ORDER NO. 09-432
ENTERED 10/30/09

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of PACIFICORP, dba PACIFIC POWER 2010 Transition Adjustment Mechanism	ORDER

DISPOSITION: STIPULATION ADOPTED

I. BACKGROUND

On March 30, 2009, PacifiCorp, dba Pacific Power (Pacific Power or the Company), filed revised tariff sheets for Schedule 200, as well as testimony and exhibits regarding the Company's 2010 Transition Adjustment Mechanism (TAM), with the Public Utility Commission of Oregon (Commission). Pursuant to Order No. 05-1050, Pacific Power is required to make an annual TAM filing by April 1 of each year. The purpose of the TAM filing is to update the Company's annual net power costs (NPC) and to set transition credits for Oregon customers choosing direct access. Pacific Power requested an effective date of January 1, 2010, for the Schedule 200 revised tariff sheets.

The 2010 TAM filing, as initially submitted on March 30, 2009 (Initial Filing), reflected a forecasted, normalized NPC for the test period (12 months ending December 31, 2010) of approximately $1.101 billion on a system-wide basis (total-Company NPC), and $273 million on an Oregon-allocated basis (Oregon NPC). The latter amount is approximately $20.6 million greater than the NPC baseline established in the 2009 TAM (docket UE 199), as adjusted for forecasted load loss in 2010, resulting in a 2.1 percent overall increase in Oregon rates.

On July 14, 2009, reply testimony was filed by Commission Staff (Staff), the Industrial Customers of Northwest Utilities (ICNU), the Citizens' Utility Board (CUB), and Sempra Energy Solutions, LLC (Sempra). On August 11, 2009, Pacific Power filed rebuttal testimony and exhibits. On August 25. 2009, surrebuttal testimony was filed by Staff, ICNU, and CUB. On September 4, 2009, Pacific Power filed sur-surrebuttal testimony and exhibits.

As part of the Company's rebuttal testimony filed on August 11, 2009, Pacific Power filed an update and corrections to the Initial Filing (Rebuttal Update). The Rebuttal Update decreased the Company's forecasted normalized 2010 NPC on an Oregon-allocated basis, as filed in the Initial Filing, by $0.6 million to $272.4 million.

Settlement conferences were held on August 18, 2009, and September 10, 2009. Pacific Power, Staff, ICNU, CUB, and Sempra participated in both settlement conferences.

On September 11, 2009, Pacific Power notified the Commission that a comprehensive settlement in principle on all 2010 TAM issues had been reached among Pacific Power, Staff, CUB, ICNU, and Sempra. On September 25, 2009, Pacific Power filed the executed Stipulation along with Joint Testimony in Support of the Stipulation.

II. THE STIPULATION AND SUPPORT FOR THE STIPULATION

The Stipulation, attached to this order as Appendix A, provides that Pacific Power, Staff, CUB, ICNU, and Sempra (the Stipulating Parties) agree, subject to the final TAM update (Final Update), to a baseline 2010 TAM NPC in rates and an increase in NPC revenues to be collected in 2010. The Stipulating Parties further agree on TAM guideline issues raised in two dockets, UE 207 and UE 210.

A. 2010 NPC

The Stipulating Parties agree that Pacific Power's total-Company NPC for 2010 will be $1.031 billion, subject to the Final Update.

The Stipulating Parties agree that the total-Company NPC of $1.031 billion results in an Oregon NPC of $256,395,751, thereby increasing Oregon rates by $4 million, or approximately 0.4 percent, as set forth in Exhibit A to Appendix A.

B. NPC Baseline and Updates

The Stipulating Parties agree that Pacific Power will revise the Rebuttal Update for the NPC elements twice, as prescribed by the TAM Guidelines. On November 9, 2009, Pacific Power will file the "Indicative Run," and on November 16, 2009, Pacific Power will file the "Final Update." Contracts will be "locked down" on November 2, 2009. Changes produced by the updates in November may be positive or negative and the Stipulating Parties agree that there is no cap on the updates to be made in November.

