr. Samuel C. Hadaway**, Principal, FINANCO, Inc. testifies concerning the Company's cost of equity. His evidence demonstrates that the current cost of common equity for the Company is in the range of 10.50 percent to 11.00 percent.

Bruce N. Williams, Vice President and Treasurer, describes the calculation of PacifiCorp's capital structure, cost of debt and preferred stock.

John A. Cupparo, Vice President, Transmission, demonstrates that the addition of the Populus to Terminal transmission line will be beneficial to customers as part of the overall long-term transmission plan, Energy Gateway.

Darrell T. Gerrard, Vice President, Transmission System Planning, provides additional details and technical information on the Company's decision to build the Populus to Terminal line.

Dean S. Brockbank, Vice President and General Counsel, explains the relicensing and settlement process for the KHSA and demonstrates that these costs are prudent expenditures.

Chad A. Teply, Vice President, Resource Development and Construction, provides the justification and description of the environmental improvements to Dave Johnston Unit 3.

Stefan A. Bird, Vice President, Commercial and Trading, demonstrates the prudent acquisition of the Dunlap I wind resource.

Mark R. Tallman, Vice President, Renewable Resource Development, demonstrates the prudent acquisition of the McFadden Ridge I wind resource.

Gregory N. Duvall, Director, Long Range Planning and Net Power Costs, presents the Company's load forecast and describes how it was developed.

R. Bryce Dalley, Manager, Revenue Requirement, presents the Company's overall revenue requirement based on the test period and allocation factors.

Erich D. Wilson, Director, Human Resources, presents an overview of compensation and benefit plans and supports the costs related to these areas included in the test period.

Norman K. Ross, Tax Director, explains how the Company calculates property taxes and explains why this method results in an accurate forecast of property taxes.

Nancy K. Kent, Managing Director, Risk & Insurance, Corporate Security and Information Technology, explains the Company's proposal related to insurance coverage beginning in 2011.

Barbara A. Coughlin, Director, Customer & Regulatory Liaison, explains the process for providing electric service request estimates and what would be required if the Company is not able to recover the costs for customer-cancelled projects in general rates.

C. Craig Paice, Regulatory Consultant, Cost of Service, presents the Company's marginal cost of service study.

William R. Griffith, Director, Pricing, Cost of Service and Regulatory Operations, presents the Company's proposed rate spread, rate design and tariffs.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/200
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Samuel C. Hadaway

March 2010

Q. Please state your name, occupation, and business address.

A. My name is Samuel C. Hadaway. I am a Principal in FINANCO, Inc., Financial Analysis Consultants, 3520 Executive Center Drive, Austin, Texas 78731.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of PacifiCorp ("Company").

Q. Briefly describe your educational and professional background.

A. I have a Bachelor's degree in economics from Southern Methodist University, as well as MBA and Ph.D. degrees with concentrations in finance and economics from the University of Texas at Austin ("UT Austin"). I am an owner and full-time employee of FINANCO, Inc. FINANCO provides financial research concerning the cost of capital and financial condition for regulated companies as well as financial modeling and other economic studies in litigation support. In addition to my work at FINANCO, I have served as an adjunct professor in the McCombs School of Business at UT Austin and in what is now the McCoy College of Business at Texas State University. In my prior academic work, I taught economics and finance courses and I conducted research and directed graduate students in the areas of investments and capital market research. I was previously Director of the Economic Research Division at the Public Utility Commission ("Texas Commission") of Texas where I supervised the Texas Commission's finance, economics, and accounting staff, and served as the Texas Commission's chief financial witness in electric and telephone rate cases. I have taught courses at various utility conferences on cost of capital, capital structure, utility financial condition, and cost allocation and rate design issues. I have made presentations before the New York Society of Security Analysts, the National Rate of Return Analysts Forum, and various other professional and legislative groups. I have served as a vice president and on the board of directors of the Financial Management Association.

A list of my publications and testimony that I have given before various regulatory bodies and in state and federal courts is contained in my resume, which is included as Exhibit PPL/201.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to estimate the market required rate of return on equity capital ("ROE") for PacifiCorp.

Q. Please state your ROE recommendation and summarize the results of your cost of equity studies.

A. I estimate the cost of equity for PacifiCorp to be 10.5 percent to 11.0 percent. My discounted cash flow ("DCF") analysis indicates that this is a reasonable ROE range. My risk premium analysis indicates an ROE range of 10.32 percent to 10.64 percent. I understand that the Company is requesting a ROE near the lower end of my DCF range and near the upper end of my risk premium range at 10.6 percent.

Q. How is your analysis structured?

In my DCF analysis, I apply a comparable company approach. PacifiCorp's cost of equity cannot be estimated directly from its own market data because the Company is a wholly-owned subsidiary of MidAmerican Energy Holdings

Company. As such, PacifiCorp does not have publicly traded common stock or other independent market data that would be required to estimate its cost of equity directly. I begin my comparable company review with all the electric utilities that are included in the *Value Line Investors Survey* ("Value Line"). Value Line is a widely-followed, reputable source of financial data that is often used by professional regulatory economists. To improve the group's comparability with PacifiCorp, I restricted the group to companies with senior secured bond ratings of at least "A-" by Standard & Poor's ("S&P") or "A3" by Moody's Investors Service ("Moody's"). I also required the comparable companies to derive at least 70 percent of revenues from regulated utility sales, to have consistent financial records not affected by recent mergers or restructuring, and to have a consistent dividend record, with no dividend cuts or resumptions in the past two years, as required by the DCF model. The fundamental characteristics and bond ratings of the 21 companies in my comparable group are presented in Exhibit PPL/202.

In my risk premium analysis, I relied on current and projected single-A utility bond interest rates. These rates are consistent with PacifiCorp's bond ratings of "A" from S&P and "A2" from Moody's. As I will explain in more detail later in this testimony, under current market conditions the DCF and risk premium models appear to provide extremely conservative estimates of PacifiCorp's cost of equity capital. The data sources and the details of my cost of equity studies are contained in Exhibits PPL/202 through PPL/206.

Q. How is the remainder of your testimony organized?

A. My testimony is divided into three additional sections. Following this introduction, I review various methods for estimating the cost of equity. In this section, I discuss comparable earnings methods, risk premium methods, and the discounted cash flow model. In the following section, I review general capital market costs and conditions and discuss recent developments in the electric utility industry that may affect the cost of capital. In the final section, I discuss the details of my cost of equity studies and summarize my ROE recommendations.

Estimating the Cost of Equity Capital

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to present a general definition of the cost of equity capital and to compare the strengths and weaknesses of several of the most widely used methods for estimating the cost of equity. Estimating the cost of equity is fundamentally a matter of informed judgment. The various models provide a concrete link to actual capital market data and assist with defining the various relationships that underlie the ROE estimation process.

Q. Please define the term "cost of equity capital" and provide an overview of the cost estimation process.

A. The cost of equity capital is the rate of return that equity investors expect to receive. Conceptually it is no different than the cost of debt or the cost of preferred stock. The cost of equity is the rate of return that common stockholders expect, just as interest on bonds and dividends on preferred stock are the returns that investors in those securities expect. Equity investors expect a return on their capital commensurate with the risks they take and consistent with returns that might be available from other similar investments. Unlike returns from debt and preferred stocks, however, the equity return is not directly observable in advance and, therefore, it must be estimated or inferred from capital market data and trading activity.

An example helps to illustrate the cost of equity concept. Assume that an investor buys a share of common stock for $20 per share. If the stock's expected dividend is $1.00, the expected dividend yield is 5.0 percent ($1.00 / $20 = 5.0 percent). If the stock price is also expected to increase to $21.20 after one year, this one dollar and 20 cent expected gain adds an additional 6.0 percent to the expected total rate of return ($1.20 / $20 = 6.0 percent). Therefore, buying the stock at $20 per share, the investor expects a total return of 11.0 percent: 5.0 percent dividend yield, plus 6.0 percent price appreciation. In this example, the total expected rate of return of 11.0 percent is the appropriate measure of the cost of equity capital, because it is this rate of return that caused the investor to commit the $20 of equity capital in the first place. If the stock were riskier, or if expected returns from other investments were higher, investors would have required a higher rate of return from the stock, which would have resulted in a lower initial purchase price in market trading.

Each day market prices change to reflect new investor expectations and requirements. Changes in market prices, all else equal, imply changes in investor required rates of return. For example, when interest rates on bonds and savings accounts rise, utility stock prices usually fall. This is true, at least in part, because higher interest rates on these alternative investments make utility stocks relatively less attractive, which causes utility stock prices to decline in market trading. This competitive market adjustment process is quick and continuous, so that market prices generally reflect investor expectations and the relative attractiveness of one investment versus another. In this context, to estimate the cost of equity one must apply informed judgment about the relative risk of the company in question and knowledge about the risk and expected rate of return characteristics of other available investments as well.

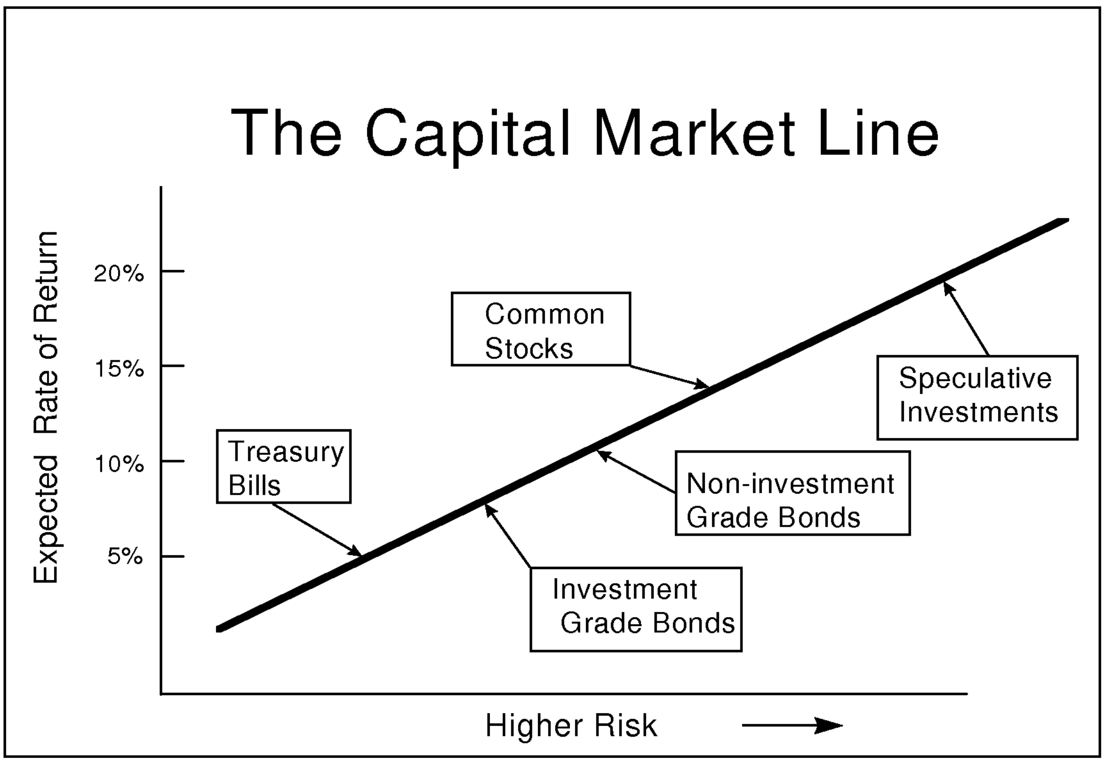
Q. How does the market account for risk differences among various investments?

A. Risk-return tradeoffs among capital market investments have been the subject of extensive financial research. Literally dozens of textbooks and hundreds of academic articles have addressed the issue. Generally, such research confirms the common sense conclusion that investors will take additional risks only if they expect to receive a higher rate of return. Empirical tests consistently show that returns from low risk securities, such as U.S. Treasury bills, are the lowest; that returns from longer-term Treasury bonds and corporate bonds are increasingly higher as risks increase; and generally, returns from common stocks and other more risky investments are even higher. These observations provide a sound theoretical foundation for both the DCF and risk premium methods for estimating the cost of equity capital. These methods attempt to capture the well founded risk-return principle and explicitly measure investors' rate of return requirements.

Q. Can you illustrate the capital market risk-return principle that you just described?

A. Yes. The following graph depicts the risk-return relationship that has become widely known as the Capital Market Line ("CML"). The CML offers a graphical representation of the capital market risk-return principle. The graph is not meant to illustrate the actual expected rate of return for any particular investment, but merely to illustrate in a general way the risk-return relationship.

Risk-Return Tradeoffs



As a continuum, the CML can be viewed as an available opportunity set for investors. Those investors with low risk tolerance or investment objectives that mandate a low risk profile should invest in assets depicted in the lower left-hand portion of the graph. Investments in this area, such as Treasury bills and short-maturity, high quality corporate commercial paper, offer a high degree of investor certainty. In nominal terms (before considering the potential effects of inflation), such assets are virtually risk-free.

Investment risks increase as one moves up and to the right along the CML. A higher degree of uncertainty exists about the level of investment value at any point in time and about the level of income payments that may be received. Among these investments, long-term bonds and preferred stocks, which offer priority claims to assets and income payments, are relatively low risk, but they are not risk-free. The market value of long-term bonds, even those issued by the U.S. Treasury, often fluctuates widely when government policies or other factors cause interest rates to change.

Farther up the CML continuum, common stocks are exposed to even more risk, depending on the nature of the underlying business and the financial strength of the issuing corporation. Common stock risks include market-wide factors, such as general changes in capital costs, as well as industry and company specific elements that may add further to the volatility of a given company's performance. As I will illustrate in my risk premium analysis, common stocks typically are more volatile (have higher risk) than high quality bond investments and, therefore, they reside above and to the right of bonds on the CML graph. Other more speculative investments, such as stock options and commodity futures contracts, contain higher risks (but offer higher potential returns). The CML's depiction of the risk-return tradeoffs available in the capital markets provides a useful perspective for estimating investors' required rates of return.

Q. How is the fair rate of return in the regulatory process related to the estimated cost of equity capital?

A. The regulatory process is guided by fair rate of return principles established in the U.S. Supreme Court cases, *Bluefield Water Works* and *Hope Natural Gas*:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-693 (1923).

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

This standard is also set forth in Oregon statute. *See* ORS 756.040. Based on these principles, the fair rate of return should closely parallel investor opportunity costs as discussed above. If a utility earns its market cost of equity, neither its stockholders nor its customers should be disadvantaged.

Q. What specific methods and capital market data are used to evaluate the cost of equity?

A. Techniques for estimating the cost of equity normally fall into three groups: comparable earnings methods, risk premium methods, and DCF methods. The first set of estimation techniques, the comparable earnings methods, has evolved over time. The original comparable earnings methods were based on book accounting returns. This approach developed ROE estimates by reviewing accounting returns for unregulated companies thought to have risks similar to those of the regulated company in question. These methods have generally been rejected because they assume that the unregulated group is earning its actual cost of capital, and that its equity book value is the same as its market value. In most situations these assumptions are not valid, and, therefore, accounting-based methods do not generally provide reliable cost of equity estimates.

More recent comparable earnings methods are based on historical stock market returns rather than book accounting returns. While this approach has some merit, it too has been criticized because there can be no assurance that historical returns actually reflect current or future market requirements. Also, in practical application, earned market returns tend to fluctuate widely from year to year. For these reasons, a current cost of equity estimate (based on the DCF model or a risk premium analysis) is usually required.

The second set of estimation techniques is grouped under the heading of risk premium methods. These methods begin with currently observable market returns, such as yields on government or corporate bonds, and add an increment to account for the additional equity risk. The capital asset pricing model ("CAPM") and arbitrage pricing theory ("APT") model are more sophisticated risk premium approaches. The CAPM and APT methods estimate the cost of equity directly by combining the "risk-free" government bond rate with explicit risk measures to determine the risk premium required by the market. Although these methods are widely used in academic cost of capital research, their additional data requirements and their potentially questionable underlying assumptions have detracted from their use in most regulatory jurisdictions. For example, in the last Oregon case in which PacifiCorp's cost of capital was litigated, Order No. 01-787, the Commission gave no weight to the CAPM model in determining PacifiCorp's return on equity. The basic risk premium methods provide a useful parallel approach with the DCF model and assures consistency with other capital market data in the equity cost estimation process.

The third set of estimation techniques, based on the DCF model, is the most widely used regulatory cost of equity estimation method. Like the risk premium approach, the DCF model has a sound basis in theory, and many argue that it has the additional advantage of simplicity. I will describe the DCF model in detail below, but in essence its estimate of ROE is simply the sum of the expected dividend yield and the expected long-term dividend, earnings, or price growth rate (all of which are assumed to grow at the same rate). While dividend yields are easy to obtain, estimating long-term growth is more difficult. Because the constant growth DCF model also requires very long-term growth estimates (technically to infinity), some argue that its application is too speculative to provide reliable results, leading to a preference for the multistage growth DCF analysis.

Q. Of the three estimation methods, which do you believe provides the most reliable results?

A. From my experience, a combination of DCF and risk premium methods provides the most reliable approach. While the caveat about estimating long-term growth must be observed, the DCF model's other inputs are readily obtainable, and the model's results typically are consistent with capital market behavior. The risk premium methods provide a good parallel approach to the DCF model and further ensure that current market conditions are accurately reflected in the cost of equity estimate.

Q. Please explain the DCF model.

A. The DCF model is predicated on the concept that stock prices represent the present value or discounted value of all future dividends that investors expect to receive. In the most general form, the DCF model is expressed in the following formula:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + ... + D_\infty/(1+k)^\infty \qquad (1)$$

where P_0 is today's stock price; D_1, D_2, etc. are all future dividends and k is the discount rate, or the investor's required rate of return on equity. Equation (1) is a routine present value calculation based on the assumption that the stock's price is the present value of all dividends expected to be paid in the future.

Under the additional assumption that dividends are expected to grow at a constant rate "g" and that k is strictly greater than g, equation (1) can be solved for k and rearranged into the simple form:

$$k = D_1/P_0 + g \qquad (2)$$

Equation (2) is the familiar constant growth DCF model for cost of equity estimation, where D_1/P_0 is the expected dividend yield and g is the long-term expected dividend growth rate.

Under circumstances when growth rates are expected to fluctuate or when future growth rates are highly uncertain, the constant growth model may not give reliable results. Although the DCF model itself is still valid (equation (1) is mathematically correct), under such circumstances the simplified form of the model must be modified to capture market expectations accurately.

Recent events and current market conditions in the electric utility industry as discussed later appear to challenge the constant growth assumption of the traditional DCF model. Since the mid-1990s, dividend growth expectations for many electric utilities have fluctuated widely. In fact, over one-third of the electric utilities in the U.S. have reduced or eliminated their common dividends over this time period. Some of these companies have reestablished their dividends, producing exceptionally high growth rates. Under these circumstances, long-term growth rate estimates may be highly uncertain, and estimating a reliable "constant" growth rate for many companies is often difficult.

Q. Can the DCF model be applied when the constant growth assumption is violated?

A. Yes. When growth expectations are uncertain, the more general version of the model represented in equation (1) should be solved explicitly over a finite "transition" period while uncertainty prevails. The constant growth version of the model can then be applied after the transition period, under the assumption that more stable conditions will prevail in the future. There are two alternatives for dealing with the nonconstant growth transition period.

Under the "terminal price" nonconstant growth approach, equation (1) is written in a slightly different form:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + ... + P_T/(1+k)^T \qquad (3)$$

where the variables are the same as in equation (1) except that P_T is the estimated stock price at the end of the transition period T. Under the assumption that normal growth resumes after the transition period, the price P_T is then expected to be based on constant growth assumptions. With the terminal price approach, the estimated cost of equity, k, is just the rate of return that investors would expect to earn if they bought the stock at today's market price, held it and received dividends through the transition period (until period T), and then sold it for price P_T. In this approach, the analyst's task is to estimate the rate of return that investors expect to receive given the current level of market prices they are willing to pay.

Under the "multistage" nonconstant growth approach, equation (1) is simply expanded to incorporate two or more growth rate periods, with the assumption that a permanent constant growth rate can be estimated for some point in the future:

$$P_0 = D_0(1+g_1)/(1+k) + ... + D_0(1+g_2)^n/(1+k)^n +$$

$$... + D_0(1+g_T)^{(T+1)}/(k-g_T) \qquad (4)$$

where the variables are the same as in equation (1), but g_1 represents the growth rate for the first period, g_2 for a second period, and g_T for the period from year T (the end of the transition period) to infinity. The first two growth rates are simply estimates for fluctuating growth over "n" years (typically 5 or 10 years) and g_T is a constant growth rate assumed to prevail forever after year T. The difficult task for analysts in the multistage approach is determining the various growth rates for each period.

Although less convenient for exposition purposes, the nonconstant growth models are based on the same valid capital market assumptions as the constant growth version. The nonconstant growth approach simply requires more explicit data inputs and more work to solve for the discount rate, k. Fortunately, the required data are available from investment and economic forecasting services, and computer algorithms can easily produce the required solutions. Both constant and nonconstant growth DCF analyses are presented in a subsequent section of my testimony.

Q. Please explain the risk premium methodology.

A. Risk premium methods are based on the assumption that equity securities are riskier than debt and, therefore, that equity investors require a higher rate of return. This basic premise is well supported by legal and economic distinctions between debt and equity securities, and it is widely accepted as a fundamental capital market principle. For example, debt holders' claims to the earnings and assets of the borrower have priority over all claims of equity investors. The contractual interest on mortgage debt must be paid in full before any dividends can be paid to shareholders, and secured mortgage claims must be fully satisfied before any assets can be distributed to shareholders in bankruptcy. Also, the guaranteed, fixed-income nature of interest payments makes year-to-year returns from bonds typically more stable than capital gains and dividend payments on stocks. All these factors demonstrate the more risky position of stockholders and support the equity risk premium concept.

Q. Are risk premium estimates of the cost of equity consistent with other current capital market costs?

A. Yes. The risk premium approach is useful because it is founded on current market interest rates, which are directly observable. This feature assures that risk premium estimates of the cost of equity begin with a sound basis, which is tied directly to current capital market costs.

Q. Is there consensus about how risk premium data should be employed?

A. No. In regulatory practice there is often considerable debate about how risk premium data should be interpreted and used. Since the analyst's basic task is to gauge investors' required returns on long-term investments, some argue that the estimated equity risk premium should be based on the longest possible time period. Others argue that market relationships between debt and equity from several decades ago are irrelevant and that only recent debt-equity observations should be given any weight in estimating investor requirements. There is no consensus on this issue. Since analysts cannot observe or measure investors' expectations directly, it is not possible to know exactly how such expectations are formed or, therefore, to know exactly what time period is most appropriate in a risk premium analysis.

The important point is to answer the following question: "What rate of return should equity investors reasonably expect relative to returns that are currently available from long-term bonds?" The risk premium studies and analyses I discuss later address this question. My risk premium recommendation is based on an intermediate position that avoids some of the problems and concerns that have been expressed about both very long and very short periods of analysis with the risk premium model.

Q. Please summarize your discussion of cost of equity estimation techniques.

A. Estimating the cost of equity is one of the most controversial issues in utility ratemaking. Because actual investor requirements are not directly observable, several methods have been developed to assist in the estimation process. The comparable earnings method is the oldest but perhaps least reliable. Its use of accounting rates of return, or even historical market returns, may or may not reflect current investor requirements. Differences in accounting methods among companies and issues of comparability also detract from this approach.

The DCF and risk premium methods have become the most widely accepted in regulatory practice. In my professional judgment, a combination of the DCF model and a review of risk premium data provides the most reliable cost of equity estimate. While the DCF model does require judgment about future growth rates, the dividend yield is straightforward, and the model's results are generally consistent with actual capital market behavior. For these reasons, I will rely on a combination of the DCF model and a risk premium analysis in the cost of equity studies that follow.

Fundamental Factors That Affect the Cost of Equity

Q. What is the purpose of this section of your testimony?

A. In this section, I review recent capital market conditions and industry factors that should be reflected in the cost of capital estimate.

Q. What has been the experience in the U.S. capital markets for the past several years?

A. In Exhibit PPL/203, page 1, I provide a review of annual interest rates and rates of inflation in the U.S. economy over the past ten years. During that time inflation and fixed income market costs declined and, generally, have been lower than rates that prevailed in the previous decade. Inflation, as measured by the Consumer Price Index ("CPI"), was essentially unchanged in 2008 and increased by about 3 percent in 2009. Over the past decade, the CPI has averaged 2.6 percent. This is lower than its long-run average of 3.5 percent to 4.0 percent.

Having reduced the Federal Funds overnight bank interest rate to virtually zero, the Federal Reserve System's current monetary policy options are limited. During the period from mid-2004 until mid-2006, the Federal Reserve System increased the short-term Federal Funds interest rate 17 times, raising it from 1 percent to 5.25 percent. In late 2007, in response to the early turbulence in the sub-prime credit markets, the Federal Reserve Open Market Committee began aggressively reducing the Federal Funds rate. Since September 2007, the rate has been lowered eleven times to its current target level of between zero and one-quarter percent. While governmental policies and "flight to safety"[1] issues have driven down interest rates on higher quality debt securities, the cost of equity for utilities has not declined to the same extent over the past year.

Q. Has the recent extreme turbulence in the capital markets increased the cost of capital for utilities?

A. Yes. At various times since late 2008, the capital markets in the U.S. have been more turbulent than at any time since the 1930s. This period has seen frequent large daily moves in the stock market and conditions in the corporate debt market that, in late 2008 and parts of early 2009, could best be characterized as near-chaos. The S&P 500 and the Dow Jones Industrial Average have fluctuated by 50 percent since November 2007. In this environment, many large financial institutions such as Countrywide Financial, Washington Mutual, the Federal Home Loan Mortgage Association, the Federal National Mortgage Association, Wachovia, Bear Stearns, and Merrill Lynch were unable to survive as independent institutions. Lehman Brothers was forced to file for bankruptcy. Other surviving institutions such as Citigroup, Goldman Sachs, American International Group, Morgan Stanley and others have required multibillion dollar capital infusions.

Since October 2008, the federal government has enacted emergency legislation and taken other steps to stabilize the economy. As part of that effort

[1] The term "flight to safety" refers to the tendency for investors, during periods of market turbulence, to remove money from more risky investments, such as corporate bonds and stocks, and to put the money into government securities such as Treasury bills and bonds. The effect causes a reduction in the supply of funds to corporations and an increase in funds invested in government securities. The result is wider "spreads" between corporate bond and government bond interest rates and higher capital costs for corporations.

the government increased federal deposit insurance for banks, lent billions of dollars to financial institutions, purchased hundreds of billions of dollars in illiquid securities, guaranteed loans between financial institutions, and purchased equity in banks. There is no question that the economic and financial uncertainties generated by the credit crisis have significantly impacted the risks surrounding public utility company cost of capital.

Q. Can you be more specific regarding the impact of the credit crisis on the cost of capital of public utilities?

A. Yes. In Exhibit PPL/203, page 2, I provide data that illustrate the volatility that has occurred in the debt markets. The schedule shows that during the past two years, single-A spreads for utility companies were at times more than three times previously existing levels. The month-by-month interest rates paid by single-A rated utilities and the U.S. Treasury since January 2008 are presented in Exhibit PPL/203, page 2. These interest rate data are summarized in Table 1 below.

Table 1
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-08	6.02	4.33	1.69
Feb-08	6.21	4.52	1.69
Mar-08	6.21	4.39	1.82
Apr-08	6.29	4.44	1.85
May-08	6.28	4.60	1.68
Jun-08	6.38	4.69	1.69
Jul-08	6.40	4.57	1.83
Aug-08	6.37	4.50	1.87
Sep-08	6.49	4.27	2.22
Oct-08	7.56	4.17	3.39
Nov-08	7.60	4.00	3.60
Dec-08	6.52	2.87	3.65
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
Mar-09	6.42	3.64	2.78
Apr-09	6.48	3.76	2.72
May-09	6.49	4.23	2.26
Jun-09	6.20	4.52	1.68
Jul-09	5.97	4.41	1.56
Aug-09	5.71	4.37	1.34
Sep-09	5.53	4.19	1.34
Oct-09	5.55	4.19	1.36
Nov-09	5.64	4.31	1.33
Dec-09	5.79	4.49	1.30
Jan-10	5.77	4.60	1.17
3-Mo Avg	**5.73**	**4.47**	**1.27**
12-Mo Avg	**5.99**	**4.19**	**1.80**

Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates).
Three month average is for November 2009 through January 2010.

The data in Table 1 vividly illustrate the market turmoil that has occurred. In fact, increased risk aversion and continuing market volatility have resulted in ongoing difficulties for many corporations. The on-going effects of the market's turbulence are not easily captured in financial models for estimating the required rate of return. However, these continuing effects and the elevated level of risk aversion should be considered in estimating the cost of equity capital.

Q. What do forecasts for the economy and interest rates show for the coming year?

A. Exhibit PPL/203, page 3, provides S&P's most recent economic forecast from its *Trends & Projection*s publication for January 2010. The S&P data reflect the significant economic contraction that occurred through the first two quarters of 2009. For all of 2009, S&P indicates that real gross domestic product ("GDP") declined by 2.5 percent. Real growth in GDP resumed during the 3rd Quarter of 2009, and for 2010 S&P expects GDP to increase by 2.3 percent.

S&P also forecasts that long-term government and high grade corporate interest rates will rise somewhat from recent levels. The summary interest rate data are presented in Table 2 below:

Table 2
Standard & Poor's Interest Rate Forecast

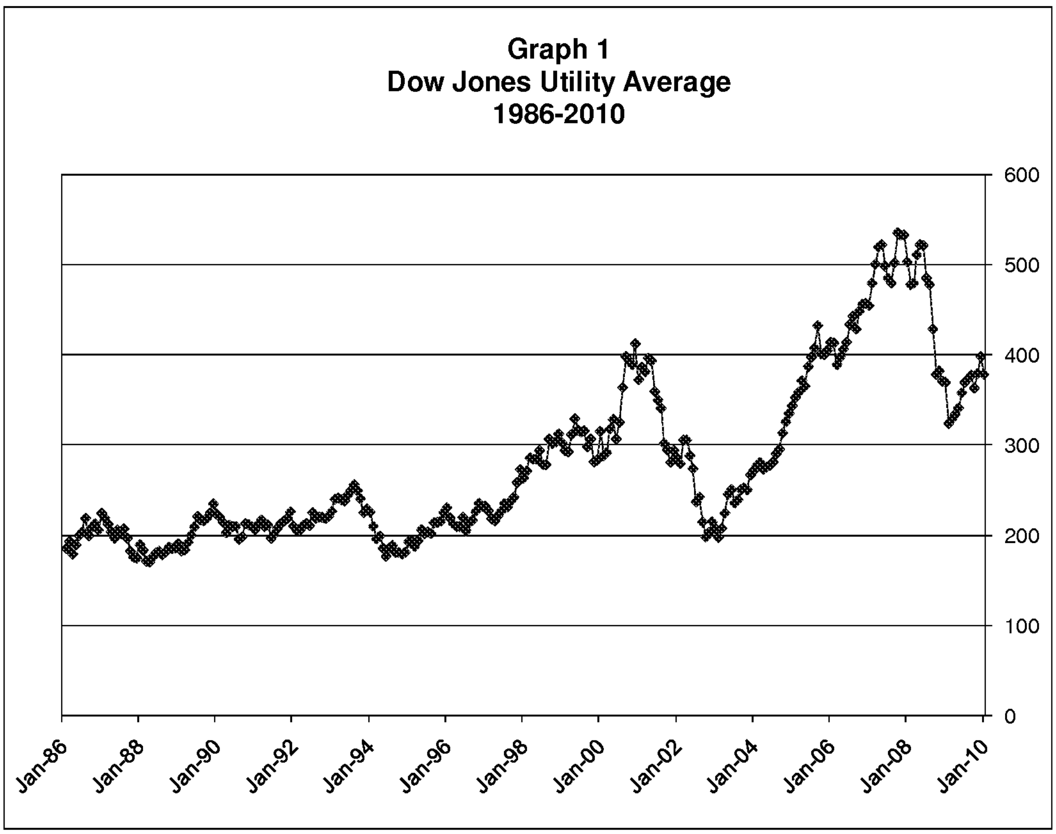
	Jan. 2010 Average	Average 2009	Average 2010 Est.
Treasury Bills	0.6%	0.2%	0.4%
10-Yr. T-Bonds	3.7%	3.3%	4.2%
30-Yr. T-Bonds	4.6%	4.1%	5.0%
Aaa Corporate Bonds	5.3%	5.4%	5.8%

Sources: www.federalreserve.gov, (Current Rates). Standard & Poor's *Trends & Projections*, January 2010, page 8 (Projected Rates).

The data in Table 2 show that long-term Treasury interest rates during 2010 are projected to increase by 40 basis points from current levels. Rates on highest grade Aaa corporate bonds are expected to increase by 50 basis points. Although in the recently turbulent market environment it has been difficult to project interest rates, these market data offer perspective for judging the cost of capital in the present case.

Q. How have utility stocks performed during the past several years?

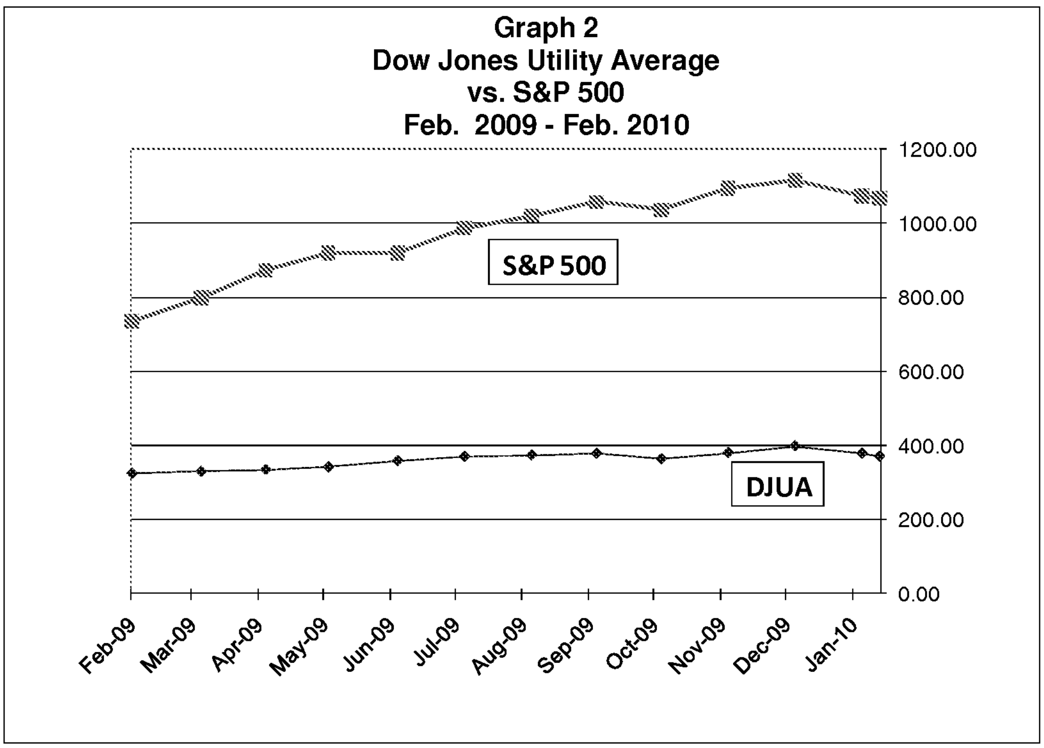
A. Utility stock prices have fluctuated widely. After reaching a level of over 400 in 2000, the Dow Jones Utility Average ("DJUA") dropped to about 200 by October 2002. From late 2002 until 2008, the DJUA trended upward. However, utility stock prices dropped materially with the overall market decline of 2008 and early 2009. The current level for the DJUA is over 25 percent below the highest levels attained in 2007. The wider fluctuations in more recent years are vividly illustrated in Graph 1, which depicts DJUA prices over the past 25 years.



Over the last decade, utility stock prices have become much more volatile than they previously were. In this environment, investors' return expectations and requirements for providing capital to the utility industry are higher than they were relative to the longer-term traditional view of the utility industry.

Q. How have utility stocks performed relative to the overall market recovery experienced during the past year?

A. Utility stock prices have lagged significantly behind the overall market recovery. Graph 2 shows the monthly levels for the DJUA versus the broader market S&P 500 index since the market lows that occurred in February and March of 2009.

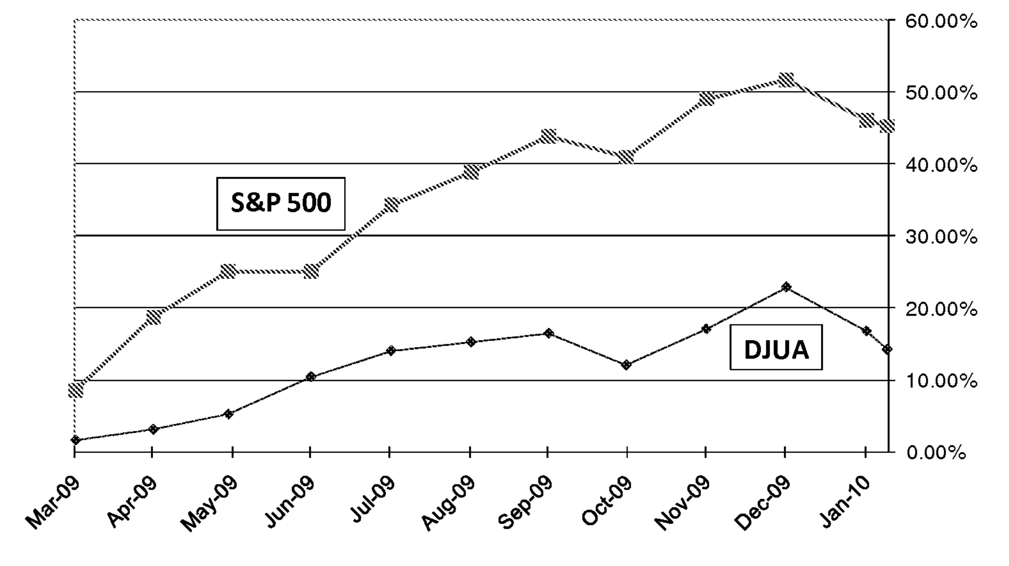


Graph 2
Dow Jones Utility Average
vs. S&P 500
Feb. 2009 - Feb. 2010

While the S&P 500 has increased significantly during the past year, utility prices have remained relatively flat. This result is a further indication that the cost of equity for utility companies has not declined to the same extent that interest rates have fallen or to the same extent that the cost of equity may have come down for the broader equity market. The relatively lower stock prices for utility shares indicates that the cost of capital for utilities is higher.

Graph 3 further illustrates this result by showing the cumulative percentage change in the two equity indexes since the March 2009 lows.

Graph 3
Dow Jones Utility Average
vs. S&P 500
Cumulative % Change
Mar. 2009 - Feb. 2010



While the S&P 500 has recovered about 45 percent from its March 2009 lows, utility stock prices have increased by only about one-third that amount. This again suggests the market difficulties that utilities face and the continuing relatively higher cost of equity of utility companies.

Q. What is the industry's current fundamental position?

A. The industry has seen significant volatility both in terms of fundamental operating characteristics and the effects of the economy. While many companies have refocused their businesses on more traditional utility service and less on marketing, the effects of deregulation of the wholesale power markets and continuing fuel price uncertainties remain prominent. The economic crisis has also reduced sales volumes and increased the difficulty of planning for future load requirements. S&P reflects this volatility in its most recent Electric Utility Industry Survey:

> **<u>Standard & Poor's Industry Surveys</u>**
>
> We expect the performance of both the electric utility sector and the individual companies within the sector to remain relatively volatile over the next several years. However, assuming that the housing, financial, and credit markets begin to stabilize, we believe the stocks will be less volatile in 2010 than they were in 2008 and 2009, or during the first few years of this decade.... *** The performance of the sector, however, will remain sensitive to the macroeconomic environment and market forces surrounding it. (Standard & Poor's Industry Surveys, Electric Utilities August 13, 2009, page 6.)

Value Line also comments on the industry's relatively poor stock price performance:

> **<u>Value Line Investment Survey</u>**
>
> Utility Stocks were laggards for much of 2009, but have performed a little bit better in recent weeks. Still, they will fall far short of the rise in the broad market averages in the year just ending *** As 2009 was nearing an end, the Value Line Composite Average had surged over 30% for the year, but the Value Line Utility Average had risen only about 5%. (*Value Line Investment Survey*, Electric Utility (Central) Industry, December 25, 2009, page 687.)

Credit market gyrations and the volatility of utility shares demonstrate the increased uncertainties that utility investors face. These uncertainties translate into a higher cost of capital for utilities than has been experienced in recent years.

Q. Do utilities continue to face the operating and financial risks that existed prior to the recent financial crisis?

A. Yes. Prior to the recent financial crisis, the greatest consideration for utility investors was the industry's continuing transition to more open market conditions and competition. With the passage of the Energy Policy Act ("EPACT") in 1992 and the Federal Energy Regulatory Commission's ("FERC") Order 888 in 1996, the stage was set for vastly increased competition in the electric utility industry. EPACT's mandate for open access to the transmission grid and FERC's implementation through Order 888 effectively opened the market for wholesale electricity to competition. Previously protected utility service territory and lack of transmission access in some parts of the country had limited the availability of competitive bulk power prices. EPACT and Order 888 have essentially eliminated such constraints for incremental power needs.

In addition to wholesale issues at the federal level, many states implemented retail access and opened their retail markets to competition. Prior to the western energy crisis, investors' concerns had focused principally on appropriate transition mechanisms and the recovery of stranded costs. More recently, however, provisions for dealing with power cost adjustments have become a larger concern.

Concern is also beginning to develop around pending climate change legislation including the recent passage by the House of Representatives of H.R. 2454 – the American Clean Energy and Security Act of 2009, also referred to as the Waxman-Markey bill. It appears increasingly likely that in the foreseeable future climate change initiatives will require utilities to balance a diverse set of supply-side and demand-side resources. In particular, utilities with significant coal-fired generation would have the added risk of addressing a reduction in greenhouse gas emissions by needing to make costly changes to existing generation fleets such as retiring existing coal plants in favor of lower-emission alternatives, operating higher cost supply options, purchasing domestic and/or foreign carbon offsets, or purchasing more expensive low-or-zero emission power. In addition, climate change legislation may require investment in a mandated percentage of renewable energy options, whether or not the investment appears to be economic, and would likely place added pressure on utilities to offer additional demand-side alternatives, including energy efficiency programs, that will reduce customers' demand for power.

As expected, the opening of previously protected utility markets to competition, the uncertainty created by the removal of regulatory protection, continuing fuel price volatility and concerns about the impact of climate change legislation have raised the level of uncertainty about investment returns across the entire industry.

Q. Is PacifiCorp affected by these same uncertainties and increasing utility capital costs?

A. Yes. While all electric utilities are being affected by the industry's transition to competition at some level, PacifiCorp is directly impacted in Oregon where the Legislature has adopted limited retail competition, while also guaranteeing customers continued access to cost-of-service rates. Although I understand that only a few large industrial customers have opted away from PacifiCorp, Oregon's competitive retail model creates potential risk to PacifiCorp in load planning, managing net power costs, estimating future revenues and other operating activities. The uncertainty associated with the changes that are transforming the utility industry as a whole, as viewed from the perspective of the investor, remain a factor in assessing any utility's required ROE, including the ROE from PacifiCorp's operations in Oregon.

Q. How do capital market concerns and financial risk perceptions affect the cost of equity capital?

A. As I discussed previously, equity investors respond to changing assessments of risk and financial prospects by changing the price they are willing to pay for a given security. When the risk perceptions increase or financial prospects decline, investors refuse to pay the previously existing market price for a company's securities and market supply and demand forces then establish a new lower price. The lower market price typically translates into a higher cost of capital through a higher dividend yield requirement as well as the potential for increased capital gains if prospects improve. In addition to market losses for prior shareholders, the higher cost of capital is transmitted directly to the company by the need to earn a higher cost of capital on existing and new investment just to maintain the stock's new lower price level and the reality that the firm must issue more shares to raise any given amount of capital for future investment. The additional shares also impose additional future dividend requirements and may reduce future earnings per share growth prospects if the proceeds of the share issuance are unable to earn their expected rate of return.

Q. How have regulatory commissions responded to these changing market and industry conditions?

A. Over the past five years, average allowed equity returns have fluctuated in a relatively narrow range. Table 3 provides a quarter-by-quarter summary of the results:

Table 3
Authorized Electric Utility Equity Returns

	2005	2006	2007	2008	2009
1st Quarter	10.51%	10.38%	10.27%	10.45%	10.29%
2nd Quarter	10.05%	10.68%	10.27%	10.57%	10.55%
3rd Quarter	10.84%	10.06%	10.02%	10.47%	10.46%
4th Quarter	10.75%	10.39%	10.56%	10.33%	10.54%
Full Year Average	10.54%	10.36%	10.36%	10.46%	10.48%
Average Utility Debt Cost	5.67%	6.08%	6.11%	6.65%	6.28%
Indicated Average Risk Premium	4.87%	4.28%	4.25%	3.81%	4.20%

Source: *Regulatory Focus*, Regulatory Research Associates, Inc., Major Rate Case Decisions, January 8, 2010. Utility debt costs are the "average" public utility bond yields as reported by Moody's.

Since 2005, equity risk premiums (the difference between allowed equity returns and utility interest rates) have ranged from 3.81 percent to 4.87 percent.

Cost of Equity Capital for PacifiCorp

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to present my quantitative studies of the cost of equity capital for PacifiCorp and to discuss the details and results of my analysis.

Q. How are your studies organized?

A. In the first part of my analysis, I apply three versions of the DCF model to a 21-

company group of electric utilities based on the selection criteria discussed previously. In the second part of my analysis, I present my risk premium analysis and review projected economic conditions and projected capital costs for the coming year.

Q. Please describe your DCF analysis.

A. My DCF analysis is based on three versions of the DCF model. In the first version of the DCF model, I use the constant growth format with long-term expected growth based on analysts' estimates of five-year utility earnings growth. While I continue to use a longer-term growth estimation approach based on growth in overall gross domestic product, I also rely on the DCF results with analysts' growth rates because this is the approach that has traditionally been used by many regulators. Because the analysts' growth estimates are objective, verifiable forecasts provided by independent third parties, this approach can minimize disputes among the parties about the appropriate inputs to and application of the model.

In the second version of the DCF model, for the estimated growth rate, I use the estimated long-term GDP growth rate. In the third version of the DCF model, I use a two-stage growth approach, with stage one based on Value Line's three-to-five-year dividend projections and stage two based on long-term projected growth in GDP. The dividend yields in all three of the annual models are from Value Line's projections of dividends for the coming year and stock prices are from the three-month average for the months that correspond to the Value Line editions from which the underlying financial data are taken.

Q. Why do you use the long-term GDP growth rate to estimate long-term growth expectations in the DCF model?

A. Growth in nominal GDP (real GDP plus inflation) is the most general measure of economic growth in the U.S. economy. For long time periods, such as those used in the Morningstar/Ibbotson Associates rate of return data, GDP growth has averaged between 5 percent and 8 percent per year. From this observation, Professors Brigham and Houston offer the following observation concerning the appropriate long-term growth rate in the DCF Model:

> Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation). On this basis, one might expect the dividend of an average, or "normal," company to grow at a rate of 5 to 8 percent a year. (Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, 11th Ed. 2007, page 298)

Other academic research on corporate growth rates offers similar conclusions about GDP growth as well as concerns about the long-term adequacy of analysts' forecasts:

> Our estimated median growth rate is reasonable when compared to the overall economy's growth rate. On average over the sample period, the median growth rate over 10 years for income before extraordinary items is about 10 percent for all firms. ... After deducting the dividend yield (the median yield is 2.5 percent per year), as well as inflation (which averages 4 percent per year over the sample period), the growth in real income before extraordinary items is roughly 3.5 percent per year. This is consistent with the historical growth rate in real gross domestic product, which has averaged about 3.4 percent per year over the period 1950-1998. (Louis K. C. Chan, Jason Karceski, and Josef Lakonishok, "The Level and Persistence of Growth Rates," The Journal of Finance, April 2003, p. 649.)

> IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons,

> however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic. … On the whole, the absence of predictability in growth fits in with the economic intuition that competitive pressures ultimately work to correct excessively high or excessively low profitability growth. (Ibid, page 683.)

These findings support the notion that long-term growth expectations are more closely predicted by broader measures of economic growth than by near-term analysts' estimates. Especially for the very long-term growth rate requirements of the DCF model, the growth in nominal GDP should be considered an important input.

Q. How did you estimate the expected long-run GDP growth rate?

A. I developed my long-term GDP growth forecast from nominal GDP data contained in the St. Louis Federal Reserve Bank data base. That data for the period 1949 through 2009 are summarized in my Exhibit PPL/204. As shown at the bottom of that exhibit, the overall average for the period was 6.9 percent. The data also show, however, that in the more recent years since 1980, lower inflation has resulted in lower overall GDP growth. For this reason I gave more weight to the more recent years in my GDP forecast. This approach is consistent with the concept that more recent data should have a greater effect on expectations. Based on this approach, my overall forecast for long-term GDP growth is 90 basis points lower than the long-term average, at a level of 6.0 percent.

Q. The DCF model requires an estimate of investors' long-term growth rate expectations. Why do you believe your forecast of GDP growth based on long-term historical data is appropriate?

A. There are at least three reasons. First, most econometric forecasts are derived from the trending of historical data or the use of weighted averages. This is the approach I have taken in Exhibit PPL/204. The long-run historical average GDP growth rate is 6.9 percent, but my estimate of long-term expected growth is only 6.0 percent. My forecast is lower because my forecasting method gives much more weight to the more recent 10- and 20-year periods.

Second, some currently lower GDP growth forecasts likely understate very long growth rate expectations that are required in the DCF model. Many of those forecasts are currently low because they are based on the assumption of permanently low inflation rates, in the range of 2 percent. As shown in my Exhibit PPL/204 the average long-term inflation rate has been over 3 percent in all but the most recent 20 years.

Finally, the current economic turmoil makes it even more important to consider longer-term economic data in the growth rate estimate. As discussed in the previous section, current near-term forecasts for both real GDP and inflation are severely depressed. To the extent that even the longer-term outlooks of professional economists are also depressed, their forecasts may be understated. Under these circumstances, a longer-term view is even more important. For all these reasons, while I am also presenting other growth rate approaches based on analysts' estimates in this testimony, I believe it is appropriate also to consider long-term GDP growth in estimating the DCF growth rate.

Q. Please summarize the results of your DCF analyses.

A. The DCF results for my comparable company group are presented in Exhibit PPL/205. As shown in the first column of page 1 of that exhibit, the traditional constant growth model indicates an ROE of 10.5 percent to 11.0 percent. In the second column of page 1, I recalculate the constant growth results with the growth rate based on long-term forecasted growth in GDP. With the GDP growth rate, the constant growth model indicates an ROE range of 10.7 percent to 10.9 percent. Finally, in the third column of page 1, I present the results from the multistage DCF model. The multistage model indicates an ROE range of 10.5 percent to 10.7 percent. The results from the DCF model, therefore, indicate a reasonable ROE range of 10.5 percent to 11.0 percent.

Q. What are the results of your equity risk premium studies?

A. The details and results of my equity risk premium studies are shown in Exhibit PPL/206. These studies indicate an ROE range of 10.32 percent to 10.64 percent. The Federal Reserve System's continuing "easy money" policies have provided renewed liquidity in the credit markets that is reflected in these lower yields. These results are not consistent with DCF results, which continue to demonstrate the equity market risk aversion that is reflected in continuing volatility and relatively low stock prices for utility shares. These circumstances indicate that the cost of equity capital has not declined to the same extent as the yields on utility debt.

Q. How are your equity risk premium studies structured?

A. My equity risk premium studies are divided into two parts. First, I compare electric utility authorized ROEs for the period 1980-2009 to contemporaneous long-term utility interest rates. The differences between the average authorized ROEs and the average interest rate for the year is the indicated equity risk premium. I then add the indicated equity risk premium to the forecasted and current single-A utility bond interest rate to estimate ROE. Because there is a strong inverse relationship between equity risk premiums and interest rates (when interest rates are high, risk premiums are low and vice versa), further analysis is required to estimate the current equity risk premium level.

The inverse relationship between equity risk premiums and interest rate levels is well documented in numerous, well-respected academic studies. These studies typically use regression analysis or other statistical methods to predict or measure the equity risk premium relationship under varying interest rate conditions. On page 3 of Exhibit PPL/206, I provide regression analyses of the allowed annual equity risk premiums relative to interest rate levels. The negative and statistically significant regression coefficients confirm the inverse relationship between equity risk premiums and interest rates. This means that when interest rates rise by one percentage point, the cost of equity increases, but by a smaller amount. Similarly, when interest rates decline by one percentage point, the cost of equity declines by less than one percentage point. I use this negative interest rate change coefficient in conjunction with current interest rates to establish the appropriate current equity risk premium.

Q. Please summarize the results of your cost of equity analysis.

A. The following table summarizes my results:

Table 4

Summary of Cost of Equity Estimates

DCF Analysis	Indicated Cost
Constant Growth (Analysts' Growth)	10.5%-11.0%
Constant Growth (GDP Growth)	10.7%-10.9%
Multistage Growth Model	10.5%-10.7%
Reasonable DCF Range	10.5%-11.0%

Equity Risk Premium Analysis	Indicated Cost
Projected Utility Debt Yield + Equity Risk Premium	
Equity Risk Premium ROE (6.27% + 4.37%)	10.64%
Current Utility Debt Yield + Equity Risk Premium	
Equity Risk Premium ROE (5.73% + 4.59%)	10.32%

PacifiCorp Estimated ROE	10.5%-11.0%

Q. How should these results be interpreted to determine the fair cost of equity for PacifiCorp?

A. The recent market turmoil and the continuing effects on capital market conditions make it difficult to strictly interpret quantitative model estimates for the cost of equity. While corporate interest rates have dropped from the levels that existed in late 2008, the DCF results, based on continuing relatively low utility stock prices, show that the cost of equity has not declined as much as utility bond yields. Under these conditions, use of a lower DCF range or equity risk premium estimates based strictly on historical risk premium relationships likely understate the cost of equity. From this perspective, and with consideration of the Company's on-going capital requirements, I estimate the fair and reasonable cost of equity capital for PacifiCorp to be 10.5 percent to 11.0 percent.

Q. Does this conclude your testimony?

A. Yes, it does.

Docket No. UE-
Exhibit PPL/201
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Resume of Dr. Samuel C. Hadaway

March 2010

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SUMMARY OF QUALIFICATIONS

- Principal, Financial Analysis Consultants (FINANCO, Inc.).
- Ph.D. in Finance and Econometrics.
- Extensive expert witness testimony in court and before regulatory agencies.
- Management of professional research staff in academic and regulatory organizations.
- Professional presentations before executive development groups, the National Rate of Return Analysts' Forum, and the New York Society of Security Analysts.
- Financial Management Association, Vice President for Practitioner Services.

EDUCATION

The University of Texas at Austin
Ph.D., Finance and Econometrics
January 1975

Dissertation: *An Evaluation of the Original and Recent Variants of the Capital Asset Pricing Model.*

The University of Texas at Austin
MBA, Finance
June 1973

Thesis: *The Pricing of Risk on the New York Stock Exchange.*

Southern Methodist University
BA, Economics
June 1969

Honors program. Departmental distinction.

OTHER EXPERIENCE

University of Texas at Austin
Adjunct Associate Professor
1985-1988, 2004-Present

Corporate Financial Management, Investments, and Integrative Finance Cases.

Texas State University San Marcos
Associate Professor of Finance
1983-1984, 2003-2004

Graduate and undergraduate courses in Financial Management, Managerial Economics, and Investment Analysis.

Public Utility Commission of Texas
Chief Economist and Director of Economic Research Division
August 1980-August 1983

Lead financial witness. Supervised Commission staff in research and testimony on rate of return, financial condition, and economic analysis.

Assistant Professor of Finance
Texas Tech University
July 1978-July 1980
University of Alabama
January 1975-June 1978

Member of graduate faculty. Conducted Ph.D. seminars and directed doctoral dissertations in capital market theory. Served as consultant to industry, church and governmental organizations.

FINANCIAL AND ECONOMIC TESTIMONY IN REGULATORY PROCEEDINGS (Client in parenthesis)

Cost of Money Testimony:

- Texas Public Utility Commission, Docket No. 37744, December 30, 2009,(Entergy Texas, Inc.)
- Kansas Corporation Commission, Docket No. 10-KCPE-415-RTS, December 17, 2009 (Kansas City Power & Light Company).
- Texas Public Utility Commission, Docket No. 37690, December 9, 2009,(El Paso Electric Company).
- California Public Utilities Commission, Application No. 09-11-015, November 20, 2009 (PacifiCorp).
- Federal Energy Regulatory Commission, Docket No. ER10-230-000, November 6, 2009 (Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company).
- Wyoming Public Service Commission, Docket No. 20000-352-ER-09, October 2, 2009 (Rocky Mountain Power dba/PacifiCorp).
- Arkansas Public Service Commission, Docket No. 09-084-U, September 4, 2009, (Entergy-Arkansas)
- Texas Public Utility Commission, Docket No. 37364, August 28, 2009,(American Electric Power-SWEPCO)
- Utah Public Service Commission, Docket No. 09-035-23, June 23, 2009 (Rocky Mountain Power/PacifiCorp).
- New Mexico Public Regulation Commission, Case No. 09-00171-UT, May 2009, (El Paso Electric Company).
- Oregon Public Utility Commission, Case No. UE-207, April 2, 2009 (PacifiCorp).
- Arkansas Public Service Commission, Docket No. 09-008-U, February 19, 2009 (American Electric Power-SWEPCO).
- Washington Utilities and Transportation Commission, Docket UE-090205, General
- Idaho Public Utilities Commission, Case No. PAC-E-08-07, September 19, 2008 (Rocky Mountain Power/PacifiCorp).
- Missouri Public Service Commission, Case No. ER-2009-089, September 5, 2008 (Kansas City Power & Light Company).
- Kansas Corporation Commission, Docket No. 09-KCPE-246-RTS, September 5, 2008 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2009-090, September 5, 2008 (Aquila, Inc. dba/KCP&L Greater Missouri Operations Company).
- Utah Public Service Commission, Docket No. 08-035-38, July 17, 2008 (Rocky Mountain Power/PacifiCorp).
- Wyoming Public Service Commission, Docket No. 20000-333-ER-08, July 2008 (Rocky Mountain Power dba/PacifiCorp).
- Texas Public Utility Commission, Docket No. 35717, June 27, 2008, (Oncor Electric Delivery Company LLC).
- Washington Utilities and Transportation Commission, Docket UG-080546/General Rate Case, March 28, 2008 (NW Natural).
- Washington Utilities and Transportation Commission, Docket UE-080220/General Rate Case, February 6, 2008 (PacifiCorp).
- Utah Public Service Commission, Docket No. 07-035-93, December 17, 2007 (PacifiCorp).
- Illinois Commerce Commission, Docket No. 07-0566, October 17, 2007 (Commonwealth Edison Company).
- Texas Public Utility Commission, Docket No. 34800, September 26, 2007, (Entergy Gulf States, Inc.)
- Texas Public Utility Commission, Docket No. 34040, August 28, 2007, (Oncor/TXU Electric Delivery Company)
- Massachusetts Department of Public Utilities, D.P.U. 07-71, August 17, 2007, (Fitchburg Gas and Electric Light Company d/b/a/ Unitil)

- Arizona Corporation Commission, Docket No. E-01933A-07-0402, July 2, 2007, (Tucson Electric Power Company).
- Wyoming Public Service Commission, Docket No. 20000-277-ER-07, June 29, 2007 (Rocky Mountain Power dba/PacifiCorp).
- Idaho Public Utilities Commission, Case No. PAC-E-05-1, June 8, 2007 (Rocky Mountain Power dba/PacifiCorp).
- Kansas Corporation Commission, Docket No. 07-KCPE-905-RTS, March 1, 2007 (Kansas City Power & Light Company).
- New Mexico Public Regulation Commission, Case No. 07-00077-UT, February 21, 2007, (Public Service Company of New Mexico).
- Missouri Public Service Commission, Case No. ER-2006-0291, February 1, 2007 (Kansas City Power & Light Company).
- Texas PUC Docket Nos. 33734, January 22, 2007 (Electric Transmission Texas, LLC).
- Texas PUC Docket Nos. 33309 and 33310, November 2006, (AEP Texas Central Company and AEP Texas North Company).
- Louisiana Public Service Commission, Docket No. U-23327, October 2006 and January 2005 (Southwestern Electric Power Company, American Electric Power Company)
- Missouri Public Service Commission, Case No. ER-2007-0004, July 3, 2006 (Aquila, Inc.).
- New Mexico Public Regulation Commission, Case No. 06-00258-UT, June 30, 2006 (El Paso Electric Company).
- New Mexico Public Regulation Commission, Case No. 06-00210-UT, May 30, 2006 (Public Service Company of New Mexico).
- Texas Public Utility Commission, Docket No. 32093, April 14, 2006 (CenterPoint Energy-Houston Electric, LLC).
- Utah Public Service Commission, Docket No. 06-035-21, March 7, 2006 (PacifiCorp).
- Oregon Public Utility Commission, Case No. UE-179, February 23, 2006 (PacifiCorp).
- Kansas Corporation Commission, Docket No. 06-KCPE-828-RTS, January 31, 2006 (Kansas City Power & Light Company).
- Missouri Public Service Commission, Case No. ER-2006-0314, January 27, 2006 (Kansas City Power & Light Company).
- California Public Utilities Commission, Docket No. 05-11-022, November 29, 2005 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 31994, November 5, 2005 (Texas-New Mexico Power Company).
- New Hampshire Public Utilities Commission, Docket No. DE 05-178, November 4, 2005 (Unitil Energy Systems).
- Wyoming Public Service Commission, Docket No. 20000-ER-05-230, October 14, 2005 (PacifiCorp).
- Minnesota Public Utilities Commission, Docket. No. G-008/GR-05-1380, October 2005 (CenterPoint Energy Minnegasco).
- Texas Railroad Commission, Gas Utilities Division No. 9625, September 2005 (CenterPoint Energy Entex).
- Illinois Commerce Commission, Docket No. 05-0597, August 31, 2005 (Commonwealth Edison Company).
- Washington Utilities and Transportation Commission, Docket ,UE-050684/General Rate Case, May 2005 (PacifiCorp).
- Missouri Public Service Commission, Case No. ER-2005-0436, May 2005 (Aquila, Inc.).
- Idaho Public Utilities Commission, Case No. PAC-E-05-1, January 14, 2005 (PacifiCorp).
- Arkansas Public Service Commission, Docket No. 04-121-U, December 3, 2004 (CenterPoint Energy Arkla).

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- Texas Public Utility Commission, Docket No. 29206, November 8, 2004 (Texas-New Mexico Power Company).
- Texas Railroad Commission, Gas Utilities Division Nos. 9533 and 9534, October 13, 2004 (CenterPoint Energy Entex).
- Texas Public Utility Commission, Docket No. 29526, August 18 and September 2, 2004 (CenterPoint Energy Houston Electric).
- Utah Public Service Commission, Docket No. 04-2035-, August 4, 2004 (PacifiCorp).
- Oklahoma Corporation Commission, Cause No. PUD-200400187, July 2, 2004, (CenterPoint Energy Arkla).
- Minnesota Public Utilities Commission, Docket No. G-008/GR-04-901, July 2004, (CenterPoint Energy Minnegasco).
- Washington Utilities and Transportation Commission, Docket ,UE-032065/General Rate Case, December 2003 (PacifiCorp).
- Washington Utilities and Transportation Commission, Docket ,UG-031885, November 2003 (Northwest Natural Gas Company.).
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- Texas PUC Docket No. 22622, June 15, 2001 (TXU Electric)
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ECONOMIC ANALYSIS AND TESTIMONY

Antitrust Litigation:

- Marginal Cost Analysis of Concrete Production/Predatory Pricing (Stiles)
- Analysis of Lost Business Opportunity due to denial of Waste Disposal Site Permit (Browning-Ferris Industries, Inc.).
- Analysis of Electric Power Transmission Costs in Purchased Power Dispute (City of College Station, Texas).

Contract Litigation:

- Analysis of Cogeneration Contract/Economic Viability Issues(Texas-New Mexico Power Company)
- Definition of Electric Sales/Franchise Fee Contract Dispute (Reliant Energy HL&P)
- Analysis of Purchased Power Agreement/Breach of Contract (Texas-New Mexico Power Company)
- Regulatory Commission Provisions in Franchise Fee Ordinance Dispute (Central Power & Light Company)
- Analysis of Economic Damages resulting from attempted Acquisition of Highway Construction Company (Dillingham Construction Corporation).
- Analysis of Economic Damages due to Contract Interference in Acquisition of Electric Utility Cooperative (PacifiCorp).
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Lender Liability/Securities Litigation:

- ERISA Valuation of Retail Drug Store Chain (Sommers Drug Stores Company).
- Analysis of Lost Business Opportunities in Failed Businesses where Lenders Refused to Extend or Foreclosed Loans (FirstCity Bank Texas, McAllen State Bank, General Electric Credit Corporation).
- Usury and Punitive Damages Analysis based on Property Valuation in Failed Real Estate Venture (Tomen America, Inc.).

Personal Injury/Wrongful Death/Lost Earnings Capacity Litigation:

- Analysis of Lost Earnings Capacity and Punitive Damages due to Industrial Accident (Worsham, Forsythe and Wooldridge).
- Analysis of Lost Earnings Capacity due to Improper Termination (Lloyd Gosselink, Ryan & Fowler).
- Present Value Analysis of Lost Earnings and Future Medical Costs due to Medical Malpractice (Sierra Medical Center).

Product Warranty/Liability Litigation:

- Analysis of Lost Profits due to Equipment Failure in Cogeneration Facility (WF Energy/Travelers Insurance Company).
- Analysis of Economic Damages due to Grain Elevator Explosion (Degesch Chemical Company).
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- Evaluation of Electric Utility Distribution System (Jasper-Newton Electric Cooperative).
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Docket No. UE-
Exhibit PPL/202
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Comparable Company Fundamental Characteristics

March 2010

PacifiCorp Oregon
Comparable Company Fundamental Characteristics

No.	Company	(1) % Regulated Revenue	(2) Credit Rating S&P	Credit Rating Moody's	(3) Capital Structure (2008) Common Equity Ratio	Long-Term Debt Ratio	Preferred Stock Ratio
1	ALLETE	88.9%	A-	A2	58.4%	41.6%	0.0%
2	Alliant Energy Co.	87.6%	A-	A2	58.6%	36.3%	5.1%
3	Black Hills Corp	74.6%	BBB	A3	67.7%	32.3%	0.0%
4	Con. Edison	84.0%	A-	A3	51.2%	48.8%	0.0%
5	DPL Inc.	100.0%	A	Aa3	41.1%	58.0%	0.9%
6	DTE Energy Co.	75.3%	A-	A2	43.6%	56.4%	0.0%
7	Duke Energy	76.6%	A	Baa2	61.3%	38.7%	0.0%
8	Edison Internat.	79.7%	A	A1	44.5%	51.2%	4.3%
9	Entergy Corp.	78.8%	A-	Baa1	40.2%	58.2%	1.6%
10	FPL Group, Inc.	71.0%	A	Aa2	45.8%	54.2%	0.0%
11	IDACORP	81.7%	A-	A3	52.4%	47.6%	0.0%
12	Northeast Utilities	98.6%	BBB+	A3	38.1%	60.4%	1.5%
13	NSTAR	95.5%	AA-	A1	42.8%	56.1%	1.1%
14	PG&E Corp.	100.0%	BBB+	A3	46.5%	52.2%	1.3%
15	Portland General	100.0%	A-	A3	53.8%	46.2%	0.0%
16	Progress Energy	99.9%	A-	A1	44.4%	55.1%	0.5%
17	Sempra Energy	74.1%	A+	Aa3	54.2%	44.5%	1.3%
18	Southern Co.	82.1%	A	A2	42.6%	53.9%	3.5%
19	Vectren Corp.	78.8%	A	A3	52.0%	48.0%	0.0%
20	Wisconsin Energy	99.9%	A-	A1	44.8%	54.8%	0.4%
21	Xcel Energy Inc.	99.3%	A	A2	47.1%	52.2%	0.7%
		85.6%	A/A-	A2	49.4%	49.5%	1.1%

Column Sources:
(1) Most recent company 10-Ks.
(2) AUS Utility Reports,Feb 2010.
(3) Value Line Investment Survey, Electric Utility (East), Nov 27, 2009; (Central), Dec 25, 2009 (West), Feb 5, 2010.

Docket No. UE-
Exhibit PPL/203
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Capital Market Data

March 2010

PacifiCorp Oregon
Historical Capital Market Costs

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Prime Rate	9.2%	6.9%	4.7%	4.1%	4.3%	6.2%	8.0%	8.1%	5.1%	3.3%
Consumer Price Index	3.4%	1.6%	2.5%	2.0%	3.3%	3.4%	2.5%	4.2%	-0.1%	2.8%
Long-Term Treasuries	5.9%	5.5%	5.4%	5.0%	5.1%	4.7%	5.0%	4.8%	4.3%	4.1%
Moody's Avg Utility Debt	8.1%	7.7%	7.5%	6.6%	6.2%	5.7%	6.1%	6.1%	6.7%	6.3%
Moody's A Utility Debt	8.2%	7.8%	7.4%	6.6%	6.2%	5.7%	6.1%	6.1%	6.5%	6.0%

SOURCES:
Prime Interest Rate - Federal Reserve Bank of St. Louis website
Consumer Price Index For All Urban Consumers: All Items (Seasonally Adjusted, December to December) - Federal Reserve Bank of St. Louis website
Long-Term Treasuries - Federal Reserve Bank of St. Louis website; 30-year Treasury bonds 1999-2001 and 2007-2009; 20-year Treasury bonds 2002-2006
Moody's Average Utility Debt - Moody's (Mergent) Bond Record
Moody's A Utility Debt - Moody's (Mergent) Bond Record

Exhibit PPL/203
Hadaway/1

PacifiCorp Oregon
Long-Term Interest Rate Trends

Month	Single-A Utility Rate	30-Year Treasury Rate	Single-A Utility Spread
Jan-08	6.02	4.33	1.69
Feb-08	6.21	4.52	1.69
Mar-08	6.21	4.39	1.82
Apr-08	6.29	4.44	1.85
May-08	6.28	4.60	1.68
Jun-08	6.38	4.69	1.69
Jul-08	6.40	4.57	1.83
Aug-08	6.37	4.50	1.87
Sep-08	6.49	4.27	2.22
Oct-08	7.56	4.17	3.39
Nov-08	7.60	4.00	3.60
Dec-08	6.52	2.87	3.65
Jan-09	6.39	3.13	3.26
Feb-09	6.30	3.59	2.71
Mar-09	6.42	3.64	2.78
Apr-09	6.48	3.76	2.72
May-09	6.49	4.23	2.26
Jun-09	6.20	4.52	1.68
Jul-09	5.97	4.41	1.56
Aug-09	5.71	4.37	1.34
Sep-09	5.53	4.19	1.34
Oct-09	5.55	4.19	1.36
Nov-09	5.64	4.31	1.33
Dec-09	5.79	4.49	1.30
Jan-10	5.77	4.60	1.17
3-Mo Avg	**5.73**	**4.47**	**1.27**
12-Mo Avg	**5.99**	**4.19**	**1.80**

Sources: Mergent Bond Record (Utility Rates); www.federalreserve.gov (Treasury Rates).

Three month average is for three months ending January 2010.

Twelve month average is for twelve months ending January 2010.

Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

			----- Annual % Change -----				---- 2009 ----			---- E2010 ----				E2011
2008	R2009	E2010	2008	R2009	E2010		2Q	R3Q	E4Q	1Q	2Q	3Q	4Q	1Q
						Gross Domestic Product								
$14,441.0	$14,243.0	$14,768.5	2.6	(1.4)	3.7	GDP (current dollars)	$14,151.2	$14,242.1	$14,400.8	$14,585.4	$14,703.5	$14,834.0	$14,951.0	$15,133.0
2.6	(1.4)	3.7	-	-	-	Annual rate of increase (%)	(0.8)	2.6	4.5	5.2	3.3	3.6	3.2	5.0
0.4	(2.5)	2.3	-	-	-	Annual rate of increase–real GDP (%)	(0.7)	2.2	3.9	2.6	1.9	1.9	2.1	3.3
2.1	1.2	1.3	-	-	-	Annual rate of increase–GDP deflator (%	(0.0)	0.4	0.7	2.6	1.3	1.6	1.0	1.6
						***Components of Real GDP**								
$9,291.0	$9,234.8	$9,390.9	(0.3)	(0.6)	1.7	Personal consumption expenditures	$9,189.0	$9,252.6	$9,288.2	$9,325.9	$9,357.3	$9,415.1	$9,465.3	$9,511.6
(0.3)	(0.6)	1.7	-	-	-	% change	(0.9)	2.8	1.5	1.6	1.4	2.5	2.2	2.0
1,146.3	1,099.9	1,142.5	(4.5)	(4.0)	3.9	Durable goods	1,071.7	1,122.7	1,118.0	1,121.7	1,124.4	1,151.2	1,172.7	1,192.4
2,057.3	2,037.2	2,073.8	(0.9)	(1.0)	1.8	Nondurable goods	2,025.7	2,033.3	2,054.2	2,065.8	2,070.8	2,077.3	2,081.4	2,085.2
6,083.1	6,088.5	6,169.4	0.7	0.1	1.3	Services	6,078.8	6,090.6	6,108.7	6,131.0	6,154.3	6,182.5	6,210.0	6,235.3
1,569.7	1,284.5	1,269.7	1.6	(18.2)	(1.1)	Nonresidental fixed investment	1,288.4	1,269.0	1,259.3	1,258.3	1,263.0	1,267.5	1,290.1	1,325.8
1.6	(18.2)	(1.1)	-	-	-	% change	(9.6)	(5.9)	(3.0)	(0.3)	1.5	1.4	7.3	11.6
1,068.6	883.8	949.2	(2.6)	(17.3)	7.4	Producers durable equipment	876.5	879.8	891.4	913.5	936.0	960.0	987.5	1,023.3
441.5	350.4	361.1	(23.2)	(20.6)	3.1	Residental fixed investment	335.5	350.5	356.6	347.9	358.0	365.4	373.0	396.2
(23.2)	(20.6)	3.1	-	-	-	% change	(23.6)	19.0	7.1	(9.4)	12.2	8.5	8.5	27.3
(25.9)	(118.5)	7.4	-	-	-	Net change in business inventories	(160.2)	(139.2)	(60.7)	(2.6)	9.5	9.7	12.7	29.6
2,518.1	2,566.6	2,614.3	3.1	1.9	1.9	Gov't purchases of goods & services	2,568.6	2,585.5	2,584.9	2,603.2	2,620.1	2,620.3	2,613.4	2,600.9
975.9	1,025.7	1,068.2	7.7	5.1	4.1	Federal	1,023.5	1,043.3	1,039.9	1,056.4	1,073.2	1,075.1	1,068.1	1,057.5
1,543.7	1,543.8	1,549.8	0.5	0.0	0.4	State & local	1,548.0	1,545.5	1,548.2	1,550.3	1,550.7	1,549.0	1,549.0	1,546.9
(494.3)	(354.0)	(375.9)	-	-	-	Net exports	(330.4)	(357.4)	(341.5)	(363.5)	(374.8)	(380.5)	(384.6)	(379.7)
1,629.2	1,468.2	1,605.3	5.4	(9.9)	9.3	Exports	1,419.5	1,478.8	1,540.1	1,573.6	1,598.4	1,614.6	1,634.8	1,664.1
2,123.5	1,822.2	1,981.2	(3.2)	(14.2)	8.7	Imports	1,749.8	1,836.2	1,881.6	1,937.2	1,973.2	1,995.1	2,019.4	2,043.8
						****Income & Profits**								
$12,239.0	$12,069.4	$12,495.1	2.9	(1.4)	3.5	Personal income	$12,048.8	$12,083.9	$12,192.2	$12,312.6	$12,436.6	$12,562.0	$12,669.3	$12,780.6
10,806.0	10,962.8	11,320.6	3.9	1.4	3.3	Disposable personal income	10,966.2	10,997.8	11,121.8	11,166.2	11,276.4	11,385.4	11,454.4	11,482.6
2.6	4.6	4.5	-	-	-	Savings rate (%)	5.4	4.5	4.7	4.2	4.7	4.6	4.3	3.7
1,462.7	1,410.1	1,629.9	(17.6)	(3.6)	15.6	Corporate profits before taxes	1,337.1	1,495.0	1,561.8	1,628.5	1,617.7	1,638.5	1,634.9	1,738.1
1,170.6	1,103.6	1,287.9	(11.5)	(5.7)	16.7	Corporate profits after taxes	1,031.1	1,173.9	1,233.1	1,279.1	1,276.7	1,297.1	1,298.7	1,282.4
14.80	48.17	58.70	(78.0)	225.5	21.9	‡Earnings per share (S&P 500)	7.43	12.49	48.17	55.86	57.20	57.29	58.70	60.58
						†Prices & Interest Rates								
3.8	(0.3)	2.2	-	-	-	Consumer price index	1.3	3.6	3.4	2.2	0.7	1.9	1.4	2.0
1.4	0.2	0.4	-	-	-	Treasury bills	0.2	0.2	0.1	0.1	0.2	0.4	0.8	1.3
3.7	3.3	4.2	-	-	-	10-yr notes	3.3	3.5	3.6	3.8	4.0	4.3	4.5	4.8
4.3	4.1	5.0	-	-	-	30-yr bonds	4.2	4.3	4.5	4.7	4.8	5.1	5.3	5.4
5.6	5.4	5.8	-	-	-	New issue rate–corporate bonds	5.5	5.3	5.5	5.5	5.7	6.0	6.2	6.4
						Other Key Indicators								
900.0	555.8	754.4	(32.9)	(38.3)	35.7	Housing starts (1,000 units SAAR)	540.0	586.7	569.1	649.4	717.8	784.4	865.9	988.3
13.2	10.3	11.2	(18.0)	(21.6)	8.1	Auto & truck sales (1,000,000 units)	9.6	11.5	10.9	10.4	10.7	11.5	12.1	12.7
5.8	9.3	10.3	-	-	-	Unemployment rate (%)	9.3	9.7	10.0	10.3	10.4	10.3	10.3	10.2
(4.4)	4.5	(3.6)	-	-	-	§U.S. dollar	(14.8)	(18.6)	(9.4)	8.2	4.9	(1.6)	(12.6)	(13.7)

Note: Annual changes are from prior year and quarterly changes are from prior quarter. Figures may not add to totals because of rounding. A–Advance data. P–Preliminary. E–Estimated. R–Revised.
*2005 Chain-weighted dollars. **Current dollars. ‡Trailing 4 quarters. †Average for period. §Quarterly % changes at quarterly rates. This forecast prepared by Standard & Poor's.

Docket No. UE-
Exhibit PPL/204
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

GDP Growth Rate Forecast

March 2010

PacifiCorp Oregon
GDP Growth Rate Forecast

	Nominal GDP	% Change	GDP Price Deflator	% Change	CPI	% Change
1949	265.2		14.4		23.6	
1950	313.3	18.1%	15.0	4.2%	25.0	5.8%
1951	347.9	11.0%	15.9	5.6%	26.5	6.0%
1952	371.4	6.8%	16.1	1.5%	26.7	0.9%
1953	375.9	1.2%	16.2	0.8%	26.9	0.6%
1954	389.4	3.6%	16.4	0.8%	26.8	-0.4%
1955	426.0	9.4%	16.8	2.6%	26.9	0.4%
1956	448.1	5.2%	17.3	3.3%	27.6	2.8%
1957	461.5	3.0%	17.8	2.7%	28.5	3.0%
1958	485.0	5.1%	18.3	2.5%	29.0	1.8%
1959	513.2	5.8%	18.4	0.9%	29.4	1.5%
1960	523.7	2.0%	18.7	1.4%	29.8	1.4%
1961	562.6	7.4%	18.9	1.1%	30.0	0.7%
1962	593.3	5.5%	19.1	1.3%	30.4	1.2%
1963	633.5	6.8%	19.4	1.4%	30.9	1.6%
1964	675.6	6.6%	19.7	1.5%	31.3	1.2%
1965	747.5	10.6%	20.1	2.0%	31.9	1.9%
1966	806.9	7.9%	20.8	3.5%	32.9	3.4%
1967	852.7	5.7%	21.4	3.1%	34.0	3.3%
1968	936.2	9.8%	22.4	4.6%	35.6	4.7%
1969	1004.5	7.3%	23.6	5.2%	37.7	5.9%
1970	1052.7	4.8%	24.7	5.0%	39.8	5.6%
1971	1151.4	9.4%	25.9	4.7%	41.1	3.3%
1972	1286.6	11.7%	27.1	4.5%	42.5	3.4%
1973	1431.8	11.3%	28.9	6.8%	46.3	8.9%
1974	1552.8	8.5%	32.0	10.7%	51.9	12.1%
1975	1713.9	10.4%	34.4	7.6%	55.6	7.1%
1976	1884.5	10.0%	36.3	5.4%	58.4	5.0%
1977	2110.8	12.0%	38.7	6.7%	62.3	6.7%
1978	2416.0	14.5%	41.5	7.3%	67.9	9.0%
1979	2659.4	10.1%	45.2	8.7%	76.9	13.3%
1980	2915.3	9.6%	49.6	9.7%	86.4	12.4%
1981	3194.7	9.6%	53.6	8.3%	94.1	8.9%
1982	3312.5	3.7%	56.4	5.2%	97.7	3.8%
1983	3688.1	11.3%	58.3	3.3%	101.4	3.8%
1984	4034.0	9.4%	60.4	3.6%	105.5	4.0%
1985	4318.7	7.1%	62.1	2.8%	109.5	3.8%
1986	4543.3	5.2%	63.5	2.3%	110.8	1.2%
1987	4883.1	7.5%	65.5	3.1%	115.6	4.3%
1988	5251.0	7.5%	67.9	3.7%	120.7	4.4%
1989	5581.7	6.3%	70.3	3.5%	126.3	4.6%
1990	5846.0	4.7%	73.2	4.2%	134.2	6.3%
1991	6092.5	4.2%	75.5	3.2%	138.2	3.0%
1992	6493.6	6.6%	77.1	2.2%	142.3	3.0%
1993	6813.8	4.9%	78.8	2.2%	146.3	2.8%
1994	7248.2	6.4%	80.5	2.1%	150.1	2.6%
1995	7542.5	4.1%	82.1	2.0%	153.9	2.5%
1996	8023.0	6.4%	83.6	1.8%	159.1	3.4%
1997	8505.7	6.0%	85.0	1.6%	161.8	1.7%
1998	9027.5	6.1%	85.9	1.1%	164.4	1.6%
1999	9607.7	6.4%	87.2	1.5%	168.8	2.7%
2000	10129.8	5.4%	89.4	2.5%	174.6	3.4%
2001	10373.1	2.4%	91.2	2.0%	177.4	1.6%
2002	10766.9	3.8%	92.8	1.8%	181.8	2.5%
2003	11416.5	6.0%	94.8	2.1%	185.5	2.0%
2004	12144.9	6.4%	97.9	3.2%	191.7	3.3%
2005	12915.6	6.3%	101.3	3.5%	198.3	3.4%
2006	13611.5	5.4%	104.2	2.9%	203.3	2.5%
2007	14337.9	5.3%	107.1	2.7%	211.7	4.2%
2008	14347.3	0.1%	109.2	2.0%	211.6	-0.1%
2009	14463.4	0.8%	109.9	0.7%	217.5	2.8%
10-Year Average		4.2%		2.3%		2.6%
20-Year Average		4.9%		2.3%		2.8%
30-Year Average		5.8%		3.0%		3.6%
40-Year Average		6.9%		4.0%		4.5%
50-Year Average		6.9%		3.7%		4.1%
60-Year Average		6.9%		3.5%		3.8%
Average of Periods		6.0%		3.1%		3.6%

Source: St. Louis Federal Reserve Bank, www.research.stlouisfed.org

Docket No. UE-
Exhibit PPL/205
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Discounted Cash Flow Analysis

March 2010

PacifiCorp Oregon
Discounted Cash Flow Analysis
Summary Of DCF Model Results

Company	Constant Growth DCF Model Analysts' Growth Rates	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model
1 ALLETE	9.4%	11.4%	10.9%
2 Alliant Energy Co.	9.2%	11.4%	11.5%
3 Black Hills Corp	12.5%	11.7%	11.2%
4 Con. Edison	8.8%	11.4%	10.7%
5 DPL Inc.	11.0%	10.3%	10.0%
6 DTE Energy Co.	10.4%	11.1%	11.1%
7 Duke Energy	10.1%	11.8%	11.5%
8 Edison Internat.	6.9%	9.7%	9.7%
9 Entergy Corp.	9.6%	9.8%	9.8%
10 FPL Group, Inc.	11.4%	9.9%	9.7%
11 IDACORP	8.7%	9.9%	9.8%
12 Northeast Utilities	12.5%	10.0%	9.9%
13 NSTAR	11.3%	10.7%	10.8%
14 PG&E Corp.	11.3%	10.2%	10.3%
15 Portland General	10.9%	11.3%	11.1%
16 Progress Energy	11.1%	12.3%	11.5%
17 Sempra Energy	9.7%	9.2%	9.3%
18 Southern Co.	11.1%	11.5%	11.2%
19 Vectren Corp.	12.0%	11.7%	11.3%
20 Wisconsin Energy	12.1%	9.3%	9.8%
21 Xcel Energy Inc.	11.3%	10.9%	10.5%
GROUP AVERAGE	10.5%	10.7%	10.5%
GROUP MEDIAN	11.0%	10.9%	10.7%

Source: Value Line Investment Survey, Electric Utility (East), Nov 27, 2009; (Central), Dec 25, 2009; (West), Feb 5, 2009.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Constant Growth DCF Model
Analysts' Growth Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				Analysts' Estimated Growth				
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	Value Line	Zacks	Thomson	Average Growth *(Cols 4-6)*	**ROE** K=Div Yld+G *(Cols 3+7)*
1 ALLETE	32.90	1.78	5.41%	NA	4.00%	4.00%	4.00%	9.4%
2 Alliant Energy Co.	29.46	1.60	5.43%	4.00%	3.00%	4.30%	3.77%	9.2%
3 Black Hills Corp	25.40	1.44	5.67%	8.50%	6.00%	6.00%	6.83%	12.5%
4 Con. Edison	43.70	2.38	5.45%	3.00%	3.60%	3.38%	3.33%	8.8%
5 DPL Inc.	27.40	1.18	4.31%	9.00%	4.00%	7.08%	6.69%	11.0%
6 DTE Energy Co.	41.52	2.12	5.11%	8.50%	4.50%	3.00%	5.33%	10.4%
7 Duke Energy	16.82	0.98	5.83%	5.00%	4.30%	3.60%	4.30%	10.1%
8 Edison Internat.	34.33	1.28	3.73%	3.50%	5.00%	1.03%	3.18%	6.9%
9 Entergy Corp.	79.84	3.00	3.76%	6.00%	4.70%	6.78%	5.83%	9.6%
10 FPL Group, Inc.	51.88	2.00	3.85%	8.00%	7.40%	7.32%	7.57%	11.4%
11 IDACORP	30.85	1.20	3.89%	4.50%	5.00%	5.00%	4.83%	8.7%
12 Northeast Utilities	24.86	1.00	4.02%	8.00%	8.90%	8.63%	8.51%	12.5%
13 NSTAR	34.35	1.63	4.74%	8.00%	6.00%	5.73%	6.58%	11.3%
14 PG&E Corp.	43.26	1.80	4.16%	6.50%	7.70%	7.33%	7.18%	11.3%
15 Portland General	19.88	1.05	5.28%	3.50%	6.70%	6.67%	5.62%	10.9%
16 Progress Energy	39.53	2.50	6.32%	6.00%	4.30%	3.98%	4.76%	11.1%
17 Sempra Energy	53.36	1.72	3.22%	5.50%	7.00%	7.00%	6.50%	9.7%
18 Southern Co.	32.58	1.80	5.53%	4.50%	7.60%	4.52%	5.54%	11.1%
19 Vectren Corp.	23.88	1.37	5.74%	5.00%	7.50%	6.30%	6.27%	12.0%
20 Wisconsin Energy	47.30	1.55	3.28%	8.00%	8.70%	9.90%	8.87%	12.1%
21 Xcel Energy Inc.	20.59	1.00	4.86%	6.50%	5.60%	7.28%	6.46%	11.3%
GROUP AVERAGE	35.89	1.64	4.74%	6.08%	5.79%	5.66%	5.81%	10.5%
GROUP MEDIAN			4.86%					11.0%

Source: Value Line Investment Survey, Electric Utility (East), Nov 27, 2009; (Central), Dec 25, 2009; (West), Feb 5, 2009.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Constant Growth DCF Model
Long-Term GDP Growth

	(9)	(10)	(11)	(12)	(13)
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	GDP Growth	**ROE** K=Div Yld+G *(Cols 11+12)*
1 ALLETE	32.90	1.78	5.41%	6.00%	11.4%
2 Alliant Energy Co.	29.46	1.60	5.43%	6.00%	11.4%
3 Black Hills Corp	25.40	1.44	5.67%	6.00%	11.7%
4 Con. Edison	43.70	2.38	5.45%	6.00%	11.4%
5 DPL Inc.	27.40	1.18	4.31%	6.00%	10.3%
6 DTE Energy Co.	41.52	2.12	5.11%	6.00%	11.1%
7 Duke Energy	16.82	0.98	5.83%	6.00%	11.8%
8 Edison Internat.	34.33	1.28	3.73%	6.00%	9.7%
9 Entergy Corp.	79.84	3.00	3.76%	6.00%	9.8%
10 FPL Group, Inc.	51.88	2.00	3.85%	6.00%	9.9%
11 IDACORP	30.85	1.20	3.89%	6.00%	9.9%
12 Northeast Utilities	24.86	1.00	4.02%	6.00%	10.0%
13 NSTAR	34.35	1.63	4.74%	6.00%	10.7%
14 PG&E Corp.	43.26	1.80	4.16%	6.00%	10.2%
15 Portland General	19.88	1.05	5.28%	6.00%	11.3%
16 Progress Energy	39.53	2.50	6.32%	6.00%	12.3%
17 Sempra Energy	53.36	1.72	3.22%	6.00%	9.2%
18 Southern Co.	32.58	1.80	5.53%	6.00%	11.5%
19 Vectren Corp.	23.88	1.37	5.74%	6.00%	11.7%
20 Wisconsin Energy	47.30	1.55	3.28%	6.00%	9.3%
21 Xcel Energy Inc.	20.59	1.00	4.86%	6.00%	10.9%
GROUP AVERAGE	35.89	1.64	4.74%	6.00%	10.7%
GROUP MEDIAN			4.86%		10.9%

Source: Value Line Investment Survey, Electric Utility (East), Nov 27, 2009; (Central), Dec 25, 2009; (West), Feb 5, 2009.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Low Near-Term Growth
Two-Stage Growth DCF Model

	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
				CASH FLOWS							
Company	Next Year's Div	2013 Div	Annual Change to 2013	Recent Price	Year 1 Div	Year 2 Div	Year 3 Div	Year 4 Div	Year 5 Div	Year 5-150 Div Growth	ROE=Internal Rate of Return *(Yrs 0-150)*
1 ALLETE	1.78	1.90	0.04	-32.90	1.78	1.82	1.86	1.90	2.01	6.00%	10.9%
2 Alliant Energy Co.	1.60	1.92	0.11	-29.46	1.60	1.71	1.81	1.92	2.04	6.00%	11.5%
3 Black Hills Corp	1.44	1.56	0.04	-25.40	1.44	1.48	1.52	1.56	1.65	6.00%	11.2%
4 Con. Edison	2.38	2.44	0.02	-43.70	2.38	2.40	2.42	2.44	2.59	6.00%	10.7%
5 DPL Inc.	1.18	1.30	0.04	-27.40	1.18	1.22	1.26	1.30	1.38	6.00%	10.0%
6 DTE Energy Co.	2.12	2.50	0.13	-41.52	2.12	2.25	2.37	2.50	2.65	6.00%	11.1%
7 Duke Energy	0.98	1.10	0.04	-16.82	0.98	1.02	1.06	1.10	1.17	6.00%	11.5%
8 Edison Internat.	1.28	1.50	0.07	-34.33	1.28	1.35	1.43	1.50	1.59	6.00%	9.7%
9 Entergy Corp.	3.00	3.60	0.20	-79.84	3.00	3.20	3.40	3.60	3.82	6.00%	9.8%
10 FPL Group, Inc.	2.00	2.30	0.10	-51.88	2.00	2.10	2.20	2.30	2.44	6.00%	9.7%
11 IDACORP	1.20	1.40	0.07	-30.85	1.20	1.27	1.33	1.40	1.48	6.00%	9.8%
12 Northeast Utilities	1.00	1.15	0.05	-24.86	1.00	1.05	1.10	1.15	1.22	6.00%	9.9%
13 NSTAR	1.63	1.95	0.11	-34.35	1.63	1.74	1.84	1.95	2.07	6.00%	10.8%
14 PG&E Corp.	1.80	2.20	0.13	-43.26	1.80	1.93	2.07	2.20	2.33	6.00%	10.3%
15 Portland General	1.05	1.20	0.05	-19.88	1.05	1.10	1.15	1.20	1.27	6.00%	11.1%
16 Progress Energy	2.50	2.56	0.02	-39.53	2.50	2.52	2.54	2.56	2.71	6.00%	11.5%
17 Sempra Energy	1.72	2.10	0.13	-53.36	1.72	1.85	1.97	2.10	2.23	6.00%	9.3%
18 Southern Co.	1.80	2.00	0.07	-32.58	1.80	1.87	1.93	2.00	2.12	6.00%	11.2%
19 Vectren Corp.	1.37	1.50	0.04	-23.88	1.37	1.41	1.46	1.50	1.59	6.00%	11.3%
20 Wisconsin Energy	1.55	2.15	0.20	-47.30	1.55	1.75	1.95	2.15	2.28	6.00%	9.8%
21 Xcel Energy Inc.	1.00	1.10	0.03	-20.59	1.00	1.03	1.07	1.10	1.17	6.00%	10.5%
GROUP AVERAGE											10.5%
GROUP MEDIAN											10.7%

Source: Value Line Investment Survey, Electric Utility (East), Nov 27, 2009; (Central), Dec 25, 2009; (West), Feb 5, 2009.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

PacifiCorp Oregon
Discounted Cash Flow Analysis
Column Descriptions

Column 1: Three-month Average Price per Share (Nov 2009-Jan 2010)

Column 2: Estimated 2010 Div per Share from Value Line

Column 3: Column 2 Divided by Column 1

Column 4: "Est'd 06-08 to 12-14" Earnings Growth Reported by Value Line

Column 5: "Next 5 Years" Company Growth Estimate as Reported by Zacks.com

Column 6: "Next 5 Years (per annum) Growth Estimate Reported by Thomson Financial Network (at Yahoo Finance)

Column 7: Average of Columns 4-6

Column 8: Column 3 Plus Column 7

Column 9: See Column 1

Column 10: See Column 2

Column 11: Column 10 Divided by Column 9

Column 12: Average of GDP Growth During the Last 10 year, 20 year, 30 year, 40 year, 50 year, and 60 year growth periods. See Exhibit PPL 204

Column 13: Column 11 Plus Column 12

Column 14: See Column 2

Column 15: Estimated 2013 Dividends per Share from Value Line

Column 16: (Column 15 Minus Column 14) Divided by Three

Column 17: See Column 1

Column 18: See Column 14

Column 19: Column 18 Plus Column 16

Column 20: Column 19 Plus Column 19

Column 21: Column 20 Plus Column 16

Column 22: Column 21 Increased by the Growth Rate Shown in Column 23

Column 23: See Column 12

Column 24: The Internal Rate of Return of the Cash Flows in Columns 17-22 along with the Dividends for the Years 6-150 Implied by the Growth Rates shown in Column 23

Docket No. UE-
Exhibit PPL/206
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Samuel C. Hadaway

Risk Premium Analysis

March 2010

PacifiCorp Oregon

Risk Premium Analysis

(Based on Projected Interest Rates)

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
2008	6.65%	10.46%	3.81%
2009	6.28%	10.48%	4.20%
AVERAGE	9.05%	12.28%	3.23%

<u>INDICATED COST OF EQUITY</u>

PROJECTED SINGLE-A UTILITY BOND YIELD*	6.27%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.05%
INTEREST RATE DIFFERENCE	-2.78%
INTEREST RATE CHANGE COEFFICIENT	-41.13%
ADUSTMENT TO AVG RISK PREMIUM	1.14%
BASIC RISK PREMIUM	3.23%
INTEREST RATE ADJUSTMENT	1.14%
EQUITY RISK PREMIUM	4.37%
PROJECTED SINGLE-A UTILITY BOND YIELD*	6.27%
INDICATED EQUITY RETURN	**10.64%**

(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Projected single-A bond yield is 127 basis points over projected long-term Treasury bond rate of 5.0% from Exhibit PPL 203, p. 3. The single-A spread is for 3 months ended Jan 2010 from Exhibit PPL 203, p. 2.

PacifiCorp Oregon

Risk Premium Analysis

(Based on Current Interest Rates)

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
2007	6.11%	10.36%	4.25%
2008	6.65%	10.46%	3.81%
2009	6.28%	10.48%	4.20%
AVERAGE	9.05%	12.28%	3.23%

INDICATED COST OF EQUITY

CURRENT SINGLE-A UTILITY BOND YIELD*	5.73%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.05%
INTEREST RATE DIFFERENCE	-3.32%
INTEREST RATE CHANGE COEFFICIENT	-41.13%
ADUSTMENT TO AVG RISK PREMIUM	1.37%
BASIC RISK PREMIUM	3.23%
INTEREST RATE ADJUSTMENT	1.37%
EQUITY RISK PREMIUM	4.59%
CURRENT SINGLE-A UTILITY BOND YIELD*	5.73%
INDICATED EQUITY RETURN	**10.32%**

(1) Moody's Investors Service

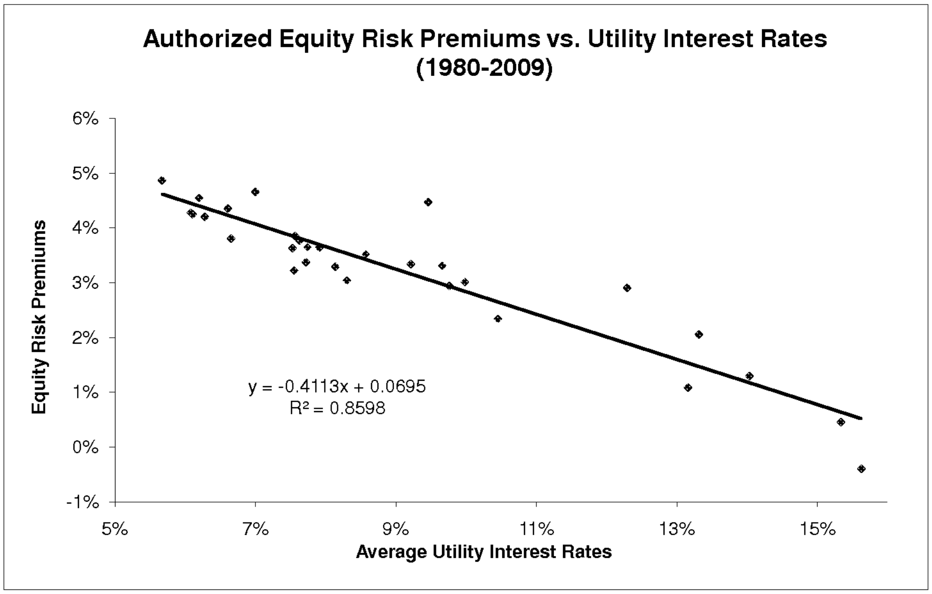
(2) Regulatory Focus, Regulatory Research Associates, Inc.

*Current single-A utility bond yield is three month average of Moody's Single-A Public Utility Bond Yield Average through Jan 2010 from Exhibit PPL 203, p. 2.

PacifiCorp Oregon

Risk Premium Analysis

Regression Analysis & Interest Rate Change Coefficient



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.927242552
R Square	0.85977875
Adjusted R Square	0.854770848
Standard Error	0.0047873
Observations	30

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.003934704	0.003934704	171.6844276	1.82118E-13
Residual	28	0.000641711	2.29182E-05		
Total	29	0.004576415			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.069475479	0.002972433	23.373272	6.55788E-20	0.063386727	0.075564232	0.063386727	0.075564232
X Variable 1	-0.411331263	0.031392526	-13.10284044	1.82118E-13	-0.475635937	-0.347026589	-0.475635937	-0.347026589

Docket No. UE-
Exhibit PPL/300
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Bruce N. Williams

March 2010

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

A. My name is Bruce N. Williams. My business address is 825 N.E. Multnomah, Suite 1900, Portland, Oregon 97232. My present position is Vice President and Treasurer.

Qualifications

Q. Please describe your education and business experience.

A. I received a Bachelor of Science degree in Business Administration with a concentration in finance from Oregon State University in June 1980. I also received the Chartered Financial Analyst designation upon passing the examination in September 1986. I have been employed by the Company for 24 years. My business experience has included financing of the Company's electric operations and non-utility activities, responsibility for the investment management of the Company's qualified and non-qualified retirement plan assets, and investor relations.

Q. Please describe your present duties.

A. I am responsible for the Company's treasury, credit risk management, pension and other investment management activities. I am also responsible for the preparation of PacifiCorp's embedded cost of debt and preferred equity and any associated testimony related to capital structure for regulatory filings in all of PacifiCorp's state and federal jurisdictions.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. I first present a financing overview of the Company. Next, I discuss the planned amounts of common equity, debt, and preferred stock included in the Company's proposed capital structure. I then analyze the embedded cost of debt and preferred stock supporting PacifiCorp's electric operations in the state of Oregon as of January 1, 2011. This analysis includes the use of forward interest rates, the historical relationship of security trading patterns, and known and measurable changes to the debt and preferred stock portfolios.

Q. What time period do your analyses cover?

A. The test period in this proceeding is the 12-months ending December 31, 2011, with new rates expected to be effective on January 1, 2011. To appropriately match the Company's costs with customers' prices, the capital structure and costs of debt and preferred stock applied in this case are measured on December 31, 2010, just prior to the effective date of the new rates. I determined the embedded cost of debt and preferred stock using the Company's actual costs adjusted for changes through December 31, 2010, as I later detail in this testimony.

Q. What is the overall cost of capital that you are proposing in this proceeding?

A. The Company is proposing an overall cost of capital of 8.38 percent. This cost includes the return on equity proposed by Company witness Mr. Richard P. Reiten and the following capital structure and costs:

Overall Cost of Capital

Component	$ (millions)	Percentage of Total	Cost	Weighted Average
Long Term Debt	$6,358	46.4%	5.85%	2.71%
Preferred Stock	41	0.3%	5.41%	0.02%
Common Stock Equity	7,312	53.3%	10.60%	5.65%
Total	13,711	100.0%		8.38%

Financing Overview

Q. Please explain the Company's requirements to generate new capital.

A. As described in Mr. Reiten's testimony, the Company is in the process of completing or adding significant new generation and transmission facilities as well as local distribution facilities. The test period in this case shows that the Company is expecting to add approximately $3 billion in total-company capital additions from June 2009 actual levels to the rate effective period. These and future capital additions will require the Company to raise funds by issuing significant amounts of new long-term debt in the capital markets, retaining earnings and obtaining new capital contributions from its parent company, MidAmerican Energy Holdings Company ("MEHC"). Since the acquisition of PacifiCorp by MEHC in March 2006, PacifiCorp has not paid common stock dividends or distributions to MEHC and has retained $1.6 billion of earnings. Additionally, MEHC has made $990 million in cash equity contributions to PacifiCorp. These figures are expected to increase as PacifiCorp continues to retain earnings and MEHC makes additional equity contributions to PacifiCorp in 2010. These actions have been critical to PacifiCorp's credit quality and its ability to support the additional investments required in the Company's service territory.

Q. How does the Company finance its electric utility operations?

A. The Company finances its regulated utility operations utilizing roughly a 50/50 percent mix of debt and common equity capital. Immediately prior to and during periods of significant capital expenditures, the Company may need to allow the common equity component of the capital structure to increase. This provides more flexibility regarding the type and timing of debt financing, better access to the capital markets, a more competitive cost of debt, and over the long-run, more stable credit ratings; all of which assist in financing such expenditures. In addition, all else being equal, the Company will need to have a greater common equity component to offset various adjustments that rating agencies make to the debt component of the Company's published financial statements. I will discuss these adjustments in greater detail later in this testimony.

Q. What type of debt and preferred equity securities does the Company employ in meeting its financing requirements?

A. The Company relies on a mix of first mortgage bonds, other secured debt, tax-exempt debt, and preferred stock to help meet its long-term financing requirements. These securities employ various maturities in order to provide flexibility and mitigate refinancing risks. The Company has completed the majority of its long-term financing utilizing secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit PPL/301 shows that, as of December 31, 2010, the Company is projected to have an average of approximately $5.6 billion of first mortgage bonds outstanding, with an average cost of 6.24 percent. Presently, all outstanding first mortgage bonds bear interest at fixed rates. Proceeds from the issuance of the first mortgage bonds (and other financing instruments) are used to finance the combined utility operation.

Another important source of financing has been the tax-exempt financing associated with certain qualifying equipment at power generation plants. Under arrangements with local counties and other tax-exempt entities, these entities issue securities, the Company borrows the proceeds of these issuances and pledges its credit quality to repay the debt in order to take advantage of the tax-exempt status of the financings. As of December 31, 2010, PacifiCorp's tax-exempt portfolio is projected to be $738 million in principal with an average cost of 2.83 percent, including the cost of issuance and credit enhancement.

Capital Structure

Q. How did the Company determine the capital structure proposed in this proceeding?

A. The capital structure is based on the actual capital structure at December 31, 2009, adjusted for known and measurable changes through December 31, 2010, including maturities of certain debt issuances that were outstanding at December 31, 2009, capital contributions from MEHC, and the retention of earnings. PacifiCorp does not expect to issue new long-term debt in 2010. The net result of the adjustments is a capital structure consisting of 53.3 percent common equity, 46.4 percent debt and 0.3 percent preferred stock. This is the same methodology that was used in the Company's most recent Oregon general rate case in Docket UE 210 ("UE 210").

Q. How does this capital structure compare to the capital structure that was originally filed in UE 210?

A. As shown in the table below, the proposed capital structure in this case has a slightly higher common equity component. That capital structure filed in UE 210 reflected an increase in the debt percentage resulting from a $1 billion long-term debt issuance in January 2009. To maintain financial ratios that meet rating agency targets, the Company has added and will continue to add equity to the capital structure in 2009 and 2010.

Comparison of Capital Structures		
	UE 210	2010 General Rate Case
Long-Term Debt	48.5%	46.4%
Preferred Stock	0.3%	0.3%
Common Equity	51.2%	53.3%
Totals	100.0%	100.0%

Q. How does the Company determine the amount of common equity, debt and preferred stock to be included in its capital structure?

A. As a regulated utility, the Company has a duty and an obligation to provide safe, adequate and reliable service to customers in its Oregon service territory while prudently balancing cost and risk. Significant capital expenditures for new plant investment, including new transmission, renewable resources and environmental investments on existing generation units and operating and maintenance costs for new and existing utility plant assets are required to fulfill this obligation.

Through its planning process, the Company determined the amounts of necessary new financing needed to support these activities and calculated the required equity and debt ratios necessary to maintain continued access to the financial markets.

Q. Has the Company's common equity balance increased following the acquisition by MEHC?

A. Yes. As noted above, following the acquisition by MEHC, the Company has added nearly $3 billion in equity to its balance sheet in retained earnings and cash contributions from MEHC. In 2010, the Company expects to receive additional cash capital contributions from MEHC and will continue to retain all earnings.

Q. Why is there a need for additional equity in the proposed capital structure?

A. PacifiCorp's need for extensive capital expenditures was discussed during the MEHC acquisition. The Company is continuing to follow through on those capital expenditure requirements and the capital structure reflects the significant new capital investments described in this case. These new costs, coupled with the credit rating agencies' expectations for credit metrics and balance sheet strength, mean the Company cannot finance itself solely with new debt. Additional equity is required along with improved business results and other considerations to support PacifiCorp's current senior secured 'A' credit rating from Standard & Poor's ("S&P"), 'A2' rating from Moody's Investors Service ("Moody's"), and 'A-' from Fitch Ratings.

Q. Please describe the changes to the amount of outstanding long-term debt.

A. Based upon the long-term debt series outstanding at December 31, 2009, I have calculated the reduction to the outstanding balances for maturities and principal amortization which are scheduled to occur during the period ending

December 31, 2010. The total long-term debt maturities and principal amortized over this period is $14.6 million. I adjusted the interest rate on the $586.7 million of long-term debt that will mature during 2011 to reflect expected refinancing rates. This adjustment is consistent with the Commission practice set forth in Order No. 01-787 and was also followed in UE 210.

Q. Is the proposed capital structure consistent with the Company's current credit rating?

A. Yes. This capital structure is intended to enable the Company to deliver its required capital expenditures while maintaining credit ratios that are expected to support the continuance of PacifiCorp's current credit ratings.

Q. Are PacifiCorp's stand-alone credit metrics consistent with the Company's current credit ratings?

A. No. As stated by S&P "[while] the.... utility's credit metrics are more consistent on a stand-alone basis with a 'BBB' category rating, the ratings benefit from the implicit and explicit support available to MEHC... from its parent, Berkshire Hathaway... As a result, the ratings assigned to PacifiCorp are higher than would be warranted..."[1] Clearly, PacifiCorp and its customers benefit from the ownership by MEHC and its parent, Berkshire Hathaway. Another important element supporting the Company's current ratings is the rating agencies' expectations that PacifiCorp will receive supportive regulatory treatment including reasonable outcomes in rate proceedings. Absent ownership by MEHC and constructive regulatory treatment, PacifiCorp's credit ratings would likely suffer at least a one rating-level downgrade.

[1] Standard & Poor's Ratings Direct November 24, 2008.

Maintaining the existing ratings however, is becoming more challenging due to the additional adjustments that rating agencies are making to PacifiCorp's published financial results. I will discuss these adjustments in more detail later in this testimony.

Q. How does maintenance of the Company's current credit rating benefit customers?

A. The credit rating of a utility has a direct impact on the price that a utility pays to attract the capital necessary to support its current and future operating needs. A solid credit rating directly benefits customers by reducing immediate and future borrowing costs related to the financing needed to support regulatory obligations.

Q. Are there other benefits?

A. Yes. During periods of capital market disruptions, higher-rated companies are more likely to have ongoing, uninterrupted access to capital and access at lower costs. This is not always the case with lower-rated companies, which find themselves either unable to secure capital or able to secure capital only on unfavorable terms and conditions during such periods.

In addition, higher-rated companies have greater access to the long-term markets for power purchases and sales. Such access provides these companies with more alternatives when attempting to meet the current and future load requirements of their customers.

Finally, a company with strong ratings will often avoid having to meet costly collateral requirements that are typically imposed on lower-rated companies when securing power in the markets.

Q. Did S&P and Moody's change the Company's credit ratings in 2009?

A. Yes. S&P upgraded PacifiCorp's senior secured debt to 'A' while it downgraded PacifiCorp's short-term debt rating to 'A-2'. Similarly, Moody's recently upgraded PacifiCorp's senior secured debt to 'A2'.

Q. Please explain these rating changes.

A. The upgrade to PacifiCorp's senior secured debt merely reflects a change in S&P's methodology rather than a change in PacifiCorp's credit quality or financial metrics. S&P changed its approach to estimating the amount of collateral available to senior secured debt holders in the event of a default by PacifiCorp on its first mortgage bonds.

S&P continues to be cautious about PacifiCorp's credit metrics and, as noted previously, views the Company's credit metrics on a stand-alone basis as more consistent with a 'BBB' rating. Indeed, in downgrading the Company's short-term debt rating, S&P cited a need to take a firmer view on linking PacifiCorp short-term ratings to stand-alone credit quality. S&P sustained their current 'A-' corporate credit rating based on their expectation "that management will achieve cash flow metrics more consistent with an 'A' rating over the next several years."[2]

Moody's upgrade of PacifiCorp's senior debt was part of an industry-wide action in which the majority of senior secured debt ratings of investment-grade regulated utilities were upgraded by one level. The action was a result of an analysis of the history of regulated utility defaults and was not specific or unique to the Company.

[2] Standard & Poor's Ratings Direct April 1, 2009, and reiterated in the Ratings Direct of February 17, 2010.

Q. Do these rating agency actions change the Company's need to add equity to its capital structure and improve its financial metrics?

A. No. Without continued improvement in financial metrics along with supportive state regulatory outcomes in rate cases, the ratings direction is likely to be lower rather than higher for PacifiCorp.

Q. Does S&P's most recent credit report on PacifiCorp underline S&P's expectation that PacifiCorp improve its financial metrics in order to maintain its current credit rating?

A. Yes. S&P made several references to the need for PacifiCorp to improve its stand-alone financial metrics, noting that PacifiCorp had a "significant" financial risk profile that reflects a large capital program and the need to shore up cash flow metrics." S&P also stated that "Given the recent turmoil in both liquidity and the capital markets, we have taken a firmer view on the need to link the short-term ratings on PacifiCorp to its stand-alone credit quality, which supports an 'A-2' short-term rating." Exhibit PPL/302 is the February 17, 2010 S+P's Ratings Direct publication. S&P also reiterated its credit views including that "supportive rate case outcomes remain key to maintaining and improving financial performance."

Purchase Power Agreements

Q. Is the Company subject to rating agency debt imputation associated with Purchase Power Agreements?

A. Yes. Rating agencies and financial analysts consider purchase power agreements ("PPAs") to be debt-like and will impute debt and related interest when calculating financial ratios. For example, S&P will adjust the Company's published financial results and impute debt balances and interest expense resulting from PPAs when assessing creditworthiness. It does so in order to obtain a more accurate assessment of a company's financial commitments and fixed payments. Exhibit PPL/303 is the May 7, 2007, publication by S&P detailing its view of the debt aspects of PPAs.

Q. How does this impact the Company?

A. In the February 17, 2010 Ratings Direct report cited above, S&P evaluated the Company's PPAs and other related long-term commitments. Approximately $425 million of additional debt and related interest expense of $27 million were added to the Company's debt and coverage tests solely as a result of PPAs. There were also other adjustments made by S&P that resulted in an imputation into PacifiCorp's credit ratios of approximately $1 billion of debt and $73 million of interest in total. These adjustments are detailed by S&P in their April 1, 2009 Ratings Direct report (Exhibit PPL/304).

Q. How would the inclusion of this PPA-related debt and these other adjustments affect the Company's capital structure as S&P reviews credit metrics?

A. Negatively. By including the imputed debt resulting from PPAs and these other adjustments, the Company's capital structure has a lower equity component as a corollary to the higher debt component, lower coverage ratios and reduced financial flexibility than what might otherwise appear to be the case from a review of the book value capital structure. For example, if one were to add the $1 billion of debt adjustments that S&P makes to the Company's capital structure in this case, the resulting common equity percentage would decline from 53.3 percent to 49.6 percent. The table below shows the proposed capital structure and how the S&P adjustments impact the components.

Illustration of Rating Agency Adjustments to PacifiCorp's Capital Structure ($ in millions)			
	Book Values / Ratios	Rating Agency Adjustments	Adjusted Book Values / Ratios
Long-Term Debt	$6,358 / 46.4%	$1,034	$7,392 / 50.1%
Preferred Stock	41 / 0.3%	0	41 / 0.3%
Common Equity	7,312 / 53.3%	0	7,312 / 49.6%
Totals	$13,711 / 100.0%		$14,745 / 100.0%

Financing Cost Calculations

Q. How did you calculate the Company's costs of long-term debt and preferred stock?

A. I calculated the embedded costs of debt and preferred stock using the methodology relied upon in the Company's previous rate cases in Oregon and other jurisdictions.

Q. Please explain the cost of long-term debt calculation.

A. I calculated the cost of debt by issue, based on each debt series' interest rate and net proceeds at the issuance date, to produce a bond yield to maturity for each series of debt. It should be noted that in the event a bond was issued to refinance a higher-cost bond, the pre-tax premium and unamortized costs, if any, associated with the refinancing were subtracted from the net proceeds of the bonds that were issued. Each bond yield was then multiplied by the principal amount outstanding of each debt issue, resulting in an annualized cost of each debt issue. Aggregating the annual cost of each debt issue produces the total annualized cost of debt. Dividing the total annualized cost of debt by the total principal amount of debt outstanding produces the weighted average cost for all debt issues. This is the Company's embedded cost of long-term debt.

Q. How did you calculate the embedded cost of preferred stock?

A. I calculated the embedded cost of preferred stock by first determining the cost of money for each issue. This is the result of dividing the annual dividend rate by the per share net proceeds for each series of preferred stock. The cost associated with each series was then multiplied by the total par or stated value outstanding for each issue to yield the annualized cost for each issue. The sum of annualized costs for each issue produces the total annual cost for the entire preferred stock portfolio. I then divided the total annual cost by the total amount of preferred stock outstanding to produce the weighted average cost for all issues. This is the Company's embedded cost of preferred stock.

Q. A portion of the securities in the Company's debt portfolio bears variable rates. What is the basis for the projected interest rates used by the Company?

A. The Company's variable rate long-term debt in this case is in the form of tax-exempt debt. Exhibit PPL/305 shows that these securities on average had been trading at approximately 91 percent of the 30-day London Inter Bank Offer Rate ("LIBOR") for the period January 2000 through December 2009. Therefore, the Company has applied a factor of 91 percent to the forward 30-day LIBOR rates at December 31, 2010 and then added the respective credit enhancement and remarketing fees for each floating rate tax-exempt bond. Credit enhancement and remarketing fees are included in the interest component because these are costs which contribute directly to the interest rate on the securities and are charged to interest expense. This method is consistent with the Company's past practices when determining the cost of debt in previous Oregon general rate cases as well as in the other states in which PacifiCorp operates.

Embedded Cost of Long-Term Debt

Q. What is the Company's embedded cost of long-term debt?

A. The cost of long-term debt is 5.85 percent measured as of December 31, 2010, as shown in Exhibit PPL/301.

Embedded Cost of Preferred Stock

Q. What is the Company's embedded cost of preferred stock?

A. The cost of preferred stock is 5.41 percent measured as of December 31, 2010, as shown in Exhibit PPL/306.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Docket No. UE-
Exhibit PPL/301
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Embedded Cost of Long Term Debt

March 2010

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
December 31, 2010

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YTM	LINE NO.
1											1
2	**Total First Mortgage Bonds**	**$5,619,371,000**	**($59,235,585)**	**($31,766,993)**	**$5,528,368,423**	**$350,850,404**	**6.092%**	**6.244%**	**25.5**	**20.8**	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$13,420,433	3.049%	3.351%	28.0	10.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$7,477,886	2.035%	2.213%	27.8	7.2	5
6	**Total Pollution Control Revenue Bonds**	**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**	**$20,898,319**	**2.585%**	**2.830%**	**27.9**	**9.0**	6
7											7
8	**Total Cost of Long Term Debt**	**$6,357,741,000**	**($74,090,626)**	**($48,938,416)**	**$6,234,711,958**	**$371,748,723**	**5.685%**	**5.847%**	**25.8**	**19.4**	8
9											9

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
December 31, 2010

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT: ORIGINAL ISSUE	PRINCIPAL AMOUNT: CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY: TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY: PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1															1
2		**First Mortgage Bonds**													2
3	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	20	2	$19,772,000	$1,867,000	$0	$0	$1,867,000	$100.000	8.492%	$158,546	3
4	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	21	2	$16,203,000	$2,949,000	$0	$0	$2,949,000	$100.000	8.796%	$259,394	4
5	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	22	3	$28,218,000	$7,259,000	$0	$0	$7,259,000	$100.000	8.733%	$633,928	5
6	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	22	3	$46,946,000	$14,882,000	$0	$0	$14,882,000	$100.000	8.293%	$1,234,164	6
7	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	23	4	$18,750,000	$7,202,000	$0	$0	$7,202,000	$100.000	8.634%	$621,821	7
8	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	23	4	$19,609,000	$8,526,000	$0	$0	$8,526,000	$100.000	8.469%	$722,067	8
9	**8.505%**	**Subtotal - Amortizing FMBs**			**22**	**3**		**$42,685,000**	**$0**	**$0**	**$42,685,000**		**8.504%**	**$3,629,920**	9
10															10
11	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	3	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.960%	$11,920,000	11
12	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	4	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	12
13	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	21	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	13
14	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	24	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	14
15	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	24	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	15
16	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	26	$350,000,000	$350,000,000	($4,048,881)	$0	$345,951,119	$98.843	6.185%	$21,647,500	16
17	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	26	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	17
18	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	27	$600,000,000	$600,000,000	($5,877,281)	$0	$594,122,719	$99.020	6.323%	$37,938,000	18
19	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	8	$500,000,000	$500,000,000	($3,971,596)	$0	$496,028,404	$99.206	5.756%	$28,780,000	19
20	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	28	$300,000,000	$300,000,000	($3,960,958)	$0	$296,039,042	$98.680	6.450%	$19,350,000	20
21	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	8	$350,000,000	$350,000,000	($4,802,369)	$0	$345,197,631	$98.628	5.681%	$19,883,500	21
22	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	28	$650,000,000	$650,000,000	($12,298,685)	$0	$637,701,315	$98.108	6.139%	$39,903,500	22
23	6.050%	Pro Forma Series	12/31/10	12/31/40	30	30	$586,686,000	$586,686,000	($5,866,860)	$0	$580,819,140	$99.000	6.123%	$35,922,784	23
24	**5.954%**	**Subtotal - Bullet FMBs**			**25**	**22**		**$5,136,686,000**	**($55,572,566)**	**($7,263,815)**	**$5,073,849,620**		**6.066%**	**$311,583,284**	24
25															25
26	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	1	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	26
27	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	1	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	27
28	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	1	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.924%	$297,720	28
29	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	11	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	29
30	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	11	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	30
31	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	11	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	31
32	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	11	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	32
33	**8.394%**	**Subtotal - Series C MTNs**			**28**	**9**		**$35,000,000**	**($261,330)**	**($4,792,483)**	**$29,946,187**		**9.938%**	**$3,478,360**	33
34															34
35	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	2	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	35
36	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	12	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	36
37	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	12	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	37
38	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	12	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	38
39	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	12	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	39
40	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	12	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	40
41	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	12	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	41
42	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	12	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	42
43	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	12	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	43
44	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	12	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	44
45	**8.100%**	**Subtotal - Series E MTNs**			**29**	**11**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	45
46															46
47	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	13	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	47
48	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	13	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	48
49	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	13	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	49
50	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	13	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	50
51	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	13	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	51
52	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	13	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	52
53	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	13	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	53

Exhibit PPL/301
Williams/2

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
December 31, 2010

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
54	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	13	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	54
55	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	13	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	55
56	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	13	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	56
57	**7.044%**	**Subtotal - Series F MTNs**			**30**	**13**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	57
58															58
59	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	15	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	59
60	**6.710%**	**Subtotal - Series G MTNs**			**30**	**15**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	60
61															61
62	**6.092%**	**Total First Mortgage Bonds**			**25**	**21**		**$5,619,371,000**	**($59,235,585)**	**($31,766,993)**	**$5,528,368,423**		**6.244%**	**$350,850,404**	62
63															63
64		**Pollution Control Revenue Bonds**													64
65	2.103%	Moffat 94 due May 2013	11/17/94	05/01/13	18	2	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	2.258%	$917,990	65
66	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	3	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.279%	$727,430	66
67	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	4	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	67
68	1.978%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	5	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	2.374%	$1,068,300	68
69	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	6	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.446%	$377,910	69
70	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	11	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.536%	$542,488	70
71	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	13	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.500%	$3,022,500	71
72	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	13	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.604%	$1,083,056	72
73	2.005%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	14	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	2.133%	$199,755	73
74	2.005%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	14	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	2.170%	$177,723	74
75	2.011%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	14	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	2.206%	$2,689,996	75
76	2.113%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	14	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	2.267%	$341,410	76
77	1.985%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	14	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	2.112%	$449,011	77
78	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	15	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	78
79	4.330%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	15	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.441%	$977,020	79
80	**3.049%**	**Subtotal - Secured PCRBs**			**28**	**11**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**3.351%**	**$13,420,433**	80
81															81
82	1.924%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	3	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	2.133%	$245,295	82
83	1.924%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	5	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	2.031%	$1,421,700	83
84	1.925%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	5	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	2.341%	$1,053,450	84
85	1.952%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	6	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	2.072%	$1,036,000	85
86	1.924%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	7	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	2.063%	$928,350	86
87	1.924%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	7	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	2.072%	$853,664	87
88	1.466%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	10	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	1.573%	$353,689	88
89	1.466%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	10	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	1.609%	$150,200	89
90	1.466%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	10	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	1.642%	$103,528	90
91	1.922%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	15	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	2.042%	$498,248	91
92	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	20	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.578%	$833,762	92
93	**2.035%**	**Subtotal - Unsecured PCRBs**			**28**	**7**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**2.213%**	**$7,477,886**	93
94															94
95	**2.585%**	**Total PCRB Obligations**			**28**	**9**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**2.830%**	**$20,898,319**	95
96															96
97	**5.685%**	**Total Long-Term Debt**			**26**	**19**		**$6,357,741,000**	**($74,090,626)**	**($48,938,416)**	**$6,234,711,958**		**5.847%**	**$371,748,723**	97
98															98

Docket No. UE-
Exhibit PPL/302
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct – February 17, 2010

March 2010

STANDARD
&POOR'S

Exhibit PPL/302
Williams/1

Global Credit Portal
RatingsDirect®

February 17, 2010

Summary:
PacifiCorp

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

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Rationale

Outlook

Summary:
PacifiCorp

Credit Rating: A-/Stable/A-2

Rationale

The 'A-' corporate credit rating (CCR) on PacifiCorp reflects its "excellent" business risk profile, which is based on a diverse and growing service territory, and a "significant" financial risk profile that reflects a large capital program and the need to shore up cash flow metrics. PacifiCorp is owned by MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--). In turn, MEHC is privately held and majority owned by Berkshire Hathaway Inc. (AA+/Stable/A-1+). As of Sept. 30, 2009, Berkshire owned 89.5% of the voting common stock in MEHC, with the balance owned by an MEHC board member and the company's president and CEO, who also sits on the board. MEHC had approximately $19.5 billion of debt, and the utility had $6.4 billion long-term debt. Consolidated long-term debt at MEHC (which includes PacifiCorp's debt) was nearly $19.5 billion as of the same date.

MEHC's credit profile is supported by Berkshire, which has in place through February 2011 a $3.5 billion equity commitment agreement with MEHC by which MEHC can unilaterally call upon Berkshire to support either its debt repayment or the capital needs of its regulated subsidiaries, including PacifiCorp. Berkshire's liquidity position and financial flexibility remain very strong, in our view, despite its Feb. 4 one-notch downgrade to 'AA+' from 'AAA'. We view this agreement between PacifiCorp's parent and a 'AA+' rated entity as reducing the likelihood of a PacifiCorp default. Nevertheless, we expect the utility to have a stand-alone credit profile consistent with our 'A-' rating. We take this view because the utility cannot cause MEHC to make an equity contribution, either from MEHC or via Berkshire through an MEHC board request. Although MEHC would typically have strong incentives to support the utility by tapping the Berkshire contingent equity, we note that in a catastrophic utility event, we would expect MEHC to call on Berkshire for equity support only if doing so were in MEHC's economic interests.

