ORDER NO 10-363
Entered 09/16/2010

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 216

In the Matter of PACIFICORP, dba PACIFIC POWER, 2011 Transition Adjustment Mechanism	ORDER

DISPOSITION: STIPULATION ADOPTED

I. INTRODUCTION

On February 26, 2010, PacifiCorp, dba Pacific Power (Pacific Power or the Company) filed revised tariff sheets for its 2011 Transition Adjustment Mechanism (TAM), to be effective January 1, 2011. The purpose of the TAM filing is to update net power costs (NPC) to set transition adjustments for the Company's Oregon customers who may choose direct access service in the November 2010 open enrollment window.

In its initial filing Pacific Power forecasted total normalized system-wide NPC for the test period (12 months ending December 31, 2011) of about $1.28 billion. On an Oregon-allocated basis, the forecast normalized NPC in the initial filing were about $312.8 million. That amount is about $56.6 million higher than the $256.1 million included in rates through the NPC baseline established in the Company's 2010 TAM proceeding (docket UE 207), or $69.2 million higher, as adjusted for load loss in 2011. That amount would have resulted in an overall increase in Oregon rates of about 7 percent.

The Citizens' Utility Board of Oregon (CUB) intervened as a matter of right. The Industrial Customers of Northwest Utilities (ICNU) and Sempra Energy Solutions, LLC (Sempra) filed petitions to intervene that were granted without objection.

On April 21, 2010, Pacific Power filed a summary of corrections or omissions from its initial filing, to be incorporated in the Company's Rebuttal Update scheduled for July 2, 2010. On May 12, 2010, the Staff of the Public Utility Commission of Oregon (Staff), CUB, ICNU, and Sempra filed reply testimony.

On July 7, 2010, Pacific Power filed its Net Power Cost Rebuttal Update. As explained in its exhibits, the net effect of the Company's filing was to increase net power costs by about $10.9 million on a total company basis.

Also on July 7, 2010, Pacific Power filed a joint stipulation of all parties intended to resolve all issues in the proceeding. The stipulation is attached as Appendix A. In the stipulation, the parties agree that the total-Company NPC for 2011 will be $1.233 billion, subject to final power cost updates. The parties agree that this is an Oregon-allocated NPC of $301.8 million, or an increase of $58.2 million (5.9 percent, including the load change adjustment.) The amount of NPC in the stipulation is a reduction of $11 million from the amount incorporated in Pacific Power's initial filing.

II. PACIFIC POWER'S APPLICATION

As explained by Pacific Power, NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. NPC are calculated for a future test period based on projected data, using the Generation and Regulation Initiative Decision model (GRID). GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

As noted above, in its initial filing Pacific Power forecasted an NPC increase of $56.6 million compared to the 2010 NPC in rates. The Company's proposed adjustment reflects the new tariff (Schedule 201) adopted in its 2009 general rate case (docket UE 210). This new tariff reflects *a decrease in* Oregon loads, when compared to the 2010 projected loads from docket UE 206. To capture this reduction in Oregon loads, rates were designed to collect an additional $12.5 million. The combination of the $56.6 million in increased NPC and the $12.5 million of decreased revenues results in the total proposed revenue increase of $69.2 million (about 7 percent).

As stated by Pacific Power, the NPC increase is driven by a range of factors, including changes in the Company's portfolio of wholesale purchase and sales contracts, expiration of the long-term gas supply contracts for the Hermiston gas-fired generating plant, increases in third-party coal contract costs (mitigated by decreases in captive coal costs) and inclusion of the cost of integrating increasing amounts of wind resources into the Company's integrated six-state system. Offsetting factors that drive NPC downward in 2011 include decreases in the load forecast and the addition of new transmission and generation resources. Each of these factors is discussed in the testimony filed by Pacific Power in support of its application.

Consistent with the TAM guidelines adopted in Order No. 09-274 (docket UE 199), Pacific Power proposes to allocate the NPC to customer classes based on the generation allocation factors from the Company's most recent cost of service study, which was filed in the Company's current general rate case with the TAM filing. According to Pacific Power, this methodology accurately allocated NPC to each customer class and ensures synchronization between the TAM and general rate case.