Exhibit B to Appendix A sets forth a baseline NPC report that reflects the stipulated total-Company NPC prior to either update. The report includes adjustments to specific NPC elements for purposes of calculating the total-company NPC and the Oregon NPC. All adjustments, except for Pacific Power's Condit facility, will be updated in November. For the Condit Facility, the Company will run the GRID model with a full year of forecast data, as the Stipulating Parties agree, rather than the nine months of forecast data and a proxy amount for the last three months of 2010 currently included in the NPC report. The Stipulating Parties agree that the adjustments reflected in this report are for settlement purposes only and do not imply agreement on the merits of the adjustments, nor acceptance of any NPC elements. Pacific Power agrees to provide workpapers with each update in November. The workpapers will track the incremental and cumulative changes to the estimated NPC for 2010.

C. UM 1355

The Stipulating Parties agree that the Commission's order in docket UM 1355 will not affect the projected $4.0 million increase in NPC for 2010 and that such notice will be filed in that docket. The Stipulating Parties further agree that Pacific Power will implement any specific orders made by the Commission in docket UM 1355 in the Company's next TAM filing or general rate case filing.

D. Accounting Application

Pacific Power agrees to request, concurrent with the filing of this Stipulation, permission to withdraw, without prejudice, the Company's application for an accounting order regarding Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) No. 04-6 (relating to coal stripping costs) in docket UM 1448. The Stipulating Parties agree not to oppose such a request.

E. TAM Guidelines

The Stipulating Parties agree to interpret or amend certain TAM Guidelines for this and all future proceedings.[1] The parties indicate that "a difference came to light" during this proceeding "between how the Company and other parties interpret the TAM Guidelines in terms of limitations on other parties."[2] The Stipulating Parties agree to language in the Stipulation that explains how the TAM Guidelines should be interpreted to apply in a more "symmetrical manner with respect to specific issues concerning inputs, costs, updates, modeling assumptions, methodologies and error corrections."[3] The Stipulating Parties agree that: (1) the TAM Guidelines define the types of errors and omissions that the Company can correct after the Initial Filing but do not limit the ability of parties, including the Company, to propose corrections consistent with TAM Guidelines after the Company's Initial Filing; (2) the TAM Guidelines define the scope of the updates that the Company can make to its GRID model after the Initial filing but do not limit the ability of other parties to propose updates consistent with the TAM Guidelines after the Company's Initial Filing; and (3) the TAM Guidelines define the cost elements that will be included in the Company's NPC in stand-alone TAM proceedings, but do not limit the ability of parties, including the Company, to propose changes to the TAM Guidelines, including changes to the cost elements that will comprise NPC in stand-alone TAM proceedings, in future rate cases.

Issues regarding the interpretation and application of TAM Guidelines were also raised in docket UE 210. The Stipulating Parties (which include all parties to docket UE 210 as well) agreed, however, to address the two TAM Guideline issues that are outstanding in docket UE 210 in this docket:

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[1] The TAM Guidelines, originally adopted by the Commission in Order No. 09-274, describe the general purpose and scope of TAM proceedings, delineate workpapers and supporting documents that Pacific Power must provide with TAM filings, and provide guidance on timing and elements of different filings in TAM proceedings. At the time the TAM Guidelines were adopted, it was acknowledged that not all potential issues regarding the process and scope of the TAM had been resolved. Order No. 09-274 at 6.
[2] Joint Testimony at 8.
[3] *Id.*

1. New Generation Resources without Fixed Cost Recovery

At issue was the question of, "whether variable costs of a new generation resource could be included in a stand-alone TAM if the Company will not recover the fixed costs in the TAM rate effective period?"[4] The Stipulating Parties agree to amend the TAM Guideline that addresses when the variable costs and dispatch benefits of new resources will be included in stand-alone TAM filings. The TAM will include the variable costs and dispatch benefits of new resources that are not eligible for recovery through the Renewable Adjustment Clause (adopted in Order No. 08-548) if: (a) the Company has acquired the resource prior to April 1 of the year of the stand-alone TAM filing; or (b) the Company built the resource, and it was used and useful prior to April 1 of the year of the stand-alone TAM filing.

The prudence of building or acquiring the resource will be determined in the stand-alone TAM proceeding. Parties are not prohibited from challenging the prudence of the Company's decision or proposing a disallowance of related costs. Notice will be provided by March 1 of the year of a stand-alone TAM filing that the filing will include a new resource that falls under this guideline.