PacifiCorp serves 1.7 million customers in portions of six Western states: Oregon, Washington, and California, where it operates as Pacific Power; and Utah, Wyoming, and Idaho, where it operates as Rocky Mountain Power. The company's two largest markets, Utah and Oregon, accounted for about 68% of the company's retail electric sales in 2008, with Wyoming and Washington at 24%, and Idaho and California the balance. Although the ring-fenced utility's credit metrics are more consistent on a stand-alone basis with the 'BBB' rating category, Standard & Poor's Ratings Services expects that management will achieve cash flow metrics more consistent with the 'A' rating category over the next several years. Supportive rate case outcomes remain key to maintaining and improving financial performance. When MEHC purchased PacifiCorp in 2006 from ScottishPower, the utility had consistently been unable to earn its authorized return on equity (ROE), which varies by jurisdiction but ranges from 10% to 10.6%. Management has focused on improving its returns, with some success. In 2008, our calculations suggest that the consolidated ROE for PacifiCorp was 8.3%. Regulatory lag remains an issue for the company, although state regulation permits the company to use forward test years for rate cases in Utah, Oregon, Wyoming, and California. (Idaho and Washington require historical test years.)

PacifiCorp has power and fuel cost adjusters in Idaho, Wyoming, and California that allow for the deferral of these costs for later collection. In Oregon, fuel and purchased power costs are updated in rates every January based on forecast power prices, but there is no true-up to reconcile these projected costs with actuals. In March 2009, PacifiCorp filed for an energy cost adjustment mechanism in Utah. The Utah commission ruled that the clause is in the public interest, and the structure of the mechanism is currently under consideration.

The company expects to spend $6.1 billion in 2009-2011, excluding non-cash allowance for funds used during construction, and capital expenditures for the first nine months of 2009 totaled $1.8 billion. The largest component of PacifiCorp's capital program is the construction of the Gateway transmission project, an estimated $6.1 billion, 2,000-mile transmission line connecting portions of Wyoming, Utah, Idaho, Oregon, and the southwestern U.S. The project is being completed in phases, with initial portions of new lines going into service as early as 2010 and completion scheduled for 2018. About 23% of the company's total capital budget over the next three years is devoted to transmission investment, of which Gateway is a component. In 2008, the Federal Energy Regulatory Commission awarded the company incentive rate treatment of 200 basis points for seven of the eight project segments.

Operating income has improved relative to 2008 due in large part to lower fuel costs and regulatory rate relief, which also resulted in higher gross margins per megawatt-hour sold for the 12 months ended Sept. 30, 2009. In that period, cash flow from operations received a boost from increased net income and the changes in regulatory assets and liabilities, as compared with year-end 2008. Approximately 30%-32% of PacifiCorp's total electric sales are to industrial customers. The company experienced an approximate 4% decline in retail sales for the first nine months of 2009.

Leverage as of Sept. 30, 2009, was 53.5%, up from 52.6% as of year-end 2008 and reflected approximately $863 million of new long-term borrowing in the first nine months of 2009, net of maturities. Equity investments from MEHC will remain key to maintaining balanced structure throughout the company's capital program. Debt to total capitalization reflects several adjustments we make, the largest of which include adding $424 million for power purchase obligations and $379 million for post-retirement obligations. We expect that PacifiCorp will not be in a position to make distributions to its parent while it executes its capital program, and that PacifiCorp's debt leverage will approach the 50% area in the next several years.

Cash flow metrics remain weak for the rating but are improving modestly. For the 12 months ended Sept. 30, 2009, funds from operations (FFO) to total debt was nearly 19% and FFO interest coverage was 4.3x, which are consistent with 2008 ratios. We would expect PacifiCorp to produce FFO interest coverage in the range of 4.0x-4.5x and FFO to total debt in the 20% area.

Short-term credit factors

The company's liquidity is strong. The 'A-2' short-term rating reflects our view that although a $3.5 billion contingent equity agreement between MEHC and Berkshire supports MEHC and its subsidiaries, the agreement is not a source of instantaneous liquidity. The agreement allows Berkshire up to 180 days to fund MEHC's request. Given the recent turmoil in both liquidity and the capital markets, we have taken a firmer view on the need to link the short-term ratings on PacifiCorp to its stand-alone credit quality, which supports an 'A-2' short-term rating. However, we note that although Berkshire contractually has up to six months to respond to an MEHC call for liquidity, it has strong economic incentives to do so.

PacifiCorp's cash and cash equivalents totaled $149 million as of Sept. 30, 2009. In addition, the company has $1.4 billion in unsecured revolving credit structured in two separate agreements: a $760 million line expiring July 2013 and a $635 million line extending through October 2012. As of Sept. 30, 2009, the company had no balances under the credit facilities and had letters of credit in place for $258 million, leaving $1.14 billion available under its revolving credit facilities. PacifiCorp's single largest exposure to any banks under its revolving facility as a percentage of total commitments is 15%, which is manageable. Regulators limit PacifiCorp to $1.5 billion in debt.

Outlook

The stable outlook for PacifiCorp incorporates our expectation that MEHC will continue to support the utility by contributing sufficient equity to ensure that the utility keeps fully adjusted debt to total capitalization over the next few years close to an adjusted 50%, and that FFO to total debt and FFO interest coverage will be 20% or better and in the range of 4.0x-4.5x, respectively. Given that PacifiCorp's financial risk profile is weak for the current ratings, we do not expect near-term upward ratings momentum. PacifiCorp's ring-fenced structure insulates it from some MEHC credit deterioration. Specifically, our criteria provide that the PacifiCorp CCR can be no more than three notches above the MEHC CCR. The company is comfortably within this range, so we see no significant prospects for the utility rating to fall as a result of adverse rating changes at MEHC, which also has a stable outlook. Upward ratings momentum is unlikely, given the need to improve credit ratios, which may be difficult to achieve due to the size of the company's capital program.

Docket No. UE-
Exhibit PPL/303
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Publication – May 7, 2007

March 2010

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Exhibit PPL/303
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May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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Docket No. UE-
Exhibit PPL/304
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct – April 1, 2009

March 2010

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STANDARD
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RATINGSDIRECT®

April 1, 2009

PacifiCorp

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PacifiCorp

Major Rating Factors

Corporate Credit Rating

A-/Stable/A-2

Strengths:

- Market and regulatory diversity afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief in the coming years to support a large capital program;
- The approval of a power cost adjuster in Wyoming (which is in place until April 2011), combined with the use of a forward mechanism to set base fuel and power costs in Oregon, as well as an existing mechanism in California have improved the company's exposure to fluctuations in natural gas and purchased power costs;
- The completion of 1,068 MW of new natural gas plants, along with wind farm investment, is reducing the company's reliance on purchased power; and
- A tentative resolution in the contentious Klamath hydro re-licensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, as is now envisioned.

Weaknesses:

- The absence of fuel and purchased power adjusters in Utah, Washington, and Idaho is material for the company given that these states together provide about 55% of revenues; near-term prospects for obtaining one appear limited in Washington and Utah. In October 2008, PacifiCorp filed for an adjuster in Idaho that is pending;
- Despite recent rate relief in nearly all states PacifiCorp serves, regulatory lag continues to allow only modest improvement in the company's financial profile; its returns on equity (ROE) remain under authorized levels and while leverage has improved since it was acquired by MidAmerican Energy Holdings Co. (MEHC) in 2006, cash flow metrics continue to be weak;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's planned capital investments, although the recessionary environment has caused some scaling back of some capital plans;
- Growth in the percentage of generation provided by natural gas costs mitigates some of the company's potential exposure to carbon regulation, but introduces greater potential for cost volatility, a credit consideration given that the company lacks power adjusters in three of the six states it serves.

Rationale

The 'A-' corporate credit rating (CCR) on PacifiCorp reflects its 'excellent' business profile, evidenced by a diverse and growing service territory, and an 'aggressive' financial profile that reflects a large capital program and the need to shore up its cash flow metrics. While the ring-fenced utility's credit metrics are more consistent on a standalone basis with a 'BBB' category rating, Standard & Poor's Ratings Services expects that management will achieve cash flow metrics more consistent with an 'A' category rating over the next several years. PacifiCorp is owned by parent MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--). In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AAA/Stable/A-1+), which at year-end had an 87.4% interest in MEHC on an undiluted basis. (MEHC's remaining common equity is owned by Walter Scott [10.9%] and two members of MEHC's executive management, Chairman of the Board David Sokol [0.7%] and President and Chief Executive Officer Greg Abel [1.0%]). MEHC has demonstrated a willingness to deploy equity to support the utility's large capital program, providing the utility with $865 million in equity contributions since it purchased the company in March 2006.

MEHC's credit profile is supported by Berkshire, which has in place through February 2011 a $3.5 billion equity commitment agreement between itself and MEHC in which MEHC can unilaterally call upon to support either its debt repayment or the capital needs of its regulated subsidiaries, including PacifiCorp. We view this agreement between PacifiCorp's parent and a 'AAA' rated entity to reduce the likelihood of a PacifiCorp default.

Nevertheless, we expect PacifiCorp to have a standalone credit profile consistent with its 'A-' rating. We take this view because the utility has no right to cause MEHC to make an equity contribution, either from MEHC or via Berkshire through an MEHC board request. While MEHC would typically have strong incentives to support the utility by tapping the Berkshire contingent equity, we would note that in a catastrophic utility event, MEHC would be expected to do so only if it were in the economic best interests of the parent. Such a scenario is remote and would require an unprecedented event such as what occurred during the western energy crisis, when regulators refused to allow utilities to recover power procurement costs.

PacifiCorp serves 1.7 million customers in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The company operates as Pacific Power in Oregon, Washington, and California, and as Rocky Mountain Power in Utah, Wyoming, and Idaho. The company's two largest markets, Utah and Oregon, comprised about 68% of the company's retail electric sales in 2008, with Wyoming and Washington at 24%, and the balance being sold to customers in Idaho and California. As of Dec. 31, 2008, the utility's long-term debt was $5.5 billion. Consolidated long-term debt at MEHC (which includes PacifiCorp's debt) was nearly $20 billion as of the same date.

Supportive rate case outcomes continue to be key to maintaining and improving upon the company's financial performance. When MEHC purchased PacifiCorp in 2006 from ScottishPower, the utility had consistently been unable to earn its authorized return on equity (ROE), which varies by jurisdiction but ranges from 10.0% to 10.6%. Management has focused on improving its returns, with some success. In 2008, our calculations suggest that the consolidated ROE for PaciCorp was 8.3%. Regulatory lag remains an issue for the company, although the company is permitted under state regulation to use forward test years for rate cases in Utah, Oregon, Wyoming, and California. (Idaho and Washington require historical test years.)

PacifiCorp has power and fuel cost adjusters in Wyoming and California that allow for the deferral of these costs for later collection. In Oregon, fuel and purchased power costs are updated in rates every January based on forecast power prices, but there is no true-up to reconcile these projected costs with actuals. The company has pending before the Idaho Public Utilities Commission a request to establish an energy cost adjustment mechanism to recover the difference between base power costs set in a general rate case and actual power costs incurred.

Recent rate case activity includes a settlement reached in Utah in the company's 2008 general rate case for $45.0 million, relative to the $57.4 million sought. The Utah Public Service Commission has not yet ruled on the proposed settlement. Retail rate adjustments have been proposed to take effect in early May. In Wyoming, the commission there recently approved the company's $18.0 million settlement over its 2008 general rate case, relative to the $28.8 million sought, with rates proposed to be effective in late May. In Idaho, the company received authorization to implement its $4.4 million rate case settlement, relative to the $5.9 million it sought. The company did not have a 2008 general rate case in Oregon, but is expected to file its 2009 general rate case in Oregon in the first half of this year. The company has submitted a 2009 general rate case request for $38.5 million in Washington, which is pending. Pro forma rate adjustments in California were made in January 2009 to address energy cost adjustments and attrition adjustments.

In September 2008 the company purchased for $308 million the Chehalis plant, a 520 MW combined-cycle plant that will now have to be authorized for recovery in current or future rate cases in all the states PacifiCorp serves but California. The investment will be part of the Washington and Oregon 2009 general rate cases and is part of pending cases in Wyoming and Utah, which has pre-approved the purchase. The company also brought online 382 MW of new wind generation in 2008. Nevertheless, the company's supply portfolio continues to be predominately coal, supplying about 65% of all requirements in 2008.

PacifiCorp completed $1.8 billion in capital expenditures in 2008, up from $1.5 billion spent in 2007. The company is projected to spend $6.1 billion in 2009 through 2011, excluding non-cash allowance for funds used during construction. The largest component of PacifiCorp's capital program is the construction of the Gateway transmission project, an estimated $6.1 billion, 2,000-mile transmission line connecting portions of Wyoming, Utah, Idaho, Oregon, and the southwestern U.S. The project is being completed in phases, with initial portions of new lines being placed in service as early as 2010 and a completion date scheduled for 2018. About 38% of the company's total capital budget over the next three years is devoted to transmission investment, of which Gateway is a component. In 2008, the Federal Energy Regulatory Commission awarded the company incentive rate treatment of 200 basis points for seven of the eight project segments.

High fuel prices impacted PacifiCorp's 2008 results, as did hydro conditions that were about 90% of normal, but nevertheless gross margins per megawatt hour sold remained roughly consistent relative to 2007, as did the company's earnings before interest and taxes. Operating income increased about 7% due in large part to retail revenues increases provided by regulatory rate relief and lower operations and maintenance expense. (Of the $198 million in increased revenues in 2008 relative to 2007, about $102 million was due to higher prices approved by regulators, with most of the balance attributable to customer growth.) Cash flow from operations was greatly boosted by deferred income taxes. For 2008, cash flows from operations rose $168 million to $992 million relative to 2007, but the majority of this was attributable to the deferred income taxes. As a result, the company was able to reflect a $308 million add-back to cash flows. Retail and wholesale sales were roughly flat in 2008 relative to 2007, and in late 2008 the company experienced declining sales volumes. Approximately 30%-32% of PacifiCorp's total electric sales are to industrial customers. As a result, we would expect sales contraction could be a drag on 2009 performance, as industrial sales are more sensitive to the business cycle than is residential electric consumption.

Year-end leverage for the company was 53% and reflects new long-term borrowing in 2008 of $800 million in July 2008, net of maturities, which resulted in total borrowing increasing about $469 million, including short-term balances. This was offset by $450 million of equity contribution from MEHC. These equity investments will be key to maintaining a balanced capital structure throughout the company's capital program. Debt to total capitalization reflects several adjustments we make, the largest of which include adding $424 million for power purchase obligations and $379 million for post-retirement obligations. We expect that PacifiCorp will not be in a position to make distributions to its parent while it is executing its capital program and that MEHC will manage PacifiCorp's debt leverage downward to the range of 50% in the next several years.

Cash flow metrics continue to be weak for the rating but are improving modestly. Funds from operations (FFO) to total debt was nearly 18% in 2008, up from 17% in 2007. FFO interest coverage was 4.0x, versus 3.5x over the same period. Going forward, we would expect PacifiCorp to produce FFO interest coverage in the range of 4.0x-4.5x and achieve FFO to total debt in the range of 20%.

Short-term credit factors

The company's liquidity position is strong. PacifiCorp's 'A-2' short-term rating considers our view that while MEHC and its subsidiaries are supported by a $3.5 billion contingent equity agreement between MEHC and Berkshire, the agreement is not a source of instantaneous liquidity. The agreement allows Berkshire up to 180 days to fund MEHC's request. Given the recent turmoil in both liquidity and capital markets, we have taken a firmer view on the need to link PacifiCorp's short-term ratings to its stand-alone credit quality, which supports an 'A-2' short-term rating. However, we would note that while Berkshire contractually has up to six months to respond to an MEHC call for liquidity, it has strong economic incentives to do so.

PacifiCorp's cash and cash equivalents totaled $59 million as of Dec. 31, 2008. In addition, the company has $1.395 billion in unsecured revolving credit structured in two separate agreements: an $800 million line expiring July 2013 and a $700 million line extending through the end of October 2012. The company had borrowed $85 million in short-term commercial paper at year-end and had letters of credit in place for $258 million, leaving $1.0 billion under its revolvers available. PacifiCorp's single largest exposure to any banks under its revolver as a percentage of total commitments is 15%, which is manageable. Regulators limit PacifiCorp to having no more than $1.5 billion in debt outstanding.

In September 2008, due to the significant reduction in its market liquidity, PacifiCorp acquired $216 million of its insured variable-rate pollution control bonds, which it is currently holding on its balance sheet. These bonds are a small component of the company's overall debt profile, and PacifiCorp can utilize its ample liquidity facility to continue to keep the obligations until market conditions support the company placing the debt back with investors.

Outlook

The stable outlook for PacifiCorp incorporates our expectation that MEHC will continue to support the utility by contributing equity sufficient to ensure that our fully adjusted debt to total capitalization is managed over the next few years to an adjusted level of closer to 50% and that FFO to total debt and interest coverage will be 20% or better and in the range of 4.0x-4.5x, respectively. Given that PacifiCorp's financial profile is weak for the current ratings, we do not anticipate near-term upward ratings momentum for the utility, which would require the company to sustain metrics above these levels. PacifiCorp's ring-fenced structure insulates it from some MEHC credit deterioration, to an extent. Specifically, our criteria provides that PaciCorp's CCR can be no more than three notches above the MEHC CCR. The company is currently comfortably within this range, and as a result we do not see significant prospects for the utility's rating to fall as a result of adverse rating changes at MEHC, which also enjoys a stable outlook.

Table 1

PacifiCorp -- Financial Summary*

Industry Sector: Integrated	--Fiscal year ended Dec. 31--		
	2008	**2007**	**2006**
Rating history	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)			
Revenues	4,498.0	4,258.0	4,154.1
Net income from cont. oper.	458.0	439.0	307.9
Funds from oper. (FFO)	1,190.1	994.8	927.6
Capital expenditures (capex)	1,757.0	1,496.4	1,375.0
Cash and investments	59.0	228.0	59.0
Debt	6,687.3	5,945.0	5,473.6
Preferred stock	41.0	41.0	41.3
Common equity	5,987.0	5,080.0	4,426.8
Total capital	12,674.3	11,025.0	9,900.4
Adjusted ratios			
EBIT interest coverage (x)	2.8	2.8	2.5
FFO interest coverage (x)	4.0	3.5	3.8
FFO/debt (%)	17.8	16.7	16.9
Discretionary cash flow/debt (%)	(10.6)	(10.4)	(10.7)
Net cash flow/capex (%)	67.6	66.3	66.1
Debt/total capital (%)	52.8	53.9	55.3
Return on common equity (%)	6.8	7.8	6.2
Common dividend payout ratio (un-adj.) (%)	--	--	5.2

*Fully adjusted (including postretirement obligations)

Table 2

PacifiCorp -- Peer Comparison*

Industry Sector: Integrated	--Average of past three fiscal years--		
	PacifiCorp	**Portland General Electric Co.**	**Pacific Gas & Electric Co.**
Rating as of March 31, 2009	A-/Stable/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2
(Mil. $)			
Revenues	4,303.4	1,669.3	12,827.1
Net income from cont. oper.	401.6	101.0	1,069.3
Funds from oper. (FFO)	1,037.5	310.7	2,530.0
Capital expenditures (capex)	1,542.8	402.5	2,969.9
Cash and investments	115.3	31.7	559.3
Debt	6,035.3	1,620.3	10,854.7
Preferred stock	41.1	-	258.0
Common equity	5,164.6	1,298.0	9,037.3
Total capital	11,199.9	2,918.3	19,892.0
Adjusted ratios			

Table 2

PacifiCorp -- Peer Comparison* (cont.)			
EBIT interest coverage (x)	2.7	2.3	2.8
FFO interest coverage (x)	3.8	3.7	3.5
FFO/debt (%)	17.2	19.2	23.3
Discretionary cash flow/debt (%)	(10.6)	(15.2)	(12.9)
Net cash flow/capex (%)	66.8	65.1	67.5
Debt/total capital (%)	53.9	55.5	54.6
Return on common equity (%)	7.0	6.2	11.4
Common dividend payout ratio (un-adj.) (%)	2.0	48.5	48.5

*Fully adjusted (including postretirement obligations)

Table 3

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

--Fiscal year ended Dec. 31, 2008--

PacifiCorp reported amounts

	Debt	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Capital expenditures
Reported	5,653.0	1,437.0	1,437.0	947.0	309.0	992.0	992.0	1,789.0
Standard & Poor's adjustments								
Operating leases	35.1	7.0	2.3	2.3	2.3	4.7	4.7	2.0
Postretirement benefit obligations	379.0	20.0	20.0	20.0	--	50.7	50.7	--
Accrued interest not included in reported debt	89.0	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	34.0	(34.0)	(34.0)	(34.0)
Power purchase agreements	424.0	53.8	53.8	26.9	26.9	26.9	26.9	--
Asset retirement obligations	107.3	10.0	10.0	10.0	10.0	7.8	7.8	--
Reclassification of nonoperating income (expenses)	--	--	--	58.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	142.0	--
Total adjustments	1,034.3	90.8	86.1	117.2	73.2	56.1	198.1	(32.0)
Standard & Poor's adjusted amounts								
	Debt	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Capital expenditures**
Adjusted	6,687.3	1,527.8	1,523.1	1,064.2	382.2	1,048.1	1,190.1	1,757.0

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of April 1, 2009)*	
PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB
Senior Secured (43 Issues)	A
Senior Secured (7 Issues)	A/Negative
Senior Secured (4 Issues)	AA-/Watch Dev
Senior Unsecured (1 Issue)	A-
Senior Unsecured (3 Issues)	A-/A-2
Senior Unsecured (2 Issues)	AA-/Watch Dev
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
06-Mar-2006	A-/Stable/A-2
25-May-2005	A-/Watch Neg/A-2
18-Aug-2004	A-/Stable/A-2
Related Entities	
CE Casecnan Water and Energy Co. Inc.	
Senior Secured (1 Issue)	BB-/Stable
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Watch Neg/A-2
Senior Unsecured (1 Issue)	A/Negative
CE Generation LLC	
Senior Secured (1 Issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 Issue)	BB/Stable
Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (9 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2
MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (7 Issues)	BBB+

Ratings Detail (As Of April 1, 2009)*(cont.)	
MidAmerican Funding LLC	
Senior Secured (2 Issues)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Watch Neg/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A/Negative
Northern Electric PLC	
Issuer Credit Rating	BBB+/Watch Neg/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (3 Issues)	BBB-/Stable
Utah Power & Light Co.	
Senior Secured (1 Issue)	AAA/Watch Neg
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Watch Neg/A-2
Senior Unsecured (1 Issue)	A-/Watch Neg
Senior Unsecured (1 Issue)	A/Negative
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Watch Neg/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Watch Neg/A-2
Senior Unsecured (1 Issue)	BBB+/Watch Neg

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Docket No. UE-
Exhibit PPL/305
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Indicative Forward Variable Rates

March 2010

Indicative Forward PCRB Variable Rates
For December 31, 2010

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%

Indicative Forward PCRB Variable Rates
For December 31, 2010

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%

Indicative Forward PCRB Variable Rates
For December 31, 2010

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08	2.47%	2.77%	112%
Jul-08	2.46%	4.12%	168%
Aug-08	2.47%	3.03%	123%
Sep-08	2.94%	4.57%	155%
Oct-08	3.87%	4.89%	126%
Nov-08	1.68%	2.34%	139%
Dec-08	1.01%	1.02%	101%
Jan-09	0.39%	0.70%	181%
Feb-09	0.46%	0.68%	147%
Mar-09	0.53%	0.66%	124%
Apr-09	0.45%	0.63%	140%
May-09	0.35%	0.53%	153%
Jun-09	0.32%	0.45%	143%
Jul-09	0.29%	0.41%	142%
Aug-09	0.27%	0.43%	158%
Sep-09	0.25%	0.40%	161%
Oct-09	0.24%	0.39%	159%
Nov-09	0.24%	0.37%	157%
Dec-09	0.23%	0.38%	165%
Average			91%

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
12/31/2010	1.50%	91%	1.36%

* Source: Bloomberg L.P. (1/13/10)

Docket No. UE-
Exhibit PPL/306
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Embedded Cost of Preferred Stock

March 2010

PACIFICORP
Electric Operations
Pro Forma Cost of Preferred Stock
December 31, 2010

Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	**5% Preferred Stock, $100 Par Value**	(a)	110.00%	5.000%	126,243	$12,624,300	($98,049)	$12,526,251	99.223%	5.039%	$636,156	1
2												2
3	**Serial Preferred, $100 Par Value**											3
4	4.52% Series	Oct-55	103.50%	4.520%	2,065	$206,500	($9,676)	$196,824	95.314%	4.742%	$9,793	4
5	7.00% Series	(b)	None	7.000%	18,046	$1,804,600	(c)	$1,804,600	100.000%	7.000%	$126,322	5
6	6.00% Series	(b)	None	6.000%	5,930	$593,000	(c)	$593,000	100.000%	6.000%	$35,580	6
7	5.00% Series	(b)	100.00%	5.000%	41,908	$4,190,800	(c)	$4,190,800	100.000%	5.000%	$209,540	7
8	5.40% Series	(b)	101.00%	5.400%	65,959	$6,595,900	(c)	$6,595,900	100.000%	5.400%	$356,179	8
9	4.72% Series	Aug-63	103.50%	4.720%	69,890	$6,989,000	($30,349)	$6,958,651	99.566%	4.741%	$331,320	9
10	4.56% Series	Feb-65	102.34%	4.560%	84,592	$8,459,200	($49,071)	$8,410,129	99.420%	4.587%	$387,990	10
11												11
12		May-95	(d)								$67,955	12
13		Oct-95	(e)								$84,019	13
14												14
15	**Total Cost of Preferred Stock**			**5.026%**	**414,633**	**$41,463,300**	**($187,146)**	**$41,276,155**		**5.414%**	**$2,244,853**	15
16												16
17												17
18	(a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company											18
19	and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.											19
20	(b) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.											20
21	(c) Original issue expense/premium has been fully amortized or expensed.											21
22	(d) Column 11 is the after-tax annual amortization of expenses related to the 8.375% QUIDS due 6/30/35 which were redeemed 11/20/00.											22
23	(e) Column 11 is the annual amortization of expenses related to the 8.55% QUIDS due 12/31/25 which were redeemed 11/20/00.											23
24												24

Exhibit PPL/400
John A. Cupparo

Docket No. UE-
Exhibit PPL/400
Witness: John A. Cupparo

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of John A. Cupparo

March 2010

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

A. My name is John A. Cupparo. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. My position is Vice President of Transmission.

Qualifications

Q. Please describe your education and business experience.

A. I hold a Bachelor of Science degree in Computer Information Systems from Colorado State University. My experience spans 24 years in the energy industry, including oil, gas and electric utilities. The majority of my experience has been in information technology supporting natural gas pipelines, energy commodity trading and end-to-end electric utility operations. I have also provided support for outage management, customer service, transmission scheduling and regulatory issues. I joined PacifiCorp as Chief Information Officer in September 2000 and assumed my current position in August 2006. I am responsible for all aspects of PacifiCorp's main grid transmission investment strategy, customer service, main grid planning, contract administration and tariff management. I am the co-chair of the Northern Tier Transmission Group ("NTTG"), which coordinates transmission planning, transmission expansion, and project reviews with sub-regional and regional planning organizations within the Western Electricity Coordinating Council ("WECC"). I am also an elected class one voting member (transmission owner class) of the WECC Board of Directors. As a member of the WECC Board of Directors, I participate with other WECC members in overseeing WECC's activities, including defining standards and policies to ensure reliability of the western electric grid. I also hold a position on WECC's Transmission Expansion Planning Policy Committee and the Reliability Coordination Committee.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information on the Populus to Terminal transmission line, which is the first segment of the Energy Gateway transmission expansion plan to be constructed, and for which the Company is seeking cost recovery in this case. The Populus to Terminal transmission line, and subsequent investments within the Company's long-term, comprehensive transmission expansion plan known as "Energy Gateway," satisfy multiple objectives for efficiently operating a six-state transmission system. The immediate benefit to PacifiCorp's customers in Oregon and elsewhere is a significant investment to enhance reliability and improve transfer capability within the existing system, followed over time by incremental capacity which is key to unlocking rich renewable resource hubs. Specifically, my testimony:

- Provides an overview of the Company's transmission system.
- Outlines the Company's transmission expansion plan and provides details on the Populus to Terminal line segment of this plan.
- Demonstrates that the Populus to Terminal transmission investment is beneficial to customers as part of the overall long-term transmission plan developed by the Company and comports with Oregon public policy.

- Describes how the Populus to Terminal transmission investment helps satisfy a commitment the Company made as part of the MidAmerican Energy Holdings Company ("MEHC") transaction.

Company witness Mr. Darrell T. Gerrard provides testimony with additional details and technical information on the Populus to Terminal transmission investment.

Q. What investment related to the Populus to Terminal transmission line is included in the revenue requirement of this rate case?

A. One of the first components of the Company's comprehensive plan related to investment in the transmission system is a new double-circuit 345 kilovolt ("kV") transmission line from the Populus substation near Downey, Idaho to the Terminal substation in Salt Lake City, Utah. The Populus to Terminal line will be placed in service in two phases. The first phase from the Ben Lomond substation (near Ogden, Utah) to the Terminal substation will be in service by June 2010, and the second phase from the Populus substation to the Ben Lomond substation will be in service by December 31, 2010. This case includes approximately $839 million of rate base in the test period on a total company basis for both phases. The testimony of Company witness Mr. R. Bryce Dalley describes the revenue requirement calculations associated with this transmission investment.

Overview of PacifiCorp's Transmission System

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 15,800 miles of transmission lines ranging from 46 kV to 500 kV across multiple western states. As of June 30, 2009, PacifiCorp's current total-company net transmission plant in service was approximately $2.1 billion. PacifiCorp is interconnected with more than 80 generation plants and 15 adjacent control areas at approximately 124 points of interconnection. To provide electric service to its retail and wholesale customers, PacifiCorp owns or has interest in generation resources directly interconnected to its transmission system with a system peak capacity of approximately 12,131 MW. This generation capacity includes a diverse mix of resources including coal, hydro, wind power, natural gas simple cycle and combined cycle combustion turbines, and geothermal.

Energy and demand requirements for PacifiCorp's Oregon customers are delivered via the Company's transmission system within PacifiCorp's Eastern and Western Balancing Areas. Energy can be delivered from the Western Balancing Area through existing 115 kV and 69 kV systems into Oregon to PacifiCorp's retail customers. Energy can also be delivered from the Eastern Balancing Area through existing transmission assets originating in Idaho and terminating in southern Oregon. PacifiCorp's Western Balancing Area electrically connects to other transmission providers who are part of the California Independent System Operator ("CAISO") with interfaces at the Malin and Cascade substations in Oregon. These interconnections provide reliability and the ability to utilize point-to-point transmission service for energy sales and purchases between the PacifiCorp balancing area and the CAISO for wholesale transactions under PacifiCorp's Open Access Transmission Tariff ("OATT") contracts.

Q. Please describe the availability of existing transmission capacity on the system.

A. The Company's 2008 Integrated Resource Plan ("IRP"), which was filed with the Public Utility Commission of Oregon ("Commission") in May 2009 and acknowledged in February 2010, identifies the need for investment in major new transmission facilities to provide ongoing reliability and to meet the forecast loads of PacifiCorp's customers. The IRP analysis is performed by evaluating loads and resource requirements over a 20-year period:

> ***TRANSMISSION RESOURCES***
> While the Energy Gateway Transmission project was treated as part of the base topology for the IRP models, PacifiCorp included three transmission options that the System Optimizer could select. These options were recommended by PacifiCorp's Transmission Department as additional potential investments to supplement the Gateway project. The first option was an incremental addition to the Energy Gateway West project. This expansion option consisted of a 750 MW capacity increase from Path C in Idaho/northern Utah to the West Main load area, representing Oregon and northern Oregon. This option was available beginning in 2015.[1]

PacifiCorp's existing transmission system, as well as the transmission grid across the western region, is severely constrained, and numerous regional study groups have identified the pressing need for investment in new transmission infrastructure. These studies are described in more detail later in my testimony.

Additionally, new federal standards that mandate increased transmission system reliability along with PacifiCorp's recent operational experience show that investing in PacifiCorp's transmission system is required to ensure the Company has the capability to provide reliable transmission service under expected

[1] PacifiCorp's 2008 IRP at p. 130 (Docket LC 47).

operating conditions, and to maintain the transmission system capacity necessary to deliver network load service and contractual point-to-point commitments.

Increasing PacifiCorp's transmission capacity will also provide the opportunity for the Company to make off-peak energy sales, which are used to reduce overall power supply costs. Lastly, additional transmission capacity provides the Company added flexibility in the location and use of generating reserves and flexibility to perform routine maintenance on transmission lines with minimal risk, all of which reduce operating costs to customers.

Overview of Energy Gateway Transmission Expansion

Q. Please generally describe how PacifiCorp's transmission expansion plan became a component of IRP.

A. As part of MEHC's acquisition of PacifiCorp, the Company performed a review of the IRP process. From that review, the Company determined there was a need for a long-term transmission investment strategy to support the long-term resource needs of customers. Historically, IRPs were relatively silent on transmission investments, assuming transmission would follow generation investments. Given the long-term needs of customers, existing transmission system constraints, the time required, and the challenges associated with designing, permitting and constructing transmission lines, transmission is now a key element of the Company's IRP. This shift in focus is evidenced by the inclusion of Energy Gateway in PacifiCorp's 2008 IRP.

Q. Please generally describe Energy Gateway.

A. Energy Gateway is a comprehensive transmission plan based on taking immediate actions while keeping long-term needs in focus. Energy Gateway will enhance reliability, reduce transmission system constraints and improve the flow of electricity to PacifiCorp's customers. The Energy Gateway plan is comprised of eight interrelated and interdependent transmission segments as outlined in Exhibit PPL/401. The eight line segments within Energy Gateway are grouped and labeled as part of Gateway Central, Gateway West, Gateway South and the Westside. The Populus to Terminal line segment is within Gateway Central. When fully implemented, Energy Gateway will traverse six states, numerous communities, counties and significant areas of federally-administered lands and will add approximately 2,000 miles of new transmission lines to PacifiCorp's transmission system. Due to the interconnected nature of PacifiCorp's transmission network, investments may be required at other facilities in order to maximize the effectiveness and efficiency of the network. For Energy Gateway, the eight identified transmission segments provide specific capabilities, but they also support other transmission segments to enhance the benefits of Energy Gateway.

Q. Please describe Gateway Central relative to the overall Energy Gateway plan.

A. Gateway Central is comprised of two transmission segments (Populus to Terminal and Mona to Oquirrh) that will improve reliability and transfer capability to the existing system and also establish the necessary electrical interconnection between Gateway West and Gateway South. The Gateway West and Gateway South line segments, when complete, will be the first 500 kV lines to be installed in Wyoming, southeast Idaho and Utah. Gateway Central will provide an essential reliability backbone allowing Gateway West and Gateway South to operate at a higher reliability and at an overall higher capacity than would otherwise be possible without the Gateway Central interconnection. This investment will not only add incremental transmission capacity, but will also strengthen PacifiCorp's overall system while supporting future generation resource development to benefit all PacifiCorp customers.

As described earlier in my testimony, the Populus to Terminal transmission segment is comprised of two smaller sections, which in total extend 135 miles from the new Populus substation near Downey, Idaho, south to the existing Terminal substation near the Salt Lake International Airport west of Salt Lake City, Utah. The Populus to Terminal transmission segment is a key element of the Energy Gateway's Gateway Central. Populus to Terminal is designated as "Segment B" within Gateway Central in Exhibit PPL/401.

Populus to Terminal Transmission Investment

Q. Please describe the Populus to Terminal transmission investment in more detail.

A. Exhibit PPL/402 is a map of the Populus to Terminal transmission line segment. Ben Lomond to Terminal is the southern section and is highlighted in red on the map. Populus to Ben Lomond is highlighted in yellow, green and blue on the map. Phase I from Ben Lomond to Terminal will be the first section of the Populus to Terminal line to be completed, and will be operational by June 30,

2010. Phase II from Populus to Ben Lomond will be complete and in service by December 31, 2010.

Q. Please describe the findings of the regional transmission studies related to Energy Gateway and specifically the Populus to Terminal segment.

A. Over the past decade, numerous studies were completed documenting the need for new transmission in the western United States. As early as 2002, the Department of Energy National Transmission Grid Study identified the Wyoming-Idaho interface as a major constrained interface. The study also found that under optimal conditions, the Wyoming-Northern Utah interface is congested during 50 percent or more of the hours during the year.[2]

In 2004, the Rocky Mountain Area Transmission Study reached similar conclusions and recommended expansion of the 345 kV transmission lines connecting the Company's Bridger substation to points south and west as critically needed improvements.[3] In addition, the Department of Energy's 2006 National Electric Transmission Congestion Study ("DOE Congestion Study") identified several constrained transmission paths in the west as shown in Exhibit PPL/403, including lines used to deliver electricity from generation plants in Wyoming to loads in the west.[4] Specifically, the DOE Congestion Study

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[2] National Transmission Grid Study at pp. 15, 18. A full copy of this report is available at http://www.pi.energy.gov/documents/TransmissionGrid.pdf.

[3] Rocky Mountain Area Transmission Study at Chapter 3-2, which shows the Bridger expansion as a critical expansion area from Wyoming to Northern Utah and Wyoming to Idaho. The full report is available at http://psc.state.wy.us/htdocs/subregional/Reports.htm.

[4] The National Electric Transmission Congestion Study (August 2006) at pp. 31-35. The transmission constraints identified in this study were identified by reviewing recent transmission studies such as those conducted by WECC and Seams Steering Group-Western Interconnection. The full report is available at http://nietc.anl.gov/documents/docs/Congestion_Study_2006-9MB.pdf.

illustrated that expansion of the Bridger West transmission facility is critical for relieving congestion from Wyoming to northern Utah, and Wyoming to Idaho.[5]

Similarly, the Western Interconnection 2006 Congestion Assessment Study, which was issued by the DOE Western Congestion Analysis Task Force, identified areas of congestion in the Rocky Mountain states, and projected that based on 2005 load and resource forecasts and a production model, many of the paths associated with the various segments of the Energy Gateway Project would be heavily congested.[6] Reports initiated by the Western Governors' Association ("WGA") also show certain paths in PacifiCorp's service territory (including the Populus to Terminal segment) as constrained.[7]

In addition, the DOE sponsored a study through Idaho National Laboratories to assess the economic impact of not building transmission. While the report focused on assessing the economic impact on the Pacific Northwest, it also provides discussion and support for the "hub and spoke" design which is similar to the Energy Gateway model for connecting resource areas to load. The report also describes the interconnected nature of transmission as being geographically dispersed, yet interdependent.[8] Finally, existing NTTG sub-regional transmission planning studies, conducted in accordance with the Federal

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[5] Such expansion is addressed by the Segment E portion of the Project.
[6] A full copy of this study is available at http://www.oe.energy.gov/DocumentsandMedia/DOE_Congestion_Study_2006_Western_Analysis.pdf.
[7] The full report is available at http://www.westgov.org/wga/initiatives/cdeac/TransmissionReport-final.pdf.
[8] The Cost of Not Building Transmission: Economic Impact of Proposed Transmission Line Projects for the Pacific Northwest Economic Region. Full report is available at http://www.pnwer.org/Portals/0/Presentations/2008%20summit/Cost%20of%20not%20building%20transmission.pdf.

Regulatory Energy Commission's ("FERC") Order 890-A, show overall benefits to the region as a result of PacifiCorp's proposed Energy Gateway.

Additionally, the Company filed for incentive rates with FERC on July 3, 2008, which is analogous to a need determination. FERC granted the Company incentive rate treatment, and of equal importance, FERC issued a 4-0 decision stating:

> [W]e find that PacifiCorp has adequately demonstrated that the Project (with the exception of segment A) will ensure reliability and reduce transmission congestion… We find that segments B through H of the Project would establish for the first time a backbone of 500 kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions. This would provide a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West, connecting existing and potential generation to loads in an efficient manner, thus reducing the cost of delivered power. Also, the Petition cites the 2006 DOE National Electric Transmission Congestion Study and the 2004 Rocky Mountain Area Transmission Study in stating that that proposed Project will reduce congestion or maintain reliability in the Western Interconnection. Additionally, the project would establish a direct link between PacifiCorp's east and west control areas, providing numerous benefits including increasing transfer capability, reducing the need for curtailments, and reducing transmission congestion.[9]

Commissioner Kelly echoed PacifiCorp's Petition in her concurrence stating, ". . . while Segments B and C provide a variety of benefits when considered in isolation, they also enable PacifiCorp to achieve the planned transfer capability rating of subsequent segments." [10]

As noted in Exhibit PPL/401, Segment B is Populus to Terminal and Segment C is Mona to Oquirrh. The full FERC order is provided as Exhibit PPL/404.

[9] *PacifiCorp*, 125 FERC ¶ 61,076 (2008) at p. 10.
[10] Id. at p.17

Q. What factors does the Company consider before building new transmission?

A. The Company considers several factors before building new transmission facilities including:

- Current and future forecasts for demand and energy required from existing and new resources to new and existing loads. These considerations are addressed in the Company's 2008 IRP including demand-side management and energy conservation programs.
- Alternatives including building local generation near load and/or energy market purchases.
- The Company's ability to use existing land rights, existing rights-of-way, and corridors.
- The use of upgrades to increase operability and reliability from existing transmission lines and substations.
- The Company's ability to maximize the capacity and capabilities of existing facilities.

Because prudent transmission investments are typically large scale to maximize efficiencies and gain economies of scale, the benefits are realized over the long term.

Q. Once the decision is made to invest in new transmission, what is the process for getting it built?

A. Once the decision is made to invest in new transmission, capacity sizing of the transmission line is taken into consideration to balance current and future needs. Constructing long, linear facilities such as transmission lines is an extensive process. Siting, permitting and constructing new transmission can take up to seven years and potentially involves acquiring new rights-of-way and permits from local, state and federal agencies. Maximizing the transmission capacity placed in approved corridors is a critical consideration to minimize disruption to communities and landowners. The Company also considers design and routing to minimize the environmental, visual and human impacts.

Q. What land rights and permits were acquired for Populus to Terminal?

A. The Company holds all of the necessary land rights, either in easements or fee ownership, between the Populus substation and the Terminal substation. However, the Company was required to secure numerous permits and approvals from federal and state entities, such as:

- The U.S. Army Corps of Engineers required permits for construction within jurisdictional wetlands.
- The Federal Aviation Administration required aviation permits for construction of Populus to Terminal near Salt Lake International Airport.
- The Utah and Idaho Departments of Transportation required permits from railroad companies for roadway crossings, overhangs and easements.
- The U.S. Bureau of Reclamation required a crossing permit for the Ogden-Brigham canal.
- The Utah Department of Wildlife Resources required a permit for crossing Wildlife and Waterfowl Management Areas, with a separate agreement required for construction within the Legacy Nature Preserve.
- The approval of the U.S. Fish & Wildlife Service, U.S. Forest Service and

Utah State Historical Preservation Office was also required as an element of various wildlife & environmental habitat permits.

Q. What permits were required by local governmental authorities for the construction of Populus to Terminal?

A. The Company holds a franchise agreement with each municipality and county within the route that grants the necessary rights for the construction of the Populus to Terminal transmission line. In addition, the Company secured conditional use and/or special use permits from all cities and counties, based on each community's requirements. The Public Service Commission of Utah ("Utah Commission ") and the Idaho Public Utilities Commission ("Idaho Commission") issued Certificates of Public Convenience and Necessity in 2008. The Idaho Commission Order states:

> Thus, Staff believes that the necessity of the Project should be viewed in conjunction with energy resources that are constructed, under way or planned. PacifiCorp elected to undergo a transmission upgrade as part of its preferred resource portfolio of an additional 2,000 MWs of renewable resources by 2013 in the Company's 2007 IRP. A significant portion of these renewable resources will be located in Wyoming. Staff then listed more than 500 MWs of renewable resources that are either under construction or in the final stage of development. In response to a Staff data request, PacifiCorp provided four alternatives that it rejected because the Company did not believe that these would provide sufficient capacity for the new resources. Staff agreed that the Project was necessary in order for the Company to continue to provide reliable service from these new resources to growing load centers. [11]

[11] In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Populus-to-Terminal 345 KV Transmission Line Project, Case No. PAC-E-08-03, Order No. 30657 (October 10, 2008) at pp. 3-4.

In the Utah Order, the Commission noted several parties concurred with the need, including the Division of Public Utilities:

> The Division states it has examined underlying information upon which a need for these additional transmission facilities may be found and concludes it supports RMP's decision to build the Transmission Line and confirms RMP's planned integration and operation of the line with future utility operations and activities. The Division agrees with RMP's conclusions that there is a need for the Transmission Line and the Company's future utility service will be more reliable and efficient with the Transmission Line's addition.[12]

Q. Please describe the approach the Company used to secure appropriate resources to construct the new transmission.

A. The Company initiated a competitive tendering process to receive blind, sealed bids for the project work scope to be delivered on a turnkey, fixed-price, guaranteed completion-date basis using an engineer, procure and construct form of contracting. The competitive tendering process began in October 2007 and provided two separate blind, sealed bidding opportunities. All bid responses were due for submittal in May 2008 and again in July 2008 after the Company provided additional information to bidders allowing a refinement of previously submitted design solutions, and terms and conditions, including price. The Company received and evaluated three qualified bids resulting from the May 2008 proposal submissions. During the evaluation period one of the bidders withdrew its participation. The Company received two competing proposals in July 2008 with qualified prices of $609 million and $528 million, respectively. After extensive

[12] In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity Authorizing Construction of the Populus to Terminal 345 KV Transmission Line Project, Docket No. 08-035-42, Report and Order Granting Certificate and Certificate of Public Need and Necessity, (September 4, 2008) at p. 3.

evaluations of bidder proposals and review of exceptions to work scope and base terms and conditions from each bid proposal, the Company ultimately awarded the contract in October 2008, details of which are provided in Mr. Gerrard's testimony. The scope of the bidding process included the Populus to Terminal segment, which includes the sections outlined in Exhibit PPL/402. The bid process is described in more detail in Mr. Gerrard's testimony.

Q. Why did the Company use the engineer, procure and construct approach?

A. The engineer, procure and construct ("EPC") solicitation is a common form of contracting for large construction projects like the Populus to Terminal transmission segment and is regarded as a prudent approach for cost control and managing design, procurement and construction risks. This approach provides certainty relative to schedule and cost outcomes for the benefit of customers, caps potential cost escalations where possible based upon the occurrence of defined risks, and ensures more timely delivery to support system needs and transmission reliability.

Q. Please explain what you mean concerning capping costs based upon the occurrence of identified risks.

A. The fixed-price EPC approach has minimal provisions for cost and schedule variances. Where cost and schedule variances were not included in the fixed price for certain contingent aspects of the work scope, these items were identified as risk items and a contingent capped price and schedule allowance was agreed upon prior to contract execution should any of these risk items materialize. Contingent risk items were limited to defined occurrences such as weather delays, environmental impacts and sub-surface ground conditions.

Q. How will the Populus to Terminal transmission line benefit PacifiCorp customers?

A. The Populus to Terminal transmission line and subsequent investments within Energy Gateway satisfy multiple objectives for efficiently operating a six-state transmission system in the long term. The initial benefit to PacifiCorp customers is a significant investment to enhance reliability and improve transfer capability within the existing system. In the future this investment will also provide benefits of incremental capacity to deliver generation resources within the Company's 2008 IRP.

Reliability is fundamental to effectively and efficiently managing the Company's six-state transmission system. As a federally-regulated transmission provider, the Company must comply with reliability standards mandated by FERC through the North American Electric Reliability Corporation ("NERC") and WECC. By meeting these standards the Company continues to maintain a stable and reliable system during a variety of operating conditions, which minimizes potential outages to all customers and financial impacts of having to deliver higher-cost resources if required. At a minimum, Populus to Terminal addresses reliability for all PacifiCorp customers.

Populus to Terminal also increases transfer capability from north to south and south to north across the Company's transmission system. By doing so, the Company addresses a key constraint (Path C), meets an MEHC transaction commitment and improves the Company's ability to import and export lower-cost resources depending on seasonal needs and operating conditions. The benefit to all PacifiCorp customers is the ability of the Company to use the least-cost dispatch of resources to serve loads and manage power costs by selling excess energy off-system or importing lower-cost market energy to serve load. Also, by providing incremental transmission capacity through this transmission segment, the Company has more flexibility in locating reserves on PacifiCorp-owned generation, and making full use of the Northwest Power Pool reserve-sharing program. This program allows the Company to cover reserve requirements without having to build additional generation. Increasing the import capability allows better access to those reserves, thereby reducing costs for all customers. Reliability and transfer capability provide benefits based on the existing system.

Populus to Terminal also establishes incremental capacity to provide long-term benefits to PacifiCorp customers. Wyoming has been long identified as a rich resource location for multiple generation resource types, most recently as a high-quality renewable resource hub. The barrier to accessing those resources for customers and producers has been transmission constraints in Wyoming and other states. Populus to Terminal is the first step within the Energy Gateway strategy to unlock those rich resources. Once unlocked, benefits will accrue to energy consumers and energy producers by allowing economic resources to be developed and delivered across the Company's service territory.

Q. Has the Oregon Commission recognized the importance of this investment in transmission infrastructure?

A. Yes. On February 2, 2010, the Commission adopted the Commission Staff's recommendation for acknowledgement of the transmission in the action plan of the 2008 IRP (Docket LC 47), which includes Populus to Terminal. The Commission Order states:

> Therefore, after reviewing the analysis, Staff concluded that the proposed transmission segments provide increased reliability, additional transfer capability, and at the same time support integration with larger segments, for an overall benefit to Oregon customers that outweighs the proposed capital investment.[13]

MEHC Transaction Commitments

Q. Did MEHC and PacifiCorp make specific commitments related to investment in PacifiCorp's transmission system as part of the acquisition approval process?

A. Yes. At the time of the acquisition of the Company by MEHC, many parties wanted to see the Company make transmission infrastructure investments to support the future demands and growth of its customers. As a result, MEHC made specific commitments and developed plans for a significant capital expansion program across the system. As part of the acquisition approval process, MEHC committed to improve capacity on a constrained path known as Path C. Specifically, MEHC agreed to increase transfer capacity on Path C by 300 MW.[14] Populus to Terminal improves the capacity on Path C and has a planned increase in transfer capacity of 1,400 MW when combined with other segments of Energy Gateway. As such, the Populus to Terminal transmission segment will significantly improve a point of constraint on the system that currently affects numerous transmission customers, strengthen reliability and

[13] *See* Order No. 10-066 at pp. 19-20.
[14] *See* Order No. 06-082 at Exhibit 1 to Appendix A (Commitment No. 34).

enable the Company
to achieve the planned transfer capability rating of subsequent Energy Gateway segments.

Conclusion

Q. Please summarize your conclusions.

A. New transmission is essential to enhance transmission system reliability, provide capacity to integrate renewable resources for the long-term benefit of customers and to meet load growth. Populus to Terminal is the first step to increase transmission capacity within PacifiCorp's six-state transmission system and to further facilitate a stronger interconnection to systems in the Pacific Northwest, including Oregon. This investment and subsequent investments in Energy Gateway support Oregon infrastructure policy and are prudent, cost effective and beneficial to customers.

Q. Is the inclusion of Populus to Terminal in Oregon rates in the public interest and if so, why?

A. Yes. The Populus to Terminal and subsequent investments within Energy Gateway satisfy multiple objectives for efficiently operating a six-state transmission system. The initial benefit to PacifiCorp's customers is a significant investment to enhance reliability and improve transfer capability within the existing system. In the future, it will also provide incremental capacity for delivery of resources within the Company's 2008 IRP, which is a key to unlocking rich renewable resource hubs for the benefit of all PacifiCorp customers and ultimately the western interconnect.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/401
Witness: John A. Cupparo

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

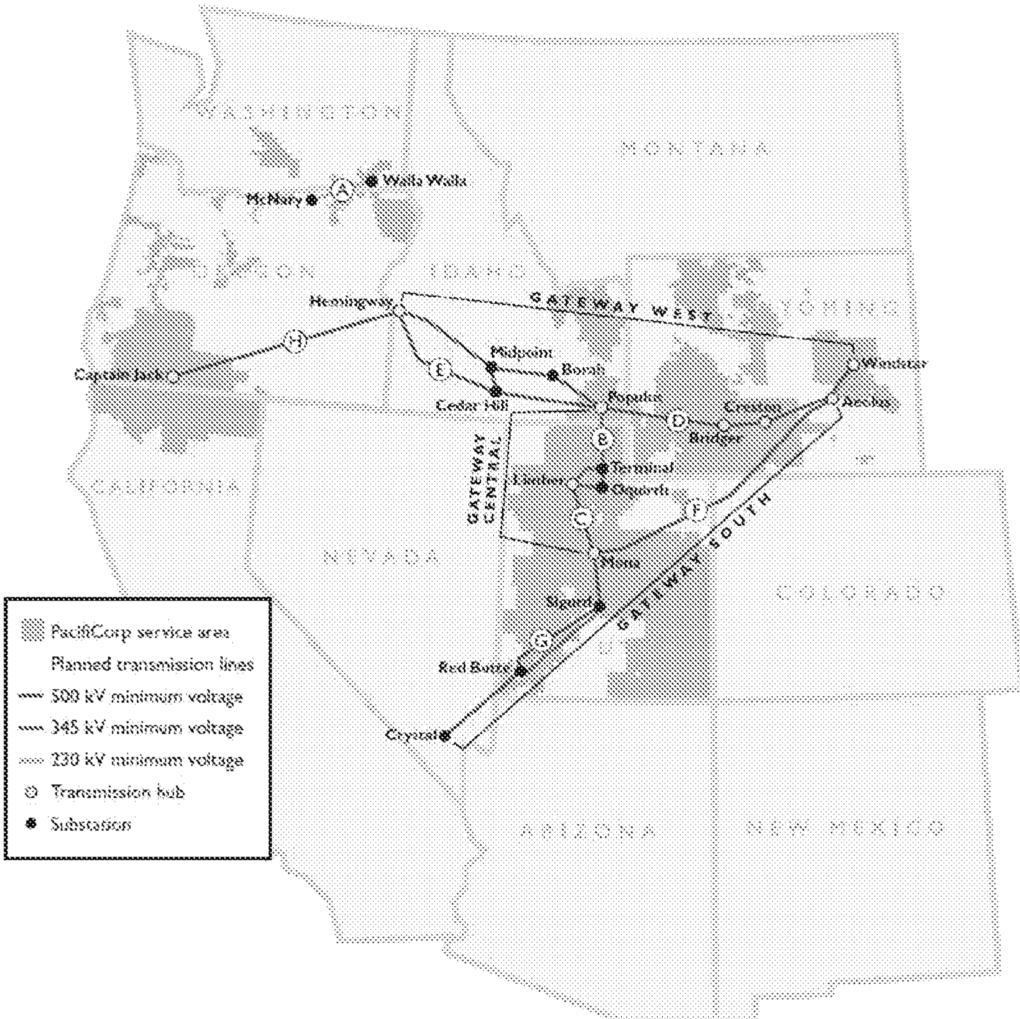
Exhibit Accompanying Direct Testimony of John A. Cupparo

Energy Gateway Transmission Expansion Plan

March 2010

Exhibit PPL/401
Cupparo/1

Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects the expansion necessary to construct Energy Gateway to its full capacity of 6,000 MW. It may not reflect the final routes or construction sequence.

Docket No. UE-
Exhibit PPL/402
Witness: John A. Cupparo

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of John A. Cupparo

Populus to Terminal Transmission Line Segment

March 2010

Docket No. UE-
Exhibit PPL/403
Witness: John A. Cupparo

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

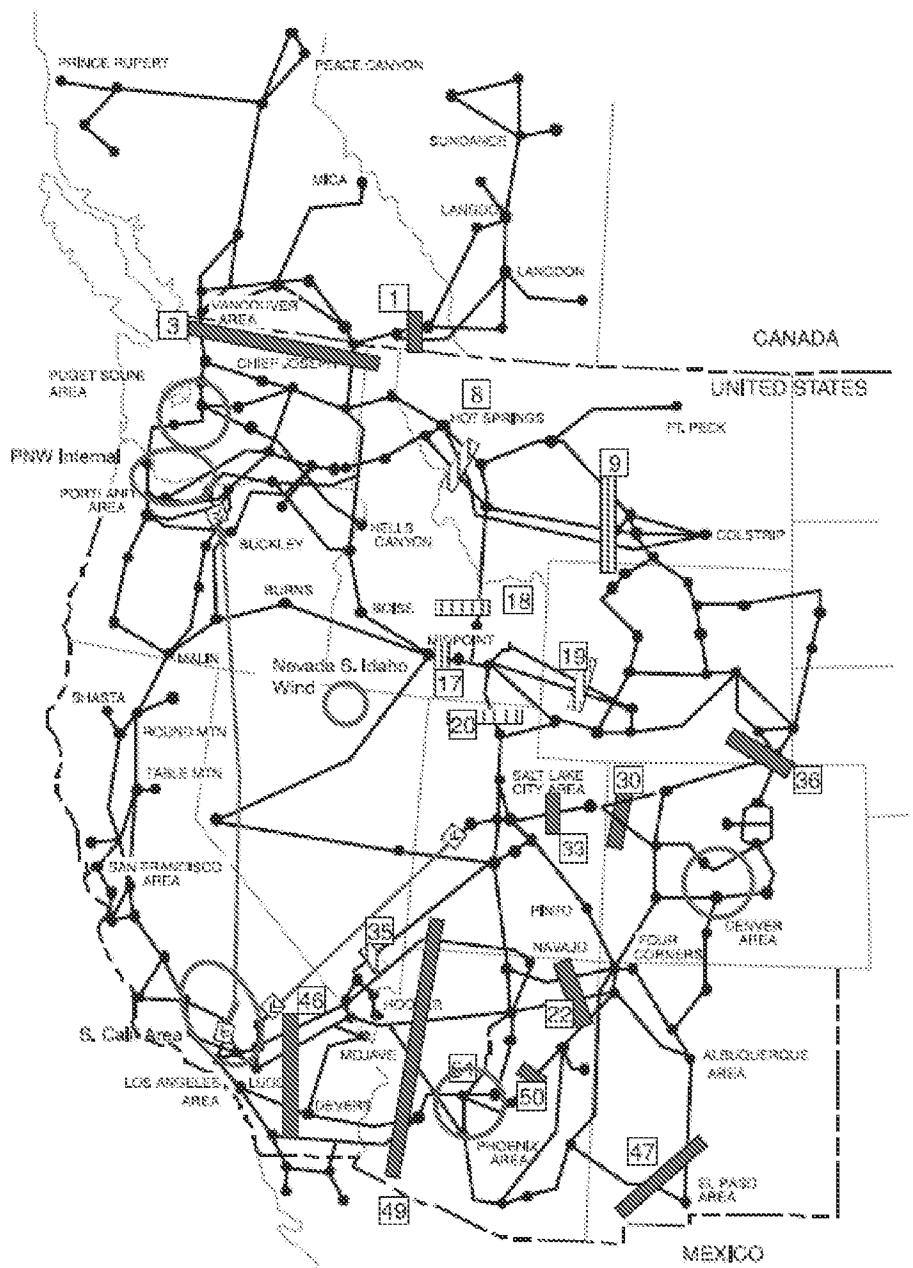
PACIFICORP

Exhibit Accompanying Direct Testimony of John A. Cupparo

DOE Congestion on Western Transmission Paths

March 2010

Figure 4-1. Congestion on Western Transmission Paths



Congested Transmission Paths

Transmission line (or lines). Solid red or hashed bars "bundle" the lines they cross or touch into a numbered transmission path.

\# The number alongside each bar is the WECC number for that path.

Congestion on the path, based on current or near-term conditions.

Subregional areas with significant existing congestion.

Congestion that would result from future development of generation capacity in the Rocky Mountain area.

Based on historical and existing modeling studies. Not all of WECC's 67 catalogued paths are shown.

Docket No. UE-
Exhibit PPL/404
Witness: John A. Cupparo

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of John A. Cupparo

FERC Order on Petition for Declaratory Order
(issued October 21, 2008)
125 FERC ¶ 61,076

March 2010

125 FERC ¶ 61,076
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Jon Wellinghoff.

PacifiCorp — Docket No. EL08-75-000

ORDER ON PETITION FOR DECLARATORY ORDER

(Issued October 21, 2008)

1. On July 3, 2008, PacifiCorp filed a petition for declaratory order (Petition) pursuant to section 219 of the Federal Power Act (FPA)[1] and Order No. 679[2] seeking incentive rate treatment for its Energy Gateway Transmission Expansion Project (Project). The Project, described by PacifiCorp as eight interdependent line segments, will expand PacifiCorp's transmission network by 2,000 miles of extra-high voltage (EHV) transmission lines. PacifiCorp seeks a 250 basis point adder to its base return on equity (ROE) and recovery of prudently-incurred abandonment costs if the Project is cancelled due to factors beyond its control. For the reasons discussed below, we will grant in part, and deny in part, PacifiCorp's Petition and grant in part, and deny in part, the requested incentive rate treatment for its Project.

I. **Background**

2. According to PacifiCorp, the Project is one of the most ambitious electric infrastructure projects planned in the western United States in the past two decades. The Project will enlarge and expand PacifiCorp's system-wide transmission network by adding approximately 2,000 miles of new EHV transmission lines in the six-state region including California, Idaho, Oregon, Utah, Washington, and Wyoming, and deliver up to 3,000 MW of capacity from location-constrained renewable resources in Wyoming to distant load centers; its estimated cost exceeds $6 billion. PacifiCorp claims that the Project will provide its customers with substantial economic, reliability and

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[1] 16 U.S.C. § 824s (2006).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

environmental benefits, including reducing transmission congestion and the future cost of delivered power throughout the six-state service territory.

3. According to PacifiCorp, the Project is a backbone transmission project providing a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West. Its configuration is described as a "hub and spoke" design which is characterized by PacifiCorp as major EHV transmission lines that connect areas with a strong potential for generation resource development (hubs) to an enhanced transmission system (spokes) for delivery to customers throughout the western United States. Under the Project, hubs are planned for western Wyoming, south central Wyoming, southwestern Idaho, south central Utah, and southern Oregon. From the hubs, power will be collected and moved in different directions to permit PacifiCorp to efficiently deliver power from a variety of generation sources to load. According to PacifiCorp, the additional transmission infrastructure and the "hub and spoke" design will provide flexibility, improve efficiency and enable development of clean and renewable energy resources and will ensure that PacifiCorp's system will be capable of meeting future regional needs.[3]

4. PacifiCorp states that each of the eight interrelated line segments has been assigned one of four priority classifications for construction.[4] PacifiCorp explains that most of the segments are dependent on the development of other segments and the priority levels have been established to ensure the most prudent approach to deliver completion of the Project. Four segments comprise Priority One of the Project (segments A, B, C and G). According to PacifiCorp, these segments are being built to enhance the base load service and reliability of PacifiCorp's transmission system. PacifiCorp anticipates that these segments will be among the earliest portions of the Project to be placed into service, and it has begun the preliminary permitting and contracting work to get these segments on-line between 2010 and 2014.[5]

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[3] PacifiCorp Petition at 8 and 9.

[4] According to PacifiCorp, the priority classification assigned to each segment is driven by efficiency and cost-effective development and construction of the Project; therefore, PacifiCorp clustered segments offering similar general benefits and asset in-service dates.

[5] Segment A is a 230 kV segment which will extend approximately 56 miles between Walla Walla, Washington and Umatilla, Oregon and cost roughly $108 million. Segment B is a double circuit 345 kV line that will be constructed in two segments. The line will run from a new substation near Downey, Idaho 135 miles south to an existing substation near Salt Lake City, Utah; the estimated cost is $800 million. Segment C extends north from central Utah running 86 miles north to two future substations. It is a

(continued…)

5. Two segments comprise Priority Two (segments D and E). PacifiCorp states that the two segments are designed to enhance the resource adequacy of the region by connecting transmission-constrained wind resources in Wyoming to westward load centers.[6] Two segments comprise Priority Three of the Project (segments E and H). PacifiCorp states that these segments are intended to integrate its two control areas within the Project footprint, and to provide a means for transmitting renewable energy supplies.[7] Priority Four consists of segment F which is intended to provide back-up system reliability, as well as rating support for PacifiCorp's newly enhanced system.[8]

6. The application states that three of the segments may be upsized from a single-circuit to a double-circuit system.[9] PacifiCorp states that it is actively working with potential equity partners to determine the interest and commitment to pursue a double-circuit configuration for these segments.

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double circuit line which will have one segment constructed at 500 kV and the other at 345 kV and is expected to cost $425 million. The segment G transmission line is approximately 280 miles and will connect an existing substation in central Utah to another substation north of Las Vegas, Nevada. The lines are planned as a single circuit 345 kV line, and could be upsized to include a 500 kV line configuration. The estimated cost is $754 million.

[6] The two portions of segment D will consist of roughly 300 miles of new transmission line running from eastern Wyoming to western Wyoming and is estimated to cost approximately $880 million. PacifiCorp states that the segment will consist of two single circuit 230 kV lines, and a double circuit 500 kV/230 kV line. The 230 kV segment of the line could be upsized to 500 kV. Segment E, also comprised of two sections both single-circuit 500 kV lines, will run from a planned generation resource hub near Rock Springs, Wyoming, across Idaho to a point southwest of Boise, Idaho and cost an estimated $1.02 billion.

[7] Segment E continues the single circuit, 500 kV, Priority Two line running to western Idaho. Segment H, single circuit 500 kV line, will run 375 miles from an existing substation in western Idaho to a Bonneville Power Administration substation in northern California. The cost is estimated at $786 million.

[8] Segment F which is also a single circuit, 500 kV line extends approximately 395 miles from a new substation in southeastern Wyoming to central Utah. Segment F is expected to cost $764 million.

[9] PacifiCorp Petition at n.9 and Cupparo Affidavit at 10-12.

A. <u>Requested Incentives</u>

7. PacifiCorp requests a 250 basis point adder to its base ROE for the revenue requirement associated with the capital costs of its Project, not to exceed the upper end of the zone of reasonableness as determined in a future proceeding under FPA section 205. PacifiCorp asserts that the ROE adder is necessary to compensate it for the unusual and significant project risks.

8. PacifiCorp also requests authorization to recover all prudently-incurred development and construction costs if the Project is cancelled or abandoned, in whole or in part, as a result of its inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority, or regulatory agency, for any reason outside PacifiCorp's control.

9. PacifiCorp states that it qualifies for the rate incentives because of the scope and magnitude of the Project, because it is intended to respond to regional needs in Idaho, Oregon, Utah, Washington, and Wyoming, and because it will improve reliability, reduce congestion, provide transmission access for renewable resources, provide transmission for forecasted load growth and will deploy advanced transmission technologies. As the Project will directly link PacifiCorp's east and west control areas, it will minimize congestion and relieve loading along paths between Wyoming and areas west and south, and, by adding interconnections and increasing transfer capacity, the Project will reduce the need for curtailments and improve access to generation resources needed to meet system demand and reserve obligations.[10]

10. PacifiCorp asserts that it is entitled to a rebuttable presumption of eligibility for the requested incentives under Order No. 679 because nearly all segments of the Project (except segments A and C) were planned and approved under a Fast Track Process developed in 2007 by the planning committee of the Northern Tier Transmission Group (NTTG), prior to finalizing requirements for the NTTG's planning process required by Order No. 890.[11] Additionally, PacifiCorp states that NTTG's 2007 Annual Report

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[10] *See* PacifiCorp Petition, Cupparo Affidavit at 19.

[11] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008). According to PacifiCorp, the Fast Track provided a forum for stakeholder input and participation in the identification of Fast Track projects critical to relieving areas of congestion and improving reliability. *See* PacifiCorp Petition, Cupparo Affidavit at 15-16.

identified the need for all of PacifiCorp's proposed segments (except segment A) to increase transmission capacity in order to reduce congestion and improve reliability.[12] PacifiCorp states that following the NTTG planning committee approval of the 2007 Annual Report and Fast Track recommendations, the Project (with the exception of segments A and C) was submitted for Western Electricity Coordinating Council (WECC) regional planning review.[13]

11. In the event that the Commission determines PacifiCorp is not entitled to that rebuttable presumption, PacifiCorp argues in the alternative that the benefits from constructing the Project nevertheless satisfy the eligibility criteria of Order No. 679. PacifiCorp contends that the Project, once completed, will result in increased reliability[14] and a reduction in congestion. Specifically, PacifiCorp points out that the Project will: (1) establish a 500 kV backbone; (2) reduce curtailments resulting from overscheduled use; (3) provide additional access to resources and reserves; (4) increase the diversity of the available resource mix; (5) connect its two control areas (Pacific Power and Rocky Mountain Power) to better serve network load; and (6) help satisfy state renewable portfolio requirements. The Petition references numerous transmission studies identifying constrained paths and interfaces and other areas critical for relieving congestion in the region; PacifiCorp states that the Project is its response to these findings, as well as responding to the projected demands on its available capacity due to growth of its network load obligation. PacifiCorp also highlights that the Project will enable it to link remote renewable resources to load centers throughout the West.

12. At this time, PacifiCorp is not seeking to change its rates under FPA section 205, but states that it will make a subsequent section 205 rate filing in the future to implement the incentive rate treatment. PacifiCorp also explains that it will ask state regulators to include the Project's investment in retail electric rates; to the extent that the recovery of all of the transmission investment is permitted in its retail rate base, "PacifiCorp will compensate its retail customers by crediting the transmission-related revenues, inclusive of any incentives granted by the Commission, against its retail revenue requirement."[15]

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[12] According to the Petition, the Fast Track process relied on studies previously done within the region to identify congested transmission that impedes efficient and reliable operation of the grid.

[13] *See* PacifiCorp Petition, Cupparo Affidavit at 17.

[14] PacifiCorp states that, by adding critical EHV infrastructure to the bulk power transmission system, the Project will provide contingency capacity throughout the system, thereby enhancing reliability within the NTTG footprint and the broader region.

[15] PacifiCorp Petition at 4.

PacifiCorp expects that the requested incentives will be an important consideration in obtaining state regulator support for including the reliability and future growth elements of the Project in retail rates.

B. Risks and Challenges

13. PacifiCorp states that its approach to this Project is a significant departure from past approaches to the development of major transmission projects. It notes that historically such projects were built when associated generation resources were sited; however, PacifiCorp notes that with the current uncertainty of conventional generating technology, the time required to permit and construct major transmission and the inability of many renewable resource developers to finance major transmission investments, transmission must be sited "ahead" of specific generation resources to best position utilities to meet future forecasted load growth. PacifiCorp asserts that with this approach, PacifiCorp faces greater risks for transmission investment.

14. PacifiCorp explains that it faces significant financial and regulatory risks in pursuing this Project. PacifiCorp cites the estimated $6 billion cost, comparing that to the average $111 million that it spent on capital expenditures annually between 2002 and 2007, and noting that the total cost is more than three times its current transmission rate base of $1.8 billion. In addition, PacifiCorp states that, since the Project would constitute the backbone for a future 500 kV infrastructure in the Project footprint, it would be "responsible for ensuring that the underlying system . . . can withstand technical and regulatory scrutiny, including the protection of neighboring electrical systems."[16] According to PacifiCorp, this factor has made it difficult to enlist additional partners in the Project. Its financial risk is also affected by the fact that it will be siting transmission lines ahead of new generation resources, as noted above, and the fact that development costs are likely to increase over time.

15. PacifiCorp asserts that its Project faces significant regulatory risks because it must garner approval of various state and federal authorities, including six states, the Bureau of Land Management and the United States Forest Service. PacifiCorp also notes that tribal issues and federal land management are implicated in the construction and development of the Project. PacifiCorp also states that large portions of the Project are expected to traverse federally-administered lands, as well as through routes that are not situated on existing rights-of-way. PacifiCorp anticipates that proceedings will be contested and prolonged, and recognizes the risk of siting delays and potential re-routing that may increase the overall cost. This, according to PacifiCorp, equates to added authorization complexities on a scale unlike previous transmission projects for which the Commission has granted requested rate incentives.

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[16] PacifiCorp Petition at 31.

16. Finally, PacifiCorp states that there will be uncommon technology-related risks because it contemplates investing in several advanced transmission technologies that have not been widely deployed.[17] PacifiCorp believes that there is added risk because there is uncertainty as to how these technologies will perform within this Project, and it notes that these novel technologies "must be designed, constructed and tested to ensure they meet the requirements of the Project."[18]

C. Technology Statement

17. PacifiCorp included an advanced technologies statement in its Petition as required by Order No. 679.[19] Subject to further study and final engineering, PacifiCorp states that it intends to utilize several types of advanced technologies in connection with various segments. PacifiCorp has not, in most cases, designated the specific segments on which the advanced technologies will be used. According to PacifiCorp, the technologies meet the standard set forth in Order No. 679, and in section 1223 of the Energy Policy Act of 2005 (EPAct 2005),[20] as they mitigate congestion and enhance grid reliability by increasing the capacity, efficiency and reliability of an existing or new transmission facility. PacifiCorp's advanced technologies fall into the categories of advanced conductor technology, enhanced power device monitoring, fiber optic technologies, power electronics and other technologies.[21]

18. PacifiCorp intends to utilize Trapezoidal Conductor technology which involves the use of Aluminum Conductor Steel Supported/Trapezoidal Wire. According to PacifiCorp, this advanced conductor design will increase transmission capacity, and reduce the sag of the transmission lines as well as avoid energy losses. PacifiCorp intends to use this technology on 500 kV lines, anticipated to be used on segments C, D, E, and G.[22]

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[17] As further discussed below, PacifiCorp plans on utilizing trapezoidal conductors, and fiber optic shield wires in addition to other innovative technologies. PacifiCorp Petition at 35.

[18] *Id.*

[19] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 302.

[20] Pub. L. No. 109-58, § 1223, 119 Stat. 594, 953 (2005).

[21] PacifiCorp Petition at 42.

[22] *Id.* at 23, Cupparo Affidavit at 24. PacifiCorp also asserts that an estimated 6,000 to 120,000 metric tons of carbon dioxide could be avoided annually, as a result of applying this technology.

19. PacifiCorp states that it is planning to use Static VAR Compensators (SVCs) which are electrical devices used to automatically match impedance to regular voltage and improve both dynamic and transient network stability. PacifiCorp is evaluating the installation of SVCs on several segments of the Project in order to support the required dynamic voltage regulation and "firming up" of the system, and also improve reliability, power quality, contingency recovery, create operational benefits and help maximize the overall total transfer capability.[23]

20. PacifiCorp plans to use fiber optic technology in order to shield phase conductors from direct lightning strikes, provide high-capacity, high-speed communication channels and reliably detect short circuits. PacifiCorp states that the installation of the fiber optic technology can also create additional latent capacity bandwidth, which could also provide an alternate secure communication path that could be used for national security and regional development purposes. PacifiCorp states that this technology has the potential to be used throughout the Project.[24]

21. PacifiCorp also intends to use phase shifters to improve and/or increase stability limits of transmission lines when the maximum power transfer is reached. PacifiCorp states that phase shifters help provide operational and seasonal flexibility, and that it is pursuing targeted applications of this technology to reduce overall system losses by eliminating circulating currents, and helping to protect neighboring transmission systems.[25]

22. In addition, PacifiCorp intends to employ Special Protection Schemes (SPS) to respond to system events and disturbance data that could potentially cause undue stress on its system as necessary to maximize grid total transfer capability, to improve long-term reliability and reduce negative impacts to the interconnected systems, as well as to benefit the interim ratings of the lines.[26]

23. Finally, PacifiCorp states that it is evaluating the use of advanced monitors in transformers at the new substations that will provide notification when the affected equipment is near failure. This technology, while not required by reliability standards, helps protect high-cost investments and improve reliability by providing for early detection of potential issues.

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[23] PacifiCorp Petition at 45.

[24] *Id.*

[25] *Id.* at 46.

[26] *Id.* at 47.

II. Notice of Filing and Responsive Pleadings

24. Notice of PacifiCorp's filing was published in the *Federal Register*, 73 Fed. Reg. 41,064 (2008), with interventions and protests due on or before July 24, 2008. Timely motions to intervene raising no substantive issues were filed by Horizon Wind Energy LLC, Arizona Public Service Company, the Transmission Agency of Northern California, and the Utah Division of Public Utilities. Timely motions to intervene and protests were filed by the Bonneville Power Administration (Bonneville), Industrial Customers of Northwest Utilities (Industrial Customers), and the Utah Municipal Power Agency (UMPA). Utah Associated Municipal Power Systems (Utah Systems) filed a timely motion to intervene and comments. On August 6, 2008, PacifiCorp filed a motion for leave to answer and an answer. On September 5, 2008, UMPA responded to PacifiCorp's answer.

25. Bonneville claims that PacifiCorp cannot establish a rebuttable presumption, as provided under Order No. 679, by satisfying the threshold criteria for eligibility for transmission incentive treatment under FPA section 219 with a showing, in pertinent part, that a transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion. Bonneville notes that PacifiCorp claims to meet this condition by virtue of its participation in the NTTG planning process. However, Bonneville contends that the Project was announced in May of 2007, while NTTG did not start its planning process until later that year. Thus, according to Bonneville, the Project could not have originated from the NTTG planning process.

26. Protesters argue that the requested 250 basis point ROE adder is too high. Bonneville asserts that, although some ROE adder would be appropriate, PacifiCorp's requested incentive is 100 basis points higher than any previously approved by the Commission. UMPA similarly argues that PacifiCorp has failed to justify such a large adder, calling the 250 basis point incentive rate adder "unprecedented."[27] UMPA also alleges that the risks attributable to the Project are reduced as a result of PacifiCorp's recovery of abandoned plant costs; thus, the proposed level of ROE adder is not warranted.[28] Utah Systems note that, although the Project may be larger than any for which incentives were previously granted, "an incentive return on equity generates dollars based on a percentage of the total equity investment."[29] According to Utah

[27] UMPA July 24, 2008 Protest at 9.

[28] *Id.* at 10 ("the abandoned plant rate incentive eliminates PacifiCorp's exposure to the very risks PacifiCorp relies on to justify its extraordinary 250 basis point adder").

[29] Utah Systems July 24, 2008 Comments at 4.

Systems, since a ROE on a large investment yields a greater number of dollars than the same ROE on a smaller investment, it is unclear why a greater percentage return is appropriate for a larger project. Bonneville and Industrial Customers contend that the large scope of the Project, which PacifiCorp relies on to justify such a large adder, was artificially created by virtue of PacifiCorp bundling a number of individual, smaller, projects together into one package.

27. As such, Bonneville and Industrial Customers argue that PacifiCorp has failed to demonstrate a nexus between the incentives sought and the investment being made. Industrial Customers contends that since PacifiCorp already planned certain transmission investments included in the Project, the ROE adder is not tailored to its actual risks and challenges. Further, it asserts that the scope and effects of the Project are not as large as PacifiCorp claims because it "is not one large transmission investment, but a series of eight separate and often unrelated transmission projects."[30] Bonneville urges the Commission to analyze each of the segments individually to determine if each is related to the other segments and whether there is a nexus for each to the requested incentive rate. In particular, Industrial Customers and Bonneville claim that segment A is a local transmission project, separately planned and operationally unrelated to the other segments.[31] They also question whether transmission that has been planned for some time for PacifiCorp to meet its load service obligations through routine investments warrants incentive rate treatment.[32]

28. UMPA similarly argues that PacifiCorp should not receive incentive rate treatment for transmission investments needed to serve the needs of existing customers.[33] UMPA suggests that the system upgrades proposed by PacifiCorp are "the kinds of routine investments made in the ordinary course of expanding the system to account for load growth."[34] Stating that PacifiCorp is required to maintain its system in order to serve load and respond to anticipated load growth, UMPA asserts that "current customers should not be forced to pay additional incentive rates in order to cause the transmission

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[30] Industrial Customers July 24, 2008 Protest at 5.

[31] *Id.* at 6; Bonneville July 24, 2008 Protest at 5.

[32] Bonneville July 24, 2008 Protest at 4; Industrial Customers July 24, 2008 Protest at 7.

[33] UMPA July 24, 2008 Protest at 5-7.

[34] *Id.* at 6.

provider to provide for the basic transmission service that the provider is obligated to provide . . ."[35] Bonneville and Industrial Customers make similar arguments.[36]

29. All four protesters assert that segments A, B, and C were requirements stemming from Mid-American Energy Holding Company's (MidAmerican) acquisition of PacifiCorp. According to Utah Systems, MidAmerican and PacifiCorp already received a construction incentive (merger approval), and further incentives now may be unnecessary. Bonneville and UMPA cite Commission precedent for rejecting a request for incentive rate treatment where a project had been ordered by the Commission in another proceeding.[37] As the Commission in *Westar* denied incentives when the applicant failed to offer evidence that conditions had changed since its prior commitments, UMPA asserts that PacifiCorp has also failed to provide any evidence that circumstances have changed since it committed to build segments A, B, and C as part of its merger with MidAmerican.

30. More generally, protesters claim that granting incentive rate treatment to PacifiCorp will not serve to promote new investment. Industrial Customers contend that PacifiCorp has not identified any regulatory and technology risks that other utilities would not have to face when making routine transmission investments, and that incentive rate treatment in this case would simply give PacifiCorp higher returns on investments it was already planning to make. Utah Systems state that investors may not stand to gain much from the requested incentives, because PacifiCorp plans that the additional revenues generated by the ROE will be used to reduce the transmission rates that otherwise would be paid by its retail customers. Utah Systems suggest that "the increased revenue credits to PacifiCorp's retail jurisdictions is the price of securing state approvals,"[38] and is concerned that the Commission in Order No. 679 did not envision retail rate relief as a valid reason for granting incentives at the federal level.

31. UMPA also raises concerns about the proposed credit to retail customers. UMPA believes that, as a result of the crediting mechanism, only PacifiCorp's wholesale

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[35] *Id.*

[36] *See* Bonneville July 24, 2008 Protest at 5 (routine investment necessary to meet wind generation interconnection requests); Industrial Customers July 24, 2008 Protest at 7 (normal and routine transmission investments related to system reliability and load growth).

[37] Bonneville July 24, 2008 Protest at 5-6 and UMPA July 24, 2008 Protest at 7-8 (citing *Westar Energy Inc.* (*Westar*), 122 FERC ¶ 61,268, at P 49-52 (2008)).

[38] Utah Systems July 24, 2008 Comments at 4-5.

customers would pay the proposed incentive rate. UMPA suggests that PacifiCorp has requested a higher incentive rate than necessary, given that it will only be recovered on ten percent of its transmission revenue requirement,[39] and concludes that the retail credit is preferential and unduly discriminatory.

32. Bonneville and UMPA request that the Commission set this case for hearing to determine a just and reasonable incentive rate treatment for the various segments of the Project[40] and to properly tailor any approved incentives to encourage investment without discriminating against wholesale customers.[41]

33. Finally, Bonneville does not object to PacifiCorp's requested incentive for recovery of prudently incurred development and construction costs if the Project is cancelled or abandoned "as a result of any action or inaction by a governmental authority."[42] But, Bonneville requests clarification that the clause "action or inaction by a governmental authority" does not include actions or inactions by Bonneville. Bonneville asserts that that provision should protect PacifiCorp from things such as denial of easements and regulatory approvals, but that action or inaction by Bonneville should not trigger cost recovery under that incentive.

III. <u>Discussion</u>

A. <u>Procedural Matters</u>

34. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2008), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

35. Rule 213(a) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a) (2008), prohibits an answer to a protest, unless otherwise permitted by the decisional authority. We are not persuaded to accept PacifiCorp's answer and UMPA's response and will, therefore, reject them.

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[39] *See* UMPA July 24, 2008 Protest at 11 (noting that PacifiCorp states it receives over ninety percent of its recovery on transmission investment through native load and retail ratemaking processes.)

[40] Bonneville July 24, 2008 Protest at 7.

[41] UMPA July 24, 2008 Protest at 2.

[42] Bonneville July 24, 2008 Protest at 6 (citing PacifiCorp July 3, 2008 Petition at 4).

B. Section 219 Requirement

36. In EPAct 2005, Congress addressed incentive-based rate treatments for new transmission construction.[43] Specifically, section 1241 of EPAct 2005 added a new section 219 to the FPA directing the Commission to establish, by rule, incentive-based (including performance-based) rate treatments for electric transmission. The Commission issued Order No. 679, which set forth processes by which a public utility could seek transmission rate incentives pursuant to section 219, including the incentives requested here by Petitioners.

37. Order No. 679 provided that a public utility may file a petition for declaratory order or FPA section 205 filing to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of FPA section 219. The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[44] Order No. 679 also established a rebuttable presumption that a project satisfies these threshold criteria for eligibility for transmission incentive treatment under section 219 if: (1) a transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) a project has received construction approval from an appropriate state commission or state siting authority.[45] Order No. 679-A clarified the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[46]

38. PacifiCorp asserts that the Project meets the rebuttable presumption under Order No. 679 since, "[v]irtually all segments of the Project were planned, coordinated and approved under the auspices of the … NTTG planning process." However, PacifiCorp also acknowledges that the NTTG formal planning process had not been fully developed when "Fast Track" review occurred, and further that certain portions of the Project were

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[43] *See* Pub L. No. 109-58, 119 Stat 594, 961 (2005).

[44] *See* 18 C.F.R. § 35.35(d) (2008).

[45] *See id.*; Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 47.

[46] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 49.

not subject to any regional planning process review at all.[47] Under those circumstances, we find that the Project is not eligible for the rebuttable presumption of relying on a regional planning process.

39. Nevertheless, we find that PacifiCorp has adequately demonstrated that the Project (with the exception of segment A) will ensure reliability and reduce transmission congestion, and therefore meets the requirements of FPA section 219 for incentive rate treatment. We find that segments B through H of the Project would establish for the first time a backbone of 500 kV transmission lines in PacifiCorp's Wyoming, Idaho and Utah regions.[48] This would provide PacifiCorp a platform for integrating and coordinating future regional and sub-regional electric transmission projects being considered in the Pacific Northwest and the Intermountain West, connecting existing and potential generation to loads in an efficient manner, thus reducing the cost of delivered power.[49] Also, the Petition cites the 2006 DOE National Electric Transmission Congestion Study and the 2004 Rocky Mountain Area Transmission Study in stating that the proposed Project will reduce congestion or maintain reliability in the Western Interconnection.[50] Additionally, the Project would establish a direct link between PacifiCorp's east and west control areas, providing numerous benefits including increasing transfer capability, reducing the need for curtailments, and reducing transmission congestion.[51]

40. With regard to segment A, which is a 230 kV segment connecting existing power substations at Walla Walla, Wallula and McNary, Washington and extending to Umatilla, Oregon, we conclude that PacifiCorp has not provided sufficient evidence to meet the requirements of FPA section 219 for incentive rate treatment and therefore, we decline to grant any incentive for this segment. In support of segment A, the Petition merely states that it "could be used to link existing and future sources of renewable resources to better benefit system power transfers."[52] There are no congestion studies or reliability assessments in the record to support a finding that segment A will either ensure reliability or reduce the cost of delivered power by reducing congestion, as required by our regulations to qualify for incentive rates. Accordingly, PacifiCorp has met the

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[47] *See* PacifiCorp Petition, Cupparo Affidavit at 15-16.

[48] *Id.* at 20 & n.41.

[49] *Id.* at 3, Cupparo Affidavit at 4, 7, and 19.

[50] *Id.* at 21-23, Cupparo Affidavit at 22.

[51] *See id.*, Cupparo Affidavit at 39.

[52] PacifiCorp Petition at 10. *See also* Cupparo Affidavit at 8-9.

requirements of FPA section 219 for segments B through H of the Project; however, we will deny incentive rate treatment for segment A of the Project, without prejudice to PacifiCorp re-filing with the required support for that portion of the Project.

C. Incentives and the Commission's Nexus Requirement

41. In addition to satisfying the section 219 requirement of ensuring reliability or reducing the cost of delivered power by reducing congestion, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. In Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[53] As part of our evaluation of whether the incentives requested are tailored to address the demonstrable risks or challenges faced by the applicant, the Commission has found the question of whether a project is "routine" to be particularly probative. In *BG&E*,[54] the Commission clarified how it will evaluate projects to determine whether they are routine and the effect this evaluation has on an applicant's request for incentives. Specifically, to determine whether a project is not routine, the Commission stated that it will consider all relevant factors presented by the applicant. For example, an applicant may present evidence on: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g., ensuring reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).[55]

42. The Project is an enormous undertaking by PacifiCorp to construct approximately 2,000 miles of new EHV transmission lines throughout six states (including 230 kV, 345 kV and 500 kV transmission lines). The Project will provide the first backbone 500 kV "superhighway" in this part of the Western Interconnection and may facilitate the addition of future 500 kV transmission lines in the area. The Project will improve transfer capacity; for example, segment B, when combined with the other segments of the Project, will increase transfer capacity by 1,400 MW, and significantly mitigate a

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[53] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[54] *Baltimore Gas and Electric Company*, 120 FERC ¶ 61,084, at P 52-55 (2007) (*BG&E*).

[55] This list provides some examples of evidence that may help inform the Commission whether a project is routine in nature, but is not intended to be exhaustive.

transmission constraint on the system.[56] The Bridger Expansion project (part of segment E) will increase transfer capacity by a significant amount.[57] In addition, the Project will relieve several other points of congestion within the PacifiCorp control areas.[58] Also, the Project will directly link PacifiCorp's east and west control areas, enabling PacifiCorp to make efficient use of resources to meet its load and reserve obligations, as well as minimize congestion and relieve loading along paths between Wyoming and areas west and south.[59] The Project will provide substantial benefits in terms of ensuring reliability in the region and will also reduce congestion costs.

43. Moreover, PacifiCorp faces significant risks and challenges in pursuing this Project. The Petition enumerates considerable siting, construction, regulatory, financing, and technology risks. Namely, the configuration of the Project[60] and the siting of its transmission facilities ahead of the siting for specific generation resources may lead to additional costs, delays, or modifications down the road. PacifiCorp notes that currently no 500 kV infrastructure exists within the Project footprint in Idaho, Utah and Wyoming; therefore, as the first entity to construct a new 500 kV system, it will be responsible for mitigating any impacts caused on the existing transmission system. PacifiCorp explains that the new 500 kV transmission system should not cause any overloads on the underlying lower voltage transmission system. It cites the need to mitigate possible overloads as the reason to construct a redundant transmission system, which effectively raises the costs and risks of incorporating a new higher voltage class of transmission in the area.[61]

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[56] *See* PacifiCorp Petition, Cupparo Affidavit at 9.

[57] *Id.* at Exhibit 4, p. IV.

[58] *See id.* at 22.

[59] *See id.* at Exhibit 5, p. 35.

[60] As noted above, PacifiCorp will employ a "hub and spoke" configuration that is characterized by major EHV transmission lines that connect areas with strong potential for generation resource development (hubs) to an enhanced transmission system (spokes) for delivery of capacity and energy to customers throughout the region.

[61] *See* PacifiCorp Petition at n.41.

44. We also find that the Project faces significant risks related to the magnitude of the financial investment required (estimated at $6 billion),[62] which represents more than a 330 percent increase in PacifiCorp's existing transmission rate base,[63] and the regulatory risks involved. There are significant siting issues because the individual segments must be approved by numerous states and several federal authorities, including the Bureau of Land Management and the United States Forest Service. Further, tribal issues and federal land management issues are implicated in the construction and development of the Project.

45. Further, PacifiCorp states that the Project will also facilitate the delivery of remote renewable resources, accommodating up to 3,000 MW of capacity from location-constrained renewable resources in Wyoming to distant load centers. We find that, in addition to the other bases discussed above, construction or enhancement of transmission facilities designed to provide access to these types of remote resources is not routine.

46. We do not agree with protesters' assertions that the large scope of the Project is an artificial creation of combining several individual, smaller projects, nor that the Commission should analyze each of the segments individually to determine whether there is a nexus for each. We conclude that each segment of this Project (with the exception of segment A, as discussed above) will improve PacifiCorp's transmission operations and, among other things, increase transfer capability. Moreover, even if we were to find that each segment is a separate project, which we do not, the Commission has held that an applicant "may present evidence that a group of projects, when considered in the aggregate, are not routine."[64] Hence, consistent with Commission precedent, we consider, and conclude that the Project as a whole satisfies the nexus requirement.

47. Similarly, Bonneville and Industrial Customers' objections that transmission already planned to meet PacifiCorp's load service obligations should not receive incentive rate treatment are not persuasive. We explained in Order No. 679 that "[i]nclusion of a facility in a plan does not mean that a project can or will get built," and that even in such instances the granting of incentives may help to secure financing.[65]

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[62] This cost estimate reflects a single circuit configuration. However; we note that PacifiCorp seeks equity partners to upsize segments D, E and F from a single circuit to double circuit configuration, and that could significantly increase the Project costs. *Id.* at n.9.

[63] *Id.* at 7, Cupparo Affidavit at 7, 29-30.

[64] *BG&E*, 120 FERC ¶ 61,084 at P 53.

[65] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 35.

Additionally, PacifiCorp has provided ample evidence that by adding the additional transmission capability, the Project will ensure reliability and provide other benefits, as well as serve to meet load service obligations.

48. Regarding protesters' claims that PacifiCorp is already obligated to build certain segments as a result of its merger with MidAmerican, and that it should not receive incentive rate treatment consistent with *Westar*, we find that this case is distinguishable. In *Westar*, the Commission found that the petitioner had not explained why it required incentives to encourage investment in its project when the Commission had already directed it to increase transfer capability on the transmission line as part of mitigation requirements in another proceeding. The Commission explained that projects an entity is required to build may not necessarily qualify for incentives because there is that obligation and a high assurance of recovery of the related costs.[66] With respect to PacifiCorp, the record does not indicate that this Commission required the parties to construct any transmission as a condition for approval of the MidAmerican/PacifiCorp merger.[67] The parties apparently made commitments to build segments A, B, and C in proceedings before various state commissions, but PacifiCorp asserts that "Segments B and C represent significant expansions, of the original transaction commitments."[68] As such, the circumstances have changed since PacifiCorp entered into those transaction commitments. These distinctions, in conjunction with the manner in which segments B and C are integrated with the Project as a whole, lead us to conclude that incentives are warranted to encourage investment for these segments.

49. Finally, we address concerns raised by Utah Systems that investors may not stand to gain much from undertaking the risks associated with this investment. Because the additional revenues generated by the ROE adder will be used to reduce the transmission rates of PacifiCorp's retail customers, Utah Systems suggest that the increased revenue credits are the price of securing state approvals, which was not identified as a reason for granting incentives in Order No. 679. There is no evidence in the record regarding the impact of the requested incentives on state commission approval, nor is there any reason to believe the incentives will not attract investors to the Project. We therefore dismiss these claims by Utah Systems as speculative.

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[66] *Westar*, 122 FERC ¶ 61,268 at 49-50, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

[67] *See MidAmerican Energy Holdings Co.,* 113 FERC ¶ 61,298 (2005), *reh'g denied*, 118 FERC ¶ 61,003 (2007).

[68] PacifiCorp Petition at n.32.

50. Accordingly, for the reasons discussed above, we find that PacifiCorp's Project is not routine in nature, and, therefore, meets the nexus requirement to be eligible for incentives under Order No. 679.

D. Requested Incentives

1. ROE Adder

51. PacifiCorp's Project is unparalleled in terms of its size, cost, siting risk, regulatory and financial risk, technology-related risks, and other factors. In addition to the numerous risks and challenges associated with this Project, PacifiCorp will require an enormous investment (well in excess of $5 billion, even without the estimated $108 million needed to construct segment A), thereby presenting financing challenges not faced by the ordinary transmission investment. It is also important to recognize that PacifiCorp has voluntarily proposed to invest a large amount of capital to build backbone 500 kV transmission facilities through large portions of its system, which will ensure reliability and/or reduce congestion costs and facilitate the construction of additional high voltage facilities throughout the region. This, together with the vast size of the Project (roughly 2,000 miles of transmission lines, even excluding segment A) and the extended period of time for completion (through 2014) is the type of infrastructure development envisioned by EPAct 2005 and Order No. 679. All of these factors support the request for an incentive ROE adder, which PacifiCorp believes will attract capital for the Project, when added to the base ROE to be determined in a future rate case.

52. We also do not agree with Utah Systems' objection that, since a ROE on a large investment yields a greater number of dollars than the same ROE on a smaller investment, a greater percentage return is not appropriate for a larger project. In Order No. 679, the Commission permitted, when justified, an incentive-based ROE to all public utilities for new investments in transmission facilities that benefit consumers by ensuring reliability or reducing congestion costs.[69] The Commission concluded that ROE incentives encourage investment, and the granting of ROE incentives could make transmission projects more attractive and, therefore, more likely.[70] In evaluating these incentives, the Commission considered "the appropriateness of a higher ROE as a

[69] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 91.

[70] *Id. See also Commonwealth Edison Co.*, 124 FERC ¶ 61,231, at P 29 (2008) ("A higher ROE encourages new transmission investment because it provides a longer term higher return on equity after the project comes on line, only for that new investment, and makes that transmission project more attractive as an investment.").

mechanism for increasing investment in new capacity."[71] In this instance, we find that PacifiCorp's incentive rate adder is justified based on the requirements of Order No. 679.

53. Accordingly, as discussed further below, we grant a 200 basis point incentive for the Project, to be added to the base ROE determined in a future PacifiCorp section 205 filing. Our grant of the incentive ROE adder will be bound by the upper end of the zone of reasonableness.

2. Recovery of Abandoned Plant Costs

54. PacifiCorp requests recovery of all prudently-incurred development and construction costs in the event the Project is cancelled or abandoned as a result of its inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority or regulatory agency, for reasons beyond PacifiCorp's control. In Order No. 679, we found that this incentive is an effective means to encourage transmission development by reducing the risk of non-recovery of costs.[72] Consistent with Order No. 679, PacifiCorp has shown a nexus between the recovery of prudently-incurred costs associated with abandoned transmission projects and its planned investment. Thus, we will grant the request for the recovery of prudently-incurred development and construction costs if the Project is cancelled or abandoned, in whole or in part, as a result of PacifiCorp's inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority or regulatory agency, for any reason determined to be outside PacifiCorp's control in subsequent section 205 filings.[73]

55. We find that this incentive will be an effective means to encourage the completion of the Project. For example, besides its scope and size, this Project requires timely approvals from multiple jurisdictions, along with various federal approvals. Dependence upon approval by multiple jurisdictions introduces a significant element of risk to this Project that is not faced by utilities building transmission facilities within a single jurisdiction. Granting the request for an abandonment incentive will help to ameliorate these risks and help ensure completion of the Project.

56. Regarding Bonneville's request for clarification regarding whether its actions could be construed as those of a "governmental authority" and thus potentially trigger PacifiCorp's ability to recover abandoned plant costs, we dismiss this request as premature. We will address any request for recovery of abandonment costs in the context

[71] *See id.* P 85.

[72] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163.

[73] *Id.* P 165-66.

of the required filing under FPA section 205. In that proceeding, PacifiCorp will bear the burden of demonstrating that the Project was cancelled or abandoned as a result of its inability to obtain necessary approvals, or as a result of any action or inaction by a governmental authority, or regulatory agency, for reasons outside PacifiCorp's control.

3. Total Package of Incentives

57. As noted earlier, in Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that the total package of incentives requested is tailored to address the demonstrable risks or challenges faced by the applicant. The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis. Consistent with Order No. 679,[74] the Commission has, in prior cases, approved multiple rate incentives for particular projects.[75] This is consistent with our interpretation of FPA section 219 as authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of the FPA section 219 and that there is a nexus between the incentives being proposed and the investment being made.

58. PacifiCorp states that the total package of incentives that it has requested is necessary to compensate it for the substantial risks posed by the Project. It also asserts that the overall risks associated with building the Project are not fully mitigated by an abandonment incentive, and argues that reducing its requested ROE adder because it has been granted an abandonment incentive "would misalign the scope of PacifiCorp's risks with its narrowly tailored incentive package."[76]

59. We find that PacifiCorp has shown, consistent with Order No. 679-A, that multiple incentives are justified to address the demonstrable risks or challenges faced by the Project.[77] An ROE adder and abandoned plant costs incentive rate treatment are not mutually exclusive, and PacifiCorp has explained why it is seeking each incentive and

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[74] Order No. 679, FERC Stats. & Regs. ¶ 31, 222 at P 55.

[75] *See, e.g.*, *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058, at P 60, 122 (2006) (approving ROE at the upper end of the zone of reasonableness and 100 percent abandoned plant recovery); *Duquesne Light Co.*, 118 FERC ¶ 61,087, at P 55 (2007) (granting an enhanced ROE, 100 percent CWIP, and 100 percent abandoned plant recovery).

[76] PacifiCorp Petition at 39.

[77] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21, 27.

how each is relevant to the proposed Project. As discussed above, PacifiCorp faces significant risks and challenges in pursuing this Project. We find here that granting the ROE incentive, together with abandoned plant recovery, will encourage greater participation from potential equity partners. Due to the number of approvals needed, the cost of the Project construction, the fact that transmission construction will precede siting of new generation, and other factors cited, PacifiCorp is exposed to greater risks of project failure which results in increased risks to debt. The two incentives sought by PacifiCorp serve different purposes; thus, we reject protestors' arguments that the total package of incentives is unwarranted, and find that PacifiCorp has shown a nexus for the total package of incentives. However, we will approve a 200 basis point adder rather than the 250 basis point adder requested by PacifiCorp. A 200 basis point adder is a significant increase in the return on equity that will be earned on this ambitious infrastructure investment; we find that such adder is just and reasonable under the circumstances presented by PacifiCorp's application.

4. **<u>Other Issues</u>**

60. In Order No. 890, the Commission required transmission providers to open their transmission planning process to customers, coordinate with customers regarding future system plans, and share necessary planning information with customers.[78] The Commission identified important benefits stemming from that requirement, finding that an open, transparent, and coordinated transmission planning process would increase the ability of customers to access new generating resources, including renewable resources, and would promote efficient utilization of transmission.[79] Such potential benefits are particularly important with respect to the development of new backbone transmission facilities like the Project. PacifiCorp indicates in the Petition that it is continuing to explore the proper size and exact location of some segments of the Project.[80] To the extent that such aspects of the Project remain under consideration, the Commission expects that PacifiCorp will address them as appropriate through the transmission planning process required by Order No. 890.[81]

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[78] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 3.

[79] *Id.* P 3, 5.

[80] *See, e.g.*, PacifiCorp Petition at 13, n.23 (regarding the section of segment E that is intended to connect the Populus substation to the Hemingway substation) and Cupparo Affidavit at 12 (regarding possible upsizing of segment G).

[81] In July 2008, the Commission accepted PacifiCorp's Order No. 890 transmission planning compliance filing, as well as comparable filings submitted by other

(continued…)

61. UMPA raises concerns about the proposed credit to retail customers. UMPA believes that, as a result of the crediting mechanism, only PacifiCorp's wholesale customers would pay the proposed incentive rate. UMPA suggests that PacifiCorp has requested a higher incentive rate than necessary, given that it will only be recovered on ten percent of its transmission revenue requirement, and concludes that the retail credit is preferential and unduly discriminatory.

62. We find that UMPA's assertion is beyond the scope of this proceeding. Any future proposal by PacifiCorp to provide a credit to its retail customers is a matter for state commission approval. We also disagree that the requested incentive is higher than necessary, as discussed above. To the extent that UMPA is concerned about the equities of rate allocation between wholesale and retail customers, this issue is properly raised when PacifiCorp files under FPA section 205 to recover costs associated with the Project.

63. Finally, we deny protestors' requests that we set this matter for hearing. In general, the Commission sets matters for a trial-type evidentiary hearing only to resolve material issues of law and fact. In this case, however, since PacifiCorp has satisfied the requirements of Order No. 679, except for segment A, we conclude that setting this matter for hearing is not appropriate.

The Commission orders:

The petition for declaratory order is hereby granted in part, and denied in part, as discussed in the body of this order.

By the Commission. Commissioners Kelly and Wellinghoff concurring with separate statements attached.
Commissioner Moeller not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

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transmission providers in the region and the related NTTG Agreements, subject to modifications and further compliance filings. *Idaho Power Co.*, 124 FERC ¶ 61,053 (2008).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp Docket No. EL08-75-000

(Issued October 21, 2008)

KELLY, Commissioner, *concurring:*

This order addresses a petition for declaratory order seeking incentive rate treatment filed by PacifiCorp. PacifiCorp requests two transmission rate incentives for its extra-high voltage (EHV) transmission project: a 250 basis point adder to its base return on equity (ROE) and recovery of prudently-incurred abandonment costs if the Project is cancelled due to factors beyond its control.

It is appropriate to consider Segments B through H of PacifiCorp's EHV petition as a single, integrated transmission project. In applying the project-based criteria that I have relied upon in previous transmission incentives proceedings to determine whether PacifiCorp's EHV transmission project warrants incentive rate treatment,[1] I conclude that it does. Thus I concur with the decision to grant the requested incentives, as modified in the order.[2] I take this opportunity to present my reasons for doing so.

PacifiCorp's objective in undertaking this EHV transmission project, among other things, is to establish a 500 kV backbone throughout 6 western states, efficiently integrate wind resources into the grid, and connect PacifiCorp's Rocky Mountain Power and Pacific Power control areas. The overall project is comprised of eight segments, which PacifiCorp has organized into four priority groups. Intervening parties argued that the various segments are not necessarily interrelated and should be analyzed on an individual basis. In a recent transmission incentives case, I warned against evaluating disparate transmission projects as a single, integrated transmission project.[3] However, for the reasons

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[1] *American Electric Power Service Corporation*, 118 FERC ¶ 61,041 (2007).

[2] The order denies incentive rate treatment to Segment A. I concur with this decision. PacifiCorp has neither demonstrated it is an integrated segment of the overall project nor shown it to merit incentives on an individual basis.

[3] *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 (2008). See separate statement (continued…)

listed below, I am satisfied that Segments B through H comprise a single integrated project. In this case, I assessed the merits of each project individually and determined that, with the exception of Segment A, all segments would be eligible for some form of incentive rate treatment. However, I also considered whether these segments are an integrated whole. I find that Segments B through H are interrelated because they satisfy the overarching goals of building an EHV transmission backbone across six states and bringing renewable resources to load centers. When considered in the aggregate, PacifiCorp's EHV transmission project represents an exceptional undertaking, larger than any other project the Commission has yet seen (within the context of incentives applications) as measured across any number of metrics, including total estimated costs, total line miles and geographic footprint. For example, while Segments B and C provide a variety of benefits when considered in isolation, they also enable PacifiCorp to achieve the planned transfer capability rating of subsequent segments.[4] Though Segment G is geographically separate from other parts of this transmission proposal, it is a piece of Gateway South, which is designed to provide access to resources from Wyoming to parts of Utah and Nevada. Because the 500 kV infrastructure proposed by PacifiCorp is so much larger in voltage terms than the exiting transmission infrastructure in parts of Idaho, Utah, and Wyoming, PacifiCorp must construct Segments, D, E, and F to provide a fully redundant transmission system. Finally, PacifiCorp is building Segment H to provide for the integration of PacifiCorp's east and west control areas, and to further support delivery of renewable energy.

It is appropriate to grant PacifiCorp's request for incentive rate treatment, as modified by the order. In absolute terms, as well as relative to PacifiCorp's current transmission plant in service, the financial undertaking here is significant. The total estimated cost of Segments B through H is $5.5 billion, representing over 3 times PacifiCorp's already large $1.8 billion transmission plant in service. The Project adds roughly approximately 2,000 miles of new EHV transmission infrastructure across 6 states—Nevada, Idaho, Oregon, Utah, Washington, and Wyoming—and the estimated time to completion for the final segments is 2014. While PacifiCorp's home territory is in most of these states, coordinating regulatory approvals across a large number of authorities will require significant effort and resource commitment. Finally, I believe that the EHV transmission project will produce an array of public interest benefits. It will create an EHV backbone transmission system that connects existing and future resources,

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of Commissioner Kelly issued August 27, 2008.

[4] PacifiCorp July 3, 2008 Petition for Declaratory Order, Docket No. EL08-75-000, Appendix A at 10.

including renewables, with consuming areas. PacifiCorp's project will facilitate delivery of as many as 3,000 MW from location-constrained renewable resources in Wyoming. Moreover, once this backbone has been installed, it should facilitate the addition of future 500 kV infrastructure at a lower cost.

I concur with the specific incentives approved in this order—recovery of prudently-incurred abandonment costs and a 200 basis point ROE adder. I have previously approved the abandoned plant incentive for projects that I believe to be eligible for incentives. In this case such treatment is supported by the long construction period, large cost, both in absolute terms and as a percentage of current rate plant in service, and risks associated with the regulatory processes.

With respect to an incentive ROE adder, PacifiCorp asserts that the overall risks associated with building the project are not fully mitigated by an abandonment incentive. While I have previously stated that basis point adders to ROE may be used to overcome either financial or non-financial impediments to transmission expansion,[5] I have approved ROE adders in a limited number of proceedings and those adders were well below 200 basis points. In this case, I agree with the order and support an ROE adder of 200 basis points for Segments B through H. Order No. 679-A states "the most compelling case for incentive ROEs are new projects that present special risks or challenges, not routine investments made in the ordinary course."[6] PacifiCorp's EHV transmission project meets this standard.

There are several features of PacifiCorp's project that subject PacifiCorp to risks and challenges not seen in the ordinary course of business. PacifiCorp will be installing Segments B through H over the course of the next five and half years at an estimated cost of $5.5 billion. While I generally prefer approving recovery of 100 percent of prudently incurred Construction Work In Progress (CWIP) incentive to mitigate some of the risks of constructing a project over a long development schedule, PacifiCorp asserts that CWIP does not provide significant protection in this case. As noted above, the abandoned plant incentive is not sufficient to address such risk alone and therefore an ROE adder is appropriate. PacifiCorp will also be deploying an assortment of advanced technologies.

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[5] *Bangor Hydro-Electric Company*, 117 FERC ¶ 61,129 (2006) (*Opinion No. 489*).

[6] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, at P 60 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

I believe that PacifiCorp's EHV transmission project provides public interest benefits that, on balance, contribute to the appropriateness of the ROE adder. The geographic and financial scope of the overall project when combined with PacifiCorp's decision to undertake transmission development ahead of generation creates significant financial risk that merits an incentive ROE adder. Rather than embark upon an incremental, small-scale expansion of its transmission system, PacifiCorp elected to construct this wide-ranging EHV transmission project. As PacifiCorp notes, this represents a departure from convention and presents novel investment risks. An incentive ROE adder is appropriate here as I do not believe that other incentives discussed in Order 679 address this circumstance. It is significant that establishing a "first-of-its-kind energy superhighway" connecting Wyoming, Idaho, Utah and Oregon will offer benefits to future developers of EHV transmission lines as they will likely face fewer engineering and system reliability obstacles.

There are also opportunities for third party equity partnership at various points in the overall project. Segments D and E appear to be on course to be jointly-owned with Idaho Power, and there are further opportunities for third party equity partnership on other segments. Segments F, G, and H are sufficiently flexible to allow for "upsizing" (i.e. from a single circuit to a double-circuit system or from 230 kV to 500 kV) or reconfiguration, depending on participation of potential equity partners. PacifiCorp states that it is "actively working with potential equity partners to determine the interest and commitment to such an upsize."[7] Approval of incentives here offers PacifiCorp an appropriate incentive to progress with development of all project segments and provides certainty with respect to approved incentives that should promote equity partnerships. In instances where the Commission can support joint ownership and "upsizing" of infrastructure, I believe that incentive rate treatment is appropriate. In future proceedings, I would support approval of a minimum level of incentives (e.g. a minimum ROE adder) and condition further incentives, such as supplemental ROE basis points, on completing equity partnership arrangements and commitments to upsizing transmission infrastructure.

Accordingly, I respectfully concur with this order.

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Suedeen G. Kelly

[7] PacifiCorp July 3, 2008 Petition for Declaratory Order, Docket No. EL08-75-000, at 5 n.9.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp Docket No. EL08-75-000

(Issued October 21, 2008)

WELLINGHOFF, Commissioner, concurring:

In today's order, the Commission approves a 200 basis point incentive ROE adder for PacifiCorp in connection with its Energy Gateway Transmission Expansion Project. I agree with that decision. I write separately to highlight important characteristics of this project that I believe warrant this significant incentive ROE adder.

I have dissented from numerous orders in which I felt that the majority undermined the nexus requirement that is an essential component of Order No. 679 and inappropriately granted incentive ROE adders.[1] By contrast, I agree that this project satisfies the nexus requirement. It is noteworthy that this project is, as described in today's order, "the first backbone 500 kV 'superhighway' in this part of the Western Interconnection and may facilitate the addition of future 500 kV transmission lines in the area."[2] At least as important, I believe that this project is a non-routine investment worthy of the significant incentive ROE adder granted here because it will use advanced technologies that will benefit all users of the grid and ultimate consumers, and because it will significantly increase the availability of renewable energy resources.

With respect to the use of advanced technologies, PacifiCorp provides substantial detail in its required technology statement and accompanying testimony. For example, PacifiCorp describes its plans concerning advanced conductor technology, Static VAR Compensators, and phase shifters, among other technologies.[3] PacifiCorp Witness John Cupparo states that "[r]eliance on novel technologies inherently posts increased risks in the form of added uncertainty as to how they will perform within the context of this large

[1] *See, e.g.*, *Commonwealth Edison Co.*, 122 FERC ¶ 61,037 (2008) (dissent in part of Commissioner Wellinghoff); *Virginia Elec. and Power Co.*, 124 FERC ¶ 61,207 (2008) (dissent of Commissioner Wellinghoff); *Duquesne Light Co.*, 125 FERC ¶ 61,028 (2008) (dissent in part of Commissioner Wellinghoff).

[2] *PacifiCorp*, 125 FERC ¶ 61,076 at P 42 (2008).

[3] PacifiCorp Petition at 41-48 and Cupparo Affidavit at 24-29.

project."[4] While recognizing such risks and challenges, PacifiCorp also states that it "is committed to optimizing the technology that will be utilized by the Project."[5]

As I have discussed previously, I believe that consideration of advanced technologies and their associated risks and challenges is an appropriate component of the nexus analysis that the Commission conducts in evaluating applications for incentives under Order No. 679.[6] Consistent with such consideration, today's order accounts for technology-related risks in evaluating PacifiCorp's incentives request.[7]

With respect to increasing the availability of renewable energy resources, PacifiCorp states that this project will facilitate the delivery of up to 3,000 MW of capacity from location-constrained renewable resources in Wyoming to distant load centers.[8] I agree with the statement in today's order that construction or enhancement of transmission facilities designed to provide access to these types of remote resources is not routine.[9] I have stated previously that amid heightened concerns about climate change and dependence on foreign oil, it is essential that our country take steps to accelerate the integration of clean, reliable, domestic renewable energy resources into our energy portfolio.[10] In light of the broad and substantial benefits associated with increasing the availability of renewable energy resources, I continue to believe that it is appropriate for the Commission to provide investment incentives in this area. I also note that in granting such incentives, it remains important for the Commission to promote the use of intelligent and efficient technologies that optimize operation of the facilities at issue.

For these reasons, I concur with today's order.

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Jon Wellinghoff
Commissioner

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[4] Cupparo Affidavit at 32.

[5] PacifiCorp Petition at 42.

[6] *See, e.g.*, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008) (dissent in part of Commissioner Wellinghoff at 1-4); *Northeast Utilities Service Co.*, 124 FERC ¶ 61,044 (2008) (dissent of Commissioner Wellinghoff at 2-3).

[7] *PacifiCorp*, 125 FERC ¶ 61,076 at P 43, 51 (2008)

[8] *Id.* P 45.

[9] *Id.*

[10] *See Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007) (concurrence of Commissioner Wellinghoff at 2).

Docket No. UE-
Exhibit PPL/500
Witness: Darrell T. Gerrard

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Darrell T. Gerrard

March 2010

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

A. My name is Darrell T. Gerrard. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. I am Vice President of Transmission System Planning.

Qualifications

Q. Briefly describe your education and business experience.

A. I hold a Bachelor of Science in Electrical Engineering (Power Systems Major) from the University of Utah and Certificate of Completion with Honors in Electrical Technology from Utah Technical College at Salt Lake. My experience spans more than 30 years in the electric utility industry. I've had working experience and management responsibility for a number of functional organizations at PacifiCorp including: Area Engineering, Area Planning, Region Engineering, transmission and distribution ("T&D") Facilities Management, Transmission, Substation and Distribution Engineering, System Protection and Control, T&D Project Management and Delivery, Asset Management, Electronic Communications, Hydro System Engineering, Transmission Grid Operations, and most recently, Transmission System Planning.

In my current position, I am responsible for transmission planning activities required to support PacifiCorp's existing and future planned bulk transmission system. I am also responsible for the conceptual and detailed system planning and architecture associated with the Company's comprehensive long-term transmission expansion plan known as Energy Gateway.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide additional details and technical information, in support of the testimony of Company witness Mr. John A. Cupparo, on the Company's decision to build the double-circuit 345 kilovolt ("kV") Populus to Terminal transmission line (Phase I and II), which is part of Segment B of Energy Gateway (see Exhibit PPL/401). Specifically, my testimony:

- Provides an overview of the Populus to Terminal transmission line.
- Explains that the benefits of adding this transmission line are to meet future load and resource requirements for customers and to maintain system reliability, consistent with the standards set by the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC").
- Explains the analyses the Company performed that support the decision to invest in this line.
- Describes the competitive procurement process used to make the investment and how cost savings opportunities were identified.
- Provides an overview of the construction process.

Overview of Transmission Project

Q. Please describe the scale and size of the Populus to Terminal transmission segment.

A. Populus to Terminal will add 135 miles of new transmission line, over 8,600,000 linear feet of conductor and approximately 900 poles will be installed on new foundations.

Q. Please describe the transmission investment included in this rate case.

A. In this case, the Company is seeking cost recovery for the Populus to Terminal transmission segment of Energy Gateway, described in more detail in the direct testimony of Mr. Cupparo. A map showing the entire route of the Populus to Terminal segment is shown in Exhibit PPL/402. The Company expects the total investment in the Populus to Terminal segment to be approximately $839 million, based on project cost estimates detailed in Exhibit PPL/501 and expects the line to be in service by December 31, 2010.

Q. What is the purpose of the Populus to Terminal transmission segment?

A. In addition to the project benefits described in the testimony of Mr. Cupparo, the purpose of the Populus to Terminal transmission line is to:

- Increase the overall transmission capacity in the existing transmission corridor between southeast Idaho and northern Utah, where the existing system has limited capacity and has demonstrated operational limitations.
- Meet the immediate need to: (1) improve system reliability in the area and maintain compliance with national electrical system reliability standards by installing new transmission capacity to ensure the system can sustain transmission outages north of Terminal Substation without curtailing loads, generation or impacting the PacifiCorp East Control Area and neighboring transmission balancing authority areas; and (2) improve the Company's ability to perform maintenance on transmission facilities

between Populus and Terminal by having alternative transmission paths that allow facilities to be taken off-line and maintained.

- Meet the transmission capacity and reliability requirements necessary to deliver resources to loads as specified in the annual Loads and Resource plans submitted to PacifiCorp under requirements of its Open Access Transmission Tariff ("OATT").
- Provide PacifiCorp with options and greater flexibility when considering future planned resources to meet customers' growing demands for energy service requirements while meeting current and future energy requirements that may be mandated by state and federal regulation.
- Facilitate the integration of potential new energy resources in Wyoming, Utah, Idaho and Oregon, and help support economic development in those states.
- Integrate with future Energy Gateway segments to increase transfer capability between PacifiCorp's east and west control areas in order to balance generating resources and loads, and enable commercial energy purchases or sales while allowing integration of new renewable generation resources.
- In the long term, provide an incremental increase in transmission capacity and reliability benefits for future Energy Gateway transmission segments planned between Wyoming, Idaho, Utah, Oregon and Washington, and interconnect the region in general.

Need for and Benefit of Additional Transmission

Q. What information was used in determining the need and justification for this investment?

A. PacifiCorp's OATT describes PacifiCorp's requirements and obligations to provide transmission service.[1] Section 28.2 defines PacifiCorp's responsibilities, which include the requirement to "plan, construct, operate and maintain the system in accordance with good utility practice." Section 31.6 defines the requirement for network customers to supply annual load and resource updates for inclusion in planning studies. The Company solicits this data annually to determine future load and resource requirements for all transmission network customers including PacifiCorp's network and third-party customers. The Company's retail loads comprise the bulk of the transmission network customer needs including those in Oregon. Section 28.3 includes the requirement for PacifiCorp to provide "firm service over the system so that designated resources can be delivered to designated loads." These future requirements and needs will be met via Energy Gateway and its segments, including the Populus to Terminal.

Q. Are other transmission performance requirements besides growing customer energy demand driving the need for this system investment?

A. Yes. In meeting the current and future customer energy needs described above, the Company must maintain a level of system reliability in order to provide adequate transmission service. The NERC and the WECC have recently adopted and enacted a significant number of standards and guidelines that specify in detail

[1] PacifiCorp's OATT may viewed at http://www.oasis.pacificorp.com/oasis/ppw/PACRESTATEDOATTASOF1-10-10.PDF

the levels of system performance that entities like PacifiCorp must maintain during the planning, operation and ongoing maintenance of their bulk electric system. NERC's reliability standards were approved by the Federal Energy Regulatory Commission ("FERC") and are mandatory for all FERC-jurisdictional entities. These reliability standards are targeted at improving the security and reliability of the nation's electric infrastructure and, specifically in PacifiCorp's case, the WECC region. Investments made in Populus to Terminal will help PacifiCorp comply with these mandatory reliability requirements. Further, the investment will provide reliability benefits to future planned high-voltage transmission additions interconnecting Wyoming, Utah, Idaho, Oregon and the region.

Q **Are there examples where these new reliability standards and guidelines resulted in changes to the system and its operation, which drives investments required in transmission?**

A. Yes. In early 2008, PacifiCorp performed an operational analysis of the transmission system north of the Ben Lomond substation. As a result of this analysis, and reflective of NERC and WECC standards and guidelines, the system firm transmission capacity was reduced from approximately 775 MW to 430 MW during heavy-load hours and reduced from approximately 900 MW to 620 MW during light-load hours. This reduction in firm capacity was a result of NERC and WECC standards and guidelines that require transmission capacity to be reduced due to potential outage risks associated with multiple transmission lines being located adjacent to each other in common corridors. The investment in the

Populus to Terminal segment is required to increase the firm capacity in this part of the transmission system.

Q. How did the Company determine that additional transmission capacity was needed?

A. The Company utilizes the Integrated Resource Plan ("IRP") to review whether additional transmission capacity is needed. The IRP uses a public process to develop a framework for the prudent future actions required to ensure the Company continues to provide reliable and least-cost electric service to its customers. It must do this while also striking an expected balance between cost and risk over the planning horizon and taking into consideration environmental issues and the energy policies of PacifiCorp's states. As stated in the 2008 IRP, "PacifiCorp's IRP mandate is to assure, on a long-term basis, adequate and reliable electricity supply at a reasonable cost and in a manner consistent with the long-run public interest."[2]

Q. Did the Company make any commitments to add transmission capacity?

A. Yes. During the MidAmerican Energy Holdings Company ("MEHC") acquisition of PacifiCorp in 2006, the Company committed to increase the transmission capacity by 300 MW from southeast Idaho to northern Utah. The objectives of the transaction commitment were to:

- Enhance the reliability of the only high use commercial path between Idaho and Utah;
- Provide for increased transfer capability between PacifiCorp's east and west control areas; and

[2] 2008 IRP at p. 19.

- Facilitate the delivery of future power from wind projects in Wyoming and Idaho, and provide PacifiCorp with greater flexibility and the opportunity to consider additional options regarding future planned generation capacity additions.

Q. Describe how the Populus to Terminal transmission segment complies with the IRP and MEHC commitment.

A. The Populus to Terminal transmission line segment is designed to meet load growth, future customer energy service requirements and improve overall system reliability. Based on the Company's 2008 IRP forecasts, PacifiCorp's network load obligation is expected to grow during the next 10 to 20 years. In addition, operational reserve obligations required to balance and maintain system reliability will increase over time as they are a function of load served. The existing transmission capacity from southeastern Idaho into Utah is fully subscribed and no additional capacity can be made available without the addition of new transmission lines. The Populus to Terminal line will add significant new incremental transmission capacity (1,400 MW planned) to this area of the system and will help integrate other future planned resources, market purchases and sales as necessary to help control energy costs. The investment also improves the system reliability as needed, which I discuss later in my testimony. All of the above support PacifiCorp's IRP and the commitments made by MEHC.

Q. Has the Company performed other studies and analyses that demonstrate the need to improve the reliability of the transmission system in this area?

A. Yes. In addition to the long-term energy resource needs discussed in the testimony of Mr. Cupparo, the Company performed specific analysis in late 2007 and 2008 addressing several system disturbance events that severely impacted generation, customers, and the operation of the transmission system. These events also impacted other utilities interconnected to PacifiCorp's transmission system.

Q. Will Populus to Terminal aid in preventing the recurrence of these types of disturbances?

A. Yes. It is evident from these disturbances and the resulting analysis that the transmission system in this area does not have the necessary capacity and reliability to meet all of the system operating conditions. NERC electric system reliability standards require that the system demonstrate adequate performance for all expected operating conditions including multiple contingencies. There were five system disturbances since September 2007 for which the Populus to Terminal line directly mitigates the risk of reoccurrence.

Q. Please provide further explanation of how Populus to Terminal will aid in the prevention of these types of system disturbances.

A. Three of these disturbances occurred on the system north of Ben Lomond substation and two occurred south in the Ben Lomond to Terminal section. These disturbances resulted in system overloads, curtailments of schedules, repeated curtailments of interruptible loads and generation reductions in Wyoming, Utah and other surrounding states. The three disturbances occurred on September 27, October 15 and October 21, 2007, during periods of heavy flow northbound from the Terminal Substation towards Ben Lomond and into Idaho and on into the northwest. As a result, over 1,450 customers were affected by the first outage, and some customer loads were either interrupted and/or reduced during all three outages. Generation curtailments and adjustments of more than 1,000 MW had to be requested for all three incidents including reduced generation from Dave Johnston and Naughton plants in Wyoming. Details and analysis of the system performance during the events and transmission limitations are detailed in PacifiCorp System Disturbance Report dated November 11, 2007, and PacifiCorp's Abbreviated System Disturbance Report to WECC dated January 28, 2008.

On November 27 and November 30, 2007, two disturbances occurred on the Ben Lomond to Terminal section of the system, causing overloads on three WECC designated and monitored transmission paths. The disturbances impacted more than 400 MW of PacifiCorp generation along with generation interconnected to three other utilities in surrounding states.

Based on the system performance, studies and analysis, it is clear that the existing system requires new capacity to meet expected operating conditions and reliability requirements on both a short and long-term basis. The investment in the Populus to Terminal line is the first step in providing the needed capacity.

Q. What is the transmission capacity and limitations on this system today?

A. The existing transmission capacity in the area between Salt Lake City and southeast Idaho is fully subscribed for firm service and has limited transfer capability between several key transmission substations (Terminal, Ben Lomond, and proposed Populus) connecting generation facilities in Idaho, Wyoming and Utah. No new capacity will be available until new transmission facilities are constructed. The limitations and system performance deficiencies are discussed later in my testimony. These limitations restrict the ability to transfer firm energy between PacifiCorp's Eastern Control Area to Western Control Area.

Q. Does the investment in the Populus to Terminal line provide reliability and capacity benefits to future planned transmission additions in the area?

A. Yes. The existing transmission in the corridor from Terminal to southeastern Idaho has limitations. Without investment in the Populus to Terminal line, the full transfer capability on both of the Gateway West and Gateway South segments, which are described in Mr. Cupparo's testimony, would not be possible. To obtain the full capacity of the Gateway West and Gateway South segments, both segments must be electrically interconnected. This interconnection is achieved by building the Populus to Terminal transmission line as part of Gateway Central.