According to Pacific Power, its application was prepared consistent with the TAM guidelines adopted by the Commission in Order No. 09-274. The filing includes updates to all NPC components. The Company provided interested parties with its workpapers and access to the Company's GRID model

III. PACIFIC POWER'S NPC REBUTTAL UPDATE

As noted above, on July 7, 2010, Pacific Power filed its Rebuttal Update. In support of its filing, the Company offered three exhibits: Exhibit 1 – Summary of Updates; Exhibit 2 – Explanation of Updates; and Exhibit 3 – Update of Attachment A to Stipulation for Oregon Allocation.

The total impact of all of the adjustments increases net power costs by about $10.9 million on a total Company basis. The material factors contributing to the higher costs include an update to the Official Forward Price Curve, an increase to the Idaho Power transmission rate, and updated coal costs.

IV. THE STIPULATION

As noted above, on July 7, 2010, Pacific Power filed a stipulation among all parties. The parties agreed that the total-Company NPC for 2011 would be $1.233 billion, subject to the Rebuttal and Final Updates. They further agreed that this results in an Oregon-allocated NPC of $301.8 million, an increase of $58.2 million (including the load change adjustment).

The parties agreed that the $11 million reduction reflects consideration of the issues in the testimony of Staff, CUB, ICNU, and Sempra, changes in net power costs for corrections identified in the Company's April 21, 2010 filing, and corrections for the addition of a reserve requirement to the Dunlap wind project, the addition of Tieton Hydro to non-owned generation reserve requirements, and a correction to Lower Valley Energy Upper Facility qualifying facility pricing. These adjustments resolve all issues related to NPC as of the date of the Company's July 7, 2010, update.

The parties agree that the stipulated $11 million reduction to the baseline NPC is for settlement purposes only and does not imply agreement on the merits of any adjustment, nor does it imply that the parties have accepted any elements of the Company's NPC study. However, Pacific Power does agree to reflect certain specified changes to its methodology in the Company's 2012 TAM filing.

The stipulation includes a number of other provisions that address concerns raised by the parties. In future stand-alone TAM filings Pacific Power agrees to reflect forecast changes in Other Revenues for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in UE 217. The Company agrees to file to modify its Open Access Transmission Tariff to include charges for wind integration services to non-owned wind facilities and update line loss charges in its next rate case before the Federal Energy Regulatory Commission. Pacific Power agrees to reflect the final

Commission decision in docket UM 1355 in its 2011 TAM filing, if the decision is timely. ICNU agreed to dismiss and not refile its deferred accounting application in UM 1465. Pacific Power agrees to file an attestation with its Indicative Filing in this and in future TAM proceedings that will confirm that all contracts executed prior to the contract lockdown date have been included (or will identify any exceptions and the reasons why such contracts were excluded). The parties will work to develop a proposal to consider a change to the Company's TAM schedule, from a January 1 effective date to a July 1 effective date. Pacific Power agrees to increase the Schedule 294 transition adjustment to reflect the potential value associated with reselling BPA Point to Point wheeling rights. Pacific Power will continue to respond to bill inquiries from potential direct access customers, providing such information as is practicable.

The stipulation provides that Pacific Power will revise its rates to reflect the rate design agreed to by the parties in docket UE 217 (the general rate case).

The stipulation provides that Pacific Power will file its Final Update on November 15, 2010. The parties agree to make a good faith effort to follow specified procedures for challenges to the Final Update and compliance filing.

V. JOINT TESTIMONY

On July 26, 2010, Pacific Power filed the joint testimony of the parties in support of the stipulation. As stated in the testimony, the stipulation is a comprehensive settlement of all issues in the TAM proceeding. The stipulating parties further note in their testimony that the stipulation includes a number of other provisions, as summarized above.

The parties state their agreement to reduce Pacific Power's Oregon-allocated NPC by $11 million, resulting in an increase of $58.2 million to Oregon-allocated NPC (including the load change adjustment). They note that the Update filings may increase or decrease the final amount to be recovered in rates.

According to the parties, the stipulated rate spread is consistent with the TAM Guidelines and the stipulation adopted by the Commission in docket UE 199. The proposed Schedule 201 revenues by rate schedule were determined by spreading the total forecast NPC for the test year to the rate schedules in the same manner as the revenues for Schedule 200 were spread to the rate schedules in the Company's current general rate case.