2. Methodological Changes

Another question asked whether "changes in methodologies utilized in the calculation of NPC will be permitted in stand-alone TAM proceedings."[5] The Stipulating Parties agree to modify TAM Guidelines to permit Pacific Power to propose changes to the methodologies used to calculate the cost elements and other inputs to the GRID model in stand-alone TAM filings. The Company will provide notice of substantial changes to the logical constructs, methodologies, or calculations used in the GRID model by March 1 of the year of a stand-alone TAM filing. Pacific Power also agrees to explain and justify any substantial change in model logic, methodology, or calculation in the Company's annual TAM filing on April 1. For each such change, the Company will provide, when practical to do so, workpapers that contain a side-by-side comparison of GRID model results with and without the proposed change. The Stipulating Parties agree that methodological changes or challenges to the Company's existing or proposed methodologies may be addressed in future general rate cases or stand-alone TAM filings.

F. Calculation of Transition Adjustments.

Transitions Adjustments in Schedules 294 and 295 will be calculated based on the Final Update. The Transition Adjustments in Schedules 294 and 295 will also be consistent with the modifications to the calculation described in Section 15 of the Stipulation adopted by the Commission in Order No. 08-543 in docket UE 199.[6]

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[4] Joint Testimony in Support of Stipulation at 6.
[5] *Id* at 7.
[6] The Stipulating Parties explain at 11 of the Joint Testimony:

Section 15 of the docket UE 199 Stipulation modifies the calculation of the transition adjustment in two ways: (1) the Company will relax the market cap limitations in the GRID model by 15 MW at Mid-Columbia and 10 MW at COB to determine the value of the freed up power; and (2) any remaining monthly thermal

For purposes of calculating the Transition Adjustments in Schedules 294 and 295, the Stipulating Parties agree that losses will include primary and secondary line losses, as applicable, in addition to the transmission losses already included in the calculation.

As the Stipulating Parties agree that direct access customers may no longer bypass Schedule 200, it will not be subtracted in the calculation of the Transition Adjustment Schedules 294 and 295 for all months in 2010. To implement this change effective on January 1, 2010, Pacific Power will file revised tariff sheets for Schedule 200 with per kilowatt-hour rates for direct access rate schedules that collect the portion of Schedule 200 that may no longer be bypassed. Direct access customers will pay the rate that is comparable to the proposed Schedule 200 in docket UE 210.

G. Multi-Year Opt Out Enrollment Period

The Stipulating Parties agree that the enrollment period for the Multi-Year Opt-Out Schedule 295 will be extended, beginning at Noon on November 16, 2009, and ending at Noon on December 7, 2009.

H. Revenue Allocation and Rate Design

The Stipulating Parties agree that the final Oregon-allocated NPC increase and load change adjustment will be calculated according to TAM Guidelines and as illustrated in Exhibit C to Appendix A.

Pursuant to TAM Guidelines and a Stipulation filed in docket UE 210, the Stipulating Parties propose to change the current rate design for Schedule 200. As proposed, all NPC would be collected through a new Schedule 201, Net Power Costs, which will be a rider to Schedule 200. Schedule 200 would collect all other generation costs. To implement the change should the Stipulation in docket UE 210 be approved, the Company will file the redesigned schedules in a compliance filing in that docket, to be effective February 2, 2010.

I. Tariffs

The Stipulating Parties agree that Pacific Power will file, concurrent with the filing of the Final Update, revised Schedule 200 rates as well as revised Schedules 294 and 295 (Transition Adjustment) as a compliance filing in docket UE 207. These revised tariffs will be consistent with the Stipulation in this docket and will be effective as of January 1, 2010. For the period of January 1, 2010, through February 1, 2010, the final NPC revenue increase will be spread by Schedule 200 alone. After February 1, 2010, the NPC rates will be collected pursuant to the new Schedule 201, if approved.

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generation that is backed down for assumed direct access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID. The monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. The existing balancing account mechanism will remain in effect.

III. DISCUSSION

The Commission encourages Staff and parties to voluntarily resolve issues to the extent that settlement is in the public interest. Staff and all parties entered into a Stipulation that resolves all primary issues in this proceeding. No person has filed an objection to the Stipulation.

The Commission has examined the Stipulation, the Joint Explanatory Brief, and the pertinent record in the case. The Commission concludes that the Stipulation is an appropriate resolution of all primary issues in this docket. The Commission adopts the Stipulation in its entirety without modification.