Q. What alternatives to the Populus to Terminal project did PacifiCorp consider?

A. The Company considered, but rejected four alternatives. The first alternative was to not build the line or to upgrade other existing paths or seek additional transmission corridors into Utah. The Company rejected this alternative because it did not improve existing system reliability, did not provide any new incremental transmission capacity and precluded the ability of new resources to be delivered into Utah from Wyoming, Idaho, or the Northwest in general. New incremental transmission capacity is needed for both load service and for contingencies.

The second alternative considered was to rebuild the majority of the existing 138 kV lines interconnecting Utah and southeast Idaho and continue operation of these lines at 138 kV. This alternative would have provided a small incremental increase of 300 MW or less in transmission capacity across the currently constrained path between southeast Idaho and Utah. It also would not have provided adequate interconnection capacity between future Gateway West and Gateway South segments or offer any additional capacity for the future. In addition to the marginal increase in transmission capacity, this alternative had serious constructability issues as it required large segments of the path to be completely removed from service for extended periods (a year or more), as these existing 138 kV facilities were rebuilt. This would have placed significant reliability exposure on the transmission system serving the area to customers during construction. Additionally, this alternative did not allow the Company to meet its current firm transmission obligations nor did it meet the long-range resource plans and network load service requirements.

The third option considered was to construct a new single circuit 345 kV transmission line from the future Populus substation near Downey, Idaho to the Ben Lomond substation in Utah, which would have provided some capacity increase from Idaho to Ben Lomond. This alternative included an upgrade of the existing 138 kV line between Ben Lomond and Terminal to realize a minimum increase in capacity of 300 MW from Ben Lomond to Terminal substation. However, this alternative would not have provided the necessary future system capacity between Gateway West and Gateway South and would have failed to take advantage of maximizing transmission capacity installed in the new corridor and the existing Ben Lomond to Terminal transmission corridor.

The fourth option considered was to build a new 500 kV line along the route. The Company rejected this option because of its high cost, its potential for significant siting and community impacts, its requirement for a completely new corridor between Populus and Terminal substations, and its failure to use existing vacant corridors and property rights that the Company previously obtained.

Q. Please explain any further considerations that inform the Company's decision to select the Populus to Terminal line.

A. The Company selected this transmission line project based on several factors:

- It meets short-term and immediate reliability needs while prudently planning for the future. This adds significant long-term incremental transmission capacity (planned rating 1,400 MW) across the currently constrained transmission system. There have been several transmission outages since 2007 along this corridor that could have been mitigated with additional transmission facilities. The risk of further unplanned disturbances is considerable if the current facilities are not improved.
- It allows import of up to 1,400 MW of forecast resource capacity from Wyoming and southern Idaho. This new capacity is required based on long-term planning results.
- Construction benefits occur on a significant portion of the transmission project due to existing corridors that were acquired by the Company many years ago just for this purpose. The project optimizes use of limited transmission corridor lands by maximizing installed transmission capacity

in new corridors.

- Construction could occur with minimum planned outages on existing facilities remaining in service without increasing reliability exposure to the current system.
- The Company's ability to perform required maintenance will be improved without significant operational risk associated with taking existing lines out of service.

Bid Process

Q. Please describe the Company's typical procurement process used for major transmission projects.

A. The Company uses a competitive blind-sealed bid process to contract for the development of each project unless certain defined conditions apply, such as a restriction in the supply of technology or design solutions that prevent an open competitive process. The form of contract tendered is a turnkey, fixed-price, date certain basis for delivery, referred to as an engineer, procure and construct approach. The Company identifies potential bidders that provide the capabilities required to deliver the work scope within a boundary of project specific technical specifications and commercial terms. The tender process includes a question and answer period to clarify any outstanding issues and provides anonymity to the requesting bidder and responses of a non-confidential nature are provided to all bidders. Upon receipt of tender documents, the technical proposals are separated from commercial proposals and a separate technical and commercial evaluation is performed on all qualified bids using pre-established evaluation criteria (see

Exhibit PPL/502, summary of bidder evaluation). The technical evaluation is assisted by external consulting firms who have been pre-contracted for such work based on their industry experience. Upon completion of technical and commercial evaluations a recommendation is made to enter post-tender negotiations to reach final terms, conditions and pricing to support contract execution.

Q. Was this typical procurement process applied to Populus to Terminal?

A. Yes. Specifically for the project, the Company adopted an open competitive process where 75 vendors were identified and received an invitation to bid. The competitive process began in October 2007 and provided two separate blind-sealed bidding opportunities. During the October 2007 to May 2008 bidding period, four communications were provided to bidders containing additional project-specific information. This information was intended to assist bidders to refine their submissions and specifically, to remove any bid qualifications associated with contingent and non-firm pricing. All bid responses were initially due in May 2008. After additional information was provided to bidders during May 2008 to July 2008, new or revised bids were due in July 2008 in order to allow a further refinement of previously submitted design solutions, terms and conditions, including price. Three qualified bids were received and evaluated resulting from the May 2008 proposal submissions. Two competing proposals were received in July 2008. During the separate technical and commercial evaluations, the Company and its consultants identified non-fixed price aspects of the bidders' proposals affecting cost and schedule. The Company consultant computed a cost associated with non-fixed price work scope submitted by each bidder, which was estimated to range from approximately $103 million to $429 million. The Company engaged in negotiations to remove or cap the cost of non-fixed priced work to mitigate post-contract award price escalation and schedule change. The Company awarded the contract in October 2008 after negotiations that reduced the contractor's price. The original contract costs associated with the Populus to Terminal investment to be placed in service in 2010 are $567.6 million.[3] As shown on Exhibit PPL/501, additional project costs are associated with changes in the contractor work orders, materials purchased by the Company, right of way acquisition costs, legal fees, internal labor and purchased services.

Q. What process, if any, did the Company use to identify and implement cost savings opportunities during the procurement process?

A. During the tender evaluation process, bidders were requested to submit cost savings opportunities for consideration. Each item was reviewed to assess savings with respect to potential impact to operability, reliability and maintainability that were included in the final contract price. In addition, post-tender negotiations included a reduction of $25 million in consideration of commodity price reductions, which occurred in the global market during the tender evaluation period.

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[3] The original contract also includes costs associated with removing and replacing conductor on a connecting transmission line that will be completed in 2011. These costs are not included in the request for cost recovery in this case.

Construction Process

Q. Please describe the construction process.

A. The construction process involves several major activities and numerous subordinate tasks in order to engineer, procure and construct transmission facilities. The high-level tasks are:

- Preconstruction, which includes: planning and engineering; construction permitting; establishment of lay down yards; development of safety and construction plans; staging of construction crews and materials; negotiation of construction stipulation forms with landowners; and public notification of construction.
- Transmission line construction, which includes: initial access road construction; foundation installation; tower installation; and installation of conductor and optical ground wire.
- Substation construction, which includes: access construction and substation grading, civil construction; steel erection and control building installation; and equipment installation.
- Testing and commissioning, which include: individual line and equipment tests and critical punch list resolution.

Q. What is the current status of construction of the Populus to Terminal line?

A. At the time of this filing, the overall Populus to Terminal segment is on schedule with a total of 833 transmission structure foundations installed, 871 access roads constructed, 755 poles set and 6,375,000 linear feet of conductor pulled. The first phase of the project between Ben Lomond and Terminal substation is nearing completion and expected to be energized by June 30, 2010. The second phase of the project between Ben Lomond and Populus substation will be energized by December 31, 2010. Exhibit PPL/503 contains photos of assets in place for the Populus to Terminal segment.

Q. Please state why you believe the project will be completed and in-service by December 31, 2010.

A. Weekly project management status reports and field verification confirm construction is on schedule and will be completed by December 31, 2010 barring unforeseen events.

Conclusion

Q. Please summarize your testimony.

A. The existing transmission system capacity from southeastern Idaho into Utah is fully utilized, significant operational limitations exist on the system in this area, and no additional capacity can be made available without the addition of new transmission lines. The Populus to Terminal transmission line investment is prudent as it meets short-term reliability requirements and longer term customer needs by adding significant incremental transmission capacity between southeast Idaho and northern Utah.

Further, the investment facilitates a stronger interconnection to systems in Idaho, Utah, and Wyoming and to the Northwest in general. The Populus to Terminal transmission line, especially when integrated with the other proposed segments of Energy Gateway, is fundamental to the development of new renewable and other generation sources in Utah, Idaho and Wyoming. The completion of the project will be an important step in strengthening the western grid's transmission infrastructure, which is necessary based upon the projected future energy service requirements of our customers including those in Oregon.

The project was bid out through a competitive bid process followed by negotiations with the best bidders. The project is on schedule for completion and to be placed into service by December 31, 2010.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/501
Witness: Darrell T. Gerrard

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Darrell T. Gerrard

Project Cost Estimates

March 2010

Populus to Terminal Estimated Costs

December 2009

Description		Populus to Terminal
Engineer, Procure & Construct (EPC)		
	EPC Original Contract	567,618,371
	EPC Change in Work	28,381,143
	Sub total	**$595,999,514**
Materials Purchased by PacifiCorp		
	Shunt Capacitors / Reactors	27,474,573
	Miscellaneous material	2,134,725
	Sub total	**$29,609,298**
Right of Way - Acquisitions		
	Right of Way - Acquisitions	69,412,546
	Right of Way Labor	10,399,772
	Sub total	**$79,812,318**
Legal Fees		
	Fees	1,440,600
	Sub total	**$1,440,600**
Internal labor		
	Construction Labor	1,036,486
	Engineering Labor	2,188,103
	Project Management Office Labor	2,795,529
	Expenses	221,382
	Sub total	**$6,241,500**
Purchased Services & Legal		
	Owners Engineer	9,171,583
	Permitting	2,394,900
	Environmental Oversight	512,075
	Project Management Office Services	3,615,049
	Inspection	6,722,551
	Sub total	**$22,416,158**
Allowance for Funds Used During Construction (AFUDC & Overheads)		
	AFUDC	74,747,731
	PacifiCorp Overheads	17,640,000
	Forecast Risk	5,226,131
		$97,613,862
Taxes		
	Capitalized Property Taxes	5,515,821
	Sub total	**$5,515,821**
	Segment Total	**$838,649,071**

Docket No. UE-
Exhibit PPL/502
Witness: Darrell T. Gerrard

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Darrell T. Gerrard

Summary of Bidder Evaluation

March 2010

RESPONDENTS			
Technical Evaluation C	50.00%		Technical Evaluators
Project Mangement		40.00%	Evaluator 1.)
Environmental Qualification		5.00%	Evaluator 2.)
Safety		7.00%	Evaluator 3)
General Engineering		15.00%	Evaluator 4.)
Trasmission		12.00%	Evaluator 4.)
Substation		6.00%	Evaluator 4.)
Protection and Control		5.00%	Evaluator 4.)
Testing and Commissioning		5.00%	Evaluator 5.)
Communications		5.00%	Evaluator 6.)
Technical Section Weighting		100.00%	
Legal/Commercial/Cre	25.00%		
Pricing Competitivene:	25.00%		
Based on 100 total poir	100.00%		

						Bidder #1		Bidder #2	
A.) Project Management Questions:	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
to describe a work execution plan for the									
1.1.1 sequence of activities from award to p	20.00%	40.00%	50.00%	4.0000%	1 to 10	3.00	0.1200	7.00	0.2800
1.1.2 firms management team, both in the	5.00%	40.00%	50.00%	1.0000%	1 to 10	3.00	0.0300	8.00	0.0800
1.1.3 construction labor and equipment reso	5.00%	40.00%	50.00%	1.0000%	1 to 10	5.00	0.0500	6.00	0.0600
1.1.4 temporary facilities	5.00%	40.00%	50.00%	1.0000%	1 to 10	6.00	0.0600	6.00	0.0600
would manage, monitor, and report the status of the	5.00%	40.00%	50.00%	1.0000%	1 to 10	6.00	0.0600	8.00	0.0800
1.1.6 mobilization plan	3.00%	40.00%	50.00%	0.6000%	1 to 10	4.00	0.0240	6.00	0.0360
1.1.7 communications plan	2.00%	40.00%	50.00%	0.4000%	1 to 10	6.00	0.0240	5.00	0.0200
1.1.8 training	1.00%	40.00%	50.00%	0.2000%	1 to 10	7.00	0.0140	7.00	0.0140
1.1.9 safety	2.00%	40.00%	50.00%	0.4000%	1 to 10	7.00	0.0280	7.00	0.0280
1.1.10 design	1.00%	40.00%	50.00%	0.2000%	1 to 10	4.00	0.0080	6.00	0.0120
1.1.11 material procurement and receiving	3.00%	40.00%	50.00%	0.6000%	1 to 10	5.00	0.0300	7.00	0.0420
1.1.12 construction	20.00%	40.00%	50.00%	4.0000%	1 to 10	7.00	0.2800	6.00	0.2400
1.1.13 testing and commissioning resources	5.00%	40.00%	50.00%	1.0000%	1 to 10	6.00	0.0600	7.00	0.0700
tools and methods used to recover	2.00%	40.00%	50.00%	0.4000%	1 to 10	3.00	0.0120	5.00	0.0200
1.1.15 right of way management	1.00%	40.00%	50.00%	0.2000%	1 to 10	5.00	0.0100	5.00	0.0100
1.1.1 jobsite security	2.00%	40.00%	50.00%	0.4000%	1 to 10	6.00	0.0240	4.00	0.0160
samples, to identify typical scope change request forms and tracking logs, monthly status report formats including cost	2.00%	40.00%	50.00%	0.4000%	1 to 10	4.00	0.0160	5.00	0.0200
member of your proposed project management team (project manager, project controls specialist, safety coordinator, environmental coordinator, materials specialist, construction	10.00%	40.00%	50.00%	2.0000%	1 to 10	5.00	0.1000	7.00	0.1400
scheduling, scoping, tracking and reporting tools your firm has experience with and	2.00%	40.00%	50.00%	0.4000%	1 to 10	4.00	0.0160	6.00	0.0240
process for documentation control. This should include	2.00%	40.00%	50.00%	0.4000%	1 to 10	5.00	0.0200	5.00	0.0200
company's communication and approval process	2.00%	40.00%	50.00%	0.4000%	1 to 10	0.00	0.0000	0.00	0.0000
Score/Total Weighted	100.00%	40.00%	50.00%	20.0000%	2.00000	101.00	0.9860	123.00	1.2720
Maximum Score for							49.30%		63.60%

2.) Environmental Qualification Questions:	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score

Exhibit PPL/502
Gerrard/1

how your firm has previously constructed transmission and substation projects in sensitive wetlands and wildlife habitat. In particular, describe any special construction	35.00%	5.00%	50.00%	0.8750%	1 to 10		9.00	0.0788	6.00	0.0525
your project manager's proposed communication methods with land	15.00%	5.00%	50.00%	0.3750%	1 to 10		8.00	0.0300	8.00	0.0300
providing specific details, what steps you would use to convey environmental stipulations and	25.00%	5.00%	50.00%	0.6250%	1 to 10		9.00	0.0563	6.00	0.0375
team would be assigned responsibility for environmental issues on the Populus	25.00%	5.00%	50.00%	0.6250%	1 to 10		10.00	0.0625	10.00	0.0625
Score/Total Weighted	100.00%	5.00%	50.00%	2.5000%		0.25000	36.00	0.2275	30.00	0.1825
Maximum Score for								91.00%		73.00%

C.) Safety Qualification Questions	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
company's interstate worker's compensation experience modification rate for	5.00%	7.00%	50.00%	0.1750%	1 to 10	7.00	0.0123	7.00	0.0123
OSHA 200 Log, provide your Incident Rate and Lost Time Rate for the past three years plus the	5.00%	7.00%	50.00%	0.1750%	1 to 10	7.00	0.0123	7.00	0.0123
reason to believe that either rate for the current year will vary	2.00%	7.00%	50.00%	0.0700%	1 to 10	7.00	0.0049	7.00	0.0049
number of fatalities you have experienced	10.00%	7.00%	50.00%	0.3500%	1 to 10	5.00	0.0175	5.00	0.0175
6. Do you have a written safety program? (Yes/No).	15.00%	7.00%	50.00%	0.5250%	1 to 10	9.00	0.0473	9.00	0.0473
7. Do you conduct site safety inspections?	5.00%	7.00%	50.00%	0.1750%	1 to 10	8.00	0.0140	8.00	0.0140
8. Do you have a drug and alcohol policy? (Yes/No). If	5.00%	7.00%	50.00%	0.1750%	1 to 10	8.00	0.0140	8.00	0.0140
9. Do you have an accident/incident investigation and	8.00%	7.00%	50.00%	0.2800%	1 to 10	8.00	0.0224	8.00	0.0224
manage	5.00%	7.00%	50.00%	0.1750%	1 to 10	7.00	0.0123	7.00	0.0123
inspected by OSHA or other industrial safety enforcement	4.00%	7.00%	50.00%	0.1400%	1 to 10	8.00	0.0112	7.00	0.0098
12. Identify the safety training that you provide to your employees. Include	8.00%	7.00%	50.00%	0.2800%	1 to 10	8.00	0.0224	8.00	0.0224
has site safety	3.00%	7.00%	50.00%	0.1050%	1 to 10	8.00	0.0084	7.00	0.0074
14. Identify the officer in your	8.00%	7.00%	50.00%	0.2800%	1 to 10	8.00	0.0224	7.00	0.0196
15. Describe your company's safety	5.00%	7.00%	50.00%	0.1750%	1 to 10	8.00	0.0140	7.00	0.0123
16. Does your company use safety	4.00%	7.00%	50.00%	0.1400%	1 to 10	7.00	0.0098	7.00	0.0098

Exhibit PPL/502
Gerrard/2

	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale		Raw Score	Weighted Score	Raw Score	Weighted Score
subcontractor selection criteria with regard to	4.00%	7.00%	50.00%	0.1400%	1 to 10		7.00	0.0098	7.00	0.0098
18. Describe any innovative process or approach that demonstrates your	4.00%	7.00%	50.00%	0.1400%	1 to 10		7.00	0.0098	5.00	0.0070
Score/Total Weighted	100.00%	7.00%	50.00%	3.5000%		0.35000	127.00	0.2646	121.00	0.2548
Maximum Score for								75.60%		72.80%

1. General Engineering	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale		Raw Score	Weighted Score	Raw Score	Weighted Score
organization chart for the Populus Terminal Project identifying all key personnel as identified in Exhibit J. The organization chart should identify	8.00%	15.00%	50.00%	0.6000%	1 to 10		4.00	0.0240	4.00	0.0240
personnel (project manager, engineer, designer, drafter) that will be working on the project team including the key personnel as identified on Exhibit J. This list should include their name,	16.00%	15.00%	50.00%	1.2000%	1 to 10		1.00	0.0120	4.00	0.0480
that will be subcontracted by the										
subcontractor, office location for	2.00%	15.00%	50.00%	0.1500%	1 to 10		4.00	0.0060	2.00	0.0030
1.3.2 Service provided	2.00%	15.00%	50.00%	0.1500%	1 to 10		4.00	0.0060	4.00	0.0060
years of experience by consultant with	4.00%	15.00%	50.00%	0.3000%	1 to 10		2.00	0.0060	0.00	0.0000
1.3.4 Contact name and email/phone numb	1.00%	15.00%	50.00%	0.0750%	1 to 10		4.00	0.0030	2.00	0.0015
additional information that would demonstrate	3.00%	15.00%	50.00%	0.2250%	1 to 10		2.00	0.0045	0.00	0.0000
provide brief description of joint	3.00%	15.00%	50.00%	0.2250%	1 to 10		2.00	0.0045	0.00	0.0000
subcontractor provide estimate of percent labor	2.00%	15.00%	50.00%	0.1500%	1 to 10		4.00	0.0060	0.00	0.0000
rate will be applied to subcontractors,	2.00%	15.00%	50.00%	0.1500%	1 to 10		0.00	0.0000	0.00	0.0000
you would manage information and	7.00%	15.00%	50.00%	0.5250%	1 to 10		4.00	0.0210	4.00	0.0210
whether or not you have a web-based document control	7.00%	15.00%	50.00%	0.5250%	1 to 10		6.00	0.0315	4.00	0.0210
1.5 Materials										
describe how you plan to manage the materials for this	15.00%	15.00%	50.00%	1.1250%	1 to 10		4.00	0.0450	6.00	0.0675
1.5.2 Please list the panel supplier.	4.00%	15.00%	50.00%	0.3000%	1 to 10		2.00	0.0060	2.00	0.0060
of all major construction equipment, weight, and method of access to the site (i.e. track or rubber tire) and steel suppliers that are	8.00%	15.00%	50.00%	0.6000%	1 to 10		0.00	0.0000	4.00	0.0240
of suppliers for all major materials. (poles, conductor,	12.00%	15.00%	50.00%	0.9000%	1 to 10		4.00	0.0360	4.00	0.0360
suppliers that are currently not	4.00%	15.00%	50.00%	0.3000%	1 to 10		4.00	0.0120	3.00	0.0090
Score/Total Weighted	100.00%	15.00%	50.00%	7.5000%		0.75000	51.00	0.2235	43.00	0.2670
Maximum Score for								29.80%		35.60%

Exhibit PPL/502
Gerrard/3

2. Transmission	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
provide alternate designs for any	15.00%	12.00%	50.00%	0.9000%	1 to 10	4.00	0.0360	4.00	0.0360
provide alternate designs for any deviations from the	15.00%	12.00%	50.00%	0.9000%	1 to 10	6.00	0.0540	4.00	0.0360
foundation concept drawings for each transmission structure foundation type anticipated to be constructed. Drawings should include an elevation sketch of	34.00%	12.00%	50.00%	2.0400%	1 to 10	2.00	0.0408	2.00	0.0408
any other exceptions to or deviations from	12.00%	12.00%	50.00%	0.7200%	1 to 10	5.00	0.0360	4.00	0.0288
conceptual design approach and designs for	8.00%	12.00%	50.00%	0.4800%	1 to 10	4.00	0.0192	4.00	0.0192
criteria will be used to determine whether temporary	8.00%	12.00%	50.00%	0.4800%	1 to 10	4.00	0.0192	2.00	0.0096
conceptual design approach and designs for	8.00%	12.00%	50.00%	0.4800%	1 to 10	4.00	0.0192	2.00	0.0096
Score/Total Weighted	100.00%	12.00%	50.00%	6.0000%	0.60000	29.00	0.2244	22.00	0.1800
Maximum Score for							37.40%		30.00%

3. Substation	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
details of any deviation from the	20.00%	6.00%	50.00%	0.6000%	1 to 10	6.00	0.0360	5.00	0.0300
any other exceptions to or deviations from	20.00%	6.00%	50.00%	0.6000%	1 to 10	6.00	0.0360	5.00	0.0300
conceptual drawings for the proposed	20.00%	6.00%	50.00%	0.6000%	1 to 10	8.00	0.0480	5.00	0.0300
in detail your approach for the design and installation of the substation ground	20.00%	6.00%	50.00%	0.6000%	1 to 10	4.00	0.0240	4.00	0.0240
conceptual design approach and designs for the site	20.00%	6.00%	50.00%	0.6000%	1 to 10	5.00	0.0300	6.00	0.0360
Score/Total Weighted	100.00%	6.00%	50.00%	3.0000%	0.30000	29.00	0.1740	25.00	0.1500
Maximum Score for							58.00%		50.00%

4. Protection and Control	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
developed, over time, a unique system of documentation on the substation one line diagrams and control schematic diagrams to adequately describe	34.00%	5.00%	50.00%	0.8500%	1 to 10	5.00	0.0425	5.00	0.0425
breakers on this project will have dual trip coils, except for the 46kV breaker at Terminal Sub. All of the lines, for this project, will have two sets of line	33.00%	5.00%	50.00%	0.8250%	1 to 10	5.00	0.0413	4.00	0.0330

Exhibit PPL/502
Gerrard/4

	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
relays will be used on most of the transmission lines on this project. List the projects that your	33.00%	5.00%	50.00%	0.8250%	1 to 10	8.00	0.0660	8.00	0.0660
Score/Total Weighted	100.00%	5.00%	50.00%	2.5000%	0.25000	18.00	0.1498	17.00	0.1415
Maximum Score for							59.90%		56.60%

5. Testing and Commissioning of Substation	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
evidence of relevant experience with									
5.1.1 Circuit Breakers									
i. 345kV	30.00%	5.00%	50.00%	0.7500%	1 to 10	3.00	0.0225	1.00	0.0075
ii. 145kV	1.00%	5.00%	50.00%	0.0250%	1 to 10	5.00	0.0013	5.00	0.0013
iii. other voltages	0.00%	5.00%	50.00%	0.0000%	1 to 10	6.00	0.0000	6.00	0.0000
5.1.2 Transformers									
5.1.2.1 10-100 MVA, < 145kV	1.00%	5.00%	50.00%	0.0250%	1 to 10	5.00	0.0013	4.00	0.0010
5.1.2.2 100MVA, > 145kV	30.00%	5.00%	50.00%	0.7500%	1 to 10	5.00	0.0375	3.00	0.0225
5.1.2.3 Currant Transformers > 69kV	1.00%	5.00%	50.00%	0.0250%	1 to 10	6.00	0.0015	6.00	0.0015
5.1.2.4 Voltage Transformers > 69kV	1.00%	5.00%	50.00%	0.0250%	1 to 10	6.00	0.0015	6.00	0.0015
5.1.2.5 CCVT's	1.00%	5.00%	50.00%	0.0250%	1 to 10	6.00	0.0015	6.00	0.0015
5.1.3 Capacitor Banks									
5.1.3.1 < 345kV	1.00%	5.00%	50.00%	0.0250%	1 to 10	5.00	0.0013	4.00	0.0010
5.1.3.2 345kV	6.00%	5.00%	50.00%	0.1500%	1 to 10	4.00	0.0060	1.00	0.0015
5.1.3.3 series capacitor	3.00%	5.00%	50.00%	0.0750%	1 to 10	2.00	0.0015	1.00	0.0008
substation equipment	2.00%	5.00%	50.00%	0.0500%	1 to 10	6.00	0.0030	6.00	0.0030
samples of installation / commissioning	10.00%	5.00%	50.00%	0.2500%	1 to 10	4.00	0.0100	3.00	0.0075
list of test equipment that will be used	9.00%	5.00%	50.00%	0.2250%	1 to 10	4.00	0.0090	2.00	0.0045
examples of test procedures and forms that may be	1.00%	5.00%	50.00%	0.0250%	1 to 10	6.00	0.0015	6.00	0.0015
standards, methodology, process and forms to be followed and submitted for	3.00%	5.00%	50.00%	0.0750%	1 to 10	6.00	0.0045	6.00	0.0045
Score/Total Weighted	100.00%	5.00%	50.00%	2.5000%	0.25000	79.00	0.1038	66.00	0.0610
Maximum Score for							41.50%		24.40%

6. Communications	Question Weighting	Section Weighting	Technical Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
plans for having communications facilities available to support bringing Populus sub into service. Address sequence of events required to have	55.00%	5.00%	50.00%	1.3750%	1 to 10	0.00	0.0000	10.00	0.1375
testing plan to ensure that fiber facilities (insertion loss and fiber splice loss)	35.00%	5.00%	50.00%	0.8750%	1 to 10	10.00	0.0875	10.00	0.0875
projected work plan for fiber splicing that you have designed to meet the required service dates. Include number of line segments under construction	10.00%	5.00%	50.00%	0.2500%	1 to 10	0.00	0.0000	5.00	0.0125
Score/Total Weighted	100.00%	5.00%	50.00%	2.5000%	0.25000	10.00	0.0875	25.00	0.2375
Maximum Score for							35.00%		95.00%

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Gerrard/5

Weighted Score for All		100.00%	50.00%	50.00%	5.00000	480.00	2.4410	472.00	2.7463
Maximum Score for All Technical							48.82%		54.93%
Non-Pricing Rank							2.00		1.00
ial Requirements: Consideration									
Management Evaluation (5%	Question Weighting	Section Weighting	Legal/Credit Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
1=10, 2=8 3=6,	100.00%	10.00%	25.00%	2.5000%	1 to 10	6.00	0.1500	6.00	0.1500
Score/Total Weighted Score for Credit	100.00%	10.00%	25.00%	2.5000%	0.25000	6.00	0.1500	6.00	0.1500
Maximum Score for							60.00%		60.00%
contract terms and conditions which	Question Weighting	Section Weighting	Commercial Weighting	Weighting Factor	Rating Scale	Raw Score	Weighted Score	Raw Score	Weighted Score
RESPONSIBILITI	7.00%	90.00%	25.00%	1.5750%	1 to 10	4.00	0.0630	6.00	0.0945
OF PAYMENT	12.00%	90.00%	25.00%	2.7000%	1 to 10	5.00	0.1350	6.00	0.1620
MAJEURE	7.00%	90.00%	25.00%	1.5750%	1 to 10	5.00	0.0788	6.00	0.0945
SUBSTANTIAL COMPLETION AND FINAL	12.00%	90.00%	25.00%	2.7000%	1 to 10	4.00	0.1080	6.00	0.1620
Article 16. DELAY	12.00%	90.00%	25.00%	2.7000%	1 to 10	3.00	0.0810	6.00	0.1620
CHANGES IN	7.00%	90.00%	25.00%	1.5750%	1 to 10	4.00	0.0630	5.00	0.0788
WARRANTIES	12.00%	90.00%	25.00%	2.7000%	1 to 10	4.00	0.1080	7.00	0.1890
INSURANCE	7.00%	90.00%	25.00%	1.5750%	1 to 10	5.00	0.0788	5.00	0.0788
INDEMNIFICATI	12.00%	90.00%	25.00%	2.7000%	1 to 10	5.00	0.1350	5.00	0.1350
LIMITATIONS OF LIABILITY	12.00%	90.00%	25.00%	2.7000%	1 to 10	5.00	0.1350	5.00	0.1350
Total Maximum Score/Total Weighted	100%	90.00%	25.00%	22.5000%	2.25000	44.00	0.9855	57.00	1.2915
Maximum Score for							43.80%		57.40%
Weighted Score for Credit/Legal/Commerc		100.00%	25.00%	25.00%	2.50000	50.00	1.1355	63.00	1.4415
Maximum Score for Credit/Legal/Commerc							45.42%		57.66%
redit/Commercial Rank							2.00		1.00
Sum Proposal Bid Price						$ 583,540,081.57		$ 605,185,000.00	
cost (from OE)						$ 428,900,000.00		$ 103,300,000.00	
Competitiveness						$ 1,012,440,081.57		$ 708,485,000.00	
Value							$ 1,012,440,081.57		$ 708,485,000.00
Pricing Rank							2.00		1.00
Competitiveness							6.9978%		10.0000%

Commodity Pricing Competitivness	Average Unit Price for Commodity		Average Unit Price for Commodity	
Fuel - (Gal.)	$ 4.0000		$ 6.5400	
Competitivness factor - 0.5% best / < 0.5% prorated for higher		0.5000%		0.3058%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Tower Steel - (Lbs.)	$ 0.7712		$ 3.1500	
Competitivness factor - 2% best / < 2% prorated for higher		2.0000%		0.4896%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Cassion Steel - (Lbs.)	$ 2.9000		$ 2.9000	
Competitivness factor - 2% best / < 2% prorated for higher		2.0000%		2.0000%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Rebar Steel - (Lbs.)	$ 1.0500		$ 1.1100	
Competitivness factor - 0.5% best / < 0.5% prorated for higher		0.5000%		0.4730%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Concrete - (CuYd)	$ 125.0000		$ 124.9300	
Competitivness factor - 0.5% best / < 0.5% prorated for higher		0.4997%		0.5000%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
OPGW - (LF)	$ 1.3320		$ 1.8600	

Exhibit PPL/502
Gerrard/6

Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Conductor (1272 KCMIL ACSR "Bittern") - (LF)	$ 2.5600		$ 3.4800	
Competitivness factor - 1.5% best / < 1.5% prorated for higher		1.5000%		1.1034%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Conductor (CTC 1020 kCM ACCC) - (LF)	$ 7.6580		$ 3.6200	
Competitivness factor - 1.5% best / < 1.5% prorated for higher		0.7091%		1.5000%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Shield Wire (1/2" EHS Galv.) - (LF)	$ 0.6150		$ 1.0200	
Competitivness factor - 0.5% best / < 0.5% prorated for higher		0.5000%		0.3015%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Galvanizing Zinc on Towers - (Lbs.)	$ 0.7230		$ 3.1500	
Competitivness factor - 0.5% best / < 0.5% prorated for higher		0.5000%		0.1148%
Stability factor - 0.5% fixed / < 0.5% prorated for adjustments		0.0000%		0.0000%
Competitiveness and Stability Value		9.2088%		7.1462%
Weighting - 50%		24.4100%		27.4650%
Legal/Commercial		11.3550%		14.4150%
Competitiveness		16.2088%		17.1462%
Evaluated Total		51.97%		59.02%

Exhibit PPL/502
Gerrard/7

Exhibit PPL/503
Darrell T. Gerrard

Docket No. UE-
Exhibit PPL/503
Witness: Darrell T. Gerrard

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

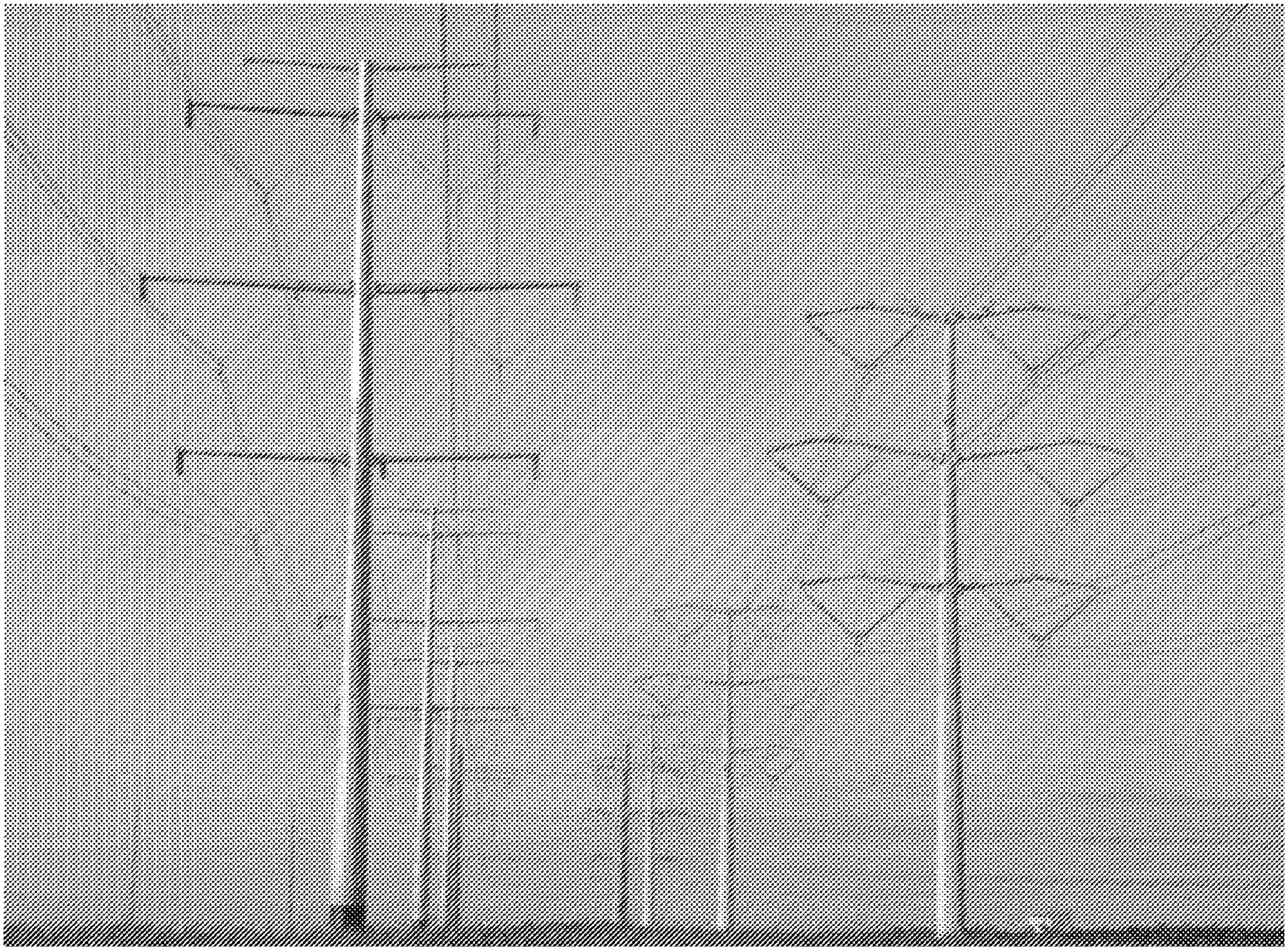
PACIFICORP

Exhibit Accompanying Direct Testimony of Darrell T. Gerrard

Project Photos

March 2010

Populus to Terminal



New structures on left (Ben Lomond to Terminal section)

Exhibit PPL/503
Gerrard/1

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Pacific Power | Rocky Mountain Power

Populus to Terminal

Stringing Optical Ground Wire

Exhibit PPL/503
Gerrard/2

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Populus to Terminal

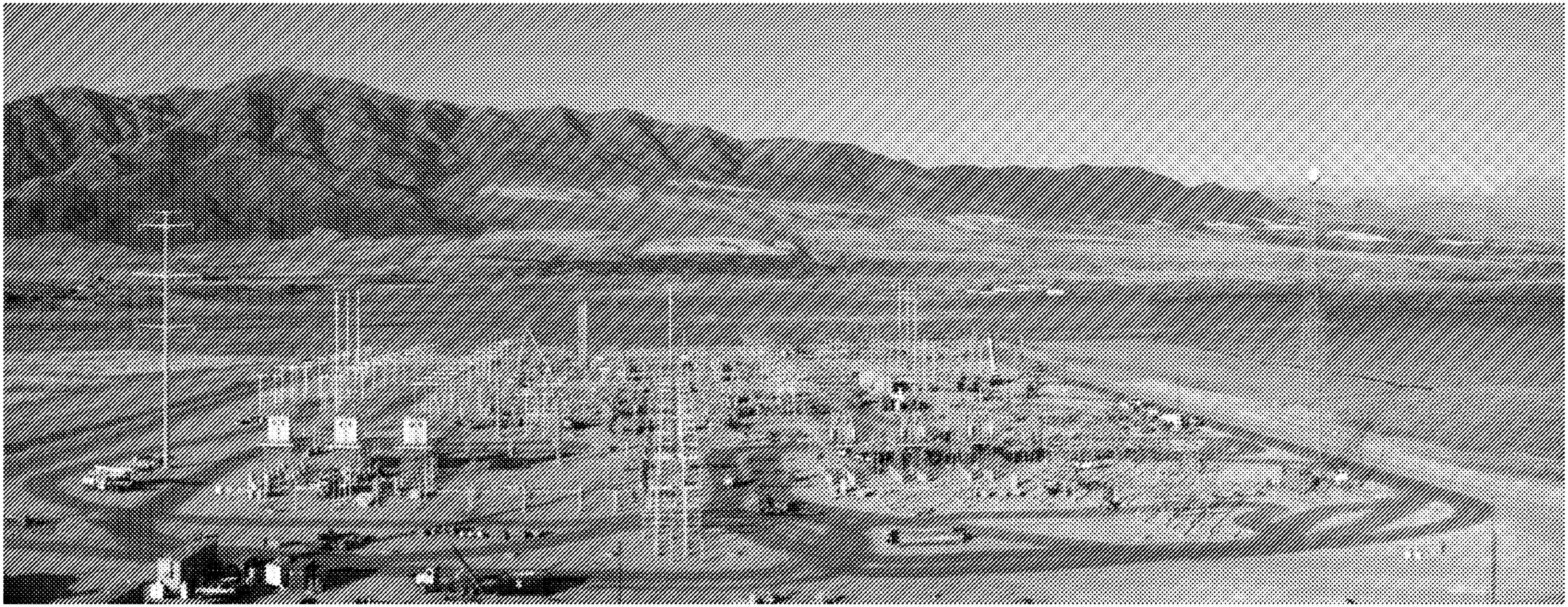
Angle Structure Installation

Exhibit PPL/503
Gerrard/3

Populus to Terminal

Installed Angle Structures

Populus Substation



Populus substation (Downey Idaho) – Sized to integrate Populus Terminal, existing Bridger West lines (from Wyoming) and future Gateway West 500kV line (from Wyoming)

Exhibit PPL/503
Gerrard/5

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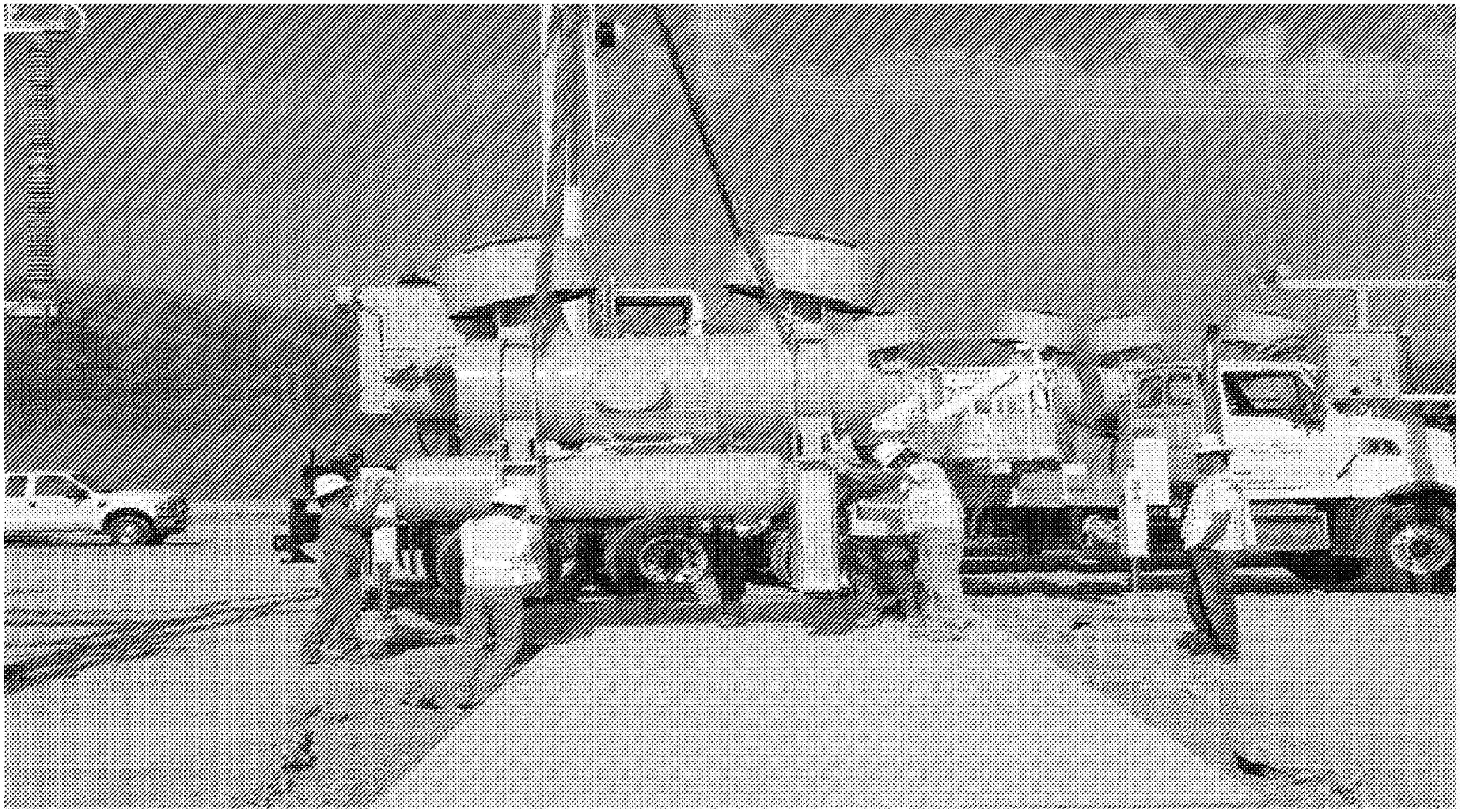
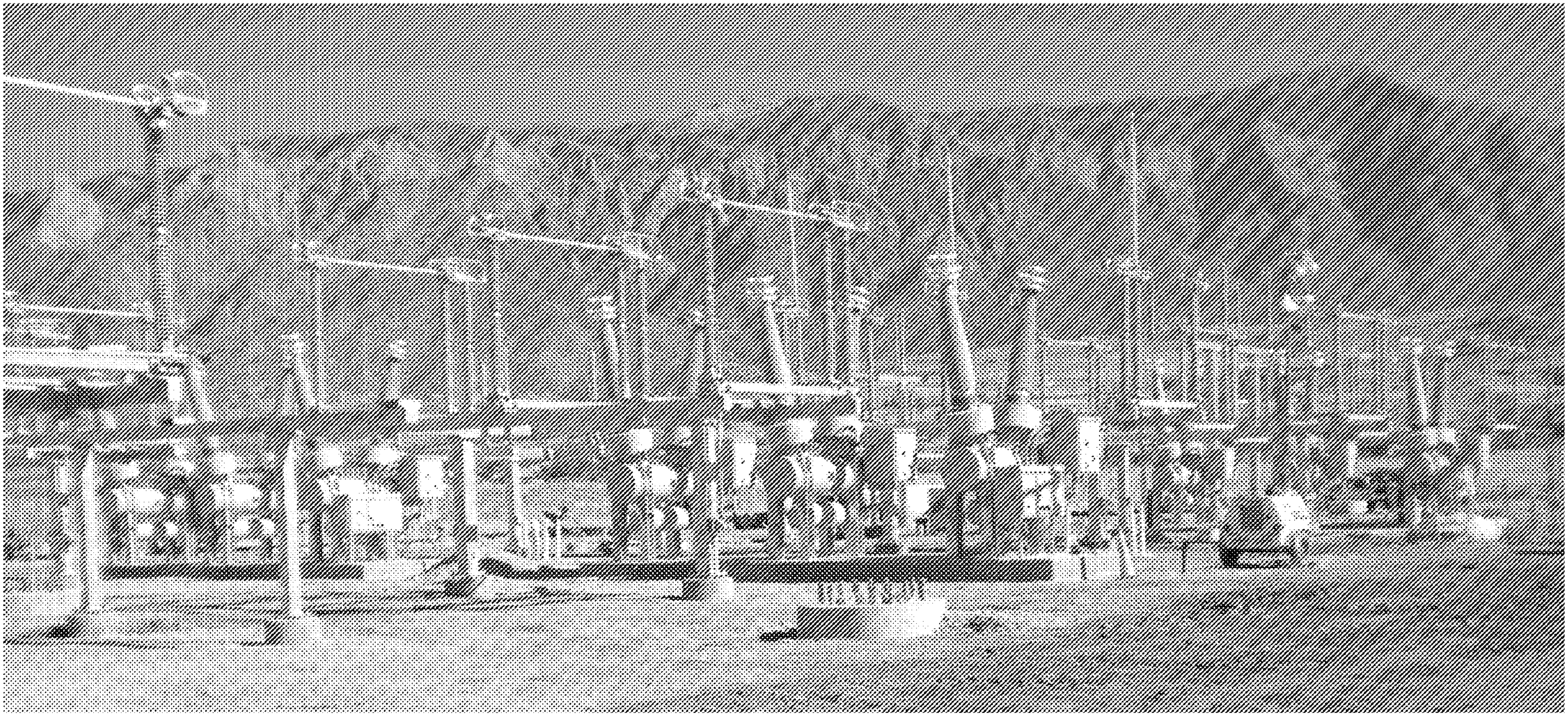
Populus Substation



Populus substation– Placing 345kV circuit breaker

Exhibit PPL/503
Gerrard/6

Populus Substation



Populus substation– 345kV circuit breakers

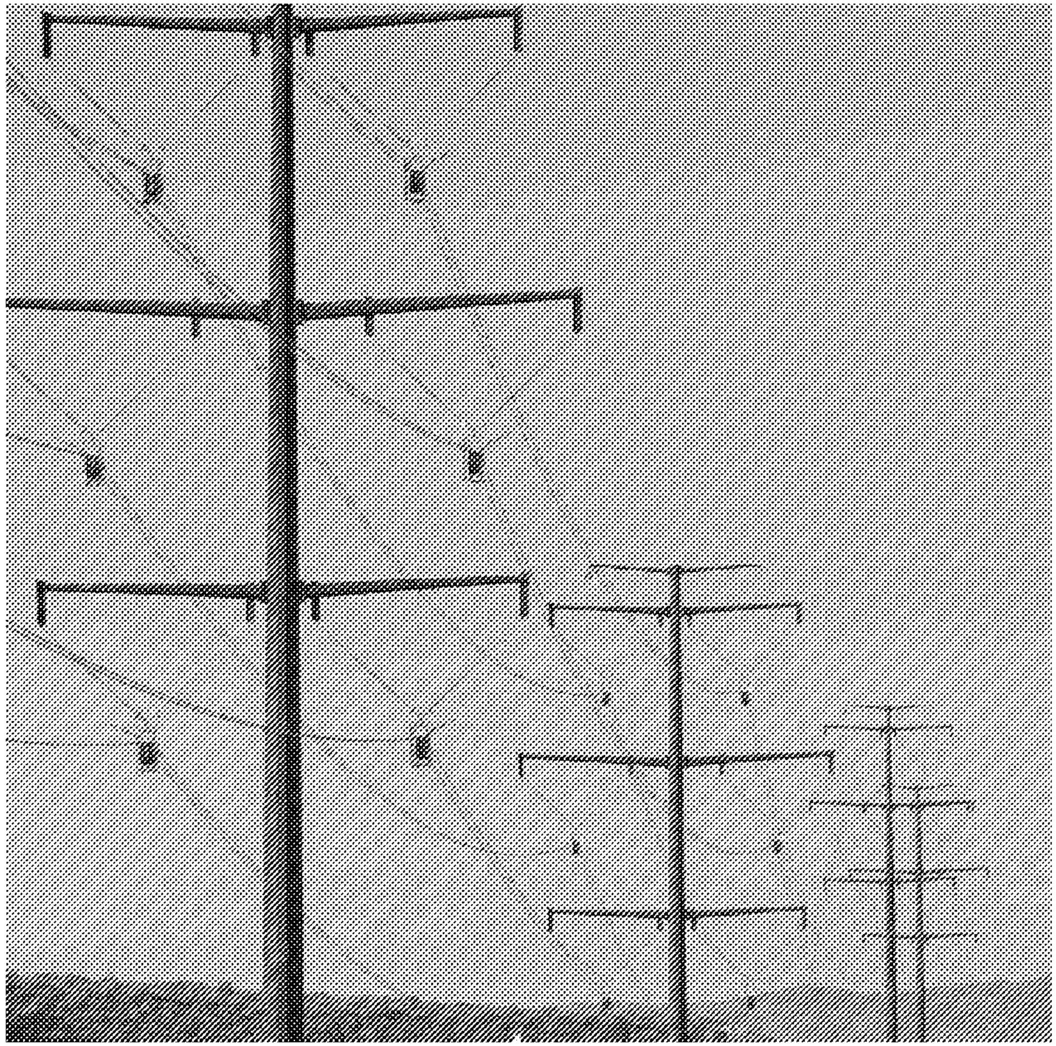
Exhibit PPL/503
Gerrard/7

Populus to Terminal

Populus to Ben Lomond section – pole setting in Idaho

Exhibit PPL/503
Gerrard/8

Populus to Terminal



Populus to Ben Lomond section – installed poles

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Docket No. UE-
Exhibit PPL/600
Witness: Dean S. Brockbank

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Dean S. Brockbank

March 2010

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

A. My name is Dean S. Brockbank. My business address is 1407 West North Temple, Salt Lake City, Utah 84116. My present position is Vice President and General Counsel of PacifiCorp Energy.

Qualifications

Q. Briefly describe your educational background and business experience.

A. I have a Bachelor of Science in Accounting from Brigham Young University and hold a law degree from George Mason University. I have been employed by PacifiCorp for over six years and support the commercial and trading and generation departments as General Counsel. Prior to joining PacifiCorp Energy I worked for the Rocky Mountain Power division of PacifiCorp as senior counsel.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. My testimony explains the process involved in pursuing a new federal operating license for hydroelectric projects in general and the specific process that has been followed for relicensing the Klamath Hydroelectric Project ("Project") and settlement of issues related to the relicensing proceeding. My testimony explains how the expenses and costs for relicensing and settlement for the Project are prudent expenditures that have been incurred in the interest of PacifiCorp's customers.

Q. Does your testimony address the reasonableness of the Company's decision to execute the Klamath Hydroelectric Settlement Agreement ("KHSA")?

A. No. My testimony in this proceeding addresses the prudency of the costs incurred by the Company in pursuit of a new license for the Project and the costs incurred by the Company to reach settlement with stakeholders. Pursuant to Senate Bill ("SB") 76, passed by the Oregon Legislature in 2009, under Section 4 of the legislation, the Commission will review the Company's decision to enter into the KHSA and decide whether to establish a dam removal surcharge in a separate proceeding to be initiated by the Company within 30 days of the execution of the KHSA.

Q. Does SB 76 also address the costs of relicensing and the settlement efforts that are the subject of your testimony?

A. Yes. Section 3 of SB 76 authorizes the Commission to provide for recovery of Oregon's allocated share of un-depreciated amounts prudently invested by PacifiCorp in the Klamath River dams. Amounts recoverable under this section of SB 76 explicitly include amounts spent by PacifiCorp in seeking relicensing of the dams and amounts spent by PacifiCorp for settlement of the issues of relicensing or removal of the dams.

Q. Please describe how you have organized your testimony.

A. First, I briefly describe the Project and the benefits customers have derived and will continue to derive from the operation of the Project. Second, I provide an overview of the process to obtain a new operating license. Third, I describe the relicensing and settlement process undertaken to date to resolve the expiration of the Project's license. Fourth, I explain the relicensing costs for which PacifiCorp seeks recovery in this case.

Overview of the Project

Q. Please describe the Project.

A. The Project is a 169 megawatt hydroelectric facility on the Klamath River in southern Oregon and northern California. It consists of eight developments including seven powerhouses, five mainstem dams on the Klamath River (Iron Gate, Copco No. 1, Copco No. 2, J.C. Boyle, and Keno), as well as two small diversion dams on Spring Creek and Fall Creek, a tributary to the Klamath River. The Project as currently licensed includes the East Side and West Side generating facilities which use water diverted by the Link River Dam, a facility owned by the Bureau of Reclamation that regulates the elevation and releases of water from Upper Klamath Lake and which is not included in the Project. The Project also includes Keno Dam, which has no hydroelectric generation facilities, but which serves to regulate water levels in Keno Reservoir as required by the Project license. The Company operates all eight developments under one Federal Energy Regulatory Commission ("FERC") license (FERC Project No. 2082). The Project is partially located on federal lands administered by the Bureau of Land Management and the Bureau of Reclamation. The first hydroelectric development, Fall Creek, was completed in 1903 and Iron Gate, the last hydroelectric development, was completed in 1962. The Keno Dam was completed in 1968.

Q. Generally, what benefits does the Project provide PacifiCorp and its customers?

A. Since its completion, the Project has provided reliable low-cost power. As currently operated in compliance with the limitations of the existing license, the Project is a source of energy, capacity, and reserves. Unlike most other sources of generation, hydro projects also provide an additional environmental benefit because they are "emissions-free." In addition, the generating units of the Project located in California qualify as renewable energy resources for the California Renewable Portfolio Standard.

Overview of Federal Relicensing

Q. Please provide an overview of the federal relicensing process.

A. Under the Federal Power Act ("FPA"), FERC has the exclusive authority to license nonfederal hydropower projects on navigable waterways. Original licenses are issued for a term of 50 years, after which a licensee may seek relicensing. FERC issues subsequent licenses for a term of not less than 30 years or more than 50 years with FERC deciding the length of the license. FERC regulations require that a licensee file a Notice of Intent to apply for a new license five and a half years prior to license expiration. A licensee must file an application for a new license two years prior to expiration of an existing license. On average, licensing takes eight to ten years, and some applications have taken as long as 30 years. During the relicensing process, FERC typically allows projects to continue operating on annual license extensions under the same terms and conditions once the old license has expired. Such is the case with the Project at this time, as the original project license expired in 2006. The licensing process requires FERC to consider the economic, engineering, environmental, and socioeconomic aspects of the project. In issuing licenses, FERC must give "equal consideration" to environmental values and adequately protect and mitigate the effects of the Project based on environmental and other concerns. In doing so, FERC attaches conditions to the license.

Q. What role do state and federal resource agencies play in the process?

A. State and federal fish and wildlife agencies review applications and submit comments to FERC regarding the impact of the Project on the environment. Based on those impacts, state and federal agencies recommend conditions to FERC to place on the license to mitigate the impacts. The FPA gives certain federal agencies the authority to require FERC to include the agency's conditions on the license. For example, the Secretaries of Commerce and the Interior have the authority to require applicants to install fishways (ladders and screens) at projects, and to require applicants to reduce variability of in-stream flows.

Q. What options does an applicant have if the mandatory conditions make the project uneconomic?

A. The applicant has limited options. The applicant may accept the uneconomic license, decommission and remove the facility, or pursue litigation and challenge the mandatory conditions. In states other than California, the applicant has the option of selling the facility as well. Because of the potential risks of removal of facilities and the uncertainty of litigation, those options are seldom favored. Consequently, applicants often try to manage uncertainty by settling issues among the various stakeholders before licensing is completed or by negotiating acceptable decommissioning and removal outcomes.

Q. Other than the FPA, what other laws must FERC take into consideration when granting licenses?

A. Because licensing is a "federal action," FERC must evaluate the application under a host of federal laws: the Clean Water Act ("CWA"), the Coastal Zone Management Act, the National Environmental Policy Act ("NEPA"), the Endangered Species Act ("ESA"), the Fish and Wildlife Coordination Act, the National Historic Preservation Act, among others.

These additional laws can add time and expense to the application process. For example, before FERC can issue a license, an applicant must obtain certification from the state in which the project is located that the project can meet state water quality standards and criteria under Section 401 of the CWA. Similarly, under the ESA, FERC must consult with the federal agencies to determine whether issuing a new license might jeopardize the existence of any endangered or threatened species or result in adverse modification of critical habitat.

The Company has sought CWA Section 401 certifications for the Project from both Oregon and California. In addition, ESA considerations are present at the Project due to the presence of threatened coho salmon in the Klamath River below Iron Gate dam, and endangered Lost River and shortnose suckers that predominantly reside in Upper Klamath Lake and its tributaries but utilize habitat within the Project boundary.

Q. Does FERC offer more than one relicensing process?

A. Yes. At the time the license application for the Project was developed and filed – the final license application was submitted to FERC in February 2004 – applicants could use either traditional or alternative licensing processes. During the process of developing the license application for the Project, FERC developed an additional licensing process called an integrated licensing process, which became the default process for relicensing in 2005. Applicants may also enter into a negotiated settlement at any time. The Company initiated licensing under the traditional approach for the Project, and has pursued settlement to resolve the issues related to the Project relicensing.

Q. Please provide a more detailed description of the traditional FERC relicensing process.

A. The traditional process involves three stages of consultation. In the first stage, the applicant distributes an Initial Consultation document, which explains the project and its operation and environmental setting to federal and state agencies, tribes, non-governmental organizations ("NGOs"), community interest groups and other stakeholders. Following the consultation document, the stakeholders meet and visit the site. Thirty days after the meeting, comments and additional study recommendations are due to the applicant. Stage one ends when a set of resource-by-resource study plans and stakeholder consultation documentation have been completed and provided to FERC.

In the second stage, the applicant conducts the proposed studies and prepares a draft license application, which it distributes to FERC and to interested agencies, tribes and stakeholders for review and comment. At this stage, agencies routinely request additional studies, which can be costly and time-consuming. The applicant may refer such requests to FERC for dispute resolution. At this stage, FERC may also request additional information. The applicant must provide FERC with a written summary of how the Company resolved any disagreements with agencies and others. The second stage ends when FERC accepts a final application for filing.

In the third stage, FERC solicits initial comments and preliminary terms and conditions from resource agencies, tribes, and stakeholders, and gives notice that the project is ready for environmental analysis under NEPA. At this stage, FERC may require additional information from the applicant to address those comments. FERC next initiates its detailed environmental and engineering review and solicits final comments, recommendations, terms and conditions, and mandatory prescriptions. FERC then prepares an Environmental Assessment or Environmental Impact Statement taking into account comments, responses and conditions. Ultimately, FERC issues a license order describing both how the project will be operated during the next license term, and what environmental and other enhancement obligations the licensee must fulfill. Those obligations include the mandatory terms and conditions provided by the Secretaries of Commerce, Agriculture and Interior. In addition, if relevant, FERC appends any conditions associated with CWA Section 401 water quality certifications that have been issued by state agencies.

Q. Please describe the relicensing process to date for the Project.

A. PacifiCorp filed a Notice of Intent to relicense and issued its First Stage Consultation Document on December 15, 2000. In an attempt to arrive at consensus-based approaches to the licensing process with the various stakeholders involved, PacifiCorp pursued a "traditional-plus" licensing approach in which the traditional process was followed with a concerted effort to solicit stakeholder input and agreement on study plans before they were submitted to FERC for review. This "traditional-plus" approach resulted in a significant number of stakeholder meetings to review proposed study plans, gather input, and attempt to achieve consensus. This approach was pursued with the hope that this collaborative approach would ultimately minimize disagreements among PacifiCorp, agencies and stakeholders on the technical and scientific questions related to project impacts and proposed mitigation alternatives. In this way, it was intended that the relicensing process could be completed more rapidly with agreement among the stakeholders in order to avoid a prolonged and expensive relicensing proceeding, which is common for hydroelectric relicensing.

Q. Please explain stakeholder participation in the relicensing process for the Project.

A. Public meetings for the relicensing process began in January 2001 and second stage consultation meetings with stakeholders on the studies necessary for the relicensing application began in August 2001. Studies and second stage consultation meetings with stakeholders continued through 2002 and 2003 and the final license application was submitted to FERC in February 2004. FERC issued its first scoping document for the environmental review process in April 2004 and scoping was completed in May 2005. FERC issued notice that the project was ready for environmental analysis on December 28, 2005. The original FERC license expired February 28, 2006 and annual licenses have been issued by FERC since that time.

Federal agencies – the National Marine Fisheries Service, U.S. Fish and Wildlife Service, Bureau of Reclamation, and Bureau of Land Management – issued draft terms and conditions for a new license in March 2006. The draft terms called for full volitional fish passage at all Project developments as well as other license conditions to benefit environmental resources that would reduce power generation and increase the costs of a new license. That same month, the Company submitted applications to California and Oregon for CWA Section 401 water quality certifications of the Project. As a result of the Energy Policy Act of 2005, the Company had the opportunity to challenge the underlying facts behind the draft agency terms and conditions and propose alternative licensing conditions. The Company filed alternative license conditions with FERC that the Company believed provided similar environmental benefits as the draft agency terms and conditions but at less cost and loss in power production from the Project. The Company's filing also challenged material facts relied upon by the agencies. A trial-type hearing was conducted on these issues of material fact underlying the agency terms and conditions in August 2006 and a decision was issued by an administrative law judge in September 2006. Also in September

2006, FERC issued a draft Environmental Impact Statement for Hydropower License.

Incorporating the findings of the trial-type hearing, the agencies issued modified terms and conditions for a new license in January 2007. FERC then initiated ESA consultation for a new license in March 2007 and the National Marine Fisheries Service and U.S. Fish and Wildlife Service issued final biological opinions in December 2007. To initiate analysis of the project under the California Environmental Quality Act pursuant to obtaining CWA Section 401 certification, the Company signed a memorandum of understanding with the California State Water Resources Control Board in September 2007. FERC completed its environmental analysis of the project and released its final Environmental Impact Statement for Hydropower License in November 2007.

Q. Please continue describing the relicensing process after the Company filed its applications for CWA Section 401 certification of the Project.

A. Since filing its applications for CWA Section 401 certification of the Project with California and Oregon, PacifiCorp has been implementing water quality studies and monitoring pursuant to reservoir management plans developed to evaluate technologies and management actions that may be feasible to improve water quality conditions in the Project reservoirs and in the Klamath River downstream of Project facilities. The result of these studies and planning efforts will help the states of California and Oregon assess whether the Project can meet applicable water quality standards. In June 2009, the California North Coast Regional Water Quality Control Board issued a draft total maximum daily load ("TMDL") report for the Klamath River. PacifiCorp has been actively involved in reviewing the TMDL since the requirements of the TMDL will ultimately inform the conditions that may be imposed on the Project through the CWA Section 401 certification process.

Q. What major changes to the Project did PacifiCorp propose in its license application?

A. PacifiCorp proposed decommissioning the East Side and West Side developments, which account for less than three percent of historic Project generation. In addition, PacifiCorp proposed removing the Keno development from the Project since that development no longer serves Project purposes, although its operation is required by the current Project license. Finally, PacifiCorp proposed reducing the amount of land included within the Project boundary so that PacifiCorp's responsibility for environmental and cultural resources management would be more in line with the area actually affected by the Project. These changes were proposed to preserve the economic benefits of the Project and ensure that the Project – and thus PacifiCorp's customers – was not assigned responsibility for mitigation measures unrelated to operation of the hydroelectric facilities.

Q. Please describe how settlement is used in FERC relicensing process.

A. Due to the complex nature of relicensing proceedings and the many issues and stakeholders involved in the process, many relicensing proceedings are resolved by settlement. As mentioned before, a settlement between the parties to a relicensing proceeding can be entered at any time while the relicensing process is ongoing. Settlements are encouraged by FERC and recent changes to the relicensing process alternatives have been made to encourage applicants and stakeholders to reach consensus on the issues related to project relicensing so the parties can reach settlement. Indeed, PacifiCorp has pursued settlement for the majority of its recently completed hydro relicensing proceedings including the North Umpqua, Bear River, and Lewis River projects. In addition, settlements have been entered among PacifiCorp, agencies and stakeholders to decommission the Condit, American Fork, and Powerdale hydro projects after those projects began the traditional FERC relicensing process.

Q. Please describe the settlement process to date for the Project.

A. For the Project, PacifiCorp initiated settlement discussions in October 2004 with stakeholders following submittal of the license application. The first mediated settlement meeting was conducted in January 2005. Settlement meetings proceeded through 2005 and mid-2006 when the settlement group turned its attention to resolving basin-wide issues among the stakeholders. This group of stakeholders, after months of negotiations, released the draft Klamath Basin Restoration Agreement ("KBRA") in January 2008. Because the provisions surrounding these broader issues were beyond the scope of the relicensing proceedings, PacifiCorp did not participate in these negotiations. The KBRA is intended to resolve issues of water allocation in the Klamath Basin and provide for habitat restoration and called for removal of PacifiCorp's main stem hydroelectric dams. Following release of the KBRA, active settlement negotiations were resumed among PacifiCorp, the federal government, and the states of California and Oregon.

Other key stakeholders joined the settlement negotiations, resulting in an Agreement in Principle ("AIP"), which was released on November 13, 2008. The AIP laid out a framework for resolution of the issues related to relicensing of the Project including the potential decommissioning and removal of PacifiCorp's four main stem dams on the Klamath River – J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate. As a result of discussions with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service, PacifiCorp also developed an Interim Conservation Plan to provide benefits to ESA-listed aquatic species during the period of interim operations prior to potential dam removal or the re-establishment of fish passage through the Project pursuant to project relicensing.

Following the release of the AIP, PacifiCorp pursued further negotiations with the parties to the AIP – the federal government, California and Oregon – as well as an expanded group of stakeholders, agencies, and other interested parties to complete a final settlement agreement for the Project. A draft of the KHSA was released on September 30, 2009 and public review drafts of the KBRA and KHSA were released on January 7 and January 8, 2010, respectively. On February 18, 2010, the KHSA was executed by over 30 parties, including PacifiCorp, the U.S. Department of the Interior, the states of Oregon and California, the Karuk, Klamath and Yurok tribes, and parties representing counties, irrigation districts, fisherman, environmentalists and other organizations.

I have provided a detailed chronology of key points in the Klamath relicensing and settlement process as Exhibit PPL/601.

Q. Is PacifiCorp a signatory to the KBRA?

A. No. In mid-2006, PacifiCorp elected to excuse itself from settlement discussions when settlement parties decided to negotiate basin-wide issues related to water allocations, wildlife refuges, and other issues not explicitly related to the relicensing of the Project. As a result, PacifiCorp is not a party to the KBRA. PacifiCorp has focused its settlement efforts on resolving the issues related to relicensing of the Project. The two agreements, however, are linked.

Q. Absent the settlement under the KHSA, what steps remain to be completed in the relicensing process?

A. In order for FERC to issue a new project license, CWA Section 401 water quality certification must first be completed by the states of California and Oregon. The California State Water Control Board has authority to issue CWA Section 401 certifications for hydropower projects in California. The conditions of the CWA Section 401 certification would then be incorporated into the new FERC license for the Project. PacifiCorp has CWA Section 401 water quality certification applications pending in both states. However, pursuant to the KHSA, relicensing of the Project will be held in abeyance while the Secretary of the Interior makes a determination as to whether the four main stem Klamath River dams owned by PacifiCorp should be decommissioned and removed or relicensed.

Costs and Benefits of Relicensing

Q. Please describe how pursuing relicensing and settlement has provided customer benefits.

A. PacifiCorp has pursued relicensing to preserve economic benefits to its customers from the Project. Had the Company not elected to pursue relicensing of the Project, it would have been required to submit an application to FERC for surrender of the Project license and decommissioning/removal of the facilities. Throughout the relicensing and settlement process, PacifiCorp has taken the position that decommissioning and removal of the Project without sufficient protections against the associated costs, risks and liability is not in the interests of the Company or its customers. To that end, it has pursued settlement in a manner that will provide those protections. In addition, the settlement process has provided benefits by allowing customers to continue to benefit from the Project while the public policy decisions on whether removal of the main stem Klamath River facilities is in the public interest are made.

Q. How much has the Company incurred in the licensing and settlement processes?

A. At the end of Calendar Year 2009 (December 31, 2009) the Project has accumulated $66.907 million on a system-wide basis in relicensing and settlement process costs. A detailed cost breakdown for the Project is provided as Confidential Exhibit PPL/602.

Q. Could you please break those costs down by major cost category?

A. Approximately 52 percent of the costs ($35 million) derive from outside expert consulting and legal services. These services included the development of the information necessary to prepare the first stage consultation document and the costs to consult with stakeholders and prepare detailed study plans for the various resource areas investigated as part of the relicensing process. These services included the execution of the vast array of technical studies required and the costs to prepare the license application. Examples of the studies and data collected include:

- Complete aerial photography and mapping of the Project,
- Bathymetric and sediment studies of Project reservoirs,
- Environmental resource investigations,
- Wildlife and vegetation surveys,
- Geomorphology studies,
- Biological and engineering studies of various fish passage alternatives, fisheries modeling and habitat assessment,
- Studies of potential Project operational enhancements,
- Historic and cultural resources investigations,
- Socioeconomic studies,
- Recreation surveys and planning,
- Extensive water quality monitoring, and development of a Project water quality model and associated water quality modeling studies,
- Development of cost estimates for potential protection, mitigation, and enhancement ("PM&E") measures likely to be required in a new license.

These costs also included license application preparation, CWA Section 401 applications costs and related studies, ESA consultation and documentation costs, legal review and legal costs associated with the Company's challenge to agency terms and conditions, responses to comments in relation to the license application, required analysis of the Project pursuant to the California Environmental Quality Act. Finally, this included costs associated with the settlement process, facilitator and mediator services, communications and other services.

The amount of information necessary to be developed for the preparation and support of hydroelectric license applications is rather astounding. The Project license application and associated study documentation and filings produced by the Company require in excess of 8 feet of shelf space. This is similar to the shelf space devoted to the Company's license application for the recently relicensed North Umpqua project.

Materials, labor and associated expenses accounted for approximately $11 million – or approximately 16 percent of total costs. These costs included labor and associated costs for the Company's project management, technical leads, environmental scientists, and administrative staff. The remaining costs are related to property taxes paid against accrued relicensing costs, and Allowance for Funds Used During Construction ("AFUDC").

Q. Can you explain AFUDC and how the Company calculates it?

A. AFUDC is a generally accepted accounting treatment for regulated utilities that permits the capitalization rather than expensing of financing costs (i.e. interest) during the construction phase. This treatment relieves current customers from providing a return on investment for these financing costs during construction and shifts the responsibility to future customers who will receive the benefit of the completed facilities. The Company computes AFUDC by applying the AFUDC rate to qualifying Construction Work In Progress ("CWIP") projects.

Q. What controls did the Company put in place to insure that the expenditures made in the relicensing process were required, necessary, and prudent?

A. First, the Company appoints a Project Manager for each relicensing project. The Project Manager works with Hydro Resources and PacifiCorp Energy management to coordinate all efforts related to the process and project cost management. The Company also assembles a project team, which is comprised of technical leads who are subject matter experts in the various relicensing areas. Examples of technical leads include: fishery and wildlife biologists, cultural and recreation specialists, engineering, etc. The team develops a relicensing strategy to address likely required studies and potential PM&E measures. The technical leads assist the Project Manager is overseeing work tasks within their area of expertise.

Finally, due to the fluid and multi-discipline nature of the FERC relicensing process, which requires significant legal support, the Office of General Counsel reviews the relicensing project and works with the Project Manager to assure that legal services in support of the relicensing effort are necessary, prudent, and procured in conformance with Company policies that are intended to control costs.

Q. Please explain how outside services costs have been managed?

A. First, an overall budget was established for the project spanning the time through expected license issuance. Each year, as part of the annual budgeting and approval process, the portion of the Project budget to be expended in the upcoming year is thoroughly reviewed and approved by management. Throughout the year, a monthly break down of all Project expenditures is provided to department management and to the Project Manager. This process provides an opportunity to look at Project costs on an overall basis and make adjustments as may be necessary to stay within the overall Project budget if possible. The process also provides an opportunity to review all expended costs on a monthly basis to ensure they are proper and represent prudent expenditures to accomplish the relicensing and settlement objectives.

More specifically, during the license development process, the Company prepared study plans, and the technical leads were responsible for considering any existing data needs and potential data gaps. A study plan was then produced and the Company contracted with consultants to conduct the study. Consultants have been generally selected through a formal bidding process unless specific expertise was needed, in conformance with general PacifiCorp procurement policy. Oversight of consultant work is the responsibility of the internal technical team lead and ultimately of the Project Manager. Consultants provide monthly reports on their activities along with detailed invoices. The Project Manager receives and reviews all invoices and reviews tasks each month.

Q. Has the complexity of the Project impacted the overall level of process costs?

A. Yes. As detailed earlier in my testimony, the relicensing process is complex and requires the expenditure of significant staff labor, outside technical support, and legal services to prepare an application and defend that application through the regulatory process. The Project has been the most complex and contentious relicensing proceeding the Company has undertaken for its many hydroelectric projects. Even so, the Project relicensing costs compare favorably with another recent relicensing effort by the Company on the North Umpqua River. At the conclusion of that relicensing process in 2005, the total cost was approximately $55.1 million. In that case, the relicensing and settlement process spanned 10 years, from 1991 to 2001. The settlement parties were fewer in number and included: U.S. Forest Service, National Marine Fisheries Service, U.S. Fish and Wildlife Service, Bureau of Land Management, Oregon Department of Environmental Quality, Oregon Department of Fish and Wildlife, and Oregon Water Resources Department.

Q. Please summarize your testimony.

A. PacifiCorp's hydro generation facilities comprise an important component of its overall power supply portfolio. The Project has provided reliable, low-cost power since it was constructed. Owners of non-federal hydropower projects are required under the FPA to apply for new operating licenses from FERC. Relicensing is a complex and often contentious regulatory process that takes many years to complete. The process requires consulting with multiple federal, state, tribal, environmental and community stakeholders; conducting and analyzing the results of numerous environmental studies; presenting and documenting the results of studies and consultation in license applications and other required documentation; and triggers compliance with other federal laws such as the CWA and ESA. In order to operate hydro facilities and to preserve their unique benefits, licensees must seek new licenses and essentially "prove," through the relicensing process, that continuing to operate the project is still in the public interest. The Company pursued relicensing of the Project given the historic benefits provided to PacifiCorp's customers and the belief that the Project could be relicensed and operated economically in conformance with environmental requirements.

The relicensing process resulted in an outcome in which the Company determined that settlement of the relicensing proceeding through the KHSA was in customers' best interests. Throughout the relicensing and settlement process, PacifiCorp has sought to protect the interests of its customers by controlling costs, reducing uncertainty and risk, avoiding expensive litigation, and accurately assessing the impact of proposed regulatory mandates on the Project.

Q. Does this complete your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/601
Witness: Dean S. Brockbank

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Dean S. Brockbank

Klamath Chronology

March 2010

Klamath Chronology

Date	**Event**
December 15, 2000	Notice of Intent to file an application filed with the Federal Energy Regulatory Commission and the First Stage Consultation Document released to public
January 23, 2001	Public meetings
August 7, 2001	Consultation meetings with stakeholders begin
August 8, 2001	Start of workgroup meetings
January 2002	PacifiCorp begins conducting additional studies
January-December 2003	PacifiCorp continues natural resource studies
January-December 2003	PacifiCorp continues stakeholder meetings (over 200 in all)
February 23, 2004	PacifiCorp submits final license application
April 16, 2004	FERC issues scoping document No. 1
August 16, 2004	FERC issues notice of application
February 17, 2005	FERC submitted additional information requests to PacifiCorp
May 17, 2005	FERC issues scoping document No. 2
December 28, 2005	FERC issues Notice of Ready for Environmental Analysis
February 28, 2006	License expires - FERC issues annual license to operate
March 24, 2006	Federal agencies issue draft terms and conditions
March 26, 2006	PacifiCorp submits 401 applications to Oregon and California
March 27, 2006	PacifiCorp files alternative conditions
August 25, 2006	Trial-type hearing closes
September 25, 2006	FERC issues draft environmental impact statement
September 27, 2006	Decision issued in trial-type hearing
November 14, 2006	Public meeting on the draft environmental impact statement begin
January 24, 2007	Federal agencies issue modified terms and conditions

February 28, 2007	PacifiCorp resubmits 401 applications
March 21, 2007	FERC initiates Endangered Species Act consultation
September 17, 2007	PacifiCorp signs MOU for California Environmental Quality Act analysis
October 22, 2007	U.S. Fish and Wildlife service issues draft biological opinion
November 2, 2007	National Marine Fisheries Service issues draft biological opinion
November 16, 2007	FERC issues final environmental impact statement
December 3, 2007	U.S. Fish and Wildlife service issues final biological opinion
January 15, 2008	Klamath Basin Restoration Agreement (proposed) released
February 22, 2008	Withdrew and resubmitted California and Oregon 401 applications
November 10, 2008	Interim Conservation Plan released
November 13, 2008	Agreement in Principle signed
June 2009	California Klamath River TMDL issued
August 27, 2009	PacifiCorp submits comments on the California Klamath River TMDL
September 10, 2009	Withdrew and resubmitted California 401 application
September 30, 2009	Draft Klamath Hydroelectric Settlement Agreement released
December 23, 2009	Revised California TMDL issued
January 7, 2010	Klamath Basin Restoration Agreement Public Review Draft released
January 8, 2010	Klamath Hydroelectric Settlement Agreement Public Review Draft released
January 20, 2010	Withdrew and resubmitted Oregon 401 application

Exhibit PPL/602
Dean S. Brockbank

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/602
Witness: Dean S. Brockbank

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Dean S. Brockbank

Relicensing Cost Summary

March 2010

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/700
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Chad A. Teply

March 2010

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

A. My name is Chad A. Teply. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah. My position is Vice President of Resource Development and Construction.

Qualifications

Q. Please describe your education and business experience.

A. I hold a Bachelor of Science Degree in Mechanical Engineering from South Dakota State University. I am a Registered Professional Engineer in the state of Iowa. I joined MidAmerican Energy Company in November 1999 and held positions of increasing responsibility within the generation organization, including the role of project manager for the 790 megawatt ("MW") Walter Scott Energy Center Unit 4 completed in June 2007. In April 2008, I moved to Northern Natural Gas Company as Senior Director of Engineering. I assumed my current position in February 2009 and have responsibility for development and execution of major resource additions and major environmental projects.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information on the pollution control investments being made at the Company's Dave Johnston Unit 3 power plant that will result in environmental improvements.

Q. Please describe the current operation of Dave Johnston Unit 3.

A. Dave Johnston Unit 3 is a nominal 230 MW pulverized coal unit located in central

Wyoming, near the town of Glenrock. It was placed into service in 1964. The unit is equipped with a coal-fired boiler. The original burners are still being used on the unit; however, combustion control modifications for nitrogen oxides ("NO_X") control are scheduled in 2010. An electrostatic precipitator for control of particulate matter was installed in 1976. Dave Johnston Unit 3 is not equipped with sulfur dioxide ("SO_2") removal equipment; however, the environmental improvement project that is the subject of this case will provide SO_2 emissions and particulate matter ("PM") emissions control with its in-service date in 2010.

Q. Does Dave Johnston Unit 3 currently have operating restrictions related to emissions?

A. Dave Johnston Unit 3 is currently operated with a 220 MW net output limit to maintain compliance with state of Wyoming SO_2 emissions limits. The new pollution control equipment will increase the auxiliary power consumption by approximately 4.2 net MW. Investment in the new pollution control equipment will remove the net output constraint on the unit associated with SO_2 emissions; however, net output of the unit will likely remain below 230 MW even after additional minor capital investments are made during the 2014 planned maintenance outage.

Description of Pollution Control Investments

Q. Please describe the Dave Johnston Unit 3 pollution control project and associated equipment.

A. The pollution control project being undertaken at the Dave Johnston Unit 3 power plant will upgrade and improve the unit's particulate matter controls and install

SO_2 controls. The capital expenditure for the project during the test period is $299.8 million. Construction began in 2008, and the project is expected to be operational by May 31, 2010. The new equipment will be tied into the existing equipment during a scheduled plant maintenance outage. The project will install a dry flue gas desulfurization ("DFGD") system with fabric filter. A DFGD system injects lime slurry in the top of an absorber vessel (scrubber) with a rapidly rotating atomizer wheel. The rapid rotation of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form calcium sulfate in the form of particulate matter. The dry particulate matter is then captured in the downstream baghouse along with fly ash from the boiler. The DFGD system will produce a nonhazardous dry waste product suitable for landfill disposal. Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, lime slurry reagent preparation systems, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Please describe the emissions improvements that will be achieved with the Dave Johnston Unit 3 pollution control project.

A. The Dave Johnston Unit 3 dry flue gas desulfurization system and baghouse will reduce SO_2 emissions from the unit by approximately 90 percent, or approximately 6,600 tons per year. In addition to reducing SO_2 emissions, the baghouse will reduce the emissions of particulate matter. The particulate matter emission limit will be reduced from 0.20 pounds per million British Thermal Units ("BTUs") to 0.015 pounds per million BTUs.

Q. Please provide additional details on the project costs.

A. The project costs are broken down into the lump sum engineering, procurement, and construction ("EPC") contract, owner's engineer costs, PacifiCorp internal costs, permitting costs, existing stack and ID Fan demolition costs, boiler reinforcement costs, contingency and the allowance for funds used during construction ("AFUDC"). As a percentage of the total cost, these categories are EPC (85.11 percent), owner's engineer (0.72 percent), PacifiCorp internal cost (1.38 percent), permitting (0.05 percent), stack and ID Fan demolition (1.88 percent), boiler reinforcement (2.50 percent), contingency (0.7 percent), and AFUDC (7.67 percent).

Q. Has the cost of the project been prudently managed?

A. Yes. The project was contracted under lump-sum turnkey EPC contract terms which resulted from a competitive bidding process. PacifiCorp project management staff continues to provide oversight of the project and closely manages any project execution plan changes or potential EPC contract scope changes.

Q. Are there additional operating costs that will be incurred as a result of the installation of the pollution control equipment?

A. Yes. Operation of the new pollution control equipment will result in increased operation and maintenance costs associated with reagent, waste disposal, and equipment maintenance.

Q. Are there net power cost savings related to adding the Dave Johnston Unit 3 pollution control equipment explained in your testimony?

A. No. While providing benefits to customers through emissions reductions and in meeting compliance requirements, the addition of pollution control equipment does not reduce net power costs. Installation of the pollution control equipment on Dave Johnston Unit 3 will reduce output by 4.2 MW and the average heat rate is expected to increase by 138 BTUs per kilowatt-hour of generation.

Q. How are the Dave Johnston Unit 3 pollution control investment costs and associated operating costs being treated in the revenue requirement?

A. The costs for the pollution control equipment have been included in this case in the testimony of Company witness Mr. R. Bryce Dalley.

Justification of Investment

Q. What is the basis for this investment?

A. This investment was identified as part of the Company's response to environmental regulations that govern its operations. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from manmade emissions in designated national parks and wilderness areas; this goal resulted in development of the Regional Haze Rules, enacted in 2005 by the Environmental Protection Agency ("EPA"). These rules trigger Best Available Retrofit Technology ("BART") reviews for all coal-fired generation facilities built between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution per year. Because Dave Johnston Unit 3 was built in 1964 and emits at least 250 tons of visibility impairing pollution per year, it is subject to BART review. A BART review of Dave Johnston Unit 3 was completed and submitted to the Wyoming Department of Environmental Quality for final disposition. A copy of the final report of the BART Analysis for Dave Johnston Unit 3 is provided as Confidential Exhibit PPL/701.

The Wyoming Department of Environmental Quality issued a BART permit for Dave Johnston Unit 3 on December 31, 2009 incorporating the Dave Johnston Unit 3 equipment and installation schedule recommended via the BART review and contemplated in this case. The conditions of the Dave Johnston Unit 3 BART permit will be incorporated into the Wyoming State Implementation Plan ("SIP") for Regional Haze in support of its goal to reduce visibility impairing emissions. The Wyoming SIP is subject to EPA review and approval. The state of Wyoming has also issued an Approval Order (i.e., permit to construct) for the Dave Johnston Unit 3 environmental improvement project. The environmental compliance activities discussed above form the basis for this investment.

Q. What factors does the Company consider when determining which capital investments to make in environmental equipment retrofit projects?

A. There are several factors the Company takes into consideration when making pollution control equipment investments including: evaluation of state and federal environmental regulatory requirements and associated compliance deadlines, review of emerging environmental regulations and rulemaking, and analyses of alternate compliance options. In the case of Dave Johnston Unit 3, the Company evaluated several technologies on their ability to economically achieve compliance and support an integrated approach to control criteria pollutants (e.g.

SO_2, NO_X) and particulate matter for the facility if it were to continue to operate and to burn coal. The BART analysis reviewed five available retrofit emission control technologies and their associated performance and cost metrics. Each of the technologies was reviewed against its ability to meet a presumptive BART emission limit based on technology and fuel characteristics. The BART analysis outlined the available emission control technologies, the cost for each and the projected improvement in visibility which can be expected by the installation of the respective technology. Once the preferred BART technology was identified, the Company moved forward with its competitive bidding process to evaluate and ultimately select the preferred provider for the project.

Q. Would the Company's decision to make this incremental investment in environmental controls at this unit change if limitations were placed on carbon dioxide emissions, such as in the Waxman-Markey bill in the U.S. House of Representatives or the Kerry-Boxer bill in the U.S. Senate?

A. No. The Company is currently engaged in assessing its existing generation resources, its planned supply and demand-side resources and its 10-year capital budget regarding the impact of carbon dioxide emissions restrictions. While planned investments in other units may change, the Company's plans regarding this investment in Dave Johnson Unit 3 would not be changed by carbon-emission restriction. The unit has a depreciation life for Oregon ratemaking purposes that concludes in 2023, providing sufficient remaining time to depreciate the investment in the environmental controls.

Timing of Investment

Q. Why is PacifiCorp installing the Dave Johnston Unit 3 pollution control equipment at this time?

A. As discussed above, the Company is installing the pollution control equipment at this time primarily to ensure compliance with Regional Haze Rules, but also in response to a variety of existing and emerging emission reduction requirements. The Wyoming Department of Environmental Quality issued a BART permit for Dave Johnston Unit 3 on December 31, 2009 incorporating the Dave Johnston Unit 3 equipment and installation schedule recommended via the BART review and contemplated in this case. The conditions of the Dave Johnston Unit 3 BART permit will be incorporated into the Wyoming SIP for Regional Haze in support of meeting presumptive BART emission rates to reduce visibility impairing emissions. The BART permit issued for Dave Johnston Unit 3 specifically requires that the new Dave Johnston Unit 3 baghouse be installed as a part of the overall pollution control investment and must be in-service and initially performance tested before the end of 2010.

Final installation activities and tie-in of the pollution control equipment can only be accomplished when the unit is off-line. Dave Johnston Unit 3 is scheduled for a maintenance overhaul during the spring of 2010. Meeting the timing requirements of the BART permit and reducing plant outage time necessitated completion of final installation activities and tie-in of the pollution control equipment during the scheduled overhaul this spring. PacifiCorp anticipates that the pollution control equipment will be installed and in service by

May 31, 2010.

Installation of the pollution control equipment and associated systems contemplated in this case represent a significant step for the PacifiCorp coal-fueled power plant fleet towards meeting the SO_2 reductions required by the Regional Haze Rules and the established SO_2 emissions reduction milestones.

Customer Considerations

Q. What are the benefits to customers of installing the Dave Johnston Unit 3 pollution control equipment?

A. Customers directly benefit from the continued availability of low-cost generation produced at the Dave Johnston plant while also achieving environmental improvements from this resource, resulting in cleaner air. In addition, the tie-in of these necessary controls is being accomplished during a planned outage, as opposed to scheduling a separate outage for this work, which reduces replacement power costs. The Company has ten BART-eligible units in Wyoming and four in Utah. The BART controls for each of these units must be installed within five years from the date the SIP is approved and prior to the compliance dates specified in the permits. Although SIP approval has not yet been received, the Company anticipates that BART-required controls will be required on some or all of these units if they are not retired or retrofitted to burn natural gas. Postponing installation on this unit to a later planned maintenance outage would make it virtually impossible for the Company to effectively ensure that all of its affected units meet compliance deadlines and would place the Company at risk of not having access to necessary capital, materials, and labor while attempting to perform these major equipment installations in a compressed timeframe.

Conclusion

Q. Please summarize your conclusions.

A. Investment in the Dave Johnston Unit 3 pollution control equipment is required to meet the Regional Haze Rules, enacted in 2005 by the EPA, and the resulting BART reviews and permitting process, if the unit is to continue to burn coal. The Company's decision to install this pollution control equipment would not be changed by the enactment of carbon dioxide emissions reduction legislation such as Waxman-Markey bill or the Kerry-Boxer bill. The $299.8 million investment during the test period and associated operating costs are reasonable and prudent, and the Company should be granted cost recovery. The investment allows for the continued operation of a low-cost coal-fired generation facility while achieving significant environmental improvements to air quality and regional haze issues.

Q. Does this conclude your direct testimony?

A. Yes.

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/701
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Chad A. Teply

Final BART Analysis for Dave Johnston Unit 3

March 2010

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/800
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Stefan A. Bird

March 2010

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

A. My name is Stefan A. Bird. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232. My present position is Senior Vice President of Commercial and Trading.

Qualifications

Q. Please describe your education and business experience.

A. I hold a B.S. in mechanical engineering from Kansas State University. I joined PacifiCorp Energy and assumed my current position in January 2007. From 2003 to 2006, I served as president of CalEnergy Generation U.S., an owner and operator of Qualifying Facility and merchant generation assets, including geothermal and natural gas-fired cogeneration projects across the United States. From 1999 to 2003, I was vice president of acquisitions and development for MidAmerican Energy Holdings Company. From 1989 to 1997, I held multiple positions at Koch Industries, Inc., including energy trading, financial trading, acquisitions, project engineering and maintenance planning in the United States, Latin America and Europe.

In my current position I oversee the Company's Commercial and Trading organization which is responsible for electricity and natural gas wholesale activities, dispatch of all of the Company's owned and contracted generation resources and wholesale purchases and sales to balance the Company's load and resources. My organization is also responsible for the Company's load and revenue forecast, integrated resource plan ("IRP") and net power costs ("NPC") modeling. Most relevant to this case, I am responsible for acquisition of power resources for utilization in the Company's east and west balancing authorities (the "System") by means that include the negotiation of power purchase agreements ("PPAs") and the acquisition of generation resources through the requests for proposal ("RFP") process.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate that the 2009R RFP was conducted fairly and properly and to demonstrate the prudence of the Dunlap I wind-powered generation resource ("Dunlap I"). Dunlap I is the Company's cost-based benchmark alternative ("Benchmark") and one of the two resources included in the Commission-approved 2009R RFP Final Shortlist.

Q. Please provide an overview of your testimony.

A. I begin by providing a general overview of the 2009R RFP. I also describe how the Company determined the resource needs targeted in the 2009R RFP. I then describe the economic analysis and selection of the 2009R RFP Initial and Final Shortlists. Finally, I describe Dunlap I and the status of the other Final Shortlist proposal ("Proposal B").

2009R RFP

Q. Please describe the 2009R RFP.

A. On May 22, 2009, the Commission opened Docket UM 1429 and selected Boston Pacific Company to serve as the Oregon independent evaluator ("IE") for the

2009R RFP.[1] The 2009R RFP targeted acquisition of up to 500 megawatts ("MW") of System-wide renewable resources with commercial operation dates between 2010 and 2012 and where no single resource exceeding 300 MW[2] would be acquired. Eligible resources were also required to: meet an expected annual output of at least 25,000 megawatt-hours ("MWh") after accounting for planned and unplanned outages; include associated renewable energy credits ("RECs"); and comply with renewable portfolio standard ("RPS") requirements in the Company's six-state service area. The 2009R RFP also allowed for the submission of a Company Benchmark.

Q. Please describe how the Company determined the resource needs targeted in the 2009R RFP.

A. The Company identifies and quantifies the need and timing of new supply-side resources through its IRP process. Resource needs are also reflected in certain MidAmerican Energy Holding Company ("MEHC") transaction commitments. The IRP process and MEHC transaction commitments related to generation resource needs are described in more detail in the direct testimony of Company witness Mr. Mark R. Tallman, included as Exhibit PPL/900.

Q. Did the Commission approve the 2009R RFP?

A. Yes. The Commission approved the 2009R RFP at its Public Meeting on July 7, 2009 with conditions, including a requirement that the Company not exceed a combined total acquisition of 600 MW between the 2008R-1 and 2009R RFPs.[3]

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[1] *See* Order No. 09-181.
[2] 300 MW is the upper limit permitted by Utah Senate Bill 202. Qualifying Facilities that are at least 10 MW are eligible, pursuant to Guideline 6 in Order No. 05-446.
[3] *See* Attachment A to Order No. 09-272 at pp. 9-10.

Q. Has the Company complied with the 600 MW limitation?

A. Yes. The Company acquired 201.5 MW as a result of the 2008R-1 RFP by signing a PPA to purchase the output from the Top of the World Wind Energy, LLC project. The acquisition of one or both of the 2009R RFP Final Shortlist resources, in addition to the procurement under the 2008R-1 RFP, would not violate the Commission's condition.

Q. Please describe the timeline associated with the 2009R RFP process.

A. The 2009R RFP was issued to the market July 8, 2009 with the Company's Benchmark submittal due no later than September 3, 2009. Proposals from the market were due September 10, 2009. Following review by the IE, the Company Benchmark was formally submitted to the IE and Commission Staff on September 3, 2009. The price and non-price analysis of the Benchmark was completed by the Company, reviewed by the IE and provided to Commission Staff prior to the Company opening proposals from the market on September 10, 2009. The IE provided a memo on the Benchmark to Staff and the Company on September 11, 2009 (the "Benchmark Memo"), attached as Confidential Exhibit PPL/801.

Q. Please explain how the IE conducted its analysis and established the conclusions set forth in the Benchmark Memo.

A. The IE undertook a detailed examination of the Company's Benchmark by reviewing the submittal and detailed cost backup sheets and through conversations with the Company's generation personnel. The IE's stated primary concern was the potential omission of capital costs. Accordingly, the IE focused on ensuring that appropriate capital costs were included in the Benchmark. As an additional check, the IE compared the Benchmark capital costs and estimated capacity factors to proposals from the 2008R-1 RFP the IE considered comparable.

Q. What did the Benchmark Memo conclude with respect to the inclusion of capital costs in the Benchmark?

A. The Benchmark Memo concluded that all capital costs were properly included and that the level of the Benchmark's estimated capital costs were appropriate. The IE also found that the Benchmark capital costs were within the range of comparable costs as indicated by proposals in the 2008R-1 RFP. Finally, the IE found that the estimated annual Benchmark capacity factor, while in the high range compared to all proposals in the 2008R-1 RFP, was within the range of capacity factors from proposals associated with potential resources in the nearby vicinity.[4]

Q. Why did the Company submit a Company Benchmark and what role does it play in the RFP process?

A. The Company's Benchmark played an important role in the 2009R RFP process by providing a cost-based alternative for the benefit of customers. The Company received proposals in the 2009R RFP under a multitude of structures with varying terms and conditions that served as alternatives to the Benchmark including PPAs, and build own transfers ("BOTs"). Including a Benchmark provides a benefit for customers because it serves as a check on market-based proposals, provides a resource alternative that the Company is prepared to undertake, and shields customers from 100 percent market exposure.

[4] *See* Benchmark Memo at p. 11-12.

Q. Please describe the 2009R RFP Initial Shortlist selection process.

A. The Company's analysis of the 2009R RFP proposals focused on determining which resources would provide the best value to customers on a System-wide planning basis to meet customer requirements at the least cost, on a risk adjusted basis. To achieve these objectives, the Company evaluated alternatives in a two step process. First, the Company selected three Initial Shortlists: (a) west wind; (b) east wind; and (c) all other renewable resources. The purpose of first selecting three separate Initial Shortlists was to capture location resource diversity and the different sources of renewable resources.

To select groups of proposals to comprise each of the three Initial Shortlists, the IE agreed with the Company's goal to: (1) select the proposals with the greatest net benefit in terms of price and non-price benefits; (2) select a diversity of proposals and projects; (3) select a mix of PPAs and BOTs; (4) determine a relatively clear split between the score of the last proposal priced and the next proposal that was not selected; and (5) achieve the RFP goal that each category contain up to 500 MW or five proposals. *See* The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2009R Renewables RFP (November 5, 2009) ("Final Report") at p. 12. The Final Report is attached as Confidential Exhibit PPL/802.

Each proposal received up to a maximum of 100 points. The three Initial Shortlists were comprised of the highest scoring proposals in each of the three respective segments, based on price (up to 70 points) and non-price factors (up to 30 points). The price factor was derived by using the PacifiCorp Structuring and

Pricing RFP base model, which determines the top performing proposals on the basis of the net present value revenue requirement ("Net PVRR") per kilowatt month. The Net PVRR component views the value of the energy and capacity as a positive and the offsetting costs of the proposal as a negative. The more positive the Net PVRR, the more valuable a given resource is to the Company's customers.

The non-price factors evaluated were negative or positive based on the following criteria: (a) conformity with 2009R RFP proposal requirements; (b) conformity with the *pro forma* PPA or BOT documents and/or Asset Acquisition and Sale Agreement attached as exhibits to the 2009R RFP; (c) feasibility of the proposal; (d) site control or permitting of the proposal; and (e) operational viability of the proposal. Based on the application of the price and non-price factors, the Company selected proposals to comprise the Initial Shortlists. The Initial Shortlists contained a total of 14 resource alternatives (13 proposals from the market and the Benchmark). The 14 alternatives contained five east wind resources, four west wind resources and five other renewable resources.

Q. Did the IE agree with the Company's selection of alternatives contained in the three Initial Shortlists?

A. Yes. The IE agreed with the Company's selection of the three Initial Shortlists.[5]

Q. Please describe the 2009R Final Shortlist selection process.

A. After the Company selected the three Initial Shortlists, it moved to step two of the evaluation process – selection of the Final Shortlist. To select the Final Shortlist, the Company applied its next highest alternative cost for compliance ("ACC")

[5] *See* Final Report at pp. 11-14.

analysis methodology for renewable resources to each of the three Initial Shortlists. This resource-specific analysis allows the Company to compare a resource against the potential next highest alternative cost for renewable resource compliance. In essence, the result of the ACC analysis shows how the resource compares to the undifferentiated power market. The ACC analysis also incorporates a resource's risk-adjusted system benefit, using the Company's IRP stochastic production cost model. A negative ACC indicates that the resource is valued below undifferentiated market alternatives; whereas a positive ACC indicates that the resource is valued above undifferentiated market alternatives. Upon completion of the ACC analysis and the PVRR(d) analysis, the Company selected two alternatives for inclusion in the Final Shortlist. The Final Shortlist included: (1) Dunlap I, the Company Benchmark; and (2) Proposal B, a BOT. Both Dunlap I and Proposal B are located in Wyoming.

Q. Did the IE concur with the Final Shortlist?

A. Yes. The IE concurred with the selection of the Final Shortlist and recommended that the Company include two additional back-up proposals for potential consideration in the event the other alternatives did not materialize. Both of the back-up alternatives are less cost-effective than Dunlap I and Proposal B. Moreover, one of the back-up proposals is not currently viable because it is sited in a location recently designated as a Greater Sage-Grouse Core Area. Wyoming's Greater Sage-Grouse Core Area is discussed in more detail later in my testimony.

Q. Did the IE recommend acknowledgement of the 2009R Final Shortlist?

A. Yes. The IE recommended that the Commission acknowledge the Final Shortlist.[6]

Q. On what basis did the IE recommend acknowledgement of the Final Shortlist?

A. As explained in the Final Report, the IE based its recommendations on six key points. First, the selected alternatives represented the resources with the greatest net benefits to customers as determined by the ACC. Second, the alternatives represented the top options from a competitive process where the Company received proposals from 26 suppliers offering a total of 39 projects. Some of these projects offered multiple options for a total of 82 proposal options and over 9,400 MW. Third, the IE's report states:

> *independent analysis confirmed that the selected bids represent the lowest cost alternatives for ratepayers, with an accounting for risk. Our independent analysis included the creation of our own cost annuity models for each bid option, a review of PacifiCorp's models, and a thorough review of the terms and condition of each bid.*[7]

Fourth, The RFP aligns with the Company's IRP process. The Initial and Final Shortlist analysis used current assumptions from the IRP. In addition, the ACC analysis uses a model from the Company's IRP process to calculate the benefit of renewable resources. Fifth, the Company Benchmark is included in the Final Shortlist and the IE took special care to confirm that selection, noting:

> *[w]e confirmed the accuracy of the Benchmark costs and scoring and provided the Commission with a complete review of all costs of the project prior to bid receipt. We*

[6] *See* Final Report at p. 1.
[7] Id. at p. 3.

> *also confirmed the Benchmark's status by; (a) reviewing the project's initial and final shortlist scores and models, (b) independently scoring the project's non-price characteristics, (c) comparing the cost and output of the project to recent third-party bids, and (d) evaluating the bid costs in our own cost model.*[8]

Sixth, while there were *two bids targeted for acquisition the shortlist also includes two 'back- up' bids which provides some assurance that, should negotiations fall through with a bidder, the RFP may still result in a winner in addition to the Benchmark.*[9]

Q. Did Commission Staff recommend acknowledgment of the 2009R RFP Final Shortlist to the Commission?

A. Yes. Commission Staff reached the following conclusions in its November 13, 2009 report to the Commission:

1. PacifiCorp conducted its 2009R RFP fairly and properly;
2. PacifiCorp selected the best bids for the final shortlist consistent with the cost-risk decision criteria used to develop the renewable resource schedule acknowledged in the 2007 IRP and currently filed 2008 IRP; and
3. PacifiCorp's Final Shortlist represents the best options from a very competitive procurement process, including the evaluation and selection of a Company benchmark resource.[10]

Q. Did the Commission acknowledge the 2009R RFP Final Shortlist?

A. Yes. The Commission acknowledged the Final Shortlist at its November 24, 2009 public meeting.[11]

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[8]Final Report at p. 3.
[9] Id. At p. 4.
[10] Public Utility Commission of Oregon Staff Report (November 13, 2009) at p. 6.
[11] *See* Order No. 09-492.

Dunlap I

Q. Please describe Dunlap I.

A. Dunlap I is a 111 MW wind project consisting of 74 wind turbine generators, an electrical collector system, a 34.5 to 230 kV collector substation (known as the Dunlap substation), a 230 kV transmission line (approximately 11 miles in length), 230 kV breakers, access roads, an operations & maintenance ("O&M") building and required communication and control facilities (e.g., metering, hardware, software, and associated communication circuits and other equipment).

Q. Where will Dunlap I be located?

A. Dunlap I will be located approximately eight miles north of Medicine Bow, Wyoming in Carbon County on property consisting of approximately 16,500 acres (the "Site").

Q. Why is the Site an appropriate place to construct Dunlap I?

A. The Site is appropriate for Dunlap I for three primary reasons: (1) studies indicate the Site will result in a desirable wind resource; (2) the Site is located in close proximity to the Company's transmission system and another Company-owned wind project; and (3) the Company owns the majority of the Site land, thereby avoiding third-party royalty payments at a benefit to customers.

Q. Please explain the division of land ownership within the Site.

A. The Company owns the vast majority of the Site land. The Bureau of Land Management ("BLM") owns two sections, the state of Wyoming owns approximately two and one half sections and one section is held by a private a third party.

Q. Please explain if any of the Dunlap I facilities will be located on land not owned by the Company.

A. The Company has no rights at this time to use the BLM land and no plans to place facilities on BLM lands. The Company holds a lease for the state lands and intends to cross one section with a 230 kV transmission line. At this time, placement of wind turbine generators ("WTGs") on the state lands is not planned for Dunlap I. Although the Company plans to install electrical facilities on the third-party lands, there are no plans for the placement of Dunlap I WTGs on such lands at this time. Finally, the Company holds a lease to an additional state section that the transmission line from the Site to the point of interconnection with the Company's transmission system will cross. The remainder of the transmission right-of-way is on land leased from a private entity.

Q. Has the Company performed an evaluation of the wind potential at the Site?

A. Yes. Wind potential studies were performed by the Company's consultant as part of the Company's Benchmark submittal. In addition, as part of the RFP process, the Company retained a separate consultant to perform an independent wind study for the Benchmark and Proposal B. The second study confirmed the Site's suitability for Dunlap I. The second study also supplied its own independent estimate of the annual capacity factor forecast for Dunlap I. The independent studies were used in the RFP analysis of the Benchmark and Proposal B.

Q. Who will supply the towers, WTGs and control systems for Dunlap I?

A. The towers, WTGs and control systems will be supplied by the General Electric Company ("GE").

Q. How was GE selected as the turbine supplier?

A. The Company solicited offers from multiple turbine suppliers and GE was determined to provide the lowest cost and risk to customers.

Q. Is GE a proven supplier of WTG equipment?

A. Yes. GE is one of the leading and most creditworthy WTG suppliers in the market and has an established track record of manufacturing wind generation components.

Q. Will GE supply a warranty?

A. Yes. GE will provide a two year warranty.

Q. What is your understanding of the 2008 Executive Order issued by Wyoming Governor David Freudenthal designating Greater Sage-Grouse Core Areas?

A. The Executive Order maps out the state of Wyoming's prime sage-grouse habitat areas and lists a number of requirements that restrict new development of coal, wind, oil, gas, recreation and agriculture within those areas.

Q. Is Dunlap I in the Greater Sage-Grouse Core area?

A. No. The Dunlap I facilities, including the 230 kV transmission line, are not located in the Greater Sage-Grouse Core Area.

Q. What is the projected commercial operation date for Dunlap I?

A. The projected commercial operation date for Dunlap 1 is November 1, 2010.

Q. What investment related to the Dunlap I resource is included in the revenue requirement in this case?

A. The Company has included $261.2 million for Dunlap I in this case. This amount is consistent with the amount utilized in the evaluation and selection of the 2009R

RFP Final Shortlist and reviewed by the IE. The O&M costs included in this case associated with Dunlap I are $2.4 million for WTG maintenance, permitting obligations, local levy tax and land use payments. The testimony of Company Witness Mr. R. Bryce Dalley includes the revenue requirement calculations with the inclusion of this resource.

Q. Does the record developed in the RFP process show that Dunlap I is a prudent and cost-effective resource?

A. Yes. Additionally, the acquisition of Dunlap I is consistent with PacifiCorp's IRP action plan and PacifiCorp's renewable resource commitments resulting from the MEHC acquisition.

Proposal B

Q. What is the status of Proposal B?

A. Proposal B has provided a credit commitment letter to support the project. The Company has initiated negotiations with Proposal B with the goal to reach prudent mutually agreeable terms and execute contracts for acquisition of a resource that benefits customers while balancing risk.

Q. Does this conclude your direct testimony?

A. Yes.

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/801
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Stefan A. Bird

Oregon IE Benchmark Memo

March 2010

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Exhibit PPL/802
Stefan A. Bird

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/802
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Direct Testimony of Stefan A. Bird

Oregon IE Final Closing Report

March 2010

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Docket No. UE-
Exhibit PPL/900
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mark R. Tallman

March 2010

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

A. My name is Mark R. Tallman. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. My present position is Vice President of Renewable Resource Acquisition.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University of Seattle. I am also a Registered Professional Engineer in the states of Oregon and Washington. I have been the Vice President of Renewable Resource Acquisition since December 2007. Prior to that, I was Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 24 years in a variety of positions of increasing responsibility, including the commercial and trading organization; the Company's engineering organization; the retail distribution organization; and five years as a District Manager.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the prudence of the McFadden Ridge I wind-powered generation resource ("McFadden Ridge I").

Q. Please summarize your testimony.

A. I start by describing the Company's integrated resource plan ("IRP") and how it is utilized to identify and quantify the need and timing of new supply-side resources. I also provide an overview of the relevant MidAmerican Energy Holdings Company ("MEHC") transaction commitments related to acquisition of renewable resources. Finally, I provide a description of McFadden Ridge I and the decision-making process leading to its acquisition.

Integrated Resource Plan

Q. Please briefly describe the IRP process.

A. The IRP is a strategic planning tool that presents a framework for resource acquisitions to ensure the Company continues to provide reliable, low-cost service with manageable and reasonable risk to customers. The IRP builds on the Company's prior resource planning efforts and reflects significant advancements in portfolio modeling and risk analysis.

Q. What is the main purpose of the IRP?

A. The mandate for an IRP is to assure that the Company has, on a long-term basis, an adequate and reliable electricity supply at the lowest reasonable cost and to ensure that such supply is provided or fulfilled in a timely and planned manner consistent with the long-term public interest. The IRP serves as a strategic roadmap to assist the Company in determining and implementing the Company's long-term resource strategy. In doing so, it accounts for state or Commission IRP requirements, expected customer resource needs, the current planning environment, corporate business goals and certain commitments made by the Company as part of MEHC's acquisition of PacifiCorp, including the acquisition of renewable resources.

Q. What is the outcome of the IRP process?

A. The outcome of the IRP process is a preferred portfolio that represents a balance of resource additions that meet future customer needs, minimize cost, balance diverse stakeholder interests and address environmental concerns.

To follow through on the findings of the resource plan, the Company's IRP includes an action plan that is intended to inform and provide guidance for the Company's resource procurement activities.

Q. How do the most recent IRPs address renewable resources?

A. The 2008 IRP was filed with the Commission on May 29, 2009, in Docket LC 47. It identifies over 2,000 megawatts ("MW") of cost-effective renewable resources to be acquired by 2013. The 2008 IRP target to acquire 2,000 MW by 2013 is consistent with the target contained in the 2007 IRP. By 2018, acquisition of renewable resources reaches 2,540 MW in the 2008 IRP, which includes over 1,400 MW of resources added from 2009 through 2018.

Q. Do the 2007 and 2008 IRPs address the procurement of renewable resources?

A. Yes. Both the 2007 and 2008 IRPs outline the general renewable resource procurement strategy as part of the IRP action plan.[1] The Company will rely on periodic issuance of renewable requests for proposals ("RFP") and pursue opportunities through bilateral negotiations, contracting with Qualifying Facilities under the Public Utilities Regulatory Policies Act ("PURPA") and self-development. Reliance on multiple procurement approaches enables the

[1] 2008 IRP at pp 264-265. 2007 IRP at p. 229.

Company to achieve regulatory compliance and react effectively to market developments.

Q. Have other state commissions acknowledged the 2008 IRP and its action plan on renewable resource acquisition?

A. Yes. The state commissions of Washington and Idaho have acknowledged the 2008 IRP and an acknowledgment order is pending from Utah. The Wyoming Public Service Commission adopted Rule 253 in 2009, which requires the Company to file an IRP but does not include an acknowledgment proceeding. In California, the Company provides its IRP on an informational basis and is not required to seek acknowledgement.

Q. Did the Commission acknowledge the 2008 IRP?

A. Yes. In Order No. 10-066, the Commission acknowledged the 2008 IRP with one exception and other agreed-upon modifications. The one exception and other modifications were unrelated to the renewable resource acquisition targets.

MEHC Transaction Commitments

Q. Please provide an overview of the MEHC transaction commitments related to the acquisition of renewable resources.

A. As part of the regulatory approvals related to the acquisition of the Company, MEHC and the Company committed to:

- Bring at least 100 MW of cost-effective wind resources in service within one year of the close of the transaction;
- Have 400 MW of cost-effective new renewable resources in the Company's generation portfolio by December 31, 2007; and
- Reaffirm the Company's commitment to acquire 1,400 MW of cost-effective new renewable generation resources.

McFadden Ridge I was acquired consistent with these commitments and, in particular, in support of the commitment to have 1,400 MW of cost-effective new renewable generation resources in the portfolio.

McFadden Ridge I

Q. Please describe McFadden Ridge I.

A. McFadden Ridge I is a 28.5 MW wind project consisting of 19 General Electric wind turbine generators, an electrical collector system, access roads, and required communication and control facilities (e.g., metering, hardware, software, and associated communication circuits).

Q. Where is McFadden Ridge I located?

A. McFadden Ridge I is located approximately three miles east of McFadden, Wyoming, (the "Site"). McFadden Ridge I is located adjacent to the High Plains wind resource. Exhibit PPL/901 shows McFadden Ridge I relative to the location of the Company's other resources (owned and contracted) that convert wind into energy.

Q. Did the Company perform an evaluation of the wind potential at the Site?

A. Yes. The Company commissioned an external consultant to perform an evaluation of the wind potential at the Site. The Company's decision to acquire the McFadden Ridge I resource took into account the technical wind study.

Q. What other factors did the Company take into consideration when making the decision to acquire the McFadden Ridge I resource?

A. The Company took into account both quantitative and qualitative factors. The quantitative factors included the next highest alternative cost of compliance (the

"ACC") of the resource, the terminal value of the resource, how the resource compared to previously offered alternatives and how the resource compared to the 2007 IRP wind proxy. *See* Confidential Exhibit PPL/902.

Q. What qualitative factors did the Company take into account when making the decision to acquire McFadden Ridge I?

A. The Company took the following qualitative factors into account: the specifications of the resource relative to other wind-powered generation resources in the Company's portfolio; the benefits of utilizing turbines during 2009; the lack of other available sites for use of the turbines as confirmed by 2008R-1 RFP; applicable state and federal tax advantages; the availability of a construction contractor; available infrastructure; net power cost benefits being achieved earlier than planned and renewable energy credits ("RECs") being available earlier than planned.

Q. Does McFadden Ridge I compare favorably with the expected non-differentiated power market?

A. Yes. The McFadden Ridge I resource compares favorably with the expected non-differentiated power market. *See* Table 4 in Confidential Exhibit PPL/902.

Q. Did the Company perform an analysis of the terminal value for McFadden Ridge I?

A. Yes. Terminal value was assessed to be a benefit to customers. *See* Table 3 of Confidential Exhibit PPL/902.

Q. You indicated earlier that McFadden Ridge I was constructed adjacent to High Plains, a Company wind resource for which a previous acquisition decision was made. Were any benefits or efficiencies achieved by constructing McFadden Ridge I adjacent to High Plains?

A. Yes. Among other things, and as described in further detail in Confidential Exhibit PPL/902, the McFadden Ridge I resource benefited from the High Plains resource in that a collector substation and transmission line to the Foote Creek substation being constructed for High Plains will also be utilized for McFadden Ridge I. This benefits customers because McFadden Ridge I will result in those previously committed assets having a higher level of utilization.

Q. Will the Company receive production tax credits ("PTCs") and RECs from McFadden Ridge I?

A. Yes.

Q. What tax benefits are associated with the McFadden Ridge I resource?

A. The primary tax benefits include federal production tax credits, federal bonus depreciation and the utilization of a Wyoming sales tax exemption that is applicable to sites meeting certain criteria and set to entirely expire by the end of 2011.

Q. Have the net power costs benefits associated with McFadden Ridge I been included in the Company's 2011 net power costs?

A. Yes. The net power cost reduction benefits are included in the Company's 2011 Transition Adjustment Mechanism, which is being filed concurrently with this case.

Q. Please describe other benefits of McFadden Ridge I to Oregon customers.

A. Customers benefit from McFadden Ridge I because it represents an economic renewable resource. The 2007 and 2008 IRPs specify that renewable resources (using wind-powered generation resources as a proxy) should be steadily added to the system. McFadden Ridge I benefits customers as its acquisition is both cost effective and consistent with the Company's robust long-term planning efforts through the IRP process. Customers further benefit from this renewable resource because it provides a zero incremental cost fuel source, thus reducing exposure to potentially volatile commodity and/or fuel risks. In addition, McFadden Ridge I is a multi-shafted generation resource that diversifies the impact of individual generator failures and provides the Company with continued ownership and operational experience with utility-scale wind projects. McFadden Ridge I utilizes General Electric wind turbines, thus complementing the Company's operating experience with other General Electric based projects and spare parts optimization.

Q. What factors does the Company consider before acquiring new generation resources?

A. Upon reviewing a detailed overview of the project including the contract support and counterparty guarantees, the risks, the need as established by the IRP, the financial assessment, and the justification of the project, Company executives make a decision as to whether it is in the best interests of customers to proceed with the acquisition of a resource. The Company followed this process in determining that McFadden Ridge I is prudent and in the public interest to pursue.

Q. Was the decision to acquire the McFadden Ridge I resource consistent with the decision making process the Company has used in adding other renewable resources to the portfolio?

A. Yes.

Q. What investment related to McFadden Ridge I is included in the revenue requirement in this case?

A. The Company has included $56.6 million for McFadden Ridge I in this case. The operation and maintenance costs associated with McFadden Ridge I are approximately $0.85 million for operation, maintenance, permitting obligations, local levy tax and land use payments. The testimony of Company witness Mr. R. Bryce Dalley includes the revenue requirement calculations associated with the inclusion of this resource.

Q. When was McFadden Ridge I placed in service?

A. McFadden Ridge I was placed in service on September 29, 2009.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/901
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark R. Tallman

McFadden Ridge I Location

March 2010

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/902
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Mark R. Tallman

McFadden Ridge I Decision Recommendation

March 2010

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/1000
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

March 2010

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

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

Qualifications

Q. Briefly describe your education and business experience.

A. I received a degree in Mathematics from the University of Washington in 1976 and a Master of Business Administration degree from University of Portland in 1979. I was first employed by Pacific Power 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, load forecasting group, market assessment group, and the net power cost group in the Company.

Purpose and Summary of Testimony

Q. Please explain the purpose of your testimony in this proceeding.

A. I describe how PacifiCorp developed the forecasts of the number of customers and bills, kilowatt-hour ("kWh")sales at the meter ("sales"), and system loads and system peak loads at the system input level ("loads") for the 12-months ending

December 31, 2011. The Company produces forecasts for all six states in which the Company serves retail customers and are necessary for the development of jurisdictional allocation factors, forecasted revenues, and net power costs. In addition to the class level forecasts for bills and sales, the Company has developed a forecast of bills and kWh sales by rate schedule for Oregon.

Q. How were the forecasts utilized in preparation of this general rate case?

A. The forecasted loads for Oregon for the 12-months ending December 31, 2011 were used to calculate net power costs, and by Company witness Mr. R. Bryce Dalley to calculate the revenue requirement and jurisdictional allocation factors. Additionally, forecasted sales by rate schedule are used by Company witnesses Mr. William R. Griffith and Mr. C. Craig Paice to allocate costs between customer classes and to design rates which correctly reflect the cost of service. The sum of energy by rate schedule ties to the forecasted energy by customer class.

Q. Please provide a summary of the forecasted energy sales.

A. Table 1 provides the forecasted energy sales for the test period.

Table 1 - Test Period Sales Forecast (MWh)

January 2011 to December 2011		
	Total Company	Oregon
Residential	15,733,922	5,309,420
Commercial	16,398,542	4,886,460
Industrial	19,082,896	2,256,190
Irrigation	1,357,020	285,110
Public Authority	438,660	
Lighting	141,480	37,480
Total	53,152,520	12,774,660

Q. How is your testimony organized?

A. First, I describe the updates to the data used to produce the forecast. Second, I describe the forecasting process for the residential, commercial, irrigation, and lighting customer classes. Then I describe the forecasting process for the industrial customer class. Third, I describe the hourly load forecasting process. Fourth, I describe the rate schedule forecasting process. Finally, I give a summary of results where I compare the sales forecast to weather normalized 2009 sales and to the sales forecast that was used in the previous general rate case, Docket UE 210.

Summary of Changes in Forecast Assumptions

Q. Does this forecast employ the same methodology as presented to the Commission in Docket UE 210?

A. Yes.

Q. Please provide a general overview of the methodology.

A. In summary, this methodology consists of first developing a forecast of monthly sales by customer class and monthly peak load by state. This sales forecast becomes the basis of the load forecast by adding line losses, i.e., kWh sales levels are grossed-up to a generation or "input" level. The monthly loads are then spread out to each hour based on the peak load forecast and typical hourly load patterns to produce the hourly load forecast.

Q. Please summarize major updates in data used to produce the forecast.

A. There are five notable updates in data inputs compared to the forecast prepared in Docket UE 210:

1. The Company updated the historical data period used to develop the monthly retail sales forecasts to add the months February 2009 through July 2009.
2. The Company updated the historical data period used to develop the monthly peak forecasts to include January 1997 through December 2008.
3. The Company updated the economic drivers from IHS Global Insight using the most recent information available for each of the Company's jurisdictions.
4. The Company updated the forecast of individual industrial customer usage based on the best information available as of August 2009.
5. The time period used to define normal weather was updated to the 20-year time period of 1989-2008.

Q. Please describe how the impact of the current economic conditions is reflected in the Company's sales forecast for Oregon.

A. The Company developed the sales forecast model using historical sales data ending July 2009, and the most recent economic data available at that time. Because the data inputs reflect the economic slowdown, the Company did not adjust the model driven results.

Forecasts for Non-Industrial Customer Classes

Q. How are monthly sales forecasts developed by customer class?

A. The Company develops monthly sales forecasts as a product of two separate forecasts: (1) the number of customers; and (2) sales per customer. The Company uses this methodology for all customer classes except for the industrial customer class.

Q. How are the forecasts for number of customers developed?

A. The Company forecast all customer classes using regression models based on the January 1997 to July 2009 time period. The Company also used the most recently available economic drivers from IHS Global Insight, which were released in June 2009. For the residential class, the Company forecast the number of customers using IHS Global Insight's forecast of each state's number of households as the major driver. For the commercial class, the Company develops the forecast for number of customers with the forecasted residential customer numbers used as the major driver. For irrigation and street lighting classes, the forecast of number of customers is fairly static and developed using regression models without any economic drivers.

Q. How is average use per customer for customer classes forecasted?

A. The Company models sales per customer for the residential class through a Statistically Adjusted End-use ("SAE") model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price.

For the commercial class, the Company forecasts sales per customer using regression analysis techniques with employment used as the major economic driver in addition to weather-related variables.

For other classes, the Company forecasts sales per customer through regression analysis techniques using time trend variables.

Industrial Class Forecasts

Q. How does the Company forecast sales for the industrial customer class?

A. The industrial customers are separated into three categories: (1) existing customers that are tracked by the Customer Account Managers ("CAMs"); (2) new large customers or expansions by existing large customers; and (3) industrial customers that are not monitored by the CAMs. Customers are tracked by the CAMs if they have a peak load of one megawatt or more at a single site.

The Company develops the forecast for the first two categories through the data gathered by the CAM assigned to each customer. The CAMs have ongoing direct contact with large customers and are in the best position to know about the customer's plans for changes in business processes, which might impact their energy consumption.

The Company develops the portion of the industrial forecast related to new large customers and expansion by existing large customers based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Smaller industrial customers, i.e., under one megawatt, are more homogeneous and are modeled using regression analysis with trend and economic variables. Employment is used as the major economic driver.

The Company develops the total industrial sales forecast by aggregating the forecast for the three industrial customer categories.

Q. Why does the Company forecast industrial sales using a different methodology than the other customer classes?

A. The Company forecasts this class differently because of the diverse makeup of the customers within the class. In the industrial class, there is no "typical" customer. Large customers have very diverse usage patterns and power requirements. It is not unusual for the entire class to be strongly influenced by the behavior of one customer or a small group of customers.

In contrast, customer classes that are made up of mostly smaller, homogeneous customers are best forecasted as a use per customer multiplied by number of customers. Those customer classes are generally composed of many smaller customers that have similar behaviors and usage patterns. No small group of customers, or single customer, influences the movement of the entire class. This difference requires the different processes for forecasting.

Hourly Load Forecast

Q. Please outline how the hourly load forecast is developed.

A. After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps:

First, monthly and seasonal peak forecasts for each state are developed. The monthly peak model uses historic peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables which drive heating and cooling usage. These weather variables include the average temperature on the peak day and lagged average temperatures. The peak forecast is based on average monthly historical peak-producing weather for the period 1990-2008.

Second, the Company obtains hourly load forecasts for each state from hourly load models using state-specific hourly load data and daily weather variables. The Company develops hourly loads using a model that incorporates the 20-year average temperatures, a typical annual weather pattern, and day-type variables such as weekends and holidays. The hourly loads are calibrated to match the monthly and seasonal peaks from the first step above. Also, the hourly loads are calibrated so that the monthly sum of hourly loads equals monthly sales plus line losses.

Q. How are monthly system coincident peaks derived?

A. After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified as well as the contribution of each jurisdiction to those monthly peaks.

Forecasts by Rate Schedule

Q. Were any additional forecasts created for this proceeding?

A. Yes. As mentioned earlier, Mr. Griffith and Mr. Paice require two additional forecasts that are based on the kWh sales forecast and the number of customers forecast. Once the kWh sales forecast is complete, it must be applied to individual rate schedules to forecast kWh sales by rate schedule. In addition, the forecast of number of customers must be expressed in number of bills.

Q. How are rate schedule level forecasts produced?

A. This forecast has been streamlined in the model, and is carried out in two steps.

First, the Company projects each rate schedule's share of the customer class sales. Second, the Company multiplies the projected rate schedule share by the forecasted customer class sales to produce the sales forecast by rate schedule.

Q. How is the number of bills for each schedule forecasted?

A. Similar to the forecast of the rate schedule sales forecast, the rate schedule bill forecast is carried out in several steps. First, the Company calculates the ratio of bills to sales by rate schedule to bills by customer class. Second, this ratio is projected for the test period based on the regression results. Third, the ratio is multiplied by the customer class bills to produce the bills by rate schedule.

Summary of Results

Q. How does the sales forecast for the 12-months ending December 31, 2011, compare to the weather normalized MWh sales for the 12-months ending December 31, 2009?

A. Table 2 shows that sales for the total Company, test period forecasted sales are 0.8 percent higher than weather normalized sales in 2009.

Table 2 - Total Company Sales Comparison (MWh)

Total Company	2009 Actual	Jan 2011 to Dec 2011 GRC Forecast	Percentage Change
Residential	15,998,640	15,733,922	-1.65%
Commercial	16,194,257	16,398,542	1.26%
Industrial	18,712,080	19,082,896	1.98%
Irrigation	1,222,189	1,357,020	11.03%
Public Authority	437,596	438,660	0.24%
Lighting	144,764	141,480	-2.27%
Total	52,709,526	53,152,520	0.84%

Table 3 shows that for Oregon, forecasted test period sales are 4.8 percent lower than weather normalized sales in 2009.