The parties explain in the stipulation the procedures regarding challenges to Pacific Power's Final Update and compliance filings. They note that parties retain their procedural rights to raise any issue regarding the Final Updates prior to and during the Commission's public meeting. Parties may request that a specific amount of the tariff change be subject to deferral, subject to specified procedures.

The parties note that the stipulation provides for methodological changes in the 2012 TAM, and explain these changes. They explain other provisions of the stipulation, including accounting for changes in Other Revenue, the FERC filing to modify the

Company's Open Access Transmission Tariff to include charges for wind-integration services to non-owned wind facilities, the incorporation of the outcome of docket UM 1355, the resolution of ICNU's application for deferred accounting (docket UM 1465), the adjustments to reflect the potential value associated with reselling BPA wheeling rights, and billing issues related to direct access customers.

The parties agree to work together to develop a proposal for a change in Pacific Power's TAM schedule that would effectuate a change in the effective date from January 1 to July 1 of each year.

The parties agree that their proposed rates would be just and reasonable. Because the July Update had not been reviewed, the Final Updates have not been filed, and the final TAM rates are unknown, the parties have not yet reached agreement that the final TAM rates will be fair, just and reasonable.

VI. DISCUSSION

In this case the parties have submitted a stipulation that encompasses a broad range of procedural and substantive issues. The scope of their stipulation reflects the scope of the testimony that was filed by the parties. The scope of their testimony reflects the extent of their discovery and preparation. Their extensive participation provides the Commission with a high degree of comfort that the stipulation is in the public interest and should be approved.

The proposed adjustment to NPC appears reasonable, based on the issues raised by the parties to this proceeding. The resolution of issues not related directly to the calculation of the 2011 NPC affirms the parties' effort and good faith. The Commission commends the parties for their effort to improve the TAM approval process.

The stipulation is adopted.

VII. ORDER

IT IS ORDERED that:

1. Advice No. 10-002, filed by PacifiCorp, dba Pacific Power, on February 26, 2010, is permanently suspended.

2. The Stipulation, by and among PacifiCorp, dba Pacific Power, the Public Utility of Oregon Commission Staff, the Industrial Customers of Northwest Utilities, Sempra Energy LLC, and the Citizens' Utility Board of Oregon, is approved and is attached as Appendix A.

3. PacifiCorp, dba Pacific Power shall update its net power costs (NPC) to reflect the provisions of the stipulation to establish its Transition Adjustment Mechanism (TAM) NPC for the calendar year 2011, with tariffs to be effective January 1, 2011.

Made, entered, and effective SEP 16 2010.

Ray Baum
Chairman

John Savage
Commissioner

Susan K. Ackerman
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 216

In the Matter of: PACIFICORP, dba PACIFIC POWER 2011 Transition Adjustment Mechanism Schedule 201, Cost-Based Supply Service	**STIPULATION**

This Stipulation is entered into for the purpose of resolving the issues among the parties to UE 216, PacifiCorp's (or the "Company") proposed transition adjustment mechanism ("TAM").

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Sempra Energy Solutions LLC ("Sempra") (together, the "Parties"). The Parties represent all participants and intervenors in this docket.

BACKGROUND

2. On February 26, 2010, PacifiCorp filed revised tariff sheets for Schedule 201, Net Power Costs, Cost-Based Supply Service, to be effective January 1, 2011, which implements PacifiCorp's 2011 TAM. The purpose of the TAM filing is to update net power costs ("NPC") for 2011 and to set transition adjustments for Oregon customers who choose direct access in the November 2010 open enrollment window.

3. The February 26, 2010 TAM filing ("Initial Filing") reflected total forecasted normalized system-wide NPC for the test period (12 months ending December 31, 2011) of approximately $1.28 billion. On an Oregon-allocated basis, the forecasted normalized NPC in the Initial Filing were approximately $312.8 million. This amount is approximately $56.6 million higher than the $256.1 million included in rates through the NPC baseline established

in the 2010 TAM (Docket UE 207), or $69.2 million as adjusted for forecasted load loss in 2011. This would have resulted in an overall increase to Oregon rates of approximately 7.0 percent.

4. All Parties participated in three settlement conferences on June 10, 2010, June 14, 2010 and June 24, 2010.

5. The Parties have reached a comprehensive settlement of all issues raised prior to the Rebuttal Update in this case. The settlement establishes the baseline 2011 TAM NPC in rates, subject to TAM updates, and various TAM-related policy issues.