The Commission notes, however, that certain methodological modeling matters raised merit additional analysis in future TAM filings. For example, the Commission expects Staff and parties to continue to evaluate and address in Pacific Power's next TAM issues regarding how to best model Pacific Power's hydro and thermal generation, and the question of whether other revenue associated with variable power costs should be updated in a stand-alone TAM filing. The Commission also expects Pacific Power to keep it apprised of the status of the Federal Energy Regulatory Commission (FERC) study on wind integration and its potential impact on Oregon customers. Pacific Power should notify the Commission when it determines whether or not to include a wind integration tariff in the Company's next FERC rate case.

IV. ORDER

IT IS ORDERED that:

1. The Stipulation is adopted.

2. Consistent with the Stipulation, Pacific Power will file two Transition Adjustment Mechanism (TAM) Updates in November. On November 9, 2009, Pacific Power will file the Indicative Run, and on November 16, 2009, Pacific Power will file the Final Update.

3. Advice No. 09-007, filed by Pacific Power on March 30, 2009, is permanently suspended.

4. Pacific Power will file revised Schedules 200, 294, and 295 rates concurrent with the filing of the Final Update. These revised tariffs will be consistent with the Stipulation in this docket and will be effective as of January 1, 2010. For the period of January 1, 2010, through February 1, 2010, the final NPC revenue increase will be spread by Schedule 200 alone. After February 1, 2010 the NPC rates will be collected pursuant to the new Schedule 201, if approved.

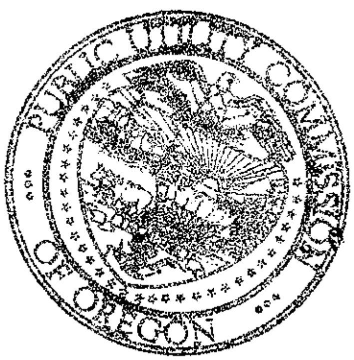
5. Pacific Power will provide an update to the Commission in 2010 on the status of the Federal Energy Regulatory Commission (FERC) study on wind integration and its potential impact on Oregon customers. Pacific Power will also notify the Commission if the Company will include a wind integration tariff in the Company's next FERC rate case.

Made, entered, and effective OCT 30 2009.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
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 207

In the Matter of: PACIFICORP, dba PACIFIC POWER 2010 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service	**STIPULATION**

This Stipulation is entered into for the purpose of resolving the issues among the parties to this Stipulation related to PacifiCorp's (or the "Company") proposed transition adjustment mechanism ("TAM") for direct access that updates the Company's net power costs ("NPC") in rates.

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("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 March 30, 2009, PacifiCorp filed revised tariff sheets for Schedule 200, PacifiCorp's 2010 Transition Adjustment Mechanism, to be effective January 1, 2010. The purpose of the TAM filing is to update NPC for 2010 and to set transition adjustments for Oregon customers who choose direct access in the November 2009 open enrollment window.

3. The March 30, 2009 TAM filing ("Initial Filing") reflected total forecasted normalized system-wide NPC for the test period (12 months ending December 31, 2010) of approximately $1.101 billion. On an Oregon-allocated basis, the forecasted normalized NPC in the Initial Filing were approximately $273 million. This amount is approximately $20.6 million higher than the $252.4 million included in rates through the NPC baseline established

in the 2009 TAM (Docket UE 199), as adjusted for forecasted load loss in 2010. This would have resulted in an overall increase to Oregon rates of approximately 2.1 percent.

4. On August 11, 2009, the Company filed an update and corrections to the Initial Filing ("Rebuttal Update"). The updates and corrections decreased the Company's forecasted normalized NPC for the calendar year 2010 on an Oregon-allocated basis to $272.4 million. This reflected a decrease of $0.6 million from the Company's Initial Filing.

5. The Parties convened settlement conferences on August 18, 2009 and September 10, 2009. All Parties to the docket participated in the settlement conferences.

6. As a result of the settlement conferences, the Parties have reached a comprehensive settlement in this case. The settlement establishes the baseline 2010 TAM NPC in rates, subject to the final TAM updates; the increase in NPC revenues to be collected in 2010; and issues relating to the TAM Guidelines addressed in this docket and in Docket UE 210.