Table 3 - Oregon Sales Comparison (MWh)

Oregon	2009 Actual	Jan 2011 to Dec 2011 GRC Forecast	Percentage Change
Residential	5,651,879	5,309,420	-6.06%
Commercial	5,009,122	4,886,460	-2.45%
Industrial	2,482,227	2,256,190	-9.11%
Irrigation	240,207	285,110	18.69%
Lighting	38,605	37,480	-2.91%
Total	13,422,041	12,774,660	-4.82%

Q. How does the sales forecast for the 12-months ending December 31, 2011 used in this case compare to the sales forecast used in Docket UE 210?

A. As shown in Table 4, the total Company sales have gone down by 1.2 percent. As shown in Table 5, the Oregon sales forecast has gone down by about 4.6 percent, which is primarily attributed to the slowdown and closures in the wood product industry.

Table 4 - Total Company Sales Forecast Comparison (MWh)

	Total Company		
	Previous GRC (CY2010)	Current GRC (CY 2011)	Percentage Change
Residential	15,866,414	15,733,922	-0.84%
Commercial	16,032,824	16,398,542	2.28%
Industrial	19,985,022	19,082,896	-4.51%
Irrigation	1,346,920	1,357,020	0.75%
Public Authority	436,110	438,660	0.58%
Lighting	139,740	141,480	1.25%
Total	53,807,030	53,152,520	-1.22%

Table 5 - Oregon Sales Forecast Comparison (MWh)

	Oregon		
	Previous GRC Forecast (CY2010)	Current GRC Forecast (CY 2011)	Percentage Change
Residential	5,438,620	5,309,420	-2.38%
Commercial	4,836,110	4,886,460	1.04%
Industrial	2,815,620	2,256,190	-19.87%
Irrigation	265,130	285,110	7.54%
Lighting	37,330	37,480	0.40%
Total	13,392,810	12,774,660	-4.62%

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/1100
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of R. Bryce Dalley

March 2010

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

A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah, Suite 2000, Portland, Oregon, 97232. I am currently employed as Manager of Revenue Requirement.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Business Management, with an emphasis in finance from Brigham Young University in 2003. In addition to my formal education, I have also attended various educational, professional and electric industry-related seminars. I have been employed by PacifiCorp since 2002 in various positions within the regulation and finance organizations. I assumed my current position in 2008. My primary responsibilities include the calculation and reporting of the Company's regulated earnings or revenue requirement, application of the inter-jurisdictional cost allocation methodologies, and the explanation of those calculations to regulators in the jurisdictions in which the Company operates.

Purpose and Overview of Testimony

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

A. My direct testimony addresses the calculation of the Company's Oregon-allocated revenue requirement, excluding net power costs ("NPC"), and the revenue increase requested in the Company's filing. Specifically, I provide testimony on the following:

- The calculation of the $130.9 million revenue increase requested in this general rate case representing the increase over current rates required for the Company to recover its Oregon non-NPC revenue requirement of $851.5 million. The Company currently recovers its NPC through the Transition Adjustment Mechanism ("TAM").
- The selection of the historical period of the 12-months ended June 2009 ("Base Period") as the basis for the test period in this proceeding.
- The development of the forecast test year in this case which is the 12-months ending December 31, 2011 ("Test Period").
- The treatment of forecasted capital additions included in the revenue requirement calculations, which have been limited to projects placed in service prior to January 1, 2011, the beginning of the Test Period.
- The presentation of the adjusted results of operations for the Test Period demonstrating that under current rates the Company will earn an overall return on equity ("ROE") in Oregon of 3.8 percent, which is far below the return on equity requested in this case and the current authorized return.
- The proposed accounting treatment to replace the captive insurance with self-insurance coverage for third-party liability, non-transmission and distribution ("T&D") property, and T&D property.
- The accounting treatment related to the estimation expenses for customer projects not completed. These estimation expenses are discussed in the direct testimony of Company witness Ms. Barbara A. Coughlin.

Revenue Requirement

Q. What is the revenue requirement to achieve the requested ROE in this case?

A. At current rate levels, the Company will earn an overall ROE in Oregon of 3.8 percent during the Test Period. This return is considerably less than the 10.6 percent ROE the Company is requesting in this proceeding, which produces a non-NPC revenue requirement of $851.5 million based on the Revised Protocol allocation methodology. The Company applied the Revised Protocol allocation method as approved by Commission Order No. 05-021 to calculate Oregon's results of operations. Exhibit PPL/1101 provides a summary of the Company's Oregon-allocated results of operations for the Test Period.

Q. Please explain how you have treated NPC in this filing.

A. As described above, the Company recovers its NPC through the TAM and is seeking to recover those costs as part of that mechanism. To model the non-NPC revenue requirement for this case, the Company first computed an overall Test Period revenue requirement including the NPC as filed in the TAM and then removed the NPC components from the overall price change. This approach is required to compute certain non-NPC components of the Test Period revenue requirement that are impacted by NPC-related items, such as renewable energy tax credits, the embedded cost differential ("ECD"), and certain Revised Protocol allocation factors. Details supporting the overall revenue requirement and the breakout between the TAM and general rate case are provided in Exhibit PPL/1101. Page 1.0 of Exhibit PPL/1102 also shows the breakout of revenue requirement into the TAM and general rate case components and the resulting general rate case-related price change requested in this proceeding.

Base Period

Q. Why did the Company use July 2008 through June 2009 as the historical basis, or Base Period, for the Test Period?

A. The Company selected the 12-month period ended June 2009 as the historical basis for this proceeding because it was the most recent total company data available for inter-jurisdictional allocations to achieve a filing date of March 1, 2010. The Company audits and extracts total company accounting information with the data components necessary for state allocations on a semi-annual basis for the 12-month periods ending June and December each year. This semi-annual data extract and review procedure is a key control measure to ensure the accuracy and reliability of the data which serves as the basis for each of the Company's results of operations and general rate case filings.

Q. Why was a March 1, 2010 filing date for this general rate case necessary?

A. The agreement of the Parties on General Guidelines related to the TAM approved by the Commission in Order No. 09-274 states:

> In all future filings after UE 207 in a year in which the Company files a general rate case, the TAM will be included in or processed concurrently with the general rate case filing. *In future filings after UE 207, the Company agrees that both filings will be made no later than March 1 to allow for a January 1 rate effective date*. (Emphasis added.)

Because of this agreement, a filing date later in the year is not possible.

Q. When will calendar year 2009 total-company data become available on an inter-jurisdictional allocation basis?

A. Only once total-company data is audited does it become available for analysis on an inter-jurisdictional allocation basis. Because of the unique complexities the Company faces as a multi-jurisdictional utility, additional time is necessary once total-company financial data is finalized to ensure accurate state-allocated data. Due to these complex steps, calendar year 2009 data will not be available for use as the basis of a forecast test period until the end of April 2010, approximately two months after the general rate case filing commitment date of March 1.

Test Period

Q. What test period did the Company use to determine revenue requirement in this case?

A. The forecast Test Period used by the Company in this proceeding is the 12-months ending December 31, 2011.

Q. Why did the Company choose the year ending December 31, 2011, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during which time the new rates will be in effect. Rates from this proceeding will be effective no later than January 1, 2011, which matches the Test Period used by the Company in the calculation of the revenue requirement. The Test Period in this general rate case also matches the test period used in the development of the NPC filed in the TAM proceeding.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case, the Company used the 12-months ended June 30, 2009. Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing rate making adjustment was warranted to reflect normal operating conditions. The historical information was adjusted to recognize known, measurable and anticipated events.

Q. What is the significance of the Company's method of beginning with historical information?

A. The Company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a solid foundation that is readily available for audit by all who wish to participate in the case. Individual adjustments are also available for review, and regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period revenues and costs.

A. Revenues are adjusted for the effect of applying the current Commission-approved tariff rates to the Test Period load projection. NPC are developed using the Generation & Regulation Initiative Decision ("GRID") model. The results of the GRID run for the Test Period are embedded in the results for calculation purposes only; as previously mentioned, recovery of these costs is sought through the TAM filing. Historical operations and maintenance ("O&M") expenses, excluding NPC, are split into labor and non-labor components. Non-labor costs are adjusted for inflation using nationally-recognized inflation indices provided by Global Insight and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs are also adjusted for contractual increases through the end of the Test Period. Specific adjustments are described in greater detail later in my testimony and exhibits, where I explain the development of the Oregon results of operations.

Q. Does the Company rely solely on its own projections of future cost increases?

A. No. For example, the adjustment made to account for inflation between the historical period and the Test Period relies on inflation indices published by Global Insight, which are developed specifically for electric utilities.

Q. How has the Company addressed areas where cost increases are different than inflation?

A. The Company's business units were asked to identify areas where budgets were significantly different than historical amounts, adjusted for wage increases and inflation. When differences were identified that needed to be adjusted in the rate case, the business units within the Company were asked to provide support for changes in the number or frequency of activities. An example of this type of adjustment is the Incremental Generation O&M adjustment (Adjustment 4.4), which includes the cost of operating and maintaining new plants. Adjustments of this nature are necessary because inflation indices account for cost increases on existing units of production, not changes in volume or processes.

Forecast Capital Additions to Electric Plant in Service

Q. How has the Company treated forecast capital additions to electric plant in service in this filing?

A. As mentioned in the direct testimony of Company witness Mr. Richard P. Reiten, the Company has included capital additions to plant in service through December 31, 2010, rather than through December 31, 2011, which is the end of the forecast Test Period and the rate effective period.

Q. Why has the Company limited forecast capital additions included in the revenue requirement to only those projects that will be placed in service prior to the beginning of the Test Period?

A. In the Company's last general rate case, Docket UE 210, Commission Staff proposed the removal of approximately $116.6 million of capital investments forecast to be placed in service during the 2010 test year in that proceeding. These investments were proposed to be removed from rate base primarily under the premise that capital projects placed into service during the test period do not satisfy the used and useful standard under Oregon Revised Statute 757.355. The Company disagrees with Staff's interpretation of this statue and believes it is inconsistent with Commission precedent. However, for the purposes of minimizing controversy in this case and to mitigate the rate impact to customers, only capital projects projected to be completed prior to January 1, 2011, the beginning of the Test Period in this filing, have been included in electric plant in service. The specific capital addition rate making adjustments included in this proceeding are discussed later in my testimony.

Oregon Results of Operations

Q. Please describe Exhibit PPL/1102.

A. Exhibit PPL/1102, which was prepared under my direction, is the Company's Oregon Results of Operations Report ("Report"). As previously explained, the Base Period for the Report is the 12-months ended June 30, 2009, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12-months ending December 31, 2011. The Report provides totals for revenue, expenses, depreciation, NPC, taxes, rate base and loads in the Test Period. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit PPL/1102 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of Oregon-allocated results according to the Revised Protocol allocation methodology. Page 1.0 breaks out the non-NPC results and calculates the required price increase the Company is requesting as part of this general rate case (column 5). Page 1.1 contains a summary of the general rate case request.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the Base Period and fully normalized results of operations for the Test Period by Federal Energy Regulatory Commission ("FERC") account and Revised Protocol allocation factor.

- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company. The contents of each of these tabs are described in more detail below.
- Tab 9 is a restatement of Tab 2 with the Oregon allocation based on the Modified Accord method, as required pursuant to Commission Order No. 05-021.
- Tab 10 is a restatement of Tab 2 with the Oregon allocation based on the Hybrid method, as required pursuant to Commission Order No. 05-021.
- Tab 11 contains the calculation of the Revised Protocol allocation factors.
- Tabs B1 through B20 contain the historical data for the Base Period and are organized by major FERC function.

Tab 3 – Revenue Adjustments

Q. Please describe the information contained behind Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index which contains a brief overview of the assumptions used to project test period revenues and a list of each normalization adjustment included in this section of the exhibit. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues and each adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit PPL/1102, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a description of the adjustment.

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Proforma Revenues (page 3.1) –** This adjustment normalizes general business revenues by adjusting to the proforma revenue level for the Test Period based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

SO2 Emission Allowances (page 3.2) – The Environmental Protection Agency ("EPA") has established guidelines that govern the volume of sulfur dioxide ("SO2") that can be emitted from power plants and granted the issuance of SO2 emission allowances to cover each ton emitted. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. This adjustment reflects the gain on sales of SO2 allowances based on a four-year amortization period ending December 2011. This is the same methodology included in the Company's last two general rate cases, Dockets UE 179 and UE 210.

Green Tag Revenues (page 3.3) – A market for green tags or renewable energy credits ("RECs") is developing where the tag or "green" traits of qualifying power production facilities can be detached and sold separately from the power itself. These RECs may be applied to meet renewable portfolio standards in various states. Currently, California and Oregon have renewable portfolio standards. As such, the Company does not sell California or Oregon eligible RECs. Instead, the Company uses the renewable output to comply with current year or future year renewable portfolio requirements. This adjustment allocates the projected green tag revenues for the Test Period to the Company's remaining jurisdictions. In the event the Company seeks to sell Oregon-allocated RECs, the Company will file a property sales application for Commission review and approval as directed by the Commission in Order No. 10-022.

Revenue Correcting Adjustment (page 3.4) – This adjustment corrects the allocation code assignment on several revenue transactions in unadjusted results of operations.

Wheeling Revenues (page 3.5) – This adjustment records the additional wheeling revenues the Company expects for the Test Period. In addition, during the Base Period, the Company experienced various wheeling revenue transactions that are not expected to occur in the Test Period. These transactions relate to various prior period adjustments and contract terminations and are removed in this adjustment.

Tab 4 – O&M Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes an O&M Expense Adjustment Index followed by a numerical summary and the specific adjustments. The O&M Expense Adjustment Index begins on page 4.0.1 with a brief overview of assumptions used to adjust operation, maintenance, administrative and general expenses. The numerical summary (pages 4.0.2 – 4.0.3) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit PPL/1102, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense (page 4.1) –** This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expenses.

Wage and Employee Benefits (page 4.2) – The Company has several labor groups, each with different effective contract renewal dates. The Company negotiates wage increases with each of these groups throughout the year. This adjustment recognizes these increases prospectively and adds them to O&M accounts. It also normalizes employee benefits and incentive compensation to levels the Company projects to incur for the Test Period. The direct testimony of Company witness Mr. Erich D. Wilson provides an overview of the Company's compensation and benefit plans.

Q. Please describe how the Company computed labor costs for the Test Period.

A. As mentioned above, the Company's adjustment to labor expense is found on page 4.2, the Wage and Employee Benefit Adjustment. Labor-related costs for the Test Period are computed by adjusting salaries, incentives, benefits and costs associated with Financial Accounting Standard ("FAS") 87 (pension), FAS 106 (post retirement benefits) and FAS 112 (post employment benefits) for changes expected beyond the actual costs experienced in the Base Period. Page 4.2.2 is a numerical summary starting with actual labor costs in June 2009 and summarizing the adjustments made to project costs forward to reflect the Test Period level of expense. This summary is followed by the detailed worksheets used to adjust the labor costs forward to the Test Period.

The first step to adjust labor is to annualize salary increases that occurred during the Base Period. This was done by identifying actual wages by labor group by month along with the date each labor group received wage increases. Those increases were then applied to wages that were paid prior to the effective date. The next step is to apply the wage increases from June 2009 through December 2011 to the annualized June 2009 salaries to project the Test Period wages. The Company used union contract agreements to escalate union labor group wages, while increases for non-union and exempt employees were based on Global Insight Consumer Price Forecast increases. This calculation is detailed on pages 4.2.3 through 4.2.4.

Q. Was an adjustment made to the annual incentive plan payout?

A. Yes. An adjustment is made to reduce total company incentive compensation from $34.2 million in the Base Period to $34.0 million in the Test Period as shown on page 4.2.2. The Company utilizes an incentive compensation program as part of its philosophy of delivering market competitive pay structured in a manner that benefits customers with safe, adequate and reliable electric service at a reasonable cost.

Q. Were employee pension and benefit costs adjusted in this section also?

A. Yes. Consistent with the aforementioned costs, pension expenses and other employee benefit costs were itemized starting with Base Period levels and walked forward to the Test Period.

Q. Were any other components of labor costs adjusted?

A. Yes. Payroll taxes were updated to capture the impact of the changes to employee salaries. This was calculated by applying the Federal Insurance Contributions Act ("FICA") tax rates to the net change in salaries and also to reflect the change in the social security cap for the Test Period.

Q. Please explain the treatment of workforce levels included in the Test Period.

A. The wage and employee benefit adjustment assumes a constant level of workforce based on the historical period. However, the incremental generation O&M adjustment (page 4.4) accounts for minor changes in workforce levels.

Q. Please continue with the description of O&M adjustments included in Tab 4.

A. **Irrigation Load Control (page 4.3) –** Incentive payments made to Idaho customers participating in the irrigation load control program were initially system allocated in unadjusted data. This adjustment corrects that allocation and assigns these costs on a situs basis consistent with other demand-side management ("DSM") programs.

Incremental Generation O&M (page 4.4) - This adjustment reflects Test Period O&M expense levels for the Glenrock, Seven Mile Hill, Seven Mile Hill II, Glenrock III, and Chehalis generation resources, which were placed into service during the Base Period. It also includes the O&M expense for the High Plains and McFadden Ridge I wind resources, which were placed in service in September 2009. In addition, this adjustment adds Test Period O&M expenses for the Dunlap I wind resource and the Dave Johnston Unit 3 pollution control project, which are projected to be placed in service during 2010.

Remove Non-Recurring Entries (page 4.5) – A variety of accounting entries were made to expense accounts during the Base Period that are non-recurring in nature or relate to a prior period. These transactions are removed in this adjustment from the results of operations to normalize the Test Period results. Details on the specific items in the adjustment can be found on page 4.5.1 of Exhibit PPL/1102.

Pension and Post-retirement Curtailment and Date Change (page 4.6) – This adjustment reflects (1) the deferral and amortization of the Pension Curtailment Gain resulting from employee participation in the 401(k) retirement plan option, and (2) the deferral and amortization of the increase in the pension and other post-retirement welfare expense caused by the change in the annual measurement date mandated by FAS 158. Commission Order No. 08-598 granted the Company permission to defer and amortize these amounts over a 10-year period beginning January 1, 2009. This adjustment removes the Base Period amortization and replaces it with the amortization for the Test Period.

Generation Overhaul Expense (page 4.7) – This adjustment normalizes generation overhaul expenses using a four-year average methodology. Overhaul expenses from June 2006 through June 2008 are escalated to a June 2009 level using escalation indices, and then those escalated expenses are averaged. For newer generating units, which include Currant Creek, Lake Side and Chehalis, the four-year average is comprised of the overhaul expense planned for the first four full years these plants are operational. The actual overhaul costs included in the

Base Period are subtracted from the four-year average which results in this adjustment.

O&M Escalation (page 4.8) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Increases are based on indices produced by Global Insight, which provides a detailed assessment of the electric market both historically and into the future. Global Insight indices are based on electric utility costs for materials and services only, which exclude labor expense, according to the Uniform System of Accounts defined by the FERC for major electric utilities and major natural gas pipeline companies. Labor-related expenses were segregated from other non-labor-related expenses to be escalated separately, as described earlier in my testimony.

Global Insight's indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The Global Insight indices utilized in the Company's filing are provided in Confidential Exhibit PPL/1103.

Chehalis Gas Swap (page 4.9) – During the Base Period, several natural gas swap entries were inadvertently booked to FERC account 557. Natural gas swaps are normally charged to FERC account 547 and are considered to be part of NPC. Since FERC account 557 is not a part of NPC in the Company's filing, this adjustment removes the amounts from the Base Period to be consistent with NPC treatment.

Remove New Tariff Riders (page 4.10) – In Order No. 10-022, the Commission authorized the Company to recover deferred costs related to the Transition Plan – Oregon, MidAmerican Energy Holdings Company ("MEHC") Transition Savings, and Grid West through separate tariff riders. In compliance with this order, this adjustment removes the amortization expense and balances included in the Base Period.

Memberships and Subscriptions (page 4.11) – This adjustment removes expenses in excess of Commission policy allowances as outlined by the Commission order in Docket UE 94. National and regional trade organizations are recognized at 75 percent. The Company's mandated membership in Western Energy Coordinating Council ("WECC") is included at 100 percent.

Oregon Intervenor Funding (page 4.12) – This adjustment removes from regulated results the amortization of the Oregon intervenor funding regulatory asset. Oregon intervenor funding is collected from Oregon customers through a separate tariff rider, Schedule 97.

Insurance Expense (page 4.13) – This adjustment changes the level of insurance expense in the Test Period to reflect the replacement of the captive insurance in calendar year 2011 after the expiration of MEHC commitment O10. This policy change is described in detail in the direct testimony of Company witness Ms. Nancy K. Kent.

Q. **Please describe the Company's proposal in this proceeding with respect to insurance coverage.**

A. As discussed by Ms. Kent, the Company is proposing to replace the captive insurance policy with self insurance coverage for third-party liability, non-T&D property, and T&D property. This self insurance method will cover O&M related damages. Capital related damages will be recovered as projects are added to rate base, consistent with other capital investments.

Q. When will the policy change from captive insurance coverage to self insurance be implemented?

A. The Company's current captive insurance policy with MEHC expires March 21, 2011. As such, the Test Period in this case assumes captive insurance coverage for three months of the Test Period. Self insurance reserve accruals are assumed for the remaining nine months of the Test Period as discussed in further detail below.

Q. Please describe the Test Period treatment of third-party liability insurance.

A. A shown on page 4.13.2, captive insurance premiums and coverage are assumed for the first three months of the Test Period. For the remaining nine months of the Test Period, self-insurance accruals are included by using a prorated three-year average of liability claim payments by MEHC captive insurance—from 2007 through 2009. Oregon's allocated portion of the Test Period amount is based on the System Overhead ("SO") factor, which is calculated based on Oregon's allocated share of total company gross plant. This self insurance method will replace the captive insurance coverage after the expiration of the Company's current policy with MEHC.

Q. Please describe the treatment of T&D and non-T&D property insurance in the Test Period.

A. As shown on page 4.13.3, T&D and non-T&D property captive insurance premiums and coverage are assumed for the first three months of the Test Period. For the remaining nine months of the Test Period, self insurance accruals are included using a prorated average of actual damage amounts from April 2005 through December 2009. Oregon's distribution related amount will be situs assigned to Oregon, consistent with the assignment of distribution plant. Oregon's allocated portion of the transmission related total is determined based on the System Generation ("SG") factor, consistent with the allocation of transmission plant. The amount associated with the non-T&D property accrual is also allocated using the SG factor, consistent with the allocation of the majority of generation plant. This self insurance method will replace the captive insurance coverage after the expiration of the Company's current policy with MEHC.

Q. Please describe the accounting entries that will be booked once self insurance coverage begins.

A. Page 4.13.4 shows the accounting entries made based on the Company's proposal in this filing. Each month, debits will be made to FERC accounts 924 – Property Insurance and 925 – Liability insurance, with the corresponding credits booked to insurance reserve FERC account 228. Separate internal accounting orders will be used for the reserve balances to track the amounts associated with the liability, state specific T&D property, and non-T&D property balances. When the Company experiences an insurance event defined using the Company's current practice, the applicable reserve balance will be debited and cash or accounts payable will be credited to pay for the damages incurred. If the Company experiences events in excess of the accumulated reserve balance, or anticipated reserve balance through the remaining portion of each calendar year, the Company may file for deferred accounting treatment with the Commission for the amounts not covered by the reserve balance.

Q. Please continue with the description of adjustments made to O&M expense in Tab 4.

A. **Affiliate Management Fee (page 4.14) –** In accordance with MEHC acquisition Commitment No. 9, the Company has been limiting the amount included in rates related to corporate allocations from MEHC to $7.3 million. This commitment expires December 31, 2010, which is prior to the beginning of the Test Period. For this filing, the Company has included only the amount of corporate allocations included in the Base Period, except for the amounts related to the Supplemental Executive Retirement Plan ("SERP") and the cost of the corporate aircraft in excess of commercial rates.

Tab 5 – Net Power Cost Adjustments

Q. Please describe the information contained behind Tab 5 Net Power Cost Adjustments.

A. Tab 5 includes adjustments to items that are generally related to NPC, but may or may not be addressed separately in the Company's TAM filings. Specifically, Adjustment 5.1 - Net Power Costs relates solely to NPC and recovery of these costs is being sought in the TAM proceeding rather than the general rate case.

This adjustment is included in my exhibit for modeling and computational purposes only. For example, the Test Period revenue requirement includes a tax credit for renewable energy generated from renewable facilities (Adjustment 7.3). This tax credit is calculated based on the generation output of these facilities as modeled in GRID (Adjustment 5.1) for the Test Period. Adjustments 5.2 through 5.5 include items that are not addressed in the Company's TAM filing. Each of these adjustments is described below.

The Net Power Cost Index on page 5.0.1 is a brief overview of assumptions used to adjust NPC-related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page in Exhibit PPL/1102, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1) –** This adjustment presents normalized Test Period steam and hydro power generation, fuel, purchased power, wheeling expense and sales for resale based on the Company's GRID model. As I previously described, this adjustment is included in the calculation of overall revenue requirement in my exhibit for computational purposes only; NPC is not part of the general rate case.

James River Royalty Offset and Little Mountain (page 5.2) – On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the 20-year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's NPC as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This adjustment adds the royalty offset to FERC account 456, other electric revenue, for the Test Period.

This adjustment also normalizes the ongoing level of steam revenues related to the Little Mountain plant. Contractually, the steam revenues from Little Mountain are tied to natural gas prices. The Company's NPC study includes the cost of running the Little Mountain plant but does not include the offsetting steam revenues. This adjustment aligns the steam revenues to the gas prices modeled in GRID.

Green Tags (page 5.3) – This adjustment removes from regulatory results the cost of RECs or green tag purchases made for the Blue Sky program. The Blue Sky program is designed to encourage voluntary participation in the acquisition and development of renewable resources. To prevent non-participants from subsidizing the program, all expenses associated with the program are removed from regulated results.

Electric Lake Settlement (page 5.4) – Canyon Fuel Company ("CFC") owns the Skyline mine located near Electric Lake, Utah. Electric Lake is owned by the Company and provides water for the Huntington Power Plant. The two companies disputed the claim made by the Company that CFC's mining operations punctured the lake and caused water to flow into the Skyline mine. The two companies negotiated a settlement and release agreement for the claims made by the Company. Consistent with UE 210, the amortization for this settlement ends December 31, 2010 and is non-recurring. As a result, all amounts related to the settlement amortization and rate base balances are removed from the Test Period.

BPA Residential Exchange (page 5.5) – The Company receives a monthly purchase power credit from Bonneville Power Administration ("BPA"). This credit is treated as a 100 percent pass-through to eligible customers. Both a revenue credit and a purchase power expense credit are posted to unadjusted results. This adjustment reverses the BPA purchase power expense credit recorded in unadjusted results. The revenue credit is removed from Test Period results in the Proforma Revenues adjustment, page 3.1.

Tab 6 – Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in

Exhibit PPL/1102, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1) –** This adjustment reflects the incremental depreciation expense associated with the capital additions included in the filing in the proforma major plant additions adjustment, page 8.6. The annualized level of 2010 depreciation and amortization expense for the Test Period is calculated by applying composite depreciation and amortization rates to the December 2010 projected plant balances. Rates used are those approved by the Commission in Docket UM 1329, effective January 1, 2008. Details are provided on pages 6.1 through 6.1.13.

This adjustment also includes the accelerated depreciation expense of the Company's existing Klamath River hydroelectric facilities and the amortization expense of the relicensing and settlement process costs, consistent with the Klamath Hydroelectric Settlement Agreement ("KHSA"). The associated depreciation and amortization reserve balances are reflected in adjustment 6.2. The KHSA is discussed in detail in the direct testimony of Company witness Mr. Dean S. Brockbank.

Depreciation and Amortization Reserve (page 6.2) – This adjustment steps forward the depreciation and amortization reserve from the Base Period to a December 2010 adjusted level. Accumulated depreciation and amortization balances are calculated by applying proforma depreciation and amortization expense and plant retirements to Base Period balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2009 to December 31, 2010. An incremental reserve amount has been added to the December 31, 2010 balances to reflect the annualized level of depreciation and amortization expense included on page 6.1. The reserve balance calculations are detailed on pages 6.2 to 6.2.12.

Tab 7 – Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index (page 7.0.1) contains a brief overview of the tax adjustments included in this proceeding. The numerical summary on page 7.0.2 identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit PPL/1102, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1) –** This adjustment details the adjustment to interest expense required to synchronize the Test Period interest expense with Test Period rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2) – Property tax expense for the Test Period is computed by adjusting accruals from the Base Period, for known or anticipated changes in the assessed values of the Company's operating property and the corresponding affect such changes will have on property tax expense for the Test Period. For additional information on the Company's property tax estimation procedures and methodologies, please refer to the direct testimony and exhibits filed by Company witness Mr. Norman K. Ross.

Renewable Energy Tax Credit (page 7.3) – The Company is entitled to recognize federal and state income tax credits as a result of placing renewable generating plants in service. The federal tax credit is based on the kilowatt hours ("kWh") generated by the plants, and the credit can be taken for the first ten years of generation from qualifying property. This adjustment reflects this credit based on the qualifying production as modeled in GRID for the Test Period NPC study.

This adjustment also reflects two state tax credits. The Utah State production tax credit is based on the kWh generated by the Blundell bottoming cycle, and the credit can be taken for four years from the in-service date. The Oregon Business Energy Tax Credit ("BETC") is based on investment in qualifying plant, and the credit is utilized over a three to five-year period on qualifying property.

AFUDC Equity (page 7.4) – This adjustment reflects the appropriate level of AFUDC-Equity into regulated results to align the tax Schedule M with regulatory income. Per the Commission Order No. 10-022, AFUDC-Equity in this case is included using flow-through tax treatment.

Proforma Schedule M (page 7.5) – The Base Period Schedule M items were updated for known and measurable adjustments through the Test Period. Non-utility items, separate tariff items and other non-recurring items were removed from the Base Period before updating. Normalizing adjustments such as SO2 emission allowances were then added. Depreciation differences on capital additions were generated in order to bring the Schedules M items in line with the Test Period. The Schedule M items were then used to develop deferred income tax expenses and balances for the Test Period.

Deferred Income Taxes (pages 7.6 & 7.7) – The non-property-related Schedule M items were used to develop the non-property-related deferred income tax expense. The property-related deferred income tax expense was generated using the capital additions and resulting book and tax depreciation. Normalizing adjustments were added consistent with the Schedule M items. The deferred income tax expense was then used to develop the deferred tax balance for the Test Period.

Q. How are current state and federal income tax expenses calculated?

A. Current state and federal income tax expenses are calculated by applying the applicable tax rates to the taxable income calculated in the Report. State income tax expense is calculated using the state statutory tax rates applied to the jurisdictional pre-tax income. The result of accumulating those state tax expense calculations is then allocated among the jurisdictions using the Income Before Tax ("IBT") factor. Federal income tax expense is calculated using the same methodology that the Company uses in preparing its filed income tax returns. The detail supporting this calculation is contained on pages 2.17 through 2.20.

Tab 8 – Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief overview of assumptions used to adjust rate base components. The numerical summary (pages 8.0.2 – 8.0.3) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit PPL/1102, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1) –** This adjustment is necessary to true-up the cash working capital for the normalizing adjustments made in this filing. Cash working capital is calculated by taking total O&M expense allocated to Oregon (excluding depreciation and amortization) and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. Net lag days are based on the Company's 2007 lead lag study.

Trapper Mine Rate Base (page 8.2) – The Company owns a 21.4 percent share of the Trapper Mine, which provides coal to the Craig generating plant. This investment is accounted for on the Company's books in account 123.1, investment in subsidiary company, which is not included as a rate base account. The normalized coal cost from Trapper Mine in NPC includes O&M costs but does not include a return on investment. This adjustment adds the Company’s portion of the forecasted Trapper Mine net plant investment as of December 31, 2010 to rate base in order for the Company to earn a return on its investment.

Jim Bridger Mine Rate Base (page 8.3) – The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company’s investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base in order for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in NPC include the O&M costs of the mine but provide no return on investment. This adjustment adds the Company’s portion of the forecasted December 31, 2010 net plant balance to rate base.

Environmental Settlement (PERCO) (page 8.4) – In 1996, the Company received an insurance settlement of $33 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company (“PERCO”). This fund balance is amortized or reduced as PERCO expends dollars on clean-up costs. PERCO received an additional $5 million of insurance proceeds plus associated liabilities from the Company in 1998. This adjustment includes the forecasted amount of unspent insurance proceeds through December 31, 2011 as a reduction to rate base.

Customer Advances for Construction (page 8.5) – Customer advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation factors of customer advances.

Proforma Plant Additions (page 8.6) – To reasonably represent the cost of system infrastructure required to serve customers, the Company has identified capital projects that will be used and useful by December 31, 2010.

Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. This adjustment is based on plant balances as of December 31, 2010. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described earlier in my testimony. Projects over $5 million (total company basis) are described on pages 8.6.14 through 8.6.27 of Exhibit PPL/1102.

This adjustment does not include the impacts of the Populus to Terminal transmission capital investment, which is reflected in a separate adjustment on page 8.13 of Exhibit PPL/1102.

Plant Retirements (page 8.7) – The Company's retirement rates were applied to proforma plant balances included in this filing. This adjustment reflects the retirements of gross electric plant in service into results.

Miscellaneous Rate Base (page 8.8) – This adjustment includes five parts as described below:

- An anticipated increase in fuel stock is added due to increases in the cost of coal and the number of tons stored at each site.
- Balances for prepaid overhauls for the Lake Side, Currant Creek, and Chehalis natural gas plants are walked forward to reflect payments and transfers to electric plant in service.
- Deferred debits and regulatory assets including the Trojan Plant Reserves and the Cholla Plant Transaction Costs are adjusted to calendar year 2010/2011 average balances.
- The accumulated provision for Electric Plant acquisition is adjusted forward to a calendar year 2010/2011 average balance.
- The Revised Protocol allocation factor related to the Chehalis natural gas plant future CO2 mitigation obligation liability is corrected.

Powerdale Hydro Removal (page 8.9) – This adjustment reflects the treatment approved by the Commission in Oregon Docket UM 1298, to account for the decommissioning of the Powerdale hydroelectric plant due to damage caused by a flood in November 2006. During 2007, the net book value (including an offset for insurance proceeds) of the assets to be retired was transferred to the unrecovered plant regulatory asset. In addition, future decommissioning costs are deferred in a regulatory asset, offset by a credit reflecting the amount not actually spent through the Test Period. This treatment is consistent with the methodology used in UE 210.

Goose Creek Transmission (page 8.10) – On April 1, 2008, the Company sold approximately 14 miles of transmission line, running from the Company's Goose Creek switching station and extending north to the Decker 230 kV substation near Decker, Montana. The assets sold included structures, miscellaneous support equipment, easements and rights-of-way associated with the transmission line. The sale of the transmission line resulted in the Goose Creek switching station no longer being useful to the Company. The Company plans to remove the Goose Creek switching station including all above-ground facilities. This adjustment removes the gross plant and accumulated depreciation related to these facilities from the Test Period. Oregon's allocated portion of the gain from the asset sale is included in the property sales balancing account and is being returned to customers through Schedule 96. This treatment was authorized by the Commission in Order No. 07-489.

Plant Held For Future Use ("PHFU") (page 8.11) – This adjustment removes all PHFU assets from FERC account 105. The Company is making this adjustment in compliance with Commission Order No. 01-787.

Remove Rolling Hills (page 8.12) – This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the Base Period. This treatment is consistent with Commission Order No. 08-548.

Populus to Terminal (page 8.13) – This adjustment adds to rate base the Populus to Terminal transmission capital project as discussed in detail in the direct testimony of Company witnesses Mr. John A. Cupparo and Mr. Darrell T. Gerrard. Page 8.13 shows the capital investment, depreciation expense, accumulated depreciation, and tax impacts associated with the Parish to Terminal segment of the line, which was placed into service in December 2009. Page 8.13 also reflects the capital investment, depreciation expense, accumulated depreciation, and tax impacts associated with the Ben Lomond to Terminal segment of the transmission line, which is projected to be placed in service in June 2010. The combined total Oregon-allocated annual revenue requirement associated with these two segments of the transmission line is shown on page 8.13.4.

Page 8.13.1 reflects the capital investment, depreciation expense, accumulated depreciation, and tax impacts associated with the Populus to Ben Lomond segment of the transmission line, which is projected to be placed in service in December 2010. The total Oregon-allocated annual revenue requirement associated with this segment of the transmission line is shown on page 8.13.5. As discussed in the direct testimony of Company witness Mr. William R. Griffith, the Company proposes to collect the annual revenue requirement associated with this segment of the transmission line through Schedule 80, Populus to Ben Lomond Cost Recovery Charge.

Tab 9 – Modified Accord and Tab 10 - Hybrid

Q. Please describe the information contained behind Tab 9 and Tab 10.

A. Tab 9 and Tab 10 are restatements of Tab 2 using the Modified Accord and Hybrid allocation methods, respectively. The Company is providing these restated results pursuant to Commission Order No. 05-021. As described on page

10.1, the Hybrid is not a fully-developed allocation methodology, and it has never been used for rate making in any of the Company's jurisdictions.

Tab 11 – Allocation Factors

Q. Please describe the information contained behind Tab 11 Allocation Factors.

A. Tab 11 Allocation Factors summarizes the derivation of the jurisdictional allocation factors using the Revised Protocol allocation methodology.

Q. Please explain how the jurisdictional allocation factors applied in this proceeding comply with the Commission order approving the Revised Protocol.

A. Each of the jurisdictional allocation factors included in this proceeding is calculated in the same manner prescribed in the Revised Protocol approved by the Commission in Order No. 05-021, pursuant to a joint-party Stipulation. Specifically, Exhibit PPL/1102, "Tab 2 - Results of Operations" applies allocation factors to the revenue requirement components as outlined in Appendix B of the Revised Protocol. In addition, the calculations of the allocation factors included in this proceeding are consistent with the algebraic definitions approved by the Commission shown in Appendix C of the Revised Protocol.

Q. What exhibits are included in this filing that demonstrate compliance with Order No. 05-021?

A. Two files are provided as part of this filing to demonstrate the Company's compliance with Order No. 05-021. First, "Tab 11 – Allocation Factors" in Exhibit PPL/1102 shows the calculation and derivation of each Revised Protocol factor included in the filing. An electronic version of this section of my exhibit is provided with the Company's workpapers. In addition, the Company's revenue requirement model, the Jurisdictional Allocation Model ("JAM"), is provided as part of the Company's workpapers. The "Factors" tab within the Excel-based model shows the linked formulas and inputs used in the development of each of the allocation percentages. As noted above, the calculations in this section of the model were developed based on the algebraic definitions set forth in Appendix C of the Revised Protocol.

Q. Have there been any changes to the allocation factor calculations since the Commission issued Order No. 05-021?

A. No. In Order No. 05-021 at page 1 the Commission stated:

> In this order, we ratify the *Revised PacifiCorp Inter-Jurisdictional Cost Allocation Protocol* (Revised Protocol) for use in future rate cases to determine how costs and wholesale revenues associated with PacifiCorp's generation, transmission, and distribution systems will be allocated among its six-state service territory.

Since this Order, the Company has used the approved factor calculations in each of its Oregon rate-making and results of operations filings.

Q. Have there been any changes to the key assumptions underlying the Revised Protocol?

A. No. There have been no changes to key assumptions to the Revised Protocol since the Commission approved the allocation methodology in Order No. 05-021. Key assumption changes would be addressed by the Multi-State Process ("MSP") standing committee, and potentially lead to proposed amendments to the Revised Protocol. As stated on page 4 in Order No. 05-021,

> An MSP Standing Committee will be formed, consisting of one member/delegate from each Commission. The MSP Standing Committee will appoint a Standing Neutral to assist the Committee, facilitate

> discussions among the states, and monitor issues. The Standing Neutral will convene at least one meeting of the MSP Standing Committee each calendar year to discuss inter-jurisdictional issues facing PacifiCorp and its customers. While the MSP Committee may consider possible amendments to the Revised Protocol, any amendments would only go into effect after each Commission that previously ratified the Revised Protocol also ratified the amendments.

Any amendments to the methodology would need to be implemented consistent with Section XIII of the Revised Protocol.

Q. Are the forecast loads used to derive the jurisdictional allocation factors the same as the forecast loads used to develop Test Period revenues and NPC?

A. Yes. The forecast loads used in the calculation of allocation factors are consistent with the loads used in the development of Test Period revenues and NPC. By using the same load forecast for each of these revenue requirement components, an appropriate matching is achieved. The load forecast applied in this case is described in detail in the direct testimony of Company witness Mr. Gregory N. Duvall.

Q. Although a consistent load forecast is used for jurisdictional allocation factors, Test Period revenues, and NPC, are there any differences in the application of these loads?

A. Yes. NPC and jurisdictional allocation factors are developed using forecasted loads at the system input level instead of the metered or sales level used in the development of Test Period revenues. The differences between the system input level and sales level are line losses. In addition, jurisdictional allocation factors are adjusted for load curtailments consistent with the Commission-approved Revised Protocol methodology.

Tabs B1 – B20

Q. Please describe the information contained behind Tabs B1 – B-20.

A. Tabs B1 through B20 contain the historical results for the Base Period and are organized by major FERC function. The data contained in this section of the exhibit match the unadjusted data found under Tab 2 – Results of Operations.

Estimation Expenses for Customer Projects Not Completed

Q. Please describe the Company's accounting treatment for estimation charges.

A. As explained in the direct testimony of Ms. Coughlin, the Company performs an average of more than 6,300 estimates for new electric service or a redesign of existing service for homes or businesses in Oregon. The costs associated with these estimates are primarily attributable to labor expenses by Company employees assigned to analyze each customer request. For each project requested, an order within the Company accounting system is created to track and itemize the costs associated with the project. Costs for this type of capital work are initially recorded in FERC account 107, Construction Work in Progress ("CWIP"), in compliance with the FERC Code of Federal Regulations ("C.F.R.") which states:

> This account shall include the total of the balances of work orders for electric plant in process of construction.[1]

The costs associated with these projects, including the estimation expenses, remain in CWIP until the project is completed, at which time the project costs are

[1] *See* 18 C.F.R. Pt. 101.

transferred from CWIP to the appropriate electric plant in service rate base accounts.

Q. What happens to the cost recorded in CWIP for projects that fail to materialize?

A. As explained by Ms. Coughlin, projects fail to materialize for a variety of reasons. In these cases, all estimator time and expenses are credited from CWIP and debited to O&M expense as part of the Company's routine and ongoing operations.

Q. Is it possible to record the estimation expenses related to these projects in O&M accounts and then transfer the costs to rate base upon project completion?

A. No. Charging estimation expenses to O&M for new capital requests would not be in compliance with FERC accounting guidelines or the Company's historical accounting practice. Per the FERC C.F.R., Electric Plant Instruction No. 3, a component of construction costs includes the amounts related to preparing estimates in connection with construction activities. In addition, recording these costs initially to O&M and then transferring the costs to rate base at a later point would be extremely inefficient given the majority of these projects ultimately end up in rate base.

Q. Should estimation expenses for customer projects not completed be included in regulated results?

A. Yes. As discussed previously, these routine costs are incurred as part of providing ongoing electric service to customers.

MEHC Transaction Commitment O11

Q. Has the Company complied with MEHC transaction commitment O11 in this filing?

A. Yes. This filing is in compliance with MEHC transaction commitment O11 which states:

> a) MEHC and PacifiCorp will hold customers harmless for increases in costs resulting from PacifiCorp corporate costs previously billed to PPM and other former affiliates of PacifiCorp. Oregon Commission Staff has valued the potential increase in total company revenue requirement if these costs are not eliminated as $7.9 million annually (total company) through December 31, 2010 and $6.4 million annually (total company) from January 1, 2011 through December 31, 2015, which shall be the amounts of the total company rate credit. This commitment shall expire on the earlier of December 31, 2015 or when PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case, that corporate costs previously billed to PPM and other former affiliates have not been included in PacifiCorp's rates. This Commitment is in lieu of Commitment 38, and a state must choose between this Commitment O 11 and Commitment 38.
>
> b) This commitment is offsetable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case, that corporate costs previously billed to PPM and other former affiliates have not been included in PacifiCorp's rates.

The Company has reduced costs and transferred 31 employees to PPM who were previously charging part of their time to PPM. This resulted in annual salary and benefit savings in excess of $6.2 million on a total-company basis. The remainder of the $7.9 million reduction was achieved through elimination of other corporate costs.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/1101
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Revenue Requirement Summary

March 2010

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec. 31, 2011

	(1)	(2)	(3)	(4)	(5)	(6)
		(3) - (1)	Ref. Page 4	Ref. Page 3	Ref. Page 2	(3) + (4) + (5)
				TAM	**GRC**	
					Requested	Total Normalized
	NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Non-NPC Related Price Change	Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	243,608,321	720,604,230	964,212,551	69,170,576	130,924,178	1,164,307,305
3 Interdepartmental		-	-			-
4 Special Sales	168,752,793	987,857	169,740,650			169,740,650
5 Other Operating Revenues		41,490,058	41,490,058			41,490,058
6 Total Operating Revenues	412,361,114	763,082,145	1,175,443,259	69,170,576	130,924,178	1,375,538,013
7						
8 Operating Expenses:						
9 Steam Production	171,384,684	78,888,001	250,272,685			250,272,685
10 Nuclear Production		-	-			-
11 Hydro Production		10,155,935	10,155,935			10,155,935
12 Other Power Supply	273,402,417	30,330,960	303,733,377			303,733,377
13 Embedded Cost Differential (ECD)		(15,579,133)	(15,579,133)			(15,579,133)
14 Transmission	36,744,589	14,915,348	51,659,937			51,659,937
15 Distribution		76,534,494	76,534,494			76,534,494
16 Customer Accounting		36,066,052	36,066,052		1,236,895	37,302,947
17 Customer Service & Info		3,660,775	3,660,775			3,660,775
18 Sales		-	-			-
19 Administrative & General		49,627,697	49,627,697			49,627,697
20						
21 Total O&M Expenses	481,531,690	284,600,129	766,131,819	-	1,236,895	767,368,715
22						
23 Depreciation		160,373,963	160,373,963			160,373,963
24 Amortization		14,389,137	14,389,137			14,389,137
25 Taxes Other Than Income		54,122,839	54,122,839		4,546,153	58,668,992
26 Income Taxes - Federal	(23,110,581)	10,028,469	(13,082,112)	23,110,581	41,810,903	51,839,372
27 Income Taxes - State	(3,140,344)	4,155,076	1,014,732	3,140,344	5,681,407	9,836,484
28 Income Taxes - Def Net		36,337,195	36,337,195			36,337,195
29 Investment Tax Credit Adj.		-	-			-
30 Misc Revenue & Expense		(1,167,283)	(1,167,283)			(1,167,283)
31						
32 Total Operating Expenses:	455,280,765	562,839,526	1,018,120,291	26,250,925	53,275,358	1,097,646,574
33						
34 Operating Rev For Return:	(42,919,651)	200,242,619	157,322,969	42,919,651	77,648,819	277,891,439
35						
36 Rate Base:						
37 Electric Plant In Service		6,041,538,075	6,041,538,075			6,041,538,075
38 Plant Held for Future Use		-	-			-
39 Misc Deferred Debits		17,414,913	17,414,913			17,414,913
40 Elec Plant Acq Adj		13,781,681	13,781,681			13,781,681
41 Nuclear Fuel		-	-			-
42 Prepayments		12,457,960	12,457,960			12,457,960
43 Fuel Stock		49,465,020	49,465,020			49,465,020
44 Material & Supplies		51,428,949	51,428,949			51,428,949
45 Working Capital		18,193,172	18,193,172			18,193,172
46 Weatherization Loans		(680)	(680)			(680)
47 Misc Rate Base		18,865	18,865			18,865
48						
49 Total Electric Plant:	-	6,204,297,955	6,204,297,955			6,204,297,955
50						
51 Rate Base Deductions:						
52 Accum Prov For Deprec		(2,066,156,392)	(2,066,156,392)			(2,066,156,392)
53 Accum Prov For Amort		(132,957,529)	(132,957,529)			(132,957,529)
54 Accum Def Income Tax		(666,349,065)	(666,349,065)			(666,349,065)
55 Unamortized ITC		(3,084,689)	(3,084,689)			(3,084,689)
56 Customer Adv For Const		(2,857,384)	(2,857,384)			(2,857,384)
57 Customer Service Deposits		-	-			-
58 Misc Rate Base Deductions		(16,936,092)	(16,936,092)			(16,936,092)
59						
60 Total Rate Base Deductions	-	(2,888,341,151)	(2,888,341,151)			(2,888,341,151)
61						
62 Total Rate Base:	-	3,315,956,804	3,315,956,804			3,315,956,804
63						
64 Return on Rate Base			4.744%			8.380%
65						
66 Return on Equity			3.778%			10.600%

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec. 31, 2011

GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) **GRC** Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	720,604,230	130,924,178	851,528,408
3	Interdepartmental	-		-
4	Special Sales	987,857		987,857
5	Other Operating Revenues	41,490,058		41,490,058
6	Total Operating Revenues	763,082,145	130,924,178	894,006,323
7				
8	Operating Expenses:			
9	Steam Production	78,888,001		78,888,001
10	Nuclear Production	-		-
11	Hydro Production	10,155,935		10,155,935
12	Other Power Supply	30,330,960		30,330,960
13	Embedded Cost Differential (ECD)	(15,579,133)		(15,579,133)
14	Transmission	14,915,348		14,915,348
15	Distribution	76,534,494		76,534,494
16	Customer Accounting	36,066,052	1,236,895	37,302,947
17	Customer Service & Info	3,660,775		3,660,775
18	Sales	-		-
19	Administrative & General	49,627,697		49,627,697
20				
21	Total O&M Expenses	284,600,129	1,236,895	285,837,024
22				
23	Depreciation	160,373,963		160,373,963
24	Amortization	14,389,137		14,389,137
25	Taxes Other Than Income	54,122,839	4,546,153	58,668,992
26	Income Taxes - Federal	10,028,469	41,810,903	51,839,372
27	Income Taxes - State	4,155,076	5,681,407	9,836,484
28	Income Taxes - Def Net	36,337,195		36,337,195
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(1,167,283)		(1,167,283)
31				
32	Total Operating Expenses:	562,839,526	53,275,358	616,114,884
33				
34	Operating Rev For Return:	200,242,619	77,648,819	277,891,439
35				
36	Rate Base:			
37	Electric Plant In Service	6,041,538,075		6,041,538,075
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	17,414,913		17,414,913
40	Elec Plant Acq Adj	13,781,681		13,781,681
41	Nuclear Fuel	-		-
42	Prepayments	12,457,960		12,457,960
43	Fuel Stock	49,465,020		49,465,020
44	Material & Supplies	51,428,949		51,428,949
45	Working Capital	18,193,172		18,193,172
46	Weatherization Loans	(680)		(680)
47	Misc Rate Base	18,865		18,865
48				
49	Total Electric Plant:	6,204,297,955	-	6,204,297,955
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,066,156,392)		(2,066,156,392)
53	Accum Prov For Amort	(132,957,529)		(132,957,529)
54	Accum Def Income Tax	(666,349,065)		(666,349,065)
55	Unamortized ITC	(3,084,689)		(3,084,689)
56	Customer Adv For Const	(2,857,384)		(2,857,384)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(16,936,092)		(16,936,092)
59				
60	Total Rate Base Deductions	(2,888,341,151)	-	(2,888,341,151)
61				
62	Total Rate Base:	3,315,956,804	-	3,315,956,804
63				
64	Return on Rate Base	6.039%		8.380%
65				
66	Return on Equity	6.207%		10.600%
67				
68	TAX CALCULATION:			
69	Operating Revenue	250,763,360	125,141,129	375,904,490
70	Other Deductions			
71	Interest (AFUDC)	(23,143,441)	-	(23,143,441)
72	Interest	90,008,331	-	90,008,331
73	Schedule "M" Additions	233,263,829	-	233,263,829
74	Schedule "M" Deductions	337,135,945	-	337,135,945
75	Income Before Tax	80,026,355	125,141,129	205,167,484
76				
77	State Income Taxes	4,155,076	5,681,407	9,836,484
78	Taxable Income	75,871,278	119,459,722	195,331,000
79				
80	Federal Income Taxes + Other	10,028,469	41,810,903	51,839,372

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec. 31, 2011

TAM RESULTS

		(1) Total Adjusted Results	(2) **TAM** Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	243,608,321	69,170,576	312,778,897
3	Interdepartmental	-		-
4	Special Sales	168,752,793		168,752,793
5	Other Operating Revenues	-		-
6	Total Operating Revenues	412,361,114	69,170,576	481,531,690
7				
8	Operating Expenses:			
9	Steam Production	171,384,684		171,384,684
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	273,402,417		273,402,417
13	Embedded Cost Differential (ECD)	-		-
14	Transmission	36,744,589		36,744,589
15	Distribution	-		-
16	Customer Accounting	-	-	-
17	Customer Service & Info	-		-
18	Sales	-		-
19	Administrative & General	-		-
20				
21	Total O&M Expenses	481,531,690	-	481,531,690
22				
23	Depreciation	-		-
24	Amortization	-		-
25	Taxes Other Than Income	-	-	-
26	Income Taxes - Federal	(23,110,581)	23,110,581	-
27	Income Taxes - State	(3,140,344)	3,140,344	-
28	Income Taxes - Def Net	-		-
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	-		-
31				
32	Total Operating Expenses:	455,280,765	26,250,925	481,531,690
33				
34	Operating Rev For Return:	(42,919,651)	42,919,651	-
35				
36	Rate Base:			
37	Electric Plant In Service	-		-
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	-		-
40	Elec Plant Acq Adj	-		-
41	Nuclear Fuel	-		-
42	Prepayments	-		-
43	Fuel Stock	-		-
44	Material & Supplies	-		-
45	Working Capital	-		-
46	Weatherization Loans	-		-
47	Misc Rate Base	-		-
48				
49	Total Electric Plant:	-	-	-
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	-		-
53	Accum Prov For Amort	-		-
54	Accum Def Income Tax	-		-
55	Unamortized ITC	-		-
56	Customer Adv For Const	-		-
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	-		-
59				
60	Total Rate Base Deductions	-	-	-
61				
62	Total Rate Base:	-	-	-
63				
64	Return on Rate Base	N/A		N/A
65				
66	Return on Equity	N/A		N/A
67				
68	TAX CALCULATION:			
69	Operating Revenue	(69,170,576)	69,170,576	0
70	Other Deductions	-		
71	Interest (AFUDC)	-	-	-
72	Interest	-	-	-
73	Schedule "M" Additions	-	-	-
74	Schedule "M" Deductions	-	-	-
75	Income Before Tax	(69,170,576)	69,170,576	0
76				
77	State Income Taxes	(3,140,344)	3,140,344	-
78	Taxable Income	(66,030,232)	66,030,232	0
79				
80	Federal Income Taxes + Other	(23,110,581)	23,110,581	-

PacifiCorp
OREGON
Normalized Results of Operations - REVISED PROTOCOL
Twelve Months Ending Dec. 31, 2011

COMBINED TAM AND GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	964,212,551	200,094,754	1,164,307,305
3	Interdepartmental	-		-
4	Special Sales	169,740,650		169,740,650
5	Other Operating Revenues	41,490,058		41,490,058
6	Total Operating Revenues	1,175,443,259	200,094,754	1,375,538,013
7				
8	Operating Expenses:			
9	Steam Production	250,272,685		250,272,685
10	Nuclear Production	-		-
11	Hydro Production	10,155,935		10,155,935
12	Other Power Supply	303,733,377		303,733,377
13	Embedded Cost Differential (ECD)	(15,579,133)		(15,579,133)
14	Transmission	51,659,937		51,659,937
15	Distribution	76,534,494		76,534,494
16	Customer Accounting	36,066,052	1,236,895	37,302,947
17	Customer Service & Info	3,660,775		3,660,775
18	Sales	-		-
19	Administrative & General	49,627,697		49,627,697
20				
21	Total O&M Expenses	766,131,819	1,236,895	767,368,715
22				
23	Depreciation	160,373,963		160,373,963
24	Amortization	14,389,137		14,389,137
25	Taxes Other Than Income	54,122,839	4,546,153	58,668,992
26	Income Taxes - Federal	(13,082,112)	64,921,484	51,839,372
27	Income Taxes - State	1,014,732	8,821,751	9,836,484
28	Income Taxes - Def Net	36,337,195		36,337,195
29	Investment Tax Credit Adj.	-		-
30	Misc Revenue & Expense	(1,167,283)		(1,167,283)
31				
32	Total Operating Expenses	1,018,120,291	79,526,284	1,097,646,574
33				
34	Operating Rev For Return	157,322,969	120,568,470	277,891,439
35				
36	Rate Base:			
37	Electric Plant In Service	6,041,538,075		6,041,538,075
38	Plant Held for Future Use	-		-
39	Misc Deferred Debits	17,414,913		17,414,913
40	Elec Plant Acq Adj	13,781,681		13,781,681
41	Nuclear Fuel	-		-
42	Prepayments	12,457,960		12,457,960
43	Fuel Stock	49,465,020		49,465,020
44	Material & Supplies	51,428,949		51,428,949
45	Working Capital	18,193,172		18,193,172
46	Weatherization Loans	(680)		(680)
47	Misc Rate Base	18,865		18,865
48				
49	Total Electric Plant:	6,204,297,955	-	6,204,297,955
50				
51	Rate Base Deductions:			
52	Accum Prov For Deprec	(2,066,156,392)		(2,066,156,392)
53	Accum Prov For Amort	(132,957,529)		(132,957,529)
54	Accum Def Income Tax	(666,349,065)		(666,349,065)
55	Unamortized ITC	(3,084,689)		(3,084,689)
56	Customer Adv For Const	(2,857,384)		(2,857,384)
57	Customer Service Deposits	-		-
58	Misc Rate Base Deductions	(16,936,092)		(16,936,092)
59				
60	Total Rate Base Deductions	(2,888,341,151)	-	(2,888,341,151)
61				
62	Total Rate Base:	3,315,956,804	-	3,315,956,804
63				
64	Return on Rate Base	4.744%		8.380%
65				
66	Return on Equity	3.778%		10.600%
67				
68	TAX CALCULATION:			
69	Operating Revenue	181,592,784	194,311,705	375,904,490
70	Other Deductions			
71	Interest (AFUDC)	(23,143,441)	-	(23,143,441)
72	Interest	90,008,331	-	90,008,331
73	Schedule "M" Additions	233,263,829	-	233,263,829
74	Schedule "M" Deductions	337,135,945	-	337,135,945
75	Income Before Tax	10,855,778	194,311,705	205,167,484
76				
77	State Income Taxes	1,014,732	8,821,751	9,836,484
78	Taxable Income	9,841,046	185,489,954	195,331,000
79				
80	Federal Income Taxes + Other	(13,082,112)	64,921,484	51,839,372

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2011

	Exhibit PPL/1102		Exhibit PPL/1102			
			Tab 3	Tab 4	Tab 5	Tab 6
	Total Company Actual Results June 2009	Oregon Allocated Actual Results June 2009	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	3,414,438,873	945,940,622	18,271,929	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	787,627,105	204,985,899	-	-	(35,245,249)	-
5 Other Operating Revenues	186,361,600	40,897,951	(1,294,047)	-	1,886,154	-
6 Total Operating Revenues	4,388,427,578	1,191,824,472	16,977,882	-	(33,359,095)	-
7						
8 Operating Expenses:						
9 Steam Production	895,367,084	223,015,516	-	3,871,921	23,385,248	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	36,618,467	9,585,648	-	570,287	-	-
12 Other Power Supply	1,181,515,220	287,959,103	-	2,257,893	13,606,204	-
13 Embedded Cost Differential (ECD)	-	(20,617,076)	20,746	(188,858)	(566,066)	1,769,296
13 Transmission	175,361,719	45,872,088	(52,521)	717,988	5,118,062	-
14 Distribution	212,663,419	72,712,990	-	3,821,504	-	-
15 Customer Accounting	99,857,675	33,885,418	-	2,180,633	-	-
16 Customer Service & Info	60,718,121	3,568,680	-	92,095	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	165,794,788	50,484,646	-	(856,949)	-	-
19						
20 Total O&M Expenses	2,827,896,492	706,467,012	(31,774)	12,466,515	41,543,449	1,769,296
21						
22 Depreciation	437,744,316	124,957,382	-	-	-	30,994,017
23 Amortization	49,266,618	13,186,015	-	-	-	1,562,265
24 Taxes Other Than Income	115,218,393	46,754,804	-	-	-	-
25 Income Taxes - Federal	(16,917,058)	13,171,107	4,531,467	(4,029,283)	(24,927,115)	(9,769,450)
26 Income Taxes - State	1,555,974	518,455	4,012,870	(842,822)	(3,681,442)	(1,568,212)
27 Income Taxes - Def Net	265,362,097	86,236,499	-	-	-	-
28 Investment Tax Credit Adj.	(1,841,780)	-	-	-	-	-
29 Misc Revenue & Expense	(7,332,547)	(1,265,520)	98,237	-	-	-
30						
31 Total Operating Expenses:	3,670,952,505	990,025,754	8,610,799	7,594,410	12,934,893	22,987,915
32						
33 Operating Rev For Return:	717,475,073	201,798,718	8,367,083	(7,594,410)	(46,293,988)	(22,987,915)
34						
35 Rate Base:						
36 Electric Plant In Service	18,871,999,960	5,245,981,994	-	-	-	-
37 Plant Held for Future Use	13,705,360	3,398,635	-	-	-	-
38 Misc Deferred Debits	142,052,496	20,078,210	-	(4,215,723)	(754,545)	-
39 Elec Plant Acq Adj	63,606,583	16,650,351	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	42,925,178	12,457,960	-	-	-	-
42 Fuel Stock	144,601,284	35,184,502	-	-	-	-
43 Material & Supplies	179,144,252	51,428,949	-	-	-	-
44 Working Capital	64,581,362	17,682,862	119,583	109,605	190,123	(159,659)
45 Weatherization Loans	35,846,785	(680)	-	-	-	-
46 Misc Rate Base	2,644,176	716,902	-	-	-	-
47						
48 Total Electric Plant:	19,561,107,436	5,403,579,685	119,583	(4,106,117)	(564,422)	(159,659)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(6,494,602,164)	(1,898,464,160)	-	-	-	(165,721,361)
52 Accum Prov For Amort	(419,560,712)	(120,358,930)	-	-	-	(12,598,599)
53 Accum Def Income Tax	(1,794,276,358)	(502,886,525)	-	-	-	-
54 Unamortized ITC	(8,106,448)	(5,259,920)	-	-	-	-
55 Customer Adv For Const	(18,985,583)	(2,879,350)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(55,082,228)	(14,420,659)	(1,906,305)	-	535,903	-
58						
59 Total Rate Base Deductions	(8,790,613,493)	(2,544,269,545)	(1,906,305)	-	535,903	(178,319,960)
60						
61 Total Rate Base:	10,770,493,943	2,859,310,140	(1,786,721)	(4,106,117)	(28,519)	(178,479,619)
62						
63 Return on Rate Base	6.661%	7.058%	0.297%	-0.256%	-1.622%	-0.494%
64						
65 Return on Equity	7.375%	8.118%	0.558%	-0.479%	-3.044%	-0.927%
66						
67 TAX CALCULATION:						
68 Operating Revenue		301,724,779	16,911,420	(12,466,515)	(74,902,544)	(34,325,578)
69 Other Deductions		-				
70 Interest (AFUDC)		(14,105,816)				
71 Interest		77,613,114	(48,499)	(111,456)	(774)	(4,844,651)
72 Schedule "M" Additions		205,843,357	-	-	-	-
73 Schedule "M" Deductions		405,910,649	-	-	-	-
74 Income Before Tax		38,150,189	16,959,919	(12,355,059)	(74,901,770)	(29,480,927)
75						
76 State Income Taxes		518,455	4,012,870	(842,822)	(3,681,442)	(1,568,212)
77 Taxable Income		37,631,733	12,947,049	(11,512,237)	(71,220,329)	(27,912,715)
78						
79 Federal Income Taxes + Other		13,171,107	4,531,467	(4,029,283)	(24,927,115)	(9,769,450)
80						
81 APPROXIMATE REVISED PROTOCOL PRICE CHANGE		62,762,501	(14,138,023)	12,045,726	76,825,275	13,327,465
82						
83 NET POWER COST		253,131,140	-	-	59,647,757	-

PacifiCorp
Normalized Results of Operations
Adjustment Summary
Twelve Months Ending Dec 31, 2011

		Exhibit PPL/1102		
		Tab 7	Tab 8	Oregon Allocated
		Tax Adjustments	Rate Base Adjustments	Normalized Results December 2011
1	Operating Revenues:			
2	General Business Revenues	-	-	964,212,551
3	Interdepartmental	-	-	-
4	Special Sales	-	-	169,740,650
5	Other Operating Revenues	-	-	41,490,058
6	Total Operating Revenues	-	-	1,175,443,259
7				
8	Operating Expenses:			
9	Steam Production	-	-	250,272,685
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	10,155,935
12	Other Power Supply	-	(89,824)	303,733,377
13	Embedded Cost Differential (ECD)	2,279,010	1,723,814	(15,579,133)
13	Transmission	-	4,319	51,659,937
14	Distribution	-	-	76,534,494
15	Customer Accounting	-	-	36,066,052
16	Customer Service & Info	-	-	3,660,775
17	Sales	-	-	-
18	Administrative & General	-	-	49,627,697
19				
20	Total O&M Expenses	2,279,010	1,638,310	766,131,819
21				
22	Depreciation	-	4,422,565	160,373,963
23	Amortization	-	(359,142)	14,389,137
24	Taxes Other Than Income	7,368,035	-	54,122,839
25	Income Taxes - Federal	19,062,334	(11,121,172)	(13,082,112)
26	Income Taxes - State	4,343,287	(1,767,404)	1,014,732
27	Income Taxes - Def Net	(52,316,747)	2,417,443	36,337,195
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	(1,167,283)
30				
31	Total Operating Expenses:	(19,264,080)	(4,769,401)	1,018,120,291
32				
33	Operating Rev For Return:	19,264,080	4,769,401	157,322,969
34				
35	Rate Base:			
36	Electric Plant In Service	-	795,556,080	6,041,538,075
37	Plant Held for Future Use	-	(3,398,635)	-
38	Misc Deferred Debits	-	2,306,971	17,414,913
39	Elec Plant Acq Adj	-	(2,868,670)	13,781,681
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	12,457,960
42	Fuel Stock	-	14,280,518	49,465,020
43	Material & Supplies	-	-	51,428,949
44	Working Capital	433,361	(182,703)	18,193,172
45	Weatherization Loans	-	-	(680)
46	Misc Rate Base	-	(698,037)	18,865
47				
48	Total Electric Plant:	433,361	804,995,525	6,204,297,955
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	(1,970,872)	(2,066,156,392)
52	Accum Prov For Amort	-	-	(132,957,529)
53	Accum Def Income Tax	(161,644,976)	(1,817,564)	(666,349,065)
54	Unamortized ITC	2,175,231	-	(3,084,689)
55	Customer Adv For Const	-	21,967	(2,857,384)
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	-	(1,145,031)	(16,936,092)
58				
59	Total Rate Base Deductions	(159,469,745)	(4,911,500)	(2,888,341,151)
60				
61	Total Rate Base:	(159,036,384)	800,084,024	3,315,956,804
62				
63	Return on Rate Base	1.081%	-1.319%	4.744%
64				
65	Return on Equity	2.028%	-2.475%	3.778%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(9,647,045)	(5,701,733)	181,592,784
69	Other Deductions			-
70	Interest (AFUDC)			(14,105,816)
71	Interest	(4,316,884)	21,717,481	90,008,331
72	Schedule "M" Additions	22,997,908	4,422,565	233,263,829
73	Schedule "M" Deductions	(79,320,237)	10,545,533	337,135,945
74	Income Before Tax	106,025,609	(33,542,182)	10,855,778
75				
76	State Income Taxes	4,343,287	(1,767,404)	1,014,732
77	Taxable Income	101,682,322	(31,774,778)	9,841,046
78				
79	Federal Income Taxes + Other	19,062,334	(11,121,172)	(13,082,112)
80				
81	APPROXIMATE REVISED PROTOCOL PRICE CHANGE	(54,089,522)	103,361,331	**200,094,754**
82				
83	NET POWER COST	-	-	**312,778,897**

Docket No. UE-
Exhibit PPL/1102
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Oregon Results of Operations
December 2011

March 2010

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/1103
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of R. Bryce Dalley

Global Insight's Escalation Factors

March 2010

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Exhibit PPL/1200
Erich D. Wilson

Docket No. UE-
Exhibit PPL/1200
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Erich D. Wilson

March 2010

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

A. My name is Erich D. Wilson. My business address is 825 NE Multnomah, Suite 1800, Portland, Oregon 97232. My position is Director, Human Resources.

Qualifications

Q. Please describe your education and business experience.

A. I received a Bachelor's degree in Economics (Business) from the University of California at San Diego in 1992. In addition, I achieved the Certified Compensation Professional status from the American Compensation Association in 1999 and have kept this certification current through attending various educational programs and seminars. I joined the Company in 2001 as Director of Compensation. Prior to that, I held various positions within the area of human resources (operations, benefits and staffing), but for the majority of my career I have directed the design and administration of compensation programs. I assumed my current position as Director of Human Resources in 2006.

My current responsibilities include managing the Company's human resource function, including compensation, benefits, compliance, staffing, training and development, employee and labor relations, and payroll. I focus on assisting the Company in attracting, retaining, and motivating qualified employees along with the administration of all associated human resource programs and employee experiences.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the compensation and benefit plans provided to employees at the Company and support the costs related to these areas included in the test period. This overview focuses on the Company's base pay, annual incentive, pension and healthcare benefit plans. These plans are designed to allow the Company to attract and retain the employee talent necessary to deliver safe and reliable service at a reasonable cost. I also demonstrate that the Company has prudently contained increases in labor costs since the last rate case, and in particular, has kept increases in benefit costs at a competitive level.

Q. How do the total labor costs in this case compare to the Company's last general rate case, Docket UE 210 ("UE 210")?

A. The current total labor costs demonstrate that costs have remained relatively flat from calendar year 2010 to calendar year 2011. The table below shows that the total wage and benefit expense in this case for the 2011 test year has decreased by less than one percent as compared to labor costs included in UE 210 for a 2010 test year. Moreover, on a dollar per megawatt-hour ("MWh") basis, wages and benefits have increased less than one percent since 2010.

	Current Case Calendar Year 2011	UE 210 Calendar Year 2010	Change
Wage & Benefit Expense	$537,618,832	$539,061,021	-0.3%
Total Load - MWh	58,023,556	58,667,781	-1.1%
$/MWh	9.27	9.19	0.8%

Q. Please briefly describe the Company's compensation philosophy.

A. Two fundamental principles underlie the Company's compensation philosophy. First, the Company's primary goal in determining employee compensation is to provide pay at the market average. Competitive compensation is critical to attracting and retaining qualified employees in a market that is becoming extremely competitive, and allows the Company to do so without incurring excessive or unreasonable costs. Thus, the Company endeavors to provide the same general pay levels and components in its total compensation package as are included in the packages provided by its competitors for labor.

Second, the Company believes that in order to encourage superior performance, a certain percentage of each employee's market compensation must be "at risk." Accordingly, under the Company's Annual Incentive Plan, each employee has the opportunity to receive total compensation at the market average, so long as the employee performs at an acceptable level. However, employees will earn less than the average compensation when performance is less than acceptable and, conversely, will earn higher than the average compensation when performance is exceptional.

Q. Has the Company made changes to the Annual Incentive Plan in response to Commission feedback?

A. Yes. In 2006, the Company adjusted its Annual Incentive Plan in response to feedback from the Commission. Prior to that time, the Company sought recovery of all awards made to employees under the plan, whether or not those awards resulted in total employee compensation that was above a target (competitive market) level. In response to the Commission's previous decisions on recovery of employee compensation, including incentives, the Company now seeks to recover only that portion of incentive payments that result in compensation at the target level.

Total Compensation

Q. How does the Company determine the total cash compensation package for each position?

A. At least annually, the Company collects market data for comparable jobs and calculates the average data point for total cash compensation by position. To do so, the Company uses a variety of compensation studies put out by various experts/organizations, including Hewitt Associates, Towers Watson, and Mercer. In addition, the Company also uses an on-line tool called MarketPay.com. MarketPay.com provides electronic access to all of the compensation studies traditionally used and some additional surveys, allowing the Company to more efficiently perform information searches and job and pay comparisons.

After the Company determines the appropriate level of total cash compensation for a position, it then determines the portion of that compensation that will constitute the "at-risk" portion – that is, the "target" incentive pay. The Company sets the "at-risk" portion by reviewing market compensation using the various compensation studies described above. The "at-risk" portion is typically in the 10-25 percent range; however, incentive pay for a few employees is set as high as 75 percent. Generally speaking, the higher the position is within the

Company, the higher the percentage of target incentive pay. The remaining percentage of total compensation is referred to as "base compensation."

Annual Incentive Plan

Q. What is the objective of the Annual Incentive Plan?

A. The objective of the Annual Incentive Plan is to provide employees with incentive to perform at an above-average level. This is achieved by putting a percentage of the competitive total compensation "at risk." If an employee performs at an acceptable level for the position, the employee will receive the target incentive amount which will allow the employee to earn compensation comparable to similar positions in the market. If an employee fails to perform at an acceptable level, the employee will receive less than the target incentive or no incentive at all. When this situation occurs, the employee will be paid less than the comparable total cash compensation in the marketplace for that year. Conversely, for exceptional performance, an employee may receive above his or her target incentive level.

The ability to earn a higher-than-target incentive payment provides the employee with an incentive to exceed average performance. This opportunity is an essential counterbalance to the risk the employee faces that the employee's performance in a particular year will be less than acceptable, with the consequence that total compensation will be less than market in that year. The symmetry of the incentive element provides the Company with the financial tool to encourage exceptional performance and discourage less than acceptable performance. As would be expected from a well-designed, symmetrical plan, the average incentive element is approximately at the target incentive level.

Q. Is incentive compensation a greater benefit to customers than compensation consisting solely of base compensation?

A. Yes. In the Company's experience, a higher level of overall employee performance is achieved when a portion of pay is "at risk." In addition, the Company's incentive compensation plan enables the Company to attract and retain talented employees in the increasingly competitive market for skilled labor. Therefore, while the total cost of the Company's base plus incentive compensation program is equal to average total cash compensation (just as a salary-only program would be) the benefit to customers is greater.

Q. How is the incentive compensation plan implemented?

A. The Company's Annual Incentive Plan provides performance awards based on the following categories: (1) the employee's performance against individual goals; (2) the employee's performance against group goals including safety goals; and (3) success in addressing new issues and opportunities that may arise during the course of the year.

Q. What are the individual goals and how are they set?

A. Individual employee goals start with the goals set for the Company as a whole. Each year, the Company President, in conjunction with MidAmerican Energy Holdings Company, sets the overall goals for the Company. All of these goals focus on delivering safe and reliable electricity to customers and providing excellent customer service. Goals include safety goals such as reducing lost time, recordable, preventable, and restricted duty incidents. Customer service related goals include implementing local and regional customer service improvements, improving visibility and relations with industrial customers and consumer associations, and improving overall customer satisfaction. Some goals relate to operating within established budgets, including maintaining operating costs, controlling cost of capital expenditures, and achieving operational efficiencies/financial targets that allow the Company to remain a low-cost utility. Other key goals relate to operational performance, major project delivery, organizational planning and development, and quality of service and regulatory commitments. The achievement of each and every one of these goals will serve to benefit customers.

Q. How do the Company goals relate to individual employee goals?

A. The Company-wide goals serve as the foundation for the goals set for each individual employee. Thus, when an individual employee sets his or her own individual goals for the year, they are set by reference to how that employee's position can advance the overall goals of the Company. The employee's performance on individual goals accounts for approximately 70 percent of his or her overall evaluation.

Q. What are the group goals?

A. In addition to performance against individual goals, all employees are evaluated against six common or "group" goals. These group goals describe the characteristics the Company believes are important to the success of all employees, *i.e.*, customer focus, job knowledge, planning and decision making, productivity, builds relationships and leadership. Detailed descriptions of these characteristics are attached as Exhibit PPL/1201. The employee's performance with respect to these group goals accounts for approximately 30 percent of the employee's overall evaluation.

Q. Explain the third category.

A. In the course of any one year, challenges will arise that were not contemplated by the goals set at the beginning of the year. For instance, the Company may become involved in a significant transaction, such as a purchase or sale, or the Company may contend with unexpected outage conditions. In these cases, some percentage of the employee's evaluation may reflect his or her performance under these unforeseen conditions.

Q. Are any of the employees judged on the financial performance of the Company?

A. No. While all employees are expected to operate within applicable budgets, corporate financial performance and returns are not a factor in determining the amount of incentive compensation awarded under the plan. The Company does maintain a separate plan for executives that awards bonuses based on overall corporate performance; however, the Company does not ask customers to absorb the costs associated with that plan.

Q. Please explain the level of incentive compensation that is included in this filing?

A. As shown in the testimony of Company witness Mr. R. Bryce Dalley, this application includes a request for total-Company incentive compensation based on a calendar year 2011 test period in the amount of $32.6 million. This is the total budgeted incentive compensation payout at the target incentive level for each employee participating in the incentive plan. The Oregon portion of this expense is approximately $6.8 million.

Q. What level of incentive compensation does the Company expect to pay out on a year after year basis?

A. As the Company's pay philosophy is to provide total compensation at the market average, and because target incentive compensation is set to market average, the Company expects that it will pay out, on a year after year basis, the target levels of incentive compensation.

Q. Does the Company recommend the full target level of incentive compensation plus base compensation be included in rates?

A. Yes, for several reasons. First, customers should fully support the cost of incentive compensation because, as previously mentioned, it is an essential component of an overall market-based competitive compensation program. Reducing customer support for incentive pay would result in under-market salaries, making it impossible for the Company to recruit and maintain a qualified labor force. This would in-turn, make it impossible for the Company to provide safe and reliable service. Moreover, the goals of the plan are designed to encourage superior performance on the part of employees to pursue the goals that directly benefit customers—safety, reliability, and customer service. This is precisely the type of prudently designed incentive plan program that provides direct benefits to customers and which customers should therefore support.

Retirement Plans

Q. Please describe the Company's retirement plan.

A. The Company strives to provide a competitive retirement plan offering with reduced expense volatility for the benefit of employees and customers. In doing so, the Company provides non-represented employees hired prior to January 1, 2008, the ability to receive their retirement through either a cash balance or 401k only design. This choice was offered in 2008 and 41 percent of the eligible population elected the 401k design. All non-represented employees hired after January 1, 2008 receive retirement through the 401k design approach.

Retirement plan benefits for represented employees are determined through the collective bargaining process, through which the Company has maintained its focus to shift the retirement approach from the traditional defined benefit to defined contribution (401k) approach.

Employee Health Benefits

Q. Please describe the Company's health care benefits.

A. As with all benefits, the Company attempts to provide employees with the same level of health care benefits provided by the employers with whom the Company competes for labor. For the Company, this means offering employees what may be described as market average health benefits. The Company seeks to provide these benefits as economically as possible.

Q. How does the Company ensure that it is providing these competitive benefits as economically as possible?

A. The Company relies on the advice of its consultant, Hewitt Associates, to ensure that it is securing market competitive benefits at the best possible rate. Hewitt Associates are respected experts in their field and the Company has relied on them for many years. With the help of Hewitt Associates, the Company periodically reviews and adjusts the sharing of healthcare-related costs with employees in an effort to stabilize cost, manage volatility, and respond to changing market practices.

Q. Has the Company faced any particular challenges in the past several years relevant to its provision of health care benefits?

A. Yes. It is widely understood that health care costs have been rising sharply over the past several years. As a result, the Company experienced significant increases in its health care benefit costs.

Q. Has the Company taken any action to contain these cost increases?

A. Yes. Beginning in 2008 the Company made adjustments to the cost sharing and plan design to reduce costs and to align with market practices. In particular, the Company established a base medical plan with a high deductible and a cost sharing of 90/10. The Company continues to offer other plan choices, however, except for a $300 deductible plan that is offered in rural areas, these plans are set at a cost sharing of 74/26. All new hires as of January 1, 2008 have the option of selecting the high deductible plan or opting out of coverage. The Company continued with this cost sharing approach in 2009 and further increases in cost sharing to the employee were implemented in 2010.

Q. What is the Company's rationale for sharing healthcare-related costs with employees?

A. This structural shift adheres to the Company's goal of providing competitive benefits to its employees, while doing so in a manner that is fair and prudent for customers.

Q. Please explain the level of healthcare costs included in this filing and compare that to previous fiscal year expenses.

A. As discussed previously, there has been a significant upward trend in healthcare costs in recent years. For calendar years 2007, 2008, and 2009, actual total Company healthcare expenses totaled $49 million, $52 million, and $57.9 million, respectively. Consistent with this trend, the Company has included in this application healthcare expenses on a total Company basis of $65.7 million, as shown in the exhibits attached to Mr. Dalley's testimony. The Oregon allocated share of healthcare costs is $13.7 million. As can be seen from the annual expense numbers above, healthcare expenses have escalated an average of approximately 8.8 percent per year since calendar year 2008.

Hewitt Associates has informed the Company that current trends indicate the rates for the Company's health benefits are anticipated to increase further in 2011 by between 8 and 10 percent.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/1201
Witness: Erich D. Wilson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Erich D. Wilson

Group Goal Characteristics

March 2010

Section II - Performance Factors

Weighting of Performance Factors: 30%

Section II - Performance Factors: . 1

Customer Focus: Dedicated to meeting the expectations of internal and external customers, co-workers and stakeholders; obtains first-hand information from customers and uses it to improve processes and services; acts with customers in mind; establishes and maintains effective relationships with customers and gains their respect and trust. - Proactively meets internal or external customer expectations by anticipating needs and effectively addressing and resolving problems, issues and concerns in a timely manner - Develops and sustains productive customer relationships through appropriate communications - Shares information with customers to build their understanding of issues and capabilities -----WEIGHTING: 5%

Section II - Performance Factors: . 2

Job Knowledge: Puts knowledge, understanding and skills to practical use on the job; demonstrates an understanding of key policies, skills and procedures in functional and related areas of work. Ensures all compliance aspects of position are known and followed; understands and complies with all policies, codes and regulations applicable to position and company. - Achieves a satisfactory level of skill and knowledge in position-related areas; demonstrates ability to learn new skills - Actively supports the company with all compliance related activities both assigned to the job as well as those encountered as an employee. This includes attending required training, understanding federal, state and local requirements applicable to the business, consulting with management and/or compliance officers on issues and completing all requirements while adhering to company policies and procedures. - Keeps up with current developments and trends in area of expertise as a part of personal development - Generates solutions in work situations; utilizes a variety of resources and tools - Demonstrates clear and effective communication in written and verbal formats -----WEIGHTING: 5%

Section II - Performance Factors: . 3

Planning and Decision Making: Identifies and understands issues, problems and opportunities, demonstrates sound judgment while utilizing plan, execute, measure and correct process. - Develops plans using a disciplined planning approach taking into account a variety of creative alternatives for choosing a recommended course of action with a clearly defined desired outcome, risks, identification of key assumptions, cost benefit analysis, milestones and metrics; properly identifies all stakeholders - Executes in accordance with the plan by taking action that is timely and consistent with available facts, constraints and probable consequences - Uses metrics and milestones, and goal reassessment to measure execution and determine whether correction to plan is needed - Makes timely and thoughtful corrections to the plan when appropriate; takes responsibility for results; properly reports the plan's progress or corrections to the appropriate individuals - Not afraid to make decisions and ensure appropriate people are informed - Makes sound, logical, business decisions; shows good judgment in prioritizing work - Demonstrates high levels of personal accountability -----WEIGHTING: 5%

Section II - Performance Factors: . 4

Productivity: Achieves a high level of relevant accomplishments for the benefit of the company and its customers. Uses appropriate methods to implement solutions; checks processes and tasks to ensure accuracy and efficiency; initiates action to correct problems or notifies others of quality issues as appropriate. - Takes initiative by generating new approaches to continuously improve efficiency and quality in every aspect of work - Performs well under pressure and does not create undue pressure for others; meets deadlines - Ensures job processes, tasks and work products are free from errors, omissions or defects - Work products are professional and clearly reflect a high level of attention to detail - Holds self and others accountable to quality results - Focuses on the desired outcomes and produces results -----WEIGHTING: 5%

Section II - Performance Factors: . 5

Builds Relationships: Identifies opportunities and takes action to develop strategic relationships across the organization and externally. Relates well to all people and builds constructive and effective relationships for the improvement of the organization as a whole. - Adapts interpersonal style to accommodate tasks, situations and individuals involved - Effectively exchanges ideas and information with others - Accepts personal differences and values diversity - Acts with integrity by demonstrating professional, courteous, ethical and fair behavior at all times - Promotes cooperation by sharing information, encouraging contributions - Open to constructive feedback and provides it to others -----WEIGHTING: 5%

Section II - Performance Factors: . 6

Leadership: Keeps the organization's vision and values at the forefront of decision-making and actions; demonstrates ability to guide individuals towards goal achievement by setting clear expectations, providing feedback and coaching. - Demonstrates passion; personal commitment and enthusiasm - Embraces change and motivates others to achieve goals - Enlists the active participation of appropriate resources to accomplish goals - Inspires employees to perform to their maximum potential - Provides opportunities for growth and development through delegation and succession planning - Provides candid and timely performance feedback - Clearly communicates expectations to teams and individuals; sets an example to others -----WEIGHTING: 5%

Docket No. UE-
Exhibit PPL/1300
Witness: Norman K. Ross

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Norman K. Ross

March 2010

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

A. My name is Norman K. Ross. My business address is PacifiCorp, 825 NE Multnomah, Suite 1900, Portland, Oregon 97232. I am a Director within the Company's corporate tax department.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a Bachelor's degree in Business Administration with a concentration in accounting from Seattle Pacific University in June 1980. I am licensed as a Certified Public Accountant and have been employed by PacifiCorp or its affiliates for the past 22 years. My business experience includes all areas of the corporate tax function. Prior to assuming my present duties in 1998, I served from 1987 through 1998 within the corporate tax department of Pacific Telecom, Inc., a former PacifiCorp subsidiary.

Q. Please describe your present duties.

A. In my present position I am responsible for all activities related to the Company's property, sales, use, excise, gross receipt and miscellaneous tax obligations. One of my specific responsibilities is to prepare annual estimates of property tax expense to be used for both budgetary and rate case purposes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony supports and explains the $106.8 million estimate of 2011 property tax expense included in the overall revenue requirement, as shown in the direct testimony of Company Witness Mr. R. Bryce Dalley. I also provide an overview of the method used by the Company to estimate property tax expense while taking into account important multi-state assumptions.

Q. What are the historical levels of property tax that the Company has experienced?

A. A comparison of the Company's property tax expense since 2006 is shown below.

	Calendar Year	Property Tax Expense	Year over Year Change
Actual	2006	$67,506,522	
Actual	2007	$69,102,426	2.4%
Actual	2008	$77,529,279	12.2%
Actual	2009	$87,317,408	12.6%
Estimate	2010	$94,995,000	8.8%
Estimate	2011	$106,765,000	12.4%

Q. What are the main factors contributing to the increase in property tax expense that the Company has experienced?

A. Increased property tax expense results primarily from higher levels of operating property which are expected to continue to rise into 2011. The Company's estimate of property tax expense for calendar years 2010 and 2011 is reasonable considering historical year-over-year increases in tax expense and the fact that the Company will continue to add to its overall level of taxable operating property.

Q. Please provide a brief overview of the method used by the Company when estimating 2011 assessed values.

A. The Company's property tax estimation methodology, which is described in a detailed narrative in Confidential Exhibit PPL/1301, gives specific consideration to all relevant and material factors that impact property tax expense. These factors include the following: state-by-state valuation procedures, the amount of tax to be capitalized for projects under construction, the amount of property tax chargeable to fuel expense for mining related assets, state specific exemptions for intangible property, pollution control equipment, and other exempt assets, state specific allocation methodologies, assessment ratios, and tax rates.

The method begins with state specific valuation models created by the Company's tax department. Each model consists of a series of worksheets that are functionally identical to the specific cost, income and sales comparison methods routinely employed by each individual state. Beginning with a version of each state's model that reflects the valuation methods employed when determining assessed values for the most recent year, the Company is then able to increase or decrease key property and income amounts within each model and produce an estimate of assessed value for later tax years.

Once adjustments for anticipated changes in key property and income data are made, the Company makes adjustments for known or anticipated changes in the level of exempt property, assessment ratios or other factors expected to impact each year's valuation. The objective is to produce an estimate of assessed value based upon anticipated changes to all material valuation data.

The resulting estimates of 2011 assessed values are then input into column "b" of the master property tax estimation worksheet. The master property tax estimation worksheet is included in Confidential Exhibit PPL/1301. The anticipated year-over-year percentage change in assessed value, calculated by dividing estimated 2011 assessed value by the final June 2009 assessed value is then used to project tax expense for 2011.

Q. Do you consider the Company's estimates of property tax expense to be reliable?

A. Yes. The Company's estimate of calendar year 2009 property tax expense was $86.3 million. Actual calendar year 2009 property tax expense was $87.3 million or 1.2 percent above the Company's estimate. The estimation methods employed for 2009 are the same as those employed when preparing the $106.8 million estimate for 2011. The Company's methodology relies upon the most current information available and gives thoughtful consideration to each of the factors previously discussed. Given the expected and substantial year over year increases in the level of taxable operating property and the complexity of the assessment processes employed by the ten western states in which the Company's operating property is located, more simplistic estimation methods which rely exclusively on historical relationships between tax expense and either rate base or net utility plant are inadequate and therefore less reliable.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit PPL/1301
Norman K. Ross

CONFIDENTIAL
Docket No. UE-
Exhibit PPL/1301
Witness: Norman K. Ross

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

CONFIDENTIAL
Exhibit Accompanying Direct Testimony of Norman K. Ross

Property Tax Estimation Method

March 2010

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/1400
Witness: Nancy K. Kent

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Nancy K. Kent

March 2010

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

A. My name is Nancy K. Kent. My business address is 825 NE Multnomah, Suite 400, Portland, Oregon 97232. My present title is Managing Director, Risk & Insurance, Corporate Security and Information Technology.

Qualifications

Q. Please describe your education and business experience.

A. I joined PacifiCorp in 1984 as Data Center Manager. Since that time, I have held positions with increasing levels of responsibility within the Company, including responsibilities associated with physical and information security, disaster recovery, risk management, business continuity and emergency management policies and programs. In my current role as Managing Director, I am responsible for physical and logical security, risk and insurance for the MidAmerican Energy Holdings' companies, delivery systems, compliance and delivery services supporting approximately 400 plus systems, including SAP, EMS/SCADA, customer service system and several hundred smaller stand-alone integrated systems that support the Company's business operations. Prior to joining PacifiCorp, I worked at North Pacific Insurance in Portland, Oregon as an information technology specialist. I earned an associate degree in business from the Nebraska Western College and hold several certificates in management and leadership education.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's proposal related to insurance coverage in the 2011 test period in three categories: (1) third-party liability; (2) non-Transmission and Distribution ("T&D") property; and (3) T&D property. Specifically, my testimony presents:

- An overview of how this insurance coverage has been provided since the acquisition of PacifiCorp by MidAmerican Energy Holdings Company ("MEHC").
- A description of the loss history that the Company has experienced over the past five years.
- A discussion of the Company's due diligence to understand the potential cost and availability of third-party commercial insurance options.
- The Company's proposal to "self-insure" in these areas beginning March 21, 2011.

Company witness Mr. R. Bryce Dalley presents the proposed accounting approach and financial impacts of the Company's proposal.

Overview of Prior Coverage

Q. How has insurance coverage for these three categories been provided since the acquisition of PacifiCorp by MEHC?

A. As part of the regulatory approval processes related to the acquisition of PacifiCorp by MEHC, the following commitment was made in the states of California, Idaho, Oregon, Washington and Wyoming:

> a) MEHC commits to use an existing, or form a new, captive insurance company to provide insurance coverage for PacifiCorp's operations. The costs of forming such captive will not be reflected in PacifiCorp's regulated accounts, nor allocated directly or indirectly to PacifiCorp. Such captive shall be comparable in costs and services to that previously provided through ScottishPower's captive insurance company Dornoch. MEHC further commits that insurance costs incurred by PacifiCorp from the captive insurance company for equivalent coverage for calendar years 2006 through 2010, inclusive, will be no more than $7.4 million (total company). Oregon Commission Staff has valued the potential increase in PacifiCorp's total revenue requirement from the loss of ScottishPower's captive insurance affiliate as $4.3 million annually, which shall be the amount of the total company rate credit. This commitment expires on December 31, 2010. [1]

With the pending expiration of the commitment on December 31, 2010, PacifiCorp undertook an evaluation of options for 2011 and beyond. As discussed in detail below, this included an assessment of PacifiCorp's loss history and a request for premium costs from third-party commercial providers. This information was used to inform the Company's decision to discontinue the coverage under the captive and rely on self-insurance.

Q. What was the level of coverage that was provided?

A. The coverage under the captive varies by category:

- Excess liability insurance provides indemnity for amounts the Company is legally obligated to pay by reason of liability imposed by law or liability assumed under contract for damages due to bodily injury, personal injury or property damage. The captive covers $750,000 per occurrence, in excess of a $250,000 deductible. Commercial insurance covers $175.0 million per occurrence.

[1] *See* Order No. 06-082 at Exhibit 1 to Appendix A (Oregon Commitment 010).

- Non-T&D property damage covers all risks of direct physical loss or damage including boiler explosion, machinery and electrical breakdown, flood and earthquake. The captive covers $6.0 million per occurrence, in excess of a $1.5 million deductible. Commercial insurance covers $400 million per occurrence.
- T&D property damage covers property damage to overhead transmission and distribution lines. The captive covers $10.0 million per occurrence, and in the aggregate annually in excess of an annual $5.0 million aggregate deductible for each and every loss. There is no commercial insurance for T&D property damage.

PacifiCorp's Loss History

Q. Please describe the factors considered to assess the Company's loss history.

A. The Company compiled the loss history over a representative number of years for each category of coverage. The loss history looks at the total amount of losses, including the amount of the deductible, the amount that was covered by insurance and, for T&D property related losses, the amount that was in excess of the maximum captive coverage.

Q. What is the loss history for the third-party liability category?

A. Over the three-year period from 2007 through 2009, the captive paid approximately $4.2 million in reimbursements to the Company. The three-year annual average is approximately $1.4 million.

Q. What is the loss history for the non-T&D related property category?

A. Over a nearly five-year period, PacifiCorp incurred losses for non-T&D related property of approximately $12 million. The annual average is approximately $2.5 million. The analysis covers the period from April 2005 through December 2009.

Q. What was the loss history for the T&D related property category?

A. Over the same time period just noted, PacifiCorp incurred losses for T&D related property of approximately $70 million, of which approximately $30 million is related to the Oregon distribution system. In the last three full policy years – years ending March 31, 2007, 2008, and 2009 – the captive paid the maximum coverage of $10 million.

Q. What did the Company conclude from this loss history assessment?

A. First, the loss history demonstrates that PacifiCorp's customers received significant value over the five-year life of the MEHC transaction commitment. Second, it became clear that the $7.4 million annual premium cap would be unsustainable once the commitment expired. As discussed in more detail in the testimony of Mr. Dalley, a comparison of the total company expense in the base period with the average payout for previous damages is shown below:

Base Period Costs	($ million)
Captive Insurance Premium	7.2
Property Losses Not Covered by Captive in Base	9.1
	16.3
Average Annual Accrued	
Average Liability Claim Payout by Captive	1.4
Average Non-T&D Property Damages	2.5
Average T&D Property Damages	14.4
	18.3

As such, the Company concluded that it needed to understand the potential cost and availability of third-party commercial options for coverage beginning in 2011.

Third-Party Commercial Options

Q. How did the Company undertake its assessment of the third-party commercial market?

A. The Company requested commercial market pricing comparisons for each of the three categories. Preliminary indicative pricing and an indication of whether the third party was willing to write a policy were provided by five separate insurance companies.

Q. What were the results of the query to third-party commercial providers?

A. If the equivalent levels of insurance were available in the market for insurance coverage for third-party liability, estimated indicative pricing would be approximately $3 million per year. Similarly, if equivalent levels of insurance were available in the market for non-T&D property, estimated indicative pricing would be approximately $7 million per year. Finally, if equivalent levels of insurance were available in the market for T&D property, estimated indicative pricing would be $11 million per year. Accordingly, the Company concluded that equivalent levels of insurance for the respective insurance coverage are not available on commercially reasonable terms.

Self-insurance Option

Q. Given the results of the third-party analysis, what other options were considered?

A. The Company evaluated the option of self-insurance as a means of replacing the coverage previously provided by the captive insurance company. Mr. Dalley describes how this will be implemented from an accounting standpoint.

Q. Did the Company consider continuation of the captive insurance company?

A. Yes. However, the Company quickly concluded that if the premiums were set at compensatory levels that avoided any cross-subsidization between affiliated companies, the captive would not provide additional benefits to customers as compared to the self-insurance option. Indeed, customers would need to pay additional administrative costs related to the captive as compared to a self-insurance option. As such, the Company decided to self-insure for the coverage previously provided by the captive. It will continue to purchase commercial coverage to the extent available for excess coverage for liability and non-T&D related property losses.

Q. Does this conclude your testimony?

A. Yes.

Exhibit PPL/1500
Barbara A. Coughlin

Docket No. UE-
Exhibit PPL/1500
Witness: Barbara A. Coughlin

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Barbara A. Coughlin

March 2010

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

A. My name is Barbara A. Coughlin. My business address is 825 NE Multnomah, Suite 800, Portland, Oregon 97232. My position is Director of Customer & Regulatory Liaison.

Qualifications

Q. Please describe your educational and professional background

A. I have worked in the gas and electric utility industry since 1978. I received a Legal Assistant Certificate from Marycrest College in 1991. From 1978 to 1997, I held various positions of increasing levels of responsibility within the legal/regulatory department of Iowa-Illinois Gas and Electric, a predecessor company to MidAmerican Energy Company. In 1997, I was promoted to a customer services supervisor and in 1999 was promoted to customer services manager at MidAmerican Energy Company. I worked as manager of regulatory projects at PacifiCorp from 2006 through 2008, when I was promoted to my current position of Director of Customer & Regulatory Liaison.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. I am providing additional information to that provided by Company witness Mr. R. Bryce Dalley concerning the recovery of estimation expenses for customer projects not completed.

Q. Please summarize your testimony.

A. My testimony discusses the process for a potential customer or an existing customer in obtaining an estimate and the reasons customers do not pursue projects. I also explain the ramifications if the Company is not allowed recovery of these costs in rates.

Q. Please explain the process for providing a customer with electric service request estimates.

A. At the request of customers, the Company performs an average of over 6,300 estimates a year for new electric service or redesigns (relocating/adding capacity) of existing service at their homes or businesses in Oregon. Following a call from a customer to the Company, a work order is generated and automatically routed to the appropriate field office. For the majority of the requests, a field office representative places a call to the customer to schedule an appointment for an estimator to visit the customer at the construction site to discuss the requested service and assess the proposed connection (some simple requests do not require a site visit). After the site visit, depending on the complexity of the connection, the estimator will design the job in the Company's estimating system, and provide the customer with an estimate for the work requested.

Once an estimate and a contract are presented to the customer, the customer has 90 days to sign the contract and pay, in advance, any applicable costs. Estimates are recalculated if the contract is not signed in 90 days or if the project has not commenced within 150 days of the contract, and the customer still wants to proceed with the job.

Q. What are some of the reasons a customer might not pursue a project after an estimate has been provided?

A. The following are typical reasons that customers cancel a project after an estimate has been provided:

- Customers may be unfamiliar with the costs associated with bringing electric service to their site. Once an estimate has been provided, a customer may determine that they are unable to pay to complete the job. Some examples: someone has inherited or acquired property and decides to develop it, with little experience or understanding that the electricity in the area is single phase and can only support a limited number of homes before adding the other two phases; a person has purchased a lot outside a subdivision with the intent to build but did not anticipate the costs to them associated with extending lines or upgrading a transformer to add the home; or, a home or business owner may not have anticipated costs to them to relocate a utility pole to accommodate construction of a garage or addition, or simply to move a pole to a more convenient location.
- A customer may not be able to obtain easements or rights-of-way from neighboring properties.
- A customer may face unexpected economic hardship such an unanticipated job loss or medical expense.
- A customer may be unable to obtain financing for a project. Often times, a written estimate is required by financial institutions prior to approving funding.

Q. Do you have an example of a customer that chose not to proceed with a project after receiving their estimate?

A. Yes. Pacific Power had a customer planning to purchase property in Mosier, Oregon. The site had existing service to a well. The customer's plan was to put a home on the property. The customer contacted the Company on September 21, 2009 to request an estimate to have service extended to the proposed home location. The customer was provided with two estimates to run service, one estimate was for overhead service and one estimate was for underground service. The contract and easement documentation were sent to the customer on October 15, 2009. The customer contacted the Company on October 26, 2009 to verify if the contract amount was correct as it was much higher than they anticipated. The applicant has since withdrawn their request for electric service because they have been unsuccessful in purchasing the property.

Q. Why is providing estimates to customers a necessary customer service?

A. Customers must have an accurate idea of the cost and requirements to help them decide whether their construction project can be undertaken as proposed, needs to be redesigned, or in some cases abandoned. To that end, the Company must prepare estimates to provide customers with this necessary information. The customer's estimate will define the installed cost for the service being requested, along with continued monthly charges for installing the requested service.

Additionally, the Company's Customer Guarantee No. 4, Estimates For New Supply, for residential and small non-residential customers states:

> An estimate for new supply will be supplied to the Applicant or Customer within 15 working days after

> the initial meeting and all necessary information is provided and any required payment is made.

If the Company fails to meet this requirement, a qualifying customer's account is automatically credited $50. *See* Oregon Rule 25, General Rules and Regulations, Customer Guarantees. The Company's Customer Guarantee Program was most recently approved by the Commission as part of the MidAmerican Energy Holdings Company acquisition of PacifiCorp in Docket UM 1209.

Q. Why does the Company guarantee the time period for which it provides estimates to a customer?

A. The Company created this guarantee to illustrate the importance of the quality of interactions with the individual customer.

Q. Does PacifiCorp require a customer to advance the costs of providing estimates in Oregon?

A. For customers requesting service under 1000 kW, the Company generally provides the initial estimate at no charge. For other customers with anticipated loads of 1000 kW or greater, the Company generally requires a customer to pay in advance the estimated engineering, design and estimation costs, which are then applied to the costs for a line extension under Oregon Rule 13(I)(C).

Q. Please explain why the Company does not require all customers to pay in advance estimation costs as allowed under its line extension tariff?

A. The Company does not require all customers to pay estimation costs in advance for several reasons. First, as a matter of policy, the Company strives to provide customers with the necessary information to make informed decisions in a prompt and professional manner. Second, charging customers a fee prior to the commencement of any estimate would require additional administrative expense, including additional employee time to administer the fees, computer system changes, accounting, processing and refunds. Additionally, requiring the estimating fee in advance would add another step to the line extension process, further delaying the timeframe to receive the estimate and deliver service upon execution of a line extension contract. Taking payments for every estimate and refunding for many of these estimates will increase unique payment and refund transactions. These transaction are unique because a site address, meter number, billing address, customer information and other records that exist for electrical payments do not exist for many of these jobs, thus unique information has to be collected, retained, and handled.

Q. Would the Company find it challenging to recover estimation expenses associated with projects by attempting to bill and recover the costs through separate charges?

A. Yes. For the same reasons identified above, it would be administratively burdensome and possibly result in delays in the timeframe to receive the estimate. Additionally, attempting to recover estimation costs after a job is cancelled would be very difficult because the customer would no longer have an incentive to pay the costs and the Company would have no leverage to collect the costs. Moreover, the Company could spend more money attempting to collect the costs associated with the cancelled job than was actually incurred to perform the estimate.

Q. Do you agree that expenses must be related to a project placed in service and used for providing utility service to Oregon customers in order to justify recovery of the expenses through customer rates?

A. No. Providing an estimate is a necessary customer service for any person requesting, relocating or upgrading service in Oregon.

Q. Should estimation expenses for customer projects not completed be shared equally between shareholders and customers?

A. No. Providing estimates is a cost of doing business. All customers are eligible to receive this service; therefore, it is reasonable for the costs to be spread across all customers.

Q. What would happen if the Commission denied recovery of these costs and required the utility to collect an advance?

A. The Company would see increased costs to administer the estimating process. Applicants and customers would be given further road blocks to successfully building or upgrading their service. Additionally, the Company would anticipate receiving a considerable number of complaints from homeowners and their contracted employees regarding the necessity of paying an advance for estimating a job. Many contractors, builders and electricians are familiar with the Company and would consider a change in practice as burdensome. When the timing of home construction and financing is of utmost concern, adding another step in an already specific and timely process would create considerable burden to applicants and customers seeking to obtain service.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit PPL/1600
C. Craig Paice

Docket No. UE-
Exhibit PPL/1600
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of C. Craig Paice

March 2010

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

A. My name is C. Craig Paice. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232, and I am currently employed as a Consultant in the Regulation Department.

Qualifications

Q. Please describe your education, business experience, and responsibilities.

A. I received a Bachelor of Science Degree in Business Management from Brigham Young University in 1976. I have also attended various educational, professional and electric industry seminars during my career with the Company. I have been employed by PacifiCorp since the merger in 1989. Prior to that time, I was employed by Utah Power & Light Company beginning in 1978 holding various positions in the accounting, customer service, and regulatory areas. In my current position, my primary responsibilities are to prepare, present, and explain the results of the Company's cost of service studies to regulators and interested parties in jurisdictions where PacifiCorp provides retail electric service.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain the Company's proposed revenue requirement for each of the unbundled service categories, the Company's functionalization procedures and the Oregon Marginal Cost Study.

Unbundled Class Revenue Requirements

Q. Please identify Exhibit PPL/1601 and explain what it shows.

A. Exhibit PPL/1601 shows the Company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services – Billing, Consumer Services – Metering, Consumer Services – Other, Retail and Public Purposes.

No revenue requirement is shown for the Retail Service or Public Purposes categories. The Company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public Purpose revenues are collected under a separate tariff.

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base assets and expenses were either assigned or allocated to unbundled categories in accordance with OAR 860-038-0200. Traditional revenue requirement methodology, (i.e., recovery of costs plus a return on rate base), was then used to determine a revenue requirement for each category. Costs and rate base assets are from PacifiCorp's Oregon Results of Operations Report, as filed by Company witness Mr. R. Bryce Dalley. The application of PacifiCorp's proposed rate increase, shown on Page 2 of Exhibit PPL/1601, is consistent with Mr. Dalley's Exhibit PPL/1101, page 1, column 6.

Q. Please identify Exhibit PPL/1602 and explain what it shows.

A. Exhibit PPL/1602 is the summary page from PacifiCorp's December 2011

Functionalized Oregon Results of Operations Report ("Functionalized Oregon Results of Operations Report") and is the basis for the unbundled revenue requirement in Exhibit PPL/1601. It separates the results of operations into the unbundled categories identified above. This process is described later in my testimony.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's most recent market prices for Regulation and Frequency Response Service, Spinning Reserve Service and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit PPL/1603. The costs associated with providing these services are included in the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PPL/1604.

A. Exhibit PPL/1604 contains a summary from PacifiCorp's State of Oregon December 2011 Marginal Cost Study ("Marginal Cost Study"). The Marginal Cost Study is described later in my testimony.

Q. Please identify Exhibit PPL/1605 and explain what it shows.

A. Page 1 of Exhibit PPL/1605 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours ("MWh") are shown on line 2. Full long-run marginal costs for each customer class, separated by function are shown on lines 5 through 11. Lines 15 through 23 show each class' share of total marginal costs for each function as well as each class' share of revenue and MWh. Lines 27 through 36 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier is shown in the total column. The total for each function is then allocated to a particular customer class based on that class' share of total marginal cost for that function. For example, the residential class accounts for 44.04 percent of generation marginal costs and is assigned 44.04 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis of class revenue. Lines 38 through 45 compare the total revenue requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PPL/1605.

A. Pages 2 and 3 of Exhibit PPL/1605 provide a reconciliation between Operating Revenues and Target Revenue Requirement as shown on page 1 of this exhibit, with those shown in Exhibit PPL/1601 and 1602. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PPL/1605 accounts for all

Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

Functionalization Procedures

Q. Please explain how the various expenses and rate base assets in the Functionalized Oregon Results of Operations were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal Energy Regulatory Commission ("FERC") account is found in Exhibit PPL/1606. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020.

Marginal Cost Study

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PPL/1607. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. Exhibit PPL/1607 contains seven summary tables followed by 17 sections of supporting data.

Q. Is this Marginal Cost of Service Study similar to studies the Company has previously filed?

A. Yes. This study is consistent with the Cost of Service Study presented in the Company's reply filing in Docket UE 210 and employs the revised methodology for determining customer class loads described later in my testimony. This methodology produces class load values that match total system loads with a high degree of accuracy, resulting in a difference of less than two percent overall.

In addition, within street lighting Schedule 51, marginal costs were not prepared for 70 watt lamps, 200 watt lamps, and all metal halide lamps. These services are or will be closed to new service, and marginal cost analysis is not appropriate for rate schedules with no new service.

Last, Exhibits PPL/1601 through 1605 and Exhibit PPL/1607 containing the Marginal Cost of Service Study and the circuit model (formerly "the feeder model") are incorporated into a single electronic file. Reducing the number of electronic files from three to one (1) increases transparency, (2) reduces the potential for errors, and (3) simplifies use of cost of service related information.

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10 and 20-year marginal costs also include the cost of expanding facilities. The costs of these added facilities results in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission or distribution costs. A detailed description of marginal cost procedures is included in Exhibit PPL/1607, Tab 1.

Q. Please describe the marginal cost summary tables included in Exhibit PPL/1607, Tab 2.

A. Tables 1 and 2 of Exhibit PPL/1607 summarize the one, 10, and 20-year marginal costs on a mills per kWh or dollars per customer basis. Table 3 summarizes the unit costs based on the results of the long-run (20-year) Marginal Cost Study.

Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand and number of customers by customer class for the 12-months ending December 31, 2011 ("Test Period"). This information is used to calculate annual long-run marginal costs by class shown on Table 4.

Q. Please describe how customer class loads used in this Marginal Cost of Service Study are developed?

A. The Marginal Cost of Service Study uses customer class loads developed using the "revised" methodology presented in the Company's reply filing in Docket UE 210. As such, customer class loads are calculated using actual average Load Research sample data expanded by customer populations and then adjusted to the forecasted energy usage for the test period. The following three load values are developed for each customer class:

- The average of 12 monthly peaks at the time of the PacifiCorp system peak or Coincident Peak ("CP") loads, referred to as system loads.
- The average of 12 monthly peaks at the time of the Company's Oregon distribution peak or Distribution Coincident Peaks ("DCP"), referred to as distribution (formerly "feeder") loads.
- The annual maximum non-coincidental peak ("NCP"), referred to as transformer loads.

This revised method replaced the method used in the Company's direct filing in Docket UE 210 which derived customer class loads using class load factors. The class load factor method could be imprecise because loads are calculated from forecasted energy, grossed up for energy-related loss factors, instead of directly using demand-related loss factors. In the Company's direct case in Docket UE 210, this method resulted in a megawatt discrepancy when class loads were compared to jurisdictional loads. The load factor method was a legacy method used for many years before information necessary to develop specific class loads was available and is no longer employed by the Company to develop the customer class loads used in the cost of service study.

Q. Please explain how generation marginal costs are calculated.

A. The marginal generation costs in this study are based on the Company's currently filed Oregon avoided cost calculations. New resource costs are based on the fixed and variable cost of a combined cycle combustion turbine, which operates as a base load unit. Recognizing that base load generation produces the dual products of capacity and energy, capacity costs are determined using the fixed costs of a simple cycle combustion turbine. The remaining fixed and all variable costs of the combined cycle turbine are considered energy related. Marginal generation costs are summarized on Table 5 of Exhibit PPL/1607.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures to meet increased load on the transmission system. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 6 of Exhibit PPL/1607.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 7 of Exhibit PPL/1607 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) Demand-related, shown in dollars per kW/year; (2) Commitment-related, shown in dollars per customer/year; and (3) Billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductor that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for the State of Oregon. Customer locations are based on actual customer distances from the substation as determined by the Company's Computer Aided Design Operations ("CADOPS") database. The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated circuit model is included the marginal cost procedures in Exhibit PPL/1607, Tab 1.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance ("O&M"). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M and meter reading expense. Current typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense and all the remaining customer accounting and customer service activities. Meter reading expense is based on historical experience of costs and allocated to customer classes based on typical meter reading times. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/1601
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Functionalized Revenue Requirement

March 2010

STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2011 Forecast

Function		Revenue Requirement
Production		$ 703,114,372
Transmission		$ 106,370,891
Distribution		$ 290,820,383
Ancillary		$ 10,554,886
Customer Billing		$ 12,802,214
Customer Metering		$ 26,568,574
Customer Other		$ 14,075,984
Retail Service	a	$ -
Public Purposes	b	$ -
Total State of Oregon		$ 1,164,307,305

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2011 Forecast

		ROR	ROE	Total	Production	Trans-mission	Distribution	Ancillary	Consumer: Billing	Consumer: Metering	Consumer: Other	Retail Service (a)	Public Purposes (b)	Distribution Components: Poles & Wires	Distribution Components: DSM	Distribution Components: Franchise Tax
1	Functionalized Situs Revenues @ Earned	4.74%	3.78%	964,212,551	604,773,430	64,407,228	234,010,949	10,554,886	12,265,604	24,568,842	13,631,613	-	-	212,119,404	-	21,891,545
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			964,212,551	604,773,430	64,407,228	234,010,949	10,554,886	12,265,604	24,568,842	13,631,613	-	-	212,119,404	-	21,891,545
4																
5	Target Increase in Return	8.38%	10.60%	120,568,470	60,598,441	25,858,331	32,274,959	0	330,663	1,232,250	273,825			32,274,959	(0)	-
6																
7	Add															
8	Uncollectible Expense			1,236,895	607,899	259,400	351,170	0	3,317	12,361	2,747	-	-	323,769	(0)	27,401
9	Franchise Tax			4,402,085			4,402,085									4,402,085
10	Other Revenue Based Taxes			144,068	70,805	30,214	40,903	0	386	1,440	320	-	-	37,711	(0)	3,192
11	Inc Taxes - State			8,821,751	4,433,866	1,892,002	2,361,494	0	24,194	90,161	20,035	-	-	2,361,494	(0)	-
12	Inc Taxes - Federal			64,921,484	32,629,930	13,923,717	17,378,824	0	178,050	663,519	147,444	-	-	17,378,824	(0)	-
13	Total Increase Needed			200,094,754	98,340,942	41,963,663	56,809,434	0	536,610	1,999,732	444,371	-	-	52,376,757	(0)	4,432,677
14																
15	Total Oregon General Business Revenue @	8.38%	10.60%	1,164,307,305	703,114,372	106,370,891	290,820,383	10,554,886	12,802,214	26,568,574	14,075,984	-	-	264,496,162	(0)	26,324,222
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,164,307,305	703,114,372	106,370,891	290,820,383	10,554,886	12,802,214	26,568,574	14,075,984	-	-	264,496,162	(0)	26,324,222
18																
19	Rate Base			3,315,956,801	1,666,619,922	711,173,555	887,648,068	1	9,094,133	33,890,198	7,530,924			887,648,073	(5)	-
					50.261%	21.447%	26.769%	0.000%	0.274%	1.022%	0.227%	0.000%	0.000%	26.769%	0.000%	0.000%

Source:
Total Column : Exhibit PPL 1002
Row 1: Exhibit PPL 1002
Row 8: Uncollectible 0.61815%
Row 9: Franchise Tax @ 2.2000%
Row 10: Other Revenue Based Taxes 0.0000%
Row 11: Inc Taxes - State 4.5400%
Row 12: Inc Taxes - Federal 35.0000%
Row 19: Exhibit PPL 1002

Notes:
a - Retail Services are conducted as unregulated activities.
b -DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

Docket No. UE-
Exhibit PPL/1602
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Unbundled Results of Operations

March 2010

Exhibit PPL/1602
Paice/1

STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2011 Forecast

	Description of Account Summary:	Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Other
	Operating Revenues								
1	General Business Revenues	964,212,551	604,773,430	64,407,228	234,010,949	10,554,886	12,265,604	24,568,842	13,631,613
2	General Business Revenues	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-
4	Special Sales	169,740,650	131,766,643	37,974,007	-	-	-	-	-
5	Other Operating Revenues	41,490,058	21,691,807	20,414,817	5,338,616	(10,554,886)	3,736,864	352,749	510,090
6	Total Operating Revenues	1,175,443,259	758,231,880	122,796,052	239,349,565	0	16,002,468	24,921,591	14,141,703
8	Operating Expenses:								
9	Steam Production	250,272,685	250,272,685	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	10,155,935	10,155,935	-	-	-	-	-	-
12	Other Power Supply	303,733,377	303,733,377	-	-	-	-	-	-
13	ECD	(15,579,133)	(15,579,133)	-	-	-	-	-	-
14	Transmission	51,659,937	271,182	51,388,755	-	-	-	-	-
15	Distribution	76,534,494	-	-	71,542,970	-	-	4,991,524	-
16	Customer Accounts	36,066,052	3,844,435	622,608	1,213,565	0	11,942,799	10,476,467	7,966,177
17	Customer Service	3,660,775	-	-	1,214,143	-	-	-	2,446,633
18	Sales	-	-	-	-	-	-	-	-
19	Administrative & General	49,627,697	15,939,922	4,625,373	21,678,386	-	2,153,053	3,470,573	1,760,391
21	Total O & M Expenses	766,131,819	568,638,403	56,636,736	95,649,064	0	14,095,852	18,938,563	12,173,200
23	Depreciation	160,373,963	81,576,251	24,788,227	50,211,134	-	679,841	2,733,379	385,130
24	Amortization Expense	14,389,137	8,827,823	773,845	1,862,440	-	1,275,570	880,532	768,927
25	Taxes Other Than Income	54,122,839	15,825,900	6,000,545	31,434,779	0	218,166	496,245	147,204
26	Income Taxes - Federal	(13,082,112)	(26,769,683)	(4,512,647)	17,617,671	0	(341,517)	733,495	190,569
27	Income Taxes - State	1,014,732	(3,935,587)	(1,632,068)	6,371,700	0	(123,515)	265,280	68,922
28	Income Taxes - Def Net	36,337,195	36,385,411	7,059,593	(6,190,492)	(0)	(233,745)	(733,913)	50,342
29	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
30	Misc Revenue & Expense	(1,167,283)	(1,388,114)	(59,250)	279,502	-	353	116	111
32	Total Operating Expenses	1,018,120,290	679,160,405	89,054,981	197,235,799	0	15,571,004	23,313,697	13,784,404
34	Operating Revenue for Return	157,322,969	79,071,475	33,741,071	42,113,766	0	431,464	1,607,894	357,299
36	Rate Base:								
37	Electric Plant in Service	6,041,538,075	2,864,498,208	1,175,284,673	1,849,611,917	-	37,609,353	90,641,873	23,892,052
38	Plant Held for Future Use	-	1,752,891	(532,085)	(1,114,108)	-	(65,098)	(41,600)	-
39	Misc Deferred Debits	17,414,913	10,373,751	6,218,497	597,153	-	(159,558)	244,544	140,526
40	Elec Plant Acq Adj	13,781,681	13,781,681	-	-	-	-	-	-
41	Nuclear Fuel	-	-	-	-	-	-	-	-
42	Prepayments	12,457,960	5,537,752	1,026,052	3,242,813	-	758,072	1,209,649	683,621
43	Fuel Stock	49,465,020	49,465,020	-	-	-	-	-	-
44	Material & Supplies	51,428,949	41,392,544	289,196	9,396,356	-	-	350,853	-
45	Working Capital	18,193,172	9,193,593	1,339,656	4,827,156	0	816,346	1,279,043	737,378
46	Weatherization Loans	(680)	-	-	(680)	-	-	-	-
47	Miscellaneous Rate Base	18,865	18,865	-	-	-	-	-	-
49	Total Electric Plant	6,204,297,955	2,996,014,306	1,183,625,989	1,866,560,605	0	38,959,115	93,684,362	25,453,578
51	Rate Base Deductions:								
52	Accum Prov For Depr	(2,066,156,392)	(926,977,963)	(319,553,652)	(779,387,734)	-	(3,080,667)	(35,374,550)	(1,781,826)
53	Accum Prov For Amort	(132,957,529)	(43,284,425)	(5,337,475)	(33,067,528)	-	(22,470,053)	(15,283,970)	(13,514,079)
54	Accum Def Income Taxes	(666,349,065)	(346,851,436)	(144,892,355)	(161,503,135)	0	(3,478,293)	(7,751,051)	(1,872,794)
55	Unamortized ITC	(3,084,689)	(1,282,156)	(173,413)	(894,664)	-	(210,008)	(335,042)	(189,405)
56	Customer Adv for Const	(2,857,384)	-	(1,978,657)	(847,740)	-	0	(30,987)	0
57	Customer Service Deposits	-	-	-	-	-	-	-	-
58	Misc. Rate Base Deductions	(16,936,092)	(10,998,404)	(516,883)	(3,211,732)	-	(625,960)	(1,018,563)	(564,549)
60	Total Rate Base Deductions	(2,888,341,151)	(1,329,394,384)	(472,452,434)	(978,912,533)	0	(29,864,982)	(59,794,164)	(17,922,654)
62	Total Rate Base	3,315,956,804	1,666,619,922	711,173,555	887,648,073	1	9,094,133	33,890,198	7,530,924
64	Return on Rate Base	4.7444%	4.7444%	4.7444%	4.7444%	4.7444%	4.7444%	4.7444%	4.7444%
66	Return on Equity	3.7782%	3.7782%	3.7782%	3.7782%	3.7782%	3.7782%	3.7782%	3.7782%

Docket No. UE-
Exhibit PPL/1603
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

CY 2011 Ancillary Services Revenue

March 2010

STATE OF OREGON
Combined GRC and TAM
CY 2011 Ancillary Services Revenue
12 Months Ended December 31, 2011 Forecast

Line	Item	Notes	Thermal Resource	Hydro Resource	Other Resource	Firm Purchases	Total Resources
1	System Resources CY 2011 (MWH)	(Note 1)	51,816,849	4,150,122	3,140,960	11,123,280	70,231,212
2	Plant allocated to Oregon based on JAM dollars	(Note 2)	26.25%	26.18%	26.13%	24.24%	
3	Oregon share of Resource Providing Service by type (MWH)	(Line 1 x Line 2)	13,600,425	1,086,381	820,617	2,696,318	18,203,742
4	Resource type % of total		74.71%	5.97%	4.51%	14.81%	100.00%
5	Oregon Retail Load, Including Losses, by resource type	(Line 4 x Line 5 Total)	10,526,986	840,879	635,173	2,087,001	14,090,040
6	FERC Tariff Ancillary Service Charges						
	Regulation and Frequency Response Service						
7	Billing Determinant (Load Energy MWH)		NA	NA	NA	NA	14,090,040
8	Charge ($/MWH)		NA	NA	NA	NA	0.1600
9	Total Cost	(Line 8 x Line 9)	NA	NA	NA	NA	$2,254,406
	Operating Reservice - Spinning Reserve Service						
10	Billing Determinant (Generated Energy in MWH)		10,526,986	840,879	635,173	2,087,001	14,090,040
11	Charge ($/MWH)		0.3730	0.2660	NA	NA	
12	Total Cost	(Line 11 x Line 12)	$3,926,566	$223,674			$4,150,240
	Operating Reservice - Supplemental Reserve Service						
13	Billing Determinant (Generated Energy in MWH)		10,526,986	840,879	635,173	2,087,001	14,090,040
14	Charge ($/MWH)		0.3730	0.2660	NA	NA	
15	Total Cost	(Line 14 x Line 15)	$3,926,566	$223,674			$4,150,240
16	Oregon Annual Ancillary Service Revenue ($ x thousands)	Line 10 + Line 13 + Line 16)					$10,554,886

Note 1 - Source :Net Power Cost Analysis

Note 2 - CY 2011 JAM Model

Total Electric Plant in Service by Plant Type ($ x Millions)		Thermal	Hydro	Other	Total
Oregon		1,571.5	194.5	811.4	2,577.4
System		5,987.3	743.1	3,105.8	9,836.2
Percent of System		26.25%	26.18%	26.13%	26.20%

2009 JAM Model - Acount 555 Purchased Power SG	Dollars
Oregon - Unadjusted	146,657,653
System	605,015,393
Percent of System	24.24%

2011 JAM Model - Production Plant	TOTAL	OTHER	OREGON
Total Steam Production Plant	5,987,254,340	4,415,773,205	1,571,481,136
Total Hydraulic Plant	743,083,409	548,565,815	194,517,594
Total Other Production Plant	3,105,829,271	2,294,390,276	811,438,995
TOTAL PRODUCTION PLANT	9,836,167,020	7,258,729,295	2,577,437,725

Exhibit PPL/1604
C. Craig Paice

Docket No. UE-
Exhibit PPL/1604
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Oregon Marginal Cost of Service Summary

March 2010

STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2011 Forecast
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Sch 51,53,54
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	Sch 41	Streetlighting
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation	$171,523	$78,835	$8,783	$6,023	$11	$6,052	$10,111	$12,773	$186	$2,721	$14,284	$1,417	$7,062	$4,850	$615	$12,479	$3,681	$1,640	
2	Transmission	$163,988	$75,371	$8,397	$5,759	$10	$5,787	$9,667	$12,212	$178	$2,601	$13,656	$1,355	$6,752	$4,637	$588	$11,931	$3,519	$1,568	
3	Distribution																			
4	Poles	$50,324	$29,962	$3,107	$2,171	$4	$1,364	$2,327	$3,009	$59	$675	$3,604	$356	$1,386	$929	$11	$175	$0	$1,185	
5	Conductor	$76,234	$44,459	$4,549	$3,180	$5	$2,189	$3,735	$4,829	$96	$1,074	$5,735	$566	$2,333	$1,564	$21	$331	$0	$1,567	
6	Substations	$59,028	$29,526	$2,790	$1,950	$4	$1,950	$3,329	$4,304	$85	$910	$4,860	$480	$2,412	$1,617	$186	$4,106	$0	$518	
7	Subtotal: Pole, Cond, Subs	$185,586	$103,947	$10,446	$7,300	$13	$5,502	$9,391	$12,142	$241	$2,659	$14,200	$1,403	$6,130	$4,111	$218	$4,612	$0	$3,271	
8	Transformers	$13,120	$9,072	$483	$346	$0	$454	$591	$668	$0	$128	$719	$0	$384	$0	$41	$0	$0	$235	
9	Distribution subtotal	$198,706	$113,019	$10,928	$7,647	$13	$5,956	$9,982	$12,810	$241	$2,787	$14,919	$1,403	$6,514	$4,111	$259	$4,612	$0	$3,506	
10																				
11	Total Demand Related	$534,217	$267,225	$28,108	$19,429	$34	$17,795	$29,760	$37,795	$605	$8,109	$42,859	$4,175	$20,328	$13,598	$1,462	$29,022	$7,200	$6,714	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$767,582	$334,720	$36,450	$27,445	$50	$27,077	$41,610	$57,088	$1,083	$13,132	$67,841	$6,250	$33,237	$23,241	$3,296	$62,534	$21,911	$9,406	$1,213
16	Transmission Energy Related	$34,540	$15,062	$1,640	$1,235	$2	$1,218	$1,872	$2,569	$49	$591	$3,053	$281	$1,496	$1,046	$148	$2,814	$986	$423	$55
17	Total Energy	$802,122	$349,782	$38,090	$28,680	$52	$28,296	$43,482	$59,656	$1,132	$13,723	$70,893	$6,531	$34,732	$24,287	$3,444	$65,348	$22,897	$9,829	$1,267
18																				
19	Customer Related Marginal Cost																			
20	Poles	$67,798	$53,204	$8,437	$1,219	$5	$246	$194	$110	$3	$15	$37	$4	$4	$1	$0	$0	$0	$2,018	$2,300
21	Conductor	$23,668	$19,196	$3,044	$440	$1	$88	$70	$40	$1	$5	$14	$1	$1	$0	$0	$0	$0	$729	$37
22	Transformers	$110,100	$62,950	$20,779	$5,867	$0	$4,875	$4,413	$2,756	$0	$307	$746	$0	$162	$0	$3	$0	$0	$7,092	$150
23	Service Drops	$46,814	$34,493	$6,270	$2,281	$0	$1,138	$929	$1,130	$0	$133	$323	$0	$115	$0	$1	$0	$0	$0	$0
24	Meters	$11,688	$8,303	$1,291	$379	$50	$180	$179	$466	$72	$54	$132	$73	$42	$77	$1	$45	$96	$245	$2
25	Meter Reading	$8,823	$7,113	$1,181	$171	$1	$82	$64	$37	$1	$19	$47	$4	$14	$7	$0	$4	$0	$76	$2
26	Billing & Collections	$18,963	$16,095	$2,026	$293	$1	$156	$123	$70	$2	$8	$20	$2	$29	$14	$0	$8	$0	$92	$24
27	Uncollectables	$5,177	$4,588	$133	$19	$0	$89	$70	$40	$1	$31	$75	$7	$61	$29	$1	$17	$1	$14	$0
28	Customer Service / Other	$6,948	$5,861	$746	$108	$0	$62	$49	$28	$1	$7	$18	$2	$11	$5	$0	$3	$0	$36	$9
29	Total Commitment & Billing Rel.	$299,977	$211,803	$43,906	$10,776	$59	$6,916	$6,092	$4,676	$80	$580	$1,412	$93	$442	$134	$7	$77	$98	$10,303	$2,523
30																				
31	Total Revenue @ Full MC																			
32	Generation	$939,105	$413,555	$45,233	$33,468	$61	$33,129	$51,721	$69,861	$1,269	$15,853	$82,125	$7,667	$40,299	$28,091	$3,911	$75,013	$25,592	$11,046	$1,213
33	Transmission	$198,528	$90,433	$10,037	$6,994	$12	$7,005	$11,539	$14,781	$227	$3,192	$16,709	$1,636	$8,248	$5,683	$736	$14,745	$4,505	$1,991	$55
34	Distribution	$447,085	$282,862	$49,457	$17,454	$20	$12,303	$15,588	$16,846	$245	$3,247	$16,039	$1,408	$6,797	$4,112	$263	$4,612	$0	$13,344	$2,487
35	Customer - Billing	$18,963	$16,095	$2,026	$293	$1	$156	$123	$70	$2	$8	$20	$2	$29	$14	$0	$8	$0	$92	$24
36	Customer - Metering	$20,510	$15,415	$2,472	$549	$51	$262	$244	$502	$73	$74	$179	$77	$57	$84	$1	$49	$96	$322	$4
37	Customer - Other	$6,948	$5,861	$746	$108	$0	$62	$49	$28	$1	$7	$18	$2	$11	$5	$0	$3	$0	$36	$9
38	Revenue (less Uncollectables)	$1,631,139	$824,221	$109,970	$58,866	$146	$52,917	$79,264	$102,088	$1,816	$22,381	$115,089	$10,792	$55,441	$37,990	$4,912	$94,430	$30,194	$26,831	$3,791
39																				
40	Customer - Uncollectables	$5,177	$4,588	$133	$19	$0	$89	$70	$40	$1	$31	$75	$7	$61	$29	$1	$17	$1	$14	$0
41	Total Revenue	$1,636,316	$828,809	$110,104	$58,885	$146	$53,006	$79,334	$102,128	$1,817	$22,412	$115,164	$10,799	$55,502	$38,019	$4,913	$94,447	$30,195	$26,845	$3,791

Docket No. UE-
Exhibit PPL/1605
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Unbundled Revenue Requirement Allocation by Rate Schedule

March 2010

STATE OF OREGON
Combined GRC and TAM
December 31, 2011 Unbundled Revenue Requirement Allocation by Rate Schedule

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	**General Service**		**General Service**		**General Service**		**Large Power Service**			**Irrigation**	**Street Lgt.**
		Total		**Sch 23**		**Sch 28**		**Sch 30**		**Sch 48T**			**Sch 41**	**Sch 51, 53, 54**
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	**Total Operating Revenues**	$933,218	$472,654	$94,107	$75	$132,673	$1,162	$79,502	$6,057	$34,907	$76,355	$17,321	$16,054.331	$2,350
2	**MWH**	12,236,472	5,306,840	1,013,023	815	1,994,100	17,727	1,283,793	102,283	579,212	1,403,764	366,079	149,120	$19,715
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation	$939,105	$413,555	$78,701	$61	$154,710	$1,269	$97,978	$7,667	$44,210	$103,104	$25,592	$11,046	$1,213
6	Transmission	$198,528	$90,433	$17,031	$12	$33,326	$227	$19,901	$1,636	$8,984	$20,428	$4,505	$1,991	$55
7	Distribution	$447,087	$282,862	$66,911	$20	$44,737	$245	$19,287	$1,408	$7,060	$8,725	$0	$13,344	$2,489
8	Customer - Billing	$18,963	$16,095	$2,318	$1	$348	$2	$28	$2	$30	$22	$0	$92	$24
9	Customer - Metering	$20,508	$15,415	$3,021	$51	$1,008	$73	$253	$77	$58	$133	$96	$322	$2
10	Customer - Other	$6,948	$5,861	$854	$0	$139	$1	$25	$2	$12	$9	$0	$36	$9
11	Total	$1,631,139	$824,221	$168,836	$146	$234,269	$1,816	$137,471	$10,792	$60,353	$132,420	$30,194	$26,831	$3,791
12														
13	**Functional Revenue Requirement Allocation Factors**													
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
15	Generation	100.00%	44.04%	8.38%	0.01%	16.47%	0.14%	10.43%	0.82%	4.71%	10.98%	2.73%	1.18%	0.13%
16	Transmission	100.00%	45.55%	8.58%	0.01%	16.79%	0.11%	10.02%	0.82%	4.53%	10.29%	2.27%	1.00%	0.03%
17	Distribution	100.00%	63.27%	14.97%	0.00%	10.01%	0.05%	4.31%	0.32%	1.58%	1.95%	0.00%	2.98%	0.56%
18	Ancillary Service	100.00%	44.04%	8.38%	0.01%	16.47%	0.14%	10.43%	0.82%	4.71%	10.98%	2.73%	1.18%	0.13%
19	Customer - Billing	100.00%	84.88%	12.23%	0.01%	1.84%	0.01%	0.15%	0.01%	0.16%	0.12%	0.00%	0.49%	0.13%
20	Customer - Metering	100.00%	75.17%	14.73%	0.25%	4.91%	0.35%	1.23%	0.38%	0.28%	0.65%	0.47%	1.57%	0.01%
21	Customer - Other	100.00%	84.37%	12.29%	0.01%	2.00%	0.01%	0.36%	0.02%	0.17%	0.12%	0.00%	0.51%	0.13%
22	Embedded DSM - (mWh)	100.00%	43.37%	8.28%	0.01%	16.30%	0.14%	10.49%	0.84%	4.73%	11.47%	2.99%	1.22%	0.16%
23	Regulatory & Franchise	100.00%	50.65%	10.08%	0.01%	14.22%	0.12%	8.52%	0.65%	3.74%	8.18%	1.86%	1.72%	0.25%
24	Taxes (Revenue)													
25														
26	**Functionalized Class Revenue Requirement - (Target)**													
27	Generation	$681,451	$300,091	$57,108	$44	$112,264	$921	$71,097	$5,563	$32,080	$74,817	$18,570	$8,015	$880
28	Transmission	$103,094	$46,961	$8,844	$6	$17,306	$118	$10,334	$850	$4,665	$10,608	$2,339	$1,034	$28
29	Distribution	$256,347	$162,185	$38,365	$12	$25,651	$140	$11,058	$808	$4,048	$5,002	$0	$7,651	$1,427
30	Ancillary Services	$10,230	$4,505	$857	$1	$1,685	$14	$1,067	$84	$482	$1,123	$279	$120	$13
31	Customer - Billing	$12,408	$10,531	$1,517	$1	$228	$1	$18	$1	$20	$14	$0	$60	$16
32	Customer - Metering	$25,750	$19,355	$3,793	$64	$1,266	$91	$317	$97	$72	$167	$121	$404	$2
33	Customer - Other	$13,642	$11,510	$1,677	$1	$273	$1	$50	$3	$23	$17	$0	$70	$17
34	Embedded DSM - (mWh)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
35	Regulatory & Franchise T	$25,513	$12,922	$2,573	$2	$3,627	$32	$2,173	$166	$954	$2,087	$474	$439	$64
36	Total	$1,128,434	$568,060	$114,735	$130	$162,300	$1,319	$96,115	$7,571	$42,344	$93,836	$21,783	$17,794	$2,448
37														
38	**Ratio of Operating Revn to Revenue Requirement-(Target)**	82.70%	83.21%	82.02%	57.52%	81.75%	88.13%	82.72%	80.00%	82.44%	81.37%	79.51%	90.22%	96.01%
39	(Line 1 / Line 36)													
40														
41	**Increase or (Decrease)**	$195,217	$95,406	$20,628	$55	$29,627	$156	$16,613	$1,514	$7,437	$17,480	$4,463	$1,740	$98
42	(Line 36 - Line 1)													
43														
44														
45	**Percent Increase (Decrease)**	20.92%	20.19%	21.92%	73.87%	22.33%	13.46%	20.90%	25.00%	21.31%	22.89%	25.77%	10.84%	4.15%
46	(Line 41 / Line 1)													

STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2011 Functionalized Revenue - Earned
($ 000)

		A	B	C	D	E	F	G	H	I	J
Line No.	**Description**	**Generation**	**Transmission**	**Distribution**	**Ancillary**	**C Billing**	**C Metering**	**C Other**	**DSM**	**Franchise Fees**	**Total**
1	Earned Functional Revenue Requirement	$604,773	$64,407	212,119	$10,555	$12,266	$24,569	$13,632	$0	21,892	$964,213
2											
3	Percent of Total	62.72%	6.68%	22.00%	1.09%	1.27%	2.55%	1.41%	0.00%	2.27%	100.00%
4											
5	Revenue From Classes Included in MC Study	$585,333	$62,337	$205,301	$10,216	$11,871	$23,779	$13,193	$0	$21,188	$933,218
6											
7	Other Revenues										
8	Partial Requirements - Sch. 47 pri										$13,251
9	Partial Requirements - Sch. 47 trn										$6,017
10	USBR Billed Revenue										$5,327
11	AGA										$2,800
12	Lighting										$3,996
13	Employee Discount										($397)
14	Total Oregon Situs Revenue										$964,212

STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2011 Functionalized Revenue - Target
($ 000)

		A	B	C	D	E	F	G	H	I	J	
Line No.	**Description**	**Generation**	**Transmission**	**Distribution**	**Ancillary**	**C Billing**	**C Metering**	**C Other**	**DSM**	**Franchise Fees**	**Total**	
1	Target Functional Revenue Requirement	703,114	106,371	264,496	10,555	12,802	26,569	14,076	(0)	26,324	$1,164,307	
2												
3	Percent of Total	60.39%	9.14%	22.72%	0.91%	1.10%	2.28%	1.21%	0.00%	2.26%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$681,451	$103,094	$256,347	$10,230	$12,408	$25,750	$13,642	$0	$25,513	$ 1,128,434	195,217
6												
7	Other Revenues											200,095
8	Partial Requirements - Sch. 47 pri										$16,289	$3,038
9	Partial Requirements - Sch. 47 trn										$7,585	$1,568
10	USBR Billed Revenue										$5,493	$166
11	AGA										$2,800	$0
12	Lighting										$4,183	$187
13	Employee Discount										($478)	($81)
14	Total Oregon Situs Revenue										$1,164,307	195,217

State of Oregon
December 31, 2011 Unbundled Revenue Requirement Allocation by Load Size
FERC Transmission Revenue

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Total	**Residential**	**General Service Schedule 23**		**General Service Schedule 28**		**General Service Schedule 30**		**Large Power Service Sche**	
Description		(sec)	Secondary (sec)	Primary (pri)	Secondary (sec)	Primary (pri)	Secondary (sec)	Primary (pri)	Secondary (sec)	Primary (pri)
Total Transmission Revenue Requirement	$103,094	$46,961	$8,844	$6	$17,306	$118	$10,334	$850	$4,665	$10,608
FERC Transmission										
Peak Mw @ Generator	2,147	987	185	0	362	2	213	18	96	217
% of Total	100.00%	45.96%	8.63%	0.01%	16.87%	0.11%	9.91%	0.83%	4.48%	10.10%
FERC Transmission Revenues	$38,016	$17,473	$3,282	$2	$6,413	$41	$3,769	$314	$1,702	$3,841
Other Transmission Revenue Requirement	$65,077	$29,488	$5,563	$4	$10,892	$76	$6,565	$536	$2,964	$6,767

	Transmission System	**Oregon**	**Oregon Load Ratio Share**
Average Monthly Load*	15,469,409 kW	2,426,525 kW	15.686%
Transmission Cost of Service	$242,358,039	$38,016,180	

* See Attachment R to PacifiCorp's Open Access Transmission Tariff.