AGREEMENT

6. 2011 NPC. The Parties agree that the total-Company NPC for 2011 will be $1.233 billion, subject to the Rebuttal and Final Updates described in Section 7. The Parties agree that this is an Oregon-allocated NPC of $301.8 million or an increase of $58.2 million, including the load change adjustment, as shown in Exhibit A. This is based on the Parties agreement that Oregon-allocated NPC shall be reduced by $11.0 million. The $11.0 million reduction reflects consideration of the issues in the testimony of Staff, ICNU, CUB and Sempra; changes in net power costs for corrections identified in the Company's April 21, 2010 filing; and corrections for the addition of a reserve requirement to the Dunlap wind project, the addition of Tieton Hydro to non-owned generation reserve requirements, and a correction to Lower Valley Energy Upper Facility qualifying facility pricing. These adjustments resolve all issues related to Net Power Costs as of the date of the Company's July 7, 2010 update, and as reflected in paragraph 7, the correction of errors resulting from future updates are the only error corrections that may be made after execution of this Stipulation. The Parties, including PacifiCorp, cannot make additional error corrections or other changes to the Company's previous filings.

7. NPC Baseline and Rebuttal and Final Updates. The Company will update its Initial Filing consistent with the schedule adopted in this proceeding and as specified in the

TAM Guidelines, adopted in Order No. 09-274 and modified in Order No. 09-432. The Company shall file its Rebuttal Update on July 7, 2010, its Indicative Filing on November 8, 2010 and the Final Update on November 15, 2010 (collectively the Indicative Filing and the Final Update are referred to as the Final Updates). Parties agree that errors resulting from future updates are the only error corrections that may be made after execution of this Stipulation. Staff and Intervenors reserve the right to challenge all other elements of the Updates. The Updates may increase or decrease the Oregon-allocated increase of $58.2 million from base NPC.

8. Adjustments to NPC. The Parties agree that the stipulated $11 million reduction to the baseline NPC is for settlement purposes only and does not imply agreement on the merits of any adjustment, nor does it imply that the Parties have accepted any elements of the Company's NPC study. The Company does, however, agree to reflect the methodology changes listed in this paragraph in the 2012 TAM. The Company will also make the methodology changes listed in this paragraph in subsequent TAM filings, absent a change in facts or circumstances identified by the Company. The Company agrees to provide Parties with the details of these modeling changes by mid-January 2011 and to meet with Parties, if requested. The obligations in Paragraph 8 apply to the Company. Staff and Intervenors reserve the right to review, challenge and propose alternatives to the methodological changes listed below.

a. Screens – The Company will use a daily screening methodology that is more effective than that used in UE 216 and is based on logic which commits all gas plants up and backs down those that are not economic.

b. Black Hills CTs – The Company will use a four-year average for the costs of the Black Hills combustion turbines.

c. Heat Rates – The Company will not implement adjustments for scrubbers or other capital projects, but instead will rely on the traditional analysis of four years of actual data to derive the heat rate inputs.

d. APS Supplemental Coal and Other – The Company will model the option contracts to be exercised only when economic.

e. The Company will not include inter-hour wind integration charges for non-owned wind facilities.

f. The Company will include modeling of non-firm transmission links and costs using a four-year average.

9. <u>Other Revenue in Future Stand-Alone TAM Filings</u>. In future stand-alone TAM filings, the Company will reflect forecast changes in Other Revenue for items that have a direct relation to NPC, for which a revenue baseline has been established in rates in Docket UE 217. Exhibit B contains the revenue baselines from Docket UE 217 for the storage and exchange agreements for Seattle City Light Stateline and the non-Company owned Foote Creek projects, revenues from the Bonneville Power Administration associated with the South Idaho Exchange, steam revenues for Little Mountain and royalty offset revenues for the Georgia Pacific Camas contract.

10. <u>Wind Integration Charges for Non-Owned Wind Facilities/Line Losses</u>. The Company agrees to file to modify its Open Access Transmission Tariff to include charges for wind integration services to non-owned wind facilities and update line loss charges in its next rate case before the Federal Energy Regulatory Commission, which is scheduled to be filed in June 2011.