AGREEMENT

7. 2010 NPC. The Parties agree that the total-Company NPC for 2010 will be $1.031 billion, subject to the Final Update described in Section 8. The Parties agree that the total-Company NPC of $1.031 billion results in Oregon-allocated NPC of $256,395,751, which is an increase of $4.0 million on an Oregon-allocated basis over the $252,395,751 that would be collected by current rates, as shown in Exhibit A. This results in an overall increase to Oregon rates of $4 million, or approximately 0.4 percent.

8. NPC Baseline and Final Update. The Company will update its Rebuttal Update for the NPC elements described in the TAM Guidelines, adopted by the Commission in Order No. 09-274, on November 9, 2009 (the "Indicative Run") and November 16, 2009 (the "Final Update"), with a contract lock-down date of November 2, 2009. Exhibit B to the Stipulation is the baseline net power cost report that reflects the stipulated total company NPC, prior to the November updates described in this Section. The Parties agree that the adjustments

reflected in the baseline net power cost report are for settlement purposes only and do not imply agreement on the merits of the adjustments, nor do they imply that the Parties have accepted any elements of the Company's NPC study. With each of the two GRID model updates listed above, the Company will provide workpapers that track the incremental and cumulative changes to the estimated NPC for 2010 from this baseline. This tracking will provide a step-by-step progression of each change to the GRID model and its incremental impact on forecasted NPC for 2010. Nothing in this paragraph is intended to change or override the workpaper and other filing requirements in place under the TAM Guidelines for the final updates.

9. UM 1355. The $4.0 million increase described in Section 7 includes any changes to NPC for 2010 that may result from the Commission's decision in Docket UM 1355. The Commission's order in Docket UM 1355 will not affect the $4.0 million increase. The Parties agree to file notice in Docket UM 1355 that the parties have resolved the potential revenue impact from that docket on the 2010 TAM through this Stipulation. The Parties further agree that the Company will implement the Commission's decision in Docket UM 1355 in its next TAM filing and/or general rate case filing.

10. EITF Accounting Application. PacifiCorp agrees that it will request concurrently with the filing of this Stipulation that the Commission permit it to withdraw without prejudice its application for an accounting order regarding EITF 04-6, now docketed in UM 1448. The Parties agree to not oppose PacifiCorp's request to withdraw its application for an accounting order regarding EITF 04-6.

11. TAM Guidelines. The Parties agree that in this and future TAM filings, the TAM Guidelines will be interpreted or amended to include the following new or clarifying provisions in sections 12-14 of this Stipulation. The Parties agree to file notice in Docket UE 210 that the Parties have resolved the TAM design-related issues in that docket through this Stipulation.

12. New Generation Resources without Fixed Cost Recovery. The Company will include the variable costs and dispatch benefits of new resources that are not eligible for inclusion in the Renewable Adjustment Clause in its NPC in stand-alone TAM proceedings, irrespective of whether the fixed capital costs of the new resource are already included in rates, if: (a) the Company acquired the resource prior to April 1st of the year of the stand-alone TAM filing, or (b) the Company built the resource and it was used and useful prior to April 1st of the year of the stand-alone TAM filing.

The prudence of the decision to build or acquire the resource will be determined in the stand-alone TAM proceeding prior to including the variable costs and dispatch benefits in rates. This provision does not limit the Parties' ability to challenge the prudence of the Company's decision to build or acquire the resource in subsequent rate proceedings based on the discovery of new information or evidence, to the extent provided by law. This provision also does not limit the Parties' ability to propose a disallowance of the fixed capital costs or fixed construction costs associated with the new resource in subsequent rate proceedings. The Company will provide notice to the parties if a new resource subject to this section will be included in the TAM filing by March 1st of the year of the stand-alone TAM filing.

13. Methodological Changes. The Company will provide notice of substantial changes to the methodologies used to calculate the cost elements and other inputs to the GRID model or to the logic of the GRID model by March 1st of the year of a stand-alone TAM filing. The Company will include in its April 1st TAM filing a justification for each substantial change in methodology, calculation of cost elements, or model logic. For each change in input methodology or model logic, where practical, the Company will also provide workpapers that contain a side-by-side comparison of GRID model results with and without the proposed change in methodology, calculation of cost elements or model logic. The Parties agree that methodological changes, or challenges to the Company's existing or proposed methodologies

can be addressed in future stand-alone TAM proceedings, whether litigated in a general rate case or a stand-alone TAM filing.