Docket No. UE-
Exhibit PPL/1606
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

Functionalized Results of Operations

March 2010

Exhibit PPL/1606

Tab 1

	REVISED PROTOCOL Description of Account Summary:	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
1	General Business Revenues	964,212,551	604,773,430	64,407,228	234,010,949	10,554,886	12,265,604	24,568,842	13,631,613
2	General Business Revenues	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-
4	Special Sales	169,740,650	131,766,643	37,974,007	-	-	-	-	-
5	Other Operating Revenues	41,490,058	21,691,807	20,414,817	5,338,616	(10,554,886)	3,736,864	352,749	510,090
6	Total Operating Revenues	1,175,443,259	758,231,880	122,796,052	239,349,565	0	16,002,468	24,921,591	14,141,703
7									
8	Operating Expenses:								
9	Steam Production	250,272,685	250,272,685	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	10,155,935	10,155,935	-	-	-	-	-	-
12	Other Power Supply	303,733,377	303,733,377	-	-	-	-	-	-
13	ECD	(15,579,133)	(15,579,133)	-	-	-	-	-	-
14	Transmission	51,659,937	271,182	51,388,755	-	-	-	-	-
15	Distribution	76,534,494	-	-	71,542,970	-	-	4,991,524	-
16	Customer Accounts	36,066,052	3,844,435	622,608	1,213,565	0	11,942,799	10,476,467	7,966,177
17	Customer Service	3,660,775	-	-	1,214,143	-	-	-	2,446,633
18	Sales	-	-	-	-	-	-	-	-
19	Administrative & General	49,627,697	15,939,922	4,625,373	21,678,386	-	2,153,053	3,470,573	1,760,391
20									
21	Total O & M Expenses	766,131,819	568,638,403	56,636,736	95,649,064	0	14,095,852	18,938,563	12,173,200
22									
23	Depreciation	160,373,963	81,576,251	24,788,227	50,211,134	-	679,841	2,733,379	385,130
24	Amortization Expense	14,389,137	8,827,823	773,845	1,862,440	-	1,275,570	880,532	768,927
25	Taxes Other Than Income	54,122,839	15,825,900	6,000,545	31,434,779	0	218,166	496,245	147,204
26	Income Taxes - Federal	(13,082,112)	(26,769,683)	(4,512,647)	17,617,671	0	(341,517)	733,495	190,569
27	Income Taxes - State	1,014,732	(3,935,587)	(1,632,068)	6,371,700	0	(123,515)	265,280	68,922
28	Income Taxes - Def Net	36,337,195	36,385,411	7,059,593	(6,190,492)	(0)	(233,745)	(733,913)	50,342
29	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
30	Misc Revenue & Expense	(1,167,283)	(1,388,114)	(59,250)	279,502	-	353	116	111
31									
32	Total Operating Expenses	1,018,120,290	679,160,405	89,054,981	197,235,799	0	15,571,004	23,313,697	13,784,404
33									
34	Operating Revenue for Return	157,322,969	79,071,475	33,741,071	42,113,766	0	431,464	1,607,894	357,299
35									
36	Rate Base:								
37	Electric Plant in Service	6,041,538,075	2,864,498,208	1,175,284,673	1,849,611,917	-	37,609,353	90,641,873	23,892,052
38	Plant Held for Future Use	-	1,752,891	(532,085)	(1,114,108)	-	(65,098)	(41,600)	-
39	Misc Deferred Debits	17,414,913	10,373,751	6,218,497	597,153	-	(159,558)	244,544	140,526
40	Elec Plant Acq Adj	13,781,681	13,781,681	-	-	-	-	-	-
41	Nuclear Fuel	-	-	-	-	-	-	-	-
42	Prepayments	12,457,960	5,537,752	1,026,052	3,242,813	-	758,072	1,209,649	683,621
43	Fuel Stock	49,465,020	49,465,020	-	-	-	-	-	-
44	Material & Supplies	51,428,949	41,392,544	289,196	9,396,356	-	-	350,853	-
45	Working Capital	18,193,172	9,193,593	1,339,656	4,827,156	0	816,346	1,279,043	737,378
46	Weatherization Loans	(680)	-	-	(680)	-	-	-	-
47	Miscellaneous Rate Base	18,865	18,865	-	-	-	-	-	-
48									
49	Total Electric Plant	6,204,297,955	2,996,014,306	1,183,625,989	1,866,560,605	0	38,959,115	93,684,362	25,453,578
50									
51	Rate Base Deductions:								
52	Accum Prov For Depr	(2,066,156,392)	(926,977,963)	(319,553,652)	(779,387,734)	-	(3,080,667)	(35,374,550)	(1,781,826)
53	Accum Prov For Amort	(132,957,529)	(43,284,425)	(5,337,475)	(33,067,528)	-	(22,470,053)	(15,283,970)	(13,514,079)
54	Accum Def Income Taxes	(666,349,065)	(346,851,436)	(144,892,355)	(161,503,135)	0	(3,478,293)	(7,751,051)	(1,872,794)
55	Unamortized ITC	(3,084,689)	(1,282,156)	(173,413)	(894,664)	-	(210,008)	(335,042)	(189,405)
56	Customer Adv for Const	(2,857,384)	-	(1,978,657)	(847,740)	-	0	(30,987)	0
57	Customer Service Deposits	-	-	-	-	-	-	-	-
58	Misc. Rate Base Deductions	(16,936,092)	(10,998,404)	(516,883)	(3,211,732)	-	(625,960)	(1,018,563)	(564,549)
59									
60	Total Rate Base Deductions	(2,888,341,151)	(1,329,394,384)	(472,452,434)	(978,912,533)	0	(29,864,982)	(59,794,164)	(17,922,654)
61									
62	Total Rate Base	3,315,956,804	1,666,619,922	711,173,555	887,648,073	1	9,094,133	33,890,198	7,530,924
63									
64	Return on Rate Base	4.744%	4.744%	4.744%	4.744%	4.744%	4.744%	4.744%	4.744%
65									
66	Return on Equity	3.778%	3.778%	3.778%	3.778%	3.778%	3.778%	3.778%	3.778%
67									
68	100 Basis Points in Equity:	17,674,050	8,883,084	3,790,555	4,731,164	0	48,472	180,635	40,140
69	Revenue Requirement Impact	28,484,020	14,316,241	6,108,970	7,624,884	0	78,118	291,116	64,691
70	Rate Base Decrease	(334,899,337)	(168,322,430)	(71,825,891)	(89,649,163)	(0)	(918,474)	(3,422,784)	(760,595)

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Sales to Ultimate Customers											
440	Residential Sales				0	0	0	(0)	0	0	0
			S	472,639,269	604,773,430	64,407,228	234,010,949	10,554,886	12,265,604	24,568,842	13,631,613
				472,639,269							
442	Commercial & Industrial Sales										
			S	486,630,368							
		P	SE	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-
				486,630,368	-	-	-	-	-	-	-
444	Public Street & Highway Lighting										
			S	4,942,914							
			SO	-							
				4,942,914	-	-	-	-	-	-	-
445	Other Sales to Public Authority										
			S	-							
				-	-	-	-	-	-	-	-
448	Interdepartmental										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers				**964,212,551**	**604,773,430**	**64,407,228**	**234,010,949**	**10,554,886**	**12,265,604**	**24,568,842**	**13,631,613**
447	Sales for Resale-Non NPC										
		WSF	S	987,857	766,856	221,001	-	-	-	-	-
				987,857	766,856	221,001	-	-	-	-	-
447NPC	Sales for Resale-NPC										
		WSF	SG	168,752,793	130,999,787	37,753,006	-	-	-	-	-
		WSF	SE	-	-	-	-	-	-	-	-
		WSF	SG	-	-	-	-	-	-	-	-
				168,752,793	130,999,787	37,753,006	-	-	-	-	-
	Total Sales for Resale			169,740,650	131,766,643	37,974,007	-	-	-	-	-
449	Provision for Rate Refund										
		WSF	S	-	-	-	-	-	-	-	-
		WSF	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Sales from Electricity				**1,133,953,201**	**736,540,073**	**102,381,235**	**234,010,949**	**10,554,886**	**12,265,604**	**24,568,842**	**13,631,613**
450	Forfeited Discounts & Interest										
		C_BILLING	S	2,699,667	-	-	-	-	2,699,667	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-
				2,699,667	-	-	-	-	2,699,667	-	-
451	Misc Electric Revenue										
		CSS_SYS	S	1,874,218	-	-	-	-	1,030,820	337,359	506,039
		GP	SG	-	-	-	-	-	-	-	-
		DSM	SO	6,060	-	-	6,060	-	-	-	-
				1,880,278	-	-	6,060	-	1,030,820	337,359	506,039
453	Water Sales										
		P	SG	3,410	3,410	-	-	-	-	-	-
				3,410	3,410	-	-	-	-	-	-
454	Rent of Electric Property										
		D	S	4,930,923	-	-	4,930,923	-	-	-	-
		T	SG	1,402,709	-	1,402,709	-	-	-	-	-
		GP	SO	1,024,464	485,733	199,293	313,639	-	6,377	15,370	4,051
				7,358,097	485,733	1,602,002	5,244,562	-	6,377	15,370	4,051
	Oregon Ancillary Services				10,554,886			(10,554,886)			
456	Other Electric Revenue										
		OTHSGR	S	(21,776,681)	(9,038,108)	(12,738,573)	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-
		OTHSE	SE	3,806,460	-	3,806,460	-	-	-	-	-
		OTHSO	SO	89,245	899	333	87,994	-	-	20	-
		OTHSGR	SG	47,429,583	19,684,987	27,744,596	-	-	-	-	-
				29,548,607	10,647,778	18,812,815	87,994	-	-	20	-
	Total Other Electric Revenues			**41,490,058**	**21,691,807**	**20,414,817**	**5,338,616**	**(10,554,886)**	**3,736,864**	**352,749**	**510,090**
Total Electric Operating Revenues				**1,175,443,259**	**758,231,880**	**122,796,052**	**239,349,565**	**0**	**16,002,468**	**24,921,591**	**14,141,703**

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Miscellaneous Revenues											
41160	Gain on Sale of Utility Plant - CR										
		D	S	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		G	SO	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
41170	Loss on Sale of Utility Plant										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances										
		P	S	-	-	-	-	-	-	-	-
		P	SE	(1,241,567)	(1,241,567)	-	-	-	-	-	-
				(1,241,567)	(1,241,567)	-	-	-	-	-	-
41181	Gain from Disposition of NOX Credits										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
4194	Impact Housing Interest Income										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant										
		D	S	276,338	-	-	276,338	-	-	-	-
		T	SG	(38,102)	-	(38,102)	-	-	-	-	-
		T	SG	(23,342)	-	(23,342)	-	-	-	-	-
		B_Center	CN	463	-	-	-	-	353	-	111
		PTD	SO	10,415	4,941	2,195	3,163.62	-	-	115.64	-
		P	SG	(151,488)	(151,488)	-	-	-	-	-	-
				74,284	(146,547)	(59,250)	279,502	-	353	116	111
Total Miscellaneous Revenues				**(1,167,283)**	**(1,388,114)**	**(59,250)**	**279,502**	**-**	**353**	**116**	**111**
Miscellaneous Expenses											
4311	Interest on Customer Deposits										
		C_BILLING	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				-	-	-	-	-	-	-	-
Net Misc Revenue and Expense				**(1,167,283)**	**(1,388,114)**	**(59,250)**	**279,502**	**-**	**353**	**116**	**111**
500	Operation Supervision & Engineering										
		P	SG	5,627,316	5,627,316	-	-	-	-	-	-
		P	SSGCH	371,491	371,491	-	-	-	-	-	-
				5,998,807	5,998,807	-	-	-	-	-	-
501	Fuel Related-Non NPC										
		P	SE	3,181,983	3,181,983	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSECT	-	-	-	-	-	-	-	-
		P	SSECH	746,390	746,390	-	-	-	-	-	-
				3,928,373	3,928,373	-	-	-	-	-	-
501NPC	Fuel Related-NPC										
		P	SE	156,459,052	156,459,052	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSECT	-	-	-	-	-	-	-	-
		P	SSECH	14,062,190	14,062,190	-	-	-	-	-	-
				170,521,242	170,521,242	-	-	-	-	-	-
	Total Fuel Related			174,449,615	174,449,615	-	-	-	-	-	-
502	Steam Expenses										
		P	SG	8,855,692	8,855,692	-	-	-	-	-	-
		P	SSGCH	1,634,726	1,634,726	-	-	-	-	-	-
				10,490,418	10,490,418	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC										
		P	SE	313	313	-	-	-	-	-	-
				313	313	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC										
		P	SE	863,442	863,442	-	-	-	-	-	-
				863,442	863,442	-	-	-	-	-	-
505	Electric Expenses										
		P	SG	762,152	762,152	-	-	-	-	-	-
		P	SSGCH	411,284	411,284	-	-	-	-	-	-
				1,173,437	1,173,437	-	-	-	-	-	-
506	Misc. Steam Expense										
		P	SG	11,474,432	11,474,432	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSGCH	676,712	676,712	-	-	-	-	-	-
				12,151,145	12,151,145	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
507	Rents										
		P	SG	85,158	85,158	-	-	-	-	-	-
		P	SSGCH	725	725	-	-	-	-	-	-
				85,883	85,883	-	-	-	-	-	-
510	Maint Supervision & Engineering										
		P	SG	1,352,915	1,352,915	-	-	-	-	-	-
		P	SSGCH	512,811	512,811	-	-	-	-	-	-
				1,865,726	1,865,726	-	-	-	-	-	-
511	Maintenance of Structures										
		P	SG	5,860,112	5,860,112	-	-	-	-	-	-
		P	SSGCH	221,778	221,778	-	-	-	-	-	-
				6,081,890	6,081,890	-	-	-	-	-	-
512	Maintenance of Boiler Plant										
		P	SG	24,348,562	24,348,562	-	-	-	-	-	-
		P	SSGCH	925,652	925,652	-	-	-	-	-	-
				25,274,214	25,274,214	-	-	-	-	-	-
513	Maintenance of Electric Plant										
		P	SG	9,171,277	9,171,277	-	-	-	-	-	-
		P	SSGCH	(527,991)	(527,991)	-	-	-	-	-	-
				8,643,286	9,171,277	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant										
		P	SG	2,632,541	2,632,541	-	-	-	-	-	-
		P	SSGCH	561,966	561,966	-	-	-	-	-	-
				3,194,507	3,194,507	-	-	-	-	-	-
Total Steam Power Generation				**250,272,685**	**250,272,685**	-	-	-	-	-	-
517	Operation Super & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
518	Nuclear Fuel Expense										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
519	Coolants and Water										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
520	Steam Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
523	Electric Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
529	Maintenance of Structures										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
530	Maintenance of Reactor Plant										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
531	Maintenance of Electric Plant										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
532	Maintenance of Misc Nuclear										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Nuclear Power Generation				-	-	-	-	-			

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
535	Operation Super & Engineering										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	2,126,485	2,126,485	-	-	-	-	-	-
		P	SG	318,770	318,770	-	-	-	-	-	-
				2,445,255	2,445,255	-	-	-	-	-	-
536	Water For Power										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	80,508	80,508	-	-	-	-	-	-
		P	SG	2,457	2,457	-	-	-	-	-	-
				82,966	82,966	-	-	-	-	-	-
537	Hydraulic Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	1,028,095	1,028,095	-	-	-	-	-	-
		P	SG	96,171	96,171	-	-	-	-	-	-
				1,124,266	1,124,266	-	-	-	-	-	-
538	Electric Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	3,298,701	3,298,701	-	-	-	-	-	-
		P	SG	1,575,060	1,575,060	-	-	-	-	-	-
				4,873,761	4,873,761	-	-	-	-	-	-
540	Rents (Hydro Generation)										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	11,342	11,342	-	-	-	-	-	-
		P	SG	636	636	-	-	-	-	-	-
				11,978	11,978	-	-	-	-	-	-
541	Maint Supervision & Engineering										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	1,061	1,061	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				1,061	1,061	-	-	-	-	-	-
542	Maintenance of Structures										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	329,182	329,182	-	-	-	-	-	-
		P	SG	32,034	32,034	-	-	-	-	-	-
				361,217	361,217	-	-	-	-	-	-
543	Maintenance of Dams & Waterways										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	236,262	236,262	-	-	-	-	-	-
		P	SG	106,581	106,581	-	-	-	-	-	-
				342,843	342,843	-	-	-	-	-	-
544	Maintenance of Electric Plant										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	258,292	258,292	-	-	-	-	-	-
		P	SG	33,687	33,687	-	-	-	-	-	-
				291,980	291,980	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant										
		P	DGP	-	-	-	-	-	-	-	-
		P	SG	437,818	437,818	-	-	-	-	-	-
		P	SG	182,791	182,791	-	-	-	-	-	-
				620,609	620,609	-	-	-	-	-	-
				-							
Total Hydraulic Power Generation				**10,155,935**	**10,155,935**	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

Exhibit PPL/1606
Paice/6 - Tab 1

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
421												
422	546	Operation Super & Engineering										
423			P	SG	70,114	70,114	-	-	-	-	-	-
424			P	SSGCT	-	-	-	-	-	-	-	-
425					70,114	70,114	-	-	-	-	-	-
426												
427	547	Fuel-Non-NPC										
428			P	SE	-	-	-	-	-	-	-	-
429			P	SSECT	-	-	-	-	-	-	-	-
430					-	-	-	-	-	-	-	-
431												
432	547NPC	Fuel-NPC										
433			P	SE	94,890,350	94,890,350	-	-	-	-	-	-
434			P	SSECT	2,229,400	2,229,400	-	-	-	-	-	-
435					97,119,750	97,119,750	-	-	-	-	-	-
436												
437	548	Generation Expense										
438			P	SG	4,212,540	4,212,540	-	-	-	-	-	-
439			P	SSGCT	478,846	478,846	-	-	-	-	-	-
440					4,691,386	4,691,386	-	-	-	-	-	-
441												
442	549	Miscellaneous Other										
443			P	SG	7,454,106	7,454,106	-	-	-	-	-	-
444			P	SSGCT	-	-	-	-	-	-	-	-
445					7,454,106	7,454,106	-	-	-	-	-	-
446												
447												
448												
449												
450	550	Maint Supervision & Engineering										
451			P	SG	601,173	601,173	-	-	-	-	-	-
452			P	SSGCT	(51,596)	(51,596)	-	-	-	-	-	-
453					549,576	549,576	-	-	-	-	-	-
454												
455	551	Maint Supervision & Engineering										
456			P	SG	-	-	-	-	-	-	-	-
457					-	-	-	-	-	-	-	-
458												
459	552	Maintenance of Structures										
460			P	SG	270,427	270,427	-	-	-	-	-	-
461			P	SSGCT	49,694	49,694	-	-	-	-	-	-
462					320,121	320,121	-	-	-	-	-	-
463												
464	553	Maint of Generation & Electric Plant										
465			P	SG	1,769,619	1,769,619	-	-	-	-	-	-
466			P	SSGCT	439,600	439,600	-	-	-	-	-	-
467					2,209,219	2,209,219	-	-	-	-	-	-
468												
469	554	Maintenance of Misc. Other										
470			P	SG	67,624	67,624	-	-	-	-	-	-
471			P	SSGCT	44,813	44,813	-	-	-	-	-	-
472					112,437	112,437	-	-	-	-	-	-
473												
474	**Total Other Power Generation**				**112,526,709**	**112,526,709**	-	-	-	-	-	-
475												
476												
477	555	Purchased Power-Non NPC										
478			DSM	S	-	-	-	-	-	-	-	-
479					-	-	-	-	-	-	-	-
480												
481	555NPC	Purchased Power-NPC										
482			P	SG	163,572,751	163,572,751	-	-	-	-	-	-
483			P	SE	12,709,916	12,709,916	-	-	-	-	-	-
484			P	SSGC	-	-	-	-	-	-	-	-
485			P	DGP	-	-	-	-	-	-	-	-
486					176,282,667	176,282,667	-	-	-	-	-	-
487												
488		Total Purchased Power			176,282,667	176,282,667	-	-	-	-	-	-
489												
490	556	System Control & Load Dispatch										
491			P	SG	516,177	516,177	-	-	-	-	-	-
492												
493					516,177	516,177	-	-	-	-	-	-
494												
495												
496												
497	557	Other Expenses										
498			P	S	(57,429)	(57,429)	-	-	-	-	-	-
499			P	SG	14,150,439	14,150,439	-	-	-	-	-	-
500			P	SGCT	314,783	314,783	-	-	-	-	-	-
501			P	SE	-	-	-	-	-	-	-	-
502			P	SSGCT	31	31	-	-	-	-	-	-
503			P	TROJP	-	-	-	-	-	-	-	-
504												
505					14,407,824	14,407,824	-	-	-	-	-	-
506												
507	**Total Other Power Supply**				**191,206,668**	**191,206,668**	-	-	-	-	-	-
508												
509	**TOTAL PRODUCTION EXPENSE**				**564,161,997**	**564,161,997**	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
	Embedded Cost Differentials										
	Company Owned Hydro	P	DGP	(34,080,634)	(34,080,634)	-	-	-	-	-	-
	Company Owned Hydro	P	SG	16,634,525	16,634,525	-	-	-	-	-	-
	Mid-C Contract	P	MC	(24,557,342)	(24,557,342)	-	-	-	-	-	-
	Mid-C Contract	P	SG	10,986,897	10,986,897	-	-	-	-	-	-
	Existing QF Contracts	P	S	25,888,544	25,888,544	-	-	-	-	-	-
	Existing QF Contracts	P	SG	(10,451,122)	(10,451,122)	-	-	-	-	-	-
				(15,579,133)	(15,579,133)	-	-	-	-	-	-
560	Operation Supervision & Engineering										
		T	SG	2,269,902	-	2,269,902	-	-	-	-	-
				2,269,902	-	2,269,902	-	-	-	-	-
561	Load Dispatching										
		T	SG	2,348,714	-	2,348,714	-	-	-	-	-
				2,348,714	-	2,348,714	-	-	-	-	-
562	Station Expense										
		T	SG	468,311	-	468,311	-	-	-	-	-
				468,311	-	468,311	-	-	-	-	-
563	Overhead Line Expense										
		T	SG	65,787	-	65,787	-	-	-	-	-
				65,787	-	65,787	-	-	-	-	-
564	Underground Line Expense										
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
565	Transmission of Electricity by Others-Non NPC										
		T	SG	-	-	-	-	-	-	-	-
		T	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
565NPC	Transmission of Electricity by Others-NPC										
		T	SG	36,720,003	-	36,720,003	-	-	-	-	-
		T	SE	24,586	-	24,586	-	-	-	-	-
				36,744,589	-	36,744,589	-	-	-	-	-
	Total Transmission of Electricity by Others			36,744,589	-	36,744,589	-	-	-	-	-
566	Misc. Transmission Expense										
		T	SG	454,182	-	454,182	-	-	-	-	-
				454,182	-	454,182	-	-	-	-	-
567	Rents - Transmission										
		T	SG	219,674	-	219,674	-	-	-	-	-
				219,674	-	219,674	-	-	-	-	-
568	Maint Supervision & Engineering										
		T	SG	5,737	-	5,737	-	-	-	-	-
				5,737	-	5,737	-	-	-	-	-
569	Maintenance of Structures										
		T	SG	1,140,673	-	1,140,673	-	-	-	-	-
				1,140,673	-	1,140,673	-	-	-	-	-
570	Maintenance of Station Equipment										
		STEP_UP	SG	3,151,046	271,182	2,879,864	-	-	-	-	-
				3,151,046	271,182	2,879,864	-	-	-	-	-
571	Maintenance of Overhead Lines										
		T	SG	4,752,733	-	4,752,733	-	-	-	-	-
				4,752,733	-	4,752,733	-	-	-	-	-
572	Maintenance of Underground Lines										
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant										
		T	SG	38,589	-	38,589	-	-	-	-	-
				38,589	-	38,589	-	-	-	-	-
	TOTAL TRANSMISSION EXPENSE			**51,659,937**	**271,182**	**51,388,755**	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
599												
600	580	Operation Supervision & Engineering										
601			D_SPLIT	S	6	-	-	5.95	-	-	0.22	-
602			D_SPLIT	SNPD	6,053,584	-	-	5,840,112.18	-	-	213,471.47	-
603					6,053,590	-	-	5,840,118	-	-	213,472	-
604												
605	581	Load Dispatching										
606			D	S	-	-	-	-	-	-	-	-
607			D	SNPD	3,923,757	-	-	3,923,757	-	-	-	-
608					3,923,757	-	-	3,923,757	-	-	-	-
609												
610	582	Station Expense										
611			D	S	1,269,183	-	-	1,269,183	-	-	-	-
612			D	SNPD	8,999	-	-	8,999	-	-	-	-
613					1,278,182	-	-	1,278,182	-	-	-	-
614												
615	583	Overhead Line Expenses										
616			D	S	2,829,951	-	-	2,829,951	-	-	-	-
617			D	SNPD	5,894	-	-	5,894	-	-	-	-
618					2,835,845	-	-	2,835,845	-	-	-	-
619												
620	584	Underground Line Expense										
621			D	S	-	-	-	-	-	-	-	-
622			D	SNPD	-	-	-	-	-	-	-	-
623					-	-	-	-	-	-	-	-
624												
625	585	Street Lighting & Signal Systems										
626			D	S	-	-	-	-	-	-	-	-
627			D	SNPD	67,245	-	-	67,245	-	-	-	-
628					67,245	-	-	67,245	-	-	-	-
629												
630	586	Meter Expenses										
631			C_Meter	S	2,897,898	-	-	-	-	-	2,897,897.67	-
632			C_Meter	SNPD	351,805	-	-	-	-	-	351,804.63	-
633					3,249,702	-	-	-	-	-	3,249,702	-
634												
635	587	Customer Installation Expenses										
636			D	S	3,793,284	-	-	3,793,284	-	-	-	-
637			D	SNPD	142	-	-	142	-	-	-	-
638					3,793,426	-	-	3,793,426	-	-	-	-
639												
640	588	Misc. Distribution Expenses										
641			D	S	600,570	-	-	600,570	-	-	-	-
642			D	SNPD	1,656,596	-	-	1,656,596	-	-	-	-
643					2,257,166	-	-	2,257,166	-	-	-	-
644												
645	908	Rents										
646			D	S	1,898,246	-	-	1,898,246	-	-	-	-
647			D	SNPD	69,264	-	-	69,264	-	-	-	-
648					1,967,510	-	-	1,967,510	-	-	-	-
649												
650	590	Maint Supervision & Engineering										
651			D_SPLIT	S	375,434	-	-	362,194.78	-	-	13,239.17	-
652			D_SPLIT	SNPD	2,092,925	-	-	2,019,120.44	-	-	73,804.16	-
653					2,468,359	-	-	2,381,315	-	-	87,043	-
654												
655	591	Maintenance of Structures										
656			D	S	582,960	-	-	582,960	-	-	-	-
657			D	SNPD	53,023	-	-	53,023	-	-	-	-
658					635,982	-	-	635,982	-	-	-	-
659												
660	592	Maintenance of Station Equipment										
661			D	S	3,636,776	-	-	3,636,776	-	-	-	-
662			D	SNPD	591,041	-	-	591,041	-	-	-	-
663					4,227,817	-	-	4,227,817	-	-	-	-
664	593	Maintenance of Overhead Lines										
665			D	S	32,711,792	-	-	32,711,792	-	-	-	-
666			D	SNPD	413,791	-	-	413,791	-	-	-	-
667					33,125,583	-	-	33,125,583	-	-	-	-
668												
669	594	Maintenance of Underground Lines										
670			D	S	6,367,146	-	-	6,367,146	-	-	-	-
671			D	SNPD	4,976	-	-	4,976	-	-	-	-
672					6,372,122	-	-	6,372,122	-	-	-	-
673												
674	595	Maintenance of Line Transformers										
675			D	S	-	-	-	-	-	-	-	-
676			D	SNPD	324,339	-	-	324,339	-	-	-	-
677					324,339	-	-	324,339	-	-	-	-
678												
679	596	Maint of Street Lighting & Signal Sys.										
680			D	S	1,020,480	-	-	1,020,480	-	-	-	-
681			D	SNPD	-	-	-	-	-	-	-	-
682					1,020,480	-	-	1,020,480	-	-	-	-
683												
684	597	Maintenance of Meters										
685			C_Meter	S	1,228,510	-	-	-	-	-	1,228,510.15	-
686			C_Meter	SNPD	212,796	-	-	-	-	-	212,796.15	-
687					1,441,306	-	-	-	-	-	1,441,306	-
688												
689	599	Maint of Misc. Distribution Plant										
690			D	S	1,338,189	-	-	1,338,189	-	-	-	-
691			D	SNPD	153,895	-	-	153,895	-	-	-	-
692					1,492,084	-	-	1,492,084	-	-	-	-
693												
694		**TOTAL DISTRIBUTION EXPENSE**			**76,534,494**	**-**	**-**	**71,542,970**	**-**	**-**	**4,991,524**	**-**

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
901	Supervision										
		CUST901	S	48,787	-	-	-	-	22,383	11,521	14,883
		CUST901	CN	821,350	-	-	-	-	376,826	193,963	250,561
				870,137	-	-	-	-	399,209	205,484	265,444
902	Meter Reading Expense										
		C_Meter	S	9,460,005	-	-	-	-	-	9,460,005.46	-
		C_Meter	CN	681,044	-	-	-	-	-	681,044.11	-
				10,141,050	-	-	-	-	-	10,141,050	-
903	Customer Receipts & Collections										
		CUST903	S	2,131,714	-	-	-	-	1,285,899	-	845,815
		CUST903	CN	16,870,301	-	-	-	-	10,176,554	-	6,693,747
				19,002,015	-	-	-	-	11,462,453	-	7,539,562
904	Uncollectible Accounts										
		REVREQ	S	5,960,327	3,844,771	622,663	1,213,671	0	81,144	126,370.06	71,708
		P	SG	-	-	-	-	-	-	-	-
		REVREQ	CN	(520)	(336)	(54)	(106)	(0)	(7)	(11.03)	(6)
				5,959,807	3,844,435	622,608	1,213,565	0	81,137	126,359	71,702
905	Misc. Customer Accounts Expense										
		CUST905	S	10,465	-	-	-	-	-	402	10,063
		CUST905	CN	82,579	-	-	-	-	-	3,172	79,407
				93,043	-	-	-	-	-	3,574	89,469
TOTAL CUSTOMER ACCOUNTS EXPENSE				**36,066,052**	**3,844,435**	**622,608**	**1,213,565**	**0**	**11,942,799**	**10,476,467**	**7,966,177**
907	Supervision										
		C_Service	S	-	-	-	-	-	-	-	-
		C_Service	CN	83,047	-	-	-	-	-	-	83,047
				83,047	-	-	-	-	-	-	83,047
908	Customer Assistance										
		DSM	S	1,214,143	-	-	1,214,143	-	-	-	-
		C_Service	CN	691,542	-	-	-	-	-	-	691,542
				1,905,685	-	-	1,214,143	-	-	-	691,542
909	Informational & Instructional Adv										
		C_Service	S	231,129	-	-	-	-	-	-	231,129
		C_Service	CN	1,431,049	-	-	-	-	-	-	1,431,049
				1,662,178	-	-	-	-	-	-	1,662,178
910	Misc. Customer Service										
		C_Service	S	-	-	-	-	-	-	-	-
		C_Service	CN	9,866	-	-	-	-	-	-	9,866
				9,866	-	-	-	-	-	-	9,866
TOTAL CUSTOMER SERVICE EXPENSE				**3,660,775**	**-**	**-**	**1,214,143**	**-**	**-**	**-**	**2,446,633**
911	Supervision										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
912	Demonstration & Selling Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
913	Advertising Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
916	Misc. Sales Expense										
		P	S	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL SALES EXPENSE				-	-	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
776												
777												
778												
779	**Total Customer Service Exp Including Sales**				**3,660,775**	**-**	**-**	**1,214,143**	**-**	**-**	**-**	**2,446,633**
780	920	Administrative & General Salaries										
781			LABOR	S	(4,949,597)	(2,057,308)	(278,254)	(1,435,551)	-	(336,973)	(537,598)	(303,914)
782			LABOR	CN	-	-	-	-	-	-	-	-
783			LABOR	SO	21,753,446	9,041,853	1,222,923	6,309,236	-	1,480,995	2,362,739	1,335,700
784					16,803,849	6,984,546	944,670	4,873,685	-	1,144,022	1,825,141	1,031,786
785												
786	921	Office Supplies & expenses										
787			LABOR	S	-	-	-	-	-	-	-	-
788			LABOR	CN	-	-	-	-	-	-	-	-
789			LABOR	SO	3,376,203	1,403,324	189,802	979,213	-	229,855	366,705	207,305
790					3,376,203	1,403,324	189,802	979,213	-	229,855	366,705	207,305
791												
792	922	Office Supplies & expenses										
793			LABOR	S	-	-	-	-	-	-	-	-
794			LABOR	CN	-	-	-	-	-	-	-	-
795			LABOR	SO	(6,477,261)	(2,692,283)	(364,135)	(1,878,625)	-	(440,978)	(703,524)	(397,715)
796					(6,477,261)	(2,692,283)	(364,135)	(1,878,625)	-	(440,978)	(703,524)	(397,715)
797												
798	923	Outside Services										
799			LABOR	S	-	-	-	-	-	-	-	-
800			LABOR	CN	-	-	-	-	-	-	-	-
801			LABOR	SO	3,198,990	1,329,665	179,839	927,815	-	217,790	347,457	196,424
802					3,198,990	1,329,665	179,839	927,815	-	217,790	347,457	196,424
803												
804	924	Property Insurance										
805			DPW	S	5,786,229	-	-	5,577,952	-	-	208,277	-
806			PT	SG	775,353	536,890	238,463	-	-	-	-	-
807			GP	SO	3,235,640	1,534,127	629,442	990,588	-	20,142	48,545	12,796
808					9,797,221	2,071,016	867,905	6,568,540	-	20,142	256,821	12,796
809												
810	925	Injuries & Damages										
811			LABOR	SO	2,211,928	919,391	124,349	641,534	-	150,590	240,247	135,816
812					2,211,928	919,391	124,349	641,534	-	150,590	240,247	135,816
813												
814	926	Employee Pensions & Benefits										
815			LABOR	S	-	-	-	-	-	-	-	-
816			LABOR	CN	-	-	-	-	-	-	-	-
817			LABOR	SO	-	-	-	-	-	-	-	-
818					-	-	-	-	-	-	-	-
819												
820	928	Franchise Requirements										
821			DSM	S	-	-	-	-	-	-	-	-
822			DSM	SG	-	-	-	-	-	-	-	-
823					-	-	-	-	-	-	-	-
824												
825	928	Regulatory Commission Expense										
826			D	S	3,271,229	-	-	3,271,229	-	-	-	-
827			C_SERVICE	CN	-	-	-	-	-	-	-	-
828			D	SO	211,303	-	-	211,303	-	-	-	-
829			FERC	SG	569,056	283,595	285,460	-	-	-	-	-
830					4,051,587	283,595	285,460	3,482,532	-	-	-	-
831												
832	929	Duplicate Charges										
833			LABOR	S	-	-	-	-	-	-	-	-
834			LABOR	SO	(1,084,933)	(450,954)	(60,992)	(314,667)	-	(73,863)	(117,839)	(66,617)
835					(1,084,933)	(450,954)	(60,992)	(314,667)	-	(73,863)	(117,839)	(66,617)
836												
837	930	Misc General Expenses										
838			LABOR	S	4,128,690	1,716,096	232,104	1,197,460	-	281,085	448,435	253,509
839			C_SERVICE	CN	2,211	-	-	-	-	-	-	2,211
840			LABOR	SO	3,718,450	1,545,579	209,042	1,078,476	-	253,156	403,877	228,319
841					7,849,350	3,261,676	441,146	2,275,936	-	534,241	852,313	484,039
842												
843	931	Rents										
844			LABOR	S	1,011,932	420,611	56,888	293,495	-	68,893	109,910	62,134
845			LABOR	SO	1,537,791	639,185	86,451	446,011	-	104,694	167,026	94,423
846					2,549,723	1,059,796	143,339	739,506	-	173,588	276,937	156,557
847												
848	935	Maintenance of General Plant										
849			G	S	21,253	5,118	5,418	9,781	-	571	365	-
850			B_Center	CN	-	-	-	-	-	-	-	-
851			G	SO	7,329,784	1,765,031	1,868,572	3,373,136	-	197,095	125,950	-
852					7,351,037	1,770,149	1,873,990	3,382,916	-	197,667	126,316	-
853												
854	**TOTAL ADMINISTRATIVE & GEN EXPENSE**				**49,627,697**	**15,939,922**	**4,625,373**	**21,678,386**	**-**	**2,153,053**	**3,470,573**	**1,760,391**
855												
856												
857	**TOTAL O&M EXPENSE**				**766,131,819**	**568,638,403**	**56,636,736**	**95,649,064**	**0**	**14,095,852**	**18,938,563**	**12,173,200**
858	403SP	Steam Depreciation										
859			P	SG	8,760,013	8,760,013	-	-	-	-	-	-
860			P	SG	8,717,331	8,717,331	-	-	-	-	-	-
861			P	SG	23,823,887	23,823,887	-	-	-	-	-	-
862			P	SSGCH	3,217,255	3,217,255	-	-	-	-	-	-
863					44,518,485	44,518,485	-	-	-	-	-	-
864												
865	403NP	Nuclear Depreciation										
866			P	SG	-	-	-	-	-	-	-	-
867					-	-	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
403HP	Hydro Depreciation										
	Pre-Merger Pacific	P	SG	893,220	893,220	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	258,547	258,547	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	3,509,619	3,509,619	-	-	-	-	-	-
	Post-Merger Utah	P	SG	972,541	972,541	-	-	-	-	-	-
				5,633,926	5,633,926	-	-	-	-	-	-
403OP	Other Production Depreciation										
		P	SG	31,717	31,717	-	-	-	-	-	-
		P	SG	27,511,188	27,511,188	-	-	-	-	-	-
		P	SSGCT	648,019	648,019	-	-	-	-	-	-
		P	SSGCH	-	-	-	-	-	-	-	-
				28,190,924	28,190,924	-	-	-	-	-	-
403TP	Transmission Depreciation										
		T_Split	SG	2,921,437	71,688.73	2,849,748.66	-	-	-	-	-
		T_Split	SG	3,270,606	80,256.94	3,190,349.41	-	-	-	-	-
		T_Split	SG	16,600,088	407,347.19	16,192,740.79	-	-	-	-	-
				22,792,132	559,293	22,232,839	-	-	-	-	-
403	Distribution Depreciation										
360	Land & Land Rights	D	S	57,796	-	-	57,796	-	-	-	-
361	Structures	D	S	235,708	-	-	235,708	-	-	-	-
362	Station Equipment	D	S	3,943,689	-	-	3,943,689	-	-	-	-
363	Storage Battery Equipm	D	S	-	-	-	-	-	-	-	-
364	Poles & Towers	D	S	14,674,905	-	-	14,674,905	-	-	-	-
365	OH Conductors	D	S	6,617,641	-	-	6,617,641	-	-	-	-
366	UG Conduit	D	S	2,077,364	-	-	2,077,364	-	-	-	-
367	UG Conductor	D	S	3,542,211	-	-	3,542,211	-	-	-	-
368	Line Trans	D	S	10,508,826	-	-	10,508,826	-	-	-	-
369	Services	D	S	4,220,077	-	-	4,220,077	-	-	-	-
370	Meters	C_Meter	S	2,182,194	-	-	-	-	-	2,182,194.48	-
371	Inst Cust Prem	D	S	116,778	-	-	116,778	-	-	-	-
372	Leased Property	D	S	-	-	-	-	-	-	-	-
373	Street Lighting	D	S	652,472	-	-	652,472	-	-	-	-
				48,829,663	-	-	46,647,469	-	-	2,182,194	-
403GP	General Depreciation										
		TD	S	4,010,924	-	1,608,097	2,318,094.96	-	-	84,732.47	-
		G-DGP	SG	71,881	49,773	22,107	-	-	-	-	-
		G-DGU	SG	127,323	88,164	39,159	-	-	-	-	-
		P	SE	5,391	5,391	-	-	-	-	-	-
		B_Center	CN	508,898	-	-	-	-	387,463	-	121,436
		G-SG	SG	1,355,705	711,109	644,596	-	-	-	-	-
		LABOR	SO	4,294,570	1,785,045	241,430	1,245,571	-	292,378	466,452	263,694
		P	SSGCT	1,537	1,537	-	-	-	-	-	-
		P	SSGCH	32,603	32,603	-	-	-	-	-	-
				10,408,832	2,673,622	2,555,388	3,563,666	-	679,841	551,185	385,130
403GV0	General Vehicles										
		G-SG	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
403MP	Mining Depreciation										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
403EP	Experimental Plant Depreciation										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
4031	ARO Depreciation										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL DEPRECIATION EXPENSE				**160,373,963**	**81,576,251**	**24,788,227**	**50,211,134**	**-**	**679,841**	**2,733,379**	**385,130**
404GP	Amort of LT Plant - Capital Lease Gen										
		TD	S	586,284	-	235,058	338,840.00	-	-	12,385.49	-
		I-SG	SG	-	-	-	-	-	-	-	-
		LABOR	SO	248,582	103,323	13,975	72,097	-	16,924	27,000	15,263
		I-DGU	SG	-	-	-	-	-	-	-	-
		B_Center	CN	74,243	-	-	-	-	56,526	-	17,716
		I-DGP	SG	-	-	-	-	-	-	-	-
				909,108	103,323	249,033	410,937	-	73,450	39,385	32,979
404SP	Amort of LT Plant - Cap Lease Steam										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
953												
954	404IP	Amort of LT Plant - Intangible Plant										
955			TD	S	9,649	-	3,869	5,576.54	-	-	203.84	-
956			P	SE	65,115	65,115	-	-	-	-	-	-
957			I-SG	SG	1,366,264	1,249,655	116,609	-	-	-	-	-
958			LABOR	SO	5,211,402	2,166,127	292,972	1,511,483	-	354,797	566,034	319,989
959			CSS_SYS	CN	1,540,587	-	-	-	-	847,323	277,306	415,958
960			I-SG	SG	1,223,534	1,119,107	104,427	-	-	-	-	-
961			I-SG	SG	81,262	74,326	6,936	-	-	-	-	-
962			I-DGP	SG	-	-	-	-	-	-	-	-
963			I-SG	SSGCT	-	-	-	-	-	-	-	-
964			I-SG	SSGCH	-	-	-	-	-	-	-	-
965			I-DGU	SG	4,387	4,387	-	-	-	-	-	-
966					9,502,200	4,678,718	524,812	1,517,060	-	1,202,120	843,543	735,948
967												
968	404MP	Amort of LT Plant - Mining Plant										
969			P	SE	-	-	-	-	-	-	-	-
970					-	-	-	-	-	-	-	-
971												
972	404OP	Amort of LT Plant - Other Plant										
973			P	SSGCT	-	-	-	-	-	-	-	-
974					-	-	-	-	-	-	-	-
975												
976												
977	404HP	Amortization of Other Electric Plant										
978		Pre-Merger Pacific	P	SG	2,043,480	2,043,480	-	-	-	-	-	-
979		Pre-Merger Utah	P	SG	10,293	10,293	-	-	-	-	-	-
980		Post-Merger Plant	P	SG	-	-	-	-	-	-	-	-
981					2,053,773	2,053,773	-	-	-	-	-	-
982												
983	**Total Amortization of Limited Term Plant**				12,465,081	6,835,814	773,845	1,927,997	-	1,275,570	882,928	768,927
984												
985												
986	405	Amortization of Other Electric Plant										
987			GP	S	-	-	-	-	-	-	-	-
988												
989					-	-	-	-	-	-	-	-
990												
991	406	Amortization of Plant Acquisition Adj										
992			P	S	-	-	-	-	-	-	-	-
993			P	SG	-	-	-	-	-	-	-	-
994			P	SG	-	-	-	-	-	-	-	-
995			P	SG	1,434,335	1,434,335	-	-	-	-	-	-
996			P	SO	-	-	-	-	-	-	-	-
997					1,434,335	1,434,335	-	-	-	-	-	-
998	407	Amort of Prop Losses, Unrec Plant, etc										
999			D_SPLIT	S	(67,953)	-	-	(65,556.84)	-	-	(2,396.28)	-
1000			GP	SO	-	-	-	-	-	-	-	-
1001			P	SG-P	0	0	-	-	-	-	-	-
1002			P	SE	-	-	-	-	-	-	-	-
1003			P	SG	36,332	36,332	-	-	-	-	-	-
1004			P	TROJP	521,342	521,342	-	-	-	-	-	-
1005					489,721	557,674	-	(65,557)	-	-	(2,396)	-
1006												
1007	**TOTAL AMORTIZATION EXPENSE**				**14,389,137**	**8,827,823**	**773,845**	**1,862,440**	**-**	**1,275,570**	**880,532**	**768,927**
1008												
1009												
1010												
1011	408	Taxes Other Than Income										
1012			D	S	21,891,545	-	-	21,891,545	-	-	-	-
1013			GP	GPS	29,478,654	13,976,830	5,734,601	9,024,866	-	183,508	442,272	116,577
1014			REVREQ	SO	2,545,701	1,642,131	265,944	518,368	0	34,657	53,973.61	30,627
1015			P	SE	206,939	206,939	-	-	-	-	-	-
1016			DSM	SG	-	-	-	-	-	-	-	-
1017			DSM	OPRV-ID	-	-	-	-	-	-	-	-
1018			GP	EXCTAX	-	-	-	-	-	-	-	-
1019			GP	SG	-	-	-	-	-	-	-	-
1020												
1021												
1022												
1023					54,122,839	15,825,900	6,000,545	31,434,779	0	218,166	496,245	147,204
1024												
1025												
1026	41140	Deferred Investment Tax Credit - Fed										
1027			PTD	DGU	-	-	-	-	-	-	-	-
1028												
1029					-	-	-	-	-	-	-	-
1030												
1031	41141	Deferred Investment Tax Credit - Idaho										
1032			PTD	DGU	-	-	-	-	-	-	-	-
1033												
1034					-	-	-	-	-	-	-	-
1035												
1036	TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-
1037												
1038												
1039	427	Interest on Long-Term Debt										
1040			NP	S	90,008,331	44,372,250	19,920,368	24,295,272	-	282,472	936,605	201,364
1041			NP	SNP	-	-	-	-	-	-	-	-
1042					90,008,331	44,372,250	19,920,368	24,295,272	-	282,472	936,605	201,364
1043												
1044	428	Amortization of Debt Disc & Exp										
1045			NP	SNP	-	-	-	-	-	-	-	-
1046					-	-	-	-	-	-	-	-
1047												
1048	429	Amortization of Premium on Debt										
1049			NP	SNP	-	-	-	-	-	-	-	-
1050					-	-	-	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
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FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
431	Other Interest Expense										
		NUTIL	OTH	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-
		NP	SNP	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
432	AFUDC - Borrowed										
		NP	SNP	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Total Electric Interest Deductions for Tax			90,008,331	44,372,250	19,920,368	24,295,272	-	282,472	936,605	201,364
	Non-Utility Portion of Interest										
	427	NUTIL	NUTIL	-	-	-	-	-	-	-	-
	428	NUTIL	NUTIL	-	-	-	-	-	-	-	-
	429	NUTIL	NUTIL	-	-	-	-	-	-	-	-
	431	NUTIL	NUTIL	-	-	-	-	-	-	-	-
	Total Non-utility Interest			-	-	-	-	-	-	-	-
	Total Interest Deductions for Tax			90,008,331	44,372,250	19,920,368	24,295,272	-	282,472	936,605	201,364
419	Interest & Dividends										
		GP	S	-	-	-	-	-	-	-	-
		GP	SNP	(23,143,441)	(10,973,091)	(4,502,187)	(7,085,346)	-	(144,071)	(347,224)	(91,524)
	Total Operating Deductions for Tax			(23,143,441)	(10,973,091)	(4,502,187)	(7,085,346)	-	(144,071)	(347,224)	(91,524)
41010	Deferred Income Tax - Federal-DR										
		GP	S	817,857	387,774	159,101	250,386	-	5,091	12,270	3,234
		P	TROJD	-	-	-	-	-	-	-	-
		PT	DGP	0	0	0	-	-	-	-	-
		LABOR	SO	(1,672,180)	(695,044)	(94,006)	(484,989)	-	(113,844)	(181,623)	(102,675)
		NP	SNP	13,580,813	6,695,061	3,005,664	3,665,767	-	42,621	141,319	30,383
		P	SE	290,479	290,479	-	-	-	-	-	-
		PT	SG	13,660,241	9,458,975	4,201,266	-	-	-	-	-
		GP	GPS	7,880,688	3,736,502	1,533,062	2,412,666	-	49,058	118,235	31,165
		TAXDEPR	TAXDEPR	92,524,802	58,133,362	12,014,968	20,930,214	-	535,923	565,412.03	344,923
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-
		CSS_SYS	CN	(0)	-	-	-	-	(0)	(0)	(0)
		IBT	IBT	0	(0)	(0)	0	0	(0)	0	0
		D	SNPD	(0)	-	-	(0)	-	-	-	-
				127,082,701	78,007,109	20,820,055	26,774,045	0	518,849	655,613	307,030
41110	Deferred Income Tax - Federal-CR										
		GP	S	(2,714,087)	(1,286,841)	(527,982)	(830,915)	-	(16,896)	(40,720)	(10,733)
		P	SE	(365,498)	(365,498)	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	0	-	-
		NP	SNP	(11,200,254)	(5,521,494)	(2,478,806)	(3,023,200)	-	(35,150)	(116,547)	(25,057)
		PT	SG	(4,353,000)	(3,014,216)	(1,338,784)	-	-	-	-	-
		D_SPLIT	CIAC	(8,508,656)	-	-	(8,208,610)	-	-	(300,046.29)	-
		LABOR	SO	(78,965)	(32,822)	(4,439)	(22,903)	-	(5,376)	(8,577)	(4,849)
		CSS_SYS	CN	2,615	-	-	-	-	1,438	470.73	706
		CSS_SYS	CN	(802,800)	-	-	-	-	(441,540)	(144,503.99)	(216,756)
		P	SGCT	(93,349)	(93,349)	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	(62,657,185)	(31,333,151)	(9,410,451)	(20,878,908)	-	(255,071)	(779,603.22)	-
		P	TROJD	(13,647)	(13,647)	-	-	-	-	-	-
		IBT	IBT	(0)	0	0	(0)	(0)	0	(0)	(0)
		P	DGP	46,265	46,265	-	-	-	-	-	-
		P	DGU	-	-	-	-	-	-	-	-
		P	SG-U	(5,148)	(5,148)	-	-	-	-	-	-
		P	SSGCH	508	508	-	-	-	-	-	-
		P	SSGCT	(2,306)	(2,306)	-	-	-	-	-	-
				(90,745,506)	(41,621,698)	(13,760,462)	(32,964,536)	(0)	(752,594)	(1,389,526)	(256,689)
TOTAL DEFERRED INCOME TAXES				36,337,195	36,385,411	7,059,593	(6,190,492)	(0)	(233,745)	(733,913)	50,342
SCHMAF	Additions - Flow Through										
		SCHMAF	S	-	-	-	-	-	-	-	-
		SCHMAF	SNP	-	-	-	-	-	-	-	-
		SCHMAF	SO	-	-	-	-	-	-	-	-
		SCHMAF	SE	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-
		SCHMAF	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent										
		P	S	-	-	-	-	-	-	-	-
		P	SE	4,857	4,857	-	-	-	-	-	-
		PTD	SNP	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	719,857	304,768	48,552	209,158	-	44,806	72,164	40,410
		SCHMAP	SG	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-
				724,714	309,625	48,552	209,158	-	44,806	72,164	40,410

RESULTS OF OPERATIONS SUMMARY
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Row	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1138												
1139	SCHMAT	Additions - Temporary										
1140			SCHMAT-SITUS	S	949,724	559,587	37,340	200,385	-	38,605	62,904	50,903
1141			SCHMAT-SG	SG-P	2,115,359	2,691,521	(576,162)	-	-	-	-	-
1142			D_SPLIT	CIAC	22,420,111	-	-	21,629,495.88	-	-	790,614.99	-
1143			SCHMAT-SNP	SNP	29,512,408	14,914,781	5,519,124	8,737,582	-	8,549	328,638	3,734
1144			P	TROJD	35,958	35,958	-	-	-	-	-	-
1145			C_BILLING	BADDEBT	(0)	-	-	-	-	(0)	-	-
1146			SCHMAT-SE	SE	963,078	963,078	-	-	-	-	-	-
1147			SCHMAT-SG	SG	11,098,709	14,121,671	(3,022,962)	-	-	-	-	-
1148			CSS_SYS	CN	(6,891)	-	-	-	-	(3,790)	(1,240)	(1,861)
1149			SCHMAT-SO	SO	208,072	89,347	17,259	59,872	-	11,025	18,071	12,498
1150			SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-
1151			CSS_SYS	CN	245,971	-	-	-	-	135,284	44,275	66,412
1152			P	DGP	(121,905)	(121,905)	-	-	-	-	-	-
1153			BOOKDEPR	SCHMDEXP	165,100,221	82,562,123	24,796,318	55,015,436	-	672,107	2,054,236.29	-
1154			P	DGU	-	-	-	-	-	-	-	-
1155			P	SG-U	13,564	13,564	-	-	-	-	-	-
1156			P	SSGCH	(1,338)	(1,338)	-	-	-	-	-	-
1157			P	SSGCT	6,075	6,075	-	-	-	-	-	-
1158					232,539,115	115,834,461	26,770,917	85,642,771	-	861,781	3,297,498	131,687
1159												
1160	TOTAL SCHEDULE - M ADDITIONS				233,263,829	116,144,086	26,819,469	85,851,929	-	906,586	3,369,663	172,097
1161												
1162	SCHMDF	Deductions - Flow Through										
1163			SCHMDF	S	-	-	-	-	-	-	-	-
1164			SCHMDF	DGP	-	-	-	-	-	-	-	-
1165			SCHMDF	DGU	-	-	-	-	-	-	-	-
1166					-	-	-	-	-	-	-	-
1167	SCHMDP	Deductions - Permanent										
1168			SCHMDP	S	-	-	-	-	-	-	-	-
1169			P	SE	95,218	95,218	-	-	-	-	-	-
1170			SCHMDP	SNP	102,181	53,641	5,159	24,270	-	5,453	8,739	4,918
1171			SCHMDP	IBT	-	-	-	-	-	-	-	-
1172			P	SG	113,292	113,292	-	-	-	-	-	-
1173			SCHMDP-SO	SO	2,374,527	986,970	133,482	688,693	-	161,664	257,914	145,804
1174					2,685,218	1,249,122	138,641	712,963	-	167,117	266,653	150,722
1175												
1176	SCHMDT	Deductions - Temporary										
1177			SCHMDT-SITUS	S	2,147,991	1,803,327	109,496	209,730	-	5,250	15,328	4,860
1178			SCHMDT	BADDEBT	-	-	-	-	-	-	-	-
1179			SCHMDT-SNP	SNP	35,785,126	18,095,967	6,697,022	10,596,473	-	-	395,665	-
1180			SCHMDT	CN	0	0	0	0	-	0	0	0
1181			SCHMDT	TROJD	-	-	-	-	-	-	-	-
1182			SCHMDT	DGP	-	-	-	-	-	-	-	-
1183			P	SE	765,406	765,406	-	-	-	-	-	-
1184			SCHMDT-SG	SG	35,592,232	17,056,362	18,535,870	-	-	-	-	-
1185			SCHMDT-GPS	GPS	20,765,429	10,403,498	3,843,882	6,133,538	-	90,637	254,286	39,588
1186			SCHMDT-SO	SO	(4,406,154)	(1,855,308)	(401,490)	(956,586)	-	(74,998)	(129,722)	(988,051)
1187			TAXDEPR	TAXDEPR	243,800,696	153,180,054	31,659,161	55,150,626	-	1,412,144	1,489,848	908,864
1188			SCHMDT-SNP	SNPD	0	0	0	0	-	-	0	-
1189					334,450,727	199,449,306	60,443,941	71,133,781	-	1,433,033	2,025,403	(34,739)
1190												
1191	TOTAL SCHEDULE - M DEDUCTIONS				337,135,945	200,698,428	60,582,583	71,846,744	-	1,600,151	2,292,056	115,983
1192												
1193	TOTAL SCHEDULE - M ADJUSTMENTS				(103,872,116)	(84,554,342)	(33,763,114)	14,005,185	-	(693,564)	1,077,606	56,113
1194												
1195												
1196												
1197	40911	State Income Taxes										
1198			IBT	IBT	1,219,755	(3,730,564)	(1,632,068)	6,371,700	0	(123,515)	265,280	68,922
1199			IBT	IBT	-	-	-	-	-	-	-	-
1200		Renewable Energy Credits	P	SG	(205,023)	(205,023)	-	-	-	-	-	-
1201			IBT	IBT	-	-	-	-	-	-	-	-
1202	**TOTAL STATE TAXES**				1,014,732	(3,935,587)	(1,632,068)	6,371,700	0	(123,515)	265,280	68,922
1203												
1204												
1205	Calculation of Taxable Income:											
1206		Operating Revenues			1,175,443,259	758,231,880	122,796,052	239,349,565	0	16,002,468	24,921,591	14,141,703
1207		Operating Deductions:										
1208		O & M Expenses			766,131,819	568,638,403	56,636,736	95,649,064	0	14,095,852	18,938,563	12,173,200
1209		Depreciation Expense			160,373,963	81,576,251	24,788,227	50,211,134	-	679,841	2,733,379	385,130
1210		Amortization Expense			14,389,137	8,827,823	773,845	1,862,440	-	1,275,570	880,532	768,927
1211		Taxes Other Than Income			54,122,839	15,825,900	6,000,545	31,434,779	0	218,166	496,245	147,204
1212		Interest & Dividends (AFUDC-Equity)			(23,143,441)	(10,973,091)	(4,502,187)	(7,085,346)	-	(144,071)	(347,224)	(91,524)
1213		Misc Revenue & Expense			(1,167,283)	(1,388,114)	(59,250)	279,502	-	353	116	111
1214		Total Operating Deductions			970,707,034	662,507,173	83,637,916	172,351,574	0	16,125,710	22,701,612	13,383,048
1215		Other Deductions:										
1216		Interest Deductions			90,008,331	44,372,250	19,920,368	24,295,272	-	282,472	936,605	201,364
1217		Interest on PCRBS			-	-	-	-	-	-	-	-
1218		Schedule M Adjustments			(103,872,116)	(84,554,342)	(33,763,114)	14,005,185	-	(693,564)	1,077,606	56,113
1219												
1220		Income Before State Taxes			10,855,778	(33,201,885)	(14,525,346)	56,707,904	0	(1,099,279)	2,360,980	613,405
1221												
1222		State Income Taxes			1,014,732	(3,935,587)	(1,632,068)	6,371,700	0	(123,515)	265,280	68,922
1223												
1224	Total Taxable Income				9,841,047	(29,266,298)	(12,893,278)	50,336,204	0	(975,764)	2,095,700	544,483
1225												
1226	Tax Rate				35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
1227												
1228	Federal Income Tax - Calculated				3,444,366	(10,243,204)	(4,512,647)	17,617,671	0	(341,517)	733,495	190,569
1229												
1230	Adjustments to Calculated Tax:											
1231	40910	PMI	P	SE	(4,857)	(4,857)	-	-	-	-	-	-
1232	40910	Renewable Energy Credits	P	SG	(16,521,622)	(16,521,622)	-	-	-	-	-	-
1233	40910		P	SO	-	-	-	-	-	-	-	-
1234	40910		P	S	-	-	-	-	-	-	-	-
1235	Federal Income Tax				(13,082,112)	(26,769,683)	(4,512,647)	17,617,671	0	(341,517)	733,495	190,569
1236												
1237	**TOTAL OPERATING EXPENSES**				**1,018,120,290**	**679,160,405**	**89,054,981**	**197,235,799**	**0**	**29,666,856**	**42,252,260**	**25,957,604**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C Billing	C Metering	C Service
310	Land and Land Rights										
		P	SG	609,800	609,800	-	-	-	-	-	-
		P	SG	9,109,220	9,109,220	-	-	-	-	-	-
		P	SG	14,738,599	14,738,599	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-
		P	SSGCH	660,775	660,775	-	-	-	-	-	-
				25,118,394	25,118,394	-	-	-	-	-	-
311	Structures and Improvements										
		P	SG	61,352,864	61,352,864	-	-	-	-	-	-
		P	SG	85,144,496	85,144,496	-	-	-	-	-	-
		P	SG	54,833,963	54,833,963	-	-	-	-	-	-
		P	SSGCH	15,369,659	15,369,659	-	-	-	-	-	-
				216,700,981	201,331,322	-	-	-	-	-	-
312	Boiler Plant Equipment										
		P	SG	182,355,926	182,355,926	-	-	-	-	-	-
		P	SG	168,322,175	168,322,175	-	-	-	-	-	-
		P	SG	570,301,880	570,301,880	-	-	-	-	-	-
		P	SSGCH	87,010,656	87,010,656	-	-	-	-	-	-
				1,007,990,638	1,007,990,638	-	-	-	-	-	-
314	Turbogenerator Units										
		P	SG	37,344,934	37,344,934	-	-	-	-	-	-
		P	SG	37,619,029	37,619,029	-	-	-	-	-	-
		P	SG	123,685,901	123,685,901	-	-	-	-	-	-
		P	SSGCH	17,206,659	17,206,659	-	-	-	-	-	-
				215,856,523	215,856,523	-	-	-	-	-	-
315	Accessory Electric Equipment										
		P	SG	23,017,149	23,017,149	-	-	-	-	-	-
		P	SG	36,349,970	36,349,970	-	-	-	-	-	-
		P	SG	18,963,762	18,963,762	-	-	-	-	-	-
		P	SSGCH	17,826,753	17,826,753	-	-	-	-	-	-
				96,157,635	96,157,635	-	-	-	-	-	-
316	Misc Power Plant Equipment										
		P	SG	1,286,037	1,286,037	-	-	-	-	-	-
		P	SG	1,374,092	1,374,092	-	-	-	-	-	-
		P	SG	3,873,806	3,873,806	-	-	-	-	-	-
		P	SSGCH	1,079,299	1,079,299	-	-	-	-	-	-
				7,613,234	7,613,234	-	-	-	-	-	-
317	Steam Plant ARO										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300										
		P	SG	2,043,732	2,043,732	-	-	-	-	-	-
				2,043,732	2,043,732	-	-	-	-	-	-
Total Steam Production Plant				**1,571,481,136**	**1,571,481,136**	-	-	-	-	-	-
320	Land and Land Rights										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
321	Structures and Improvements										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
322	Reactor Plant Equipment										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
323	Turbogenerator Units										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
324	Land and Land Rights										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
325	Misc. Power Plant Equipment										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
NP	Unclassified Nuclear Plant - Acct 300										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Nuclear Production Plant				-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
330	Land and Land Rights										
	Pre-Merger Pacific	P	SG	2,780,299	2,780,299	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	1,379,870	1,379,870	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	817,432	817,432	-	-	-	-	-	-
	Post-Merger Utah	P	SG	175,902	175,902	-	-	-	-	-	-
				5,153,504	5,153,504	-	-	-	-	-	-
331	Structures and Improvements										
	Pre-Merger Pacific	P	SG	5,566,744	5,566,744	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	1,387,186	1,387,186	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	15,239,845	15,239,845	-	-	-	-	-	-
	Post-Merger Utah	P	SG	1,990,267	1,990,267	-	-	-	-	-	-
				24,184,041	24,184,041	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways										
	Pre-Merger Pacific	P	SG	39,390,880	39,390,880	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	5,202,753	5,202,753	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	62,791,753	62,791,753	-	-	-	-	-	-
	Post-Merger Utah	P	SG	11,501,491	11,501,491	-	-	-	-	-	-
				118,886,877	118,886,877	-	-	-	-	-	-
333	Water Wheel, Turbines, & Generators										
	Pre-Merger Pacific	P	SG	8,610,222	8,610,222	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	2,329,977	2,329,977	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	9,400,228	9,400,228	-	-	-	-	-	-
	Post-Merger Utah	P	SG	7,024,961	7,024,961	-	-	-	-	-	-
				27,365,388	27,365,388	-	-	-	-	-	-
334	Accessory Electric Equipment										
	Pre-Merger Pacific	P	SG	1,213,585	1,213,585	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	993,288	993,288	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	10,348,623	10,348,623	-	-	-	-	-	-
	Post-Merger Utah	P	SG	1,773,874	1,773,874	-	-	-	-	-	-
				14,329,369	14,329,369	-	-	-	-	-	-
335	Misc. Power Plant Equipment										
	Pre-Merger Pacific	P	SG	316,995	316,995	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	48,740	48,740	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	260,825	260,825	-	-	-	-	-	-
	Post-Merger Utah	P	SG	2,972	2,972	-	-	-	-	-	-
				629,532	629,532	-	-	-	-	-	-
336	Roads, Railroads & Bridges										
	Pre-Merger Pacific	P	SG	1,208,215	1,208,215	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	216,990	216,990	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	2,379,242	2,379,242	-	-	-	-	-	-
	Post-Merger Utah	P	SG	164,435	164,435	-	-	-	-	-	-
				3,968,882	3,968,882	-	-	-	-	-	-
337	Hydro Plant ARO										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300										
	Pre-Merger Pacific	P	S	-	-	-	-	-	-	-	-
	Pre-Merger Utah	P	SG	-	-	-	-	-	-	-	-
	Post-Merger Pacific	P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Hydraulic Plant				**194,517,594**	**194,517,594**	-	-	-	-	-	-
340	Land and Land Rights										
		P	SG	6,155,989	6,155,989	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
				6,155,989	6,155,989	-	-	-	-	-	-
341	Structures and Improvements										
		P	SG	33,173,729	33,173,729	-	-	-	-	-	-
		P	SG	42,803	42,803	-	-	-	-	-	-
		P	SSGCT	998,288	998,288	-	-	-	-	-	-
				34,214,820	34,214,820	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories										
		P	SG	2,200,501	2,200,501	-	-	-	-	-	-
		P	SG	31,763	31,763	-	-	-	-	-	-
		P	SSGCT	553,230	553,230	-	-	-	-	-	-
				2,785,494	2,785,494	-	-	-	-	-	-
343	Prime Movers										
		P	S	-	-	-	-	-	-	-	-
		P	SG	190,938	190,938	-	-	-	-	-	-
		P	SG	623,605,145	623,605,145	-	-	-	-	-	-
		P	SSGCT	13,415,364	13,415,364	-	-	-	-	-	-
				637,211,447	637,211,447	-	-	-	-	-	-
344	Generators										
		P	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	79,283,290	79,283,290	-	-	-	-	-	-
		P	SSGCT	3,844,697	3,844,697	-	-	-	-	-	-
				83,127,987	83,127,987	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
345	Accessory Electric Plant										
		P	SG	44,467,582	44,467,582	-	-	-	-	-	-
		P	SG	40,990	40,990	-	-	-	-	-	-
		P	SSGCT	707,158	707,158	-	-	-	-	-	-
				45,215,730	45,215,730	-	-	-	-	-	-
346	Misc. Power Plant Equipment										
		P	SG	2,724,436	2,724,436	-	-	-	-	-	-
		P	SG	3,092	3,092	-	-	-	-	-	-
				2,727,528	2,727,528	-	-	-	-	-	-
347	Other Production ARO										
		P	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300										
		P	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
Total Other Production Plant				**811,438,995**	**811,438,995**	-	-	-	-	-	-
Experimental Plant											
103	Experimental Plant										
		P	SG	-	-	-	-	-	-	-	-
Total Experimental Plant				-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT				**2,577,437,725**	**2,577,437,725**	-	-	-	-	-	-
350	Land and Land Rights										
		T	SG	5,544,538	-	5,544,538	-	-	-	-	-
		T	SG	12,700,481	-	12,700,481	-	-	-	-	-
		T	SG	7,680,882	-	7,680,882	-	-	-	-	-
				25,925,900	-	25,925,900	-	-	-	-	-
352	Structures and Improvements										
		T	S	-	-	-	-	-	-	-	-
		T	SG	2,022,484	-	2,022,484	-	-	-	-	-
		T	SG	4,792,938	-	4,792,938	-	-	-	-	-
		T	SG	12,219,899	-	12,219,899	-	-	-	-	-
				19,035,321	-	19,035,321	-	-	-	-	-
353	Station Equipment										
		STEP_UP	SG	34,108,468	2,935,404	31,173,064	-	-	-	-	-
		STEP_UP	SG	50,111,081	4,312,602	45,798,479	-	-	-	-	-
		STEP_UP	SG	242,197,567	20,843,729	221,353,837	-	-	-	-	-
				326,417,116	28,091,736	298,325,381	-	-	-	-	-
354	Towers and Fixtures										
		T	SG	40,920,749	-	40,920,749	-	-	-	-	-
		T	SG	33,182,350	-	33,182,350	-	-	-	-	-
		T	SG	39,939,946	-	39,939,946	-	-	-	-	-
				114,043,045	-	114,043,045	-	-	-	-	-
355	Poles and Fixtures										
		T	SG	16,294,289	-	16,294,289	-	-	-	-	-
		T	SG	29,649,670	-	29,649,670	-	-	-	-	-
		T	SG	410,746,706	-	410,746,706	-	-	-	-	-
				456,690,665	-	456,690,665	-	-	-	-	-
356	Clearing and Grading										
		T	SG	51,658,742	-	51,658,742	-	-	-	-	-
		T	SG	41,285,228	-	41,285,228	-	-	-	-	-
		T	SG	96,309,743	-	96,309,743	-	-	-	-	-
				189,253,713	-	189,253,713	-	-	-	-	-
357	Underground Conduit										
		T	SG	1,668	-	1,668	-	-	-	-	-
		T	SG	23,991	-	23,991	-	-	-	-	-
		T	SG	815,104	-	815,104	-	-	-	-	-
				840,763	-	840,763	-	-	-	-	-
358	Underground Conductors										
		T	SG	-	-	-	-	-	-	-	-
		T	SG	284,689	-	284,689	-	-	-	-	-
		T	SG	1,686,373	-	1,686,373	-	-	-	-	-
				1,971,062	-	1,971,062	-	-	-	-	-
359	Roads and Trails										
		T	SG	487,687	-	487,687	-	-	-	-	-
		T	SG	115,314	-	115,314	-	-	-	-	-
		T	SG	2,395,614	-	2,395,614	-	-	-	-	-
				2,998,615	-	2,998,615	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300										
		T	SG	7,609,621	-	7,609,621	-	-	-	-	-
				7,609,621	-	7,609,621	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300										
		T	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL TRANSMISSION PLANT				**1,144,785,823**	**28,091,736**	**1,116,694,087**	-	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
360	Land and Land Rights										
		D	S	11,540,060	-	-	11,540,060	-	-	-	-
				11,540,060	-	-	11,540,060	-	-	-	-
361	Structures and Improvements										
		D	S	15,345,519	-	-	15,345,519	-	-	-	-
				15,345,519	-	-	15,345,519	-	-	-	-
362	Station Equipment										
		D	S	184,091,737	-	-	184,091,737	-	-	-	-
				184,091,737	-	-	184,091,737	-	-	-	-
363	Storage Battery Equipment										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
364	Poles, Towers & Fixtures										
		D	S	382,324,551	-	-	382,324,551	-	-	-	-
				382,324,551	-	-	382,324,551	-	-	-	-
365	Overhead Conductors										
		D	S	221,708,505	-	-	221,708,505	-	-	-	-
				221,708,505	-	-	221,708,505	-	-	-	-
366	Underground Conduit										
		D	S	80,314,589	-	-	80,314,589	-	-	-	-
				80,314,589	-	-	80,314,589	-	-	-	-
367	Underground Conductors										
		D	S	148,191,013	-	-	148,191,013	-	-	-	-
				148,191,013	-	-	148,191,013	-	-	-	-
368	Line Transformers										
		D	S	370,045,364	-	-	370,045,364	-	-	-	-
				370,045,364	-	-	370,045,364	-	-	-	-
369	Services										
		D	S	209,114,791	-	-	209,114,791	-	-	-	-
				209,114,791	-	-	209,114,791	-	-	-	-
370	Meters										
		C_Meter	S	60,320,091	-	-	-	-	-	60,320,090.51	-
				60,320,091	-	-	-	-	-	60,320,091	-
371	Installations on Customers' Premises										
		D	S	2,430,979	-	-	2,430,979	-	-	-	-
				2,430,979	-	-	2,430,979	-	-	-	-
372	Leased Property										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
373	Street Lights										
		D	S	21,513,492	-	-	21,513,492	-	-	-	-
				21,513,492	-	-	21,513,492	-	-	-	-
DP	Unclassified Dist Plant - Acct 300										
		D	S	3,605,072	-	-	3,605,072	-	-	-	-
				3,605,072	-	-	3,605,072	-	-	-	-
DS0	Unclassified Dist Sub Plant - Acct 300										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT				**1,710,545,763**	**-**	**-**	**1,650,225,672**	**-**	**-**	**60,320,091**	**-**
389	Land and Land Rights										
		D_SPLIT	S	3,046,462	-	-	2,939,032.21	-	-	107,429.36	-
		B_Center	CN	348,472	-	-	-	-	265,317.62	-	83,153.90
		G-DGU	SG	87	60	27	-	-	-	-	-
		G-SG	SG	321	169	153	-	-	-	-	-
		LABOR	SO	1,545,667	642,459	86,893	448,296	-	105,230	167,882	94,907
				4,941,008	642,688	87,073	3,387,328	-	370,548	275,311	178,061
390	Structures and Improvements										
		D_SPLIT	S	33,666,830	-	-	32,479,614.44	-	-	1,187,215.37	-
		G-DGP	SG	93,747	64,915	28,832	-	-	-	-	-
		G-DGU	SG	397,884	275,513	122,371	-	-	-	-	-
		B_Center	CN	3,752,954	-	-	-	-	2,857,406.94	-	895,547.56
		G-SG	SG	963,761	505,522	458,239	-	-	-	-	-
		LABOR	SO	27,960,652	11,621,888	1,571,877	8,109,535	-	1,903,587	3,036,931	1,716,833
				66,835,828	12,467,838	2,181,319	40,589,150	-	4,760,994	4,224,147	2,612,381
391	Office Furniture & Equipment										
		D_SPLIT	S	3,933,114	-	-	3,794,418.35	-	-	138,695.98	-
		G-DGP	SG	274	190	84	-	-	-	-	-
		G-DGU	SG	1,386	960	426	-	-	-	-	-
		B_Center	CN	2,666,108	-	-	-	-	2,029,909.19	-	636,199.27
		G-SG	SG	1,251,792	656,603	595,188	-	-	-	-	-
		P	SE	25,380	25,380	-	-	-	-	-	-
		LABOR	SO	16,600,553	6,900,045	933,241	4,814,722	-	1,130,181	1,803,060	1,019,303
		P	SSGCH	20,068	20,068	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
				24,498,674	7,603,245	1,528,940	8,609,141	-	3,160,090	1,941,756	1,655,502

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1626												
1627	392	Transportation Equipment										
1628			D_SPLIT	S	20,432,685	-	-	19,712,153.89	-	-	720,531.09	-
1629			LABOR	SO	2,246,815	933,892	126,310	651,652	-	152,965	244,037	137,958
1630			G-SG	SG	4,433,674	2,325,598	2,108,076	-	-	-	-	-
1631			B_Center	CN	-	-	-	-	-	-	-	-
1632			G-DGU	SG	239,738	166,006	73,732	-	-	-	-	-
1633			P	SE	135,861	135,861	-	-	-	-	-	-
1634			G-DGP	SG	31,487	21,803	9,684	-	-	-	-	-
1635			P	SSGCH	100,992	100,992	-	-	-	-	-	-
1636			P	SSGCT	10,816	10,816	-	-	-	-	-	-
1637					27,632,067	3,694,967	2,317,803	20,363,806	-	152,965	964,568	137,958
1638												
1639	393	Stores Equipment										
1640			D_SPLIT	S	2,510,536	-	-	2,422,005.57	-	-	88,530.68	-
1641			G-DGP	SG	28,384	19,654	8,730	-	-	-	-	-
1642			G-DGU	SG	94,254	65,266	28,988	-	-	-	-	-
1643			LABOR	SO	99,909	41,527	5,617	28,977	-	6,802	10,852	6,135
1644			G-SG	SG	1,033,609	542,160	491,449	-	-	-	-	-
1645			P	SSGCT	13,072	13,072	-	-	-	-	-	-
1646					3,779,764	681,679	534,784	2,450,983	-	6,802	99,382	6,135
1647												
1648	394	Tools, Shop & Garage Equipment										
1649			D_SPLIT	S	10,139,089	-	-	9,781,548.15	-	-	357,541.32	-
1650			G-DGP	SG	571,379	395,649	175,730	-	-	-	-	-
1651			G-SG	SG	5,190,868	2,722,769	2,468,098	-	-	-	-	-
1652			LABOR	SO	1,100,645	457,485	61,875	319,224	-	74,933	119,546	67,582
1653			P	SE	1,726	1,726	-	-	-	-	-	-
1654			G-SG	SG	674,196	353,637	320,560	-	-	-	-	-
1655			P	SSGCH	463,090	463,090	-	-	-	-	-	-
1656			P	SSGCT	21,778	21,778	-	-	-	-	-	-
1657					18,162,771	4,416,133	3,026,263	10,100,773	-	74,933	477,087	67,582
1658												
1659	395	Laboratory Equipment										
1660			D_SPLIT	S	10,071,882	-	-	9,716,710.49	-	-	355,171.34	-
1661			G-DGP	SG	5,398	3,738	1,660	-	-	-	-	-
1662			G-DGU	SG	4,164	2,883	1,281	-	-	-	-	-
1663			LABOR	SO	1,435,200	596,543	80,683	416,257	-	97,710	155,883	88,124
1664			P	SE	1,844	1,844	-	-	-	-	-	-
1665			G-SG	SG	1,626,381	853,087	773,294	-	-	-	-	-
1666			P	SSGCH	68,285	68,285	-	-	-	-	-	-
1667			P	SSGCT	3,396	3,396	-	-	-	-	-	-
1668					13,216,550	1,529,777	856,918	10,132,967	-	97,710	511,055	88,124
1669												
1670	396	Power Operated Equipment										
1671			D_SPLIT	S	27,599,252	-	-	26,626,001.54	-	-	973,250.42	-
1672			G-DGP	SG	221,225	153,186	68,039	-	-	-	-	-
1673			G-SG	SG	8,004,131	4,198,412	3,805,718	-	-	-	-	-
1674			LABOR	SO	390,879	162,469	21,974	113,368	-	26,611	42,455	24,001
1675			G-DGU	SG	477,252	330,471	146,781	-	-	-	-	-
1676			P	SE	17,927	17,927	-	-	-	-	-	-
1677			P	SSGCT	-	-	-	-	-	-	-	-
1678			P	SSGCH	261,510	261,510	-	-	-	-	-	-
1679					36,972,175	5,123,976	4,042,512	26,739,370	-	26,611	1,015,706	24,001
1680	397	Communication Equipment										
1681			COM_EQ	S	50,959,201	8,311,650	20,391,273	21,550,442	-	-	-	705,836
1682			COM_EQ	SG	1,092,565	178,202	437,189	462,041	-	-	-	15,133
1683			COM_EQ	SG	1,958,106	319,375	783,534	828,075	-	-	-	27,122
1684			COM_EQ	SO	15,144,486	2,470,126	6,060,051	6,404,542	-	-	-	209,766
1685			COM_EQ	CN	297,501	48,524	119,045	125,812	-	-	-	4,121
1686			COM_EQ	SG	20,304,389	3,311,727	8,124,781	8,586,645	-	-	-	281,236
1687			COM_EQ	SE	(5,972)	(974)	(2,390)	(2,526)	-	-	-	(83)
1688			COM_EQ	SSGCH	268,280	43,758	107,352	113,455	-	-	-	3,716
1689			COM_EQ	SSGCT	(2,298)	(375)	(919)	(972)	-	-	-	(32)
1690					90,016,258	14,682,012	36,019,916	38,067,516	-	-	-	1,246,815
1691												
1692	398	Misc. Equipment										
1693			D_SPLIT	S	564,211	-	-	544,315.19	-	-	19,896.15	-
1694			G-DGP	SG	-	-	-	-	-	-	-	-
1695			G-DGU	SG	523	362	161	-	-	-	-	-
1696			B_Center	CN	61,685	-	-	-	-	46,965.80	-	14,719.68
1697			LABOR	SO	925,537	384,701	52,031	268,437	-	63,011	100,527	56,830
1698			P	SE	405	405	-	-	-	-	-	-
1699			G-SG	SG	477,949	250,699	227,250	-	-	-	-	-
1700			P	SSGCT	-	-	-	-	-	-	-	-
1701					2,030,310	636,167	279,442	812,752	-	109,977	120,423	71,549
1702												
1703	399	Coal Mine										
1704			P	SE	119,986,950	119,986,950	-	-	-	-	-	-
1705	MP	Unckassified Mine Plant	P	SE	-	-	-	-	-	-	-	-
1706					119,986,950	119,986,950	-	-	-	-	-	-
1707												
1708	399L	WIDCO Capital Lease										
1709			P	SE	-	-	-	-	-	-	-	-
1710												
1711												
1712		Remove Capital Leases			-	-	-	-	-	-	-	-
1713					-	-	-	-	-	-	-	-
1714												
1715	1011390	General Capital Leases										
1716			D_SPLIT	S	5,882,166	-	-	5,674,739.74	-	-	207,426.67	-
1717			P	SG	4,437,486	4,437,486	-	-	-	-	-	-
1718			LABOR	SO	3,562,468	1,480,745	200,273	1,033,236	-	242,536	386,936	218,742
1719					13,882,120	5,918,231	200,273	6,707,976	-	242,536	594,362	218,742
1720												
1721		Remove Capital Leases			(13,882,120)	(5,918,231)	(200,273)	(6,707,976)	-	(242,536)	(594,362)	(218,742)
1722					-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1011346	General Gas Line Capital Leases										
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
GP	Unclassified Gen Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		LABOR	SO	12,662	5,263	712	3,672	-	862	1,375	777
		B_Center	CN	-	-	-	-	-	-	-	-
		G-SG	SG	(136)	(71)	(64)	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-
				12,526	5,192	647	3,672	-	862	1,375	777
399G	Unclassified Gen Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT				**408,084,884**	**171,470,623**	**50,875,617**	**161,257,457**	-	**8,761,493**	**9,630,809**	**6,088,885**
301	Organization										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
302	Franchise & Consent										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		I-SG	SG	4,669,502	4,270,966	398,536	-	-	-	-	-
		I-DGP	SG	25,561,402	25,561,402	-	-	-	-	-	-
		I-DGU	SG	2,418,957	2,418,957	-	-	-	-	-	-
		I-DGP	SG	(22,701)	(22,701)	-	-	-	-	-	-
		I-DGU	SG	157,322	157,322	-	-	-	-	-	-
				32,784,482	32,385,946	398,536	-	-	-	-	-
303	Miscellaneous Intangible Plant										
		D_SPLIT	S	396,247	-	-	382,273.91	-	-	13,973.12	-
		LABOR	SG	25,164,236	10,459,553	1,414,669	7,298,480	-	1,713,205	2,733,200	1,545,128
		LABOR	SO	104,980,964	43,635,499	5,901,763	30,448,033	-	7,147,202	11,402,451	6,446,016
		P	SE	926,925	926,925	-	-	-	-	-	-
		CSS_SYS	CN	36,340,826	-	-	-	-	19,987,454	6,541,349	9,812,023
		I-DGP	SG	90,200	90,200	-	-	-	-	-	-
		I-DGP	SSGCT	-	-	-	-	-	-	-	-
				167,899,398	55,112,178	7,316,433	38,128,788	-	28,847,860	20,690,973	17,803,167
303	Less Non-Utility Plant										
		I-SITUS	S	-	-	-	-	-	-	-	-
				167,899,398	55,112,178	7,316,433	38,128,788	-	28,847,860	20,690,973	17,803,167
IP	Unclassified Intangible Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL INTANGIBLE PLANT				**200,683,880**	**87,498,124**	**7,714,969**	**38,128,788**	-	**28,847,860**	**20,690,973**	**17,803,167**
TOTAL ELECTRIC PLANT IN SERVICE				**6,041,538,075**	**2,864,498,208**	**1,175,284,673**	**1,849,611,917**	-	**37,609,353**	**90,641,873**	**23,892,052**
105	Plant Held For Future Use										
		D_SPLIT	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		T	SG	85,083	-	85,083	-	-	-	-	-
		P	SG	2,335,860	2,335,860	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		G	SG	(2,420,944)	(582,969)	(617,168)	(1,114,108)	-	(65,098)	(41,600)	-
				-	1,752,891	(532,085)	(1,114,108)	-	(65,098)	(41,600)	-
114	Electric Plant Acquisition Adjustments										
		P	S	-	-	-	-	-	-	-	-
		P	SG	37,337,183	37,337,183	-	-	-	-	-	-
		P	SG	3,811,570	3,811,570	-	-	-	-	-	-
				41,148,753	41,148,753	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments										
		P	S	-	-	-	-	-	-	-	-
		P	SG	(24,253,245)	(24,253,245)	-	-	-	-	-	-
		P	SG	(3,113,828)	(3,113,828)	-	-	-	-	-	-
				(27,367,072)	(27,367,072)	-	-	-	-	-	-
120	Nuclear Fuel										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
124	Weatherization										
		DSM	S	0	-	-	0	-	-	-	-
		DSM	SO	(680)	-	-	(680)	-	-	-	-
				(680)	-	-	(680)	-	-	-	-

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
182W	Weatherization										
		DSM	S	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-
		DSM	SGCT	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
186W	Weatherization										
		DSM	S	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Total Weatherization			(680)	-	-	(680)	-	-	-	-
151	Fuel Stock										
		P	DEU	-	-	-	-	-	-	-	-
		P	SE	48,600,182	48,600,182	-	-	-	-	-	-
		P	SSECT	-	-	-	-	-	-	-	-
		P	SSECH	1,964,007	1,964,007	-	-	-	-	-	-
				50,564,188	50,564,188	-	-	-	-	-	-
152	Fuel Stock - Undistributed										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit										
		P	SE	(631,852)	(631,852)	-	-	-	-	-	-
				(631,852)	(631,852)	-	-	-	-	-	-
25317	DG&T Working Capital Deposit										
		P	SE	(467,316)	(467,316)	-	-	-	-	-	-
				(467,316)	(467,316)	-	-	-	-	-	-
25319	Provo Working Capital Deposit										
		P	SE	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
	Total Fuel Stock			49,465,020	49,465,020	-	-	-	-	-	-
154	Materials and Supplies										
		MSS	S	28,773,143	23,158,039	161,797	5,257,014	-	-	196,293	-
		MSS	SG	702,664	565,538	3,951	128,381	-	-	4,794	-
		MSS	SE	1,142,427	919,481	6,424	208,728	-	-	7,794	-
		MSS	SO	(12,220)	(9,835)	(69)	(2,233)	-	-	(83)	-
		MSS	SNPPS	20,469,144	16,474,572	115,102	3,739,827	-	-	139,642	-
		MSS	SNPPH	(487)	(392)	(3)	(89)	-	-	(3)	-
		MSS	SNPD	(1,034,316)	(832,468)	(5,816)	(188,975)	-	-	(7,056)	-
		MSS	SNPT	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-
		MSS	SSGCT	-	-	-	-	-	-	-	-
		MSS	SNPPO	1,460,289	1,175,312	8,212	266,803	-	-	9,962	-
		MSS	SSGCH	-	-	-	-	-	-	-	-
				51,500,645	41,450,249	289,599	9,409,455	-	-	351,342	-
163	Stores Expense Undistributed										
		MSS	SO	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit										
		MSS	SNPPS	(71,696)	(57,704)	(403)	(13,099)	-	-	(489)	-
				(71,696)	(57,704)	(403)	(13,099)	-	-	(489)	-
	Total Materials & Supplies			51,428,949	41,392,544	289,196	9,396,356	-	-	350,853	-
165	Prepayments										
		LABOR	S	2,498,875	1,038,661	140,480	724,758	-	170,126	271,414	153,435
		GP	GPS	47,650	22,592	9,269	14,588	-	297	715	188
		PT	SG	1,271,496	880,442	391,054	-	-	-	-	-
		P	SE	8,305	8,305	-	-	-	-	-	-
		LABOR	SO	8,631,635	3,587,752	485,249	2,503,466	-	587,650	937,520	529,998
				12,457,960	5,537,752	1,026,052	3,242,813	-	758,072	1,209,649	683,621
182M	Misc Regulatory Assets										
		DDS2	S	(434,989)	(105,561)	(56,285)	(4,632)	-	(300,818)	19,182	13,125
		DEFSG	SG	1,042,362	541,258	501,104	-	-	-	-	-
		P	SGCT	1,794,350	1,794,350	-	-	-	-	-	-
		DEFSG	SG-P	(275,829)	(143,227)	(132,602)	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-
		P	SSGCT	-	-	-	-	-	-	-	-
		LABOR	SO	2,060,927	856,628	115,860	597,739	-	140,310	223,846	126,545
				4,186,821	2,943,448	428,077	593,106	-	(160,508)	243,029	139,670
186M	Misc Deferred Debits										
		LABOR	S	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
		DEFSG	SG	12,043,204	6,253,568	5,789,636	-	-	-	-	-
		LABOR	SO	13,951	5,799	784	4,046	-	950	1,515	857
		P	SE	1,170,936	1,170,936	-	-	-	-	-	-
		P	SNPPS	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-
				13,228,092	7,430,303	5,790,420	4,046	-	950	1,515	857

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

Exhibit PPL/1606
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	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1916												
1917	Working Capital											
1918	CWC	Cash Working Capital										
1919			CWC	S	11,600,437	7,948,463	810,874	2,168,451.91	0	198,783	293,296.48	180,567
1920			CWC	SO	-	-	-	-	-	-	-	-
1921			CWC	SE	-	-	-	-	-	-	-	-
1922					11,600,437	7,948,463	810,874	2,168,452	0	198,783	293,296	180,567
1923												
1924	OWC	Other Working Capital										
1925	131	Cash	GP	SNP	-	-	-	-	-	-	-	-
1926	135	Working Funds	GP	SG	519	246	101	159	-	3	8	2
1927	141	Notes Receivable	GP	SO	98,915	46,899	19,242	30,283	-	616	1,484	391
1928	143	Other Accounts Receivabl	LABOR	SO	10,534,256	4,378,580	592,209	3,055,291	-	717,182	1,144,172	646,822
1929	232	Accounts Payable	LABOR	S	-	-	-	-	-	-	-	-
1930	232	Accounts Payable	LABOR	SO	(1,472,341)	(611,981)	(82,771)	(427,029)	-	(100,238)	(159,917)	(90,404)
1931	232	Accounts Payable	P	SE	(381,998)	(381,998)	-	-	-	-	-	-
1932	253	Deferred Hedge	P	SG	-	-	-	-	-	-	-	-
1933	2533	Other Deferred Credits - M	P	S	-	-	-	-	-	-	-	-
1934	2533	Other Deferred Credits - M	P	SE	(1,443,675)	(1,443,675)	-	-	-	-	-	-
1935	230	Asset Retirement Obligatic	P	SE	(590,632)	(590,632)	-	-	-	-	-	-
1936	230	Asset Retirement Obligatic	P	S	-	-	-	-	-	-	-	-
1937	254105	ARO Regulatory Liability	P	S	-	-	-	-	-	-	-	-
1938	254105	ARO Regulatory Liability	P	SE	(152,310)	(152,310)	-	-	-	-	-	-
1939	2533	Cholla Reclamation	P	SSECH	-	-	-	-	-	-	-	-
1940					6,592,736	1,245,130	528,781	2,658,704	-	617,563	985,747	556,811
1941												
1942	Total Working Capital				18,193,172	9,193,593	1,339,656	4,827,156	0	816,346	1,279,043	737,378
1943	Miscellaneous Rate Base											
1944	18221	Unrec Plant & Reg Study Costs										
1945			P	S	-	-	-	-	-	-	-	-
1946												
1947					-	-	-	-	-	-	-	-
1948												
1949	18222	Nuclear Plant - Trojan										
1950			P	S	(2,832)	(2,832)	-	-	-	-	-	-
1951			P	TROJP	8,815	8,815	-	-	-	-	-	-
1952			P	TROJD	12,882	12,882	-	-	-	-	-	-
1953					18,865	18,865	-	-	-	-	-	-
1954												
1955												
1956												
1957	1869	Misc Deferred Debits-Trojan										
1958			P	S	-	-	-	-	-	-	-	-
1959			P	SNPPN	-	-	-	-	-	-	-	-
1960					-	-	-	-	-	-	-	-
1961												
1962	TOTAL MISCELLANEOUS RATE BASE				18,865	18,865	-	-	-	-	-	-
1963												
1964	**TOTAL RATE BASE ADDITIONS**				**162,759,881**	**131,516,098**	**8,341,316**	**16,948,689**	**0**	**1,349,762**	**3,042,490**	**1,561,526**
1965	235	Customer Service Deposits										
1966			C_BILLING	S	-	-	-	-	-	-	-	-
1967			C_BILLING	CN	-	-	-	-	-	-	-	-
1968					-	-	-	-	-	-	-	-
1969												
1970	2281	Prov for Property Insuranc	LABOR	SO	-	-	-	-	-	-	-	-
1971	2282	Prov for Injuries & Damag	LABOR	SO	(2,360,042)	(980,955)	(132,676)	(684,492)	-	(160,674)	(256,335)	(144,911)
1972	2283	Prov for Pensions and Ber	LABOR	SO	(6,053,069)	(2,515,967)	(340,288)	(1,755,595)	-	(412,099)	(657,451)	(371,669)
1973	2283	Prov for Pensions and Ber	LABOR	SO	(28,867)	(11,998)	(1,623)	(8,372)	-	(1,965)	(3,135)	(1,772)
1974	254	Reg Liabilities - Insurance	LABOR	SE	-	-	-	-	-	-	-	-
1975					(8,441,977)	(3,508,921)	(474,587)	(2,448,459)	-	(574,738)	(916,921)	(518,352)
1976												
1977	22844	Accum Hydro Relicensing Obligation										
1978			P	S	-	-	-	-	-	-	-	-
1979			P	SG	-	-	-	-	-	-	-	-
1980					-	-	-	-	-	-	-	-
1981												
1982	22841	Chehalis Rate Base	P	SG	(392,656)	(392,656)	-	-	-	-	-	-
1983	230	Asset Retirement Obligatic	P	TROJP	(525,747)	(525,747)	-	-	-	-	-	-
1984	254105	ARO Regulatory Liability	P	TROJP	(860,044)	(860,044)	-	-	-	-	-	-
1985	254		P	S	-	-	-	-	-	-	-	-
1986					(1,778,447)	(1,778,447)	-	-	-	-	-	-
1987												
1988	252	Customer Advances for Construction										
1989			D_SPLIT	S	(878,727)	-	-	(847,739.58)	-	-	(30,987.11)	-
1990			T	SE	-	-	-	-	-	-	-	-
1991			T	SG	(1,978,657)	-	(1,978,657)	-	-	-	-	-
1992			D_SPLIT	SO	-	-	-	-	-	-	-	-
1993			B_Center	CN	0	-	-	-	-	0	-	0
1994					(2,857,384)	-	(1,978,657)	(847,740)	-	0	(30,987)	0
1995												
1996	25398	SO2 Emissions										
1997			P	SE	(1,906,305)	(1,906,305)	-	-	-	-	-	-
1998					(1,906,305)	(1,906,305)	-	-	-	-	-	-
1999												
2000	25399	Other Deferred Credits										
2001			D_SPLIT	S	(564,982)	-	-	(545,059.08)	-	-	(19,923.34)	-
2002			LABOR	SO	(752,375)	(312,726)	(42,297)	(218,214.12)	-	(51,222)	(81,718.77)	(46,197)
2003			P	SG	(3,108,249)	(3,108,249)	-	-	-	-	-	-
2004			P	SE	(383,756)	(383,756)	-	-	-	-	-	-
2005					(4,809,363)	(3,804,731)	(42,297)	(763,273)	-	(51,222)	(101,642)	(46,197)

RESULTS OF OPERATIONS SUMMARY
REVISED PROTOCOL

	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
2006												
2007	190	Accumulated Deferred Income Taxes										
2008			D_SPLIT	S	-	-	-	-	-	-	-	-
2009			CSS_SYS	CN	20,222	-	-	-	-	11,122	3,640	5,460
2010			LABOR	SO	8,486,205	3,527,304	477,073	2,461,287	-	577,749	921,725	521,068
2011			P	GPS	-	-	-	-	-	-	-	-
2012			IBT	IBT	13,696,355	(41,889,653)	(18,326,119)	71,546,373	0	(1,386,922)	2,978,766	773,911
2013			P	SG-P	-	-	-	-	-	-	-	-
2014			P	SG-U	-	-	-	-	-	-	-	-
2015			C_BILLING	BADDEBT	1,313,931	-	-	-	-	1,313,931	-	-
2016			P	TROJD	514,879	514,879	-	-	-	-	-	-
2017			P	SG	10,291,632	10,291,632	-	-	-	-	-	-
2018			P	SE	(4,021,242)	(4,021,242)	-	-	-	-	-	-
2019			LABOR	SNP	-	-	-	-	-	-	-	-
2020			D_SPLIT	SNPD	197,927	-	-	190,946.96	-	-	6,979.61	-
2021			P	SSGCT	-	-	-	-	-	-	-	-
2022					30,499,908	(31,577,080)	(17,849,046)	74,007,659	0	515,880	3,911,110	1,300,439
2023												
2024	281	Accumulated Deferred Income Taxes										
2025			P	S	-	-	-	-	-	-	-	-
2026			PT	DGP	-	-	-	-	-	-	-	-
2027			T	SNPT	-	-	-	-	-	-	-	-
2028					-	-	-	-	-	-	-	-
2029												
2030	282	Accumulated Deferred Income Taxes										
2031			GP	S	(685,408,489)	(324,975,422)	(133,335,267)	(209,837,246)	-	(4,266,756)	(10,283,260)	(2,710,537)
2032			CSS_SYS	CN	(2,615)	-	-	-	-	(1,438)	(471)	(706)
2033			P	DGU	-	-	-	-	-	-	-	-
2034			ACCMDIT	DITBAL	-	-	-	-	-	-	-	-
2035			P	DGP	(46,265)	(46,265)	-	-	-	-	-	-
2036			P	SG-P	802,800	802,800	-	-	-	-	-	-
2037			P	SSGCH	(508)	(508)	-	-	-	-	-	-
2038			P	SG-U	5,148	5,148	-	-	-	-	-	-
2039			LABOR	SO	88,594	36,824	4,981	25,695	-	6,032	9,623	5,440
2040			P	SSGCT	2,306	2,306	-	-	-	-	-	-
2041			P	SE	(1,273,645)	(1,273,645)	-	-	-	-	-	-
2042			P	SG	(1,867,462)	(1,867,462)	-	-	-	-	-	-
2043					(687,700,136)	(327,316,224)	(133,330,286)	(209,811,550)	-	(4,262,163)	(10,274,108)	(2,705,804)
2044												
2045	283	Accumulated Deferred Income Taxes										
2046			GP	S	1,846,809	875,635	359,267	565,399	-	11,497	27,708	7,303
2047			P	SG	(842,783)	(842,783)	-	-	-	-	-	-
2048			P	SE	-	-	-	-	-	-	-	-
2049			LABOR	SO	(1,816,915)	(755,204)	(102,142)	(526,967)	-	(123,697)	(197,343)	(111,562)
2050			GP	GPS	(1,570,241)	(744,504)	(305,465)	(480,728)	-	(9,775)	(23,558)	(6,210)
2051			LABOR	SNP	(1,402,122)	(582,794)	(78,824)	(406,663)	-	(95,458)	(152,291)	(86,093)
2052			P	TROJD	-	-	-	-	-	-	-	-
2053			P	SSGCT	-	-	-	-	-	-	-	-
2054			P	SGCT	(569,861)	(569,861)	-	-	-	-	-	-
2055			IBT	IBT	(4,793,725)	14,661,380	6,414,142	(25,041,232)	(0)	485,423	(1,042,568)	(270,869)
2056					(9,148,838)	12,041,868	6,286,978	(25,890,191)	(0)	267,989	(1,388,053)	(467,430)
2057												
2058	TOTAL ACCUMULATED DEF INCOME TAX				(666,349,065)	(346,851,436)	(144,892,355)	(161,503,135)	0	(3,478,293)	(7,751,051)	(1,872,794)
2059	255	Accumulated Investment Tax Credit										
2060			LABOR	S	-	-	-	-	-	-	-	-
2061			LABOR	ITC84	(619,351)	(257,434)	(34,818)	(179,633)	-	(42,166)	(67,271)	(38,029)
2062			LABOR	ITC85	(1,371,497)	(570,065)	(77,102)	(397,781)	-	(93,373)	(148,964)	(84,212)
2063			LABOR	ITC86	(717,034)	(298,036)	(40,310)	(207,964)	-	(48,816)	(77,880)	(44,027)
2064			LABOR	ITC88	(108,816)	(45,230)	(6,117)	(31,560)	-	(7,408)	(11,819)	(6,681)
2065			LABOR	ITC89	(224,527)	(93,325)	(12,622)	(65,120)	-	(15,286)	(24,387)	(13,786)
2066			LABOR	ITC90	(43,463)	(18,065)	(2,443)	(12,606)	-	(2,959)	(4,721)	(2,669)
2067			LABOR	DGU	-	-	-	-	-	-	-	-
2068					(3,084,689)	(1,282,156)	(173,413)	(894,664)	-	(210,008)	(335,042)	(189,405)
2069												
2070	**TOTAL RATE BASE DEDUCTIONS**				**(689,227,230)**	**(359,131,996)**	**(147,561,308)**	**(166,457,271)**	**0**	**(4,314,262)**	**(9,135,643)**	**(2,626,749)**
2071												
2072												
2073												
2074	108SP	Steam Prod Plant Accumulated Depr										
2075			P	S	-	-	-	-	-	-	-	-
2076			P	SG	(228,316,039)	(228,316,039)	-	-	-	-	-	-
2077			P	SG	(250,608,736)	(250,608,736)	-	-	-	-	-	-
2078			P	SG	(176,048,029)	(176,048,029)	-	-	-	-	-	-
2079			P	SSGCH	(45,436,132)	(45,436,132)	-	-	-	-	-	-
2080					(700,408,936)	(700,408,936)	-	-	-	-	-	-
2081												
2082	108NP	Nuclear Prod Plant Accumulated Depr										
2083			P	SG	-	-	-	-	-	-	-	-
2084			P	SG	-	-	-	-	-	-	-	-
2085			P	SG	-	-	-	-	-	-	-	-
2086					-	-	-	-	-	-	-	-
2087												
2088												
2089	108HP	Hydraulic Prod Plant Accum Depr										
2090			P	S	-	-	-	-	-	-	-	-
2091		Pre-Merger Pacific	P	SG	(39,683,718)	(39,683,718)	-	-	-	-	-	-
2092		Pre-Merger Utah	P	SG	(7,641,696)	(7,641,696)	-	-	-	-	-	-
2093		Post-Merger Pacific	P	SG	(18,327,218)	(18,327,218)	-	-	-	-	-	-
2094		Post-Merger Utah	P	SG	(4,452,105)	(4,452,105)	-	-	-	-	-	-
2095					(70,104,737)	(70,104,737)	-	-	-	-	-	-
2096												
2097	108OP	Other Production Plant - Accum Depr										
2098			P	S	-	-	-	-	-	-	-	-
2099			P	SG	(376,094)	(376,094)	-	-	-	-	-	-
2100			P	SG	-	-	-	-	-	-	-	-
2101			P	SG	(81,359,204)	(81,359,204)	-	-	-	-	-	-
2102			P	SSGCT	(5,584,836)	(5,584,836)	-	-	-	-	-	-
2103					(87,320,135)	(87,320,135)	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
108EP	Experimental Plant - Accum Depr										
		P	SG	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT DEPRECIATION				**(857,833,807)**	**(857,833,807)**	**-**	**-**	**-**	**-**	**-**	**-**
108TP	Transmission Plant Accumulated Depr										
		T_Split	SG	(103,022,548)	(2,528,055.57)	(100,494,491.98)	-	-	-	-	-
		T_Split	SG	(103,579,925)	(2,541,733)	(101,038,192)	-	-	-	-	-
		T_Split	SG	(111,960,251)	(2,747,376.61)	(109,212,874.65)	-	-	-	-	-
TOTAL TRANS PLANT ACCUM DEPR				**(318,562,724)**	**(7,817,165)**	**(310,745,559)**	**-**	**-**	**-**	**-**	**-**
108360	Land and Land Rights										
		D	S	(1,659,817)	-	-	(1,659,817)	-	-	-	-
				(1,659,817)	-	-	(1,659,817)	-	-	-	-
108361	Structures and Improvements										
		D	S	(3,083,376)	-	-	(3,083,376)	-	-	-	-
				(3,083,376)	-	-	(3,083,376)	-	-	-	-
108362	Station Equipment										
		D	S	(53,393,183)	-	-	(53,393,183)	-	-	-	-
				(53,393,183)	-	-	(53,393,183)	-	-	-	-
108363	Storage Battery Equipment										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108364	Poles, Towers & Fixtures										
		D	S	(246,393,150)	-	-	(246,393,150)	-	-	-	-
				(246,393,150)	-	-	(246,393,150)	-	-	-	-
108365	Overhead Conductors										
		D	S	(116,624,345)	-	-	(116,624,345)	-	-	-	-
				(116,624,345)	-	-	(116,624,345)	-	-	-	-
108366	Underground Conduit										
		D	S	(32,012,020)	-	-	(32,012,020)	-	-	-	-
				(32,012,020)	-	-	(32,012,020)	-	-	-	-
108367	Underground Conductors										
		D	S	(52,515,231)	-	-	(52,515,231)	-	-	-	-
				(52,515,231)	-	-	(52,515,231)	-	-	-	-
108368	Line Transformers										
		D	S	(152,859,488)	-	-	(152,859,488)	-	-	-	-
				(152,859,488)	-	-	(152,859,488)	-	-	-	-
108369	Services										
		D	S	(59,025,036)	-	-	(59,025,036)	-	-	-	-
				(59,025,036)	-	-	(59,025,036)	-	-	-	-
108370	Meters										
		C_Meter	S	(31,492,599)	-	-	-	-	-	(31,492,599.06)	-
				(31,492,599)	-	-	-	-	-	(31,492,599)	-
108371	Installations on Customers' Premises										
		D	S	(2,383,353)	-	-	(2,383,353)	-	-	-	-
				(2,383,353)	-	-	(2,383,353)	-	-	-	-
108372	Leased Property										
		D	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108373	Street Lights										
		D	S	(7,870,627)	-	-	(7,870,627)	-	-	-	-
				(7,870,627)	-	-	(7,870,627)	-	-	-	-
108D00	Unclassified Dist Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300										
		D_SPLIT	S	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300										
		D_SPLIT	S	91,000	-	-	87,791.01	-	-	3,208.99	-
				91,000	-	-	87,791	-	-	3,209	-
TOTAL DISTRIBUTION PLANT DEPR				**(759,221,225)**	**-**	**-**	**(727,731,835)**	**-**	**-**	**(31,489,390)**	**-**
108GP	General Plant Accumulated Depr										
		D_SPLIT	S	(47,418,651)	-	-	(45,746,496.64)	-	-	(1,672,154.82)	-
		G-DGP	SG	(1,563,243)	(1,082,461)	(480,782)	-	-	-	-	-
		G-DGU	SG	(2,654,372)	(1,838,009)	(816,364)	-	-	-	-	-
		G-SG	SG	(12,785,302)	(6,706,283)	(6,079,018)	-	-	-	-	-
		B_Center	CN	(2,224,300)	-	-	-	-	(1,693,527.33)	-	(530,772.93)
		LABOR	SO	(20,374,870)	(8,468,846)	(1,145,423)	(5,909,402)	-	(1,387,140)	(2,213,006)	(1,251,053)
		P	SE	(86,151)	(86,151)	-	-	-	-	-	-
		G-SG	SSGCT	(7,795)	(4,088)	(3,706)	-	-	-	-	-
		G-SG	SSGCH	(594,779)	(311,980)	(282,799)	-	-	-	-	-
				(87,709,463)	(18,497,818)	(8,808,093)	(51,655,899)	-	(3,080,667)	(3,885,160)	(1,781,826)

Row	FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	PITA FACTOR	OREGON Normalized	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
2205	108MP	Mining Plant Accumulated Depr.										
2206			P	S	-	-	-	-	-	-	-	-
2207			P	SE	(42,829,173)	(42,829,173)	-	-	-	-	-	-
2208					(42,829,173)	(42,829,173)	-	-	-	-	-	-
2209	108MP	Less Centralia Situs Depreciation										
2210			P	S	-	-	-	-	-	-	-	-
2211					(42,829,173)	(42,829,173)	-	-	-	-	-	-
2213	1081390	Accum Depr - Capital Lease										
2214			LABOR	SO	-	-	-	-	-	-	-	-
2215					-	-	-	-	-	-	-	-
2217		Remove Capital Leases			-	-	-	-	-			
2218					-	-	-	-	-	-	-	-
2220	1081399	Accum Depr - Capital Lease										
2221			P	S	-	-	-	-	-	-	-	-
2222			P	SE	-	-	-	-	-	-	-	-
2223					-	-	-	-	-	-	-	-
2225		Remove Capital Leases			-	-	-	-	-	-	-	-
2226					-	-	-	-	-	-	-	-
2229	**TOTAL GENERAL PLANT ACCUM DEPR**				**(130,538,636)**	**(61,326,991)**	**(8,808,093)**	**(51,655,899)**	**-**	**(3,080,667)**	**(3,885,160)**	**(1,781,826)**
2235	**TOTAL ACCUM DEPR - PLANT IN SERVICE**				**(2,066,156,392)**	**(926,977,963)**	**(319,553,652)**	**(779,387,734)**	**-**	**(3,080,667)**	**(35,374,550)**	**(1,781,826)**
2236	111SP	Accum Prov for Amort-Steam										
2237			P	SSGCH	-	-	-	-	-	-	-	-
2238			P	SSGCT	-	-	-	-	-	-	-	-
2239					-	-	-	-	-	-	-	-
2242	111GP	Accum Prov for Amort-General										
2243			D_SPLIT	S	(7,694,691)	-	-	(7,423,348.47)	-	-	(271,342.92)	-
2244			CSS_SYS	CN	(828,965)	-	-	-	-	(455,931)	(149,214)	(223,821)
2245			I-SG	SG	-	-	-	-	-	-	-	-
2246			LABOR	SO	(3,030,432)	(1,259,604)	(170,363)	(878,928)	-	(206,315)	(329,149)	(186,074)
2247			P	SE	-	-	-	-	-	-	-	-
2248					(11,554,088)	(1,259,604)	(170,363)	(8,302,276)	-	(662,245)	(749,705)	(409,894)
2251	111HP	Accum Prov for Amort-Hydro										
2252		Pre-Merger Pacific	P	SG	(90,200)	(90,200)	-	-	-	-	-	-
2253		Pre-Merger Utah	P	SG	-	-	-	-	-	-	-	-
2254		Post-Merger Pacific	P	SG	(2,045,763)	(2,045,763)	-	-	-	-	-	-
2255		Post-Merger Utah	P	SG	(112,270)	(112,270)	-	-	-	-	-	-
2256					(2,248,233)	(2,248,233)	-	-	-	-	-	-
2259	111IP	Accum Prov for Amort-Intangible Plant										
2260			D_SPLIT	S	100,724	-	-	97,171.69	-	-	3,551.88	-
2261			LABOR	SG	22,701	9,436	1,276	6,584	-	1,546	2,466	1,394
2262			LABOR	SG	(91,462)	(38,016)	(5,142)	(26,527)	-	(6,227)	(9,934)	(5,616)
2263			P	SE	(397,316)	(397,316)	-	-	-	-	-	-
2264			LABOR	SG	(10,991,601)	(4,568,676)	(617,920)	(3,187,936)	-	(748,318)	(1,193,847)	(674,904)
2265			I-SG	SG	(3,181,677)	(2,910,125)	(271,552)	-	-	-	-	-
2266			I-SG	SG	(895,842)	(819,383)	(76,459)	-	-	-	-	-
2267			CSS_SYS	CN	(29,039,529)	-	-	-	-	(15,971,741)	(5,227,115)	(7,840,673)
2268			P	SSGCT	-	-	-	-	-	-	-	-
2269			P	SSGCH	(19,080)	(19,080)	-	-	-	-	-	-
2270			LABOR	SO	(74,662,125)	(31,033,427)	(4,197,315)	(21,654,544)	-	(5,083,067)	(8,109,387)	(4,584,386)
2271					(119,155,208)	(39,776,588)	(5,167,111)	(24,765,251)	-	(21,807,808)	(14,534,265)	(13,104,184)
2272	111IP	Less Non-Utility Plant										
2273			NUTIL	OTH	-	-	-	-	-	-	-	-
2274					(119,155,208)	(39,776,588)	(5,167,111)	(24,765,251)	-	(21,807,808)	(14,534,265)	(13,104,184)
2276	111390	Accum Amtr - Capital Lease										
2277			LABOR	S	(1,245,947)	(517,880)	(70,044)	(361,367)	-	(84,825)	(135,328)	(76,503)
2278			P	SG	(311,838)	(311,838)	-	-	-	-	-	-
2279			LABOR	SO	580,199	241,160	32,617	168,277	-	39,500	63,018	35,625
2280					(977,586)	(588,557)	(37,427)	(193,090)	-	(45,325)	(72,310)	(40,878)
2282		Remove Capital Lease Amtr			977,586	588,557	37,427	193,090	-	45,325	72,310	40,878
2284	**TOTAL ACCUM PROV FOR AMORTIZATION**				**(132,957,529)**	**(43,284,425)**	**(5,337,475)**	**(33,067,528)**	**-**	**(22,470,053)**	**(15,283,970)**	**(13,514,079)**

Exhibit PPL/1606

Tab 2

PacifiCorp
12 Months Ended June 2009
FUNCTIONAL FACTORS

Function	Description	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
ANC	Ancillary Function	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
B_Center	Business Centers	0.0000%	0.0000%	0.0000%	0.0000%	76.1375%	0.0000%	23.8625%	0.0000%	100.0000%
BOOKDEPR	Book Depreciation	50.0073%	15.0189%	33.3224%	0.0000%	0.4071%	1.2442%	0.0000%	0.0000%	100.0000%
C_BILLING	Customer Billing	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	
C_METER	Customer Metering	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100.0000%
C_SERVICE	Customer Other	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
COM_EQ	Communication Equipment Acct 397	16.3104%	40.0149%	42.2896%	0.0000%	0.0000%	0.0000%	1.3851%	0.0000%	100.0000%
CSS_SYS	CSS System	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%	100.0000%
CUST	Customer	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%	100.0000%
CUST901	Supervision	0.0000%	0.0000%	0.0000%	0.0000%	45.8789%	23.6152%	30.5059%	0.0000%	100.0000%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	60.3223%	0.0000%	39.6777%	0.0000%	100.0000%
CUST905	Misc. Customer Acct. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	3.8412%	96.1588%	0.0000%	100.0000%
D	Distribution Only	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDS2	Deferred Debits - Situs	24.2675%	12.9395%	1.0649%	0.0000%	69.1552%	-4.4098%	-3.0174%	0.0000%	100.0000%
DDS6	Deferred Debits - Situs	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDSO2	Deferred Debits - System Overhead	29.6134%	1.8037%	68.5824%	0.0000%	0.0000%	0.0005%	0.0000%	0.0000%	100.0000%
DDSO6	Deferred Debits - System Overhead	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DEFSG	Deferred Debit - System Generation	51.9261%	48.0739%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DMSC	Distribution Miscellaneous	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DPW	Distribution Poles & Wires	0.0000%	0.0000%	96.4005%	0.0000%	0.0000%	3.5995%	0.0000%	0.0000%	100.0000%
ESD	Environmental Services Department	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
FERC	FERC Fees	49.8361%	50.1639%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G	General Plant	24.0803%	25.4929%	46.0196%	0.0000%	2.6890%	1.7183%	0.0000%	0.0000%	100.0000%
GP	Total Plant	50.1001%	18.5110%	29.5373%	0.0000%	0.4365%	1.2246%	0.1906%	0.0000%	100.0000%
G-SG	General Plant - SG Factor	52.4531%	47.5469%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SITUS	General Plant - SITUS Factor	0.0000%	21.5072%	75.6674%	0.0000%	0.0000%	2.8254%	0.0000%	0.0000%	100.0000%
I	Intangible Plant	52.7298%	11.5504%	17.4342%	0.0000%	9.2660%	4.3409%	4.6787%	0.0000%	100.0000%
I-DGP	Intangible Plant - DGP Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-DGU	Intangible Plant - DGU Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SG	Intangible Plant - SG Factor	91.4651%	8.5349%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SITUS	Intangible Plant - SITUS Factor	5.6319%	35.7273%	56.5301%	0.0000%	0.0000%	2.1108%	0.0000%	0.0000%	100.0000%
LABOR	Oregon Direct Labor Expense	41.5652%	5.6217%	29.0034%	0.0000%	6.8081%	10.8614%	6.1402%	0.0000%	100.0000%
MSS	Materials & Supplies	80.4849%	0.5623%	18.2706%	0.0000%	0.0000%	0.6822%	0.0000%	0.0000%	100.0000%
NONE	Not Functionalized	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
NUTIL	Non-Utility	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHDGP	Other Revenues - DGP Factor	41.5036%	58.4964%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHDGU	Other Revenues - DGU Factor	41.5036%	58.4964%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSE	Other Revenues - SE Factor	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSG	Other Revenues - SG Factor	41.5036%	58.4964%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSGR	Other Revenues - Rolled-In SG Factor	41.5036%	58.4964%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSITUS	Other Revenues - SITUS	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSO	Other Revenues - SO Factor	1.0072%	0.3727%	98.5980%	0.0000%	0.0000%	0.0220%	0.0000%	0.0000%	100.0000%
P	Production	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMA	Schedule M Additions	49.7055%	14.8124%	31.5050%	0.0000%	1.0111%	2.1092%	0.8568%	0.0000%	100.0000%
SCHMAF	Schedule M Additions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAP	Schedule M Additions - Permanent	42.8956%	6.6793%	28.7742%	0.0000%	6.1640%	9.9277%	5.5592%	0.0000%	100.0000%
SCHMAP-SO	Schedule M Additions - Permanent-SO	42.3373%	6.7446%	29.0555%	0.0000%	6.2242%	10.0248%	5.6136%	0.0000%	100.0000%
SCHMAT	Schedule M Additions - Temporary	49.7974%	14.9222%	31.5419%	0.0000%	0.9416%	2.0036%	0.7933%	0.0000%	100.0000%
SCHMAT-SG	Schedule M Additions - Temporary-SG	127.2371%	-27.2371%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAT-SE	Schedule M Additions - Temporary-SE	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAT-SITUS	Schedule M Additions - Temporary-SITUS	58.9210%	3.9317%	21.0993%	0.0000%	4.0649%	6.6234%	5.3598%	0.0000%	100.0000%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	50.5373%	18.7010%	29.6065%	0.0000%	0.0290%	1.1136%	0.0127%	0.0000%	100.0000%
SCHMAT-SO	Schedule M Additions - Temporary-SO	42.9403%	8.2946%	28.7746%	0.0000%	5.2987%	8.6850%	6.0067%	0.0000%	100.0000%
SCHMD	Schedule M Deductions	61.8403%	13.3699%	22.2675%	0.0000%	0.5691%	0.8031%	1.1500%	0.0000%	100.0000%
SCHMDF	Schedule M Deductions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDP	Schedule M Deductions - Permanent	52.4964%	5.0492%	23.7521%	0.0000%	5.3369%	8.5522%	4.8133%	0.0000%	100.0000%
SCHMDP-SO	Schedule M Deductions - Permanent- SO	41.5649%	5.6214%	29.0034%	0.0000%	6.8083%	10.8617%	6.1403%	0.0000%	100.0000%
SCHMDT	Schedule M Deductions - Temporary	61.9070%	13.4294%	22.2569%	0.0000%	0.5351%	0.7478%	1.1238%	0.0000%	100.0000%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	50.1001%	18.5110%	29.5373%	0.0000%	0.4365%	1.2246%	0.1906%	0.0000%	100.0000%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	47.9216%	52.0784%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDT-SITUS	Schedule M Deductions - Temporary-SITUS	83.9541%	5.0976%	9.7640%	0.0000%	0.2444%	0.7136%	0.2262%	0.0000%	100.0000%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	50.5684%	18.7145%	29.6114%	0.0000%	0.0000%	1.1057%	0.0000%	0.0000%	100.0000%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	42.1072%	9.1120%	21.7102%	0.0000%	1.7021%	2.9441%	22.4243%	0.0000%	100.0000%
STEP_UP	Step-up Transformers	8.6061%	91.3939%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
T	Transmission	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
TAXDEPR	Tax Depreciation	62.8300%	12.9857%	22.6212%	0.0000%	0.5792%	0.6111%	0.3728%	0.0000%	100.0000%
TD	Transmission / Distribution	0.0000%	37.8595%	59.9038%	0.0000%	0.0000%	2.2368%	0.0000%	0.0000%	100.0000%
WSF	Wholesale Sales Firm	77.6282%	22.3718%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%

Exhibit PPL/1606
Paice/1 - Tab 2

PacifiCorp
12 Months Ended June 2009
FERC FORM 1 Funtionalization Factors

Factor	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
PLANT	16,982,642	8,587,851	3,178,223	5,028,796			187,772	0	0
UNCLASSIFIED PLANT	0							0	0
TOTAL PLANT	16,982,642	8,587,851	3,178,223	5,028,796	0	0	187,772	0	0
PLANT %									
P	100.0000%	100.0000%							
T	100.0000%		100.0000%						
CUST						100.0000%			
DPW	100.0000%			96.4005%			3.5995%		
PTD	100.0000%	50.5684%	18.7145%	29.6114%			1.1057%	0.0000%	0.0000%
PT	100.0000%	72.9882%	27.0118%						
TD	100.0000%		37.8595%	59.9038%			2.2368%		

Source: Sept 2007 Results of Operations

Material & Supplies	88,498,624	71,228,040	497,646	16,169,192			603,746	0	0
Material & Supplies %	100.0000%	80.4849%	0.5623%	18.2706%	0.0000%	0.0000%	0.6822%	0.0000%	0.0000%

Source: Ferc Form 1 (Apr 2008) - pg. 227

Meter Percent of Total Distribution		
Account 370	187,772	3.60%
Total Distribution	5,216,568	100.00%

Source: CA JAM Dec 2011 GRC.xls
Tab: UTCR

FERC (mWh)	34,227,973	17,057,893	17,170,080	0	0	0	0	0	0
FERC %	100.0000%	49.8361%	50.1639%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Source: 2008 FERC reporting requirment No. 582

Wholesale Sales	787,627,105	611,420,892	176,206,213	0	0	0	0	0	0
WSF %	100.0000%	77.6282%	22.3718%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Exhibit PPL/1606
Paice/2 - Tab 2

PacifiCorp
12 Months Ended June 2009
Depreciation Expense

Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
CUST	1,710	-	-	-	-	1,710	-	-	-
DPW	140,469	-	-	135,412	-	-	5,056	-	-
P	202,268	202,268	-	-	-	-	-	-	-
PTD	15,440	7,808	2,889	4,572	-	-	171	-	-
T	60,204	-	60,204	-	-	-	-	-	-
Book Depreciation	420,090	210,075	63,093	139,984	-	1,710	5,227	-	-
BookDepr Factor	**100.00%**	**50.0073%**	**15.0189%**	**33.3224%**	**0.0000%**	**0.4071%**	**1.2442%**	**0.0000%**	**0.0000%**

P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.4005%	0.0000%	0.0000%	3.5995%	0.0000%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
PTD	100.0000%	50.5684%	18.7145%	29.6114%	0.0000%	0.0000%	1.1057%	0.0000%	0.0000%
TD	100.0000%	0.0000%	37.8595%	59.9038%	0.0000%	0.0000%	2.2368%	0.0000%	0.0000%
G	100.0000%	24.0803%	25.4929%	46.0196%	0.0000%	2.6890%	1.7183%	0.0000%	0.0000%

Exhibit PPL/1606
Paice/3 - Tab 2

PacifiCorp
12 Months Ended June 2009
Communication Equipment Account 397
Total Company

Class	Description		Acq.value	Accum.dep.	Net Book Val	P%	Prod	T%	Transm	D%	Distribution	CS%	Cust Svc	Total
39700	Communications Equipment	Older - much transmission construction -Includes hand written entries - very old	14,581,660	(4,783,324)	9,798,336	0.17	1,665,717	0.40	3,919,335	0.40	3,919,335	0.03	293,950	$9,798,336.25
39702	Mass Property Communications -Items never tracked - teles & port radios, plus non-unitized projects	Includes portable radios, telephones, & noon-unitized like Biz Center, MW, Mobile Radio	-	-	-	0.20	-	0.20	-	0.50	-	0.10	-	$0.00
39705	Alarm Systems	Alarms for MW system - MW %	6,520,575	(2,627,206)	3,893,370	0.05	194,668	0.75	2,920,027	0.20	778,674	0.00	-	$3,893,369.72
39708	Baseband Equipment	MW system - MW %	1,508,494	(784,003)	724,490	0.05	36,225	0.75	543,368	0.20	144,898	0.00	-	$724,490.09
39710	Communication Equipment-Dist Automation	Distribution Automation	1,207,028	(435,010)	772,017	0.00	-	0.00	-	1.00	772,017	0.00	-	$772,017.23
39711	Base Station	Dist Radio System	15,474,184	(5,607,796)	9,866,388	0.05	493,319	0.10	986,639	0.84	8,287,766	0.01	98,664	$9,866,387.55
39714	Data Network Equipment	Field Off Data net Eq	26,893,667	(6,435,486)	20,458,181	0.13	2,659,563	0.15	3,068,727	0.70	14,320,726	0.02	409,164	$20,458,180.64
39717	Fiber Optics	Much fiber on Hydro Projects	15,602,101	(2,991,180)	12,610,921	0.50	6,305,461	0.35	4,413,823	0.15	1,891,638	0.00	-	$12,610,921.45
39720	Load Management Equipment	Dist Only	1,395,913	(542,201)	853,712	0.00	-	0.00	-	1.00	853,712	0.00	-	$853,711.66
39723	Microwave Equipment	MW installed for TX Line Protection/Control + Dist Traffic	38,513,034	(14,644,422)	23,868,613	0.05	1,193,431	0.75	17,901,459	0.20	4,773,723	0.00	-	$23,868,612.54
39726	Miscellaneous	Dist Traffic on MW	8,072,749	(4,264,130)	3,808,620	0.05	190,431	0.25	952,155	0.70	2,666,034	0.00	-	$3,808,619.69
39729	Multiplex Equip	Dist Traffic on MW	20,804,926	(7,053,464)	13,751,462	0.05	687,573	0.20	2,750,292	0.75	10,313,596	0.00	-	$13,751,461.69
39732	Power Line Carrier	TX Line Protection	6,379,309	(2,594,358)	3,784,951	0.00	-	0.95	3,595,703	0.05	189,248	0.00	-	$3,784,951.00
39735	Power System Equipment	Tx LineTone Protection	12,592,365	(4,081,158)	8,511,207	0.05	425,560	0.85	7,234,526	0.10	851,121	0.00	-	$8,511,207.26
39738	Telemetry/Protective Relaying	TX Line Protection	9,525,647	(3,651,343)	5,874,304	0.00	-	0.95	5,580,589	0.05	293,715	0.00	-	$5,874,303.75
39741	Telephone Equipment "Pbx Related"	PBX for all - field office, plant	28,250,546	(6,712,723)	21,537,823	0.25	5,384,456	0.20	4,307,565	0.50	10,768,912	0.05	1,076,891	$21,537,823.26
39744	Telephone Line Equipment	PBX Line Eq for all	9,676,209	(3,915,844)	5,760,365	0.25	1,440,091	0.20	1,152,073	0.50	2,880,183	0.05	288,018	$5,760,365.11
39747	Structures - Telephone Lines	Cable Installations - fiber, copper, coax - plants	15,917,125	(6,097,237)	9,819,889	0.50	4,909,944	0.35	3,436,961	0.15	1,472,983	0.00	-	$9,819,888.51
39750	Mobile Radio Equipment	Dist Radio System	3,583,595	(1,808,701)	1,774,894	0.05	88,745	0.10	177,489	0.84	1,490,911	0.01	17,749	$1,774,893.61
39758	Satellite Equipment	Satellite term and clock source for Y2K plants & protections SER	359,340	(123,862)	235,478	0.20	47,096	0.70	164,834	0.10	23,548	0.00	-	$235,477.58
*	General Assets - In Service		236,858,468	(79,153,449)	157,705,019		25,722,280		63,105,565		66,692,737		2,184,436	$157,705,018.59
	Com_Eq Factor				**100.00%**		**16.31%**		**40.01%**		**42.29%**		**1.39%**	

From SAP Asset Balance variant Commnunication

Class	Description	Acq.value	Accum.dep.	Book val	
39700	Communications Equip	14,581,660.34	(4,783,324.09)	9,798,336.25	USD
39702	Mass Property Commun	-	-	-	USD
39705	Alarm Systems	6,520,575.33	(2,627,205.61)	3,893,369.72	USD
39708	Baseband Equipment	1,508,493.54	(784,003.45)	724,490.09	USD
39710	Communication Equipm	1,207,027.52	(435,010.29)	772,017.23	USD
39711	Base Station	15,474,183.81	(5,607,796.26)	9,866,387.55	USD
39714	Data Network Equipme	26,893,666.93	(6,435,486.29)	20,458,180.64	USD
39717	Fiber Optics	15,602,101.25	(2,991,179.80)	12,610,921.45	USD
39720	Load Management Equi	1,395,912.54	(542,200.88)	853,711.66	USD
39723	Microwave Equipment	38,513,034.38	(14,644,421.84)	23,868,612.54	USD
39726	Miscellaneous	8,072,749.29	(4,264,129.60)	3,808,619.69	USD
39729	Multiplex Equip	20,804,926.03	(7,053,464.34)	13,751,461.69	USD
39732	Power Line Carrier	6,379,308.83	(2,594,357.83)	3,784,951.00	USD
39735	Power System Equipme	12,592,364.91	(4,081,157.65)	8,511,207.26	USD
39738	Telemetry/Protective	9,525,647.23	(3,651,343.48)	5,874,303.75	USD
39741	Telephone Equipment	28,250,546.43	(6,712,723.17)	21,537,823.26	USD
39744	Telephone Line Equip	9,676,209.19	(3,915,844.08)	5,760,365.11	USD
39747	Struct - Phone Lines	15,917,125.18	(6,097,236.67)	9,819,888.51	USD
39750	Mobile Radio Equipme	3,583,595.06	(1,808,701.45)	1,774,893.61	USD
39753	Struct and Found	406,770.12	(132,556.87)	274,213.25	USD
39758	Satellite Equipment	359,339.92	(123,862.34)	235,477.58	USD
	Total	**$237,265,237.83**	**-$79,286,005.99**	**$157,979,231.84**	

Exhibit PPL/1606
Paice/4 - Tab 2

PacifiCorp
CSS System Allocation Factor
Business Center Allocation Factor
12 Months Ended June 2009

Description	Total	Production	Transmission	Distribution	Retail	Ancillary	C_Billing	C_Metering	C_Service
Customer Service System (CSS)									
CSS_SYS	100.0000%						55.0000%	18.0000%	27.0000%

The size is based on the lines of code; regardless of type of code.
Some Additional Code related to general use and system maintenance is assumed to be shared by all functions.