11. <u>UM 1355 – Forced Outage Rates</u>. The Company agrees to reflect the final Commission decision in Docket UM 1355 in the 2011 TAM if the decision is timely and issued prior to the Indicative Filing. The Parties agree that the adopted schedule in UM 1355, including the proposed Commission decision date, would result in a timely final order.

PacifiCorp will implement the final Commission decision in UM 1355, even if a party in UM 1355 seeks rehearing, reconsideration or appeal of the Commission decision. The Parties agree that this provision does not contain an express or implied waiver of PacifiCorp's rights, including but not limited to the right to seek clarification or challenge the UM 1355 decision or to seek to have the impact of the decision made subject to refund or deferral.

12. UM 1465 – 2010 TAM ICNU Deferral. ICNU agrees to dismiss and not refile its deferred accounting application in Docket UM 1465 based upon the resolution of the Company's application in Docket UP 260, authorizing the Company to sell Oregon-allocated renewable energy credits generated in 2010 that are ineligible for Oregon's renewable portfolio standard, with net proceeds to be credited to the property sales balancing account.

13. Attestation with Indicative Filing. The Company agrees to file an attestation with the Indicative Filing in this case and in future TAM filings. The attestation will confirm that all contracts executed prior to the contract lockdown date have been included in the Indicative Filing and will identify any exceptions and the reason why such contracts were excluded.

14. Challenges to Final Updates. Without waiving any procedural rights, the Parties agree to make a good faith effort to follow the following procedures for challenges to the Final Updates and compliance filing. Staff and Intervenors retain their procedural rights to raise any issue regarding the Company's Final Updates to the Commission prior to and during the Commission public meeting, including filing for a deferral of costs related to the final TAM updates or requesting that a portion of the TAM be allowed subject to refund. These procedures will apply to the 2011 and 2012 TAM filings. During the 2013 TAM filing, the Parties will review the effectiveness of these procedures.

a. PacifiCorp agrees to make a good faith effort to respond to all discovery requests after the Indicative Filing in five business days.

b. At least 10 business days before the Commission public meeting scheduled immediately prior to the effective date of the compliance filing, a Party will provide notice to the Parties of any potential concerns with the Company's Final Updates. The notice will identify the specific elements of the Updates that are relevant to the potential challenge and provide an explanation of the Party's concern.

c. No more than five business days after receiving the Party's notice, the Company will provide an initial response to the Parties regarding the concerns raised in the notice and the Parties will work to reach resolution of the issue.

d. If the matter is not resolved by the Parties prior the Commission public meeting, the Parties may make recommendations to the Commission at the public meeting to set a process to resolve the matter, if additional process is required. The recommendations may include that a specific amount of the tariff change will be subject to deferral until the Commission resolves the matter through additional process.

e. PacifiCorp will not oppose the filing of a deferral of any limited and specific cost which is identified by the Parties at least 10 business days before the Commission public meeting. Specifically, the Company will not challenge the deferral on the basis that it fails to meet the Commission's standards for deferred accounting as initially set forth in Order No. 05-1070 (Docket UM 1147), including issues related to the materiality of the filing and a showing of substantial harm. PacifiCorp otherwise retains the right to object to subject to refund or deferral treatment.

f. The Parties agree to request a schedule that will result in a Commission decision within 90 days of the effective date for new rates for any additional process after the Commission public meeting.

g. If the final Commission decision on any challenges to the Final Updates results in changes to the transition adjustments approved in Schedules 294 and 295, the Company may reflect in the direct access balancing account any difference between the approved transition adjustments and the transition adjustments that would have been in effect consistent with the Commission's decision on the challenged items.

15. Schedule for Future PacifiCorp TAMs. The Parties will work collaboratively to develop a proposal by fall of 2010 to consider a change to PacifiCorp's TAM schedule from an annual filing with a rate effective date of January 1 to an annual filing with a rate effective date of July 1. The proposal will consider mechanisms to mitigate financial impacts to PacifiCorp due to a potential six-month delay during the transition period. The Parties agree to work in good faith to reach agreement in a timeframe that will avoid a March 1, 2011 TAM and general rate case filing date.

16. BPA Transmission Credit for Direct Access. PacifiCorp agrees to increase the Schedule 294 transition adjustment by $(0.50)/MWh for the 2011 TAM for Schedule 747 and 748 customers to reflect the potential value associated with reselling BPA Point to Point ("PTP") wheeling rights from Mid-C to the Company's Oregon Service territory that are freed-up as a result of customers choosing direct access.