14. Clarification/Revision of TAM Guidelines.

a. The TAM Guidelines, established in Order No. 09-274, define the types of errors and omissions that the Company can correct after its Initial Filing. The Parties agree that the TAM Guidelines do not limit the ability of Parties, including the Company, to propose corrections consistent with the TAM Guidelines after the Company's Initial Filing.

b. The TAM Guidelines, established in Order No. 09-274, define the scope of the updates that the Company can make to its GRID model after its Initial Filing. The Parties agree that the TAM Guidelines do not limit the ability of other Parties to propose updates consistent with the TAM Guidelines after the Company's Initial Filing.

c. The TAM Guidelines, established in Order No. 09-274, define the cost elements that will be included in the Company's NPC in stand-alone TAM proceedings. The Parties agree that the TAM Guidelines do not limit the ability of the Company or other Parties to propose changes to the TAM Guidelines, including changes to the cost elements that will comprise NPC in stand-alone TAM proceedings, in future general rate cases.

15. Transition Adjustments.

a. Transition adjustments in Schedules 294 and 295 will be calculated based on the Final Update and consistent with the modifications to the calculation described in Section 15 of the Stipulation adopted by the Commission in Order No. 08-543 in Docket UE 199.

b. For consistency, the Transition Adjustment for all months in 2010 shall reflect the Parties' agreement that, with the implementation of changes to Schedules 200 and 201 in UE 210, Schedule 200 will no longer be bypassable to direct access customers and will not be subtracted in the calculation of the Transition Adjustment. For January 2010, the Company will calculate the rate that is comparable to the proposed Schedule 201 in UE 210, and direct access customers will pay the rate that is comparable to the proposed Schedule 200 in UE 210.

c. For purposes of calculating the transition adjustments in Schedules 294 and 295, losses will include primary and secondary line losses, as applicable, in addition to the transmission losses already included in the calculation.

16. Multi-Year Opt Out Enrollment Period. The Parties agree that the enrollment period for the Multi-Year Opt Out (Schedule 295) will begin at Noon on November 16, 2009 and end at Noon on December 7, 2009.

17. Revenue Allocation and Rate Design. The Parties agree that the final Oregon-allocated NPC increase and load change adjustment will be calculated consistently with the TAM Guidelines and as illustrated in Exhibit C.

18. Tariff. Upon approval of this Stipulation and concurrent with the filing of the Final Update, PacifiCorp will file revised Schedule 200 rates and revised transition adjustment Schedules 294 and 295 as a compliance filing in Docket UE 207, effective January 1, 2010, reflecting rates designed as agreed in this Stipulation.

19. The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the adjustments and the rates resulting from their application are sufficient, fair, just, and reasonable.

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

21. 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 disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

22. 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.

23. 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	STAFF
By: Andrea Kelly	By: ____________
Date: ____________	Date: ____________
CUB	ICNU
By: ____________	By: ____________
Date: ____________	Date: ____________
SEMPRA	
By: ____________	
Date: ____________	

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: 9/25/9

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: Rt Jul

Date: 9-25-09

ICNU

By: ______________________

Date: ______________________

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

STAFF

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: [signature]