Description	Total	Production	Transmission	Distribution	Retail	Ancillary	C_Billing	C_Metering	C_Service
Business Center Expenses									
Wasatch Business Center -									
2008/09	10,092,734						9,947,584		145,151
2008/09 Support	1,353,740						676,870		676,870
Portland Business Center -									
2008/09	22,690,422						16,753,652		5,936,770
2008/09 Support	5,306,986						2,653,493		2,653,493
Total	$ 39,443,882						$ 30,031,599		$ 9,412,284
B_CENTER	100.0000%						76.1375%		23.8625%

Exhibit PPL/1606
Paice/5 - Tab 2

PacifiCorp
Summary of Ferc Accounts 901 - 910 by Funtional Groups

Line No.	Description	FERC Account	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
1	Supervision	901	2,641,114					1,211,713	623,704	805,697
2	Meter Reading	902	24,373,167					-	24,373,167	-
3	Cust. Records & Coll. Exp.	903	58,055,055					35,020,146	-	23,034,908
4	Misc. Customer Acct. Exp.	905	260,837					-	10,019	250,817
5	Supervision	907	250,935					-	-	250,935
6	Customer Assistance Exp.	908	55,395,680					-	-	55,395,680
7	Information & Instructional Exp.	909	5,040,889					-	-	5,040,889
8	Misc. cust. Serv. & Inform. Exp.	910	30,617					-	-	30,617
9		Total	146,048,294							
10										
11	Uncollectible Accounts	904	14,527,502							
12	Grand Total		160,575,796							

Account	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
CUST901	100.0000%					45.8789%	23.6152%	30.5059%
CUST903	100.0000%					60.3223%	-	39.6777%
CUST905	100.0000%					-	3.8412%	96.1588%

Exhibit PPL/1606
Paice/6 - Tab 2

PacifiCorp
12 Months Ended June 2009
Deferred Debits / Reg Assets

	Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
RA-SE	182M	SE	P	0	0	0	0	0	0	0	0
RA-SG	182M	SG	P	0	0	0	0	0	0	0	0
RA-SGCT	182M	SGCT	P	9,073	9,073	0	0	0	0	0	0
RA-SG-P	182M	SG-P	P	3,982	3,982	0	0	0	0	0	0
RA-SO	182M	SO	DMSC	4,310	0	0	4,310	0	0	0	0
RA-SO	182M	SO	DPW	1	0	0	1	0	0	0	0
RA-SO	182M	SO	ESD	1,346	404	135	808	0	0	0	0
RA-SO	182M	SO	P	1,807	1,807	0	0	0	0	0	0
RA-SO	182M	SO	TD	0	0	0	0	0	0	0	0
RA-TROJD	182M	TROJD	P	1,895	1,895	0	0	0	0	0	0
RA-TROJP	182M	TROJP	P	1,294	1,294	0	0	0	0	0	0
RA-SITUS	182M	SITUS	DMSC	-586	0	0	-586	0	0	0	0
RA-SITUS	182M	SITUS	LABOR	-3,021	-1,256	-170	-876	0	-206	-328	-186
RA-SITUS	182M	SITUS	P	139	139	0	0	0	0	0	0
RA-SITUS	182M	SITUS	PTD	5,158	2,608	965	1,527	0	0	57	0
RA-SITUS	182M	SITUS	CUST	4,457	0	0	0	0	4,457	0	0
	Total-SO			7,464	2,210	135	5,119	-	-	0	-
	Total SITUS			6,148	1,492	795	65	-	4,252	(271)	(186)
	Total RA			29,855	19,946	930	5,185	-	4,252	(271)	(186)
	DDSO2 FACTOR			**100.00%**	**29.6134%**	**1.8037%**	**68.5824%**	**0.0000%**	**0.0000%**	**0.0005%**	**0.0000%**
	DDS2 FACTOR			**100.00%**	**24.2675%**	**12.9395%**	**1.0649%**	**0.0000%**	**69.1552%**	**-4.4098%**	**-3.0174%**
DD-SE	186M	SE	P	9,052	9,052	0	0	0	0	0	0
DD-SG	186M	SG	P	17,055	17,055	0	0	0	0	0	0
DD-SG	186M	SG	T	15,790	0	15,790	0	0	0	0	0
DD-SO	186M	SO	DMSC	51	0	0	51	0	0	0	0
DD-SITUS	186M	SITUS	T	94	0	94	0	0	0	0	0
DD-SITUS	186M	SITUS	LABOR	-	0	0	0	0	0	0	0
	Total SITUS			94	-	94	-	-	-	-	-
	Total SG			32,845	17,055	15,790	-	-	-	-	-
	Total-SO			51	-	-	51	-	-	-	-
	Total-DD			42,041	26,107	15,884	51	-			-
	DDS6 FACTOR			**100.00%**	**0.0000%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	DEFSG FACTOR			**100.00%**	**51.9261%**	**48.0739%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	DDSO6 FACTOR			**100.00%**	**0.0000%**	**0.0000%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**

Exhibit PPL/1606
Paice/7 - Tab 2

PacifiCorp
12 Months Ended June 2009
Deferred Debits / Reg Assets

Pri-Acct	Factor	Function	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Major Adjustment										
1998 Early Retirement		LABOR	-	0	0	0	0	0	0	0
1999 Early Retirement		LABOR	-	0	0	0	0	0	0	0
Transition Planning		PTD	-	0	0	0	0	0	0	0
Environmental Clean-up		ESD	-	0	0	0	0	0	0	0
Y2K		PTD	-	0	0	0	0	0	0	0
Subtotal Major Adjustments			-	-	-	-	-	-	-	-
Total 186M SO			51	-	-	51	-	-	-	-
Total 182 &186			71,897	46,053	16,814	5,235	-	4,252	(271)	(186)

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
DMSC	100.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.4005%	0.0000%	0.0000%	3.5995%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
ESD	100.0000%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GP	100.0000%	50.1001%	18.5110%	29.5373%	0.0000%	0.4365%	1.2246%	0.1906%
LABOR	100.0000%	41.5652%	5.6217%	29.0034%	0.0000%	6.8081%	10.8614%	6.1402%
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PTD	100.0000%	50.5684%	18.7145%	29.6114%	0.0000%	0.0000%	1.1057%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TAXDEPR	100.0000%	62.8300%	12.9857%	22.6212%	0.0000%	0.5792%	0.6111%	0.3728%
TD	100.0000%	0.0000%	37.8595%	59.9038%	0.0000%	0.0000%	2.2368%	0.0000%

Exhibit PPL/1606
Paice/8 - Tab 2

PacifiCorp
12 Months Ended June 2009
General Plant

Description		Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
Business Centers		CN	CUST	24,639	0	0	0	0	24,639	0	0
		SE	P	869	869	0	0	0	0	0	0
		SG	P	93,452	93,452	0	0	0	0	0	0
		SG	T	88,965	0	88,965	0	0	0	0	0
		SG	TD	0	0	0	0	0	0	0	0
General Plant		SO	DPW	0	0	0	0	0	0	0	0
		SO	PTD	240,526	121,630	45,013	71,223	0	0	2,659	0
		SO	TD	0	0	0	0	0	0	0	0
		SO	P	0	0	0	0	0	0	0	0
	SSGCH	SG	P	4,490	4,490	0	0	0	0	0	0
	SSGCT	SG	DPW	0	0	0	0	0	0	0	0
	SSGCT	SG	P	204	204	0	0	0	0	0	0
		SITUS	DPW	200,041	0	0	192,840	0	0	7,201	0
		SITUS	P	0	0	0	0	0	0	0	0
		SITUS	TD	263,102	0	99,609	157,608	0	0	5,885	0
Total-CUST				24,639	0	0	0	0	24,639	0	0
Total-TD				263,102	0	99,609	157,608	0	0	5,885	0
Total-PTD				240,526	121,630	45,013	71,223	0	0	2,659	0
Total-DPW				200,041	0	0	192,840	0	0	7,201	0
Total-SSGCH				0	0	0	0	0	0	0	0
Total-SSGCT				0	0	0	0	0	0	0	0
Total-G-SG				187,111	98,145	88,965	0	0	0	0	0
Total-UT				869	869	0	0	0	0	0	0
Total-G-Situs				463,143	0	99,609	350,449	0	0	13,085	0
Total-SO				240,526	121,630	45,013	71,223	0	0	2,659	0
Total-General Plant				916,288	220,645	233,588	421,672	0	24,639	15,745	0
G-SG Factor				**100.00%**	**52.4531%**	**47.5469%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
UT Factor				**100.00%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
G-SITUS Factor				**100.00%**	**0.0000%**	**21.5072%**	**75.6674%**	**0.0000%**	**0.0000%**	**2.8254%**	**0.0000%**
SO Factor				**100.00%**	**50.5684%**	**18.7145%**	**29.6114%**	**0.0000%**	**0.0000%**	**1.1057%**	**0.0000%**
G Allocator				**100.00%**	**24.0803%**	**25.4929%**	**46.0196%**	**0.0000%**	**2.6890%**	**1.7183%**	**0.0000%**
Total Gen. Plant				916,288							
Mining			acct 399 fror	271,600	869	869	0	0	0	0	0
Total			P	1,187,888							

Functional Allocators:

		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	37.86%	59.90%	0.00%	0.00%	2.24%	0.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
DPW	100.00%	0.00%	0.00%	96.40%	0.00%	0.00%	3.60%	0.00%
PTD	100.00%	50.57%	18.71%	29.61%	0.00%	0.00%	1.11%	0.00%
GP	100.00%	50.10%	18.51%	29.54%	0.00%	0.44%	1.22%	0.19%

Exhibit PPL/1606
Paice/9 - Tab 2

PacifiCorp
12 Months Ended June 2009
Intangible Plant
(In 000's)

Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
CN	CSS_SYS	107,129	0	0	0	0	58,921	19,283	28,925
CN	CUST	4,517	0	0	0	0	2,484	813	1,220
CN	C_METER	2,417	0	0	0	0	0	2,417	0
CN	C_SERVICE	1,981	0	0	0	0	0	0	1,981
SE	P	3,817	3,817	0	0	0	0	0	0
SG	P	87,961	87,961	0	0	0	0	0	0
SG	PTD	-	0	0	0	0	0	0	0
SG	T	18,353	0	18,353	0	0	0	0	0
SG	P	98,882	98,882	0	0	0	0	0	0
SG	P	9,842	9,842	0	0	0	0	0	0
SO	CUST	2,563	0	0	0	0	1,409	461	692
SO	C_METER	2,908	0	0	0	0	0	2,908	0
SO	C_BILLING	2,179	0	0	0	0	2,179	0	0
SO	DPW	24,000	0	0	23,136	0	0	864	0
SO	P	16,178	16,178	0	0	0	0	0	0
SO	PTD	302,521	152,980	56,615	89,581	0	0	3,345	0
SO	TD	12,646	0	4,788	7,575	0	0	283	0
SO	LABOR	-	0	0	0	0	0	0	0
SITUS	PTD	393	199	74	116	0	0	4	0
SITUS	TD	3,137	0	1,188	1,879	0	0	70	0
Total-DGP		-	-	-	-	-	-	-	-
Total-DGU		-	-	-	-	-	-	-	-
Total-SG		215,039	196,685	18,353	-	-	-	-	-
Total-SITUS		3,530	199	1,261	1,995	-	-	75	-
Total-Intangible		701,424	369,859	81,018	122,288	-	64,994	30,448	32,817
I-SG FACTOR		**100.00%**	**91.4651%**	**8.5349%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
I-Situs FACTOR		**100.00%**	**5.6319%**	**35.7273%**	**56.5301%**	**0.0000%**	**0.0000%**	**2.1108%**	**0.0000%**
I FACTOR		**100.00%**	**52.7298%**	**11.5504%**	**17.4342%**	**0.0000%**	**9.2660%**	**4.3409%**	**4.6787%**

Functional Allocators:		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	37.86%	59.90%	0.00%	0.00%	2.24%	0.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
C_BILLING	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
C_METER	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
C_SERVICE	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
CSS_SYS	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	55.00%	18.00%	27.00%
DPW	100.00%	0.00%	0.00%	96.40%	0.00%	0.00%	3.60%	0.00%
PTD	100.00%	50.57%	18.71%	29.61%	0.00%	0.00%	1.11%	0.00%
LABOR	100.00%	41.57%	5.62%	29.00%	0.00%	6.81%	10.86%	6.14%

Exhibit PPL/1606
Paice/10 - Tab 2

PacifiCorp
Oregon Labor Costs
12 Months Ended June 2009

Ferc Account	Funct.	FERC Form 1	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
500-554, 913,916	P	52,215,725	52,215,725	-	-	-	-	-	-
560-569, 571-573	T	5,136,378	-	5,136,378	-	-	-	-	-
580,590	D_Split	7,472,881	-	-	7,203,893	-	-	268,988	-
581,585,587-589,591,596,598, 599	D	29,359,435	-	-	29,359,435	-	-	-	-
586,597,902	C_Meter	13,261,223	-	-	-	-	-	13,261,223	-
901	CUST901	677,776	-	-	-	-	310,956	160,058	206,762
903	CUST903	13,712,533	-	-	-	-	8,271,716	-	5,440,817
905	CUST905	59,658	-	-	-	-	-	2,292	57,366
907,908	C_Service	1,881,540	-	-	-	-	-	-	1,881,540
909,910	C_Service	154,172	-	-	-	-	-	-	154,172
570	Step_Up	2,134,406	183,689	1,950,717	-	-	-	-	-
	Total Labor	126,065,727	52,399,413	7,087,095	36,563,328	-	8,582,672	13,692,561	7,740,657
	LABOR	**100.0000%**	**41.5652%**	**5.6217%**	**29.0034%**	**-**	**6.8081%**	**10.8614%**	**6.1402%**

Functional Allocation Factor		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
C_METER	100.0000%	-	-	-	-	-	100.000%	-
C_Service	100.0000%	-	-	-	-	-	-	100.000%
CUST901	100.0000%	-	-	-	-	45.879%	23.615%	30.506%
CUST903	100.0000%	-	-	-	-	60.322%	-	39.678%
CUST905	100.0000%	-	-	-	-	-	3.841%	96.159%
D	100.0000%	-	-	100.000%	-	-	-	-
D_SPLIT	100.0000%	-	-	96.400%	-	-	3.600%	-
P	100.0000%	100.000%	-	-	-	-	-	-
STEP_UP	100.0000%	8.6061%	91.3939%	-	-	-	-	-
T	100.0000%	-	100.0000%	-	-	-	-	-
1	2	3	4	5	6	7	8	9

Exhibit PPL/1606
Paice/11 - Tab 2

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
						ADDITIONS					
SCHMAP-SE	SCHMAP	SE	P	97	97	-	-	-	-	-	-
SCHMAP-SO	SCHMAP	SO	LABOR	9,030	3,753	508	2,619	-	615	981	554
SCHMAP-SO	SCHMAP	SO	PTD	847	428	159	251	-	-	9	-
	Total-SO			9,877	4,182	666	2,870	-	615	990	554
	Total SCHMAP			9,974	4,278	666	2,870	-	615	990	554
	SCHMAP-SO			**100.00%**	**42.3373%**	**6.7446%**	**29.0555%**	**0.0000%**	**6.2242%**	**10.0248%**	**5.6136%**
	SCHMAP FACTOR			**100.00%**	**42.8956%**	**6.6793%**	**28.7742%**	**0.0000%**	**6.1640%**	**9.9277%**	**5.5592%**
SCHMAT-CIAC	SCHMAT	CIAC	DPW	41,630	-	-	40,132	-	-	1,498	-
SCHMAT-BADDEBT	SCHMAT	BADDEBT	CUST	882	-	-	-	-	882	-	-
SCHMAT-SCHMDEXP	SCHMAT	SCHMDEXP	GP	514,728	257,879	95,281	152,037	-	2,247	6,303	981
SCHMAT-SE	SCHMAT	SE	P	20,541	20,541	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	P	5,038	5,038	-	-	-	-	-	-
SCHMAT-SG	SCHMAT	SG	T	(1,079)	-	(1,079)	-	-	-	-	-
SCHMAT-SGCT	SCHMAT	SGCT	P	939	939	-	-	-	-	-	-
SCHMAT-SNP	SCHMAT	SNP	GP	4,223	2,116	782	1,247	-	18	52	8
SCHMAT-SNP	SCHMAT	SNP	PTD	59,409	30,042	11,118	17,592	-	-	657	-
SCHMAT-SNPD	SCHMAT	SNPD	DPW	2,196	-	-	2,117	-	-	79	-
SCHMAT-SO	SCHMAT	SO	DMSC	190	-	-	-	-	-	-	190
SCHMAT-SO	SCHMAT	SO	LABOR	12,059	5,012	678	3,498	-	821	1,310	740
SCHMAT-SO	SCHMAT	SO	PTD	3,245	1,641	607	961	-	-	36	-
SCHMAT-TROJD	SCHMAT	TROJD	P	1,465	1,465	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	DPW	2,572	-	-	2,480	-	-	93	-
SCHMAT-SITUS	SCHMAT	SITUS	DMSC	1,246	-	-	-	-	-	-	1,246
SCHMAT-SITUS	SCHMAT	SITUS	ESD	94	28	9	57	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	LABOR	43,925	18,257	2,469	12,740	-	2,990	4,771	2,697
SCHMAT-SITUS	SCHMAT	SITUS	P	24,641	24,641	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	PTD	831	420	156	246	-	-	9	-
SCHMAT-SITUS	SCHMAT	SITUS	CUST	-	-	-	-	-	-	-	-
SCHMAT-SITUS	SCHMAT	SITUS	T	258	-	258	-	-	-	-	-
	Total-SG			3,960	5,038	(1,079)	-	-	-	-	-
	Total-SE			20,541	20,541	-	-	-	-	-	-
	Total-SNP			63,632	32,158	11,900	18,839	-	18	709	8
	Total-SITUS			73,568	43,347	2,892	15,522	-	2,990	4,873	3,943
	Total SO			15,494	6,653	1,285	4,458	-	821	1,346	931
	Total-SCHMAT			739,034	368,020	110,280	233,105	-	6,959	14,808	5,863
	SCHMAT-SG			**100.00%**	**127.2371%**	**-27.2371%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	SCHMAT-SE			**100.00%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	SCHMAT-SNP			**100.00%**	**50.5373%**	**18.7010%**	**29.6065%**	**0.0000%**	**0.0290%**	**1.1136%**	**0.0127%**
	SCHMAT-SITUS			**100.00%**	**58.9210%**	**3.9317%**	**21.0993%**	**0.0000%**	**4.0649%**	**6.6234%**	**5.3598%**
	SCHMAT-SO			**100.00%**	**42.9403%**	**8.2946%**	**28.7746%**	**0.0000%**	**5.2987%**	**8.6850%**	**6.0067%**
	SCHMAT FACTOR			**100.00%**	**49.7974%**	**14.9222%**	**31.5419%**	**0.0000%**	**0.9416%**	**2.0036%**	**0.7933%**
SCHMAF-DGP	SCHMAF	DGP	P	-	-	-	-	-	-	-	-
SCHMAF-TROJP	SCHMAF	TROJP	P	-	-	-	-	-	-	-	-
	Total-SCHMAF			-	-	-	-	-	-	-	-
	SCHMAF FACTOR			**0.00%**							
	Total-SCHMA			749,008	372,298	110,946	235,975	-	7,573	15,798	6,418
	SCHMA FACTOR			**100.00%**	**49.7055%**	**14.8124%**	**31.5050%**	**0.0000%**	**1.0111%**	**2.1092%**	**0.8568%**

Exhibit PPL/1606
Paice/12 - Tab 2

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
						DEDUCTIONS					
SCHMDP-SE	SCHMDP	SE	LABOR	-	-	-	-	-	-	-	-
SCHMDP-SE	SCHMDP	SE	P	1,972	1,972	-	-	-	-	-	-
SCHMDP-SG	SCHMDP	SG	P	-	-	-	-	-	-	-	-
SCHMDP-SNP	SCHMDP	SNP	PTD	372	188	70	110	-	-	4	-
SCHMDP-SO	SCHMDP	SO	LABOR	8,502	3,534	478	2,466	-	579	923	522
SCHMDP-SO	SCHMDP	SO	PTD	(0)	(0)	(0)	(0)	-	-	(0)	-
	Total-SO			8,502	3,534	478	2,466	-	579	923	522
	Total-SCHMDP			10,846	5,694	548	2,576	-	579	928	522
	SCHMDP-SO			**100.00%**	**41.5649%**	**5.6214%**	**29.0034%**	**0.0000%**	**6.8083%**	**10.8617%**	**6.1403%**
	SCHMDP FACTOR			**100.00%**	**52.4964%**	**5.0492%**	**23.7521%**	**0.0000%**	**5.3369%**	**8.5522%**	**4.8133%**
SCHMDT-BADDEBT	SCHMDT	BADDEBT	CUST	-	-	-	-	-	-	-	-
SCHMDT-CN	SCHMDT	CN	CUST	63	-	-	-	-	63	-	-
SCHMDT-DGP	SCHMDT	DGP	P	1	1	-	-	-	-	-	-
SCHMDT-GPS	SCHMDT	GPS	GP	185	93	34	55	-	1	2	0
SCHMDT-TROJD	SCHMDT	GPS	PTD	78,287	39,589	14,651	23,182	-	-	866	-
SCHMDT-SITUS	SCHMDT	SE	P	33,903	33,903	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	P	8,856	8,856	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	GP	-	-	-	-	-	-	-	-
SCHMDT-SG	SCHMDT	SG	T	9,624	-	9,624	-	-	-	-	-
SCHMDT-SNP	SCHMDT	SNP	PTD	81,923	41,427	15,331	24,258	-	-	906	-
SCHMDT-SNPD	SCHMDT	SNPD	DPW	224	-	-	216	-	-	8	-
SCHMDT-SO	SCHMDT	SO	DMSC	11,599	-	-	-	-	-	-	11,599
SCHMDT-SO	SCHMDT	SO	ESD	3,076	923	308	1,846	-	-	-	-
SCHMDT-SO	SCHMDT	SO	GP	11,507	5,765	2,130	3,399	-	50	141	22
SCHMDT-SO	SCHMDT	SO	LABOR	12,747	5,298	717	3,697	-	868	1,385	783
SCHMDT-SO	SCHMDT	SO	P	5,041	5,041	-	-	-	-	-	-
SCHMDT-SO	SCHMDT	SO	PTD	7,160	3,621	1,340	2,120	-	-	79	-
SCHMDT-SO	SCHMDT	SO	TAXDEPR	4,256	2,674	553	963	-	25	26	16
SCHMDT-TAXDEPR	SCHMDT	TAXDEPR	TAXDEPR	1,189,293	747,233	154,438	269,032	-	6,889	7,268	4,434
SCHMDT-TROJD	SCHMDT	TROJD	P	-	-	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	DMSC	6	-	-	-	-	-	-	6
SCHMDT-SITUS	SCHMDT	SITUS	DPW	1,088	-	-	1,049	-	-	39	-
SCHMDT-SITUS	SCHMDT	SITUS	GP	379	190	70	112	-	2	5	1
SCHMDT-SITUS	SCHMDT	SITUS	LABOR	3,385	1,407	190	982	-	230	368	208
SCHMDT-SITUS	SCHMDT	SITUS	P	32,054	32,054	-	-	-	-	-	-
SCHMDT-SITUS	SCHMDT	SITUS	PTD	24,079	12,176	4,506	7,130	-	-	266	-
SCHMDT-SITUS	SCHMDT	SITUS	T	74	-	74	-	-	-	-	-
	Total-GPS			185	93	34	55	-	1	2	0
	Total-SG			18,481	8,856	9,624	-	-	-	-	-
	Total-SNP			81,923	41,427	15,331	24,258	-	-	906	-
	Total-SNPD			224	-	-	216	-	-	8	-
	Total SO			55,386	23,321	5,047	12,024	-	943	1,631	12,420
	Total-SITUS			94,970	79,731	4,841	9,273	-	232	678	215
	Total SCHMDT			1,518,813	940,251	203,967	338,041	-	8,127	11,358	17,069
	SCHMDT-GPS			**100.00%**	**50.1001%**	**18.5110%**	**29.5373%**	**0.0000%**	**0.4365%**	**1.2246%**	**0.1906%**
	SCHMDT-SG			**100.00%**	**47.9216%**	**52.0784%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	SCHMDT-SNP			**100.00%**	**50.5684%**	**18.7145%**	**29.6114%**	**0.0000%**	**0.0000%**	**1.1057%**	**0.0000%**
	SCHMDT-SNPD			**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
	SCHMDT-SO			**100.00%**	**42.1072%**	**9.1120%**	**21.7102%**	**0.0000%**	**1.7021%**	**2.9441%**	**22.4243%**
	SCHMDT-SITUS			**100.00%**	**83.9541%**	**5.0976%**	**9.7640%**	**0.0000%**	**0.2444%**	**0.7136%**	**0.2262%**
	SCHMDT FACTOR			**100.00%**	**61.9070%**	**13.4294%**	**22.2569%**	**0.0000%**	**0.5351%**	**0.7478%**	**1.1238%**

Exhibit PPL/1606
Paice/13 - Tab 2

	Primary Account	PITA Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
SCHMDF-DGP	SCHMDF	DGP	P	-	-	-	-	-	-	-	-
	Total-SCHMDF			-	-	-	-		-		-
	SCHMDF FACTOR			**0.00%**							
	Total-SCHMD			1,529,659	945,945	204,515	340,617	-	8,706	12,285	17,591
	SCHMD FACTOR			**100.00%**	**61.8403%**	**13.3699%**	**22.2675%**	**0.0000%**	**0.5691%**	**0.8031%**	**1.1500%**
	Net SCHM										

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service
DMSC	100.00%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DPW	100.00%	0.0000%	0.0000%	96.4005%	0.0000%	0.0000%	3.5995%	0.0000%
CUST	100.00%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
ESD	100.00%	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%
GP	100.00%	50.1001%	18.5110%	29.5373%	0.0000%	0.4365%	1.2246%	0.1906%
LABOR	100.00%	41.5652%	5.6217%	29.0034%	0.0000%	6.8081%	10.8614%	6.1402%
P	100.00%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PT	100.00%	72.9882%	27.0118%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
PTD	100.00%	50.5684%	18.7145%	29.6114%	0.0000%	0.0000%	1.1057%	0.0000%
T	100.00%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TAXDEPR	100.00%	62.8300%	12.9857%	22.6212%	0.0000%	0.5792%	0.6111%	0.3728%
TD	100.00%	0.0000%	37.8595%	59.9038%	0.0000%	0.0000%	2.2368%	0.0000%

PacifiCorp
12 Months Ended June 2009
Step-up Transformer Factor

Asset Class 35340 = GSU and Assoc Equip

Class	Description	Acq.value	Accum.dep.	Book Value
35300	Station Equipment	285,267,843.08	-39,552,719.68	245,715,123.40
35301	Transformers	216,491,122.96	-63,765,985.39	152,725,137.57
35303	Static Var Unit	21,506,467.81	-2,384,877.82	19,121,589.99
35305	Synchronous Condens.	5,727,108.08	-2,408,150.90	3,318,957.18
35307	Regulators	962,443.49	-332,002.16	630,441.33
35309	Circuit Breakers	124,210,852.39	-28,422,754.01	95,788,098.38
35311	Capacitor Bank	34,503,646.95	-8,187,864.73	26,315,782.22
35313	Metal Clad Switchgr.	3,434,094.03	-549,065.24	2,885,028.79
35315	Switching Equipment	59,322,302.82	-15,763,741.35	43,558,561.47
35317	Structures & Foundn.	109,851,270.24	-25,231,365.67	84,619,904.57
35319	Relay & Control Eqp.	105,410,790.32	-20,811,598.20	84,599,192.12
35321	Storage Battery Eqp.	5,303,108.41	-809,284.04	4,493,824.37
35323	Auxiliary Power Eqp.	1,660,801.37	-399,259.94	1,261,541.43
35325	Grounding System	14,591,289.90	-2,688,250.34	11,903,039.56
35327	Bus,Wire,Cable&Insul	96,585,567.58	-23,788,416.72	72,797,150.86
35329	Station Lighting	1,515,773.96	-390,322.14	1,125,451.82
35331	Mobile Substation	987,910.50	-511,018.31	476,892.19
35333	Mobile Circuit Swtcr	227,698.97	-57,218.40	170,480.57
35337	Crane Or Hoist	850.74	-602.51	248.23
35339	Fire Protection Sys.	91,267.57	-20,694.38	70,573.19
35340	GSU and Assoc Equip	106,360,077.91	-23,394,065.94	82,966,011.97
35341	Supervsry Cont Equip	28,341,890.92	-10,037,731.92	18,304,159.00
35342	Sprvsry Cntl Eqp 353	1,028,540.33	-242,045.84	786,494.49
35343	Dispatch Comp. Sys.	18,037,582.93	-10,217,789.74	7,819,793.19
35344	Dsptch Comp Sys(353)	256,881.73	-81,638.16	175,243.57
35345	Dispatch Hardware	4,677,145.51	-2,469,238.90	2,207,906.61
35347	Dsptch Strg Btry Eqp	274,776.57	-197,038.99	77,737.58
35348	Dsptch Strg Btry 353	66,081.69	-19,830.59	46,251.10
35349	Dispatch Time Stdrd	26,934.25	-12,224.53	14,709.72
35350	Dsptch Time Std(353)	51,563.88	-17,574.45	33,989.43
35351	Dispatch Aux Pwr Eqp	183,663.97	-154,065.75	29,598.22
	PacifiCorp	1,246,957,350.86	(282,918,436.74)	964,038,914.12

		$	Percent	
35340	Step-up Transformers included in Acct 353	82,966,011.97	8.606085%	Production
	Acct 353 other than step-up transformers	881,072,902.15	91.393915%	Transmission
35300-35399	Account 353 Station Equipment	964,038,914.12	100.000000%	

		$	Percent	
35340	Step-up Transformers included in Acct 353	-	0.000000%	Production
	Acct 353 other than step-up transformers	706,249,527.15	100.000000%	Transmission
35300-35399	Account 353 Station Equipment	706,249,527.15	100.000000%	
		52,154,084.06	(14,054,299.62)	38,099,784.44

Exhibit PPL/1606
Paice/15 - Tab 2

PacifiCorp
12 Months Ended June 2009
Tax Depreciation

	Total	Production	Transmission	Distribution	General	Mining
Total	939,854,138	538,450,150	113,719,968	185,381,813	93,076,992	9,225,215

Conversion to COS Functions	**Total**	**Production**	**Transmission**	**Distribution**	**Ancillary**	**C_Billing**	**C_Metering**	**C_Service**	**DSM**
Percent of GenPlant in Functions (%'s developed in JAM Dec 2011 - use "Total Plant" variable)	100.0000%	46.0213%	8.9457%	29.2493%	0.0000%	5.8487%	6.1706%	3.7643%	0.0000%
Allocation of GenPlant to Functions	93,076,992	42,835,285	8,326,417	27,224,406	-	5,443,828	5,743,377	3,503,678	-
Assignment of Mining to Prod Function	9,225,215	9,225,215							
Adjusted Totals	939,854,138	590,510,650	122,046,385	212,606,219	-	5,443,828	5,743,377	3,503,678	-
TAXDEPR FACTOR	**100.0000%**	**62.8300%**	**12.9857%**	**22.6212%**	**0.0000%**	**0.5792%**	**0.6111%**	**0.3728%**	**0.0000%**

Exhibit PPL/1606
Paice/16 - Tab 2

12 Months Ended June 2009
Gross Plant
(In 000's)

Description	Alloc. Factor	Funct.	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
Production Plant		P	8,587,851	8,587,851	0	0	0	0	0	0	0
Transmission Plant		T	3,178,223	0	3,178,223	0	0	0	0	0	0
Distribution Plant		DPW	5,216,568	0	0	5,028,796	0	0	187,772	0	0
Mining	SE	P	271,600	271,600	0	0	0	0	0	0	0
General Plant				0	0	0	0	0	0	0	0
Business Centers	CN	B_Center	24,639	0	0	0	0	18,759	0	5,879	0
Utah Mine	SE	P	869	869	0	0	0	0	0	0	0
	SG	P	93,452	93,452	0	0	0	0	0	0	0
	SG	T	88,965	0	88,965	0	0	0	0	0	0
	SO	DPW	0	0	0	0	0	0	0	0	0
	SG	P	4,490	4,490	0	0	0	0	0	0	0
	SG	DPW	0	0	0	0	0	0	0	0	0
	SG	P	204	204	0	0	0	0	0	0	0
General Plant	SITUS	DPW	200,041	0	0	192,840	0	0	7,201	0	0
General Plant	SITUS	P	0	0	0	0	0	0	0	0	0
General Plant	SITUS	TD	263,102	0	99,609	157,608	0	0	5,885	0	0
Total General Plant			675,762	99,014	188,575	350,449	0				0
Intangible Plant											
	CN	CSS_SYS	107,129	0	0	0	0	58,921	19,283	28,925	0
	SE	P	3,817	3,817	0	0	0	0	0	0	0
	SG	P	87,961	87,961	0	0	0	0	0	0	0
	SG	PTD	0	0	0	0	0	0	0	0	0
	SG	T	18,353	0	18,353	0	0	0	0	0	0
	SG	P	98,882	98,882	0	0	0	0	0	0	0
	SG	P	9,842	9,842	0	0	0	0	0	0	0
	SO	CUST	2,563	0	0	0	0	1,409	461	692	0
	SO	C_METER	2,908	0	0	0	0	0	2,908	0	0
	SO	C_BILLING	2,179	0	0	0	0	2,179	0	0	0
	SO	DPW	24,000	0	0	23,136	0	0	864	0	0
	SO	P	16,178	16,178	0	0	0	0	0	0	0
	SO	PTD	302,521	152,980	56,615	89,581	0	0	3,345	0	0
	SO	TD	12,646	0	4,788	7,575	0	0	283	0	0
	SO	LABOR	0	0	0	0	0	0	0	0	0
Total Intangible Plant			688,979	369,661	79,756	120,292	0				0
Total Gross Plant			18,618,983	9,328,126	3,446,554	5,499,537	0	81,269	228,001	35,496	0
GP Factor			**100.0000%**	**50.1001%**	**18.5110%**	**29.5373%**	**0.0000%**	**0.4365%**	**1.2246%**	**0.1906%**	**0.0000%**

Functional Allocators:		Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
T	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
TD	100.0000%	0.0000%	37.8595%	59.9038%	0.0000%	0.0000%	2.2368%	0.0000%	0.0000%
B_Center	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	76.1375%	0.0000%	23.8625%	0.0000%
CSS_SYS	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%
CUST	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	55.0000%	18.0000%	27.0000%	0.0000%
C_BILLING	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%
C_METER	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
C_SERVICE	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
DPW	100.0000%	0.0000%	0.0000%	96.4005%	0.0000%	0.0000%	3.5995%	0.0000%	0.0000%
PTD	100.0000%	50.5684%	18.7145%	29.6114%	0.0000%	0.0000%	1.1057%	0.0000%	0.0000%
LABOR	100.0000%	41.5652%	5.6217%	29.0034%	0.0000%	6.8081%	10.8614%	6.1402%	0.0000%

Exhibit PPL/1606
Paice/17 - Tab 2

PacifiCorp
12 Months Ended June 2009
Account 456

Main Account	Factor	Function	Amount	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
456	SO	DMSC	40,720	0	0	40,720	0	0	0	0	0
456	SE	P	0	0	0	0	0	0	0	0	0
456	SE	T	13,863	0	13,863	0	0	0	0	0	0
456	SG	P	40,177	40,177	0	0	0	0	0	0	0
456	SG	T	56,627	0	56,627	0	0	0	0	0	0
456	SO	PTD	828	418	155	245	0	0	9	0	0
456	SITUS	DMSC	-208	0	0	-208	0	0	0	0	0
456	SITUS	PTD	0	0	0	0	0	0	0	0	0
Total Situs Revenues			-208	0	0	-208	0	0	0	0	0
Total CN Revenues			0	0	0	0	0	0	0	0	0
Total SE Revenues			13,863	0	13,863	0	0	0	0	0	0
Total SG Revenues			96,804	40,177	56,627	0	0	0	0	0	0
Total SO Revenues			41,548	418	155	40,966	0	0	9	0	0
Total Operation			152,007	40,596	70,645	40,758	0	0	9	0	0
OTHSITUS			**100.0000%**	**0.0000%**	**0.0000%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
CN Factor			**0.0000%**								
OTHSE			**100.0000%**	**0.0000%**	**100.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
OTHSG			**100.0000%**	**41.5036%**	**58.4964%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
OTHSO			**100.0000%**	**1.0072%**	**0.3727%**	**98.5980%**	**0.0000%**	**0.0000%**	**0.0220%**	**0.0000%**	**0.0000%**
Total Operation Factor			**100.0000%**	**26.7063%**	**46.4747%**	**26.8129%**	**0.0000%**	**0.0000%**	**0.0060%**	**0.0000%**	**0.0000%**

	Total	Production	Transmission	Distribution	Ancillary	C_Billing	C_Metering	C_Service	DSM
P	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
T	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TD	100.00%	0.00%	37.86%	59.90%	0.00%	0.00%	2.24%	0.00%	0.00%
CUST	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
DPW	100.00%	0.00%	0.00%	96.40%	0.00%	0.00%	3.60%	0.00%	0.00%
PTD	100.00%	50.57%	18.71%	29.61%	0.00%	0.00%	1.11%	0.00%	0.00%
DMSC	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Exhibit PPL/1606
Paice/18 - Tab 2

REDACTED
Docket No. UE-
Exhibit PPL/1607
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

December 2011 Marginal Cost Study for the State of Oregon

March 2010

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE-
Exhibit PPL/1700
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of William R. Griffith

March 2010

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

A. My name is William R. Griffith. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon. My present position is Director, Pricing, Cost of Service & Regulatory Operations, in the Regulation Department.

Qualifications

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree with High Honors and distinction in Political Science and Economics from San Diego State University and a Master of Arts degree in Political Science from that same institution; I was subsequently employed on the faculty for one year. I also attended the University of Oregon and completed all course work towards a Ph.D. in Political Science. I joined the Company in the Pricing & Regulatory Affairs Department in December 1983. In June 1989, I became Manager, Pricing in the Regulation Department. In February 2001, I assumed my present responsibilities.

Purpose of Testimony

Q. What are your responsibilities in this proceeding?

A. I am responsible for the design of the Company's proposed prices in this proceeding. The proposed tariffs incorporate the Company's proposed price increase and are designed consistent with the Commission's rules under OAR 860-038-0200. I am sponsoring the Company's Oregon electric tariff schedules submitted for approval in this filing. Exhibit PPL/1701 contains the proposed tariffs.

Allocation of the Functionalized Revenue Requirement

Q. How is the Company proposing to allocate the functionalized revenue requirement across classes of customers in this proceeding?

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's rules for Direct Access Regulation in OAR 860, Division 38. The rules indicate that rates are to be based on cost. As stated in OAR 860-038-0240(2)(b), "rates for any class of consumer must be based on the unbundled costs to serve that class." In this filing, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study sponsored by Company witness Mr. C. Craig Paice. The Company's proposed base rates for each class are based on the unbundled costs to serve that class.

Q. Please explain in detail how PacifiCorp's proposed rate spread appropriately reflects cost of service.

A. The Company's base rates are designed directly based on the results of the cost of service study presented by Mr. Paice. The proposed rates for each rate schedule included in the cost of service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the base rate increase to each rate schedule exactly reflects the costs to serve consumers under that schedule, as determined by the cost of service study.

Q. Do you have an exhibit which summarizes the functionalized results of the cost of service study presented by Mr. Paice?

A. Yes. Exhibit PPL/1702, pages one and two, summarizes the functionalized results of the cost of service study in column (4). This summary is provided at the level used to design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, Distribution, Schedule 80 - Populus to Ben Lomond (to be explained further below), Generation Energy Other (Non-NPC) and Generation Energy NPC.

Q. Please explain why this summary of cost components is appropriately chosen to show target functionalized revenue requirement.

A. The summary level for revenue requirement shown in Exhibit PPL/1702, pages one and two, has been chosen to summarize the cost of service results into the target revenue requirement components used in rate design.

The process of unbundling the Company's proposed prices is consistent with the method the Company implemented in UE 116. For each rate schedule, the functionalized costs developed by Mr. Paice are applied to rates as follows: distribution, billing, metering and customer costs are included in each proposed delivery service schedule's Distribution rates (including Schedule 80); the Federal Energy Regulatory Commission ("FERC")-regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; non-net power cost generation costs are included in Schedule 200, Base Supply Service rates; and net power costs are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost of service study sponsored by Mr. Paice?

A. Yes, the Company has made one adjustment. The functionalized revenue requirement has been adjusted to remove the proposed changes to net power costs ("NPC") collected through Schedule 201. Changes to Schedule 201 are implemented through the Transition Adjustment Mechanism ("TAM") which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that docket. The modified cost of service results reflecting this adjustment removing NPC from the functionalized revenue requirement is shown in Exhibit PPL/1702, pages one and two, column (5). This column displays the target functionalized revenue requirement utilized in the design of rates proposed in this general rate case.

Q. Do the Company's proposed rates accurately collect the target functionalized revenues?

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (6) of Exhibit PPL/1702, pages one and two. A direct comparison to the target functionalized revenues shown in column (5) of this exhibit shows that the calculated revenues equal the target revenues with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown in Exhibit PPL/1702, pages four through 14.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. Exhibit PPL/1703 shows the estimated effect of the Company's proposed prices. It contains a summary table showing the effect of the proposed prices by delivery service rate schedule (Table 1703-1), along with monthly billing comparisons for each of the affected delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. Table 1703-1 contains the effect of the price change on both base rates and on net rates. Base rates show the effect on rates before the impacts of any adjustment tariffs.

The net rates in Table 1703-1 (Columns (8) and (11)) exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297). Table 1703-2 shows the calculation of the adjustments included in Table 1703-1. Table 1703-3 shows the present and proposed rates for these adjustment schedules.

Q. Please explain Table 1703-1 in Exhibit PPL/1703 in detail.

A. Table 1703-1 shows the estimated effect of the proposed general rate case price change by rate schedule for the forecast test period. The table displays the present schedule number, the proposed schedule number, the average number of customers during the test period and the megawatt-hours of energy use in Columns (2) through (5). Revenues by tariff schedule are divided into six columns—three for present revenues and three for proposed revenues. Column

(6) shows annualized revenues under present base rates; Column (7) shows present revenues from current adjustment tariffs (Schedules 93, 96, 97, 102, 193, 194, 195, 203, 296, and 299); and Column (8) shows net present revenues. Column (9) shows annualized revenues under proposed base rates; Column (10) shows proposed revenues from all adjustment tariffs (Schedules 93, 96, 97, 102, 193, 194, 195, 203, 296, and 299); and Column (11) shows the net estimated revenues which would be received if the proposed prices were in effect during the entire test period as forecast. Columns (12) and (13) show the dollar and percentage changes in base rates. Columns (14) and (15) show the dollar and percentage changes comparing present net rates with proposed net rates.

Q. What are the Company's rate spread objectives in this case?

A. The Company's rate spread objectives in this case are to minimize price impacts on our customers while fairly reflecting cost of service and sending proper signals about increasing costs.

Q. What is the Company's rate spread proposal in this case?

A. Based on the cost of service results and in order to achieve the Company's rate spread objectives in this case, the Company proposes a uniform net percentage increase to residential, general service, agricultural pumping, and large general service rate schedules. For lighting schedules, the Company proposes no net rate change.

The Company's proposed rate spread strikes a balance between moderating rate impacts on customers, while sending proper price signals about increasing costs. As has occurred in prior cases, the Company proposes to modify the Rate Mitigation Adjustment ("RMA") in order to achieve the equal percentage rate spread to the major customer rate schedules.

Q. Please explain the RMA.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the ultimate rates that customers pay, once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in UE 116. It is a tariff rider included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. What are the present and proposed RMA rates in this case?

A. The present and proposed RMA rates are shown in Exhibit PPL/1703, Table 1703-3.

Rate Design

Q. Please generally describe the process for designing rates which collect the proposed revenue requirement.

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants such as monthly bills, kilowatts and kilowatt-hours for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12-months ending December 2011.

Q. How are the forecast billing determinants developed?

A. Forecast test period billing determinants are developed based on the Company's forecast test period bills and energy forecasts along with the historic test period billing determinants.

A three step process occurs in developing test period billing determinants. First, monthly forecast test period bills and energy by class and by rate schedule are prepared by the Company as described by Company witness Mr. Gregory N. Duvall.

Second, a full set of billing determinants, including all rate elements such as demand, load size, reactive power quantities and kilowatt-hours by rate block, are retrieved at the customer invoice level from the Company's billing system for the historic test period – in this case, the 12-months ended June 2009. These historic billing determinants are summarized by class, rate schedule and voltage level.

Finally, a full set of forecast billing determinants is developed using the historic test period data and the forecast test period information. The forecast billing determinants are calculated based upon the ratio of historic bills and energy (temperature normalized) in the historic test period to the forecast bills and energy provided in the load forecast.

Q. Have you prepared an exhibit showing proposed rates and the billing determinants used to design rates?

A. Yes. Historic and forecast billing determinants along with present and proposed base rates are shown in Exhibit PPL/1702, pages four through 14.

Q. What rate design changes does the Company propose?

A. The basic structure of the Company's current tariffs, broken out into Delivery Service and Supply Service tariffs as first approved in UE 116, is proposed to remain in effect. The Company is proposing a separate rate schedule to collect the Populus to Ben Lomond transmission costs, discussed later in my testimony.

Q. Please explain the proposed tariffs for residential customers.

A. Residential customers are served on Delivery Service Schedule 4. For the Basic Charge, the Company proposes to increase the current Basic Charge by $1.00 per month. This results in a proposed Basic Charge of $9.00 per month. This change will better reflect the fixed costs of serving residential customers while keeping customer impacts in line with the overall rate change. In addition, even with this change, the Company's Basic Charge will remain in the lowest half of Basic/Minimum Charges across 23 electric utilities surveyed by the Company in Oregon.

For residential customers, as well as for all classes of customers, Schedule 200, Base Supply Service, is proposed to reflect changes in the non-net power cost generation revenue requirement as indicated in Exhibit PPL/1702, pages one and two. The portfolio options (Schedules 210 through 213) do not require changes since they are adders to customers' Schedule 200 rates.

Q. Please explain the proposed tariffs for general service customers.

A. The proposed general service tariffs are Schedule 23/723 for small (less than 31 kW) nonresidential general service customers, Schedule 28/728 for general service customers between 31 and 200 kW, and Schedule 30/730 for general service customers over 200 kW but less than 1,000 kW. The Company automatically migrates these customers to the appropriate rate schedule once they meet its applicability criteria. The Company has proposed to modify base delivery and Schedule 200 Base Supply Service prices, at different voltage levels, to collect the target functionalized revenue requirement.

Q. Please explain the proposed tariffs for irrigation customers.

A. In line with the changes for general service customers, Schedule 41/741, Agricultural Pumping Service, has been modified to reflect the target revenue requirement and to track unit costs more closely.

Q. Has the Company proposed any changes for Schedule 33 customers?

A. No. According to Order No. 06-172, as clarified in Order No. 06-440, the Company does not propose changes for Schedule 33, Klamath Basin Irrigation and Drainage Pumping customers in this case. Present and proposed rates for Schedule 33 customers in this case reflect forecasted rates which will be in effect in 2011 consistent with Order No. 06-172. The proposed rate change shown for these customers is based on the flow through of the rate increase proposed for standard irrigation Schedule 41 to which Schedule 33 rates are targeted. This proposed rate change is consistent with the rate change methodology specified in the two Commission orders referenced above. Due to the increase proposed for Schedule 41 rates in this case, the target rate for Schedule 33 will increase, causing higher rates in 2011 than would have been in place absent the general rate case.

Q. How has the Company treated Schedule 92, Klamath Rate Reconciliation Adjustment in this case?

A. Schedule 92 is designed to collect or credit base revenues lost or gained by changes in Schedule 33 base rates between rate cases. As a result of resetting all rates in this general rate case, the Schedule 92 adjustment is not currently necessary, nor will it be needed after the April 2011 rate change for Schedule 33 customers, as that rate change has been assumed in this case. Schedule 92 will remain in place for use in potential future Klamath transition rate change filings outside of general rate case test period years, and the Company will revise Schedule 92 at such time that it is needed to offset additional Schedule 33 rate increases in those years.

Q. Please explain the proposed tariffs for large general service customers.

A. For Schedules 48/748, Large General Service, the Company has proposed to modify base prices, at different voltage levels, to collect the target functionalized revenue requirement. For partial requirements customers served on Schedule 47/747, most prices are linked to changes in Schedule 48/748 prices. Changes to Schedule 48/748 continue to flow through to Schedule 47/747. The Company proposes to maintain the current Schedule 48/748 rate structure, including an on-peak period demand charge only and a 0.1 cents per kWh on-peak/off-peak time of use energy charge differential.

Q. Please explain the proposed tariffs for lighting customers.

A. For lighting (Schedules 15, 50, 51/751, 52/752, 53/753, and 54/754) the proposed revisions are designed to collect the overall functionalized target revenue requirement.

Q. Are any changes being proposed for lighting tariffs?

A. Yes. The Company proposes that the metal halide offerings currently available in Schedule 51 and 53 be closed to new service. The Energy Independence and Security Act of 2007 Section 324 indicates that the metal halide fixtures in our tariffs cannot be manufactured after January 1, 2009.

Q. How has the Company treated the Renewable Adjustment Clause ("RAC") Schedule 202.

A. The RAC is an automatic adjustment clause designed to provide timely recovery of the revenue requirement of new renewable resources and associated transmission outside of a general rate case. In the Company's last general rate case, Schedule 202 rates were set to zero. The Company has proposed no change to the RAC rates in this case. Schedule 202 will remain in place for use in potential future RAC filings.

Schedule 80 - Populus to Ben Lomond Cost Recovery Charge

Q. Please explain proposed Schedule 80.

A. Schedule 80, Populus to Ben Lomond Cost Recovery Charge, reflects the $21 million annual revenue requirement change to recover the Populus to Ben Lomond transmission investment planned to go into service in December 2010. The rates in Schedule 80 reflect functionalized transmission costs related to this project.

Q. Why has the Company proposed a separate tariff schedule for this project?

A. As discussed by Company witness Mr. Richard P. Reiten, the Company has proposed a separate tariff schedule for this project in order for the prudency of this project to be reviewed in this general rate case while, in the unlikely event that an in-service date after January 2011 occurs, allowing this project to be properly reflected in rates in a timely manner.

Q. Please explain.

A. If the Populus to Ben Lomond project is placed into service in December 2010 as planned, the Company proposes that Schedule 80 become effective on the same date as other proposed tariff changes in this general rate case, on January 1, 2011.

If this project is placed into service after January 1, 2011, the Company proposes that Schedule 80 become effective on the day following the certified in-service date of the Populus to Ben Lomond project. This will assure that costs are properly reflected in base rates and that timely cost recovery of this project occurs.

Q. Are the rates in proposed Schedule 80 reflected in the proposed rate spread and Monthly Billing Comparisons exhibits filed in this case?

A. Yes. The effects of Schedule 80 are included in proposed base rates filed in this case and the effect of Schedule 80 is reflected in the proposed bills presented in the Monthly Billing Comparisons exhibits.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE-
Exhibit PPL/1701
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Proposed Tariffs

March 2010

PACIFIC POWER & LIGHT COMPANY
TARIFF INDEX

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PACIFIC POWER & LIGHT COMPANY **OREGON**
RESIDENTIAL SERVICE **SCHEDULE 4**
DELIVERY SERVICE

Available
In all territory served by the Company in the State of Oregon.

Applicable
To single-family Residential Consumers only for all single-phase and three-phase electric requirements when all service is supplied at one point of delivery. Three-phase service will be supplied only when service is available from Company's presently existing facilities, or where such facilities can be installed under Company's Line Extension Rules, and, in any event, only when deliveries can be made by using one service for Consumer's single-phase and three-phase requirements.

Monthly Billing
The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

Distribution Charge		
Basic Charge, per month	$9.00	(I)
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	3.474¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.414¢	(I)

Supply Service Options
All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Special Conditions
Consumer shall so arrange his wiring as to make possible the separate metering of the three-phase demand at a location adjacent to the kWh meter. If, on November 25, 1975, any present Consumer's wiring was arranged only for combined single and three-phase demand measurement, and continues to be so arranged, such demands will be metered and billed hereunder except that the first 10 kW of such combined demand will be deducted before applying demand charges for three phase service. No new combined demand installations will be allowed such a demand deduction.

Continuing Service
This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations
Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

Issued:	March 1, 2010	P.U.C. OR No. 35
Effective:	With service rendered on and after March 31, 2010	Eighth Revision of Sheet No. 4 Canceling Seventh Revision of Sheet No. 4

Issued By
Andrea L. Kelly, Vice President, Regulation

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Consumers for outdoor area lighting service furnished from dusk to dawn by means of presently-installed Company-owned mercury vapor or high-pressure sodium luminaires which may be served by secondary voltage circuits from the Company's existing overhead distribution system. Luminaires shall be mounted on Company-owned wood poles and served in accordance with the Company's specifications as to equipment and installation.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

Type of Luminaire	Nominal Rating	Monthly kWh	Rate Per Luminaire	
Mercury Vapor	7,000	76	$ 6.46	(R)
Mercury Vapor	21,000	172	$11.61	
Mercury Vapor	55,000	412	$22.89	
High Pressure Sodium	5,800	31	$ 9.07	
High Pressure Sodium	22,000	85	$12.31	
High Pressure Sodium	50,000	176	$18.91	(R)

Pole Charge

A monthly charge of $1.00 per pole shall be made for each additional pole required in excess of the number of luminaires installed.

Supply Service Option

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Special Conditions

Maintenance will be performed during regular working hours as soon as practicable after the Consumer has notified the Company of service failure.

The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

The Consumer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by the Company's estimated average monthly relamping and energy costs for the luminaire. The Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by the Consumer.

(continued)

PACIFIC POWER & LIGHT COMPANY
GENERAL SERVICE – SMALL NONRESIDENTIAL DELIVERY SERVICE

OREGON
SCHEDULE 23

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers whose entire electric service requirements are supplied hereunder and as specified in the Company's Rules & Regulations, Rule 7.K. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Single Phase, per month	$20.40	$20.40	(I)
Three Phase, per month	$30.45	$30.45	
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$ 1.40	$ 1.40	
Demand Charge, the first 15 kW of demand, per kW	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$ 4.74	$ 4.61	
Distribution Energy Charge, per kWh	2.806¢	2.718¢	
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.409¢	0.396¢	(I)

kW Load Size

For determination of the Basic Charge and Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
GENERAL SERVICE – LARGE NONRESIDENTIAL **SCHEDULE 28**
31 KW TO 200 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.K. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 16.00	$ 18.00	(I)
Load Size 51-100 kW, per month	$ 30.00	$ 32.00	
Load Size 101 - 300 kW, per month	$ 73.00	$ 75.00	
Load Size > 300 kW, per month	$104.00	$ 108.00	
Load Size Charge			
≤50 kW, per kW load size	$ 1.05	$ 1.05	
51 - 100 kW, per kW load size	$ 0.80	$ 0.85	
101 – 300 kW, per kW Load Size	$ 0.45	$ 0.50	
> 300 kW, per kW Load Size	$ 0.35	$ 0.25	
Demand Charge, per kW	$ 3.08	$ 3.29	
Distribution Energy Charge, per kWh	0.366¢	0.046¢	
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	(I)
Transmission & Ancillary Services Charge			
Per kW	$ 1.20	$ 0.87	(R)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
GENERAL SERVICE – LARGE NONRESIDENTIAL **SCHEDULE 30**
201 KW TO 999 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤200 kW, per month	$415.00	$397.00	(I)
Load Size 201 - 300 kW, per month	$125.00	$127.00	
Load Size > 300 kW, per month	$327.00	$330.00	
Load Size Charge			
≤200 kW, per kW load size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 1.45	$ 1.35	
> 300 kW, per kW Load Size	$ 0.70	$ 0.70	
Demand Charge, per kW	$ 3.15	$ 3.12	
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	(I)
Transmission & Ancillary Services Charge			
Per kW	$ 1.34	$ 1.32	(R)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
AGRICULTURAL PUMPING SERVICE **SCHEDULE 41**
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 47 or 48. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the monthly billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C) (C)

<u>Distribution Charge</u>	<u>Delivery Voltage</u> Secondary	Primary	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 390.00	$ 380.00	(I)
Three Phase Load Size > 300 kW	$1,530.00	$1,490.00	
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW LS	$ 19.00	$ 18.00	(C)
Three Phase 51 - 300 kW, per kW Load Size	$ 12.00	$ 12.00	
Three Phase > 300 kW, per kW Load Size	$ 7.00	$ 7.00	
Single Phase, Minimum Charge	$ 65.00	$ 65.00	
Three Phase, Minimum Charge	$ 115.00	$ 110.00	
Distribution Energy Charge, per kWh	4.393¢	4.255¢	(I)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	
<u>Transmission & Ancillary Services Charge</u>			
Per kWh	0.324¢	0.314¢	(R)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of the Company's meter, or by appropriate test, for the 15-minute period of the Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

(continued)

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS – 1,000 KW AND OVER
DELIVERY SERVICE

OREGON
SCHEDULE 47

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage			
Distribution Charge	Secondary	Primary	Transmission	
Basic Charge				
Facility Capacity <= 4,000 kW, per month	$370.00	$380.00	$620.00	(I)
Facility Capacity > 4,000 kW, per month	$690.00	$690.00	$1,140.00	
Facilities Charge				
<=4,000 kW, per kW Facility Capacity	$1.45	$0.80	$0.90	
> 4,000 kW, per kW Facility Capacity	$1.35	$0.75	$0.90	
On-Peak Demand Charge, per kW	$2.22	$2.41	$1.90	
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	(I)
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)				
per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)	
Transmission & Ancillary Services Charge				
per kW of On-Peak Demand	$0.83	$0.97	$1.43	(R)

(continued)

PACIFIC POWER & LIGHT COMPANY
LARGE GENERAL SERVICE - 1,000 KW AND OVER
DELIVERY SERVICE

OREGON
SCHEDULE 48

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

	Delivery Voltage			
	Secondary	Primary	Transmission	
Distribution Charge				
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$370.00	$380.00	$620.00	(I)
Facility Capacity > 4000 kW, per month	$690.00	$690.00	$1,140.00	
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$ 1.45	$ 0.80	$ 0.90	
> 4000 kW, per kW Facility Capacity	$ 1.35	$ 0.75	$ 0.90	
On-Peak Demand Charge, per kW	$ 2.22	$ 2.41	$ 1.90	
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	$ 0.55	(I)
Transmission & Ancillary Services Charge				
Per kW of On-Peak demand	$ 1.37	$ 1.51	$ 1.97	(R)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
MERCURY VAPOR **SCHEDULE 50**
STREET LIGHTING SERVICE - NO NEW SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished from dusk to dawn for the lighting of public streets, highways, alleys and parks by means of presently-installed mercury vapor lights. Street lights will be served by either series or multiple circuits as the Company may determine. The type and kind of fixtures and supports will be in accordance with the Company's specifications. Service includes installation, maintenance, energy, lamp and glassware renewals.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

A. Company-owned Overhead System

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$6.03	$10.45	$20.20	(R)
Vertical, per lamp	$5.53	$9.58		

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$8.28		
On 26-foot poles, vertical, per lamp	$7.73		
On 30-foot poles, horizontal , per lamp		$13.10	
On 30-foot poles, vertical, per lamp		$12.23	
On 33-foot poles, horizontal , per lamp			$22.82

B. Company-owned Underground System

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$8.28			
On 26-foot poles, vertical, per lamp	$7.73			
On 30-foot poles, horizontal , per lamp		$12.55		
On 30-foot poles, vertical, per lamp		$11.73		
On 33-foot poles, horizontal , per lamp			$22.27	(R)
plus rate per foot of underground cable:				
In paved area	$0.05	$0.05	$0.05	
in unpaved area	$0.03	$0.03	$0.03	

(continued)

PACIFIC POWER & LIGHT COMPANY
STREET LIGHTING SERVICE
COMPANY-OWNED SYSTEM
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

High Pressure Sodium Vapor							
Lumen Rating	5,800*	9,500	16,000	22,000*	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Functional Lighting	$ 5.40	$ 6.03	$ 7.31	$ 8.59	$ 11.04	$ 13.52	(R)
Decorative - Series 1	N/A	$ 20.45	$ 20.38	N/A	N/A	N/A	|
Decorative - Series 2	N/A	$ 17.54	$ 17.41	N/A	N/A	N/A	(R)

Metal Halide – No New Service					(C)
Lumen Rating	9,000*	12,000*	19,500*	32,000*	(C)
Watts	100	175	250	400	
Monthly kWh	39	68	94	149	
Functional Lighting	N/A	$ 14.28	$ 16.00	$ 15.44	(R)
Decorative - Series 1	$ 20.57	$ 21.95	N/A	N/A	|
Decorative - Series 2	$ 18.94	$ 18.96	N/A	N/A	(R)

*Existing fixtures only. Service is not available under this schedule to new 5,800 or 22,000 lumen High Pressure Sodium Vapor fixtures or to Metal Halide fixtures of any size. (C)

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 751, Direct Access Delivery Service.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
STREET LIGHTING SERVICE (NO NEW SERVICE) **SCHEDULE 52**
COMPANY-OWNED SYSTEM
DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

To service furnished by means of the Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. The Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

A flat rate equal to one-twelfth of the Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including Distribution Charge as follows:

For dusk to dawn operation, per kWh	1.856¢	(R)
For dusk to midnight operation, per kWh	2.232¢	(R)

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 752, Direct Access Delivery Service.

Suspension of Service

The Consumer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by the Company's estimated average monthly relamping and energy costs for the luminaire. The Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by Consumer.

Termination of Service

Service furnished hereunder by means of incandescent and mercury-vapor lights is subject to termination by not less than sixty (60) days written notice given by the Company to Consumer.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
STREET LIGHTING SERVICE **SCHEDULE 53**
CONSUMER-OWNED SYSTEM
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)
(C)

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.35	$ 1.92	$ 2.79	$ 3.70	$ 5.01	$ 7.67

(R)

(C)
(C)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	107,800 *
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.70	$ 2.96	$ 4.10	$ 6.49	$ 15.42

(R)

*Existing fixtures only. Service is not available under this Schedule to new Metal Halide fixtures of any size.

For non-listed luminaires the cost will be calculated for 3940 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below. (R)

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.357

(continued)

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Issued By
Andrea L. Kelly, Vice President, Regulation

TF1 53-1.REV Advice No. 10-003

PACIFIC POWER & LIGHT COMPANY **OREGON**
RECREATIONAL FIELD LIGHTING **SCHEDULE 54**
RESTRICTED
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At the Consumer's option, service for recreational field lighting may be taken under the Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)

Distribution Charge		
Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.282¢	(R)
Transmission & Ancillary Services Charge		
per kWh	0.069¢	(I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 754, Direct Access Delivery Service.

Special Conditions

The Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery. The Company will supply one transformer, or transformer bank, for each athletic or recreational field; any additional transformers required shall be supplied and owned by the Consumer. All transformers owned by the Consumer must be properly fused and of such types and characteristics as conform to the Company's standards. When service is supplied to more than one transformer or transformer bank, the Company may meter such an installation at primary voltage.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

(continued)

Purpose

To provide Consumers served on Schedule 47 with the opportunity of purchasing Energy from the Company to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to between Company and Consumer.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 47 plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90: (C) (C)

	Delivery Voltage Secondary	Primary	Transmission	
Transmission and Ancillary Services Charge				
per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.032	$0.038	$0.056	(R)
Daily ERP Demand Charge				
per kW of Daily ERP On- Peak Demand	$0.086	$0.094	$0.074	(I)

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

(continued)

PACIFIC POWER & LIGHT COMPANY
POPULUS TO BEN LOMOND COST RECOVERY CHARGE

OREGON
SCHEDULE 80

(N)

Purpose

This schedule recovers the costs associated with the Populus to Ben Lomond transmission investment.

Monthly Billing

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.35 shall pay the following applicable rates as listed by Delivery Service schedule

	Secondary	Primary	Transmission
Schedule 4, per kWh	0.176¢		
Schedule 15, per kWh	0.029¢		
Schedule 23, 723, per kWh	0.174¢	0.169¢	
Schedule 28, 728, per kW	$0.51	$0.37	
Schedule 30, 730, per kW	$0.57	$0.56	
Schedule 41, 741, per kWh	0.138¢	0.134¢	
Schedule 47, 747, per On-Peak kW	$0.58	$0.64	$0.84
Schedule 48, 748, per On-Peak kW	$0.58	$0.64	$0.84
Schedule 50, per kWh	0.029¢		
Schedule 51, 751, per kWh	0.029¢		
Schedule 52, 752, per kWh	0.029¢		
Schedule 53, 753, per kWh	0.029¢		
Schedule 54, 754, per kWh	0.029¢		

Rates per kWh shall apply to all kilowatt-hours of use.
Rates per kW and per On-Peak kW shall be charged based on Demand and On-Peak Demand as defined in each respective Delivery Service schedule.

(N)

PACIFIC POWER & LIGHT COMPANY **OREGON**
BASE SUPPLY SERVICE **SCHEDULE 200**

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

The Monthly Billing shall be the Energy Charge and/or Demand Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			Delivery Voltage Secondary	Primary	Transmission	
4	Per kWh	0 - 500 kWh	2.662¢			(I)
		501-1000 kWh	3.155¢			
		> 1000 kWh	3.893¢			

For Schedule 4, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	3.321¢	3.216¢		
	All additional kWh, per kWh	2.465¢	2.387¢		
28, 728	First 20,000 kWh, per kWh	3.147¢	2.916¢		
	All additional kWh, per kWh	3.063¢	2.838¢		
30, 730	Demand Charge, per kW	$1.19	$1.21		
	First 20,000 kWh, per kWh	3.094¢	3.029¢		
	All additional kWh, per kWh	2.683¢	2.618¢		

Demand shall be as defined in the Delivery Service Schedule.

		Secondary	Primary	Transmission	
41, 741	Winter, first 100 kWh/kW, per kWh	4.355¢	4.218¢		
	Winter, all additional kWh, per kWh	2.968¢	2.874¢		
	Summer, all kWh, per kWh	2.968 ¢	2.874¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing *(continued)*

Delivery Service Schedule No.		Secondary	Primary	Transmission	
		Delivery Voltage			
47/48,	Demand Charge, per kW of On-Peak Demand	$1.18	$1.19	$1.20	(I)
747/748	Per kWh On-Peak	2.766¢	2.698¢	2.650¢	
	Per kWh, Off-Peak	2.716¢	2.648¢	2.600¢	

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

On-peak Demand shall be as defined in the Delivery Service Schedule.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52, 752	For dusk to dawn operation, per kWh	2.961¢
	For dusk to midnight operation, per kWh	2.961¢
54, 754	Per kWh	2.175¢

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire
Mercury Vapor	7,000	76	$2.06
Mercury Vapor	21,000	172	$4.66
Mercury Vapor	55,000	412	$11.17
High Pressure Sodium	5,800	31	$0.84
High Pressure Sodium	22,000	85	$2.31
High Pressure Sodium	50,000	176	$4.77

50 **A. Company-owned Overhead System**
Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)
Horizontal, per lamp	$1.86	$4.21	$10.08
Vertical, per lamp	$1.86	$4.21	

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)
On 26-foot poles, horizontal, per lamp	$1.86		
On 26-foot poles, vertical, per lamp	$1.86		
On 30-foot poles, horizontal, per lamp		$4.21	
On 30-foot poles, vertical, per lamp		$4.21	
On 33-foot poles, horizontal, per lamp			$10.08

(I)

(continued)

Monthly Billing *(continued)*

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.86			(I)
On 26-foot poles, vertical, per lamp	$1.86			
On 30-foot poles, horizontal, per lamp		$4.21		
On 30-foot poles, vertical, per lamp		$4.21		
On 33-foot poles, horizontal, per lamp			$10.08	

51,751

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**
High Pressure Sodium	5,800	70	31	$1.20
High Pressure Sodium	9,500	100	44	$1.70
High Pressure Sodium	16,000	150	64	$2.47
High Pressure Sodium	22,000	200	85	$3.28
High Pressure Sodium	27,500	250	115	$4.44
High Pressure Sodium	50,000	400	176	$6.80
Metal Halide	9,000	100	39	$1.51
Metal Halide	12,000	175	68	$2.63
Metal Halide	19,500	250	94	$3.63
Metal Halide	32,000	400	149	$5.76

53,753

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**
High Pressure Sodium	5,800	70	31	$0.39
High Pressure Sodium	9,500	100	44	$0.56
High Pressure Sodium	16,000	150	64	$0.81
High Pressure Sodium	22,000	200	85	$1.07
High Pressure Sodium	27,500	250	115	$1.45
High Pressure Sodium	50,000	400	176	$2.22
Metal Halide	9,000	100	39	$0.49
Metal Halide	12,000	175	68	$0.86
Metal Halide	19,500	250	94	$1.19
Metal Halide	32,000	400	149	$1.88
Metal Halide	107,800	1,000	354	$4.47

Non-Listed Luminaire, per kWh 1.264¢ (I)

PACIFIC POWER & LIGHT COMPANY **OREGON**
RATE MITIGATION ADJUSTMENT **SCHEDULE 299**

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No.35 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

Schedule 4	0.144	cents	(C)
Schedule 15	1.805	cents	
Schedule 23, 723	(0.515)	cents	
Schedule 28, 728	0.336	cents	
Schedule 30, 730	0.165	cents	
Schedule 41, 741	(1.984)	cents	
Schedule 47, 747	(0.346)	cents	
Schedule 48, 748	(0.346)	cents	
Schedule 50	1.733	cents	
Schedule 51, 751	2.751	cents	
Schedule 52, 752	1.800	cents	
Schedule 53, 753	1.050	cents	
Schedule 54, 754	1.200	cents	(C)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers who have chosen to receive electricity from an ESS, and as specified in the Company's Rules & Regulations, Rule 7.K. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)
(C)

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$20.40	$20.40	(I)
Three Phase, per month	$30.45	$30.45	
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 1.40	$ 1.40	
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, per kW in excess of 15 kW	$ 4.74	$ 4.61	
Distribution Energy Charge, per kWh	2.806¢	2.718¢	
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
GENERAL SERVICE – LARGE NONRESIDENTIAL **SCHEDULE 728**
31 KW TO 200 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.K. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule (C)
80 and applicable adjustments as specified in Schedule 90. (C)

Distribution Charge	Delivery Voltage Secondary	Delivery Voltage Primary	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 16.00	$ 18.00	(I)
Load Size 51-100 kW, per month	$ 30.00	$ 32.00	
Load Size 101 - 300 kW, per month	$ 73.00	$ 75.00	
Load Size > 300 kW, per month	$ 104.00	$ 108.00	
Load Size Charge			
≤ 50 kW, per kW load size	$ 1.05	$ 1.05	
51-100 kW, per kW load size	$ 0.80	$ 0.85	
101 – 300 kW, per kW Load Size	$ 0.45	$ 0.50	
> 300 kW, per kW Load Size	$ 0.35	$ 0.25	
Demand Charge, per kW	$ 3.08	$ 3.29	
Distribution Energy Charge, per kWh	0.366¢	0.046¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
GENERAL SERVICE – LARGE NONRESIDENTIAL **SCHEDULE 730**
201 KW TO 999 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule (C)
80 and applicable adjustments as specified in Schedule 90. (C)

Distribution Charge	Delivery Voltage Secondary	Primary	
Basic Charge			
Load Size ≤ 200 kW, per month	$415.00	$397.00	(I)
Load Size 201 - 300 kW, per month	$125.00	$127.00	
Load Size > 300 kW, per month	$327.00	$330.00	
Load Size Charge			
≤ 200 kW, per kW load size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 1.45	$ 1.35	
> 300 kW, per kW Load Size	$ 0.70	$ 0.70	
Demand Charge, per kW	$ 3.15	$ 3.12	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER & LIGHT COMPANY
AGRICULTURAL PUMPING SERVICE
DIRECT ACCESS DELIVERY SERVICE

OREGON
SCHEDULE 741

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers who have chosen to receive electricity from an ESS and desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the Monthly Billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C) | (C)

Distribution Charge	Delivery Voltage		
	Secondary	**Primary**	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 390.00	$ 380.00	(I)
Three Phase Load Size > 300 kW	$1,530.00	$1,490.00	|
Load Size Charge (November billing only)			|
Single Phase Any Size, Three Phase ≤ 50 kW, per kW LS	$ 19.00	$ 18.00	(C)
Three Phase 51 - 300 kW, per kW Load Size	$ 12.00	$ 12.00	I
Three Phase > 300 kW, per kW Load Size	$ 7.00	$ 7.00	(C)
Single Phase, Minimum Charge	$ 65.00	$ 65.00	|
Three Phase, Minimum Charge	$ 115.00	$ 110.00	|
Distribution Energy Charge, per kWh	4.393¢	4.255¢	
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size Is:	Monthly kW is:
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
LARGE GENERAL SERVICE **SCHEDULE 747**
PARTIAL REQUIREMENTS – 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Reserves Charges plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)
(C)

	Delivery Voltage			
Distribution Charge	Secondary	Primary	Transmission	
Basic Charge				(I)
Facility Capacity <= 4,000 kW, per month	$370.00	$380.00	$620.00	
Facility Capacity > 4,000 kW, per month	$690.00	$690.00	$1,140.00	
Facilities Charge				
<=4,000 kW, per kW Facility Capacity	$1.45	$0.80	$0.90	
> 4,000 kW, per kW Facility Capacity	$1.35	$0.75	$0.90	
On-Peak Demand Charge, per kW	$2.22	$2.41	$1.90	(I)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved load reduction plan or Self-Supply Agreement)				
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)	

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service will be provided only by application of the provisions of Schedule 747.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)
(C)

<u>Distribution Charge</u>	<u>Delivery Voltage</u>			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$370.00	$380.00	$620.00	(I)
Facility Capacity > 4000 kW, per month	$690.00	$690.00	$1,140.00	
Facilities Charge				
≤ 4000 kW, per kW, Facility Capacity	$1.45	$0.80	$0.90	
> 4000 kW, per kW, Facility Capacity	$1.35	$0.75	$0.90	
On-Peak Demand Charge, per kW	$2.22	$2.41	$1.90	
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	(I)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

PACIFIC POWER & LIGHT COMPANY
STREET LIGHTING SERVICE
COMPANY-OWNED SYSTEM
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C)
(C)

High Pressure Sodium Vapor							
Lumen Rating	5,800*	9,500	16,000	22,000*	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Functional Lighting	$ 5.38	$ 6.00	$ 7.27	$ 8.53	$ 10.96	$ 13.40	(R)
Decorative - Series 1	N/A	$ 20.42	$ 20.34	N/A	N/A	N/A	I
Decorative - Series 2	N/A	$ 17.51	$ 17.37	N/A	N/A	N/A	(R)

(C)
(C)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	
Watts	100	175	250	400	
Monthly kWh	39	68	94	149	
Functional Lighting	N/A	$ 14.23	$ 15.94	$ 15.34	(R)
Decorative - Series 1	$ 20.54	$ 21.90	N/A	N/A	I
Decorative - Series 2	$ 18.91	$ 18.91	N/A	N/A	(R)

*Existing fixtures only. Service is not available under this schedule to new 5,800 or 22,000 lumen High Pressure Sodium Vapor fixtures or Metal Halide fixtures of any size. (C)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this Schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
STREET LIGHTING SERVICE (NO NEW SERVICE) **SCHEDULE 752**
COMPANY-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company (except Multnomah County) in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To service furnished by means of Company-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. Company may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

Monthly Billing

For systems owned, operated and maintained by Company. The Monthly Billing shall be the Rate Per kWh below plus the applicable rate in Schedule 80 and applicable adjustments as specified in (C)
Schedule 90. (C)

A flat rate equal to one-twelfth of Company's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including energy costs as follows:

For dusk to dawn operation, per kWh	1.787¢	(R)
For dusk to midnight operation, per kWh	2.149¢	(R)

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Term of Contract

Not less than five years for service to an overhead, or ten years to an underground, Company-owned system by written contract when unusual conditions prevail.

Suspension of Service

The Consumer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by Company's estimated average monthly relamping and energy costs for the luminaire. Company will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by Consumer.

Termination of Service

Service furnished hereunder by means of incandescent and mercury-vapor lights is subject to termination by not less than sixty (60) days written notice given by Company to Consumer.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER & LIGHT COMPANY
STREET LIGHTING SERVICE
CONSUMER-OWNED SYSTEM
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90. (C) (C)

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.33	$ 1.89	$ 2.74	$ 3.64	$ 4.93	$ 7.55

(R)

(C)

Metal Halide – No New Service					
Lumen Rating	9,000*	12,000*	19,500*	32,000*	107,800 *
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.67	$ 2.92	$ 4.03	$ 6.39	$ 15.18

(R)

*Existing fixtures only. Service is not available under this schedule to new Metal Halide fixtures of any size. (N)

For non-listed luminaires the cost will be calculated for 3940 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.288

(R)

(continued)

PACIFIC POWER & LIGHT COMPANY **OREGON**
RECREATIONAL FIELD LIGHTING **SCHEDULE 754**
RESTRICTED
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At Consumer's option, service for recreational field lighting may be taken under Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the Distribution Charge plus the applicable rate in Schedule 80 and (C)
applicable adjustments as specified in Schedule 90. (C)

Distribution Charge

Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.282¢	(R)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Special Conditions

Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery. Company will supply one transformer, or transformer bank, for each athletic or recreational field; any additional transformers required shall be supplied and owned by Consumer. All transformers owned by Consumer must be properly fused and of such types and characteristics as conform to Company's standards. When service is supplied to more than one transformer or transformer bank, Company may meter such an installation at primary voltage.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER & LIGHT COMPANY **OREGON**

LARGE GENERAL SERVICE/PARTIAL REQUIREMENTS SERVICE – ECONOMIC REPLACEMENT SERVICE RIDER DIRECT ACCESS DELIVERY SERVICE **SCHEDULE 776R**

Purpose

To provide Consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement service except as explicitly agreed to between Company and Consumer.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers receiving Delivery Service under Schedule 747.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 747 plus the applicable (C)
rate in Schedule 80 and applicable adjustments as specified in Schedule 90: (C)

	Secondary	Delivery Voltage Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERP On- Peak Demand	$0.086	$0.094	$0.074	(I)

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

ERS and ENF

Economic Replacement Service (ERS) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Service Agreement (ERSA).

(continued)

Docket No. UE-
Exhibit PPL/1702
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Target Functionalized Revenues and Billing Determinants

March 2010

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenue
Forecast 12 Months Ended December 31, 2011

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 4, Residential					
	Transmission & Ancillary Services[1]	$20,484	$21,978	$21,978	$21,970
	Distribution	$210,012	$236,642	$236,642	$236,676
	Schedule 80 - Populus to Ben Lomond		$9,349	$9,349	$9,340
	Generation Energy - Other (non-NPC) (Sch 200)	$138,366	$166,455	$166,455	$166,443
	Generation Energy - Net Power Costs (Sch 201)	$103,791	$133,637	$103,791	$103,791
	Total	$472,654	$568,060	$538,214	$538,221
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$3,782	$4,142	$4,142	$4,146
	Distribution	$44,594	$51,808	$51,808	$51,796
	Schedule 80 - Populus to Ben Lomond		$1,762	$1,762	$1,764
	Generation Energy - Other (non-NPC) (Sch 200)	$26,168	$31,701	$31,701	$31,704
	Generation Energy - Net Power Costs (Sch 201)	$19,638	$25,451	$19,638	$19,638
	Total	$94,181	$114,865	$109,051	$109,048
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$8,271	$8,099	$8,099	$8,069
	Distribution	$32,837	$38,492	$38,492	$38,528
	Schedule 80 - Populus to Ben Lomond		$3,445	$3,445	$3,429
	Generation Energy - Other (non-NPC) (Sch 200)	$52,314	$62,271	$62,271	$62,270
	Generation Energy - Net Power Costs (Sch 201)	$39,251	$49,993	$39,251	$39,251
	Total	$132,673	$162,300	$151,558	$151,547
Primary Voltage					
	Transmission & Ancillary Services[1]	$74	$55	$55	$55
	Distribution	$300	$319	$319	$320
	Schedule 80 - Populus to Ben Lomond		$23	$23	$23
	Generation Energy - Other (non-NPC) (Sch 200)	$450	$511	$511	$511
	Generation Energy - Net Power Costs (Sch 201)	$338	$410	$338	$338
	Total	$1,162	$1,319	$1,246	$1,246
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$5,122	$4,836	$4,836	$4,834
	Distribution	$16,358	$18,125	$18,125	$18,025
	Schedule 80 - Populus to Ben Lomond		$2,057	$2,057	$2,056
	Generation Energy - Other (non-NPC) (Sch 200)	$33,097	$39,436	$39,436	$39,544
	Generation Energy - Net Power Costs (Sch 201)	$24,925	$31,661	$24,925	$24,925
	Total	$79,502	$96,115	$89,380	$89,385
Primary Voltage					
	Transmission & Ancillary Services[1]	$383	$398	$398	$398
	Distribution	$1,210	$1,441	$1,441	$1,432
	Schedule 80 - Populus to Ben Lomond		$169	$169	$169
	Generation Energy - Other (non-NPC) (Sch 200)	$2,542	$3,086	$3,086	$3,096
	Generation Energy - Net Power Costs (Sch 201)	$1,921	$2,477	$1,921	$1,921
	Total	$6,057	$7,571	$7,015	$7,016
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$650	$484	$484	$483
	Distribution	$8,651	$9,089	$9,089	$9,090
	Schedule 80 - Populus to Ben Lomond		$206	$206	$206
	Generation Energy - Other (non-NPC) (Sch 200)	$3,859	$4,446	$4,446	$4,446
	Generation Energy - Net Power Costs (Sch 201)	$2,894	$3,569	$2,894	$2,894
	Total	$16,054	$17,794	$17,119	$17,119

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenue
Forecast 12 Months Ended December 31, 2011

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$2,401	$2,183	$2,183	$2,179
	Distribution	$6,257	$7,152	$7,152	$7,163
	Schedule 80 - Populus to Ben Lomond		$929	$929	$922
	Generation Energy - Other (non-NPC) (Sch 200)	$15,023	$17,794	$17,794	$17,794
	Generation Energy - Net Power Costs (Sch 201)	$11,226	$14,286	$11,226	$11,226
	Total	$34,907	$42,344	$39,284	$39,284
Primary Voltage					
	Transmission & Ancillary Services[1]	$5,276	$4,964	$4,964	$4,979
	Distribution	$10,250	$11,943	$11,943	$11,901
	Schedule 80 - Populus to Ben Lomond		$2,112	$2,112	$2,110
	Generation Energy - Other (non-NPC) (Sch 200)	$34,864	$41,499	$41,499	$41,526
	Generation Energy - Net Power Costs (Sch 201)	$25,965	$33,317	$25,965	$25,965
	Total	$76,355	$93,836	$86,483	$86,482
Transmission Voltage					
	Transmission & Ancillary Services[1]	$1,094	$1,095	$1,095	$1,094
	Distribution	$1,172	$1,653	$1,653	$1,667
	Schedule 80 - Populus to Ben Lomond		$466	$466	$467
	Generation Energy - Other (non-NPC) (Sch 200)	$8,601	$10,301	$10,301	$10,286
	Generation Energy - Net Power Costs (Sch 201)	$6,453	$8,270	$6,453	$6,453
	Total	$17,321	$21,783	$19,967	$19,968
Schedules 51, 53, 54, Lighting[2]					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$2	$13	$13	$13
	Distribution	$1,937	$1,549	$1,549	$1,549
	Schedule 80 - Populus to Ben Lomond		$6	$6	$6
	Generation Energy - Other (non-NPC) (Sch 200)	$235	$488	$488	$488
	Generation Energy - Net Power Costs (Sch 201)	$176	$392	$176	$176
	Total	$2,350	$2,448	$2,233	$2,231
TOTAL		**$933,218**	**$1,128,434**	**$1,061,550**	**$1,061,548**
Additional Rate Schedules					
	Schedule 33	$5,327		$5,493	$5,493
	Schedule 47	$19,269		$21,950	$21,950
	Lighting 15, 50, 51[2], 52	$3,996		$3,797	$3,797
	Employee Discount	($397)		($452)	($452)
Total Oregon		**$961,412**		**$1,092,338**	**$1,092,336**
			Revenue Increase	**$130,926**	**$130,924**

[1]Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.
[2]Cost of Service study includes only certain lamp types under Schedule 51.

PACIFIC POWER
STATE OF OREGON
Functionalized Populus to Ben Lomond Revenue Requirement
Forecast 12 Months Ended December 31, 2011
Dollars in Thousands

Line	Description	Total	(A) Residential	(B) General Service	(C)	(D) General Service	(E)	(F) General Service	(G)	(H) Large Power Service	(I)	(J)	(K) Irrigation	(L) Street Lgt.
				Sch 23		Sch 28		Sch 30		Sch 48T			Sch 41	Sch 51, 53, 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)		
1	Populus to Ben Lomond Revenue Requirement	$21,032												
2	Pop. to Ben Lom. Collection for Schedules not included in COS Study*	$508												
3	Pop. to Ben Lom. for Schedules Included in COS Study	$20,524												
4														
5														
6	Transmission Allocation Factors from GRC	100.00%	45.55%	8.58%	0.01%	16.79%	0.11%	10.02%	0.82%	4.53%	10.29%	2.27%	1.00%	0.03%
7														
8														
9	**Functionalized Populus to Ben Lomond Revenue Requirement- (Target)**	**$20,524**	**$9,349**	**$1,761**	**$1**	**$3,445**	**$23**	**$2,057**	**$169**	**$929**	**$2,112**	**$466**	**$206**	**$6**

*Revenues by rate schedule as follow:

Schedule 47 Primary	$291
Schedule 47 Transmission	$216
Schedule 15	$3
Schedule 50	$3
Schedule 51 (partial)	$2
Schedule 52	$0
Employee Discount	($8)
Total not in study	$508

Exhibit PPL/1702
Griffith/3

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2009
Forecast 12 Months Ended December 31, 2011

Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,626,702,107	5,399,118,767	5,306,839,724	kWh	0.386 ¢	$20,484,401	0.414 ¢	$21,970,316
Distribution Charge								
Basic Charge, per month	5,656,602	5,656,602	5,808,134	bill	$8.00	$46,465,070	$9.00	$52,273,204
Three Phase Demand Charge, per kW demand	17,355	17,355	17,058	kW	$2.20	$37,528	$2.20	$37,528
Three Phase Minimum Demand Charge, per month	1,515	1,515	1,556	bill	$3.80	$5,913	$3.80	$5,913
Distribution Energy Charge, per kWh	5,626,702,107	5,399,118,767	5,306,839,724	kWh	3.081 ¢	$163,503,732	3.474 ¢	$184,359,612
Energy Charge - Schedule 200								
First Block kWh	2,521,149,499	2,419,176,499	2,377,829,142	kWh	2.213 ¢	$52,621,359	2.662 ¢	$63,297,812
Second Block kWh	1,563,259,696	1,500,030,696	1,474,392,920	kWh	2.623 ¢	$38,673,326	3.155 ¢	$46,517,097
Third Block kWh	1,542,292,912	1,479,911,572	1,454,617,662	kWh	3.236 ¢	$47,071,428	3.893 ¢	$56,628,266
Subtotal	5,626,702,107	5,399,118,767	5,306,839,724	kWh		$368,862,757		$425,089,748
Renewable Adjustment Clause, per kWh	5,626,702,107	5,399,118,767	5,306,839,724	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	5,626,702,107	5,399,118,767	5,306,839,724	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	5,626,702,107	5,399,118,767	5,306,839,724	kWh	0.000 ¢	$0	0.176 ¢	$9,340,038
Subtotal						$368,862,757		$434,429,786
Schedule 201								
First Block kWh	2,521,149,499	2,419,176,499	2,377,829,142	kWh	1.660 ¢	$39,471,964	1.660 ¢	$39,471,964
Second Block kWh	1,563,259,696	1,500,030,696	1,474,392,920	kWh	1.967 ¢	$29,001,309	1.967 ¢	$29,001,309
Third Block kWh	1,542,292,912	1,479,911,572	1,454,617,662	kWh	2.428 ¢	$35,318,117	2.428 ¢	$35,318,117
Total	5,626,702,107	5,399,118,767	5,306,839,724	kWh		$472,654,147		$538,221,176
							Change	$65,567,029
Schedule No. 4 - Employee Discount								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	18,358,789	18,358,789	18,045,010	kWh	0.386 ¢	$69,654	0.414 ¢	$74,706
Distribution Charge								
Basic Charge, per month	14,176	14,176	14,556	bill	$8.00	$116,448	$9.00	$131,004
Three Phase Demand Charge, per kW demand	88	88	86	kW	$2.20	$189	$2.20	$189
Three Phase Minimum Demand Charge, per month	12	12	12	bill	$3.80	$46	$3.80	$46
Distribution Energy Charge, per kWh	18,358,789	18,358,789	18,045,010	kWh	3.081 ¢	$555,967	3.474 ¢	$626,884
Energy Charge - Schedule 200								
First Block kWh	6,889,324	6,889,324	6,771,575	kWh	2.213 ¢	$149,855	2.662 ¢	$180,259
Second Block kWh	5,252,493	5,252,493	5,162,720	kWh	2.623 ¢	$135,418	3.155 ¢	$162,884
Third Block kWh	6,216,972	6,216,972	6,110,715	kWh	3.236 ¢	$197,743	3.893 ¢	$237,890
Subtotal	18,358,789	18,358,789	18,045,010	kWh		$1,225,320		$1,413,862
Renewable Adjustment Clause, per kWh	18,358,789	18,358,789	18,045,010	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	18,358,789	18,358,789	18,045,010	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	18,358,789	18,358,789	18,045,010	kWh	0.000 ¢	$0	0.176 ¢	$31,759
Subtotal						$1,225,320		$1,445,621
Schedule 201								
First Block kWh	6,889,324	6,889,324	6,771,575	kWh	1.660 ¢	$112,408	1.660 ¢	$112,408
Second Block kWh	5,252,493	5,252,493	5,162,720	kWh	1.967 ¢	$101,551	1.967 ¢	$101,551
Third Block kWh	6,216,972	6,216,972	6,110,715	kWh	2.428 ¢	$148,368	2.428 ¢	$148,368
Total	18,358,789	18,358,789	18,045,010	kWh		$1,587,647		$1,807,948
Schedule 201 Employee Discount						($90,582)		($90,582)
Total Employee Discount						($396,912)		($451,987)

PACIFIC POWER
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Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite								
General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,128,047,757	1,098,300,597	1,013,023,494	kWh	0.373 ¢	$3,778,578	0.409 ¢	$4,143,266
Distribution Charge								
Basic Charge								
Single Phase, per month	709,544	709,544	694,173	bill	$17.55	$12,182,736	$20.40	$14,161,129
Three Phase, per month	200,315	200,315	195,868	bill	$26.20	$5,131,742	$30.45	$5,964,181
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	875,917	875,917	808,003	kW	$1.20	$969,604	$1.40	$1,131,204
Demand Charge, the first 15 kW of demand				kW	No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	464,644	464,644	428,608	kW	$4.08	$1,748,721	$4.74	$2,031,602
Reactive Power Charge, per kvar	66,197	66,197	61,110	kvar	65.00 ¢	$39,722	65.00 ¢	$39,722
Distribution Energy Charge, per kWh	1,128,047,757	1,098,300,597	1,013,023,494	kWh	2.417 ¢	$24,484,778	2.806 ¢	$28,425,439
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	872,713,216	849,698,216	783,723,212	kWh	2.741 ¢	$21,481,853	3.321 ¢	$26,027,448
All additional kWh, per kWh	255,334,541	248,602,381	229,300,282	kWh	2.035 ¢	$4,666,261	2.465 ¢	$5,652,252
Subtotal	1,128,047,757	1,098,300,597	1,013,023,494	kWh		$74,483,995		$87,576,243
Renewable Adjustment Clause, per kWh	1,128,047,757	1,098,300,597	1,013,023,494	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,128,047,757	1,098,300,597	1,013,023,494	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	1,128,047,757	1,098,300,597	1,013,023,494	kWh	0.000 ¢	$0	0.174 ¢	$1,762,661
Subtotal						$74,483,995		$89,338,904
Schedule 201								
1st 3,000 kWh, per kWh	872,713,216	849,698,216	783,723,212	kWh	2.057 ¢	$16,121,186	2.057 ¢	$16,121,186
All additional kWh, per kWh	255,334,541	248,602,381	229,300,282	kWh	1.527 ¢	$3,501,415	1.527 ¢	$3,501,415
Total	1,128,047,757	1,098,300,597	1,013,023,494	kWh	0.000 0	$94,106,596		$108,961,505
							Change	$14,854,909
Schedule No. 23/723 - Composite								
General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	881,448	881,448	814,563	kWh	0.361 ¢	$2,941	0.396 ¢	$3,226
Distribution Charge								
Basic Charge								
Single Phase, per month	235	235	230	bill	$17.55	$4,037	$20.40	$4,692
Three Phase, per month	200	200	207	bill	$26.20	$5,423	$30.45	$6,303
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	2,871	2,871	2,666	kW	$1.20	$3,199	$1.40	$3,732
Demand Charge, the first 15 kW of demand				kW	No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	1,001	1,001	926	kW	$3.97	$3,676	$4.61	$4,269
Reactive Power Charge, per kvar	2,568	2,568	2,379	kvar	60.00 ¢	$1,427	60.00 ¢	$1,427
Distribution Energy Charge, per kWh	881,448	881,448	814,563	kWh	2.342 ¢	$19,077	2.718 ¢	$22,140
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	626,231	626,231	578,291	kWh	2.655 ¢	$15,354	3.216 ¢	$18,598
All additional kWh, per kWh	255,217	255,217	236,272	kWh	1.971 ¢	$4,657	2.387 ¢	$5,640
Subtotal	881,448	881,448	814,563	kWh		$59,791		$70,027
Renewable Adjustment Clause, per kWh	881,448	881,448	814,563	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	881,448	881,448	814,563	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	881,448	881,448	814,563	kWh	0.000 ¢	$0	0.169 ¢	$1,377
Subtotal						$59,791		$71,404
Schedule 201								
1st 3,000 kWh, per kWh	626,231	626,231	578,291	kWh	1.993 ¢	$11,525	1.993 ¢	$11,525
All additional kWh, per kWh	255,217	255,217	236,272	kWh	1.479 ¢	$3,494	1.479 ¢	$3,494
Total	881,448	881,448	814,563	kWh	0.000 0	$74,810		$86,423
							Change	$11,613

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Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,831,949	6,831,949	6,724,252	kW	$1.23	$8,270,830	$1.20	$8,069,102
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	55,899	55,899	57,482	bill	$14.00	$804,748	$16.00	$919,712
Load Size 51-100 kW, per month	41,817	41,817	42,926	bill	$26.00	$1,116,076	$30.00	$1,287,780
Load Size 101-300 kW, per month	22,933	22,933	23,480	bill	$62.00	$1,455,760	$73.00	$1,714,040
Load Size > 300 kW, per month	485	485	495	bill	$89.00	$44,055	$104.00	$51,480
Load Size Charge								
≤ 50 kW	2,145,983	2,145,983	2,113,664	kW	$0.90	$1,902,298	$1.05	$2,219,347
51-100 kW, per kW	2,911,099	2,911,099	2,865,684	kW	$0.70	$2,005,979	$0.80	$2,292,547
101-300 kW, per kW	3,434,095	3,434,095	3,377,900	kW	$0.40	$1,351,160	$0.45	$1,520,055
>300 kW, per kW	194,754	194,754	191,361	kW	$0.30	$57,408	$0.35	$66,976
Demand Charge, per kW	6,831,949	6,831,949	6,724,252	kW	$2.63	$17,684,783	$3.08	$20,710,696
Reactive Power Charge, per kvar	571,866	571,866	560,381	kvar	65.00 ¢	$364,248	65.00 ¢	$364,248
Distribution Energy Charge, per kWh	2,048,191,681	2,048,191,681	2,016,754,744	kWh	0.300 ¢	$6,050,264	0.366 ¢	$7,381,322
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	1,455,364,810	1,439,049,810	1,416,918,832	kWh	2.644 ¢	$37,463,334	3.147 ¢	$44,590,436
All additional kWh, per kWh	592,826,871	586,168,561	577,181,460	kWh	2.573 ¢	$14,850,879	3.063 ¢	$17,679,068
Subtotal	2,048,191,681	2,025,218,371	1,994,100,292	kWh		$93,421,822		$108,866,809
Renewable Adjustment Clause, per kWh	2,048,191,681	2,025,218,371	1,994,100,292	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	2,048,191,681	2,025,218,371	1,994,100,292	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kW	6,831,949	6,831,949	6,724,252	kW	$0.00	$0	$0.51	$3,429,369
Subtotal						$93,421,822		$112,296,178
Schedule 201								
1st 20,000 kWh, per kWh	1,455,364,810	1,439,049,810	1,416,918,832	kWh	1.984 ¢	$28,111,670	1.984 ¢	$28,111,670
All additional kWh, per kWh	592,826,871	586,168,561	577,181,460	kWh	1.930 ¢	$11,139,602	1.930 ¢	$11,139,602
Total	2,048,191,681	2,025,218,371	1,994,100,292	kWh		$132,673,094		$151,547,450
							Change	$18,874,356
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	64,381	64,381	63,011	kW	$1.18	$74,353	$0.87	$54,820
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	50	50	52	bill	$17.00	$884	$18.00	$936
Load Size 51-100 kW, per month	174	174	173	bill	$30.00	$5,190	$32.00	$5,536
Load Size 101-300 kW, per month	378	378	379	bill	$71.00	$26,909	$75.00	$28,425
Load Size > 300 kW, per month	40	40	41	bill	$102.00	$4,182	$108.00	$4,428
Load Size Charge								
≤ 50 kW	1,905	1,905	1,875	kW	$1.00	$1,875	$1.05	$1,969
51-100 kW, per kW	12,283	12,283	11,970	kW	$0.80	$9,576	$0.85	$10,175
101-300 kW, per kW	64,201	64,201	62,843	kW	$0.45	$28,279	$0.50	$31,422
>300 kW, per kW	15,318	15,318	15,105	kW	$0.25	$3,776	$0.25	$3,776
Demand Charge, per kW	64,381	64,381	63,011	kW	$3.10	$195,334	$3.29	$207,306
Reactive Power Charge, per kvar	29,663	29,663	29,064	kvar	60.00 ¢	$17,438	60.00 ¢	$17,438
Distribution Energy Charge, per kWh	18,108,755	18,108,755	17,726,857	kWh	0.039 ¢	$6,913	0.046 ¢	$8,154
Energy Charge - Schedule 200								
1st 20,000 kWh, per kWh	10,124,577	10,124,577	9,894,023	kWh	2.568 ¢	$254,079	2.916 ¢	$288,510
All additional kWh, per kWh	7,984,178	7,984,178	7,832,834	kWh	2.499 ¢	$195,743	2.838 ¢	$222,296
Subtotal	18,108,755	18,108,755	17,726,857	kWh		$824,531		$885,191
Renewable Adjustment Clause, per kWh	18,108,755	18,108,755	17,726,857	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	18,108,755	18,108,755	17,726,857	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kW	64,381	64,381	63,011	kW	$0.00	$0	$0.37	$23,314
Subtotal						$824,531		$908,505
Schedule 201								
1st 20,000 kWh, per kWh	10,124,577	10,124,577	9,894,023	kWh	1.927 ¢	$190,658	1.927 ¢	$190,658
All additional kWh, per kWh	7,984,178	7,984,178	7,832,834	kWh	1.875 ¢	$146,866	1.875 ¢	$146,866
Total	18,108,755	18,108,755	17,726,857	kWh		$1,162,055		$1,246,029
							Change	$83,974

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Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,563,245	3,563,245	3,607,345	kW	$1.42	$5,122,430	$1.34	$4,833,842
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	197	197	196	bill	$373.00	$72,948	$415.00	$81,162
Load Size 201-300 kW, per month	2,874	2,874	2,845	bill	$113.00	$321,444	$125.00	$355,580
Load Size > 300 kW, per month	6,979	6,979	6,890	bill	$295.00	$2,032,456	$327.00	$2,252,926
Load Size Charge								
≤ 200 kW	14,041	14,041	14,344	kW	No Charge		No Charge	
201-300 kW, per kW	739,011	739,011	750,660	kW	$1.30	$975,858	$1.45	$1,088,457
>300 kW, per kW	3,436,369	3,436,369	3,478,481	kW	$0.65	$2,261,013	$0.70	$2,434,937
Demand Charge, per kW	3,563,245	3,563,245	3,607,345	kW	$2.84	$10,244,860	$3.15	$11,363,137
Reactive Power Charge, per kvar	691,809	691,809	691,204	kvar	65.00 ¢	$449,283	65.00 ¢	$449,283
Energy Charge - Schedule 200								
Demand Charge, per kW	3,563,245	3,563,245	3,607,345	kW	$1.00	$3,607,345	$1.19	$4,292,741
1st 20,000 kWh, per kWh	193,703,431	193,703,431	196,457,339	kWh	2.502 ¢	$4,915,363	3.094 ¢	$6,078,390
All additional kWh, per kWh	1,068,564,658	1,068,564,658	1,087,336,008	kWh	2.260 ¢	$24,573,794	2.683 ¢	$29,173,225
Subtotal	1,262,268,089	1,262,268,089	1,283,793,347	kWh		$54,576,794		$62,403,680
Renewable Adjustment Clause, per kWh	1,262,268,089	1,262,268,089	1,283,793,347	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,262,268,089	1,262,268,089	1,283,793,347	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kW	3,563,245	3,563,245	3,607,345	kW	$0.00	$0	$0.57	$2,056,187
Subtotal						$54,576,794		$64,459,867
Schedule 201								
1st 20,000 kWh, per kWh	193,703,431	193,703,431	196,457,339	kWh	2.188 ¢	$4,298,487	2.188 ¢	$4,298,487
All additional kWh, per kWh	1,068,564,658	1,068,564,658	1,087,336,008	kWh	1.897 ¢	$20,626,764	1.897 ¢	$20,626,764
Total	1,262,268,089	1,262,268,089	1,283,793,347	kWh		$79,502,045		$89,385,118
							Change	$9,883,073
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	297,645	297,645	301,758	kW	$1.27	$383,233	$1.32	$398,321
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	9	9	9	bill	$337.00	$3,041	$397.00	$3,582.00
Load Size 201-300 kW, per month	106	106	106	bill	$107.00	$11,316	$127.00	$13,431.00
Load Size > 300 kW, per month	544	544	538	bill	$277.00	$148,989	$330.00	$177,496.00
Load Size Charge								
≤ 200 kW	106	106	109	kW	No Charge		No Charge	
201-300 kW, per kW	27,146	27,146	27,800	kW	$1.15	$31,970	$1.35	$37,530
>300 kW, per kW	333,625	333,625	337,932	kW	$0.60	$202,759	$0.70	$236,552
Demand Charge, per kW	297,645	297,645	301,758	kW	$2.62	$790,606	$3.12	$941,485
Reactive Power Charge, per kvar	36,061	36,061	35,783	kvar	60.00 ¢	$21,470	60.00 ¢	$21,470
Energy Charge - Schedule 200								
Demand Charge, per kW	297,645	297,645	301,758	kW	$1.00	$301,758	$1.21	$365,127
1st 20,000 kWh, per kWh	12,671,077	12,671,077	12,885,979	kWh	2.383 ¢	$307,073	3.029 ¢	$390,316
All additional kWh, per kWh	87,696,722	87,696,722	89,396,932	kWh	2.163 ¢	$1,933,656	2.618 ¢	$2,340,412
Subtotal	100,367,799	100,367,799	102,282,911	kWh		$4,135,871		$4,925,722
Renewable Adjustment Clause, per kWh	100,367,799	100,367,799	102,282,911	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	100,367,799	100,367,799	102,282,911	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kW	297,645	297,645	301,758	kW	$0.00	$0	$0.56	$168,984
Subtotal						$4,135,871		$5,094,706
Schedule 201								
1st 20,000 kWh, per kWh	12,671,077	12,671,077	12,885,979	kWh	2.131 ¢	$274,600	2.131 ¢	$274,600
All additional kWh, per kWh	87,696,722	87,696,722	89,396,932	kWh	1.842 ¢	$1,646,691	1.842 ¢	$1,646,691
Total	100,367,799	100,367,799	102,282,911	kWh		$6,057,162		$7,015,997
							Change	$958,835

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Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 33										
Klamath Irrigation and Drainage Pumping										
Total Customers	2,185	2,185	2,056							
Monthly Bills	9,691	9,691	9,117							
Charges										
On-Project (Rate Code 40)	55,791,668	55,791,668	68,041,966	kWh	3.902	¢	$2,654,998	4.031	¢	$2,742,772
Off-Project (Rate Code 35)	45,760,549	45,760,549	55,808,292	kWh	4.152	¢	$2,317,160	4.289	¢	$2,393,618
U.S. Government (Rate Code 33TX)	*2,959,045*	*2,959,045*	*3,608,769*	kWh				0.000		
U.S. Gov - On Peak	1,178,893	1,178,893	1,437,745	kWh	3.708	¢	$53,312	3.831	¢	$55,080
U.S. Gov - Off Peak	1,780,152	1,780,152	2,171,024	kWh	3.055	¢	$66,325	3.055	¢	$66,325
Minimum Charges On-Project							$220,617			$220,617
Minimum Charges Off-Project							$14,346			$14,346
Subtotal	104,511,262	104,511,262	127,459,027	kWh			$5,326,757			$5,492,757
Renewable Adjustment Clause, per kWh	104,511,262	104,511,262	127,459,027	kWh	0.000	¢	$0	0.000	¢	$0
Total	104,511,262	104,511,262	127,459,027	kWh			$5,326,757			$5,492,757
Note: Rates reflect estimated rate changes through 2010.								Change		$166,000

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Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	133,922,580	133,922,580	148,416,639	kWh	0.436 ¢	$647,097	0.324 ¢	$480,870
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, or Single Phase Any Size	5,684	5,684	5,723	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per month	467	467	470	bill	$370.00	$173,900	$390.00	$183,300
Three Phase Load Size > 300 kW, per month	14	14	14	bill	$1,460.00	$20,440	$1,530.00	$21,420
Total Customers	6,165	6,165	6,207	bill				
Monthly Bills	32,412	32,412	32,633					
Load Size Charge								
Single Phase Any Size, Three Phase ≤ 50 kW	73,254	73,254	81,182	kW	$18.00	$1,461,276	$19.00	$1,542,458
Three Phase 51-300 kW, per kW	39,442	39,442	43,711	kW	$11.00	$480,821	$12.00	$524,532
Three Phase > 300 kW, kW	6,969	6,969	7,723	kW	$7.00	$54,061	$7.00	$54,061
Single Phase, Minimum Charge	843	843	849	bill	$60.00	$50,940	$65.00	$55,185
Three Phase, Minimum Charge	1,133	1,133	1,141	bill	$110.00	$125,510	$115.00	$131,215
Distribution Energy Charge, per kWh	133,922,580	133,922,580	148,416,639	kWh	4.196 ¢	$6,227,562	4.393 ¢	$6,519,943
Reactive Power Charge, per kvar	27,782	27,782	30,789	kvar	65.00 ¢	$20,013	65.00 ¢	$20,013
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	1,368,030	1,368,030	1,516,088	kWh	3.780 ¢	$57,308	4.355 ¢	$66,026
Winter, All additional kWh, per kWh	1,142,726	1,142,726	1,266,400	kWh	2.576 ¢	$32,622	2.968 ¢	$37,587
Summer, All kWh, per kWh	131,411,824	131,411,824	145,634,151	kWh	2.576 ¢	$3,751,536	2.968 ¢	$4,322,422
Subtotal	133,922,580	133,922,580	148,416,639	kWh		$13,103,086		$13,959,032
Renewable Adjustment Clause, per kWh	133,922,580	133,922,580	148,416,639	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	133,922,580	133,922,580	148,416,639	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	133,922,580	133,922,580	148,416,639	kWh	0.000 ¢	$0	0.138 ¢	$204,815
Subtotal						$13,103,086		$14,163,847
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	1,368,030	1,368,030	1,516,088	kWh	2.836 ¢	$42,996	2.836 ¢	$42,996
Winter, All additional kWh, per kWh	1,142,726	1,142,726	1,266,400	kWh	1.932 ¢	$24,467	1.932 ¢	$24,467
Summer, All kWh, per kWh	131,411,824	131,411,824	145,634,151	kWh	1.932 ¢	$2,813,652	1.932 ¢	$2,813,652
Total	133,922,580	133,922,580	148,416,639	kWh		$15,984,201		$17,044,962
							Change	$1,060,761
Schedule No. 41/741								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	634,842	634,842	703,549	kWh	0.422 ¢	$2,969	0.314 ¢	$2,209
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, or Single Phase Any Size	3	3	3	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per month	0	0	0	bill	$360.00	$0	$380.00	$0
Three Phase Load Size > 300 kW, per month	1	1	1	bill	$1,420.00	$1,420	$1,490.00	$1,490
Total Customers	4	4	4	bill				
Monthly Bills	33	33	33					
Load Size Charge								
Single Phase Any Size, Three Phase ≤ 50 kW	16	16	18	kW	$17.00	$306	$18.00	$324
Three Phase 51-300 kW, per kW	0	0	0	kW	$11.00	$0	$12.00	$0
Three Phase > 300 kW, kW	613	613	679	kW	$7.00	$4,753	$7.00	$4,753
Single Phase, Minimum Charge	0	0	0	bill	$60.00	$0	$65.00	$0
Three Phase, Minimum Charge	1	1	1	bill	$105.00	$105	$110.00	$110
Distribution Energy Charge, per kWh	634,842	634,842	703,549	kWh	4.065 ¢	$28,599	4.255 ¢	$29,936
Reactive Power Charge, per kvar	1,561	1,561	1,730	kvar	60.00 ¢	$1,038	60.00 ¢	$1,038
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	9,186	9,186	10,180	kWh	3.662 ¢	$373	4.218 ¢	$429
Winter, All additional kWh, per kWh	52,816	52,816	58,532	kWh	2.496 ¢	$1,461	2.874 ¢	$1,682
Summer, All kWh, per kWh	572,840	572,840	634,837	kWh	2.496 ¢	$15,846	2.874 ¢	$18,245
Subtotal	634,842	634,842	703,549	kWh		$56,870		$60,216
Renewable Adjustment Clause, per kWh	634,842	634,842	703,549	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	634,842	634,842	703,549	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	634,842	634,842	703,549	kWh	0.000 ¢	$0	0.134 ¢	$943
Subtotal						$56,870		$61,159
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	9,186	9,186	10,180	kWh	2.747 ¢	$280	2.747 ¢	$280
Winter, All additional kWh, per kWh	52,816	52,816	58,532	kWh	1.872 ¢	$1,096	1.872 ¢	$1,096
Summer, All kWh, per kWh	572,840	572,840	634,837	kWh	1.872 ¢	$11,884	1.872 ¢	$11,884
Total	634,842	634,842	703,549	kWh		$70,130		$74,419
							Change	$4,289