PacifiCorp also agrees to meet with an Energy Service Supplier ("ESS") upon request in advance of the November 2010 shopping window to discuss price, terms and potential quantities of BPA PTP wheeling rights to be purchased from PacifiCorp for delivery from all points of receipt considered to be Mid-C to the Company's Oregon service territory to serve direct access load.

Nothing in this agreement obligates PacifiCorp to sell any transmission rights to an ESS. PacifiCorp further agrees to evaluate this issue using the actual direct access customer data that results from the November 2010 shopping window, report its findings back to the parties, and use any knowledge gained to guide its filing of the 2012 TAM.

17. Direct Access Billing Information. PacifiCorp will continue to respond as appropriate to individual bill inquiries by potential direct access customers. To the extent that additional information is requested by a participating direct access customer on an on-going basis, the Company will endeavor to provide such information as practicable, consistent with

Schedule 300, Rule 11-2. Nothing in this provision prejudges the appropriateness of application of Schedule 300, Rule 11-2 in these circumstances.

Prior to the November 2010 shopping window, PacifiCorp will work with interested Parties to identify the billing information that PacifiCorp's CSS billing system can provide on a routine basis to direct access customers sufficient to allow such customers to reconcile their bills to the PacifiCorp tariff. If resolution of this issue is not reached by the start of the 2011 shopping window, the Parties agree to support the establishment of a collaborative process to address this issue.

18. Schedule 201. The Company will revise the Schedule 4 rates in Schedule 201 to reflect the rate design agreed to by the parties in Docket UE 217, the Company's general rate case proceeding. The rate spread will be as shown in Exhibit C.

19. Tariff. Upon approval of this Stipulation and concurrent with the filing of the Final Update, PacifiCorp will file revised Schedule 201 rates and revised transition adjustment Schedules 294 and 295 as a compliance filing in Docket UE 216, to be effective January 1, 2011, reflecting rates as agreed in this Stipulation.

20. This Stipulation will be offered into the record as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at hearing, and recommend that the Commission issue an order adopting the Stipulation.

21. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

22. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material

conditions in approving this Stipulation, any Party shall have the rights provided in OAR 860-014-0085, including the right to withdraw from the Stipulation, and shall be entitled to seek reconsideration or appeal of the Commission's Order.

23. By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

24. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such Party's signature.

PACIFICORP

By: Andrea Kelly

Date: 6 July 2010

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: 7/6/10

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: 7-6-2010

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: Irion Sanger

Date: July 6, 2010

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ________________________

Date:________________________

STAFF

By: ________________________

Date:________________________

CUB

By: ________________________

Date:________________________

ICNU

By: ________________________

Date:________________________

SEMPRA

By: Greg Cede

Date: July 6, 2010

Exhibit A

CY 2011 TAM

	ACCOUNT	UE-207 FINAL CY 2010	TAM CY 2011		Factors CY 2010	2011 GRC Factors CY 2011	UE-207 FINAL CY 2010	TAM CY 2011
Sales for Resale								
Existing Firm PPL	447	24,974,154	**25,032,103**	SG	26.877%	26.177%	6,712,274	**6,552,676**
Existing Firm UPL	447	25,490,589	**25,490,589**	SG	26.877%	26.177%	6,851,076	**6,672,694**
Post-Merger Firm	447	641,195,998	**594,135,708**	SG	26.877%	26.177%	172,333,505	**155,527,424**
Non-Firm	447	55,979,012	**-**	SE	25.002%	24.283%	13,995,816	**-**
Total Sales for Resale		747,639,753	**644,658,400**				199,892,672	**168,752,793**
Purchased Power								
Existing Firm Demand PPL	555	58,677,959	**47,758,104**	SG	26.877%	26.177%	15,770,807	**12,501,681**
Existing Firm Demand UPL	555	46,338,071	**48,168,584**	SG	26.877%	26.177%	12,454,230	**12,609,132**
Existing Firm Energy	555	57,763,587	**52,340,132**	SE	25.002%	24.283%	14,441,994	**12,709,916**
Post-merger Firm	555	376,161,158	**490,088,073**	SG	26.877%	26.177%	101,100,399	**128,290,783**
Secondary Purchases	555	(12,954,749)	**-**	SE	25.002%	24.283%	(3,238,933)	**-**
Seasonal Contracts	555		**-**	SSGC	0.000%	0.000%	-	**-**
Other Generation Expense	555	7,682,475	**38,855,180**	SG	26.877%	26.177%	2,064,810	**10,171,154**
Total Purchased Power		533,668,503	**677,210,072**				142,593,306	**176,282,667**
Wheeling Expense								
Existing Firm PPL	565	43,189,893	**40,049,244**	SG	26.877%	26.177%	11,608,098	**10,483,726**
Existing Firm UPL	565	168,268	**259,960**	SG	26.877%	26.177%	45,225	**68,050**
Post-merger Firm	565	100,938,303	**99,966,153**	SG	26.877%	26.177%	27,128,533	**26,168,227**
Non-Firm	565	253,429	**101,247**	SE	25.002%	24.283%	63,362	**24,586**
Total Wheeling Expense		144,547,893	**140,376,605**				38,845,218	**36,744,589**
Fuel Expense								
Fuel Consumed - Coal	501	610,479,015	**638,135,027**	SE	25.002%	24.283%	152,631,345	**154,960,306**
Cholla / APS Exchange	501	55,113,078	**56,675,765**	SSECH	25.408%	24.812%	14,003,311	**14,062,190**
Fuel Consumed - Gas	501	7,304,914	**6,171,919**	SE	25.002%	24.283%	1,826,367	**1,498,746**
Natural Gas Consumed	547	410,130,960	**390,763,656**	SE	25.002%	24.283%	102,540,527	**94,890,350**
Simple Cycle Combustion Turbines	547	11,664,948	**9,951,264**	SSECT	23.286%	22.403%	2,716,330	**2,229,400**
Steam from Other Sources	503	3,498,000	**3,555,701**	SE	25.002%	24.283%	874,566	**863,442**
Total Fuel Expense		1,098,190,915	**1,105,253,332**				274,592,445	**268,504,434**
Net Power Cost		1,028,767,558	**1,278,181,609**				256,138,297	**312,778,897**

Settlement Adjustment	(11,000,000)
OR-Allocated NPC Baseline in Rates	301,778,897
Increase Absent Load Change	**45,640,600**
Weighted Ave OR Allocation Factor	0.24471
Updated NPC Baseline in Rates	1,233,229,734

Oregon-allocated NPC Baseline in Rates from UE 207	256,138,297
$ Change due to load variance from UE-207 forecast	(12,529,976)
2011 Recovery of NPC in Rates	243,608,321
Increase Including Load Change	**58,170,576**

PacifiCorp
Other Revenues - Baseline

	12 ME Dec 2011	OR Factor	OR %	OR Alloc	Reference
Seattle City Light - Stateline Wind Farm	4,923,706	SG	26.177%	1,288,883	Attachment OPUC 21 (UE-216)
Non-company owned Foote Creek	2,277,984	SG	26.177%	596,310	Attachment OPUC 21 (UE-216)
BPA South Idaho Exchange	8,553,309	SG	26.177%	2,239,007	Attachment OPUC 21 (UE-216)
Little Mountain Steam Revenues	6,873,305	SG	26.177%	1,799,231	UE 217 Exhibit PPL/1102, Page 5.2
James River Royalty Offset	5,430,652	SG	26.177%	1,421,586	UE 217 Exhibit PPL/1102, Page 5.2
Total Other Revenue	28,058,956			7,345,017	