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2009
Forecast 12 Months Ended December 31, 2011

Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Industrial								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	592,038	592,038	454,631	kW	$1.06	$481,909	$0.97	$440,992
credit per kW of on-peak demand	0	0	0	kW	($1.06)	$0	($0.97)	$0
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	0	0	0	bill	$330.00	$0	$380.00	$0
Load Size > 4,000 kW, per month	37	37	32	bill	$590.00	$18,880	$690.00	$22,080
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	0	0	0	kW	$0.70	$0	$0.80	$0
Load Size > 4,000 kW, per kW	679,317	679,317	521,653	kW	$0.65	$339,074	$0.75	$391,240
Demand Charge, per kW of on-peak demand	592,038	592,038	454,631	kW	$2.05	$931,994	$2.41	$1,095,661
Reactive Power Charge, per kvar	22,693	22,693	17,426	kvar	60.00 ¢	$10,456	60.00 ¢	$10,456
Reactive Hours, per kvarh	3,810,080	3,810,080	2,925,790	kvarh	0.080 ¢	$2,341	0.080 ¢	$2,341
Reserves Charges								
Spinning Reserves, per kW of Facility	679,317	679,317	521,653	kW	$0.27	$140,846	$0.27	$140,846
Supplemental Reserves, per kW of Facility	679,317	679,317	521,653	kW	$0.27	$140,846	$0.27	$140,846
Spinning Reserves Credit, per kW of Facility	586,575	586,575	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW of Facility	586,575	586,575	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	592,038	592,038	454,631	kW	$1.00	$454,631	$1.19	$541,011
On-Peak, per on-peak kWh	190,360,582	190,360,582	146,179,349	kWh	2.268 ¢	$3,315,348	2.698 ¢	$3,943,919
Off-Peak, per off-peak kWh	148,447,232	148,447,232	113,993,767	kWh	2.218 ¢	$2,528,382	2.648 ¢	$3,018,555
Unscheduled Energy, per kWh	6,949,386	6,949,386	5,336,487	kWh	*1.518 ¢*	$81,033	*1.518 ¢*	$81,033
Subtotal	345,757,200	345,757,200	265,509,603	kWh		$8,445,740		$9,828,980
Renewable Adjustment Clause, per kWh	345,757,200	345,757,200	265,509,603	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	345,757,200	345,757,200	265,509,603	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per on-peak kW	592,038	592,038	454,631	kW	$0.00	$0	$0.64	$290,964
Subtotal						$8,445,740		$10,119,944
Schedule 201								
On-Peak, per on-peak kWh	190,360,582	190,360,582	146,179,349	kWh	1.869 ¢	$2,732,092	1.869 ¢	$2,732,092
Off-Peak, per off-peak kWh	148,447,232	148,447,232	113,993,767	kWh	1.819 ¢	$2,073,547	1.819 ¢	$2,073,547
Total	345,757,200	345,757,200	265,509,603	kWh		$13,251,379		$14,925,583
							Change	$1,674,204
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	303,931	303,931	257,607	kW	$1.43	$368,378	$1.43	$368,378
credit per kW of on-peak demand	0	0	0	kW	($1.43)	$0	($1.43)	$0
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	24	24	27	bill	$440.00	$11,880	$620.00	$16,740
Load Size > 4,000 kW, per month	24	24	24	bill	$810.00	$19,440	$1,140.00	$27,360
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	33,190	33,190	38,058	kW	$0.60	$22,835	$0.90	$34,252
Load Size > 4,000 kW, per kW	333,600	333,600	291,628	kW	$0.60	$174,977	$0.90	$262,465
Demand Charge, per kW of on-peak demand	303,931	303,931	257,607	kW	$1.35	$347,769	$1.90	$489,453
Reactive Power Charge, per kvar	20,524	20,524	18,839	kvar	55.00 ¢	$10,361	55.00 ¢	$10,361
Reactive Hours, per kvarh	976,000	976,000	1,119,163	kvarh	0.080 ¢	$895	0.08 ¢	$895
Reserves Charges								
Spinning Reserves, per kW of Facility	366,790	366,790	329,686	kW	$0.27	$89,015	$0.27	$89,015
Supplemental Reserves, per kW of Facility	366,790	366,790	329,686	kW	$0.27	$89,015	$0.27	$89,015
Spinning Reserves Credit, per kW of Facility	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW of Facility	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	303,931	303,931	257,607	kW	$1.00	$257,607	$1.20	$309,128
On-Peak, per on-peak kWh	87,130,098	87,130,098	67,655,805	kWh	2.220 ¢	$1,501,959	2.650 ¢	$1,792,879
Off-Peak, per off-peak kWh	58,109,390	58,109,390	45,412,927	kWh	2.170 ¢	$985,461	2.600 ¢	$1,180,736
Unscheduled Energy, per kWh	4,265,987	4,265,987	3,412,243	kWh	*4.162 ¢*	$142,012	*4.162 ¢*	$142,012
Subtotal	149,505,475	149,505,475	116,480,975	kWh		$4,021,604		$4,812,689
Renewable Adjustment Clause, per kWh	149,505,475	149,505,475	116,480,975	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	149,505,475	149,505,475	116,480,975	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per on-peak kW	303,931	303,931	257,607	kW	$0.00	$0	$0.84	$216,390
Subtotal						$4,021,604		$5,029,079
Schedule 201								
On-Peak, per on-peak kWh	87,130,098	87,130,098	67,655,805	kWh	1.785 ¢	$1,207,656	1.785 ¢	$1,207,656
Off-Peak, per off-peak kWh	58,109,390	58,109,390	45,412,927	kWh	1.735 ¢	$787,914	1.735 ¢	$787,914
Total	149,505,475	149,505,475	116,480,975	kWh		$6,017,174		$7,024,649
							Change	$1,007,475

PACIFIC POWER
State of Oregon
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Actual 12 Months Ended June 30, 2009
Forecast 12 Months Ended December 31, 2011

Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.038	$0	$0.032	$0
Primary	0	0	0	kW	$0.041	$0	$0.038	$0
Transmission	0	0	0	kW	$0.056	$0	$0.056	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.073	$0	$0.086	$0
Primary	0	0	0	kW	$0.080	$0	$0.094	$0
Transmission	0	0	0	kW	$0.053	$0	$0.074	$0
Schedule No. 48/748 - Composite								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,772,418	1,772,418	1,590,198	kW	$1.51	$2,401,199	$1.37	$2,178,571
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	1,451	1,451	1,434	bill	$320.00	$458,880	$370.00	$530,580
Load Size > 4,000 kW, per month	23	23	24	bill	$600.00	$14,400	$690.00	$16,560
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	1,975,162	1,975,162	1,764,643	kW	$1.30	$2,294,036	$1.45	$2,558,732
Load Size > 4,000 kW, per kW	186,053	186,053	178,020	kW	$1.20	$213,624	$1.35	$240,327
Demand Charge, per kW of on-peak demand	1,772,418	1,772,418	1,590,198	kW	$1.88	$2,989,572	$2.22	$3,530,240
Reactive Power Charge, per kvar	506,192	506,192	440,375	kvar	65.00 ¢	$286,244	65.00 ¢	$286,244
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,772,418	1,772,418	1,590,198	kW	$1.00	$1,590,198	$1.18	$1,876,434
On-Peak, per on-peak kWh	412,955,864	412,955,864	372,517,681	kWh	2.337 ¢	$8,705,738	2.766 ¢	$10,303,839
Off-Peak, per off-peak kWh	228,366,764	228,366,764	206,694,746	kWh	2.287 ¢	$4,727,109	2.716 ¢	$5,613,829
Subtotal	641,322,628	641,322,628	579,212,427	kWh		$23,681,000		$27,135,356
Renewable Adjustment Clause, per kWh	641,322,628	641,322,628	579,212,427	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	641,322,628	641,322,628	579,212,427	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per on-peak kW	1,772,418	1,772,418	1,590,198	kW	$0.00	$0	$0.58	$922,315
Subtotal						$23,681,000		$28,057,671
Schedule 201								
On-Peak, per on-peak kWh	412,955,864	412,955,864	372,517,681	kWh	1.956 ¢	$7,286,446	1.956 ¢	$7,286,446
Off-Peak, per off-peak kWh	228,366,764	228,366,764	206,694,746	kWh	1.906 ¢	$3,939,602	1.906 ¢	$3,939,602
Total	641,322,628	641,322,628	579,212,427	kWh	0.000	$34,907,048		$39,283,719
							Change	$4,376,671
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,797,512	3,797,512	3,297,589	kW	$1.60	$5,276,142	$1.51	$4,979,359
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	685	685	687	bill	$330.00	$226,710	$380.00	$261,060
Load Size > 4,000 kW, per month	404	404	385	bill	$590.00	$227,150	$690.00	$265,650
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	1,318,659	1,318,659	1,180,150	kW	$0.70	$826,105	$0.80	$944,120
Load Size > 4,000 kW, per kW	3,165,574	3,165,574	2,724,071	kW	$0.65	$1,770,646	$0.75	$2,043,053
Demand Charge, per kW of on-peak demand	3,797,512	3,797,512	3,297,589	kW	$2.05	$6,760,057	$2.41	$7,947,189
Reactive Power Charge, per kvar	856,290	856,290	732,645	kvar	60.00 ¢	$439,587	60.00 ¢	$439,587
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,797,512	3,797,512	3,297,589	kW	$1.00	$3,297,589	$1.19	$3,924,131
On-Peak, per on-peak kWh	990,769,250	990,769,250	861,217,531	kWh	2.268 ¢	$19,532,414	2.698 ¢	$23,235,649
Off-Peak, per off-peak kWh	624,226,602	624,226,602	542,546,863	kWh	2.218 ¢	$12,033,689	2.648 ¢	$14,366,641
Subtotal	1,614,995,852	1,614,995,852	1,403,764,394	kWh		$50,390,089		$58,406,439
Renewable Adjustment Clause, per kWh	1,614,995,852	1,614,995,852	1,403,764,394	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,614,995,852	1,614,995,852	1,403,764,394	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per on-peak kW	3,797,512	3,797,512	3,297,589	kW	$0.00	$0	$0.64	$2,110,457
Subtotal						$50,390,089		$60,516,896
Schedule 201								
On-Peak, per on-peak kWh	990,769,250	990,769,250	861,217,531	kWh	1.869 ¢	$16,096,156	1.869 ¢	$16,096,156
Off-Peak, per off-peak kWh	624,226,602	624,226,602	542,546,863	kWh	1.819 ¢	$9,868,927	1.819 ¢	$9,868,927
Total	1,614,995,852	1,614,995,852	1,403,764,394	kWh		$76,355,172		$86,481,979
							Change	$10,126,807

PACIFIC POWER
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Forecast 12 Months Ended December 31, 2011

Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 48/748 - Industrial										
Large General Service (Transmission)										
Transmission & Ancillary Services Charge										
per kW of on-peak demand	665,286	665,286	555,435	kW	$1.97		$1,094,207	$1.97		$1,094,207
Distribution Charge										
Basic Charge										
Load Size ≤ 4,000 kW, per month	0	0	0	bill	$440.00		$0	$620.00		$0
Load Size > 4,000 kW, per month	24	24	22	bill	$810.00		$17,820	$1,140.00		$25,080
Load Size/Facility Charge										
Load Size ≤ 4,000 kW, per kW	0	0	0	kW	$0.60		$0	$0.90		$0
Load Size > 4,000 kW, per kW	728,546	728,546	608,249	kW	$0.60		$364,949	$0.90		$547,424
Demand Charge, per kW of on-peak demand	665,286	665,286	555,435	kW	$1.35		$749,837	$1.90		$1,055,327
Reactive Power Charge, per kvar	86,129	86,129	71,907	kvar	55.00	¢	$39,549	55.00	¢	$39,549
Energy Charge - Schedule 200										
Demand Charge, per kW of On-Peak demand	665,286	665,286	555,435	kW	$1.00		$555,435	$1.20		$666,522
On-Peak, per on-peak kWh	243,750,000	243,750,000	203,502,316	kWh	2.220	¢	$4,517,751	2.650	¢	$5,392,811
Off-Peak, per off-peak kWh	194,730,000	194,730,000	162,576,434	kWh	2.170	¢	$3,527,909	2.600	¢	$4,226,987
Subtotal	438,480,000	438,480,000	366,078,750	kWh			$10,867,457			$13,047,907
Renewable Adjustment Clause, per kWh	438,480,000	438,480,000	366,078,750	kWh	0.000	¢	$0	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	438,480,000	438,480,000	366,078,750	kWh	0.000	¢	$0	0.000	¢	$0
Populus to Ben Lomond Surcharge, per on-peak kW	665,286	665,286	555,435	kW	$0.00		$0	$0.84		$466,565
Subtotal							$10,867,457			$13,514,472
Schedule 201										
On-Peak, per on-peak kWh	243,750,000	243,750,000	203,502,316	kWh	1.785	¢	$3,632,516	1.785	¢	$3,632,516
Off-Peak, per off-peak kWh	194,730,000	194,730,000	162,576,434	kWh	1.735	¢	$2,820,701	1.735	¢	$2,820,701
Total	438,480,000	438,480,000	366,078,750	kWh			$17,320,674			$19,967,689
								Change		$2,647,015

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2009
Forecast 12 Months Ended December 31, 2011

Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	7,481	7,481	7,166					
Transmission & Ancillary Services Charge								
per kWh	10,907,652	10,907,652	10,138,210	kWh	0.016 ¢	$1,622	0.069 ¢	$6,815
Distribution Charge								
Distribution Charge, per kWh	10,907,652	10,907,652	10,138,210	kWh	11.795 ¢	$1,087,623	8.588 ¢	$870,658
Energy Charge - Schedule 200								
per kWh	10,907,652	10,907,652	10,138,210	kWh	1.307 ¢	$132,506	2.712 ¢	$274,784
Subtotal	10,907,652	10,907,652	10,138,210	kWh		$1,221,751		$1,152,257
Renewable Adjustment Clause, per kWh	10,907,652	10,907,652	10,138,210	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	10,907,652	10,907,652	10,138,210	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	10,907,652	10,907,652	10,138,210	kWh	0.000 ¢	$0	0.029 ¢	$2,940
Subtotal						$1,221,751		$1,155,197
Schedule 201								
per kWh	10,907,652	10,907,652	10,138,210	kWh	1.077 ¢	$109,189	1.077 ¢	$109,244
Total	10,907,652	10,907,652	10,138,210	kWh		$1,330,940		$1,264,441
							Change	($66,500)
Schedule No. 50								
Mercury Vapor Street Lighting Service								
No. of Customers	266	266	258					
Transmission & Ancillary Services Charge								
per kWh	10,606,332	10,606,332	10,594,088	kWh	0.013 ¢	$1,377	0.069 ¢	$7,086
Distribution Charge								
Distribution Charge, per kWh	10,606,332	10,606,332	10,594,088	kWh	10.112 ¢	$977,476	7.308 ¢	$774,268
Energy Charge - Schedule 200								
per kWh	10,606,332	10,606,332	10,594,088	kWh	1.179 ¢	$124,904	2.446 ¢	$259,273
Subtotal	10,606,332	10,606,332	10,594,088	kWh		$1,103,757		$1,040,626
Renewable Adjustment Clause, per kWh	10,606,332	10,606,332	10,594,088	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	10,606,332	10,606,332	10,594,088	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	10,606,332	10,606,332	10,594,088	kWh	0.000 ¢	$0	0.029 ¢	$3,072
Subtotal						$1,103,757		$1,043,698
Schedule 201								
per kWh	10,606,332	10,606,332	10,594,088	kWh	0.885 ¢	$93,758	0.885 ¢	$93,475
Total	10,606,332	10,606,332	10,594,088	kWh		$1,197,515		$1,137,173
							Change	($60,342)
Schedule No. 51/751								
Street Lighting Service, Company-Owned System								
No. of Customers	677	677	710					
Transmission & Ancillary Services Charge								
per kWh	17,472,448	17,472,448	16,562,760	kWh	0.020 ¢	$3,313	0.069 ¢	$11,364
Distribution Charge								
Distribution Charge, per kWh	17,472,448	17,472,448	16,562,760	kWh	16.360 ¢	$2,478,288	11.975 ¢	$1,983,455
Energy Charge - Schedule 200								
per kWh	17,472,448	17,472,448	16,562,760	kWh	1.862 ¢	$308,399	3.864 ¢	$639,758
Subtotal	17,472,448	17,472,448	16,562,760	kWh		$2,790,000		$2,634,578
Renewable Adjustment Clause, per kWh	17,472,448	17,472,448	16,562,760	kWh	0.000 ¢	$0	0.000 ¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	17,472,448	17,472,448	16,562,760	kWh	0.000 ¢	$0	0.000 ¢	$0
Populus to Ben Lomond Surcharge, per kWh	17,472,448	17,472,448	16,562,760	kWh	0.000 ¢	$0	0.029 ¢	$4,803
Subtotal						$2,790,000		$2,639,381
Schedule 201								
per kWh	17,472,448	17,472,448	16,562,760	kWh	1.397 ¢	$231,382	1.397 ¢	$230,702
Total	17,472,448	17,472,448	16,562,760	kWh		$3,021,382		$2,870,083
							Change	($151,299)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2009
Forecast 12 Months Ended December 31, 2011

Schedule	Actual 7/08-6/09 Units	Normalized 7/08-6/09 Units	Forecast 1/11 - 12/11 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 52/752										
Street Lighting Service, Company-Owned System										
No. of Customers	65	65	65							
Transmission & Ancillary Services Charge										
per kWh	1,073,836	1,073,836	1,061,343	kWh	0.016	¢	$170	0.069	¢	$732
Distribution Charge										
Distribution Charge, per kWh	1,073,836	1,073,836	1,061,343	kWh	9.595	¢	$90,488	6.357	¢	$67,467
Energy Charge - Schedule 200										
per kWh	1,073,836	1,073,836	1,061,343	kWh	1.427	¢	$15,145	2.961	¢	$31,426
Subtotal	1,073,836	1,073,836	1,061,343	kWh			$105,803			$99,626
Renewable Adjustment Clause, per kWh	1,073,836	1,073,836	1,061,343	kWh	0.000	¢	$0	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	1,073,836	1,073,836	1,061,343	kWh	0.000	¢	$0	0.000	¢	$0
Populus to Ben Lomond Surcharge, per kWh	1,073,836	1,073,836	1,061,343	kWh	0.000	¢	$0	0.029	¢	$308
Subtotal							$105,803			$99,934
Schedule 201										
per kWh	1,073,836	1,073,836	1,061,343	kWh	1.070	¢	$11,356	1.070	¢	$11,356
Total	1,073,836	1,073,836	1,061,343	kWh			$117,159			$111,290
								Change		($5,869)
Schedule No. 53/753										
Street Lighting Service, Consumer-Owned System										
No. of Customers	255	255	266							
Transmission & Ancillary Services Charge										
per kWh	9,090,929	9,090,929	9,250,113	kWh	0.005	¢	$463	0.069	¢	$6,383
Distribution Charge										
Distribution Charge, per kWh	9,090,929	9,090,929	9,250,113	kWh	5.927	¢	$506,001	4.394	¢	$406,470
Energy Charge - Schedule 200										
per kWh	9,090,929	9,090,929	9,250,113	kWh	0.609	¢	$56,333	1.264	¢	$116,921
Subtotal	9,090,929	9,090,929	9,250,113	kWh			$562,797			$529,774
Renewable Adjustment Clause, per kWh	9,090,929	9,090,929	9,250,113	kWh	0.000	¢	$0	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	9,090,929	9,090,929	9,250,113	kWh	0.000	¢	$0	0.000	¢	$0
Populus to Ben Lomond Surcharge, per kWh	9,090,929	9,090,929	9,250,113	kWh	0.000	¢	$0	0.029	¢	$2,683
Subtotal							$562,797			$532,457
Schedule 201										
per kWh	9,090,929	9,090,929	9,250,113	kWh	0.457	¢	$42,273	0.457	¢	$42,273
Total	9,090,929	9,090,929	9,250,113	kWh			$605,070			$574,730
								Change		($30,340)
Schedule No. 54/754										
Recreational Field Lighting										
Transmission & Ancillary Services Charge										
per kWh	992,606	992,606	846,933	kWh	0.011	¢	$93	0.069	¢	$584
Distribution Charge										
Basic Charge, Single Phase, per month	828	828	826	bill	$6.00		$4,956	$6.00		$4,956
Basic Charge, Three Phase, per month	407	407	406	bill	$9.00		$3,654	$9.00		$3,654
Distribution Energy Charge, per kWh	992,606	992,606	846,933	kWh	5.937	¢	$50,282	4.282	¢	$36,266
Energy Charge - Schedule 200										
per kWh	992,606	992,606	846,933	kWh	1.048	¢	$8,876	2.175	¢	$18,421
Subtotal	992,606	992,606	846,933	kWh			$67,861			$63,881
Renewable Adjustment Clause, per kWh	992,606	992,606	846,933	kWh	0.000	¢	$0	0.000	¢	$0
Klamath Rate Reconciliation Surcharge, per kWh	992,606	992,606	846,933	kWh	0.000	¢	$0	0.000	¢	$0
Populus to Ben Lomond Surcharge, per kWh	992,606	992,606	846,933	kWh	0.000	¢	$0	0.029	¢	$246
Subtotal							$67,861			$64,127
Schedule 201										
per kWh	992,606	992,606	846,933	kWh	0.787	¢	$6,665	0.787	¢	$6,665
Total	992,606	992,606	846,933	kWh			$74,526			$70,792
								Change		($3,734)
TOTAL OREGON	13,663,841,278	13,383,537,468	12,774,659,998				$961,809,037			$1,092,787,965
Employee Discount							($396,912)			($451,987)
TOTAL OREGON (WITH EMPLOYEE DISCOUNT)							$961,412,125			$1,092,335,978

Docket No. UE-
Exhibit PPL/1703
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Estimated Effect of Proposed Rates

March 2010

GRC Price Change - Table 1703-1

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2011

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates[2]	Adders[1]	Net Rates	($000)	%[3]	($000)	%[3]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	484,011	5,306,840	$472,654	$19,369	$492,023	$538,221	$18,998	$557,219	$65,567	13.9%	$65,196	13.3%	1
2	**Total Residential**			484,011	5,306,840	$472,654	$19,369	$492,023	$538,221	$18,998	$557,219	$65,567	13.9%	$65,196	13.3%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,207	1,013,838	$94,181	($628)	$93,553	$109,048	($3,042)	$106,006	$14,867	15.8%	$12,453	13.3%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,419	2,011,827	$133,835	$10,844	$144,679	$152,793	$11,146	$163,939	$18,958	14.2%	$19,260	13.3%	4
5	Gen. Svc. 201 - 999 kW	30	30	882	1,386,076	$85,559	$4,215	$89,774	$96,401	$5,296	$101,697	$10,842	12.7%	$11,923	13.3%	5
6	Large General Service >= 1,000 kW	48	48	212	2,349,055	$128,583	($2,726)	$125,857	$145,733	($3,196)	$142,537	$17,150	13.4%	$16,680	13.3%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	381,991	$19,268	($446)	$18,822	$21,950	($522)	$21,428	$2,682	13.4%	$2,606	13.3%	7
8	Agricultural Pumping Service	41	41	6,211	149,120	$16,054	($3,276)	$12,778	$17,119	($2,637)	$14,482	$1,065	6.6%	$1,704	13.3%	8
9	Agricultural Pumping - Other	33	33	2,056	127,459	$5,327	$272	$5,599	$5,493	$272	$5,765	$166	3.1%	$166	3.0%	9
10	**Total Commercial & Industrial**			93,994	7,419,366	$482,807	$8,255	$491,062	$548,537	$7,317	$555,854	$65,730	13.6%	$64,792	13.2%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,167	10,138	$1,332	$136	$1,468	$1,265	$203	$1,468	($67)	-5.0%	$0	0.0%	11
12	Street Lighting Service	50	50	258	10,594	$1,198	$144	$1,342	$1,137	$205	$1,342	($61)	-5.1%	$0	0.0%	12
13	Street Lighting Service HPS	51	51	710	16,563	$3,021	$338	$3,359	$2,870	$489	$3,359	($151)	-5.0%	$0	0.0%	13
14	Street Lighting Service	52	52	65	1,061	$117	$15	$132	$111	$21	$132	($6)	-5.1%	$0	0.0%	14
15	Street Lighting Service	53	53	266	9,250	$605	$83	$688	$575	$113	$688	($30)	-5.0%	$0	0.0%	15
16	Recreational Field Lighting	54	54	103	847	$75	$7	$82	$71	$11	$82	($4)	-5.3%	$0	0.0%	16
17	**Total Public Street Lighting**			8,569	48,453	$6,348	$723	$7,071	$6,029	$1,042	$7,071	($319)	-5.0%	$0	0.0%	17
18	**Total Sales to Ultimate Consumers**			586,574	12,774,659	$961,809	$28,347	$990,156	$1,092,787	$27,357	$1,120,144	$130,978	13.6%	$129,988	13.1%	18
19	**Employee Discount**				18,045	($397)	($17)	($414)	($452)	($16)	($468)	($55)		($54)		19
20	**Total Sales with Employee Discount**			586,574	12,774,659	$961,412	$28,330	$989,742	$1,092,335	$27,341	$1,119,676	$130,923	13.6%	$129,934	13.1%	20
21	AGA Revenue					$2,800		$2,800	$2,800		$2,800	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			586,574	12,774,659	$964,212	$28,330	$992,542	$1,095,135	$27,341	$1,122,476	$130,923	13.6%	$129,934	13.1%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Includes the Populus to Ben Lomond Cost Recovery Charge (Schedule 80).

[3] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Exhibit PPL/1703
Griffith/1

Table 1703-2
PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2011

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 (000)	Prop. Sales 96 (000)	Interv. Fndg. 97 (000)	Tax Adj 102 (000)	OR Trns Plan 193 (000)	MEHC Sev 194 (000)	Grid West 195 (000)	RAC Defer. 203 (000)	Shop. Inctv. 296 (000)	RMA 299 (000)	RMA 299 (000)	Total (000)	Total (000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
													PRE	PRO	PRE	PRO
	<u>**Residential**</u>															
1	Residential	4	4	$371	($531)	$0	$7,536	$796	$849	$159	$2,176	$0	$8,013	$7,642	$19,369	$18,998
2	**Total Residential**															
	<u>**Commercial & Industrial**</u>															
3	Gen. Svc. < 31 kW	23	23	$71	($101)	$0	$1,439	$152	$162	$31	$426	$0	($2,808)	($5,222)	($628)	($3,042)
4	Gen. Svc. 31 - 200 kW	28	28	$141	($201)	$0	$2,857	$302	$322	$60	$824	$81	$6,458	$6,760	$10,844	$11,146
5	Gen. Svc. 201 - 999 kW	30	30	$97	($139)	$0	$1,969	$208	$222	$42	$554	$56	$1,206	$2,287	$4,215	$5,296
6	Large General Service >= 1,000 kW	48	48	$164	($235)	$0	$3,335	$353	$376	$70	$869	$0	($7,658)	($8,128)	($2,726)	($3,196)
7	Partial Req. Svc. >= 1,000 kW	47	47	$26	($39)	$0	$542	$58	$61	$11	$141	$0	($1,246)	($1,322)	($446)	($522)
8	Agricultural Pumping Service	41	41	$10	($15)	$0	$212	$22	$24	$4	$61	$4	($3,598)	($2,959)	($3,276)	($2,637)
9	Agricultural Pumping - Other	33	33	$9	($13)	$0	$181	$19	$20	$4	$52	$0	$0	$0	$272	$272
10	**Total Commercial & Industrial**			$518	($743)	$0	$10,535	$1,114	$1,187	$222	$2,927	$141	($7,646)	($8,584)	$8,255	$7,317
	<u>**Lighting**</u>															
11	Outdoor Area Lighting Service	15	15	$1	($1)	$0	$15	$1	$1	$0	$3	$0	$116	$183	$136	$203
12	Street Lighting Service	50	50	$1	($1)	$0	$15	$2	$2	$0	$2	$0	$123	$184	$144	$205
13	Street Lighting Service HPS	51	51	$1	($2)	$0	$24	$2	$3	$0	$5	$0	$305	$456	$338	$489
14	Street Lighting Service	52	52	$0	$0	$0	$2	$0	$0	$0	$0	$0	$13	$19	$15	$21
15	Street Lighting Service	53	53	$1	($1)	$0	$13	$1	$1	$0	$1	$0	$67	$97	$83	$113
16	Recreational Field Lighting	54	54	$0	$0	$0	$1	$0	$0	$0	$0	$0	$6	$10	$7	$11
17	**Total Public Street Lighting**			$4	($5)	$0	$70	$6	$7	$0	$11	$0	$630	$949	$723	$1,042
18	**Total**			$893	($1,279)	$0	$18,141	$1,916	$2,043	$381	$5,114	$141	$997	$7	$28,347	$27,357
19	**Employee Discount**			$0	$0	$0	($6)	($1)	($1)	$0	($2)	$0	($7)	($6)	($17)	($16)
20	**Total Sales with Employee Discount**			$893	($1,279)	$0	$18,135	$1,915	$2,042	$381	$5,112	$141	$990	$1	$28,330	$27,341

Table 1703-3
PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2011

Line No.	Description	Pre Sch No.	Pro Sch No.	Indep. Eval. 93 ¢/kWh	Prop. Sales 96 ¢/kWh	Interv. Fndg. 97 ¢/kWh	Tax Adj 102 ¢/kWh	OR Trns Plan 193 ¢/kWh	MEHC Sev 194 ¢/kWh	Grid West 195 ¢/kWh	RAC Defer. 203 ¢/kWh	Shop. Inctv. 296 ¢/kWh	RMA 299 ¢/kWh	RMA 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
													PRE	PRO
	Residential													
1	Residential	4	4	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.041	0.000	0.151	0.144
	Commercial & Industrial													
2	Gen. Svc. < 31 kW	23	23	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.042	0.000	(0.277)	(0.515)
3	Gen. Svc. 31 - 200 kW	28	28	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.041	0.004	0.321	0.336
4	Gen. Svc. 201 - 999 kW	30	30	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.040	0.004	0.087	0.165
5	Large General Service >= 1,000 kW	48	48	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.037	0.000	(0.326)	(0.346)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.037	0.000	(0.326)	(0.346)
7	Agricultural Pumping Service	41	41	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.041	0.004	(2.413)	(1.984)
8	Agricultural Pumping - Other	33	33	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.041	0.000	0.000	0.000
	Lighting													
9	Outdoor Area Lighting Service	15	15	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.022	0.000	1.150	1.805
10	Street Lighting Service	50	50	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.019	0.000	1.160	1.733
11	Street Lighting Service HPS	51	51	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.029	0.000	1.840	2.751
12	Street Lighting Service	52	52	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.023	0.000	1.200	1.800
13	Street Lighting Service	53	53	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.010	0.000	0.725	1.050
14	Recreational Field Lighting	54	54	0.007	(0.010)	0.000	0.142	0.015	0.016	0.003	0.017	0.000	0.760	1.200

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Supply Service Schedule 200
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$16.44	$18.53	$2.09	12.71%
200	$24.13	$27.30	$3.17	13.14%
300	$31.83	$36.07	$4.24	13.32%
400	$39.52	$44.84	$5.32	13.46%
500	$47.23	$53.60	$6.37	13.49%
600	$55.66	$63.19	$7.53	13.53%
700	$64.09	$72.78	$8.69	13.56%
800	$72.52	$82.37	$9.85	13.58%
900	**$80.96**	**$91.97**	**$11.01**	**13.60%**
1,000	$89.40	$101.55	$12.15	13.59%
1,100	$98.93	$112.38	$13.45	13.60%
1,200	$108.48	$123.21	$14.73	13.58%
1,300	$118.01	$134.03	$16.02	13.58%
1,400	$127.56	$144.85	$17.29	13.55%
1,500	$137.10	$155.68	$18.58	13.55%
1,600	$146.64	$166.51	$19.87	13.55%
2,000	$184.81	$209.81	$25.00	13.53%
3,000	$280.22	$318.06	$37.84	13.50%
4,000	$375.63	$426.31	$50.68	13.49%
5,000	$471.03	$534.56	$63.53	13.49%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price Single Phase	Monthly Billing* Present Price Three Phase	Monthly Billing* Proposed Price Single Phase	Monthly Billing* Proposed Price Three Phase	Percent Difference Single Phase	Percent Difference Three Phase
5	500	$58	$67	$66	$76	13.37%	13.74%
	750	$78	$87	$88	$99	13.04%	13.35%
	1,000	$98	$107	$111	$121	12.85%	13.12%
	1,500	$138	$147	$156	$166	12.62%	12.84%
10	1,000	$98	$107	$111	$121	12.85%	13.12%
	2,000	$179	$187	$201	$211	12.50%	12.68%
	3,000	$259	$268	$291	$301	12.37%	12.50%
	4,000	$326	$335	$366	$377	12.31%	12.41%
20	4,000	$353	$362	$398	$408	12.62%	12.70%
	6,000	$488	$497	$549	$560	12.47%	12.53%
	8,000	$623	$632	$701	$711	12.38%	12.43%
	10,000	$758	$767	$852	$862	12.32%	12.37%
30	9,000	$745	$754	$840	$850	12.64%	12.68%
	12,000	$948	$957	$1,066	$1,077	12.52%	12.55%
	15,000	$1,150	$1,159	$1,293	$1,304	12.44%	12.47%
	18,000	$1,353	$1,362	$1,520	$1,531	12.38%	12.41%
31	9,300	$771	$780	$869	$879	12.65%	12.69%
	12,400	$980	$989	$1,103	$1,113	12.52%	12.56%
	15,500	$1,189	$1,198	$1,338	$1,348	12.44%	12.47%
	18,600	$1,399	$1,408	$1,572	$1,582	12.39%	12.41%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Supply Service Schedule 200
General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price Single Phase	Present Price Three Phase	Proposed Price Single Phase	Proposed Price Three Phase	Percent Difference Single Phase	Percent Difference Three Phase
5	500	$57	$66	$65	$75	13.32%	13.71%
	750	$76	$85	$86	$97	12.97%	13.30%
	1,000	$96	$105	$108	$118	12.77%	13.06%
	1,500	$135	$144	$152	$162	12.53%	12.75%
10	1,000	$96	$105	$108	$118	12.77%	13.06%
	2,000	$174	$183	$195	$206	12.40%	12.59%
	3,000	$251	$260	$282	$293	12.26%	12.40%
	4,000	$317	$326	$356	$366	12.20%	12.31%
20	4,000	$344	$352	$386	$397	12.51%	12.60%
	6,000	$474	$483	$533	$543	12.35%	12.42%
	8,000	$605	$614	$680	$690	12.26%	12.32%
	10,000	$736	$745	$826	$836	12.20%	12.25%
30	9,000	$724	$733	$815	$825	12.52%	12.57%
	12,000	$920	$929	$1,034	$1,045	12.40%	12.43%
	15,000	$1,117	$1,126	$1,254	$1,265	12.31%	12.34%
	18,000	$1,313	$1,322	$1,474	$1,484	12.26%	12.28%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$351	$397	13.04%
	7,500	$527	$591	12.12%
	10,500	$703	$785	11.66%
31	9,300	$711	$803	13.01%
	15,500	$1,074	$1,204	12.09%
	21,700	$1,435	$1,601	11.63%
40	12,000	$913	$1,032	13.01%
	20,000	$1,381	$1,548	12.08%
	28,000	$1,839	$2,053	11.63%
60	18,000	$1,362	$1,538	12.92%
	30,000	$2,052	$2,299	12.03%
	42,000	$2,739	$3,056	11.59%
80	24,000	$1,802	$2,035	12.92%
	40,000	$2,718	$3,045	12.03%
	56,000	$3,634	$4,055	11.58%
100	30,000	$2,240	$2,529	12.92%
	50,000	$3,385	$3,792	12.02%
	70,000	$4,530	$5,054	11.58%
200	60,000	$4,402	$4,971	12.92%
	100,000	$6,692	$7,496	12.01%
	140,000	$8,983	$10,022	11.57%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$344	$367	6.63%
	7,500	$508	$542	6.75%
	10,500	$671	$717	6.81%
31	9,300	$693	$739	6.65%
	15,500	$1,031	$1,100	6.76%
	21,700	$1,366	$1,459	6.82%
40	12,000	$889	$948	6.65%
	20,000	$1,325	$1,414	6.76%
	28,000	$1,751	$1,870	6.82%
60	18,000	$1,326	$1,415	6.73%
	30,000	$1,967	$2,101	6.81%
	42,000	$2,606	$2,784	6.86%
80	24,000	$1,752	$1,870	6.73%
	40,000	$2,604	$2,781	6.81%
	56,000	$3,456	$3,692	6.85%
100	30,000	$2,176	$2,323	6.73%
	50,000	$3,241	$3,462	6.81%
	70,000	$4,306	$4,601	6.85%
200	60,000	$4,267	$4,557	6.82%
	100,000	$6,396	$6,836	6.87%
	140,000	$8,525	$9,114	6.90%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,476	$2,811	13.52%
	50,000	$3,437	$3,875	12.75%
	70,000	$4,397	$4,938	12.31%
200	60,000	$4,459	$5,050	13.27%
	100,000	$6,379	$7,177	12.51%
	140,000	$8,300	$9,305	12.10%
300	90,000	$6,575	$7,439	13.14%
	150,000	$9,456	$10,629	12.41%
	210,000	$12,337	$13,820	12.02%
400	120,000	$8,611	$9,726	12.95%
	200,000	$12,452	$13,981	12.27%
	280,000	$16,294	$18,235	11.91%
500	150,000	$10,660	$12,037	12.92%
	250,000	$15,462	$17,355	12.25%
	350,000	$20,264	$22,673	11.89%
600	180,000	$12,709	$14,349	12.90%
	300,000	$18,472	$20,730	12.23%
	420,000	$24,234	$27,112	11.88%
800	240,000	$16,808	$18,971	12.87%
	400,000	$24,491	$27,480	12.20%
	560,000	$32,174	$35,988	11.86%
1000	300,000	$20,906	$23,594	12.85%
	500,000	$30,510	$34,229	12.19%
	700,000	$40,114	$44,865	11.84%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,349	$2,751	17.10%
	50,000	$3,278	$3,790	15.61%
	70,000	$4,207	$4,829	14.77%
200	60,000	$4,246	$4,949	16.54%
	100,000	$6,105	$7,027	15.10%
	140,000	$7,963	$9,104	14.34%
300	90,000	$6,262	$7,286	16.35%
	150,000	$9,049	$10,402	14.95%
	210,000	$11,836	$13,519	14.21%
400	120,000	$8,226	$9,564	16.26%
	200,000	$11,943	$13,720	14.88%
	280,000	$15,659	$17,875	14.15%
500	150,000	$10,185	$11,834	16.19%
	250,000	$14,831	$17,028	14.82%
	350,000	$19,476	$22,223	14.10%
600	180,000	$12,144	$14,104	16.14%
	300,000	$17,719	$20,337	14.78%
	420,000	$23,293	$26,570	14.07%
800	240,000	$16,063	$18,644	16.07%
	400,000	$23,495	$26,955	14.73%
	560,000	$30,927	$35,266	14.03%
1000	300,000	$19,981	$23,184	16.03%
	500,000	$29,271	$33,573	14.70%
	700,000	$38,562	$43,961	14.00%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$208	$230	$185	$240	$264	$196	15.50%	14.85%	5.56%
	5,000	$347	$369	$185	$401	$424	$196	15.50%	15.09%	5.56%
	7,000	$486	$507	$185	$561	$585	$196	15.50%	15.21%	5.56%
Three Phase										
20	6,000	$416	$460	$371	$481	$528	$391	15.50%	14.85%	5.56%
	10,000	$694	$737	$371	$801	$849	$391	15.50%	15.09%	5.56%
	14,000	$971	$1,015	$371	$1,122	$1,169	$391	15.50%	15.20%	5.56%
100	30,000	$2,082	$2,300	$1,514	$2,404	$2,642	$1,638	15.50%	14.84%	8.16%
	50,000	$3,470	$3,689	$1,514	$4,007	$4,245	$1,638	15.50%	15.09%	8.16%
	70,000	$4,857	$5,077	$1,514	$5,610	$5,849	$1,638	15.50%	15.20%	8.16%
300	90,000	$6,245	$6,900	$3,780	$7,213	$7,925	$4,110	15.50%	14.84%	8.72%
	150,000	$10,409	$11,066	$3,780	$12,022	$12,736	$4,110	15.50%	15.09%	8.72%
	210,000	$14,572	$15,232	$3,780	$16,831	$17,547	$4,110	15.50%	15.20%	8.72%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Supply Service Schedule 200
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$199	$220	$175	$231	$254	$185	15.85%	15.18%	5.88%
	5,000	$332	$353	$175	$385	$408	$185	15.86%	15.43%	5.88%
	7,000	$465	$486	$175	$539	$562	$185	15.86%	15.55%	5.88%
Three Phase										
20	6,000	$399	$441	$350	$462	$508	$371	15.85%	15.17%	5.88%
	10,000	$665	$707	$350	$770	$816	$371	15.86%	15.43%	5.88%
	14,000	$930	$972	$350	$1,078	$1,124	$371	15.85%	15.55%	5.88%
100	30,000	$1,994	$2,205	$1,504	$2,310	$2,540	$1,627	15.86%	15.17%	8.22%
	50,000	$3,323	$3,535	$1,504	$3,850	$4,080	$1,627	15.86%	15.42%	8.22%
	70,000	$4,652	$4,865	$1,504	$5,390	$5,621	$1,627	15.86%	15.54%	8.22%
300	90,000	$5,981	$6,615	$3,770	$6,929	$7,619	$4,099	15.86%	15.17%	8.74%
	150,000	$9,969	$10,605	$3,770	$11,549	$12,241	$4,099	15.86%	15.42%	8.74%
	210,000	$13,956	$14,595	$3,770	$16,169	$16,863	$4,099	15.86%	15.54%	8.74%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$19,524	$21,983	12.59%
	500,000	$28,413	$31,715	11.62%
	700,000	$37,303	$41,446	11.11%
2,000	600,000	$38,719	$43,585	12.57%
	1,000,000	$55,207	$61,758	11.87%
	1,400,000	$72,270	$80,506	11.40%
4,000	1,200,000	$75,460	$85,140	12.83%
	2,000,000	$109,585	$122,635	11.91%
	2,800,000	$143,710	$160,130	11.43%
6,000	1,800,000	$112,446	$126,981	12.93%
	3,000,000	$163,633	$183,224	11.97%
	4,200,000	$214,821	$239,467	11.47%

Notes:

On-Peak kWh	64.39%
Off-Peak kWh	35.61%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$18,693	$21,247	13.67%
	500,000	$27,254	$30,653	12.47%
	700,000	$35,816	$40,060	11.85%
2,000	600,000	$37,046	$42,103	13.65%
	1,000,000	$52,879	$59,626	12.76%
	1,400,000	$69,286	$77,722	12.18%
4,000	1,200,000	$72,104	$82,167	13.96%
	2,000,000	$104,918	$118,360	12.81%
	2,800,000	$137,733	$154,553	12.21%
6,000	1,800,000	$107,694	$122,815	14.04%
	3,000,000	$156,916	$177,104	12.87%
	4,200,000	$206,138	$231,394	12.25%

Notes:

On-Peak kWh	61.35%
Off-Peak kWh	38.65%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power & Light Company
Monthly Billing Comparison
Delivery Service Schedule 48 + Supply Service Schedule 200
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$17,938	$21,337	18.95%
	500,000	$26,215	$30,459	16.19%
	700,000	$34,493	$39,581	14.75%
2,000	600,000	$35,422	$42,035	18.67%
	1,000,000	$50,688	$58,989	16.38%
	1,400,000	$66,527	$76,518	15.02%
4,000	1,200,000	$68,743	$81,783	18.97%
	2,000,000	$100,422	$116,840	16.35%
	2,800,000	$132,102	$151,898	14.99%
6,000	1,800,000	$103,019	$122,640	19.05%
	3,000,000	$150,538	$175,227	16.40%
	4,200,000	$198,057	$227,814	15.02%

Notes:

On-Peak kWh	55.59%
Off-Peak kWh	44.41%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

REDACTED
Docket No. UE-
Exhibit PPL/1607
Witness: C. Craig Paice

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of C. Craig Paice

December 2011 Marginal Cost Study for the State of Oregon

March 2010

PacifiCorp
Oregon Marginal Cost Study
December 2011

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PacifiCorp
Marginal Cost Description of Procedures

INTRODUCTION

Customer class marginal costs are developed to illustrate the resources required to produce one additional unit of electricity or add one additional customer to the system. One, five, ten and twenty years marginal costs are calculated because the Company believes the Commission should have information about the Company's marginal costs over different time periods. Twenty-year (or long run) marginal costs, however, are the primary time frame used in setting retail tariff prices.

The one-year marginal costs includes only changes in operating costs, while ten- and twenty-year marginal costs also include the cost of expanding facilities. The cost of added facilities results in long-run costs, which are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. There are no short-run, demand-related generation, transmission or distribution costs. Long-run costs include ten or twenty years of generation costs, transmission and distribution costs.

One, ten and twenty-year marginal costs are summarized by customer class and load size group and shown in mills/kilowatt-hour (kWh). Marginal commitment costs and billing expenses, which are sometimes referred to as customer costs, are shown in dollars per customer per year. Costs are shown for both the one-year and the long-run time periods.

Unit costs are adjusted to December 2011 values and are shown by generation, transmission, and distribution functional categories and by demand, energy, and commitment and billing costing classifications. Also included are energy usage, peak demand, and number of customers by customer class for the 12 month period ending December 2011.

One, ten and twenty-year marginal costs in mills/kilowatt-hour (kWh) are shown on "Summary of Marginal Costs Demand & Energy in Mills/kWh" (Sheet 'Table 1'). Marginal commitment costs and billing expenses are shown on "Summary of Marginal Costs Commitment and Billing in $ / Customer / Month" (Sheet 'Table 2'). Unit costs and billing information are shown on "20 Year Costing Inputs and Customer Data Marginal Unit Costs" (Sheet 'Table 3').

MARGINAL GENERATION COSTS

The development of marginal generation costs for this study is consistent with the analysis done to prepare the Company's avoided costs filings. Marginal generation costs are based on the Company's most recent avoided cost calculations. The analysis recognizes that baseload generation produces the dual products of capacity and energy. The new resource costs are based on the fixed and variable cost of a Combined Cycle Combustion Turbine (CCCT), which operates as a baseload unit. The cost of the CCCT is split into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) defines the fixed costs of the CCCT that are assigned to capacity. CCCT fixed costs which are in excess of SCCT fixed costs are assigned to energy and are added to the variable production cost of the CCCT to determine total avoided energy cost. Energy and capacity costs are present valued, summed and an annual charge applied to the total. The marginal generation cost calculation is shown within the study on sheet "Summary of Marginal Generation Costs In Nominal Dollars" (Sheet 'Table 5').

MARGINAL TRANSMISSION COSTS
The calculation of transmission costs are based on a five-year (2011-2015) analysis of forecasted expenditures to meet increased load on the transmission system. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand.

Unlike growth-related system support and local transmission investments, the Company's investment in bulk power lines is classified both to demand and energy in the same proportions as twenty-year marginal costs of generation resources. Bulk transmission costs are classified this way because they are thought to be an integral part of the generation system. The Company's investments in high voltage bulk transmission lines are being made to move both energy and capacity. It is usually not possible to site a thermal plant close to the customers the plant is intended to serve. Instead, bulk power lines are constructed to transmit the energy being generated, along with the accompanying capacity.

Each year's growth-related transmission investments are adjusted to December 2011 dollars and the five years are totaled. The total transmission investment is divided by the forecasted growth in system demand over the 5-year period to determine the marginal investment per kilowatt (kW). An annual charge for including an A&G expense loading factor and a transmission O&M loading factor are added to the per kW investment to arrive at long-run transmission marginal cost.

The marginal transmission calculation including the split between demand and energy can be seen within the marginal cost study on page "Marginal Transmission Investment and O&M Expenses" (Sheet 'Transm1'). A summarized version of this page is "Marginal Cost of Transmission Investment and Associated Expenses" (Sheet 'Table 6').

MARGINAL DISTRIBUTION COSTS
Distribution costs are classified into three components: Demand-related, shown in dollars per kW/year, commitment-related, shown in dollars per customer/year, and billing-related, shown in dollars per customer/year. Commitment costs consist of the costs of transformers, poles, and conductor that are not determined by the level of demand customers place on the system. Demand-related costs are the additional costs of larger transformers, substations, poles, and conductors with sufficient capacity to serve the level of demand a customer class places on the system. Billing costs are the costs of meters, service drops, and customer accounting functions.

A summary of distribution marginal costs showing these three components are on page "Marginal Distribution & Billing Costs By Load Size December 2011 Dollars" (Sheet 'Table 7').

Marginal line transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs were separated by the nature of the statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Line transformer regression results are shown on page "Calculation of Escalation Factors for Transformers (Regression weighted by number of transformer banks)" (Sheet 'XFMR 3'). Transformer demand costs are shown on page "Transformer Demand Costs" (Sheet 'XFMR 2') and commitment costs are shown on page "Transformer Commitment Costs By Customer Load Class" (Sheet 'XFMR 1').

Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model (Sheets 'PC4' through 'PC14'). The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics for the state of Oregon. The model determines the cost of the circuit by using current cost estimates to construct one mile of distribution facilities using each of the Company's single and three phase wire sizes. The results are segregated into commitment related and demand related costs for each customer class. A more detailed description of the circuit model is included as an appendix to this narrative.

Marginal poles and wire costs are shown on page "Hypothetical Circuit Study Results Annual Demand and Commitment Costs" (Sheet 'PC 1').

Marginal substation costs are determined using the per kW cost of budgeted and forecasted substation additions for the five year period 2009 - 2013. As part of the capital budgeting process the company determines which substations are approaching their maximum design loading. When load can no longer be shifted to adjacent substations, an upgrade, either greater capacity at the substation or a new substation, is required. The capital investment in common year dollars are totaled across all projects and across the budget-planning horizon to produce total substation investment. The substation investment is divided by the associated incremental substation capacity to get dollars / kW. The dollars per kW is adjusted to an annual value by applying a real levelized carrying charge. Substation marginal costs are classified entirely to demand, and are allocated to customer classes based on the distribution peak load for each class.

Page "Substation Investment" (Sheet 'Dist Sub 2') shows the detail of the substation calculation. "Distribution Substation Costs / kW December 2011 Dollars" (Sheet 'Dist Sub 1') shows the annualized cost in $/kW.

The marginal cost of services includes the costs of new service drop investment plus associated O&M expense. Average service drop investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Incremental service drop O&M is based on the average of ten years of historical expenditures.

The metering category includes the marginal cost of metering equipment with associated O&M expense. Average meter investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M expense is based on historical expenditures.

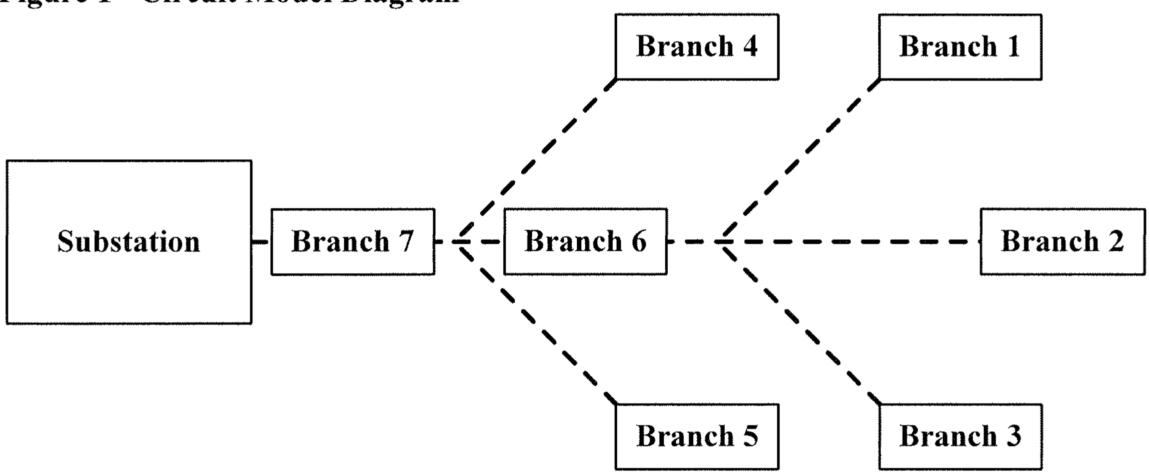
The billing, customer service/other category includes the costs of billing, payment processing, debt recovery, meter reading expenses and all remaining customer accounting and customer service activities. Customer accounting and customer service expense are based on the most recent five years of expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

Meter and Service investment calculations for residential and Schedules 23/28/30 are located on pages "Weighted Average Installed Meter Costs Residential & Schedules 23/28/30" (Sheet 'Meters 1') and "Weighted Average Installed Service Drop Costs Residential & Schedules 23/28/30" (Sheet 'Services 1'). The customer accounting and informational expense calculation is on page "Summary of Customer Accounting Expense By Schedule" (Sheet 'Cust Exp Sum'). These calculations are brought together on "Marginal Distribution & Billing Costs By Load Size December 2011 Dollars" (Sheet 'Table 7') to calculate Metering, Billing and Customer Service Related Costs ($/Customer/Yr).

PacifiCorp
Distribution Circuit Model
PacifiCorp Distribution Circuit Model

General Overview
The PacifiCorp Distribution Circuit Model is an Excel workbook that calculates the cost of building a hypothetical circuit (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical circuit is used rather than a sampling of actual existing circuits. This is because the diverse characteristics of PacifiCorp's six state service area, consisting of over 2,000 distribution circuits, makes the selection of any single, or small number of typical circuits impractical. The fundamental concept of the hypothetical circuit is to create a model that reduces the elements of distribution cost assignment to a workable form.

Figure 1 - Circuit Model Diagram



The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the circuit. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite circuit using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the circuit between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.

Required Engineering & Statistical Data
Listed below are the basic statistics that we use to calculate the composite circuit for a given state:

1. Current One Mile Line Construction Cost Estimates for Each Conductor Size
2. Economic Conductor Loading for Each Conductor Size

3. Overhead and Underground Line Miles
4. Number of Poles
5. Number of Circuits -- distribution line points of origin radiating from a substation.
6. Actual Customer Distances from Distribution Substations
7. Number of Customers and Loads by Class
8. Percentages of Three-Phase and Single-Phase Customers by Class

One Mile Line Estimate

The model determines the cost of the circuit by using cost estimates to construct one mile of distribution facilities using each of the Company's single and three-phase wire sizes. These cost estimates are based on typical topography and equipment configuration for an average mile of line construction. Since the number of poles per mile varies between states, we use a factor to adjust the line cost estimate from the system wide average of 26.53 poles per mile to the state average poles per mile. For example, Oregon has an average of 26.27 poles per mile. Figure 2 shows the circuit cost per mile calculation for Oregon.

Figure 2 – Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Account 364 Pole Cost per Mile: Adjustment Factor	Account 364 Pole Cost per Mile: Adjusted Pole Cost	Account 365 Conductor Cost per Mile
1 Phase -1/0 ACSR	$ 31,531	0.990	$ 31,216	$ 11,771
3 Phase - 1/0 ACSR 1\0 ACSR	$ 37,600	0.990	$ 37,224	$ 24,157
3 Phase - 447 AAC & 4\0 AAC	$ 43,923	0.990	$ 43,484	$ 39,582
3 Phase -795 AAC & 477 AAC	$ 47,673	0.990	$ 47,196	$ 94,037

State	State Specific Account 364 Pole Statistics: Poles	Pole Feet	Pole Miles	Poles / Mile	Adjustment Factor
California	55,376	12,117,471	2,295	24.13	0.909
Idaho	101,768	23,191,716	4,392	23.17	0.873
Oregon	371,574	74,689,291	14,146	26.27	0.990
Utah	363,003	60,744,533	11,505	31.55	1.189
Washington	98,596	18,718,373	3,545	27.81	1.048
Wyoming	154,013	38,258,772	7,246	21.25	0.801
Total	1,144,330	227,720,156	43,129	26.53	1.000

Customer Placement

One of the most significant cost drivers of marginal distribution costs is the distance between the customer and the substation. Costs increase as the distance from the substation increases.

The circuit model takes distance into account by assigning customers to the different branches of the circuit based upon actual customer locations. The actual customer distances are derived from PacifiCorp's outage management system (CADOPS). The system is able to accurately trace the flow of electricity from substation to customer as well as ascertain the exact distance it must travel.

Figure 3 shows the Customer Distribution on the Hypothetical Circuit Branch for Oregon.

Figure 3 Customer Distribution

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
1	Residential	0.96%	0.96%	0.96%	3.50%	3.50%	3.50%	86.61%	100.00%
2	GS 0-15 kW (sec) (23)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
3	GS >15 kW (sec) (23)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
4	GS (pri) (23)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
5	GS < 50 kW (sec) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
6	GS 51-100 kW (sec) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
7	GS > 100 kW (sec) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
8	GS (pri) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
9	GS 0-300 kW (sec) (30)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
10	GS >300 kW (sec) (30)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
11	GS (pri) (30)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
12	Irrigation	2.42%	2.42%	2.42%	12.59%	12.59%	12.59%	54.96%	100.00%
13	USBR / UKRB	4.51%	4.51%	4.51%	10.50%	10.50%	10.50%	54.96%	100.00%
14	Large GS 1 - 4 MW (sec)	0.16%	0.16%	0.16%	1.42%	1.42%	1.42%	95.26%	100.00%
15	Large GS 1 - 4 MW (pri)	0.16%	0.16%	0.16%	1.42%	1.42%	1.42%	95.26%	100.00%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-

Customer Density

The next significant driver of distribution costs is customer density. The model uses state specific line and customer statistics to calculate the average number of customers by circuit branch. Total state distribution line miles and state customers, by class, are divided by the number of distribution circuits in the state to determine the average length of the composite circuit (line miles / number of circuits) and the number of customers on the circuit (customers / circuits). Figure 4 shows the average number of customers located on each of the seven circuit branches for Oregon.

Figure 4 – Oregon Average Customers by Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Average Customers								
1	Residential	8.20	8.20	8.20	29.78	29.78	29.78	736.95	850.87
2	GS 0-15 kW (sec) (23)	1.48	1.48	1.48	4.33	4.33	4.33	102.13	119.58
3	GS >15 kW (sec) (23)	0.21	0.21	0.21	0.63	0.63	0.63	14.76	17.29
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.07
5	GS < 50 kW (sec) (28)	0.04	0.04	0.04	0.15	0.15	0.15	7.60	8.15
6	GS 51-100 kW (sec) (28)	0.03	0.03	0.03	0.12	0.12	0.12	5.98	6.42
7	GS > 100 kW (sec) (28)	0.02	0.02	0.02	0.07	0.07	0.07	3.41	3.66
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.41	0.44
10	GS >300 kW (sec) (30)	0.01	0.01	0.01	0.02	0.02	0.02	1.00	1.07
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
12	Irrigation	0.27	0.27	0.27	1.40	1.40	1.40	6.12	11.13
13	USBR / UKRB	0.18	0.18	0.18	0.41	0.41	0.41	2.17	3.94
14	Large GS 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.22
15	Large GS 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	10.43	10.43	10.43	36.92	36.92	36.92	881.07	1,023.13

Load Accumulation

The kW load that a customer or class places on the system influences the size of the conductor necessary to serve the load. At each point on the circuit, the conductor must be sized to carry the entire downstream load. At the far ends of the outer branches, loads are minimal. As you move upstream closer to the substation, the load on the circuit becomes greater requiring larger conductor sizes. In the model, load can accumulate two ways. The first occurs as customers accumulate on a branch of the circuit. When enough customers, or load, accumulate it is necessary to increment up to the next wire size. Upstream from that point, customer segments increase in cost due to the increase in wire size. The second method of load accumulation is when several branches converge at a central point on the trunk of the circuit. The trunk branches must be of adequate size to carry the load of the customers on that branch plus all downstream branches.

Figure 5 shows the circuit kW loading on each of the circuit branches for Oregon. Loads are for customers located on that branch. Accumulated loads for branch 6 would be the combined loads of branches 1, 2, 3 and 6. Accumulated loads for branch 7 would be the combined loads of all branches.

Figure 5 – Oregon Circuit kW Load by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							
		1	2	3	4	5	6	7	Total
	Circuit kW Loads								
1	Residential	17.2	17.2	17.2	62.4	62.4	62.4	1,543.0	1,781.5
2	GS 0-15 kW (sec) (23)	2.1	2.1	2.1	6.1	6.1	6.1	143.8	168.3
3	GS >15 kW (sec) (23)	1.5	1.5	1.5	4.3	4.3	4.3	100.5	117.7
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
5	GS < 50 kW (sec) (28)	0.5	0.5	0.5	2.1	2.1	2.1	109.7	117.7
6	GS 51-100 kW (sec) (28)	0.9	0.9	0.9	3.7	3.7	3.7	187.2	200.8
7	GS > 100 kW (sec) (28)	1.1	1.1	1.1	4.7	4.7	4.7	242.1	259.7
8	GS (pri) (28)	0.0	0.0	0.0	0.1	0.1	0.1	4.9	5.3
9	GS 0-300 kW (sec) (30)	0.4	0.4	0.4	0.8	0.8	0.8	51.3	54.9
10	GS >300 kW (sec) (30)	1.9	1.9	1.9	4.4	4.4	4.4	274.2	293.3
11	GS (pri) (30)	0.2	0.2	0.2	0.4	0.4	0.4	27.9	29.8
12	Irrigation	0.8	0.8	0.8	3.9	3.9	3.9	17.2	31.3
13	USBR / UKRB	1.1	1.1	1.1	2.6	2.6	2.6	13.4	24.3
14	Large GS 1 - 4 MW (sec)	0.2	0.2	0.2	2.1	2.1	2.1	138.6	145.5
15	Large GS 1 - 4 MW (pri)	0.2	0.2	0.2	1.4	1.4	1.4	95.6	100.4
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	28.0	28.0	28.0	99.0	99.0	99.0	2,949.5	3,330.6

Circuit Model Cost Assignment

Line statistics for the PacifiCorp service area show that the distribution system is predominately overhead. To calculate the cost of branch construction, miles per branch is calculated by taking the distance per circuit (total line miles / total number of circuits) and dividing it by the number of branches per circuit (7 branches, see figure 1). Next, using an assumption from distribution engineers that the typical outer branches are 35% single phase, the circuit branch length is split between single and three-phase. The total branch construction cost can then be calculated by taking the single and three-phase distances per branch and multiplying them by the one mile construction costs for poles and conductors, as shown in figure 6.

Costs are split between demand and commitment by assuming that the cost of constructing the branch with the smallest single-phase conductor and smallest pole is the commitment related portion and all costs above this amount are demand related. Branches 6 and 7 are 100% three-phase and are considered all demand. Figure 6 shows the circuit costs per mile, costs for each branch and miles per branch broken out by single and three-phase for Oregon.

Figure 6 – Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR	$ 31,531	0.990	$ 31,216	$ 11,771	$ 42,987
3 Phase - 1/0 ACSR 1\0 ACSR	$ 37,600	0.990	$ 37,224	$ 24,157	$ 61,381
3 Phase - 447 AAC & 4\0 AAC	$ 43,923	0.990	$ 43,484	$ 39,582	$ 83,066
3 Phase -795 AAC & 477 AAC	$ 47,673	0.990	$ 47,196	$ 94,037	$ 141,233

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSR	3 Phase - 1/0 ACSR 1\0 ACSR	Total	
Poles	$ 53,464	$ 118,400	$ 171,864	
Conductors	$ 20,160	$ 76,837	$ 96,998	
Total	$ 73,624	$ 195,238	$ 268,862	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 212,786		$ 230,953	
Conductors	$ 193,693		$ 460,167	
Total	$ 406,480		$ 691,120	

Miles per Branch	4.89
Single Phase Miles Per Branch	1.71
Three Phase Miles Per Branch	3.18

Customer Circuit Costs

After calculating the cost per mile for single and three-phase construction for all of the branches, we compile the data and create a hypothetical circuit model branch cost sheet, as shown in figure 7. Figure 7 includes the total cost per circuit branch in columns (A) and (B), and the allocation of total cost between commitment and demand in columns (C) through (F) for Oregon.

Figure 7 – Oregon Hypothetical Circuit Model Branch Costs

Conductors Type	(A)	(B)	(C)	(D)	(E)	(F)
	Total Cost		Commitment Cost		Demand Cost	
	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total segment	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 2						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 3						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 4						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 5						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 212,786	$ 193,693	NA	NA	$ 212,786	$ 193,693
Total Segments	$ 212,786	$ 193,693	$ -	$ -	$ 212,786	$ 193,693
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 230,953	$ 460,167	NA	NA	$ 230,953	$ 460,167
Total segment	$ 230,953	$ 460,167	$ -	$ -	$ 230,953	$ 460,167

Cost Sharing Calculation

As mentioned before, one of the critical factors of cost-responsibility is the location of a customer or class on the circuit branches. Customer classes that locate on all branches share cost responsibility for all branches of the circuit including the trunk. Large industrial customers, who locate on the trunk of the circuit, share cost responsibility for only the trunk. We determine cost responsibility by calculating the percentage of demand, or percentage of customers, by class, that shares a particular branch of the circuit. We then multiply the total branch costs by the share percentage and then total the branch costs by class. To calculate the total branch cost, we assign the applicable cost of branches 6 and 7 to customers on branches 1, 2, 3, 4 and 5. Demand costs calculated in an earlier step are allocated between customer classes at this point. Figure 8 shows this calculation along with the allocation of branch costs to the individual customer classes for Oregon. Demand costs are totaled for each customer class then divided by circuit kW to get demand cost in dollars per kW.

Figure 8 – Oregon Poles Demand Calculations, Branch 6 & 7 Cost Assignment

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	15.30%	15.30%	15.30%	NA	NA	54.10%	NA	100.00%	
2	Branch 6 Cost	$ 32,556	$ 32,556	$ 32,556	NA	NA	$ 115,119	NA	$ 212,786	$ / kW
3	% Demand	0.84%	0.84%	0.84%	2.97%	2.97%	2.97%	88.56%	100.00%	
4	Branch 7 Cost	$ 1,942	$ 1,942	$ 1,942	$ 6,867	$ 6,867	$ 6,867	$ 204,525	$ 230,953	
5	Branch Demand Cost	$ 19,111	$ 19,111	$ 19,111	$ 19,111	$ 19,111	NA	NA		Average
6	Total	$ 53,609	$ 53,609	$ 53,609	$ 25,978	$ 25,978	$ 121,987	$ 204,525	$ 539,295	$ 161.92
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 32,846	$ 32,846	$ 32,846	$ 16,356	$ 16,356	$ 76,801	$ 106,993	$ 315,044	$ 176.84
11	GS 0-15 kW (sec) (23)	$ 3,991	$ 3,991	$ 3,991	$ 1,601	$ 1,601	$ 7,516	$ 9,970	$ 32,661	$ 194.02
12	GS >15 kW (sec) (23)	$ 2,790	$ 2,790	$ 2,790	$ 1,119	$ 1,119	$ 5,253	$ 6,968	$ 22,827	$ 194.02
13	GS (pri) (23)	$ 5	$ 5	$ 5	$ 2	$ 2	$ 10	$ 13	$ 44	$ 194.02
14	GS < 50 kW (sec) (28)	$ 990	$ 990	$ 990	$ 562	$ 562	$ 2,638	$ 7,605	$ 14,336	$ 121.85
15	GS 51-100 kW (sec) (28)	$ 1,689	$ 1,689	$ 1,689	$ 959	$ 959	$ 4,504	$ 12,983	$ 24,473	$ 121.85
16	GS > 100 kW (sec) (28)	$ 2,184	$ 2,184	$ 2,184	$ 1,240	$ 1,240	$ 5,822	$ 16,785	$ 31,639	$ 121.85
17	GS (pri) (28)	$ 44	$ 44	$ 44	$ 25	$ 25	$ 119	$ 342	$ 645	$ 121.85
18	GS 0-300 kW (sec) (30)	$ 694	$ 694	$ 694	$ 217	$ 217	$ 1,021	$ 3,560	$ 7,097	$ 129.23
19	GS >300 kW (sec) (30)	$ 3,705	$ 3,705	$ 3,705	$ 1,161	$ 1,161	$ 5,450	$ 19,012	$ 37,898	$ 129.23
20	GS (pri) (30)	$ 377	$ 377	$ 377	$ 118	$ 118	$ 554	$ 1,933	$ 3,854	$ 129.23
21	Irrigation	$ 1,451	$ 1,451	$ 1,451	$ 1,033	$ 1,033	$ 4,850	$ 1,192	$ 12,462	$ 398.46
22	USBR / UKRB	$ 2,099	$ 2,099	$ 2,099	$ 669	$ 669	$ 3,142	$ 926	$ 11,701	$ 481.67
23	Large GS 1 - 4 MW (sec)	$ 440	$ 440	$ 440	$ 543	$ 543	$ 2,548	$ 9,612	$ 14,566	$ 100.10
24	Large GS 1 - 4 MW (pri)	$ 304	$ 304	$ 304	$ 374	$ 374	$ 1,758	$ 6,631	$ 10,049	$ 100.10
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 53,609	$ 53,609	$ 53,609	$ 25,978	$ 25,978	$ 121,987	$ 204,525	$ 539,295	

Commitment costs are calculated using a similar method. Commitment costs calculated in an earlier step are allocated to classes using percent of customers on a given branch. Commitment dollars are totaled by customer class then divided by the number of customers in the class to get commitment costs in dollars per customer. Figure 9 shows these calculations for Oregon.

Figure 9–Oregon Poles Commitment Calculations, Branch 1,2,3,4 & 5 Cost Assignment

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% customer	15.29%	15.29%	15.29%	NA	NA	54.12%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	$ Per
3	% customer	1.02%	1.02%	1.02%	3.61%	3.61%	3.61%	86.12%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ 152,753	NA	NA		average
6	Total	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ -	$ -	$ 763,765	$ 746.50
7										
8									Total	$ Per
9									Commitment	Customer
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 120,017	$ 120,017	$ 120,017	$ 123,207	$ 123,207	$ -	$ -	$ 606,463	$ 712.75
12	GS 0-15 kW (sec) (23)	$ 21,690	$ 21,690	$ 21,690	$ 17,933	$ 17,933	$ -	$ -	$ 100,936	$ 844.10
13	GS >15 kW (sec) (23)	$ 3,135	$ 3,135	$ 3,135	$ 2,592	$ 2,592	$ -	$ -	$ 14,590	$ 844.10
14	GS (pri) (23)	$ 12	$ 12	$ 12	$ 10	$ 10	$ -	$ -	$ 55	$ 844.10
15	GS < 50 kW (sec) (28)	$ 524	$ 524	$ 524	$ 614	$ 614	$ -	$ -	$ 2,800	$ 343.68
16	GS 51-100 kW (sec) (28)	$ 413	$ 413	$ 413	$ 483	$ 483	$ -	$ -	$ 2,205	$ 343.68
17	GS > 100 kW (sec) (28)	$ 235	$ 235	$ 235	$ 275	$ 275	$ -	$ -	$ 1,257	$ 343.68
18	GS (pri) (28)	$ 6	$ 6	$ 6	$ 7	$ 7	$ -	$ -	$ 33	$ 343.68
19	GS 0-300 kW (sec) (30)	$ 43	$ 43	$ 43	$ 27	$ 27	$ -	$ -	$ 182	$ 414.81
20	GS >300 kW (sec) (30)	$ 104	$ 104	$ 104	$ 67	$ 67	$ -	$ -	$ 445	$ 414.81
21	GS (pri) (30)	$ 10	$ 10	$ 10	$ 6	$ 6	$ -	$ -	$ 41	$ 414.81
22	Irrigation	$ 3,953	$ 3,953	$ 3,953	$ 5,799	$ 5,799	$ -	$ -	$ 23,456	$ 2,106.80
23	USBR / UKRB	$ 2,605	$ 2,605	$ 2,605	$ 1,712	$ 1,712	$ -	$ -	$ 11,241	$ 2,851.36
24	Large GS 1 - 4 MW (sec)	$ 5	$ 5	$ 5	$ 13	$ 13	$ -	$ -	$ 41	$ 187.05
25	Large GS 1 - 4 MW (pri)	$ 2	$ 2	$ 2	$ 6	$ 6	$ -	$ -	$ 19	$ 187.05
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Check Total	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ -	$ -	$ 763,765	

Large Industrial Customers

Distribution studies have shown that very large industrial customers are not placed on a circuit in the same manner as residential or smaller commercial and industrial customers. Rather the customer is located very close to a substation (the average distance in Oregon is 2/3 of a mile) and has a dedicated circuit for their exclusive use. Since they have a dedicated circuit, they do not share in the costs of other common distribution investments, but they are responsible for the entire cost of the dedicated circuit. Dividing the total cost of a 2/3 of a mile circuit by the customer's kW gets the customers demand cost in dollars per kW. Table 10 shows this calculation for Oregon.

Table 10 – Oregon Dedicated Circuit Trunk Costs for Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		**Large GS + 4 MW (sec)**	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	$ 47,196	$ 94,037	$ 47,196	$ 94,037
2 Average Trunk Length	0.67	miles	0.67	miles
3 Total Construction Cost	$ 31,622	$ 63,005	$ 31,622	$ 63,005
4 Customer Peak Demand	4,279	kW	3,115	kW
5 Demand Cost $/kW	$7.39	$14.72	$10.15	$20.23

Summary

The final step in the circuit model is to bring the various results together in a single summary page. Table 11 shows the results calculated earlier in the study. Note that the $/customer and $/circuit kW is the distribution investment to serve that customer and not the price that the customer is expected to pay.

Table 11 – Oregon Summary of Results

	(A)	(B)	(C)	(D)	(E)	(F)		
	Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
Residential	$ 712.75	$ 268.77	$ 176.84	$ 274.27	850.9	1,781.50	$ 315,044	$ 488,605
GS 0-15 kW (sec) (23)	$ 844.10	$ 318.30	$ 194.02	$ 296.95	119.6	168.33	$ 32,661	$ 49,987
GS >15 kW (sec) (23)	$ 844.10	$ 318.30	$ 194.02	$ 296.95	17.3	117.65	$ 22,827	$ 34,937
GS (pri) (23)	$ 844.10	$ 318.30	$ 194.02	$ 296.95	0.1	0.22	$ 44	$ 67
GS < 50 kW (sec) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	8.1	117.65	$ 14,336	$ 24,048
GS 51-100 kW (sec) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	6.4	200.85	$ 24,473	$ 41,054
GS > 100 kW (sec) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	3.7	259.66	$ 31,639	$ 53,074
GS (pri) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	0.1	5.29	$ 645	$ 1,081
GS 0-300 kW (sec) (30)	$ 414.81	$ 156.42	$ 129.23	$ 214.94	0.4	54.92	$ 7,097	$ 11,804
GS >300 kW (sec) (30)	$ 414.81	$ 156.42	$ 129.23	$ 214.94	1.1	293.25	$ 37,898	$ 63,031
GS (pri) (30)	$ 414.81	$ 156.42	$ 129.23	$ 214.94	0.1	29.82	$ 3,854	$ 6,410
Irrigation	$ 2,106.80	$ 794.45	$ 398.46	$ 550.82	11.1	31.28	$ 12,462	$ 17,227
USBR / UKRB	$ 2,851.36	$ 1,075.21	$ 481.67	$ 666.50	3.9	24.29	$ 11,701	$ 16,191
Large GS 1 - 4 MW (sec)	$ 187.05	$ 70.53	$ 100.10	$ 176.20	0.2	145.51	$ 14,566	$ 25,639
Large GS 1 - 4 MW (pri)	$ 187.05	$ 70.53	$ 100.10	$ 176.20	0.1	100.39	$ 10,049	$ 17,689
Total -	$ 746.50	$ 281.49	$ 161.92	$ 255.46	1,023.1	3,330.6	$ 539,295	$ 850,844
Large GS + 4 MW (sec)	$ -	$ -	$ 10.15	$ 20.23	-	3,114.88	$ 31,622	$ 63,005
Large GS + 4 MW (pri)	$ -	$ -	$ 7.39	$ 14.72	-	4,279.13	$ 31,622	$ 63,005
							$ 602,538	$ 976,854

	Commitment	Demand	Total
Poles	$ 763,765	$ 602,538	$ 1,366,302
Conductor	$ 288,005	$ 976,854	$ 1,264,859
Total	$ 1,051,770	$ 1,579,391	$ 2,631,161

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2011 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	63.57	66.41	65.91	63.57	116.71	116.27
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	63.57	66.41	65.91	63.57	114.99	114.55
5	15+ kW	(sec)	63.57	66.41	65.91	63.57	111.01	110.56
6	Primary	(pri)	61.38	64.34	63.85	61.38	107.31	105.89
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	63.57	66.41	65.91	63.57	107.80	107.36
10	51-100 kW	(sec)	63.57	66.41	65.91	63.57	111.46	111.02
11	> 101kW	(sec)	63.57	66.41	65.91	63.57	108.11	107.67
12	Primary	(pri)	61.60	64.37	63.85	61.60	98.38	97.96
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	63.57	66.41	65.91	63.57	105.30	104.86
16	301+ kW	(sec)	63.57	66.41	65.91	63.57	106.20	105.76
17	Primary	(pri)	61.58	64.34	63.85	61.58	105.11	104.67
18								
19	LPS - Schedule 48T							
20	1 - 4 MW	(sec)	63.57	66.41	65.91	63.57	104.93	104.49
21	1 - 4 MW	(pri)	61.59	64.34	63.85	61.59	100.03	99.60
22	> 4 MW	(sec)	63.57	66.42	65.91	63.57	94.34	93.89
23	> 4 MW	(pri)	61.59	64.34	63.85	61.59	92.65	92.21
24								
25	Trans	(trn)	60.33	63.02	62.55	60.33	82.65	82.21
26								
27								
28	Schedule 41- Irrigation	(sec)	63.57	66.42	65.91	63.57	111.39	110.93
29	Schedule 33*- Irrigation	(sec)	63.57	66.41	65.91	63.57	115.25	114.79

Sources:
(A) Tab 2.13 (1 Year MC:) `1 Year Marginal Costs by Load Class'
(B) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(C) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2011 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
(D) Column (A)
(E) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(F) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class December 2011 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'

Energy costs include both generation and transmission energy-related costs.
* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2011 Dollars

Line	Description		(A) 1 Year 1&3 Phase	(B) 10 & 20 Year 1&3 Phase
1	Res - Schedule 4	(sec)	$13.16	$36.47
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	14.98	56.46
5	15+ kW	(sec)	28.91	95.87
6	Primary	(pri)	118.17	132.93
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	30.70	124.35
10	51-100 kW	(sec)	32.31	139.08
11	> 101kW	(sec)	70.90	187.33
12	Primary	(pri)	119.90	125.91
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	87.37	200.52
16	301+ kW	(sec)	87.39	200.74
17	Primary	(pri)	135.54	142.80
18				
19	Total			
20	1 - 4 MW	(sec)	190.12	306.00
21	1 - 4 MW	(pri)	193.72	196.99
22	> 4 MW	(sec)	190.12	302.73
23	> 4 MW	(pri)	193.72	193.72
24	Trans	(trn)	4,075.50	4,075.50
25				
26				
27	Schedule 41- Irrigation	(sec)	9.99	141.99
28	Schedule 41- Irrigation	(sec)	9.99	141.99
29	Schedule 33*- Irrigation	(sec)	10.68	170.30

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead and maintenance, service drops, service drop overhead and maintenance, customer accounting and informational expenses, and billing expenses.

* Schedule 33 Cost of Service results are provided for informational purposes only.

Sources:
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2011 Dollars

Line	Description		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrigation Sch 41	Irrigation Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Peak Mw @ Meter	System	887	99	68	0	68	114	144	2	31	161	16	79	56	7	144	44	18	16
2		Distribution	987	93	65	0	65	111	144	3	30	162	17	81	56	6	141	0	17	15
3		Transformer	3,240	172	124	1	162	211	239	7	46	257	25	137	90	15	215	64	84	72
4																				
5	Demand Loss Factor		1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.0819	1.1131	1.0819	1.1131	1.0819	1.0498	1.1131	1.1131
6																				
7	Peak Mw @ Generator	System	987	110	75	0	76	127	160	2	34	179	18	88	61	8	156	46	21	18
8		Distribution	1,099	104	73	0	73	124	160	3	34	181	18	90	60	7	153	N/A	19	16
9		Transformer	3,606	192	138	N/A	180	235	266	N/A	51	286	N/A	153	N/A	16	N/A	N/A	93	80
10																				
11	Energy																			
12	Energy - Annual Mwh	@ Meter	5,306,840	577,893	435,130	815	429,296	659,704	905,100	17,727	208,208	1,075,585	102,283	526,955	380,354	52,257	1,023,411	366,079	149,120	127,459
13	Energy Loss Factor		1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0918	1.0577	1.0918	1.0918	1.0577	1.0918	1.0577	1.0918	1.0577	1.0361	1.0918	1.0918
14	Energy - Annual Mwh	@ Generator	5,794,008	630,944	475,075	862	468,705	720,265	988,188	18,750	227,322	1,174,324	108,186	575,330	402,304	57,054	1,082,472	379,276	162,809	139,160
15																				
16	Customer																			
17	Annual Customers		484,011	64,803	9,367	37	4,635	3,650	2,080	53	241	586	54	120	57	2	33	2	6,211	2,056
18	Average Customers																		2,722	760
19																				
20	Unit Costs																			
21																				
22	Generation	$ / System Peak Kw	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88	$79.88
23	Transmission	$ / System Peak Kw	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37
24	Poles, Cond., Subst.	$ / Dist. Kw	$94.62	$100.63	$100.63	$100.63	$75.83	$75.83	$75.83	$75.83	$78.52	$78.52	$78.52	$68.31	$68.31	$31.43	$30.19	$0.00	$169.61	$199.51
25	Transformers	$ / Xfmr Kw	$2.52	$2.52	$2.52	$0.00	$2.52	$2.52	$2.52	$0.00	$2.52	$2.52	$0.00	$2.52	$0.00	$2.52	$0.00	$0.00	$2.52	$2.52
26																				
27	Energy - @ Generator																			
28	Generation	$ / Kwh	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777
29	Transmission	$ / Kwh	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260
30																				
31	Poles	$ / Cust / Year	$109.92	$130.18	$130.18	$130.18	$53.01	$53.01	$53.01	$53.01	$63.98	$63.98	$63.98	$28.84	$28.84	$0.00	$0.00	$0.00	$324.91	$439.74
32	Conductor	$ / Cust / Year	$39.66	$46.97	$46.97	$46.97	$19.12	$19.12	$19.12	$19.12	$23.08	$23.08	$23.08	$10.41	$10.41	$0.00	$0.00	$0.00	$117.23	$158.67
33	Transformers	$ / Cust / Year	$130.06	$320.65	$626.32	$0.00	$1,051.64	$1,209.10	$1,325.03	$0.00	$1,270.75	$1,273.16	$0.00	$1,351.32	$0.00	$1,351.32	$0.00	$0.00	$1,141.87	$1,317.03
34	Service Drop	$ / Cust / Year	$71.26	$96.77	$243.46	$0.00	245.71	254.72	543.08	-	551.13	551.12	-	$959.54	$0.00	$959.54	$0.00	$0.00	$0.00	$0.00
35	Meters	$ / Cust / Year	$17.15	$19.92	$40.44	$1,354.95	38.84	49.17	223.88	1,354.95	225.69	225.93	1,354.95	$352.29	$1,354.95	$352.29	$1,354.95	$47,936	$39.49	$47.43
36	Meter Reading	$ / Cust / Year	$14.70	$18.22	$18.22	$18.22	17.63	17.63	17.63	17.63	79.50	79.50	79.50	120.65	$120.65	$120.65	$120.65	$120.65	$28.07	$28.00
37	Billing & Collections	$ / Cust / Year	$33.25	$31.26	$31.26	$31.26	33.59	33.59	33.59	33.59	33.59	33.59	33.59	245.41	$245.41	$245.41	$245.41	$245.41	$33.92	$33.87
38	Uncollectables	$ / Cust / Year	$9.48	$2.06	$2.06	$2.06	19.20	19.20	19.20	19.20	127.84	127.84	127.84	508.84	$508.84	$508.84	$508.84	$508.84	$5.24	$5.70
39	Customer Service / Other	$ / Cust / Year	$12.11	$11.51	$11.51	$11.51	13.42	13.42	13.42	13.42	30.66	30.66	30.66	94.73	$94.73	$94.73	$94.73	$94.73	$13.10	$13.13
40	Total Commitment & Billing	$ / Cust / Year	$437.59	$677.55	$1,150.44	$1,595.16	$1,492.16	$1,668.96	$2,247.96	$1,510.92	$2,406.21	$2,408.85	$1,713.59	$3,672.02	$2,363.83	$3,632.78	$2,324.58	$48,906	$1,703.84	$2,043.57

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) 'Customer Loads12 Months Ended December 2011'
Lines 5 & 13 Tab 16.1 (Losses:) 'Energy Loss Factors'
Lines 12 & 17 Tab 17.2 (Cust Data 2:) 'Customers and MWh's12 Months Ended December 2011 - Normalized'
Line 22 Tab 4.1 (Capacity:) 'Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 23 Tab 6.1 (Transm1:) 'Marginal Transmission Investment and O&M Expenses'
Line 24 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'
Line 28 Tab 5.1 (Energy:) 'Marginal Generation Energy Costs'
Line 29 Tab 2.6 (Table 6:) 'Marginal Cost of Transmission Investment and Associated Expenses'
Lines 31 - 39 Tab 2.7 (Table 7:) 'Marginal Distribution & Billing Costs By Load Size'

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 4

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
December 2011 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Residential	General Service - Schedule 23			General Power - Schedule 28			
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)
	Demand Related Marginal Cost									
1	Generation	$171,523	$78,835	$8,783	$6,023	$11	$6,052	$10,111	$12,773	$186
2	Transmission	$163,988	$75,371	$8,397	$5,759	$10	$5,787	$9,667	$12,212	$178
3	Distribution									
4	Poles	$50,324	$29,962	$3,107	$2,171	$4	$1,364	$2,327	$3,009	$59
5	Conductor	$76,234	$44,459	$4,549	$3,180	$5	$2,189	$3,735	$4,829	$96
6	Substations	$59,028	$29,526	$2,790	$1,950	$4	$1,950	$3,329	$4,304	$85
7	Subtotal: Pole, Cond, Subs	$185,586	$103,947	$10,446	$7,300	$13	$5,502	$9,391	$12,142	$241
8	Transformers	$13,120	$9,072	$483	$346	$0	$454	$591	$668	$0
9	Distribution subtotal	$198,706	$113,019	$10,928	$7,647	$13	$5,956	$9,982	$12,810	$241
10										
11	Total Demand Related	$534,217	$267,225	$28,108	$19,429	$34	$17,795	$29,760	$37,795	$605
12	(Lines 1+2+9)									
13										
14	Energy Related Marginal Cost									
15	Generation Energy Related	$767,582	$334,720	$36,450	$27,445	$50	$27,077	$41,610	$57,088	$1,083
16	Transmission Energy Related	$34,540	$15,062	$1,640	$1,235	$2	$1,218	$1,872	$2,569	$49
17	Total Energy	$802,122	$349,782	$38,090	$28,680	$52	$28,296	$43,482	$59,656	$1,132
18										
19	Customer Related Marginal Cost									
20	Poles	$67,798	$53,204	$8,437	$1,219	$5	$246	$194	$110	$3
21	Conductor	$23,668	$19,196	$3,044	$440	$1	$88	$70	$40	$1
22	Transformers	$110,100	$62,950	$20,779	$5,867	$0	$4,875	$4,413	$2,756	$0
23	Service Drops	$46,814	$34,493	$6,270	$2,281	$0	$1,138	$929	$1,130	$0
24	Meters	$11,688	$8,303	$1,291	$379	$50	$180	$179	$466	$72
25	Meter Reading	$8,823	$7,113	$1,181	$171	$1	$82	$64	$37	$1
26	Billing & Collections	$18,963	$16,095	$2,026	$293	$1	$156	$123	$70	$2
27	Uncollectables	$5,177	$4,588	$133	$19	$0	$89	$70	$40	$1
28	Customer Service / Other	$6,948	$5,861	$746	$108	$0	$62	$49	$28	$1
29	Total Commitment & Billing Rel.	$299,977	$211,803	$43,906	$10,776	$59	$6,916	$6,092	$4,676	$80
30										
31	Total Revenue @ Full MC									
32	Generation	$939,105	$413,555	$45,233	$33,468	$61	$33,129	$51,721	$69,861	$1,269
33	Transmission	$198,528	$90,433	$10,037	$6,994	$12	$7,005	$11,539	$14,781	$227
34	Distribution	$447,085	$282,862	$49,457	$17,454	$20	$12,303	$15,588	$16,846	$245
35	Customer - Billing	$18,963	$16,095	$2,026	$293	$1	$156	$123	$70	$2
36	Customer - Metering	$20,510	$15,415	$2,472	$549	$51	$262	$244	$502	$73
37	Customer - Other	$6,948	$5,861	$746	$108	$0	$62	$49	$28	$1
38	Revenue (less Uncollectables)	$1,631,139	$824,221	$109,970	$58,866	$146	$52,917	$79,264	$102,088	$1,816
39										
40	Customer - Uncollectables	$5,177	$4,588	$133	$19	$0	$89	$70	$40	$1
41	Total Revenue	$1,636,316	$828,809	$110,104	$58,885	$146	$53,006	$79,334	$102,128	$1,817

		(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)
		General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg	Sch 51,53,54
		0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	Sch 41	Sch 33*	Streetlighting
Line	Description	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)	(sec)
	Demand Related Marginal Cost											
1	Generation	$2,721	$14,284	$1,417	$7,062	$4,850	$615	$12,479	$3,681	$1,640	$1,401	
2	Transmission	$2,601	$13,656	$1,355	$6,752	$4,637	$588	$11,931	$3,519	$1,568	$1,340	
3	Distribution											
4	Poles	$675	$3,604	$356	$1,386	$929	$11	$175	$0	$1,185	$1,225	
5	Conductor	$1,074	$5,735	$566	$2,333	$1,564	$21	$331	$0	$1,567	$1,621	
6	Substations	$910	$4,860	$480	$2,412	$1,617	$186	$4,106	$0	$518	$443	
7	Subtotal: Pole, Cond, Subs	$2,659	$14,200	$1,403	$6,130	$4,111	$218	$4,612	$0	$3,271	$3,289	
8	Transformers	$128	$719	$0	$384	$0	$41	$0	$0	$235	$201	
9	Distribution subtotal	$2,787	$14,919	$1,403	$6,514	$4,111	$259	$4,612	$0	$3,506	$3,489	
10												
11	Total Demand Related	$8,109	$42,859	$4,175	$20,328	$13,598	$1,462	$29,022	$7,200	$6,714	$6,230	
12	(Lines 1+2+9)											
13												
14	Energy Related Marginal Cost											
15	Generation Energy Related	$13,132	$67,841	$6,250	$33,237	$23,241	$3,296	$62,534	$21,911	$9,406	$8,039	$1,213
16	Transmission Energy Related	$591	$3,053	$281	$1,496	$1,046	$148	$2,814	$986	$423	$362	$55
17	Total Energy	$13,723	$70,893	$6,531	$34,732	$24,287	$3,444	$65,348	$22,897	$9,829	$8,401	$1,267
18												
19	Customer Related Marginal Cost											
20	Poles	$15	$37	$4	$4	$1	$0	$0	$0	$2,018	$905	$2,300
21	Conductor	$5	$14	$1	$1	$0	$0	$0	$0	$729	$326	$37
22	Transformers	$307	$746	$0	$162	$0	$3	$0	$0	$7,092	$2,708	$150
23	Service Drops	$133	$323	$0	$115	$0	$1	$0	$0	$0	$0	
24	Meters	$54	$132	$73	$42	$77	$1	$45	$96	$245	$98	$2
25	Meter Reading	$19	$47	$4	$14	$7	$0	$4	$0	$76	$21	$2
26	Billing & Collections	$8	$20	$2	$29	$14	$0	$8	$0	$92	$26	$24
27	Uncollectables	$31	$75	$7	$61	$29	$1	$17	$1	$14	$4	$0
28	Customer Service / Other	$7	$18	$2	$11	$5	$0	$3	$0	$36	$10	$9
29	Total Commitment & Billing Rel.	$580	$1,412	$93	$442	$134	$7	$77	$98	$10,303	$4,097	$2,523
30												
31	Total Revenue @ Full MC											
32	Generation	$15,853	$82,125	$7,667	$40,299	$28,091	$3,911	$75,013	$25,592	$11,046	$9,440	$1,213
33	Transmission	$3,192	$16,709	$1,636	$8,248	$5,683	$736	$14,745	$4,505	$1,991	$1,702	$55
34	Distribution	$3,247	$16,039	$1,408	$6,797	$4,112	$263	$4,612	$0	$13,344	$7,428	$2,487
35	Customer - Billing	$8	$20	$2	$29	$14	$0	$8	$0	$92	$26	$24
36	Customer - Metering	$74	$179	$77	$57	$84	$1	$49	$96	$322	$119	$4
37	Customer - Other	$7	$18	$2	$11	$5	$0	$3	$0	$36	$10	$9
38	Revenue (less Uncollectables)	$22,381	$115,089	$10,792	$55,441	$37,990	$4,912	$94,430	$30,194	$26,831	$18,724	$3,791
39												
40	Customer - Uncollectables	$31	$75	$7	$61	$29	$1	$17	$1	$14	$4	$0
41	Total Revenue	$22,412	$115,164	$10,799	$55,502	$38,019	$4,913	$94,447	$30,195	$26,845	$18,729	$3,791

Source: Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 7) x (Table 3, Row 22)/1000
Line 2 Transmission (Table 3, Row 7) x (Table 3, Row 23)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 8) x (Table 7, Row 1 - 3) x (1 + .3747) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 9) x (Table 7, Row 7) x (1 + .3747) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 14) x (Table 3, Row 28 - 29)
Lines 20-29 Commitment Related (Table 3, Row 17) x (Table 7, Row 13 - 27) including O&M Adders

* Schedule 33 Cost of Service results are provided for informational purposes only.

Table 5

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs
In Nominal Dollars

Year			(A) Resource Cost (Mills / kWh) (B) + (C)	(B) Energy Only (Mills / kWh)	(C) Capacity Only (Mills / kWh)	(D) Capacity Only ($ / kW)
2011			75.79	58.23	17.56	$79.20
2012			78.71	60.84	17.87	$80.62
2013			80.31	62.10	18.21	$82.17
2014			81.94	63.38	18.56	$83.73
2015			82.49	63.58	18.91	$85.32
2016			81.34	62.07	19.27	$86.95
2017			81.42	61.78	19.64	$88.61
2018			82.58	62.56	20.02	$90.30
2019			85.68	65.28	20.40	$92.03
2020			89.37	68.58	20.79	$93.79
2021			93.64	72.46	21.18	$95.57
2022			94.13	72.54	21.59	$97.40
2023			95.35	73.35	22.00	$99.26
2024			87.43	65.01	22.42	$101.16
2025			90.68	67.83	22.85	$103.08
2026			95.37	72.08	23.29	$105.05
2027			96.85	73.12	23.73	$107.06
2028			100.35	76.17	24.18	$109.10
2029			103.22	78.58	24.64	$111.18
2030			107.54	82.42	25.12	$113.31
2011	**1 year -**					
|	Sum of PV Costs	@ 8.59%	75.79	58.23	17.56	$79.20
2011 - 2015	**5 year -**					
|	Sum of PV Costs	@ 8.59%	339.68	262.13	77.55	$349.85
|	Annual Cost of R/E	@ 22.67%	77.00	59.42		
|	Annual Cost of Capacity	@ 22.67%			17.58	$79.31
2011 - 2020	**10 years -**					
|	Sum of PV Costs	@ 8.59%	576.42	442.44	133.98	$604.41
|	Annual Cost of R/E	@ 13.16%	75.86	58.23		
|	Annual Cost of Capacity	@ 13.16%			17.63	$79.54
2011 - 2030	**20 years -**					
|	Sum of PV Costs	@ 8.59%	873.57	668.65	204.92	$924.50
|	Annual Cost of R/E	@ 8.64%	75.48	57.77		
|	Annual Cost of Capacity	@ 8.64%			17.71	$79.88

Footnotes:
(B) Tab 5.1 (Energy:) `Marginal Generation Energy Costs'
(C) Tab 4.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
(D) Tab 4.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item		$'s	
1	Growth Related Investments - (2011 to 2015 in $000's)		$796,904	
2				
3	System Growth MW's from 2011 to 2015		982	mW
4				
5	Marginal Investment	(growth invest / kW)	$811.33	/ kW
6				
7	Annualized Investment	x 8.85%	71.80	/ kW
8	Admin. & General Factor	x 1.52%	12.33	
9	Annual O&M Expenses	x 1.269%	10.30	/ kW
10	Annualized Marginal Cost		$94.43	/ kW
11				
12	Marginal Cost of Demand-Related Transmission		$76.37	/ kW
13				
14	Marginal Cost of Energy-Related Transmission	(Line 10 - Line 12)	$18.07	/ kW
15	Marginal Cost of Energy-Related Transmission		$0.00260	/ kWh
16	$18.07 / (8760 x 79.35% LF))			

Sources:
Tab 6.2 (Transm2:) \`2011-2015 Forecasted Transmission'
Tab 6.1 (Transm1:) \`Marginal Transmission Investment and O&M Expenses'

Table 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
December 2011 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Costs ($/kW)																			
1	Poles		19.84	21.77	21.77	21.77	13.67	13.67	13.67	13.67	14.50	14.50	14.50	11.23	11.23	1.14	0.83	NA	44.70	54.04
2	Conductors		29.44	31.88	31.88	31.88	$21.94	21.94	21.94	21.94	23.07	23.07	23.07	18.91	18.91	2.17	1.58	NA	59.13	71.54
3	Substation		19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	19.55	NA	19.55	19.55
4	Dist. O&M @ of Total Investment	37.47%	25.79	27.43	27.43	27.43	20.67	20.67	20.67	20.67	21.40	21.40	21.40	18.62	18.62	8.57	8.23	NA	46.23	54.38
5	Total $/ Dist. kW		$94.62	$100.63	$100.63	$100.63	$75.83	$75.83	$75.83	$75.83	$78.52	$78.52	$78.52	$68.31	$68.31	$31.43	$30.19	-	$169.61	$199.51
6																				
7	Transformers		1.83	1.83	1.83	NA	1.83	1.83	1.83	NA	1.83	1.83	NA	1.83	NA	1.83	NA	NA	1.83	1.83
8	Dist. O&M @ of Total Investment	37.47%	0.69	0.69	0.69	NA	0.69	0.69	0.69	NA	0.69	0.69	NA	0.69	NA	0.69	NA	NA	0.69	0.69
9	Total $/ Transformer kW		$2.52	$2.52	$2.52	$0.00	$2.52	$2.52	$2.52	$0.00	$2.52	$2.52	$0.00	$2.52	$0.00	$2.52	$0.00	$0.00	$2.52	$2.52
10																				
11																				
12	Commitment Related Costs ($/Customer)																			
13	Poles		79.96	94.70	94.70	94.70	38.56	38.56	38.56	38.56	46.54	46.54	46.54	20.98	20.98	-	-	NA	236.35	319.88
14	Conductors		28.85	34.17	34.17	34.17	13.91	13.91	13.91	13.91	16.79	16.79	16.79	7.57	7.57	-	-	NA	85.28	115.42
15	Transformers		94.61	233.25	455.61	NA	764.99	879.54	963.87	NA	924.38	926.13	NA	982.99	NA	982.99	NA	NA	830.63	958.05
16	Dist. O&M @ of Total Investment	37.47%	76.22	135.69	219.00	48.29	306.30	349.22	380.82	19.66	370.10	370.75	23.73	379.02	10.70	368.33	-	NA	431.75	522.09
17	Total Commitment Related		$279.64	$497.81	$803.48	$177.16	$1,123.76	$1,281.23	$1,397.16	$72.13	$1,357.81	$1,360.21	$87.06	$1,390.56	$39.25	$1,351.32	$0.00	$0.00	$1,584.01	$1,915.44
18																				
19	Billing Related Costs ($/Customer/Yr)																			
20	Service Drop		51.84	70.39	177.10	NA	178.74	185.29	395.05	NA	400.91	400.90	NA	698.00	NA	698.00	NA	NA	NA	NA
21	Service Drop O&M @	37.47%	19.42	26.38	66.36	NA	66.97	69.43	148.03	NA	150.22	150.22	NA	261.54	NA	261.54	NA	NA	NA	NA
22	Meter		11.84	13.75	27.91	$935.22	26.81	33.94	154.53	935.22	155.78	155.94	935.22	243.16	935.22	243.16	935.22	33,086.98	27.26	32.74
23	Meter O&M at	44.88%	5.31	6.17	12.53	419.73	12.03	15.23	69.35	419.73	69.91	69.99	419.73	109.13	419.73	109.13	419.73	14,849.44	12.23	14.69
24	Meter Reading		14.70	18.22	18.22	18.22	17.63	17.63	17.63	17.63	$79.50	$79.50	$79.50	120.65	120.65	120.65	120.65	120.65	28.07	28.00
25	Billing & Collections		33.25	31.26	31.26	31.26	33.59	33.59	33.59	33.59	$33.59	$33.59	$33.59	245.41	245.41	245.41	245.41	245.41	33.92	33.87
26	Uncollectables		9.48	2.06	2.06	2.06	19.20	19.20	19.20	19.20	$127.84	$127.84	$127.84	508.84	508.84	508.84	508.84	508.84	5.24	5.70
27	Customer Service / Other		12.11	11.51	11.51	11.51	13.42	13.42	13.42	13.42	30.66	30.66	30.66	94.73	94.73	94.73	94.73	94.73	13.10	13.13
28	Total Billing Related		$157.95	$179.74	$346.95	$1,418.00	$368.39	$387.73	$850.80	$1,438.79	$1,048.40	$1,048.63	$1,626.53	$2,281.46	$2,324.58	$2,281.46	$2,324.58	$48,906.05	$119.82	$128.13
29																				
30																				
31	Monthly Billing Related (Line 28 / 12)		$13.16	$14.98	$28.91	$118.17	$30.70	$32.31	$70.90	$119.90	$87.37	$87.39	$135.54	$190.12	$193.72	$190.12	$193.72	$4,075.50	$9.99	$10.68
32																				
33	Total Distribution (Comm & Billing Costs)		$437.59	$677.55	$1,150.43	$1,595.16	$1,492.15	$1,668.96	$2,247.96	$1,510.92	$2,406.21	$2,408.85	$1,713.59	$3,672.02	$2,363.83	$3,632.78	$2,324.58	$48,906.05	$1,703.83	$2,043.57
34	Line 17 + Line 28																			
35	Monthly Commitment & Bill (Line 33 / 12)		$36.47	$56.46	$95.87	$132.93	$124.35	$139.08	$187.33	$125.91	$200.52	$200.74	$142.80	$306.00	$196.99	$302.73	$193.72	$4,075.50	$141.99	$170.30

Sources: Lines
Line 1 - 2 Tab 8.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 3 Tab 7.1 (Dist Sub 1:) `Distribution Substation Costs / kW'
Line 4 Sum of lines 1 to 3 multiplied by 37.47%
Tab 10.1 (Dist OM:) `Distribution O&M Expense Loading Factor as a Percent of Dist. Plant' (for 37.47% Factor)
Line 7 Tab 9.2 (XFMR 2:) `Transformer Demand Costs'
Line 13 - 14 Tab 8.1 (PC 1:) `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 15 Tab 9.1 (XFMR 1:) `Transformer Commitment Costs'
Line 20 Tab 12.1 (Services 1:) `Weighted Average Installed Service Drop Costs'
Line 22 Tab 11.1 (Meters 1:) `Weighted Average Installed Meter Costs'
Line 23 Tab 11.5 (Meters 5:) `Distribution Meters Expense Loading Factor' (for 44.88% Factor)
Line 24 -27 Tab 13.1 (Cust Exp Sum:) `Summary of Customer Accounting Expense By Schedule'

* Schedule 33 Cost of Service results are provided for informational purposes only.

Billing Costs

PacifiCorp
Oregon Marginal Cost Study
Total 20 Year Demand Costs Divided by Billing kW
December 2011 Dollars
(Dollars in 000's)

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg Sch 41	Irrg Sch 33*
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 M	> 4 MW	> 4 M	Trans		
Line	Description	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation -	$171,523	$78,835	$8,783	$6,023	$11	$6,052	$10,111	$12,773	$186	$2,721	$14,284	$1,417	$7,062	$4,850	$615	$12,479	$3,681	$1,640	$1,401
2	Transmission -	$163,988	$75,371	$8,397	$5,759	$10	$5,787	$9,667	$12,212	$178	$2,601	$13,656	$1,355	$6,752	$4,637	$588	$11,931	$3,519	$1,568	$1,340
3																				
4	Distribution -																			
5	Poles, Wire, Sub	$185,586	$103,947	$10,446	$7,300	$13	$5,502	$9,391	$12,142	$241	$2,659	$14,200	$1,403	$6,130	$4,111	$218	$4,612	$0	$3,271	$3,289
6	Transformers	$13,120	$9,072	$483	$346	$0	$454	$591	$668	$0	$128	$719	$0	$384	$0	$41	$0	$0	$235	$201
7	Distribution Subtotal	$198,706	$113,019	$10,928	$7,647	$13	$5,956	$9,982	$12,810	$241	$2,787	$14,919	$1,403	$6,514	$4,111	$259	$4,612	$0	$3,506	$3,489
8																				
9	Total Demand Related	$534,217	$267,225	$28,108	$19,429	$34	$17,795	$29,760	$37,795	$605	$8,109	$42,859	$4,175	$20,328	$13,598	$1,462	$29,022	$7,200	$6,714	$6,230
10																				
11	Average Billing kW	6,836,884	4,835,502	223,891	160,433	1,315	161,869	211,197	238,749	6,567	45,668	256,588	25,392	137,133	90,016	14,551	215,142	63,841	83,880	65,150
12																				
13	Generation -		$16.30	$39.23	$37.54	$8.36	$37.39	$47.87	$53.50	$28.32	$59.58	$55.67	$55.80	51.50	53.88	42.27	58.00	57.66	19.55	21.50
14	Transmission -		$15.59	$37.50	$35.90	$7.60	$35.75	$45.77	$51.15	$27.10	$56.95	$53.22	$53.36	49.24	51.51	40.41	55.46	55.12	18.69	20.57
15																				
16	Distribution -																			
17	Poles, Wire, Sub		$21.50	$46.66	$45.50	$10.06	$33.99	$44.47	$50.86	$36.63	$58.22	$55.34	$55.25	44.70	45.67	14.98	21.44	0.00	38.99	50.48
18	Transformers		$1.88	$2.16	$2.16	$0.00	$2.80	$2.80	$2.80	$0.00	$2.80	$2.80	$0.00	2.80	0.00	2.83	0.00	0.00	2.80	3.08
19	Distribution subtotal		$23.37	$48.81	$47.66	$10.06	$36.79	$47.27	$53.66	$36.63	$61.02	$58.14	$55.25	47.50	45.67	17.82	21.44	0.00	41.79	53.56
20																				
21																				
22																				
23																				
24	Total Demand Related		$55.26	$125.54	$121.10	$26.03	$109.93	$140.91	$158.31	$92.06	$177.56	$167.03	$164.42	$148.23	$151.06	$100.49	$134.90	$112.78	$80.04	$95.63
25																				
26	Monthly Demand Costs		$4.61	$10.46	$10.09	$2.17	$9.16	$11.74	$13.19	$7.67	$14.80	$13.92	$13.70	$12.35	$12.59	$8.37	$11.24	$9.40	$6.67	$7.97

* Schedule 33 Cost of Service results are provided for informational purposes only.

Full MC %

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage @ Meter
December 2011 Dollars

Line	Description		(A) Marginal Cost (000)s	(B) Mills / kWh	(C) % of Total
	Demand Related Marginal Cost -				
1	Generation		$171,523	13.87	10.5%
2	Transmission		163,988	13.26	10.0%
3	Dist. Poles, Cond., Subst.		185,586	15.01	11.3%
4	Dist. Transformers		13,120	1.06	0.8%
5	Total Demand Related		$534,217	43.20	32.6%
6					
7	Energy Related Marginal Cost -				
8					
9	Generation		$767,582	62.08	46.9%
10	Transmission		34,540	2.79	2.1%
11	Total Energy Related		$802,122	64.88	49.0%
12					
13	Commitment & Billing -				
14	Commitment		201,565	16.30	12.3%
15	Billing		98,412	7.96	6.0%
16	Total Commitment & Billing		$299,977	24.26	18.3%
17					
18					
19	TOTAL MARGINAL COST		$1,636,316	132.34	100.0%
20					
21					
22	Note: Total MWh =	12,363,443			

PacifiCorp
Oregon Marginal Cost Study
10 Year Run Costing Inputs and Customer Data
Marginal Unit Costs
December 2011 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41	Sch 33*
Line	Description		(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Peak MW @ Meter	System	887	99	68	0	68	114	144	2	31	161	16	79	56	7	144	44	18	16
2		Distribution	987	93	65	0	65	111	144	3	30	162	17	81	56	6	141	0	17	15
3		Transformer	3,240	172	124	1	162	211	239	7	46	257	25	137	90	15	215	64	84	72
4	Demand Loss Factor		1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.0819	1.1131	1.0819	1.1131	1.0819	1.0498	1.1131	1.1131
5	Peak MW @ Generator	System	987	110	75	0	76	127	160	2	34	179	18	88	61	8	156	46	21	18
6		Distribution	1,099	104	73	0	73	124	160	3	34	181	18	90	60	7	153	-	19	16
7		Transformer	3,606	192	138	N/A	180	235	266	N/A	51	286	N/A	153	N/A	16	N/A	N/A	93	80
8																				
9																				
10	Energy																			
11	Energy - Annual Mwh	@ Meter	5,306,840	577,893	435,130	815	429,296	659,704	905,100	17,727	208,208	1,075,585	102,283	526,955	380,354	52,257	1,023,411	366,079	149,120	127,459
12	Energy Loss Factor		1.09180	1.09180	1.09180	1.05771	1.09180	1.09180	1.09180	1.05771	1.09180	1.09180	1.05771	1.09180	1.05771	1.09180	1.05771	1.03605	1.09180	1.09180
13	Energy - Annual Mwh	@ Generator	5,794,008	630,944	475,075	862	468,705	720,265	988,188	18,750	227,322	1,174,324	108,186	575,330	402,304	57,054	1,082,472	379,276	162,809	139,160
14																				
15																				
16	Customer																			
17	Annual Customers		484,011	64,803	9,367	37	4,635	3,650	2,080	53	241	586	54	120	57	2	33	2	6,211	2,056
18	Average Customers																		2,722	760
19																				
20	Unit Costs																			
21																				
22	Generation	$ / System Peak kW	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54	$79.54
23	Transmission	$ / System Peak kW	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37	$76.37
24	Poles, Cond., Subst.	$ / Dist. kW	$94.62	$100.63	$100.63	$100.63	$75.83	$75.83	$75.83	$75.83	$78.52	$78.52	$78.52	$68.31	$68.31	$31.43	$30.19	$0.00	$169.61	$199.51
25	Transformers	$ / Xfmr kW	$2.52	$2.52	$2.52	$0.00	$2.52	$2.52	$2.52	$0.00	$2.52	$2.52	$0.00	$2.52	$0.00	$2.52	$0.00	$0.00	$2.52	$2.52
26																				
27																				
28	Energy @ Generator	$ / Kwh	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083	$0.06083
29																				
30																				
31	Commitment & Billing	$ / Cust. / Year	$437.59	$677.55	$1,150.43	1,595.16	$1,492.15	$1,668.96	$2,247.96	$1,510.92	$2,406.21	$2,408.85	$1,713.59	3,672.02	$2,363.83	$3,632.78	$2,324.58	$48,906.05	1,703.83	2,043.57

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost By Load Class
December 2011 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41	Sch 33*
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Demand Related Marginal Cost																			
1	Generation -	$172,187	$78,500	$8,745	$5,998	$11	$6,027	$10,068	$12,718	$185	$2,709	$14,223	$1,411	$7,032	$4,829	$612	$12,426	$3,665	$1,633	$1,395
2	Transmission -	$165,328	$75,371	$8,397	$5,759	$10	$5,787	$9,667	$12,212	$178	$2,601	$13,656	$1,355	$6,752	$4,637	$588	$11,931	$3,519	$1,568	$1,340
3																				
4	Distribution -																			
5	Poles, Conductor, Substations	$188,873	$103,945	$10,446	$7,301	$14	$5,501	$9,392	$12,142	$240	$2,659	$14,199	$1,404	$6,129	$4,110	$218	$4,613	$0	$3,271	$3,289
6	Transformers	$13,344	$9,087	$484	$347	$0	$454	$592	$670	$0	$128	$720	$0	$385	$0	$41	$0	$0	$235	$201
7	Distribution subtotal	$202,217	$113,032	$10,930	$7,648	$14	$5,955	$9,984	$12,812	$240	$2,787	$14,919	$1,404	$6,514	$4,110	$259	$4,613	$0	$3,506	$3,490
8																				
9	Total Demand Related	$539,732	$266,903	$28,072	$19,405	$35	$17,769	$29,719	$37,742	$603	$8,097	$42,798	$4,170	$20,298	$13,576	$1,459	$28,970	$7,184	$6,707	$6,225
10	(Lines 1+2+7)																			
11																				
12																				
13	Energy Related Marginal Cost																			
14																				
15	Total Energy Related	$815,424	$352,447	$38,380	$28,899	$52	$28,511	$43,813	$60,111	$1,141	$13,828	$71,434	$6,581	$34,997	$24,472	$3,471	$65,846	$23,071	$9,904	$8,465
16																				
17																				
18	Customer Related Marginal Cost																			
19																				
20	Commitment & Billing Rel.	$301,547	$211,798	$43,907	$10,776	$59	$6,916	$6,092	$4,676	$80	$580	$1,412	$93	$441	$135	$7	$77	$98	$10,303	$4,097
21																				
22																				
23	Total Revenue @ Full MC	$1,656,703	$831,148	$110,359	$59,080	$146	$53,196	$79,624	$102,529	$1,824	$22,505	$115,644	$10,844	$55,736	$38,183	$4,937	$94,893	$30,353	$26,914	$18,787

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Costs by Load Class
December 2011 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41	Sch 33*
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Demand																			
1	Peak MW @ Meter	System	887	99	68	0	68	114	144	2	31	161	16	79	56	7	144	44	18	16
2	Demand Loss Factor		1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.1131	1.0819	1.1131	1.1131	1.0819	1.1131	1.0819	1.1131	1.0819	1.0498	1.1131	1.1131
3	Peak MW @ Generator	System	987	110	75	0	76	127	160	2	34	179	18	88	61	8	156	46	21	18
4																				
5	Energy																			
6	Energy - Annual Mwh @ Meter	12,344,216	5,306,840	577,893	435,130	815	429,296	659,704	905,100	17,727	208,208	1,075,585	102,283	526,955	380,354	52,257	1,023,411	366,079	149,120	127,459
7	Energy Loss Factor		1.09180	1.09180	1.09180	1.05771	1.09180	1.09180	1.09180	1.05771	1.09180	1.09180	1.05771	1.09180	1.05771	1.09180	1.05771	1.03605	1.09180	1.09180
8	Energy - Annual Mwh @ Generator	13,405,033	5,794,008	630,944	475,075	862	468,705	720,265	988,188	18,750	227,322	1,174,324	108,186	575,330	402,304	57,054	1,082,472	379,276	162,809	139,160
9																				
10	Customer																			
11	Average Customers	577,998	484,011	64,803	9,367	37	4,635	3,650	2,080	53	241	586	54	120	57	2	33	2	6,211	2,056
12																			2,722	760
13	Unit Costs																			
14																				
15	Generation - $ / System Peak Kw		$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31	$79.31
16	Energy @ Generator $ / Kwh		$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942	$0.05942
17	Billing Related Costs		$157.95	$179.74	$346.95	$1,418.00	$368.39	387.73	$850.80	$1,438.79	$1,048.40	$1,048.63	$1,626.53	$2,281.46	$2,324.58	$2,281.46	$2,324.58	$48,906.05	$39.49	$47.43
18																			$80.33	$80.70
19	Marginal Costs $000																			
20																				
21	Total Demand Related	$171,690	$78,273	$8,720	$5,980	$11	$6,009	$10,039	$12,682	$185	$2,701	$14,182	$1,407	$7,012	$4,815	$611	$12,390	$3,654	$1,628	$1,391
22																				
23	Total Energy Related	$796,525	$344,280	$37,491	$28,229	$51	$27,850	$42,798	$58,718	$1,114	$13,507	$69,778	$6,428	$34,186	$23,905	$3,390	$64,320	$22,537	$9,674	$8,269
24																				
25	Billing Related Costs	$98,532	$76,449	$11,648	$3,250	$52	$1,707	$1,415	$1,770	$76	$253	$614	$88	$274	$133	$5	$77	$98	$464	$159
26																				
27	Total Revenue @ Full MC	$1,066,747	$499,002	$57,859	$37,459	$114	$35,566	$54,252	$73,170	$1,375	$16,461	$84,574	$7,923	$41,472	$28,853	$4,006	$76,787	$26,289	$11,766	$9,819

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs by Load Class
December 2011 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48T					Irrg	Irrg
				0-15 kW	15+ kW		0-50 kW	51-100 kW	> 101kW	Primary	0-300 kW	301+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW		Sch 41	Sch 33*
Line		Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
	Billing Units																			
	Energy																			
1	Energy - Annual Mwh @ Meter	12,344,216	5,306,840	577,893	435,130	815	429,296	659,704	905,100	17,727	208,208	1,075,585	102,283	526,955	380,354	52,257	1,023,411	366,079	149,120	127,459
2	Energy Loss Factor		1.09180	1.09180	1.09180	1.05771	1.09180	1.09180	1.09180	1.05771	1.09180	1.09180	1.05771	1.09180	1.05771	1.09180	1.05771	1.03605	1.09180	1.09180
3	Energy - Annual Mwh @ Generator	13,405,033	5,794,008	630,944	475,075	862	468,705	720,265	988,188	18,750	227,322	1,174,324	108,186	575,330	402,304	57,054	1,082,472	379,276	162,809	139,160
4																				
5	Customer																			
6	Average Customers	577,998	484,011	64,803	9,367	37	4,635	3,650	2,080	53	241	586	54	120	57	2	33	2	6,211	2,056
7																			2,722	760
8	Unit Costs																			
9																				
10	Energy @ Generator $ / Kwh		$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823	$0.05823
11																				
12	Billing Related Costs		$157.95	$179.74	$346.95	1,418.00	$368.39	387.73	$850.80	$1,438.79	$1,048.40	$1,048.63	$1,626.53	$2,281.46	$2,324.58	$2,281.46	$2,324.58	$48,906.05	$39.49	$47.43
13																			$80.33	$80.70
14																				
15	Marginal Costs $000																			
16																				
17	Total Energy Related	$780,522	$337,362	$36,737	$27,662	$50	$27,291	$41,938	$57,538	$1,092	$13,236	$68,376	$6,299	$33,499	$23,425	$3,322	$63,028	$22,084	$9,480	$8,103
18																				
19	Billing Related Costs	$98,532	$76,449	$11,648	$3,250	$52	$1,707	$1,415	$1,770	$76	$253	$614	$88	$274	$133	$5	$77	$98	$464	$159
20																				
21																				
22	Total Revenue @ Full MC	$879,054	$413,811	$48,385	$30,912	$102	$28,998	$43,353	$59,308	$1,168	$13,489	$68,990	$6,387	$33,773	$23,558	$3,327	$63,105	$22,182	$9,944	$8,262

* Schedule 33 Cost of Service results are provided for informational purposes only.