Exhibit C

ORDER NO 10-363

APPENDIX A
PAGE 17 OF 16

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

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[2]	Change Net Rates ($000)	Change Net Rates %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (6) + (7)	(9)	(10)	(11) (9) + (10)	(12) (9) - (6)	(13) (12)/(6)	(14) (11) - (8)	(15) (14)/(8)	
	Residential															
1	Residential	4	4	484,011	5,306,840	$472,654	$19,369	$492,023	$497,805	$19,369	$517,174	$25,151	5.3%	$25,151	5.1%	1
2	**Total Residential**			484,011	5,306,840	$472,654	$19,369	$492,023	$497,805	$19,369	$517,174	$25,151	5.3%	$25,151	5.1%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,207	1,013,838	$94,181	($628)	$93,553	$99,099	($628)	$98,471	$4,918	5.2%	$4,918	5.3%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,419	2,011,827	$133,835	$10,844	$144,679	$142,877	$10,844	$153,721	$9,042	6.8%	$9,042	6.3%	4
5	Gen. Svc. 201 - 999 kW	30	30	882	1,386,076	$85,559	$4,215	$89,774	$91,653	$4,215	$95,868	$6,094	7.1%	$6,094	6.8%	5
6	Large General Service >= 1,000 kW	48	48	212	2,349,055	$128,583	($2,726)	$125,857	$138,860	($2,726)	$136,134	$10,277	8.1%	$10,277	8.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	381,991	$19,268	($446)	$18,822	$20,887	($446)	$20,441	$1,619	8.1%	$1,619	8.2%	7
8	Agricultural Pumping Service	41	41	6,211	149,120	$16,054	($3,276)	$12,778	$16,604	($3,276)	$13,328	$550	3.4%	$550	4.3%	8
9	Agricultural Pumping - Other	33	33	2,056	127,459	$5,327	$272	$5,599	$5,327	$272	$5,599	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			93,994	7,419,366	$482,807	$8,255	$491,062	$515,307	$8,255	$523,562	$32,500	6.7%	$32,500	6.6%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,167	10,138	$1,332	$136	$1,468	$1,457	$136	$1,593	$125	9.4%	$125	8.5%	11
12	Street Lighting Service	50	50	258	10,594	$1,198	$144	$1,342	$1,305	$144	$1,449	$107	8.9%	$107	8.0%	12
13	Street Lighting Service HPS	51	51	710	16,563	$3,021	$338	$3,359	$3,286	$338	$3,624	$265	8.8%	$265	7.9%	13
14	Street Lighting Service	52	52	65	1,061	$117	$15	$132	$130	$15	$145	$13	11.1%	$13	9.9%	14
15	Street Lighting Service	53	53	266	9,250	$605	$83	$688	$653	$83	$736	$48	7.9%	$48	7.0%	15
16	Recreational Field Lighting	54	54	103	847	$75	$7	$82	$83	$7	$90	$8	10.7%	$8	9.8%	16
17	**Total Public Street Lighting**			8,569	48,453	$6,348	$723	$7,071	$6,914	$723	$7,637	$566	8.9%	$566	8.0%	17
18	**Total Sales to Ultimate Consumers**			586,574	12,774,659	$961,809	$28,347	$990,156	$1,020,026	$28,347	$1,048,373	$58,217	6.1%	$58,217	5.9%	18
19	**Employee Discount**				18,045	($397)	($17)	($414)	($418)	($17)	($435)	($21)		($21)		19
20	**Total Sales with Employee Discount**			586,574	12,774,659	$961,412	$28,330	$989,742	$1,019,608	$28,330	$1,047,938	$58,196	6.1%	$58,196	5.9%	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	$1,022,408	$28,330	$1,050,738	$58,196	6.0%	$58,196	5.9%	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] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Exhibit C

Line No.	Description	Pre Sch No.	Line No.
	(1)	(2)	
	Residential		
1	Residential	4	1
2	**Total Residential**		2
	Commercial & Industrial		
3	Gen. Svc. < 31 kW	23	3
4	Gen. Svc. 31 - 200 kW	28	4
5	Gen. Svc. 201 - 999 kW	30	5
6	Large General Service >= 1,000 kW	48	6
7	Partial Req. Svc. >= 1,000 kW.	47	7
8	Agricultural Pumping Service	41	8
9	Agricultural Pumping - Other	33	9
10	**Total Commercial & Industrial**		10
	Lighting		
11	Outdoor Area Lighting Service	15	11
12	Street Lighting Service	50	12
13	Street Lighting Service HPS	51	13
14	Street Lighting Service	52	14
15	Street Lighting Service	53	15
16	Recreational Field Lighting	54	16
17	**Total Public Street Lighting**		17
18	**Total Sales to Ultimate Consumers**		18
19	**Employee Discount**		19
20	**Total Sales with Employee Discount**		20
21	AGA Revenue		21
22	**Total Sales with Employee Discount and AGA**		22

[1] Excludes effects of the Low Income Bill Payment Ass

[2] Percentages shown for Schedules 48 and 47 reflect th