Streetlight 1

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Commitment & Billing Related Cost per Customer

Line	Description	100 Watt HPSV	150 Watt HPSV	250 Watt HPSV	400 Watt HPSV	Schedule 53 Customer Owned	Schedule 54 Customer Owned
1	Light Installation Cost - per lamp	$150.89	$169.72	$190.62	$255.84	N. A.	N. A.
2							
3	Distribution Commitment Costs - per customer						
4	Acct. 364 Poles	$94.70	$94.70	$94.70	$94.70	$94.70	$94.70
5	Acct. 365 Conductors	$34.17	$34.17	$34.17	$34.17	$34.17	$34.17
6	Acct. 368 Transformers	N. A.	N. A.	N. A.	N. A.	233.25	455.61
7	Dist O&M at 37.5% of Annual Charge	$48.29	$48.29	$48.29	$48.29	$135.69	$219.00
8	Acct. 370 Meters	N. A.	N. A.	N. A.	N. A.	N. A.	$13.75
9	Meter O&M at 44.88% of Annual Charge	N. A.	N. A.	N. A.	N. A.	N. A.	$6.17
10	Total Commitment Related	$177.16	$177.16	$177.16	$177.16	$497.80	$823.40
11							
12	Billing Costs per Customer	$41.93	$41.93	$41.93	$41.93	$41.93	$60.15
13							
14	Total Marginal Commitment & Billing Cost per Cust.	$219.09	$219.09	$219.09	$219.09	$539.74	$883.56

Sources:
Line 1 "Distribution Cost Development For Street Lighting"
Line 4 `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 5 `Hypothetical Circuit Study Results Annual Demand and Commitment Costs'
Line 6 `Transformer Commitment Costs By Customer Load Class'
Line 7 Sum of lines 4 to 6 multiplied by
Distribution O&M Expense Loading Factor as a Percent of Dist. Plant'
Line 14 Sum of Commitment & Billing Costs per Customer

Streetlight 2

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Full Marginal Cost by Schedule

Line	Description	Units	Schedule 51 High Pressure Sodium Vapor 9,500 Lumen 100 Watt	16,000 Lumen 150 Watt	27,500 Lumen 250 Watt	50,000 Lumen 400 Watt	Schedule 53 Customer Owned	Schedule 54	Total Streetlighting
	Energy								
1	Generation Energy $/kWh @ Generator	$/kWh	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	$0.05777	
2	Transmission Energy $/kWh @ Generator	$/kWh	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	$0.00260	
3									
4	Energy @ Meter 2009	kWh	6,913,842	102,717	218,547	2,396,123	9,090,929	992,606	
5	Energy @ Meter 2011		6,553,877	97,369	207,169	2,271,371	9,250,113	846,933	19,226,832
6	Losses		1.09180	1.09180	1.09180	1.09180	1.09180	1.09180	
7	Energy @ Generator - (5)*(6)	kWh	7,155,523	106,307	226,187	2,479,883	10,099,273	924,682	20,991,856
8									
9	Generation Energy Related Marginal Costs - (1)*(7)	$	$413,375	$6,141	$13,067	$143,263	$583,435	$53,419	$1,212,699
10	Transmission Energy Related Marginal Costs - (2)*(7)	$	$18,601	$276	$588	$6,447	$26,254	$2,404	$54,569
11									
12	Commitment								
13	Total of Monthly Lamp Billing Units 2011	#	148,951	1,521	1,801	12,905			
14	Number of Lamps 2011 - (13) / 12	#	12,413	127	150	1,075			
15	Light Installation Cost	$/Lamp	$150.89	$169.72	$190.62	$255.84			
16	Light Installation Related		$1,872,959	$21,512	$28,609	$275,130			$2,198,210
17									
18	Average customers - 2011	#	289	25	31	68	266	103	782
19									
20									
21	Acct. 364 Poles		$94.70	$94.70	$94.70	$94.70	$94.70	$94.70	
22	Acct. 365 Conductors		$34.17	$34.17	$34.17	$34.17	$34.17	$34.17	
23	Acct. 368 Transformers		N. A.	N. A.	N. A.	N. A.	$233.25	$455.61	
24	Acct. 370 Meters							$13.75	
25									
26	Acct. 364 Poles with O&M		$37,623	$3,255	$4,036	$8,853	$34,629	$13,409	$101,804
27	Acct. 365 Conductors with O&M		$13,575	$1,174	$1,456	$3,194	$12,495	$4,838	$36,733
28	Acct. 368 Transformers with O&M		N.A.	N.A.	N.A.	N.A.	$85,292	$64,511	$149,804
29	Acct. 370 Meter with O&M		N.A.	N.A.	N.A.	N.A.	N.A.	$2,052	$2,052
30	Total Poles, Conductors, Transfomers		$51,199	$4,429	$5,492	$12,047	$132,416	$84,810	$290,393
31									
32	Total Commitment Marginal Cost		$1,924,157	$25,940	$34,101	$287,177	$132,416	$84,810	$2,488,602
33									
34	Billing / Customer								
35	Billing Related	$/Customer	$30.59	$30.59	$30.59	$30.59	$30.59	$30.59	
36	Meter Reading	$/Customer	-	-	-	-	-	$18.22	
37	Customer Other	$/Customer	$11.34	$11.34	$11.34	$11.34	$11.34	$11.34	
38									
39	Billing Related	$	8,841	765	948	2,080	8,138	3,151	$23,924
40	Meter Reading	$	-	-	-	-	-	1,877	$1,877
41	Customer Other	$	3,277	283	352	771	3,016	1,168	$8,867
42	Total Billing Related Marginal Cost		$12,119	$1,048	$1,300	$2,851	$11,154	$6,196	$34,668
43									
44	Total Marginal Cost		$2,368,252	$33,407	$49,056	$439,737	$753,259	$146,829	$3,790,539

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$575,846	$583,435	$53,419	$1,212,699
Transmission	$25,912	$26,254	$2,404	$54,569
Distribution	$2,271,376	$132,416	$84,810	$2,488,602
Customer - Billing	$12,635	8,138	3,151	$23,924
Customer - Metering	-	-	1,877	$1,877
Customer - Other	4,683	3,016	1,168	$8,867
	$2,890,451	$753,259	$146,829	$3,790,539

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$575.85	$583.44	$53.42	$1,212.70
Transmission	$25.91	$26.25	$2.40	$54.57
Distribution	$2,271.38	$132.42	$84.81	$2,488.60
Customer - Billing	$12.63	$8.14	$3.15	$23.92
Customer - Metering	$0.00	$0.00	$1.88	$1.88
Customer - Other	$4.68	$3.02	$1.17	$8.87

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PacifiCorp
Oregon Marginal Cost Study
Cost of Streetlighting Transformer

Transformer Cost Per Light - 100 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,847

Lamp Line Watts = 117 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
117 / 25000 X $2847 = $ 13.32

Transformer Cost Per Light - 150 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,847

Lamp Line Watts = 171 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
171 / 25000 X $2847 = $ 19.47

Transformer Cost Per Light - 250 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,847

Lamp Line Watts = 305 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
305 / 25000 X $2847 = $ 34.73

Transformer Cost Per Light - 400 Watt

Assume Installed Cost* 25 KVA Transformer is $ 2,847

Lamp Line Watts = 468 watts

Transformer Cost = Total Watts/25,000 X Installed Cost
468 / 25000 X $2847 = $ 53.30

Capacity

PacifiCorp
Oregon Marginal Cost Study
Marginal Capacity Costs
Based on Avoided Capacity Costs

	(A)	(B)	(C)	(D)	(E)
Calendar Year (12 Mo Ended Dec)	Projected Capacity $/kW	Present Value Factors	PV of Capacity $/kW	Capacity Mills/kWh	PV of Capacity Mills/kWh
		@ 8.59%	(A) x (B)	(A) / 0.515 / 8,760	(B) * (D)
2011	$79.20	1.0000	79.20	17.56	17.56
2012	$80.62	0.9209	74.24	17.87	16.46
2013	$82.17	0.8480	69.68	18.21	15.44
2014	$83.73	0.7809	65.38	18.56	14.49
2015	$85.32	0.7191	61.35	18.91	13.60
2016	$86.95	0.6622	57.58	19.27	12.76
2017	$88.61	0.6098	54.03	19.64	11.98
2018	$90.30	0.5615	50.70	20.02	11.24
2019	$92.03	0.5171	47.59	20.40	10.55
2020	$93.79	0.4762	44.66	20.79	9.90
2021	$95.57	0.4385	41.91	21.18	9.29
2022	$97.40	0.4038	39.33	21.59	8.72
2023	$99.26	0.3718	36.90	22.00	8.18
2024	$101.16	0.3424	34.64	22.42	7.68
2025	$103.08	0.3153	32.50	22.85	7.20
2026	$105.05	0.2903	30.50	23.29	6.76
2027	$107.06	0.2673	28.62	23.73	6.34
2028	$109.10	0.2461	26.85	24.18	5.95
2029	$111.18	0.2266	25.19	24.64	5.58
2030	$113.31	0.2087	23.65	25.12	5.24

			$/kW	mills / kWh
2011	1 Year -	Sum of PV Costs @ 8.59%	79.20	17.56
2011 - 2015	5 Year -	Short Run -		
		Sum of PV Costs @ 8.59%	$349.85	$77.55
		Annual Cost of Capacity @ 22.67%	79.31	17.58
2011 - 2020	10 Years -	Medium Run -		
		Sum of PV Costs @ 8.59%	$604.41	133.98
		Annual Cost of Capacity @ 13.16%	79.54	17.63
2011 - 2030	20 Years -	Long Run -		
		Sum of PV Costs @ 8.59%	$924.50	204.92
		Annual Cost of Capacity @ 8.64%	79.88	17.71

Footnote:

Column A: Total Cost of Simple Cycle: Table 8, Page 1, column (f)

Energy

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

Calendar Year (12 Mo Ended Dec)	(A) SCCT Fixed Costs ($/kW-yr) (1)	(B) SCCT Fixed Costs ($/kW-mo) (2)	(C) CCCT Fixed Costs ($/kW-yr) (3)	(D) CCCT Fixed Costs ($/kW-mo) (4)	(E) Capitalized Energy Cost ($/kW-mo) (4) - (2) = (5)	(F) Capitalized Energy Cost 51.5% CF ($/MWh) (6)	(G) Purchase Cost ($/MWh) (7)	(H) Updated Gas Price ($/MMBtu) (8)	(I) CCCT Energy Costs 7,150 Btu/kWh ($/MWh) (9)	(J) Variable Avoided Energy Cost ($/MWh) (7) + (9) =(10)	(K) Capitalized Energy Cost 51.5% CF ($/MWh) (6)=(11)	(L) Total Avoided Energy Cost ($/MWh) (10) + (11) =(12)	(M) Present Value Factors (13) @ 8.59%	(N) Present Value of Energy (14) (12)*(13)
2011	79.20	6.60	124.47	10.37	3.77	10.03	0.00	6.74	48.19	48.19	10.03	58.23	1.0000	58.23
2012	80.62	6.72	126.71	10.56	3.84	10.22	0.00	7.08	50.62	50.62	10.22	60.84	0.9209	56.03
2013	82.17	6.85	129.13	10.76	3.91	10.41	0.00	7.23	51.69	51.69	10.41	62.10	0.8480	52.66
2014	83.73	6.98	131.59	10.97	3.99	10.61	0.00	7.38	52.77	52.77	10.61	63.38	0.7809	49.49
2015	85.32	7.11	134.09	11.17	4.06	10.81	0.00	7.38	52.77	52.77	10.81	63.58	0.7191	45.72
2016	86.95	7.25	136.65	11.39	4.14	11.02	0.00	7.14	51.05	51.05	11.02	62.07	0.6622	41.10
2017	88.61	7.38	139.26	11.61	4.22	11.23	0.00	7.07	50.55	50.55	11.23	61.78	0.6098	37.67
2018	90.30	7.53	141.91	11.83	4.30	11.44	0.00	7.15	51.12	51.12	11.44	62.56	0.5615	35.13
2019	92.03	7.67	144.63	12.05	4.38	11.66	0.00	7.50	53.63	53.63	11.66	65.28	0.5171	33.76
2020	93.79	7.82	147.39	12.28	4.47	11.88	0.00	7.93	56.70	56.70	11.88	68.58	0.4762	32.66
2021	95.57	7.96	150.21	12.52	4.55	12.11	0.00	8.44	60.35	60.35	12.11	72.46	0.4385	31.77
2022	97.40	8.12	153.07	12.76	4.64	12.34	0.00	8.42	60.20	60.20	12.34	72.54	0.4038	29.29
2023	99.26	8.27	155.99	13.00	4.73	12.57	0.00	8.50	60.78	60.78	12.57	73.35	0.3718	27.27
2024	101.16	8.43	158.97	13.25	4.82	12.81	0.00	7.30	52.20	52.20	12.81	65.01	0.3424	22.26
2025	103.08	8.59	162.01	13.50	4.91	13.06	0.00	7.66	54.77	54.77	13.06	67.83	0.3153	21.39
2026	105.05	8.75	165.10	13.76	5.00	13.31	0.00	8.22	58.77	58.77	13.31	72.08	0.2903	20.93
2027	107.06	8.92	168.25	14.02	5.10	13.56	0.00	8.33	59.56	59.56	13.56	73.12	0.2673	19.55
2028	109.10	9.09	171.46	14.29	5.20	13.82	0.00	8.72	62.35	62.35	13.82	76.17	0.2461	18.75
2029	111.18	9.27	174.74	14.56	5.30	14.09	0.00	9.02	64.49	64.49	14.09	78.58	0.2266	17.81
2030	113.31	9.44	178.07	14.84	5.40	14.35	0.00	9.52	68.07	68.07	14.35	82.42	0.2087	17.20

				Mills / kWh
2011	1 Year -	Sum of PV Costs		58.23
2011 - 2015	5 Year -	Short Run -		
		Sum of PV Costs	@ 8.59% =	262.13
		Annual Cost of Energy	@ 22.67% =	59.42
2011 - 2020	10 Years -	Medium Run -		
		Sum of PV Costs	@ 8.59% =	442.44
		Annual Cost of Energy	@ 13.16% =	58.23
2011 - 2030	20 Years -	Long Run -		
		Sum of PV Costs	@ 8.59% =	668.65
		Annual Cost of Energy	@ 8.64% =	57.77

Footnote:

Column A: Total Cost of Simple Cycle: Table 8, Page 1, column (f)
Column C: Total Cost of Combined Cycle: Table 8, Page 2, column (f)
Column H: Gas Price: Table 9, column (b)
Column I: Heat Rate for Combined Cycle: Table 8, Page 3

Avoided Costs

PacifiCorp Marginal Generation Costs Filed						
	12 Months Ended December			12 Months Ended December		
Calendar Year	Avoided Simple Cycle CT Fixed Costs ($/kW-yr)	Avoided Combined Cycle CT Fixed Costs ($/kW-yr)	Gas Price ($/MMBtu)	Avoided Firm Capacity Costs ($/kW-yr)	Combined Cycle CT Fixed Cost ($/kW-yr)	Gas Price ($/MMBtu)
2011	79.20	124.47	6.74	79.20	124.47	6.74
2012	80.62	126.71	7.08	80.62	126.71	7.08
2013	82.17	129.13	7.23	82.17	129.13	7.23
2014	83.73	131.59	7.38	83.73	131.59	7.38
2015	85.32	134.09	7.38	85.32	134.09	7.38
2016	86.95	136.65	7.14	86.95	136.65	7.14
2017	88.61	139.26	7.07	88.61	139.26	7.07
2018	90.30	141.91	7.15	90.30	141.91	7.15
2019	92.03	144.63	7.50	92.03	144.63	7.50
2020	93.79	147.39	7.93	93.79	147.39	7.93
2021	95.57	150.21	8.44	95.57	150.21	8.44
2022	97.40	153.07	8.42	97.40	153.07	8.42
2023	99.26	155.99	8.50	99.26	155.99	8.50
2024	101.16	158.97	7.30	101.16	158.97	7.30
2025	103.08	162.01	7.66	103.08	162.01	7.66
2026	105.05	165.10	8.22	105.05	165.10	8.22
2027	107.06	168.25	8.33	107.06	168.25	8.33
2028	109.10	171.46	8.72	109.10	171.46	8.72
2029	111.18	174.74	9.02	111.18	174.74	9.02
2030	113.31	178.07	9.52	113.31	178.07	9.52

CCCT Capacity Factor	51.5%
CCCT Heat Rate (Btu/kWh)	7,150

Source:

Total Cost of Simple Cycle: Table 8, Page 1, column (f)
Total Cost of Combined Cycle: Table 8, Page 2, column (f)
Gas Price: Table 9, Column (b)

(Fiscal Year):
(Previous Year * 75%)+(Current Year * 25%)

(Calendar Year):
(Previous Year * 0%)+(Current Year * 100%)

Previous Yr = 0%
Current Yr = 100%

Transm1

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
December 2011 Dollars

Line	Item	(A) Total (B) + (C)	(B) Demand Related	(C) Energy Related	
1	2011 Forecasted	175,892	153,373	22,519	
2	2012 Forecasted	180,032	165,637	14,395	
3	2013 Forecasted	132,170	84,918	47,252	
4	2014 Forecasted	146,537	101,711	44,826	
5	2015 Forecasted	162,273	138,804	23,469	
6					
7	Growth Related Investments - (2011 to 2015 in $000's)	$796,904	$644,443	$152,461	
8					
9	System Growth mW's from 2011-2015	982			mW
10					
11	Marginal Investment (7) / (9)	$811.33	$656.11	$155.22	/kW
12					
13	Annualized Investment (11) x 8.85%	$71.80	$58.07	$13.74	/kW
14	Admin. & General Factor (11) x 1.52%	$12.33	$9.97	$2.36	/kW
15	Annual O&M Expenses (11) x 1.269%	$10.30	$8.33	$1.97	/kW
16					
17	Annualized Marginal Cost Sum (13) to (15)	$94.43	$76.37	$18.07	/kW
18					
19	Marginal Cost of Energy-Related Transmission			$0.00260	/kWh
20	$18.07 / 8760 hours / 79.35% Load Factor))				

Footnote:

Lines 1-7	Tab 6.2 (Transm2:) `2011-2015 Forecasted Transmission'
Line 9	Peak Load Forecast Detail, Dec. 16, 2009 - Forecasting Dept.
Line 13	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 8.85% factor)
Line 14	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 1.52% factor)
Line 15	Tab 6.3 (Tran_OM:) `Transmission O & M Expenses' (for 1.269% factor)
Line 20	See Tab "TransLF"

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Tran_OM

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

Line	Description	(A) 1999	(B) 2000	(C) 2001	(D) 2002	(E) 2003	(F) 2004	(G) 2005	(H) 2006	(I) 2007	(J) 2008	
1	Transmission O&M Exp.	83,874	103,968	123,213	102,419	105,962	105,324	115,283	136,930	154,195	174,010	
2	Wheeling	71,336	78,405	94,737	76,949	77,497	76,944	83,360	94,111	106,592	121,167	
3	Net Transmission O&M Line (1) - (2)	12,538	25,563	28,476	25,469	28,465	28,379	31,922	42,820	47,603	52,843	
4	Transmission Plant	2,135,940	2,172,469	2,232,246	2,299,173	2,396,665	2,487,677	2,578,317	2,688,839	2,874,659	3,054,529	
5	Tran. O&M Loading Line (3) / (4)	0.587%	1.177%	1.276%	1.108%	1.188%	1.141%	1.238%	1.593%	1.656%	1.730%	1.269%

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(3) page 321, line 96

Dist Sub 1

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
December 2011 Dollars

Line			
1	Incremental Substation Cost - $ / kW	$180.87	
2			
3	Annual Distribution Carrying Charge	10.81%	
4			
5	Substation Marginal Cost - $ / kW	$19.55	/ kW

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PacifiCorp
Oregon Marginal Cost Study
Hypothetical Circuit Study Results
Annual Demand and Commitment Costs
December 2011 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Demand				Commitment			
			Investment $ / kW **		Annual $ / kW **		Investment $ / Customer		Annual $ / Customer	
Line	Load Class		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 10.81%	(B) x 10.81%			(E) x 10.81%	(F) x 10.81%
1	Res - Schedule 4	(sec)	$183.53	$272.35	$19.84	$29.44	$739.70	$266.89	$79.96	$28.85
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$201.36	$294.87	$21.77	$31.88	$876.01	$316.07	$94.70	$34.17
5	15+ kW	(sec)	$201.36	$294.87	$21.77	$31.88	$876.01	$316.07	$94.70	$34.17
6	Primary	(pri)	$201.36	$294.87	$21.77	$31.88	$876.01	$316.07	$94.70	$34.17
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$126.46	$202.97	$13.67	$21.94	$356.67	$128.69	$38.56	$13.91
10	51-100 kW	(sec)	$126.46	$202.97	$13.67	$21.94	$356.67	$128.69	$38.56	$13.91
11	> 101kW	(sec)	$126.46	$202.97	$13.67	$21.94	$356.67	$128.69	$38.56	$13.91
12	Primary	(pri)	$126.46	$202.97	$13.67	$21.94	$356.67	$128.69	$38.56	$13.91
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$134.12	$213.43	$14.50	$23.07	$430.49	$155.33	$46.54	$16.79
16	301+ kW	(sec)	$134.12	$213.43	$14.50	$23.07	$430.49	$155.33	$46.54	$16.79
17	Primary	(pri)	$134.12	$213.43	$14.50	$23.07	$430.49	$155.33	$46.54	$16.79
18										
19	LPS - Schedule 48T									
20	1 - 4 MW	(sec)	$103.88	$174.97	$11.23	$18.91	$194.12	$70.04	$20.98	$7.57
21	1 - 4 MW	(pri)	$103.88	$174.97	$11.23	$18.91	$194.12	$70.04	$20.98	$7.57
22	> 4 MW	(sec)	$10.54	$20.09	$1.14	$2.17	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$7.67	$14.62	$0.83	$1.58	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$413.52	$546.96	$44.70	$59.13	$2,186.44	$788.88	$236.35	$85.28
26	Irrigation - Schedule 33*	(sec)	$499.88	$661.83	$54.04	$71.54	$2,959.14	$1,067.68	$319.88	$115.42

Footnotes:
**$ / kW are in terms of Distribution kW.
* Schedule 33 Cost of Service results are provided for informational purposes only.

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PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

Line	Class		(A) Annual MWH	(B) Number of Customers	(C) Average MWh per Customer (A) / (B)	(D) Distribution Peak MW	(E) Average kW per customer (D)/(B) * 1,000	(F) Percent Single Phase
1	Res - Schedule 4	(sec)	5,399,119	471,384	11.45	987	2.09	100.00%
2	GS - Schedule 23 - 0-15 kW	(sec)	643,510	66,246	9.71	93	1.41	83.07%
3	GS - Schedule 23 - 15+ kW	(sec)	484,537	9,576	50.60	65	6.81	42.83%
4	GS - Schedule 23 - Primary	(pri)	881	36	24.32	0	3.43	-
5	GS - Schedule 28 - 0-50 kW	(sec)	440,941	4,514	97.69	65	14.44	28.69%
6	GS - Schedule 28 - 51-100 kW	(sec)	677,599	3,555	190.60	111	31.30	13.61%
7	GS - Schedule 28 - > 101kW	(sec)	929,651	2,026	458.94	144	71.01	2.52%
8	GS - Schedule 28 - Primary	(pri)	18,109	53	339.01	3	54.86	-
9	GS - Schedule 30 - 0-300 kW	(sec)	204,717	244	840.15	30	124.86	0.41%
10	GS - Schedule 30 - 301+ kW	(sec)	1,057,551	594	1,780.89	162	273.58	0.17%
11	GS - Schedule 30 - Primary	(pri)	100,368	55	1,830.42	17	301.30	-
12	Irrigation - Sch 41	(sec)	134,557	6,168	21.82	17	2.81	19.58%
13	Schedule 33*- Irrigation	(sec)	104,511	2,184	47.85	13	6.16	-
14	LPS - Schedule 48T - 1 - 4 MW	(sec)	583,462	121	4,828.65	81	667.14	-
15	LPS - Schedule 48T - 1 - 4 MW	(pri)	437,587	58	7,577.27	56	963.06	-
16	LPS - Schedule 48T - > 4 MW	(sec)	57,861	2	28,930.40	6	3,114.88	-
17	LPS - Schedule 48T - > 4 MW	(pri)	1,177,408	33	35,679.04	141	4,279.13	-
18	Total -		12,452,371	566,848		1,993		

Customer Distribution on the Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
19	Res - Schedule 4 (sec)	0.96%	0.96%	0.96%	3.50%	3.50%	3.50%	86.61%	100.00%
20	GS - Schedule 23 - 0-15 kW (sec)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
21	GS - Schedule 23 - 15+ kW (sec)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
22	GS - Schedule 23 - Primary (pri)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
23	GS - Schedule 28 - 0-50 kW (sec)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
24	GS - Schedule 28 - 51-100 kW (sec)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
25	GS - Schedule 28 - > 101kW (sec)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
26	GS - Schedule 28 - Primary (pri)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
27	GS - Schedule 30 - 0-300 kW (sec)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
28	GS - Schedule 30 - 301+ kW (sec)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
29	GS - Schedule 30 - Primary (pri)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
30	Irrigation - Sch 41	2.42%	2.42%	2.42%	12.59%	12.59%	12.59%	54.96%	100.00%
31	Schedule 33*- Irrigation	4.51%	4.51%	4.51%	10.50%	10.50%	10.50%	54.96%	100.00%
32	LPS - Schedule 48T - 1 - 4 MW (sec)	0.16%	0.16%	0.16%	1.42%	1.42%	1.42%	95.26%	100.00%
33	LPS - Schedule 48T - 1 - 4 MW (pri)	0.16%	0.16%	0.16%	1.42%	1.42%	1.42%	95.26%	100.00%
34	LPS - Schedule 48T - > 4 MW (sec)		Large Customers are on dedicated circuits and are not included here						
35	LPS - Schedule 48T - > 4 MW (pri)		Large Customers are on dedicated circuits and are not included here						

Line	System property records & engineering information			
37	Number of pole feet in Oregon	74,689,291	Poles per mile	26.27
38	Number of pole miles in Oregon	14,146	Customers per mile	29.87
39	Number of trench feet in Oregon	25,508,565	MWH per customer	21.97
40	Number of trench miles in Oregon	4,831	MWH per circuit	22,477
41	Total miles in Oregon	18,977	Branches per circuit	7
42			Distance per circuit	34.25
43	Number of circuits in Oregon	554	Distance per branch	4.89
44	Number of poles in Oregon	371,574		

36 System property records & engineering information

45

46 12 kV circuit 12 miles long has approx. 3 miles of single phase.

47 which is approx. 25 percent of circuit distance.

48 8.56 = 25 percent of typical Oregon circuit

49

50 5 divide by outer branches

51 1.713 distance of single phase on outer branch

52 35.00% equals percentage of single phase outer branch Segments

53

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Circuit Model Study
Customer Distribution on the Hypothetical Circuit Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
		1	2	3	4	5	6	7	Total
1	Residential	0.96%	0.96%	0.96%	3.50%	3.50%	3.50%	86.61%	100.00%
2	GS 0-15 kW (sec) (23)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
3	GS >15 kW (sec) (23)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
4	GS (pri) (23)	1.24%	1.24%	1.24%	3.62%	3.62%	3.62%	85.41%	100.00%
5	GS < 50 kW (sec) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
6	GS 51-100 kW (sec) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
7	GS > 100 kW (sec) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
8	GS (pri) (28)	0.44%	0.44%	0.44%	1.82%	1.82%	1.82%	93.22%	100.00%
9	GS 0-300 kW (sec) (30)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
10	GS >300 kW (sec) (30)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
11	GS (pri) (30)	0.66%	0.66%	0.66%	1.51%	1.51%	1.51%	93.49%	100.00%
12	Irrigation	2.42%	2.42%	2.42%	12.59%	12.59%	12.59%	54.96%	100.00%
13	USBR / UKRB	4.51%	4.51%	4.51%	10.50%	10.50%	10.50%	54.96%	100.00%
14	Large GS 1 - 4 MW (sec)	0.16%	0.16%	0.16%	1.42%	1.42%	1.42%	95.26%	100.00%
15	Large GS 1 - 4 MW (pri)	0.16%	0.16%	0.16%	1.42%	1.42%	1.42%	95.26%	100.00%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-

Except where customers own their own transformers.

PacifiCorp
Oregon Circuit Model Study
Average Customers by Hypothetical Circuit Branch

Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
	1	2	3	4	5	6	7	Total

Average Customers

	Class	1	2	3	4	5	6	7	Total
1	Residential	8.20	8.20	8.20	29.78	29.78	29.78	736.95	850.87
2	GS 0-15 kW (sec) (23)	1.48	1.48	1.48	4.33	4.33	4.33	102.13	119.58
3	GS >15 kW (sec) (23)	0.21	0.21	0.21	0.63	0.63	0.63	14.76	17.29
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.07
5	GS < 50 kW (sec) (28)	0.04	0.04	0.04	0.15	0.15	0.15	7.60	8.15
6	GS 51-100 kW (sec) (28)	0.03	0.03	0.03	0.12	0.12	0.12	5.98	6.42
7	GS > 100 kW (sec) (28)	0.02	0.02	0.02	0.07	0.07	0.07	3.41	3.66
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.41	0.44
10	GS >300 kW (sec) (30)	0.01	0.01	0.01	0.02	0.02	0.02	1.00	1.07
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10
12	Irrigation	0.27	0.27	0.27	1.40	1.40	1.40	6.12	11.13
13	USBR / UKRB	0.18	0.18	0.18	0.41	0.41	0.41	2.17	3.94
14	Large GS 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.22
15	Large GS 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	10.43	10.43	10.43	36.92	36.92	36.92	881.07	1,023.13

Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 8.3
Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 4) Tab 8.4
Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state.
For Example 8.20 is 471,384 Residential Customers X .963% customers on Branch 1 divided by 554 circuits.

Percent of Customers

	Class	1	2	3	4	5	6	7	Total
1	Residential	78.57%	78.57%	78.57%	80.66%	80.66%	80.66%	83.64%	83.16%
2	GS 0-15 kW (sec) (23)	14.20%	14.20%	14.20%	11.74%	11.74%	11.74%	11.59%	11.69%
3	GS >15 kW (sec) (23)	2.05%	2.05%	2.05%	1.70%	1.70%	1.70%	1.68%	1.69%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	0.34%	0.34%	0.34%	0.40%	0.40%	0.40%	0.86%	0.80%
6	GS 51-100 kW (sec) (28)	0.27%	0.27%	0.27%	0.32%	0.32%	0.32%	0.68%	0.63%
7	GS > 100 kW (sec) (28)	0.15%	0.15%	0.15%	0.18%	0.18%	0.18%	0.39%	0.36%
8	GS (pri) (28)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
9	GS 0-300 kW (sec) (30)	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.05%	0.04%
10	GS >300 kW (sec) (30)	0.07%	0.07%	0.07%	0.04%	0.04%	0.04%	0.11%	0.10%
11	GS (pri) (30)	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.01%	0.01%
12	Irrigation	2.59%	2.59%	2.59%	3.80%	3.80%	3.80%	0.69%	1.09%
13	USBR / UKRB	1.71%	1.71%	1.71%	1.12%	1.12%	1.12%	0.25%	0.39%
14	Large GS 1 - 4 MW (sec)	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.02%	0.02%
15	Large GS 1 - 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Loads

		1	2	3	4	5	6	7	Total
19	1,2,3,6	10.4	10.4	10.4			36.9		68.2
20	1,2,3,4,5,6,7	10.4	10.4	10.4	36.9	36.9	36.9	881.1	1,023.1
21									
22	1,2,3,6	15.3%	15.3%	15.3%			54.1%		100.0%
23	1,2,3,4,5,6,7	1.0%	1.0%	1.0%	3.6%	3.6%	3.6%	86.1%	100.0%

PacifiCorp
Oregon Circuit Model Study
Circuit kW Load by Branch

Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
	1	2	3	4	5	6	7	Total

Circuit kW Loads

	Class	1	2	3	4	5	6	7	Total
1	Residential	17.2	17.2	17.2	62.4	62.4	62.4	1,543.0	1,781.5
2	GS 0-15 kW (sec) (23)	2.1	2.1	2.1	6.1	6.1	6.1	143.8	168.3
3	GS >15 kW (sec) (23)	1.5	1.5	1.5	4.3	4.3	4.3	100.5	117.7
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
5	GS < 50 kW (sec) (28)	0.5	0.5	0.5	2.1	2.1	2.1	109.7	117.7
6	GS 51-100 kW (sec) (28)	0.9	0.9	0.9	3.7	3.7	3.7	187.2	200.8
7	GS > 100 kW (sec) (28)	1.1	1.1	1.1	4.7	4.7	4.7	242.1	259.7
8	GS (pri) (28)	0.0	0.0	0.0	0.1	0.1	0.1	4.9	5.3
9	GS 0-300 kW (sec) (30)	0.4	0.4	0.4	0.8	0.8	0.8	51.3	54.9
10	GS >300 kW (sec) (30)	1.9	1.9	1.9	4.4	4.4	4.4	274.2	293.3
11	GS (pri) (30)	0.2	0.2	0.2	0.4	0.4	0.4	27.9	29.8
12	Irrigation	0.8	0.8	0.8	3.9	3.9	3.9	17.2	31.3
13	USBR / UKRB	1.1	1.1	1.1	2.6	2.6	2.6	13.4	24.3
14	Large GS 1 - 4 MW (sec)	0.2	0.2	0.2	2.1	2.1	2.1	138.6	145.5
15	Large GS 1 - 4 MW (pri)	0.2	0.2	0.2	1.4	1.4	1.4	95.6	100.4
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	28.0	28.0	28.0	99.0	99.0	99.0	2,949.5	3,330.6

Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 8.3
Source - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 8.5
Customers multiplied by circuit kW per customer.
For Example 17.2 is 8.20 Residential Customers multiplied by 2.09 average Dist. kW per Customer.

Percent of Branch Load

	Class	1	2	3	4	5	6	7	Total
1	Residential	61.27%	61.27%	61.27%	62.96%	62.96%	62.96%	52.31%	53.49%
2	GS 0-15 kW (sec) (23)	7.44%	7.44%	7.44%	6.16%	6.16%	6.16%	4.87%	5.05%
3	GS >15 kW (sec) (23)	5.20%	5.20%	5.20%	4.31%	4.31%	4.31%	3.41%	3.53%
4	GS (pri) (23)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
5	GS < 50 kW (sec) (28)	1.85%	1.85%	1.85%	2.16%	2.16%	2.16%	3.72%	3.53%
6	GS 51-100 kW (sec) (28)	3.15%	3.15%	3.15%	3.69%	3.69%	3.69%	6.35%	6.03%
7	GS > 100 kW (sec) (28)	4.07%	4.07%	4.07%	4.77%	4.77%	4.77%	8.21%	7.80%
8	GS (pri) (28)	0.08%	0.08%	0.08%	0.10%	0.10%	0.10%	0.17%	0.16%
9	GS 0-300 kW (sec) (30)	1.29%	1.29%	1.29%	0.84%	0.84%	0.84%	1.74%	1.65%
10	GS >300 kW (sec) (30)	6.91%	6.91%	6.91%	4.47%	4.47%	4.47%	9.30%	8.80%
11	GS (pri) (30)	0.70%	0.70%	0.70%	0.45%	0.45%	0.45%	0.95%	0.90%
12	Irrigation	2.71%	2.71%	2.71%	3.98%	3.98%	3.98%	0.58%	0.94%
13	USBR / UKRB	3.91%	3.91%	3.91%	2.58%	2.58%	2.58%	0.45%	0.73%
14	Large GS 1 - 4 MW (sec)	0.82%	0.82%	0.82%	2.09%	2.09%	2.09%	4.70%	4.37%
15	Large GS 1 - 4 MW (pri)	0.57%	0.57%	0.57%	1.44%	1.44%	1.44%	3.24%	3.01%
16	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
17	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
18	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Sum of Branch Loads

	1	2	3	4	5	6	7	Total
1,2,3,6	28.0	28.0	28.0			99.0		183.1
1,2,3,4,5,6,7	28.0	28.0	28.0	99.0	99.0	99.0	2,949.5	3,330.6

	1	2	3	4	5	6	7	Total
1,2,3,6	15.3%	15.3%	15.3%			54.1%		100.0%
1,2,3,4,5,6,7	0.8%	0.8%	0.8%	3.0%	3.0%	3.0%	88.6%	100.0%

PacifiCorp
Oregon Circuit Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

Wire Sizes	Account 364 Pole Cost per Mile: Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR	$ 31,531	0.990	$ 31,216	$ 11,771	$ 42,987
3 Phase - 1/0 ACSR 1\0 ACSR	$ 37,600	0.990	$ 37,224	$ 24,157	$ 61,381
3 Phase - 447 AAC & 4\0 AAC	$ 43,923	0.990	$ 43,484	$ 39,582	$ 83,066
3 Phase -795 AAC & 477 AAC	$ 47,673	0.990	$ 47,196	$ 94,037	$ 141,233

	State Specific Account 364 Pole Statistics				Adjustment
State	**Poles**	**Pole Feet**	**Pole Miles**	**Poles / Mile**	**Factor**
California	55,376	12,117,471	2,295	24.13	0.909
Idaho	101,768	23,191,716	4,392	23.17	0.873
Oregon	371,574	74,689,291	14,146	26.27	0.990
Utah	363,003	60,744,533	11,505	31.55	1.189
Washington	98,596	18,718,373	3,545	27.81	1.048
Wyoming	154,013	38,258,772	7,246	21.25	0.801
Total	1,144,330	227,720,156	43,129	26.53	1.000

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 ACSR	3 Phase - 1/0 ACSR 1\0 ACSR	Total	
Poles	$ 53,464	$ 118,400	$ 171,864	
Conductors	$ 20,160	$ 76,837	$ 96,998	
Total	$ 73,624	$ 195,238	$ 268,862	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 212,786		$ 230,953	
Conductors	$ 193,693		$ 460,167	
Total	$ 406,480		$ 691,120	

Miles per Branch	4.89
Single Phase Miles Per Branch	1.71
Three Phase Miles Per Branch	3.18

Source: Input Tab

Commitment and Demand Costs Per Branch

	Poles			Conductor		
Wire Sizes	**Total Cost**	**Commitment**	**Demand**	**Total Cost**	**Commitment**	**Demand**
Branches 1,2,3,4,5						
1 Phase -1/0 ACSR	$ 53,464	$ 53,464	$ -	$ 20,160	$ 20,160	$ -
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 99,289	$ 19,111	$ 76,837	$ 37,441	$ 39,397
Total Branches 1,2,3,4,5	$ 171,864	$ 152,753	$ 19,111	$ 96,998	$ 57,601	$ 39,397
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 212,786	N/A	$ 212,786	$ 193,693	N/A	$ 193,693
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 230,953	N/A	$ 230,953	$ 460,167	N/A	$ 460,167
Total All Branches	$ 1,303,059	$ 763,765	$ 539,295	$ 1,138,849	$ 288,005	$ 850,844

PacifiCorp
Oregon Circuit Model Study
Calculation of Hypothetical Circuit Model Branch Cost

Conductors Type	(A)	(B)	(C)	(D)	(E)	(F)
	Total Cost		Commitment Cost		Demand Cost	
	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total segment	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 2						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 3						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 4						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 5						
1 Phase -1/0 ACSR	$ 53,464	$ 20,160	$ 53,464	$ 20,160	NA	NA
3 Phase - 1/0 ACSR 1\0 ACSR	$ 118,400	$ 76,837	$ 99,289	$ 37,441	$ 19,111	$ 39,397
Total Segments	$ 171,864	$ 96,998	$ 152,753	$ 57,601	$ 19,111	$ 39,397
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$ 212,786	$ 193,693	NA	NA	$ 212,786	$ 193,693
Total Segments	$ 212,786	$ 193,693	$ -	$ -	$ 212,786	$ 193,693
Branch 7						
3 Phase -795 AAC & 477 AAC	$ 230,953	$ 460,167	NA	NA	$ 230,953	$ 460,167
Total segment	$ 230,953	$ 460,167	$ -	$ -	$ 230,953	$ 460,167
$2,441,909	**$1,303,059**	**$1,138,849**	**$763,765**	**$288,005**	**$539,295**	**$850,844**

Source - 'System-wide Pole and Conductor Costs' (PC 7) Tab 8.7

PacifiCorp
Oregon Circuit Model Study
Poles Demand Calculations
Branch 6 & 7 Cost Assignment

Line	**Poles**	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	15.30%	15.30%	15.30%	NA	NA	54.10%	NA	100.00%	
2	Branch 6 Cost	$ 32,556	$ 32,556	$ 32,556	NA	NA	$ 115,119	NA	$ 212,786	**$ / kW**
3	% Demand	0.84%	0.84%	0.84%	2.97%	2.97%	2.97%	88.56%	100.00%	
4	Branch 7 Cost	$ 1,942	$ 1,942	$ 1,942	$ 6,867	$ 6,867	$ 6,867	$ 204,525	$ 230,953	
5	Branch Demand Cost	$ 19,111	$ 19,111	$ 19,111	$ 19,111	$ 19,111	NA	NA		Average
6	Total	$ 53,609	$ 53,609	$ 53,609	$ 25,978	$ 25,978	$ 121,987	$ 204,525	$ 539,295	$ 161.92
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 32,846	$ 32,846	$ 32,846	$ 16,356	$ 16,356	$ 76,801	$ 106,993	$ 315,044	$ 176.84
11	GS 0-15 kW (sec) (23)	$ 3,991	$ 3,991	$ 3,991	$ 1,601	$ 1,601	$ 7,516	$ 9,970	$ 32,661	$ 194.02
12	GS >15 kW (sec) (23)	$ 2,790	$ 2,790	$ 2,790	$ 1,119	$ 1,119	$ 5,253	$ 6,968	$ 22,827	$ 194.02
13	GS (pri) (23)	$ 5	$ 5	$ 5	$ 2	$ 2	$ 10	$ 13	$ 44	$ 194.02
14	GS < 50 kW (sec) (28)	$ 990	$ 990	$ 990	$ 562	$ 562	$ 2,638	$ 7,605	$ 14,336	$ 121.85
15	GS 51-100 kW (sec) (28)	$ 1,689	$ 1,689	$ 1,689	$ 959	$ 959	$ 4,504	$ 12,983	$ 24,473	$ 121.85
16	GS > 100 kW (sec) (28)	$ 2,184	$ 2,184	$ 2,184	$ 1,240	$ 1,240	$ 5,822	$ 16,785	$ 31,639	$ 121.85
17	GS (pri) (28)	$ 44	$ 44	$ 44	$ 25	$ 25	$ 119	$ 342	$ 645	$ 121.85
18	GS 0-300 kW (sec) (30)	$ 694	$ 694	$ 694	$ 217	$ 217	$ 1,021	$ 3,560	$ 7,097	$ 129.23
19	GS >300 kW (sec) (30)	$ 3,705	$ 3,705	$ 3,705	$ 1,161	$ 1,161	$ 5,450	$ 19,012	$ 37,898	$ 129.23
20	GS (pri) (30)	$ 377	$ 377	$ 377	$ 118	$ 118	$ 554	$ 1,933	$ 3,854	$ 129.23
21	Irrigation	$ 1,451	$ 1,451	$ 1,451	$ 1,033	$ 1,033	$ 4,850	$ 1,192	$ 12,462	$ 398.46
22	USBR / UKRB	$ 2,099	$ 2,099	$ 2,099	$ 669	$ 669	$ 3,142	$ 926	$ 11,701	$ 481.67
23	Large GS 1 - 4 MW (sec)	$ 440	$ 440	$ 440	$ 543	$ 543	$ 2,548	$ 9,612	$ 14,566	$ 100.10
24	Large GS 1 - 4 MW (pri)	$ 304	$ 304	$ 304	$ 374	$ 374	$ 1,758	$ 6,631	$ 10,049	$ 100.10
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 53,609	$ 53,609	$ 53,609	$ 25,978	$ 25,978	$ 121,987	$ 204,525	$ 539,295	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6) Tab 8.6
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $212,786
Line 1 X $212,786
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $230,953
Line 3 X $230,953
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6) Tab 8.6

PacifiCorp
Oregon Circuit Model Study
Conductor Demand Calculations
Branch 6 & 7 Cost Assignment

	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% Demand	15.30%	15.30%	15.30%	NA	NA	54.10%	NA	100.00%	
2	Branch 6 Cost	$ 29,634	$ 29,634	$ 29,634	NA	NA	$ 104,790	NA	$ 193,693	**$ / kW**
3	% Demand	0.84%	0.84%	0.84%	2.97%	2.97%	2.97%	88.56%	100.00%	
4	Branch 7 Cost	$ 3,869	$ 3,869	$ 3,869	$ 13,683	$ 13,683	$ 13,683	$ 407,510	$ 460,167	
5	Branch Demand Cost	$ 39,397	$ 39,397	$ 39,397	$ 39,397	$ 39,397	NA	NA		average
6	Total	$ 72,901	$ 72,901	$ 72,901	$ 53,080	$ 53,080	$ 118,473	$ 407,510	$ 850,844	$ 255.46
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 44,666	$ 44,666	$ 44,666	$ 33,418	$ 33,418	$ 74,589	$ 213,180	$ 488,605	$ 274.27
11	GS 0-15 kW (sec) (23)	$ 5,427	$ 5,427	$ 5,427	$ 3,271	$ 3,271	$ 7,300	$ 19,864	$ 49,987	$ 296.95
12	GS >15 kW (sec) (23)	$ 3,793	$ 3,793	$ 3,793	$ 2,286	$ 2,286	$ 5,102	$ 13,884	$ 34,937	$ 296.95
13	GS (pri) (23)	$ 7	$ 7	$ 7	$ 4	$ 4	$ 10	$ 27	$ 67	$ 296.95
14	GS < 50 kW (sec) (28)	$ 1,346	$ 1,346	$ 1,346	$ 1,148	$ 1,148	$ 2,562	$ 15,153	$ 24,048	$ 204.40
15	GS 51-100 kW (sec) (28)	$ 2,297	$ 2,297	$ 2,297	$ 1,960	$ 1,960	$ 4,374	$ 25,868	$ 41,054	$ 204.40
16	GS > 100 kW (sec) (28)	$ 2,970	$ 2,970	$ 2,970	$ 2,534	$ 2,534	$ 5,655	$ 33,443	$ 53,074	$ 204.40
17	GS (pri) (28)	$ 61	$ 61	$ 61	$ 52	$ 52	$ 115	$ 681	$ 1,081	$ 204.40
18	GS 0-300 kW (sec) (30)	$ 944	$ 944	$ 944	$ 444	$ 444	$ 991	$ 7,094	$ 11,804	$ 214.94
19	GS >300 kW (sec) (30)	$ 5,038	$ 5,038	$ 5,038	$ 2,371	$ 2,371	$ 5,293	$ 37,880	$ 63,031	$ 214.94
20	GS (pri) (30)	$ 512	$ 512	$ 512	$ 241	$ 241	$ 538	$ 3,852	$ 6,410	$ 214.94
21	Irrigation	$ 1,974	$ 1,974	$ 1,974	$ 2,111	$ 2,111	$ 4,711	$ 2,375	$ 17,227	$ 550.82
22	USBR / UKRB	$ 2,854	$ 2,854	$ 2,854	$ 1,367	$ 1,367	$ 3,051	$ 1,845	$ 16,191	$ 666.50
23	Large GS 1 - 4 MW (sec)	$ 598	$ 598	$ 598	$ 1,109	$ 1,109	$ 2,475	$ 19,151	$ 25,639	$ 176.20
24	Large GS 1 - 4 MW (pri)	$ 413	$ 413	$ 413	$ 765	$ 765	$ 1,708	$ 13,213	$ 17,689	$ 176.20
25	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 72,901	$ 72,901	$ 72,901	$ 53,080	$ 53,080	$ 118,473	$ 407,510	$ 850,844	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6) Tab 8.6
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $193,693
Line 1 X $193,693
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $460,167
Line 3 X $460,167
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6) Tab 8.6

PacifiCorp
Oregon Circuit Model Study
Poles Commitment Calculations
Branch 1, 2, 3, 4 & 5 Cost Assignment

	Poles	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% customer	15.29%	15.29%	15.29%	NA	NA	54.12%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	**$ Per**
3	% customer	1.02%	1.02%	1.02%	3.61%	3.61%	3.61%	86.12%	100.00%	**Customer**
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ 152,753	NA	NA		average
6	Total	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ -	$ -	$ 763,765	$ 746.50
7										
8									Total	**$ Per**
9									Commitment	**Customer**
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 120,017	$ 120,017	$ 120,017	$ 123,207	$ 123,207	$ -	$ -	$ 606,463	$ 712.75
12	GS 0-15 kW (sec) (23)	$ 21,690	$ 21,690	$ 21,690	$ 17,933	$ 17,933	$ -	$ -	$ 100,936	$ 844.10
13	GS >15 kW (sec) (23)	$ 3,135	$ 3,135	$ 3,135	$ 2,592	$ 2,592	$ -	$ -	$ 14,590	$ 844.10
14	GS (pri) (23)	$ 12	$ 12	$ 12	$ 10	$ 10	$ -	$ -	$ 55	$ 844.10
15	GS < 50 kW (sec) (28)	$ 524	$ 524	$ 524	$ 614	$ 614	$ -	$ -	$ 2,800	$ 343.68
16	GS 51-100 kW (sec) (28)	$ 413	$ 413	$ 413	$ 483	$ 483	$ -	$ -	$ 2,205	$ 343.68
17	GS > 100 kW (sec) (28)	$ 235	$ 235	$ 235	$ 275	$ 275	$ -	$ -	$ 1,257	$ 343.68
18	GS (pri) (28)	$ 6	$ 6	$ 6	$ 7	$ 7	$ -	$ -	$ 33	$ 343.68
19	GS 0-300 kW (sec) (30)	$ 43	$ 43	$ 43	$ 27	$ 27	$ -	$ -	$ 182	$ 414.81
20	GS >300 kW (sec) (30)	$ 104	$ 104	$ 104	$ 67	$ 67	$ -	$ -	$ 445	$ 414.81
21	GS (pri) (30)	$ 10	$ 10	$ 10	$ 6	$ 6	$ -	$ -	$ 41	$ 414.81
22	Irrigation	$ 3,953	$ 3,953	$ 3,953	$ 5,799	$ 5,799	$ -	$ -	$ 23,456	$ 2,106.80
23	USBR / UKRB	$ 2,605	$ 2,605	$ 2,605	$ 1,712	$ 1,712	$ -	$ -	$ 11,241	$ 2,851.36
24	Large GS 1 - 4 MW (sec)	$ 5	$ 5	$ 5	$ 13	$ 13	$ -	$ -	$ 41	$ 187.05
25	Large GS 1 - 4 MW (pri)	$ 2	$ 2	$ 2	$ 6	$ 6	$ -	$ -	$ 19	$ 187.05
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Check Total	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ 152,753	$ -	$ -	$ 763,765	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 8.5
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 8.5

PacifiCorp
Oregon Circuit Model Study
Conductor Commitment Calculations
Branch 1, 2, 3, 4 & 5 Cost Assignment

	Conductors	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Branch	1	2	3	4	5	6	7		
1	% customer	15.29%	15.29%	15.29%	NA	NA	54.12%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	**$ Per**
3	% customer	1.02%	1.02%	1.02%	3.61%	3.61%	3.61%	86.12%	100.00%	**Customer**
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 57,601	$ 57,601	$ 57,601	$ 57,601	$ 57,601	NA	NA		average
6	Total	$ 57,601	$ 57,601	$ 57,601	$ 57,601	$ 57,601	$ -	$ -	$ 288,005	$ 281.49
7										
8									Total	**$ Per**
9									Commitment	**Customer**
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 45,257	$ 45,257	$ 45,257	$ 46,460	$ 46,460	$ -	$ -	$ 228,689	$ 268.77
12	GS 0-15 kW (sec) (23)	$ 8,179	$ 8,179	$ 8,179	$ 6,762	$ 6,762	$ -	$ -	$ 38,061	$ 318.30
13	GS >15 kW (sec) (23)	$ 1,182	$ 1,182	$ 1,182	$ 978	$ 978	$ -	$ -	$ 5,502	$ 318.30
14	GS (pri) (23)	$ 4	$ 4	$ 4	$ 4	$ 4	$ -	$ -	$ 21	$ 318.30
15	GS < 50 kW (sec) (28)	$ 198	$ 198	$ 198	$ 231	$ 231	$ -	$ -	$ 1,056	$ 129.60
16	GS 51-100 kW (sec) (28)	$ 156	$ 156	$ 156	$ 182	$ 182	$ -	$ -	$ 832	$ 129.60
17	GS > 100 kW (sec) (28)	$ 89	$ 89	$ 89	$ 104	$ 104	$ -	$ -	$ 474	$ 129.60
18	GS (pri) (28)	$ 2	$ 2	$ 2	$ 3	$ 3	$ -	$ -	$ 12	$ 129.60
19	GS 0-300 kW (sec) (30)	$ 16	$ 16	$ 16	$ 10	$ 10	$ -	$ -	$ 69	$ 156.42
20	GS >300 kW (sec) (30)	$ 39	$ 39	$ 39	$ 25	$ 25	$ -	$ -	$ 168	$ 156.42
21	GS (pri) (30)	$ 4	$ 4	$ 4	$ 2	$ 2	$ -	$ -	$ 15	$ 156.42
22	Irrigation	$ 1,490	$ 1,490	$ 1,490	$ 2,187	$ 2,187	$ -	$ -	$ 8,845	$ 794.45
23	USBR / UKRB	$ 982	$ 982	$ 982	$ 646	$ 646	$ -	$ -	$ 4,239	$ 1,075.21
24	Large GS 1 - 4 MW (sec)	$ 2	$ 2	$ 2	$ 5	$ 5	$ -	$ -	$ 15	$ 70.53
25	Large GS 1 - 4 MW (pri)	$ 1	$ 1	$ 1	$ 2	$ 2	$ -	$ -	$ 7	$ 70.53
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Check Total	$ 57,601	$ 57,601	$ 57,601	$ 57,601	$ 57,601	$ -	$ -	$ 288,005	

Sources: Line 1 & 3 - 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 8.5
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $ 0
Line 1 X $ 0
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8 For $ 0
Line 3 X $ 0
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) Tab 8.8
Line 7 to 18 - Line 6 X Percent of Customers 'Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 8.5

PacifiCorp
Oregon Circuit Model Study
Dedicated Circuit Trunk Costs
For Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	$ 47,196	$ 94,037	$ 47,196	$ 94,037
2 Average Trunk Length	0.67	miles	0.67	miles
3 Total Construction Cost	$ 31,622	$ 63,005	$ 31,622	$ 63,005
4 Customer Peak Demand	4,279	kW	3,115	kW
5 Demand Cost $/kW	$7.39	$14.72	$10.15	$20.23

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 7) Tab 8.7
Line 2 - Distribution Engineering Studies
Line 3 - Line 1 multiplied by Line 2
Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 3) Tab 8.3
Line 5 - Line 3 divided by Line 4

PacifiCorp
Oregon Circuit Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

	(A)	(B)	(C)	(D)	(E)	(F)		
	Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
Residential	$ 712.75	$ 268.77	$ 176.84	$ 274.27	850.9	1,781.50	$ 315,044	$ 488,605
GS 0-15 kW (sec) (23)	$ 844.10	$ 318.30	$ 194.02	$ 296.95	119.6	168.33	$ 32,661	$ 49,987
GS >15 kW (sec) (23)	$ 844.10	$ 318.30	$ 194.02	$ 296.95	17.3	117.65	$ 22,827	$ 34,937
GS (pri) (23)	$ 844.10	$ 318.30	$ 194.02	$ 296.95	0.1	0.22	$ 44	$ 67
GS < 50 kW (sec) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	8.1	117.65	$ 14,336	$ 24,048
GS 51-100 kW (sec) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	6.4	200.85	$ 24,473	$ 41,054
GS > 100 kW (sec) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	3.7	259.66	$ 31,639	$ 53,074
GS (pri) (28)	$ 343.68	$ 129.60	$ 121.85	$ 204.40	0.1	5.29	$ 645	$ 1,081
GS 0-300 kW (sec) (30)	$ 414.81	$ 156.42	$ 129.23	$ 214.94	0.4	54.92	$ 7,097	$ 11,804
GS >300 kW (sec) (30)	$ 414.81	$ 156.42	$ 129.23	$ 214.94	1.1	293.25	$ 37,898	$ 63,031
GS (pri) (30)	$ 414.81	$ 156.42	$ 129.23	$ 214.94	0.1	29.82	$ 3,854	$ 6,410
Irrigation	$ 2,106.80	$ 794.45	$ 398.46	$ 550.82	11.1	31.28	$ 12,462	$ 17,227
USBR / UKRB	$ 2,851.36	$ 1,075.21	$ 481.67	$ 666.50	3.9	24.29	$ 11,701	$ 16,191
Large GS 1 - 4 MW (sec)	$ 187.05	$ 70.53	$ 100.10	$ 176.20	0.2	145.51	$ 14,566	$ 25,639
Large GS 1 - 4 MW (pri)	$ 187.05	$ 70.53	$ 100.10	$ 176.20	0.1	100.39	$ 10,049	$ 17,689
Total -	$ 746.50	$ 281.49	$ 161.92	$ 255.46	1,023.1	3,330.6	$ 539,295	$ 850,844
Large GS + 4 MW (sec)	$ -	$ -	$ 10.15	$ 20.23	-	3,114.88	$ 31,622	$ 63,005
Large GS + 4 MW (pri)	$ -	$ -	$ 7.39	$ 14.72	-	4,279.13	$ 31,622	$ 63,005
							$ 602,538	$ 976,854

	Commitment	Demand	Total
Poles	$ 763,765	$ 602,538	$ 1,366,302
Conductor	$ 288,005	$ 976,854	$ 1,264,859
Total	$ 1,051,770	$ 1,579,391	$ 2,631,161

Source : Column (A) - Poles Commitment Calculations' (PC 11) Tab 8.11
Column (B) - Conductor Commitment Calculations' (PC 12) Tab 8.12
Column (C) - Poles Demand Calculations' (PC 9) Tab 8.9
Column (D) - Conductor Demand Calculations' (PC 10) Tab 8.10
Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 5) Tab 8.5
Column (F) - Circuit kW Load by Branch' (PC 6) Tab 8.6

PacifiCorp
Oregon Marginal Cost Study
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran.	(D) # Cust. / Tran.	(E) Transformer $ / Cust.	(F) Average Customers	(G) Tot. Trans. Commitment $
				(A) x (B)		(C) / (D)		(E) x (F)
1	Res - Schedule 4	100.00%	354.78	354.78	3.75	$94.61	484,011	$45,792,281
2								
3	GS - Schedule 23							
4	1 Phase	83.07%	354.78	294.70	2.54	$116.02		
5	3 Phase	16.93%	982.99	166.46	1.42	$117.23		
6	0-15 kW	100.00%				$233.25	64,803	$15,115,233
7								
8	1 Phase	42.83%	354.78	151.94	2.54	$59.82		
9	3 Phase	57.17%	982.99	562.02	1.42	$395.79		
10	15+ kW	100.00%				$455.61	9,367	$4,267,677
11								
12	Primary	100.00%	-	-	0.00	0	37	$0
13								
14	GS - Schedule 28							
15	1 Phase	28.69%	354.78	101.78	1.59	$64.01		
16	3 Phase	71.31%	982.99	700.98	1.00	$700.98		
17	0-50 kW	100.00%				$764.99	4,635	$3,545,740.60
18								
19	1 Phase	13.61%	354.78	48.30	1.59	$30.38		
20	3 Phase	86.39%	982.99	849.16	1.00	$849.16		
21	51-100 kW	100.00%				$879.54	3,650	$3,210,311
22								
23	1 Phase	2.52%	354.78	8.93	1.59	$5.62		
24	3 Phase	97.48%	982.99	958.25	1.00	$958.25		
25	> 101kW	100.00%				$963.87	2,080	$2,004,842
26								
27	Primary	100.00%	-	-	0.00	0	53	$0
28								
29	GS - Schedule 30							
30	1 Phase	0.41%	354.78	1.46	1.71	$0.85		
31	3 Phase	99.59%	982.99	978.94	1.06	$923.53		
32	0-300 kW	100.00%				$924.38	241	$222,776
33								
34	1 Phase	0.17%	354.78	0.60	1.71	$0.35		
35	3 Phase	99.83%	982.99	981.33	1.06	$925.78		
36	301+ kW	100.00%				$926.13	586	$542,714
37								
38	Primary	100.00%	-	-	0.00	0	54	$0
39								
40	LPS - Schedule 48T							
41	1 - 4 MW (sec)	100.00%	982.99	982.99	1.00	982.99	120	$117,959
42	1 - 4 MW (pri)	100.00%	-	-	0.00	0	57	$0
43	> 4 MW (sec)	100.00%	982.99	982.99	1.00	982.99	2	$1,966
44	> 4 MW (pri)	100.00%	-	-	0.00	0	33	$0
45	Trans (trn)	100.00%	-	-	0.00	0	2	$0
46								
47	Schedule 41- Irrigation							
48	1 Phase	19.58%	354.78	69.48	1.73	$40.16		
49	3 Phase	80.42%	982.99	790.47	1.00	$790.47		
50	Total	100.00%				$830.63	6,211	$5,159,054
51								
52	Schedule 33*- Irrigation							
53	1 Phase	3.21%	354.78	11.37	1.73	$6.57		
54	3 Phase	96.79%	982.99	951.48	1.00	$951.48		
55	Total	100.00%				$958.05	2,056	$1,969,755

* Schedule 33 Cost of Service results are provided for informational purposes only.

XFMR 2

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand Costs

Line	Customer Type		(A) Weighted $ / kW	(B) Transformer Peak kW's	(C) Tot. Trans. Demand $ (A) x (B)
1	Res - Schedule 4	(sec)	$1.83	3,239,786	$5,928,809
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	$1.83	172,396	$315,485
5	15+ kW	(sec)	$1.83	123,533	$226,066
6	Primary	(pri)	$0.00	0	$0
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	$1.83	161,869	$296,220
10	51-100 kW	(sec)	$1.83	211,197	$386,490
11	> 101kW	(sec)	$1.83	238,749	$436,910
12	Primary	(pri)	$0.00	0	$0
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	$1.83	45,668	$83,572
16	301+ kW	(sec)	$1.83	256,588	$469,557
17	Primary	(pri)	$1.83	0	$0
18					
19					
20	LPS - Schedule 48T				
21	1 - 4 MW	(sec)	$1.83	137,133	$250,954
22	1 - 4 MW	(pri)	$0.00	0	$0
23	> 4 MW	(sec)	$1.83	215,142	$393,709
24	> 4 MW	(pri)	$0.00	0	$0
25	Trans	(trn)	$0.00	0	$0
26					
27	Irrigation - Schedule 41 (Average)				
28	Secondary	(sec)	$1.83	83,880	$153,501
29					
30	Irrigation - Schedule 33* (Average)				
31	Secondary	(sec)	$1.83	71,696	$131,203
32					
33	Totals			4,885,941	$8,941,273

Footnote: * Schedule 33 Cost of Service results are provided for information

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PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	34,852,307	42,485,996	48,122,256	48,559,856	48,811,823	71,993,550	67,011,911	68,781,531	71,602,482	73,614,647
2	Less:										
3	585 St Ltg & Signal Systems	-	-	-	-	13,067	89,965	45,553	48,057	75,549	64,882
4	586 Meter Expense	-	-	1,479,307	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057	2,848,811
5	587 Customer Installation Expense	332,819	132,472	11,531	9,542	90,751	62,896	-	-	3,636,287	3,568,921
6	596 Main. of St Ltg & Signal Systems	249,477	289,510	609,632	814,491	756,545	885,374	843,436	851,273	945,804	910,118
7	597 Main. of Meters	1,047,453	674,571	664,777	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945	1,433,131
8											
9	Total Adjusted Distribution O & M Expense	33,222,557	41,389,443	45,357,009	45,110,206	44,750,901	67,825,184	62,652,513	64,154,665	63,177,840	64,788,784
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	Distribution Plant										
14	Total Distribution Plant	1,192,703,978	1,235,859,101	1,271,410,972	1,303,063,520	1,341,098,219	1,384,196,236	1,431,636,624	1,476,365,173	1,530,307,351	1,590,201,846
15	Less:										
16	370 Meters	56,597,405	55,765,666	56,108,548	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811	59,791,712
17	373 Street Lighting	14,339,640	15,038,442	15,408,466	16,135,274	16,827,066	17,637,977	18,351,472	19,120,699	20,208,050	21,082,794
18											
19	Adjusted Distribution Plant	1,121,766,933	1,165,054,993	1,199,893,958	1,229,861,243	1,267,442,464	1,309,852,465	1,355,189,989	1,398,787,483	1,450,930,490	1,509,327,340
20	Line 14 - Line 16 - Line 17										
21											
22											
23	O & M Expense Loading Factor										
24	Distribution O & M Loading	2.96%	3.55%	3.78%	3.67%	3.53%	5.18%	4.62%	4.59%	4.35%	4.29%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	4.05%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	10.81%									
31											
32	Annualized Distribution O & M Loading Factor	37.47%									
33	Line 27 / Line 30										

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	471,384	100.00%	100.00%		$110	$109.53	$109.53	
2	Annualized - (Line 1) x 10.81%						$11.84	$11.84	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	50,552	76.31%	91.87%		$91	$69.58	$83.76	
7	kW = 0, 3 Phase	3,500	5.28%		31.20%	$261	$13.79		$81.46
8	kW > 1, 1 Phase	4,476	6.76%	8.13%		$198	$13.37	$16.10	
9	kW > 1, 3 Phase	7,718	11.65%		68.80%	$261	$30.42		$179.64
10	Total 0-15 kW	66,246	100.00%	100.00%	100.00%		$127.16	$99.86	$261.10
11	Annualized - (Line 10) x 10.81%						$13.75	$10.79	$28.22
12									
13	15+ kW								
14	1 Phase	4,101	42.83%	100.00%		$216	$92.29	$215.51	
15	3 Phase W/O KVAR	4,490	46.89%		82.01%	$261	$122.42		$214.12
16	3 Phase With KVAR	985	10.29%		17.99%	$423	$43.48		$76.05
17	Total 15+ kW	9,576	100.00%	100.00%	100.00%		$258.19	$215.51	$290.17
18	Annualized - (Line 17) x 10.81%						$27.91	$23.30	$31.37
19									
20	Primary								
21	12.47 KV 4-wire Wye OH	36	100.00%		100.00%	$8,651	$8,651.44		$8,651.44
22	Annualized - (Line 21) x 10.81%						$935.22	$0.00	$935.22
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	1	0.02%	0.08%		$216	$0.05	$0.17	
27	kW = 0, 3 Phase	4	0.09%		0.12%	$261	$0.23		$0.32
28	kW > 1, 1 Phase	1,294	28.67%	99.92%		$216	$61.78	$215.34	
29	kW > 1, 3 Phase	3,215	71.22%		99.88%	$261	$185.96		$260.77
30	Total 0-50 kW	4,514	100.00%	100.00%	100.00%		$248.02	$215.51	$261.09
31	Annualized - (Line 30) x 10.81%						$26.81	$23.30	$28.22
32									
33	51-100 kW								
34	1 Phase	484	13.61%	100.00%		$216	$29.34	$215.51	
35	3 Phase W/O KVAR	1,772	49.85%		57.70%	$261	$130.14		$150.66
36	3 Phase With KVAR	1,299	36.54%		42.30%	$423	$154.47		$178.81
37	Total 51-100 kW	3,555	100.00%	100.00%	100.00%		$313.95	$215.51	$329.47
38	Annualized - (Line 37) x 10.81%						$33.94	$23.30	$35.62
39									
40	> 101kW								
41	1 Phase	51	2.52%	100.00%		$896	$22.56	$896.23	
42	3 Phase W/O KVAR	822	40.57%		41.62%	$1,443	$585.58		$600.70
43	3 Phase With KVAR	1,153	56.91%		58.38%	$1,443	$821.38		$842.59
44	Total > 101kW	2,026	100.00%	100.00%	100.00%		$1,429.52	$896.23	$1,443.29
45	Annualized - (Line 44) x 10.81%						$154.53	$96.88	$156.02
46									
47	Primary								
48	12.47 KV 4-wire Wye OH	53	100.00%		100.00%	$8,651	$8,651.44		$8,651.44
49	Annualized - (Line 48) x 10.81%						$935.22	$0.00	$935.22

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2009.

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
GS - Schedule 30 / LPS - Schedule 48T / Irrigation - Schedule 41 (Annual)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E) (F) x 10.81%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	1	0.41%	100.00%		$896	$3.69	$896.23	
4	3 Phase W/O KVAR	41	16.87%		16.94%	$1,443	$243.52		$244.52
5	3 Phase With KVAR	201	82.72%		83.06%	$1,443	$1,193.83		$1,198.76
6	Total 0-300 kW	243	100.00%	100.00%	100.00%		$1,441.04	$896.23	$1,443.28
7	Annualized - (Line 6) x 10.81%						$155.78	$96.88	$156.02
8									
9	301+ kW								
10	1 Phase	1	0.17%	100.00%		$980	$1.65	$980.15	
11	3 Phase W/O KVAR	79	13.32%		13.34%	$1,443	$192.28		$192.60
12	3 Phase With KVAR	513	86.51%		86.66%	$1,443	$1,248.58		$1,250.69
13	301+ kW	593	100.00%	100.00%	100.00%		$1,442.51	$980.15	$1,443.29
14	Annualized - (Line 13) x 10.81%						$155.94	$105.95	$156.02
15									
16	Primary								
17	12.47 KV 4-wire Wye OH	55	100.00%		100.00%	$8,651	$8,651.44		$8,651.44
18	Annualized - (Line 17) x 10.81%						$935.22		$935.22
19									
20	LPS - Schedule 48T								
21	1 - 4 MW (sec)	121	100.00%		100.00%	$2,249	$2,249.37		$243.16
22	1 - 4 MW (pri)	58	100.00%		100.00%	$8,651	$8,651.44		$935.22
23	> 4 MW (sec)	2	100.00%		100.00%	$2,249	$2,249.37		$243.16
24	> 4 MW (pri)	33	100.00%		100.00%	$8,651	$8,651.44		$935.22
25	Trans (trn)	2	100.00%		100.00%	$306,078	$306,077.50		$33,086.98
26		216							
27	Irrigation - Schedule 41 (Annual)								
28	0 - 50 kW								
29	kW = 0, 1 Phase	162	2.63%	13.41%		$91	$2.39	$12.23	
30	kW = 0, 3 Phase	702	11.38%		14.15%	$261	$29.72		$36.95
31	kW > 1, 1 Phase	1,045	16.94%	86.51%		$198	$33.53	$171.19	
32	kW > 1, 3 Phase	3,777	61.24%		76.15%	$261	$159.88		$198.82
33									
34	51 - 300 kW								
35	1 Phase	1	0.02%	0.08%		$216	$0.03	$0.18	
36	3 Phase W/O KVAR	335	5.43%		6.75%	$261	$14.18		$17.63
37	3 Phase With KVAR	131	2.12%		2.64%	$423	$8.98		$11.16
38									
39	> 300 kW								
40	1 Phase	-	0.00%	0.00%		$980	$0.00	$0.00	
41	3 Phase W/O KVAR	3	0.05%		0.06%	$1,443	$0.70		$0.87
42	3 Phase With KVAR	12	0.19%		0.24%	$1,443	$2.81		$3.49
43	Total Irrigation	6,168	100.00%	100.00%	100.00%		$252.22	$183.60	$268.92
44							$27.26	$19.85	$29.07
45									
46	Primary	-	100.00%		100.00%	$0	$0.00		$0.00
47							$0.00	$0.00	$0.00
48	Irrigation - Schedule 33* (Annual)								
49	0 - 50 kW								
50	kW = 0, 1 Phase	60	2.75%	85.71%		$91	$2.50	$78.15	
51	kW = 0, 3 Phase	202	9.25%		9.56%	$261	$24.15		$24.95
52	kW > 1, 1 Phase	10	0.46%	14.29%		$198	$0.91	$28.27	
53	kW > 1, 3 Phase	1,317	60.30%		62.30%	$261	$157.45		$162.66
54									
55	51 - 300 kW								
56	1 Phase	-	0.00%	0.00%		$216	$0.00	$0.00	
57	3 Phase W/O KVAR	2	0.09%		0.09%	$261	$0.24		$0.25
58	3 Phase With KVAR	587	26.88%		27.77%	$423	$113.62		$117.38
59									
60	> 300 kW								
61	1 Phase	-	0.00%	0.00%		$980	$0.00	$0.00	
62	3 Phase W/O KVAR	-	0.00%		0.00%	$1,443	$0.00		$0.00
63	3 Phase With KVAR	6	0.27%		0.28%	$1,443	$3.97		$4.10
64	Total Irrigation	2,184	100.00%	100.00%	100.00%		$302.84	$106.42	$309.34
65							$32.74	$11.50	$33.44

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2009.
* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Incremental Three Phase
Meter and Services Costs

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meters				Service Drops			
Line	Load Class	Single Phase	Three Phase	Difference	Annualized Difference	Single Phase	Three Phase	Difference	Annualized Difference
				(B) - (A)	(C) x 10.81%			(F) - (E)	(G) x 10.81%
1	Residential	$109.53	$261.10	$151.57	$16.38	$479.58	$811.92	$332.33	$35.93
2									
3	0-15 kW	$91.18	$261.10	$169.92	$18.37	$778.36	$970.53	$192.17	$20.77
4									
5	16-100 kW	$215.51	$261.10	$45.59	$4.93	$1,431.17	$1,793.39	$362.22	$39.16
6									
7	101-1000 kW	$980.15	$1,443.29	$463.14	$50.07	$3,707.52	$3,653.16	($54.36)	($5.88)
8									
9	1 - 4 MW	N.A.	$2,249.37	N.A.	N.A.	N.A.	$6,456.94	N.A.	N.A.

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Meters 5

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

Line	Description	(A) 1999	(B) 2000	(C) 2001	(D) 2002	(E) 2003	(F) 2004	(G) 2005	(H) 2006	(I) 2007	(J) 2008
	Distribution Meters Expenses										
1	586 Meter Expense	-	-	1,479,307	1,800,451	2,010,097	1,892,897	2,122,259	2,058,440	2,206,057	2,848,811
2	597 Main. of Meters	1,047,453	674,571	664,777	825,166	1,190,462	1,237,234	1,348,150	1,669,096	1,560,945	1,433,131
3											
4	Total Adjusted Distribution Meters Expens	1,047,453	674,571	2,144,084	2,625,617	3,200,559	3,130,131	3,470,409	3,727,536	3,767,002	4,281,942
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	56,597,405	55,765,666	56,108,548	57,067,003	56,828,689	56,705,794	58,095,163	58,456,991	59,168,811	59,791,712
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	1.85%	1.21%	3.82%	4.60%	5.63%	5.52%	5.97%	6.38%	6.37%	7.16%
16	Line 3 / Line 4										
17											
18	Average Meter O&M Loading	4.85%									
19	Average of Line 5										
20											
21	Distribution Annual Charge	10.81%									
22											
23	Annualized Meter O&M Loading Factor	44.88%									
24	Line 6 / Line 7										

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			% of Customers			Overhead Service Drop Cost	Underground Service Drop Cost	Overhead %	Underground %	Weighted Service Drop Cost	Weighted Service Drop Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase						1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø						(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	471,384	100.00%	100.00%						$480	$479.58	$479.58	
2	Annualized - Line 1 x 10.81%										$51.84	$51.84	
3													
4	GS - Schedule 23												
5	0-15 kW												
6	kW = 0, 1 Phase	50,552	76.31%	91.87%		$582	$576	68.5%	31.5%	$580	$442.75	$533.00	
7	kW = 0, 3 Phase	3,500	5.28%		31.20%	$787	$856	68.5%	31.5%	$809	$42.72		$252.27
8	kW > 1, 1 Phase	4,476	6.76%	8.13%		$839	$646	68.5%	31.5%	$778	$52.59	$63.31	
9	kW > 1, 3 Phase	7,718	11.65%		68.80%	$998	$911	68.5%	31.5%	$971	$113.07		$667.73
10	Total 0-15 kW	66,246	100.00%	100.00%	100.00%						$651.13	$596.31	$920.00
11	Annualized - Line 10 x 10.81%										$70.39	$64.46	$99.45
12													
13	15+ kW												
14	1 Phase	4,101	42.83%	100.00%		$1,556	$1,159	68.5%	31.5%	$1,431	$612.91	$1,431.17	
15	3 Phase W/O KVAR	4,490	46.89%		82.01%	$1,841	$1,689	68.5%	31.5%	$1,793	$840.89		$1,470.74
16	3 Phase With KVAR	985	10.29%		17.99%	$1,841	$1,689	68.5%	31.5%	$1,793	$184.47		$322.65
17	Total 15+ kW	9,576	100.00%	100.00%	100.00%						$1,638.27	$1,431.17	$1,793.39
18	Annualized - Line 17 x 10.81%										$177.10	$154.71	$193.87
19													
20	Primary												
21	12.47 KV 4-wire Wye OH	36	100.00%		100.00%					$0		$0.00	$0.00
22	Annualized - (Line 21) x 10.81%									$0.00	$0.00	$0.00	$0.00
23													
24	GS - Schedule 28												
25	0-50 kW												
26	kW = 0, 1 Phase	1	0.02%	0.08%		$1,556	$1,159	52.3%	47.7%	$1,367	$0.30	$1.06	
27	kW = 0, 3 Phase	4	0.09%		0.12%	$1,841	$1,689	52.3%	47.7%	$1,769	$1.57		$2.20
28	kW > 1, 1 Phase	1,294	28.67%	99.92%		$1,556	$1,159	52.3%	47.7%	$1,367	$391.81	$1,365.73	
29	kW > 1, 3 Phase	3,215	71.22%		99.88%	$1,841	$1,689	52.3%	47.7%	$1,769	$1,259.79		$1,766.60
30	Total 0-50 kW	4,514	100.00%	100.00%	100.00%						$1,653.47	$1,366.79	$1,768.80
31	Annualized - Line 30 x 10.81%										$178.74	$147.75	$191.21
32													
33	51-100 kW												
34	1 Phase	484	13.61%	100.00%		$1,556	$1,159	52.3%	47.7%	$1,367	$186.08	$1,366.79	
35	3 Phase W/O KVAR	1,772	49.85%		57.70%	$1,841	$1,689	52.3%	47.7%	$1,769	$881.66		$1,020.62
36	3 Phase With KVAR	1,299	36.54%		42.30%	$1,841	$1,689	52.3%	47.7%	$1,769	$646.32		$748.18
37	Total 51-100 kW	3,555	100.00%	100.00%	100.00%						$1,714.06	$1,366.79	$1,768.80
38	Annualized - Line 37 x 10.81%										$185.29	$147.75	$191.21
39													
40	> 101kW												
41	1 Phase	51	2.52%	100.00%		$3,654	$3,767	52.3%	47.7%	$3,708	$93.33	$3,707.52	
42	3 Phase W/O KVAR	822	40.57%		41.62%	$3,531	$3,787	52.3%	47.7%	$3,653	$1,482.18		$1,520.46
43	3 Phase With KVAR	1,153	56.91%		58.38%	$3,531	$3,787	52.3%	47.7%	$3,653	$2,079.02		$2,132.71
44	Total > 101kW	2,026	100.00%	100.00%	100.00%						$3,654.53	$3,707.52	$3,653.17
45	Annualized - Line 44 x 10.81%										$395.05	$400.78	$394.91
46													
47	Primary												
48	12.47 KV 4-wire Wye OH	53	100.00%		100.00%					$0	$0.00		$0.00
49	Annualized - (Line 48) x 10.81%										$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2009.

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
GS - Schedule 30 / LPS - Schedule 48T

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			% of Customers			Overhead Service Drop Cost	Underground Service Drop Cost			Weighted Service Drop Cost	Weighted Service Drop Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase			Overhead %	Underground %		1 & 3 Phase	1 Phase	Annualized 3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø						(B) x (E)	(C) x (E)	
1	GS - Schedule 30												
2													
3	0-300 kW												
4	1 Phase	1	0.41%	100.00%		$3,654	$3,767	30.7%	69.3%	$3,732	$15.36	$3,731.89	
5	3 Phase W/O KVAR	41	16.87%		16.94%	$3,531	$3,787	30.7%	69.3%	$3,709	$625.73		$628.31
6	3 Phase With KVAR	201	82.72%		83.06%	$3,531	$3,787	30.7%	69.3%	$3,709	$3,067.59		$3,080.27
7	Total 0-300 kW	243	100.00%	100.00%	100.00%						$3,708.68	$3,731.89	$3,708.58
8	Annualized - Line 7 x 10.81%										$400.91	$403.42	$400.90
9													
10	301+ kW												
11	1 Phase	1	0.17%	100.00%		$3,654	$3,767	30.7%	69.3%	$3,732	$6.29	$3,731.89	
12	3 Phase W/O KVAR	79	13.32%		13.34%	$3,531	$3,787	30.7%	69.3%	$3,709	$494.06		$494.90
13	3 Phase With KVAR	513	86.51%		86.66%	$3,531	$3,787	30.7%	69.3%	$3,709	$3,208.27		$3,213.69
14	Total 301+ kW	593	100.00%	100.00%	100.00%						$3,708.62	$3,731.89	$3,708.59
15	Annualized - Line 14 x 10.81%										$400.90	$403.42	$400.90
16													
17	Primary												
18	12.47 KV 4-wire Wye OH	55	100.00%		100.00%					$0	$0.00		$0.00
19	Annualized - Line 18 x 10.81%										$0.00		$0.00
20													
21	LPS - Schedule 48T												
22	1 - 4 MW (sec)	121	100.00%		100.00%	$5,898	$6,930	45.8%	54.2%	$6,457	$6,456.94		$698.00
23	1 - 4 MW (pri)	58	100.00%		100.00%					$0	$0.00		$0.00
24	> 4 MW (sec)	2	100.00%		100.00%	$5,898	$6,930	45.8%	54.2%	$6,457	$6,456.94		$698.00
25	> 4 MW (pri)	33	100.00%		100.00%					$0	$0.00		$0.00
26	Trans (trn)	2	100.00%		100.00%					$0	$0.00		$0.00

Footnote:
Columns (E) & (F) - see Tab 12.3 (Services 3:) `Summary of Average Installed Costs Service Drops'

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SEPARATE COVER

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2011 Dollars

Line	FERC Account	Description	(A) Sch. 4 Residential	(B) Sch. 23 General Service	(C) Sch. 28 General Service	(D) Sch. 30 General Service	(E) Sch. 48T General Service	(F) Sch. 41 Irrigation	(G) Sch. 33* Irrigation	(H) Streetlighting	(I) Total
1		Average Number of Customers	484,011	74,207	10,418	881	214	2,722	760	782	573,235
2											
3		Write-offs By Schedule	4,678,209	155,736	203,920	114,829	111,021	14,552	4,419	-	5,278,267
4											
5	901										
6	Supervision	Account 902 + 903 + 904	$27,796,202	$3,824,545	$733,622	$212,256	$187,229	$183,000	$51,354	$25,303	$32,962,157
7		% of Total 902 + 903 +904	84.33%	11.60%	2.23%	0.64%	0.57%	0.56%	0.16%	0.08%	100.00%
8		Total 901 $	$2,548,135	$350,604	$67,253	$19,458	$17,164	$16,776	$4,708	$2,320	$3,021,709
9		Dollars Per Customer	$5.26	$4.72	$6.46	$22.09	$80.20	$6.16	$6.19	$2.97	$5.27
10	902										
11	Meter Reading Expense	902 Weighting Factor	1.00	1.24	1.20	5.41	8.21	1.91	1.91	0.12	
12		Weighted Customers	484,011	92,017	12,502	4,766	1,757	5,199	1,452	94	600,345
13		% of Total $	80.62%	15.33%	2.08%	0.79%	0.29%	0.87%	0.24%	0.02%	100.00%
14		Total 902 $	$7,112,725	$1,352,220	$183,716	$70,041	$25,819	$76,402	$21,280	$1,379	$8,822,302
15		Dollars Per Customer	$14.70	$18.22	$17.63	$79.50	$120.65	$28.07	$28.00	$1.76	$15.39
16	903										
17	Cust. Receipts & Collect.	903 Weighting Factor	1.00	0.94	1.01	1.01	7.38	1.02	1.02	0.92	
18		Weighted Customers	484,011	69,755	10,522	890	1,579	2,776	775	719	570,253
19		% of Total $	84.88%	12.23%	1.85%	0.16%	0.28%	0.49%	0.14%	0.13%	100.00%
20		Total 903 $	$16,095,004	$2,319,576	$349,898	$29,589	$52,518	$92,326	$25,743	$23,924	$18,962,835
21		Dollars Per Customer	$33.25	$31.26	$33.59	$33.59	$245.41	$33.92	$33.87	$30.59	$33.08
22	904										
23	Uncollectibles	Total 904 $	$4,588,472	$152,749	$200,008	$112,626	$108,892	$14,273	$4,331	$0	$5,177,020
24		% of Write-offs	88.63%	2.95%	3.86%	2.18%	2.10%	0.28%	0.08%	0.00%	
25		Dollars Per Customer	$9.48	$2.06	$19.20	$127.84	$508.84	$5.24	$5.70	$0.00	$9.03
26	905										
27	Misc Cust Acct Expense	Account 902 + 903 + 904	$27,796,202	$3,824,545	$733,622	$212,256	$187,229	$183,000	$51,354	$25,303	$32,962,157
28		% of Total 902 + 903 +904	84.33%	11.60%	2.23%	0.64%	0.57%	0.56%	0.16%	0.08%	100.00%
29		Total 905 $	$261,203	$35,940	$6,894	$1,995	$1,759	$1,720	$483	$238	$309,748
30		Dollars Per Customer	$0.54	$0.48	$0.66	$2.26	$8.22	$0.63	$0.63	$0.30	$0.54
31	907-910										
32	Supervision, Cust. Assist.	Average Number of customers	484,011	74,207	10,418	881	214	2,722	760	782	573,235
33	Info & Instructional Exp.,	% of Total	84.44%	12.95%	1.82%	0.15%	0.04%	0.47%	0.13%	0.14%	100.13%
34	Misc Cust Svc & Info Exp.		$3,052,065	$467,933	$65,694	$5,555	$1,349	$17,164	$4,786	$4,931	$3,614,692
35		Dollars Per Customer	$6.31	$6.31	$6.31	$6.31	$6.31	$6.31	$6.30	$6.31	$6.31
36											
37	Total 901 - 910	Total 901 - 910 $	$33,657,606	$4,679,021	$873,462	$239,264	$207,501	$218,660	$61,331	$32,791	$39,908,306
38											
39		Dollars Per Customer	$69.54	$63.05	$83.84	$271.58	$969.63	$80.33	$80.70	$41.93	$69.62

* Schedule 33 Cost of Service results are provided for informational purposes only.

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2011 Dollars

Line	Description	(A) Actual 2004 Dollars	(B) Actual 2005 Dollars	(C) Actual 2006 Dollars	(D) Actual 2007 Dollars	(E) Actual 2008 Dollars	(F) Adjusted 2011 Dollars
							[(A) x 1.1312+ (B) x 1.1114+ (C) x 1.0920+ (D) x 1.0730+ (E) x 1.0542] / 5
	Customer Accounting						
1	901 Supervision	3,174,507	3,981,235	4,869,032	900,404	768,055	$3,021,709
2	902 Meter Reading Expense	7,168,249	7,441,361	7,127,052	9,563,375	9,190,112	$8,822,302
3	903 Cust Records & Collection	15,439,733	17,239,535	17,663,200	17,918,701	18,662,255	$18,962,835
4	904 Uncollectible Accounts	3,642,666	5,085,904	5,205,538	3,555,170	6,272,907	$5,177,020
5	905 Misc Cust Acct Expense	377,084	405,292	417,356	124,686	77,974	$309,748
6	Total	29,802,239	34,153,327	35,282,178	32,062,336	34,971,304	$36,293,614
7							
8	Customer Service & Info Expense						
9	907 Supervision	1,293,118	878,667	429,900	138,616	77,577	$627,859
10	908 Cust Assistance Expense	1,388,517	1,301,282	2,358,698	2,488,601	1,998,956	$2,074,040
11	909 Info & Instructional Expense	329,063	199,651	996,352	1,248,551	1,236,009	$864,968
12	910 Misc Cust Svc & Info Expense	95,307	94,643	3,238	1,429	19,976	$47,825
13	Total	3,106,005	2,474,243	3,788,188	3,877,197	3,332,517	$3,614,692
14							$39,908,306
15	Distribution Expenses						
16	586 Meter Expenses	$1,892,897	$2,122,259	$2,058,440	$2,206,057	$2,848,811	$2,423,611
17	597 Meter Maintenance	$1,237,234	$1,348,150	$1,669,096	$1,560,945	$1,433,131	$1,581,249
18		$3,130,131	$3,470,409	$3,727,536	$3,767,002	$4,281,942	$4,004,860
19							
20							
21	(1) Inflation Adjustment -	1.1312	1.1114	1.0920	1.0730	1.0542	

Source:
Source: FERC Form 1 (State of Oregon) & Results of Operations

AG Expenses

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

Year	(A) Administrative and General Expenses (000)	(B) Electric Plant in Service (000)	(C) Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
1999	$209,710	$12,110,787	1.73%
2000	$100,360	$11,910,796	0.84%
2001	$180,629	$12,289,187	1.47%
2002	$277,395	$12,690,449	2.19%
2003	$251,357	$13,208,159	1.90%
2004	$244,893	$13,688,398	1.79%
2005	$236,709	$14,335,797	1.65%
2006	$238,645	$15,317,103	1.56%
2007	$180,356	$16,417,338	1.10%
2008	$170,044	$18,224,943	0.93%
10 Year Average A&G to EPIS Loading Factor			1.52%

Footnotes:
(A) FERC Form 1 Page 322-323
(B) FERC Form 1 Page 206-207

Exhibit PPL/1607
Tab 15. Annual Charges

Charge 1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

Line	Description	(A) 20 years - Generation	(B) 10 years - Generation	(C) 5 years - Generation	(D) System Transmission	(E) Distribution
1	Levelized Income Taxes *	NA	NA	NA	1.96%	1.98%
2	Levelized Property Tax *	NA	NA	NA	1.07%	1.15%
3	Total	NA	NA	NA	3.03%	3.13%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	$30.30	$31.30
6	(per $1,000 of Investment)					
7						
8	Expected Life	20	10	5	58	50
9						
10	Nominal Interest Rate *	8.59%	8.59%	8.59%	8.59%	8.59%
11						
12	Present Value: Income **	NA	NA	NA	$349.63	$358.32
13	Taxes & Property Taxes per				(PV of $30.30 per year	(PV of $31.30 per year
14	$1,000 of Investment				for 58 years at 8.59%)	for 50 years at 8.59%)
15						
16	Removal Cost Per $1,000 Investment				$204.38	$463.24
17						
18	Present Value: Removal Cost				$1.71	$7.51
19	at End of Useful Life				(PV of $204.38 in	(PV of $463.24 in
20					58 years at 8.59%)	50 years at 8.59%)
21						
22	Investment and Taxes	$1,000.00	$1,000.00	$1,000.00	$1,351.34	$1,365.83
23	w/o PVCD (Line 12 + Line 18 + $1000)					
24						
25	PVCD Factor	NA	NA	NA	0.018590	0.040517
26						
27	PVCD $ (Line 22 x Line 25)	NA	NA	NA	$25.12	$55.34
28						
29	Total (Line 22 + Line 27)	$1,000.00	$1,000.00	$1,000.00	$1,376.46	$1,421.17
30						
31	EOY Annual Charge ***	$86.40	$131.58	$226.74	$88.47	$92.85
32						
33	Annual Economic Carrying	8.64%	13.16%	22.67%	8.85%	9.29%
34	Adm &Gen Expense Loading Factor	0.00%	0.00%	0.00%	1.52%	1.52%
35						
36	Annual Econ Carrying + A&G Loading	8.64%	13.16%	22.67%	10.37%	10.81%

Footnotes:
From Financial Analysis -
** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]
30.30*(1/0.0859-(1/0.0859)/(1+0.0859)^58)
31.30*(1/0.0859-(1/0.0859)/(1+0.0859)^50)

Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula: AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)

Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate = 1.8%
a = expected investment life
r = nominal interest rate

PacifiCorp
Oregon Marginal Cost Study
Financial Inputs to the Economic Carrying Charge Calculation

	(A)	(B)	(C)	(D)
	Financial Inputs		Levelized	
1	Weighted Cost of Capital	8.59%	Income Taxes	
2	Borrowing Rate	8.59%	Transmission	1.96%
3	Inflation	1.78%	Distribution	1.98%
4			Property Taxes	
5	Real Cost of Capital		Transmission	1.07%
6	(1+0.0859)/(1+0.0178)-1 =	$\boxed{6.70\%}$	Distribution	1.15%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: Financial Analysis, Use of Facilities Charges 12/31/08 Basis (prepared 8/13/09)
Inflation Rate 2009-2028, 2009 Avoided Cost, Table 8

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 3.0 & 58 Year Average Life

Real Cost of Capital = 6.70%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0670 ^Year	(C) / (D)	(B)	1.0670 ^58	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000145	1.59%	0.0159	1.066983	0.014866	0.0159	42.966542	0.000369	0.014497	99.9841
2	0.000416	3.17%	0.0317	1.138452	0.027866	0.0317	42.966542	0.000738	0.027128	99.9524
3	0.000670	3.17%	0.0317	1.214709	0.026117	0.0317	42.966542	0.000738	0.025378	99.9207
4	0.000976	4.08%	0.0408	1.296074	0.031501	0.0408	42.966542	0.000950	0.030551	99.8799
5	0.001304	4.69%	0.0469	1.382888	0.033912	0.0469	42.966542	0.001091	0.032821	99.8330
6	0.001611	4.69%	0.0469	1.475518	0.031783	0.0469	42.966542	0.001091	0.030692	99.7861
7	0.001988	6.16%	0.0616	1.574352	0.039140	0.0616	42.966542	0.001434	0.037706	99.7244
8	0.002376	6.79%	0.0679	1.679807	0.040440	0.0679	42.966542	0.001581	0.038859	99.6565
9	0.002740	6.79%	0.0679	1.792325	0.037901	0.0679	42.966542	0.001581	0.036320	99.5886
10	0.003188	8.97%	0.0897	1.912380	0.046918	0.0897	42.966542	0.002088	0.044829	99.4989
11	0.003632	9.52%	0.0952	2.040477	0.046642	0.0952	42.966542	0.002215	0.044427	99.4037
12	0.004047	9.52%	0.0952	2.177153	0.043714	0.0952	42.966542	0.002215	0.041499	99.3085
13	0.004564	12.68%	0.1268	2.322985	0.054597	0.1268	42.966542	0.002952	0.051645	99.1817
14	0.005059	13.03%	0.1303	2.478585	0.052588	0.1303	42.966542	0.003034	0.049555	99.0513
15	0.005522	13.03%	0.1303	2.644608	0.049287	0.1303	42.966542	0.003034	0.046253	98.9210
16	0.006099	17.45%	0.1745	2.821751	0.061835	0.1745	42.966542	0.004061	0.057774	98.7465
17	0.006638	17.45%	0.1745	3.010760	0.057953	0.1745	42.966542	0.004061	0.053892	98.5720
18	0.007156	17.99%	0.1799	3.212429	0.056011	0.1799	42.966542	0.004188	0.051823	98.3921
19	0.007771	22.90%	0.2290	3.427607	0.066800	0.2290	42.966542	0.005329	0.061471	98.1631
20	0.008344	22.90%	0.2290	3.657198	0.062607	0.2290	42.966542	0.005329	0.057278	97.9342
21	0.008908	24.21%	0.2421	3.902167	0.062052	0.2421	42.966542	0.005635	0.056417	97.6920
22	0.009548	29.48%	0.2948	4.163545	0.070812	0.2948	42.966542	0.006862	0.063950	97.3972
23	0.010143	29.48%	0.2948	4.442431	0.066366	0.2948	42.966542	0.006862	0.059504	97.1024
24	0.010740	31.83%	0.3183	4.739997	0.067154	0.3183	42.966542	0.007408	0.059746	96.7841
25	0.011391	37.31%	0.3731	5.057496	0.073772	0.3731	42.966542	0.008684	0.065089	96.4110
26	0.011996	37.31%	0.3731	5.396261	0.069141	0.3731	42.966542	0.008684	0.060458	96.0379
27	0.012612	40.98%	0.4098	5.757718	0.071173	0.4098	42.966542	0.009537	0.061635	95.6281
28	0.013260	46.48%	0.4648	6.143386	0.075663	0.4648	42.966542	0.010818	0.064845	95.1632
29	0.013861	46.48%	0.4648	6.554887	0.070913	0.4648	42.966542	0.010818	0.060095	94.6984
30	0.014481	51.79%	0.5179	6.993952	0.074054	0.5179	42.966542	0.012054	0.062000	94.1805
31	0.015114	57.10%	0.5710	7.462426	0.076521	0.5710	42.966542	0.013290	0.063231	93.6094
32	0.015698	57.10%	0.5710	7.962280	0.071717	0.5710	42.966542	0.013290	0.058427	93.0384
33	0.016307	64.45%	0.6445	8.495616	0.075861	0.6445	42.966542	0.015000	0.060861	92.3939
34	0.016910	69.34%	0.6934	9.064676	0.076500	0.6934	42.966542	0.016139	0.060361	91.7005
35	0.017466	69.34%	0.6934	9.671854	0.071698	0.6934	42.966542	0.016139	0.055558	91.0070
36	0.018049	79.17%	0.7917	10.319702	0.076716	0.7917	42.966542	0.018426	0.058291	90.2153
37	0.018612	83.38%	0.8338	11.010944	0.075724	0.8338	42.966542	0.019406	0.056318	89.3816
38	0.019127	83.38%	0.8338	11.748488	0.070970	0.8338	42.966542	0.019406	0.051565	88.5478
39	0.019672	96.34%	0.9634	12.535435	0.076858	0.9634	42.966542	0.022423	0.054435	87.5843
40	0.020185	99.59%	0.9959	13.375094	0.074456	0.9959	42.966542	0.023178	0.051279	86.5884
41	0.020651	99.59%	0.9959	14.270995	0.069782	0.9959	42.966542	0.023178	0.046605	85.5926
42	0.021144	116.28%	1.1628	15.226906	0.076367	1.1628	42.966542	0.027064	0.049303	84.4298
43	0.021596	118.14%	1.1814	16.246847	0.072714	1.1814	42.966542	0.027495	0.045219	83.2484
44	0.022002	118.14%	1.1814	17.335106	0.068150	1.1814	42.966542	0.027495	0.040654	82.0670
45	0.022431	139.28%	1.3928	18.496261	0.075299	1.3928	42.966542	0.032415	0.042885	80.6742
46	0.022813	139.28%	1.3928	19.735192	0.070572	1.3928	42.966542	0.032415	0.038157	79.2815
47	0.023156	141.63%	1.4163	21.057111	0.067262	1.4163	42.966542	0.032964	0.034298	77.8651
48	0.023502	162.86%	1.6286	22.467575	0.072488	1.6286	42.966542	0.037904	0.034583	76.2365
49	0.023802	162.86%	1.6286	23.972516	0.067937	1.6286	42.966542	0.037904	0.030033	74.6079
50	0.024068	167.95%	1.6795	25.578262	0.065662	1.6795	42.966542	0.039089	0.026573	72.9284
51	0.024319	188.31%	1.8831	27.291566	0.068999	1.8831	42.966542	0.043827	0.025172	71.0453
52	0.024528	188.31%	1.8831	29.119632	0.064668	1.8831	42.966542	0.043827	0.020841	69.1622
53	0.024703	196.04%	1.9604	31.070146	0.063095	1.9604	42.966542	0.045626	0.017470	67.2018
54	0.024850	214.07%	2.1407	33.151312	0.064573	2.1407	42.966542	0.049822	0.014751	65.0611
55	0.024957	214.07%	2.1407	35.371880	0.060520	2.1407	42.966542	0.049822	0.010697	62.9204
56	0.025029	223.53%	2.2353	37.741188	0.059227	2.2353	42.966542	0.052024	0.007203	60.6851
57	0.025066	237.72%	2.3772	40.269198	0.059034	2.3772	42.966542	0.055328	0.003706	58.3079
58	0.025066	237.72%	2.3772	42.966542	0.055328	2.3772	42.966542	0.055328	0.000000	55.9306
59	0.025030	246.88%	2.4688	45.844562	0.053851	2.4688	42.966542	0.057459	-0.003607	53.4618
60	0.024958	256.03%	2.5603	48.915359	0.052342	2.5603	42.966542	0.059589	-0.007247	50.9015

Charge 4

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 3.0 & 58 Year Average Life
Page 2 of 2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0670 ^Year	(C) / (D)	(B)	1.0670 ^58	(F) / (G)	(E) - (H)	(Given)
61	0.024852	256.03%	2.5603	52.191847	0.049056	2.5603	42.966542	0.059589	-0.010533	48.3411
62	0.024713	261.70%	2.6170	55.687803	0.046995	2.6170	42.966542	0.060909	-0.013914	45.7241
63	0.024542	265.48%	2.6548	59.417929	0.044681	2.6548	42.966542	0.061788	-0.017108	43.0693
64	0.024343	265.48%	2.6548	63.397908	0.041876	2.6548	42.966542	0.061788	-0.019913	40.4144
65	0.024119	263.96%	2.6396	67.644478	0.039022	2.6396	42.966542	0.061434	-0.022412	37.7748
66	0.023871	263.31%	2.6331	72.175495	0.036482	2.6331	42.966542	0.061283	-0.024801	35.1417
67	0.023600	263.31%	2.6331	77.010012	0.034192	2.6331	42.966542	0.061283	-0.027091	32.5086
68	0.023321	251.34%	2.5134	82.168359	0.030588	2.5134	42.966542	0.058496	-0.027908	29.9952
69	0.023026	248.34%	2.4834	87.672226	0.028327	2.4834	42.966542	0.057800	-0.029473	27.5118
70	0.022714	248.34%	2.4834	93.544758	0.026548	2.4834	42.966542	0.057800	-0.031251	25.0283
71	0.022416	224.39%	2.2439	99.810648	0.022481	2.2439	42.966542	0.052223	-0.029742	22.7845
72	0.022108	221.72%	2.2172	106.496245	0.020820	2.2172	42.966542	0.051604	-0.030784	20.5672
73	0.021787	221.72%	2.2172	113.629662	0.019513	2.2172	42.966542	0.051604	-0.032091	18.3500
74	0.021506	187.10%	1.8710	121.240896	0.015432	1.8710	42.966542	0.043546	-0.028114	16.4790
75	0.021215	187.10%	1.8710	129.361951	0.014464	1.8710	42.966542	0.043546	-0.029083	14.6079
76	0.020922	183.31%	1.8331	138.026978	0.013281	1.8331	42.966542	0.042664	-0.029383	12.7748
77	0.020676	149.17%	1.4917	147.272412	0.010129	1.4917	42.966542	0.034718	-0.024589	11.2831
78	0.020423	149.17%	1.4917	157.137131	0.009493	1.4917	42.966542	0.034718	-0.025225	9.7914
79	0.020178	141.86%	1.4186	167.662617	0.008461	1.4186	42.966542	0.033015	-0.024555	8.3728
80	0.019979	112.59%	1.1259	178.893130	0.006293	1.1259	42.966542	0.026203	-0.019910	7.2470
81	0.019776	112.59%	1.1259	190.875893	0.005898	1.1259	42.966542	0.026203	-0.020305	6.1211
82	0.019587	102.87%	1.0287	203.661296	0.005051	1.0287	42.966542	0.023942	-0.018891	5.0924
83	0.019437	80.21%	0.8021	217.303101	0.003691	0.8021	42.966542	0.018667	-0.014976	4.2903
84	0.019285	80.21%	0.8021	231.858672	0.003459	0.8021	42.966542	0.018667	-0.015208	3.4882
85	0.019152	69.35%	0.6935	247.389217	0.002803	0.6935	42.966542	0.016141	-0.013338	2.7947
86	0.019048	53.07%	0.5307	263.960040	0.002010	0.5307	42.966542	0.012351	-0.010341	2.2640
87	0.018944	53.07%	0.5307	281.640825	0.001884	0.5307	42.966542	0.012351	-0.010467	1.7333
88	0.018859	42.14%	0.4214	300.505917	0.001402	0.4214	42.966542	0.009807	-0.008405	1.3120
89	0.018797	31.21%	0.3121	320.634646	0.000973	0.3121	42.966542	0.007263	-0.006290	0.9999
90	0.018733	31.21%	0.3121	342.111655	0.000912	0.3121	42.966542	0.007263	-0.006351	0.6878
91	0.018689	21.32%	0.2132	365.027253	0.000584	0.2132	42.966542	0.004961	-0.004377	0.4747
92	0.018659	14.72%	0.1472	389.477802	0.000378	0.1472	42.966542	0.003427	-0.003049	0.3274
93	0.018628	14.72%	0.1472	415.566118	0.000354	0.1472	42.966542	0.003427	-0.003073	0.1802
94	0.018612	7.46%	0.0746	443.401903	0.000168	0.0746	42.966542	0.001736	-0.001568	0.1056
95	0.018603	4.34%	0.0434	473.102206	0.000092	0.0434	42.966542	0.001011	-0.000919	0.0621
96	0.018594	4.34%	0.0434	504.791919	0.000086	0.0434	42.966542	0.001011	-0.000925	0.0187
97	0.018592	1.14%	0.0114	538.604298	0.000021	0.0114	42.966542	0.000266	-0.000245	0.0072
98	0.018591	0.34%	0.0034	574.681525	0.000006	0.0034	42.966542	0.000080	-0.000074	0.0038
99	0.018590	0.34%	0.0034	613.175306	0.000006	0.0034	42.966542	0.000080	-0.000075	0.0003
100	0.018590	0.03%	0.0003	654.247508	0.000001	0.0003	42.966542	0.000008	-0.000007	0.0000
101	0.018590	0.00%	0.0000	698.070841	0.000000	0.0000	42.966542	0.000000	0.000000	0.0000
102	0.018590	0.00%	0.0000	744.829585	0.000000	0.0000	42.966542	0.000000	0.000000	0.0000
103	0.018590	0.00%	0.0000	794.720360	0.000000	0.0000	42.966542	0.000000	0.000000	0.0000
104	0.018590	0.00%	0.0000	847.952959	0.000000	0.0000	42.966542	0.000000	0.000000	0.0000
		100.0000	100.0000							

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.0 & 50 Year Average Life

Real Cost of Capital = 6.70%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0670 ^Year	(C) / (D)	(B)	1.0670 ^50	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000912	10.16%	0.1016	1.066983	0.095222	0.1016	25.578262	0.003972	0.091250	99.8984
2	0.002618	20.32%	0.2032	1.138452	0.178488	0.2032	25.578262	0.007944	0.170544	99.6952
3	0.004211	20.32%	0.2032	1.214709	0.167283	0.2032	25.578262	0.007944	0.159339	99.4920
4	0.005963	23.92%	0.2392	1.296074	0.184557	0.2392	25.578262	0.009352	0.175206	99.2528
5	0.007600	23.92%	0.2392	1.382888	0.172971	0.2392	25.578262	0.009352	0.163620	99.0136
6	0.009260	26.00%	0.2600	1.475518	0.176209	0.2600	25.578262	0.010165	0.166044	98.7536
7	0.010934	28.08%	0.2808	1.574352	0.178359	0.2808	25.578262	0.010978	0.167381	98.4728
8	0.012496	28.08%	0.2808	1.679807	0.167162	0.2808	25.578262	0.010978	0.156184	98.1920
9	0.014193	32.72%	0.3272	1.792325	0.182556	0.3272	25.578262	0.012792	0.169764	97.8648
10	0.015776	32.72%	0.3272	1.912380	0.171096	0.3272	25.578262	0.012792	0.158304	97.5376
11	0.017370	35.34%	0.3534	2.040477	0.173195	0.3534	25.578262	0.013816	0.159378	97.1842
12	0.018965	37.96%	0.3796	2.177153	0.174356	0.3796	25.578262	0.014841	0.159515	96.8046
13	0.020451	37.96%	0.3796	2.322985	0.163410	0.3796	25.578262	0.014841	0.148570	96.4250
14	0.022048	43.84%	0.4384	2.478585	0.176875	0.4384	25.578262	0.017140	0.159736	95.9866
15	0.023535	43.84%	0.4384	2.644608	0.165771	0.4384	25.578262	0.017140	0.148632	95.5482
16	0.025019	47.08%	0.4708	2.821751	0.166847	0.4708	25.578262	0.018406	0.148440	95.0774
17	0.026494	50.32%	0.5032	3.010760	0.167134	0.5032	25.578262	0.019673	0.147461	94.5742
18	0.027863	50.32%	0.5032	3.212429	0.156642	0.5032	25.578262	0.019673	0.136969	94.0710
19	0.029319	57.60%	0.5760	3.427607	0.168047	0.5760	25.578262	0.022519	0.145528	93.4950
20	0.030668	57.60%	0.5760	3.657198	0.157498	0.5760	25.578262	0.022519	0.134979	92.9190
21	0.032007	61.62%	0.6162	3.902167	0.157912	0.6162	25.578262	0.024091	0.133821	92.3028
22	0.033327	65.64%	0.6564	4.163545	0.157654	0.6564	25.578262	0.025662	0.131992	91.6464
23	0.034547	65.64%	0.6564	4.442431	0.147757	0.6564	25.578262	0.025662	0.122095	90.9900
24	0.035828	74.52%	0.7452	4.739997	0.157215	0.7452	25.578262	0.029134	0.128081	90.2448
25	0.037010	74.52%	0.7452	5.057496	0.147346	0.7452	25.578262	0.029134	0.118212	89.4996
26	0.038171	79.40%	0.7940	5.396261	0.147139	0.7940	25.578262	0.031042	0.116097	88.7056
27	0.039306	84.28%	0.8428	5.757718	0.146377	0.8428	25.578262	0.032950	0.113428	87.8628
28	0.040348	84.28%	0.8428	6.143386	0.137188	0.8428	25.578262	0.032950	0.104238	87.0200
29	0.041425	94.92%	0.9492	6.554887	0.144808	0.9492	25.578262	0.037110	0.107698	86.0708
30	0.042411	94.92%	0.9492	6.993952	0.135717	0.9492	25.578262	0.037110	0.098608	85.1216
31	0.043367	100.70%	1.0070	7.462426	0.134943	1.0070	25.578262	0.039369	0.095573	84.1146
32	0.044288	106.48%	1.0648	7.962280	0.133731	1.0648	25.578262	0.041629	0.092101	83.0498
33	0.045125	106.48%	1.0648	8.495616	0.125335	1.0648	25.578262	0.041629	0.083706	81.9850
34	0.045972	118.96%	1.1896	9.064676	0.131235	1.1896	25.578262	0.046508	0.084726	80.7954
35	0.046737	118.96%	1.1896	9.671854	0.122996	1.1896	25.578262	0.046508	0.076488	79.6058
36	0.047463	125.56%	1.2556	10.319702	0.121670	1.2556	25.578262	0.049089	0.072582	78.3502
37	0.048146	132.16%	1.3216	11.010944	0.120026	1.3216	25.578262	0.051669	0.068357	77.0286
38	0.048755	132.16%	1.3216	11.748488	0.112491	1.3216	25.578262	0.051669	0.060822	75.7070
39	0.049349	146.00%	1.4600	12.535435	0.116470	1.4600	25.578262	0.057080	0.059390	74.2470
40	0.049869	146.00%	1.4600	13.375094	0.109158	1.4600	25.578262	0.057080	0.052078	72.7870
41	0.050343	153.06%	1.5306	14.270995	0.107253	1.5306	25.578262	0.059840	0.047413	71.2564
42	0.050769	160.12%	1.6012	15.226906	0.105156	1.6012	25.578262	0.062600	0.042556	69.6552
43	0.051129	160.12%	1.6012	16.246847	0.098555	1.6012	25.578262	0.062600	0.035954	68.0540
44	0.051452	174.16%	1.7416	17.335106	0.100467	1.7416	25.578262	0.068089	0.032378	66.3124
45	0.051713	174.16%	1.7416	18.496261	0.094160	1.7416	25.578262	0.068089	0.026071	64.5708
46	0.051922	180.84%	1.8084	19.735192	0.091633	1.8084	25.578262	0.070701	0.020933	62.7624
47	0.052080	187.52%	1.8752	21.057111	0.089053	1.8752	25.578262	0.073312	0.015741	60.8872
48	0.052181	187.52%	1.8752	22.467575	0.083463	1.8752	25.578262	0.073312	0.010150	59.0120
49	0.052234	199.48%	1.9948	23.972516	0.083212	1.9948	25.578262	0.077988	0.005224	57.0172
50	0.052234	199.48%	1.9948	25.578262	0.077988	1.9948	25.578262	0.077988	0.000000	55.0224
51	0.052183	204.36%	2.0436	27.291566	0.074880	2.0436	25.578262	0.079896	-0.005016	52.9788
52	0.052084	209.24%	2.0924	29.119632	0.071855	2.0924	25.578262	0.081804	-0.009949	50.8864
53	0.051939	209.24%	2.0924	31.070146	0.067344	2.0924	25.578262	0.081804	-0.014459	48.7940
54	0.051746	215.92%	2.1592	33.151312	0.065132	2.1592	25.578262	0.084415	-0.019284	46.6348
55	0.051513	215.92%	2.1592	35.371880	0.061043	2.1592	25.578262	0.084415	-0.023373	44.4756

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.0 & 50 Year Average Life

Real Cost of Capital = 6.70%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0670 ^Year	(C) / (D)	(B)	1.0670 ^50	(F) / (G)	(E) - (H)	(Given)
56	0.051239	217.28%	2.1728	37.741188	0.057571	2.1728	25.578262	0.084947	-0.027376	42.3028
57	0.050927	218.64%	2.1864	40.269198	0.054295	2.1864	25.578262	0.085479	-0.031184	40.1164
58	0.050581	218.64%	2.1864	42.966542	0.050886	2.1864	25.578262	0.085479	-0.034593	37.9300
59	0.050207	216.76%	2.1676	45.844562	0.047282	2.1676	25.578262	0.084744	-0.037462	35.7624
60	0.049802	216.76%	2.1676	48.915359	0.044313	2.1676	25.578262	0.084744	-0.040431	33.5948
61	0.049377	213.28%	2.1328	52.191847	0.040865	2.1328	25.578262	0.083383	-0.042519	31.4620
62	0.048934	209.80%	2.0980	55.687803	0.037674	2.0980	25.578262	0.082023	-0.044348	29.3640
63	0.048466	209.80%	2.0980	59.417929	0.035309	2.0980	25.578262	0.082023	-0.046714	27.2660
64	0.048005	197.88%	1.9788	63.397908	0.031212	1.9788	25.578262	0.077363	-0.046150	25.2872
65	0.047524	197.88%	1.9788	67.644478	0.029253	1.9788	25.578262	0.077363	-0.048110	23.3084
66	0.047045	189.68%	1.8968	72.175495	0.026280	1.8968	25.578262	0.074157	-0.047876	21.4116
67	0.046571	181.48%	1.8148	77.010012	0.023566	1.8148	25.578262	0.070951	-0.047385	19.5968
68	0.046083	181.48%	1.8148	82.168359	0.022086	1.8148	25.578262	0.070951	-0.048865	17.7820
69	0.045635	161.60%	1.6160	87.672226	0.018432	1.6160	25.578262	0.063179	-0.044746	16.1660
70	0.045176	161.60%	1.6160	93.544758	0.017275	1.6160	25.578262	0.063179	-0.045903	14.5500
71	0.044738	150.60%	1.5060	99.810648	0.015089	1.5060	25.578262	0.058878	-0.043790	13.0440
72	0.044324	139.60%	1.3960	106.496245	0.013108	1.3960	25.578262	0.054578	-0.041469	11.6480
73	0.043901	139.60%	1.3960	113.629662	0.012286	1.3960	25.578262	0.054578	-0.042292	10.2520
74	0.043540	116.92%	1.1692	121.240896	0.009644	1.1692	25.578262	0.045711	-0.036067	9.0828
75	0.043173	116.92%	1.1692	129.361951	0.009038	1.1692	25.578262	0.045711	-0.036672	7.9136
76	0.042836	105.82%	1.0582	138.026978	0.007667	1.0582	25.578262	0.041371	-0.033704	6.8554
77	0.042530	94.72%	0.9472	147.272412	0.006432	0.9472	25.578262	0.037031	-0.030600	5.9082
78	0.042220	94.72%	0.9472	157.137131	0.006028	0.9472	25.578262	0.037031	-0.031004	4.9610
79	0.041975	73.88%	0.7388	167.662617	0.004406	0.7388	25.578262	0.028884	-0.024477	4.2222
80	0.041728	73.88%	0.7388	178.893130	0.004130	0.7388	25.578262	0.028884	-0.024754	3.4834
81	0.041510	64.24%	0.6424	190.875893	0.003366	0.6424	25.578262	0.025115	-0.021750	2.8410
82	0.041324	54.60%	0.5460	203.661296	0.002681	0.5460	25.578262	0.021346	-0.018665	2.2950
83	0.041135	54.60%	0.5460	217.303101	0.002513	0.5460	25.578262	0.021346	-0.018834	1.7490
84	0.041006	37.08%	0.3708	231.858672	0.001599	0.3708	25.578262	0.014497	-0.012897	1.3782
85	0.040876	37.08%	0.3708	247.389217	0.001499	0.3708	25.578262	0.014497	-0.012998	1.0074
86	0.040773	29.38%	0.2938	263.960040	0.001113	0.2938	25.578262	0.011486	-0.010373	0.7136
87	0.040696	21.68%	0.2168	281.640825	0.000770	0.2168	25.578262	0.008476	-0.007706	0.4968
88	0.040618	21.68%	0.2168	300.505917	0.000721	0.2168	25.578262	0.008476	-0.007754	0.2800
89	0.040584	9.36%	0.0936	320.634646	0.000292	0.0936	25.578262	0.003659	-0.003367	0.1864
90	0.040551	9.36%	0.0936	342.111655	0.000274	0.0936	25.578262	0.003659	-0.003386	0.0928
91	0.040530	5.60%	0.0560	365.027253	0.000153	0.0560	25.578262	0.002189	-0.002036	0.0368
92	0.040523	1.84%	0.0184	389.477802	0.000047	0.0184	25.578262	0.000719	-0.000672	0.0184
93	0.040517	1.84%	0.0184	415.566118	0.000044	0.0184	25.578262	0.000719	-0.000675	0.0000
94	0.040517	0.00%	0.0000	443.401903	0.000000	0.0000	25.578262	0.000000	0.000000	0.0000
			99.9816	50.9667						

CHARGE 6

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 12/31/2006 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount
		$		Yrs	%	$
	TRANSMISSION PLANT					
350.20	Land Rights	61,181,203	R5	70.00	0.00%	-
352.00	Structures & Improvements	55,260,234	S1	75.00	-1.00%	(552,602)
353.00	Station Equipment	907,682,638	R1.5	58.00	-4.00%	(36,307,306)
353.70	Supervisory Equipment	55,509,184	R2	25.00	0.00%	-
354.00	Towers & Fixtures	380,678,705	R5	65.00	-7.00%	(26,647,509)
355.00	Poles & Fixtures	508,938,637	R2.5	52.00	-42.00%	(213,754,228)
356.00	OH Conductors & Devices	630,352,557	R4	60.00	-42.00%	(264,748,074)
356.20	Clearing	30,355,853	S6	65.00	0.00%	-
357.00	UG Conduit	3,277,188	R2	60.00	0.00%	-
358.00	UG Conductors & Devices	7,274,658	R2	60.00	0.00%	-
359.00	Roads & Trails	11,494,522	R5	70.00	0.00%	-
	Total Transmission Plant	2,652,005,379		58.41	-20.44%	(542,009,719)
				Use 58 Years		

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[1] Account Number	[2] Description	[3] 12/31/2006 Balance			
	TRANSMISSION PLANT excludes land accounts				
352.00	Structures & Improvements	55,260,234	-	2.13%	-
353.00	Station Equipment	907,682,638	1.50	35.03%	0.5255
353.70	Supervisory Equipment	55,509,184	2.00	2.14%	0.0429
354.00	Towers & Fixtures	380,678,705	5.00	14.69%	0.7347
355.00	Poles & Fixtures	508,938,637	2.50	19.64%	0.4911
356.00	OH Conductors & Devices	630,352,557	4.00	24.33%	0.9732
356.20	Clearing	30,355,853	-	1.17%	-
357.00	UG Conduit	3,277,188	2.00	0.13%	0.0025
358.00	UG Conductors & Devices	7,274,658	2.00	0.28%	0.0056
359.00	Roads & Trails	11,494,522	5.00	0.44%	0.0222
	Total Transmission Plant	2,590,824,176		100.00%	2.7977 **Use R 3**

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 12/31/2006 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount
		$		Yrs	%	$
	DISTRIBUTION PLANT (OREGON)					
360.20	Land Rights	3,556,253	R4	53.00	0.00%	-
361.00	Structures & Improvements	12,345,312	R1.5	65.00	-5.00%	(617,266)
362.00	Station Equipment	160,587,683	R1	52.00	-10.00%	(16,058,768)
362.70	Supervisory & Alarm Equipment	2,779,659	R2.5	23.00	0.00%	-
364.00	Poles, Towers & Fixtures	282,793,465	R2	49.00	-100.00%	(282,793,465)
365.00	OH Conductors & Devices	210,301,551	R1.5	58.00	-80.00%	(168,241,241)
366.00	UG Conduit	75,474,348	R2.5	60.00	-60.00%	(45,284,609)
367.00	UG Conductors & Devices	133,175,353	R2.5	58.00	-45.00%	(59,928,909)
368.00	Line Transformers	340,095,762	R1.5	40.00	-20.00%	(68,019,152)
369.10	Overhead Services	60,741,141	R2	65.00	-25.00%	(15,185,285)
369.20	Underground Services	122,060,821	R4	55.00	-20.00%	(24,412,164)
370.00	Meters	58,792,161	R2.5	26.00	-2.00%	(1,175,843)
371.00	I.O.C.P.	2,433,995	S1	25.00	-40.00%	(973,598)
373.00	Street Lighting & Signal Systems	19,600,663	R1	40.00	-26.00%	(5,096,172)
	Total OREGON Distribution Plant	1,484,738,167		50.08	-46.32%	(687,786,473)
				Use 50 years		

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	DISTRIBUTION PLANT excludes land accounts (OREGON)				
361.00	Structures & Improvements	12,345,312	1.5	0.83%	0.01
362.00	Station Equipment	160,587,683	1	10.84%	0.11
362.70	Supervisory & Alarm Equipment	2,779,659	2.5	0.19%	0.00
364.00	Poles, Towers & Fixtures	282,793,465	2	19.09%	0.38
365.00	OH Conductors & Devices	210,301,551	1.5	14.20%	0.21
366.00	UG Conduit	75,474,348	2.5	5.10%	0.13
367.00	UG Conductors & Devices	133,175,353	2.5	8.99%	0.22
368.00	Line Transformers	340,095,762	1.5	22.96%	0.34
369.10	Overhead Services	60,741,141	2	4.10%	0.08
369.20	Underground Services	122,060,821	4	8.24%	0.33
370.00	Meters	58,792,161	2.5	3.97%	0.10
371.00	I.O.C.P.	2,433,995	0	0.16%	0.00
373.00	Street Lighting & Signal Systems	19,600,663	1	1.32%	0.01
	Total OREGON Distribution Plant	1,481,181,914		100.00%	1.94 **Use R 2**

Curves:
R=positive
L=negative
S=0

R means right of the standard
L means left of the standard
S is at the standard

**Source: Depreciation Rates.xls (02-10-2009)

Losses

PacifiCorp
Oregon Marginal Cost Study
Energy Loss Factors

Line	(A) Voltage Level	(B) Energy Factor	(C) Energy Loss Percent	(D) Demand Factor	(E) Demand Loss Percent
1	Transmission Line	1.03605	3.60%	1.04975	4.98%
2	(>= 69 kV)				
3					
4					
5					
6	Primary Line	1.05771	5.77%	1.08191	8.19%
7	(2.4 kV thru 34.5 kV)				
8					
9					
10					
11	Secondary Distribution	1.09180	9.18%	1.11306	11.31%
12	(<= 600 Volts)				

**Source: 2007 Losses (Updated 2009)

Cust Data 1

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended June 30, 2009 - Actual

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class
1	Res - Schedule 4	(sec)	471,384	100.0%	5,399,119	100.0%	4,835,502	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	66,246	87.4%	643,510	57.0%	223,891	58.3%
5	15+ kW	(sec)	9,576	12.6%	484,537	43.0%	160,433	41.7%
6	Sec Subtotal		75,822	100.0%	1,128,048	100.0%	384,324	100.0%
7	Primary	(pri)	36		881		1,315	
8	Total		75,858		1,128,929		385,640	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,514	44.7%	440,941	21.5%	161,869	7.9%
12	51-100 kW	(sec)	3,555	35.2%	677,599	33.1%	211,197	10.3%
13	> 101kW	(sec)	2,026	20.1%	929,651	45.4%	238,749	11.6%
14	Sec Subtotal		10,094	100.0%	2,048,192	100.0%	2,058,288	29.7%
15	Primary	(pri)	53		18,109		6,567	
16	Total		10,148		2,066,300		2,064,855	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	244	29.1%	204,717	16.2%	45,668	15.1%
20	301+ kW	(sec)	594	70.9%	1,057,551	83.8%	256,588	84.9%
21	Sec Subtotal		838	100.0%	1,262,268	100.0%	302,256	100.0%
22	Primary	(pri)	55		100,368		25,392	
23	Total		892		1,362,636		327,648	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	121	98.4%	583,462	91.0%	137,133	90.4%
27	> 4 MW	(sec)	2	1.6%	57,861	9.0%	14,551	9.6%
28	Sec Subtotal		123	100.0%	641,323	100.0%	151,684	100.0%
29	1 - 4 MW	(pri)	58	63.6%	437,587	27.1%	90,016	29.5%
30	> 4 MW	(pri)	33	36.4%	1,177,408	72.9%	215,142	70.5%
31	Pri Subtotal		91	100.0%	1,614,996	100.0%	305,158	100.0%
32	Trans	(trn)	2		438,480		63,841	
33	Total		216		2,694,798		520,683	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	2,704	100.0%	134,557	100.0%	83,880	100.0%
36	Irrigation - Schedule 33* (Average)	(sec)	808	100.0%	104,511	100.0%	65,150	100.0%
37								
38	Irrigation - Schedule 41 (Annual)	(sec)	6,168					
39	Irrigation - Schedule 33* (Annual)	(sec)	2,184					

Source:
Columns B & D - PacifiCorp, Pricing Department

Cust Data 2

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended December 2011 - Normalized

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class
1	Res - Schedule 4	(sec)	484,011	100.0%	5,306,840	100.0%	4,835,502	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	64,803	87.4%	577,893	57.0%	223,891	58.3%
5	15+ kW	(sec)	9,367	12.6%	435,130	43.0%	160,433	41.7%
6	Sec Subtotal		74,170	100.0%	1,013,023	100.0%	384,324	100.0%
7	Primary	(pri)	37		815		1,315	
8	Total		74,207		1,013,838		385,640	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,635	44.7%	429,296	21.5%	161,869	7.9%
12	51-100 kW	(sec)	3,650	35.2%	659,704	33.1%	211,197	10.3%
13	> 101kW	(sec)	2,080	20.1%	905,100	45.4%	238,749	11.6%
14	Sec Subtotal		10,365	100.0%	1,994,100	100.0%	611,814	29.7%
15	Primary	(pri)	53		17,727		6,567	
16	Total		10,418		2,011,827		618,381	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	241	29.1%	208,208	16.2%	45,668	15.1%
20	301+ kW	(sec)	586	70.9%	1,075,585	83.8%	256,588	84.9%
21	Sec Subtotal		827	100.0%	1,283,793	100.0%	302,256	100.0%
22	Primary	(pri)	54		102,283		25,392	
23	Total		881		1,386,076		327,648	
24								
25	LPS - Schedule 48T							
26	1 - 4 MW	(sec)	120	98.4%	526,955	91.0%	137,133	90.4%
27	> 4 MW	(sec)	2	1.6%	52,257	9.0%	14,551	9.6%
28	Sec Subtotal		122	100.0%	579,212	100.0%	151,684	100.0%
29	1 - 4 MW	(pri)	57	63.6%	380,354	27.1%	90,016	29.5%
30	> 4 MW	(pri)	33	36.4%	1,023,411	72.9%	215,142	70.5%
31	Pri Subtotal		90	100.0%	1,403,764	100.0%	305,158	100.0%
32	Trans	(trn)	2		366,079		63,841	
33	Total		214		2,349,056		520,683	
34								
35								
36	Irrigation - Schedule 41 (Average)	(sec)	2,722	100.0%	149,120	100.0%	83,880	100.0%
37	Irrigation - Schedule 33* (Average)	(sec)	760	100.0%	127,459	100.0%	65,150	100.0%
38								
39								
40	Irrigation - Schedule 41 (Annual)	(sec)	6,211	100.0%	149,120	100.0%	83,880	100.0%
41	Irrigation - Schedule 33* (Annual)	(sec)	2,056	100.0%	127,459	100.0%	65,150	100.0%

Source:
Columns B & D - PacifiCorp, Pricing Department

* Schedule 33 Cost of Service results are provided for informational purposes only.

Cust Data 3

PacifiCorp
Oregon Marginal Cost Study
Customer Class Split between
Three Phase / Single Phase

Line	Customer Class		Voltage Level	Three Phase	Total Customers	Three Phase % of Customers	Single Phase % of Customers
			(A)	(B)	(C)	(D)	(E)
						(A) / (B)	100% - (C)
1	Res - Schedule 4		(sec)	-	471,384	0.0000%	100.0000%
2							
3	GS - Schedule 23						
4	0-15 kW		(sec)	11,218	66,246	16.9339%	83.0661%
5	15+ kW		(sec)	5,475	9,576	57.1742%	42.8258%
6		Sec Subtotal		16,693	75,822		
7	Primary		(pri)	36	36	100.0000%	0.0000%
8		Total		16,729	75,858	22.0533%	77.9467%
9							
10	GS - Schedule 28						
11	0-50 kW		(sec)	3,219	4,514	71.3115%	28.6885%
12	51-100 kW		(sec)	3,071	3,555	86.3854%	13.6146%
13	> 101kW		(sec)	1,975	2,026	97.4827%	2.5173%
14		Sec Subtotal		8,265	10,095		
15	Primary		(pri)	53	53	100.0000%	0.0000%
16		Total		8,318	10,148	81.9676%	18.0324%
17							
18	GS - Schedule 30						
19	0-300 kW			242	243	99.5885%	0.4115%
20	301+ kW			592	593	99.8314%	0.1686%
21		Sec Subtotal		834	836		
22	Primary			55	55	100.0000%	0.0000%
23		Total		889	891	99.7755%	0.2245%
24							
25	LPS - Schedule 48T						
26	1 - 4 MW		(sec)	121	121	100.0000%	0.0000%
27	1 - 4 MW		(pri)	58	58	100.0000%	0.0000%
28	> 4 MW		(sec)	2	2	100.0000%	0.0000%
29	> 4 MW		(pri)	33	33	100.0000%	0.0000%
30	Trans		(trn)	2	2	100.0000%	0.0000%
31	Total			216	216	100.0000%	0.0000%
32							
33	Irrigation - Schedule 41 (Annual)		(sec)	4,960	6,168	80.4150%	19.5850%
34							
35	Irrigation - Schedule 33* (Annual)		(sec)	2,114	2,184	96.7949%	3.2051%
36							
37							
38	TOTAL			33,226	566,849	5.8615%	94.1385%

* Schedule 33 Cost of Service results are provided for informational purposes only.

Cust Data 4

PacifiCorp
Oregon Marginal Cost Study
Customer Loads
12 Months Ended December 2011

	(A)	(B)	(C)	(D)	(E)
			12 Month Average Peak Loads @ Sales		
Line	Description	Del. Volt	System	Distribution	Transformer
1	Res - Schedule 4	(sec)	887	987	3,240
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	99	93	172
5	15+ kW	(sec)	68	65	124
6	Primary	(pri)	0	0	1
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	68	65	162
10	51-100 kW	(sec)	114	111	211
11	> 101kW	(sec)	144	144	239
12					
13	Primary	(pri)	2	3	7
14					
15	GS - Schedule 30				
16	0-300 kW	(sec)	31	30	46
17	301+ kW	(sec)	161	162	257
18	Primary	(pri)	16	17	25
19					
20	LPS - Schedule 48T				
21	1 - 4 MW	(sec)	79	81	137
22	1 - 4 MW	(pri)	56	56	90
23	> 4 MW	(sec)	7	6	15
24	> 4 MW	(pri)	144	141	215
25	Trans	(trn)	44	0	64
26					
27	Irrigation - Sch 41	(sec)	18	17	84

Source:
Columns C, D & F - PacifiCorp, Load Research Dept.
Column E - Column F x Column H
Column H - PacifiCorp Distribution Construction Standard, DA 411

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2011

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Revenues		Percent of				
			Del.	June 2009		Total Revenues		Allocated Net Uncollectible		
Line	Description		Volt	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	Total
1	Res - Schedule 4		(sec)	0	0	0.00%	0.00%	-	-	4,678,209
2										
3	GS - Schedule 23									
4			(sec)	98,929,965	2,026,982	28.85%	1.61%	154,841	789	155,630
5			(pri)	63,850	16,210	0.02%	0.01%	100	6	106
6		Total		$98,993,815	$2,043,192	28.87%	1.63%	154,941	796	155,736
7										
8	GS - Schedule 28									
9			(sec)	127,557,653	7,060,412	37.20%	5.62%	199,648	2,749	202,397
10			(pri)	902,463	283,717	0.26%	0.23%	1,412	110	1,523
11		Total		$128,460,116	$7,344,129	37.47%	5.85%	201,060	2,860	203,920
12										
13	GS - Schedule 30									
14			(sec)	64,673,385	13,675,285	18.86%	10.90%	101,224	5,325	106,549
15			(pri)	5,068,836	888,967	1.48%	0.71%	7,934	346	8,280
16		Total		$69,742,221	$14,564,252	20.34%	11.60%	109,158	5,671	114,829
17										
18	LPS - Schedule 48T									
19			(sec)	21,034,699	17,647,950	6.14%	14.06%	32,923	6,872	39,794
20			(pri)	24,630,515	63,174,934	7.18%	50.33%	38,551	24,599	63,150
21			(trn)	0	20,744,369	0.00%	16.53%	-	8,077	8,077
22		Total		$45,665,214	$101,567,253	13.32%	80.92%	71,473	39,548	111,021
23										
24	Irrigation - Schedule 41		(sec)	-	$14,520,503	0.00%	76.70%	-	14,552	14,552
25	Irrigation - Schedule 33*		(sec)	-	$4,410,028	0.00%	23.30%	-	4,419	4,419
26				$0	$18,930,531	0.00%	100.00%	-	18,971	18,971
27										
28	Total			$342,861,366	$144,449,357			536,632	67,846	5,282,687

* Schedule 33 Cost of Service results are provided for informational purposes only.