Date: Sept 25 2009

SEMPRA

By: ______________________

Date: ______________________

PACIFICORP

By: ____________________

Date: ____________________

STAFF

By: ____________________

Date: ____________________

CUB

By: ____________________

Date: ____________________

ICNU

By: ____________________

Date: ____________________

SEMPRA

By: Peter J. Richardson

Date: 9/25/09

Peter Richardson

Docket UE 207

STIPULATION OF JOINT PARTIES

Exhibit A

NPC Allocation

September 25, 2009

Exhibit A - NPC (UE 207)
Settlement - September 2009

	ACCOUNT	FINAL UE-199 CY 2009	Original Filing CY2010	August Update CY2010	Settlement Adjustment CY2010	Settlement CY2010		FINAL UE-199 CY 2009	FILED CY2010	GRC Reply Factors CY2010	FINAL UE-199 CY 2009	Original Filing CY2010	August Update CY2010	Settlement CY2010
Sales for Resale														
Existing Firm PPL	447	24,281,555	24,656,916	24,975,068	-	24,975,068	SG	26.411%	26.877%	26.877%	6,413,106	6,627,011	6,712,520	6,712,520
Existing Firm UPL	447	25,490,590	25,490,589	25,490,589	-	25,490,589	SG	26.411%	26.877%	26.877%	6,732,429	6,851,076	6,851,076	6,851,076
Post-Merger Firm	447	882,169,664	696,790,188	639,656,892	(4,392,436)	635,264,457	SG	26.411%	26.877%	26.877%	232,993,623	187,275,491	171,919,842	170,739,292
Non-Firm	447	-	-	-	55,979,012	55,979,012	SE	25.525%	25.002%	25.002%	-	-	-	13,995,816
Total Sales for Resale		931,941,809	746,937,693	690,122,550	51,586,576	741,709,126					246,139,158	200,753,578	185,483,438	198,298,704
Purchased Power														
Existing Firm Demand PPL	555	62,711,383	57,671,363	59,132,864	-	59,132,864	SG	26.411%	26.877%	26.877%	16,562,973	15,500,265	15,893,071	15,893,071
Existing Firm Demand UPL	555	46,726,726	47,195,846	46,584,477	-	46,584,477	SG	26.411%	26.877%	26.877%	12,341,196	12,684,773	12,520,456	12,520,456
Existing Firm Energy	555	66,847,124	55,596,693	58,930,634	-	58,930,634	SE	25.525%	25.002%	25.002%	17,062,586	13,900,229	14,733,777	14,733,777
Post-merger Firm	555	707,106,149	376,422,870	351,557,140	316,504	351,873,644	SG	26.411%	26.877%	26.877%	186,756,845	101,170,739	94,487,605	94,572,672
Secondary Purchases	555	-	-	-	(12,954,749)	(12,954,749)	SE	25.525%	25.002%	25.002%	-	-	-	(3,238,933)
Seasonal Contracts	555	7,688,490	-	-	-	-	SSGC	24.488%	0.000%	0.000%	1,882,756	-	-	
Other Generation Expense	555	5,247,531	11,022,399	7,682,475	-	7,682,475	SG	26.411%	26.877%	26.877%	1,385,948	2,962,477	2,064,810	2,064,810
Total Purchased Power		896,327,403	547,909,171	523,887,589	(12,638,244)	511,249,345					235,992,304	146,218,483	139,699,720	136,545,853
Wheeling Expense														
Existing Firm PPL	565	31,031,711	43,189,893	43,189,893	-	43,189,893	SG	26.411%	26.877%	26.877%	8,195,919	11,608,098	11,608,098	11,608,098
Existing Firm UPL	565	172,448	168,268	168,268	-	168,268	SG	26.411%	26.877%	26.877%	45,546	45,225	45,225	45,225
Post-merger Firm	565	83,334,742	96,107,739	100,936,303	-	100,936,303	SG	26.411%	26.877%	26.877%	22,009,897	25,830,766	27,128,533	27,128,533
Non-Firm	565	184,789	282,748	274,921	-	274,921	SE	25.525%	25.002%	25.002%	47,167	70,692	68,735	68,735
Total Wheeling Expense		114,723,691	139,748,649	144,569,385	-	144,569,385					30,298,529	37,554,781	38,850,591	38,850,591
Fuel Expense														
Fuel Consumed - Coal	501	568,676,213	604,154,098	610,654,307	-	610,654,307	SE	25.525%	25.002%	25.002%	145,153,389	151,049,995	152,675,171	152,675,171
Cholla / APS Exchange	501	57,517,646	54,964,906	55,207,439	-	55,207,439	SSECH	25.897%	25.405%	25.408%	14,895,507	13,963,575	14,027,286	14,027,286
Fuel Consumed - Gas	501	27,408,356	21,128,538	8,793,603	-	8,793,603	SE	25.525%	25.002%	25.002%	6,995,924	5,282,536	2,198,568	2,198,568
Natural Gas Consumed	547	374,811,293	458,583,217	426,442,274	-	426,442,274	SE	25.525%	25.002%	25.002%	95,669,782	114,654,511	106,618,665	106,618,665
Simple Cycle Combustion Turb	547	23,655,228	17,499,425	12,469,820	-	12,469,820	SSECT	24.286%	23.563%	23.286%	5,744,981	4,123,302	2,903,754	2,903,754
Steam from Other Sources	503	3,541,671	3,494,899	3,498,000	-	3,498,000	SE	25.525%	25.002%	25.002%	904,004	873,791	874,566	874,566
Total Fuel Expense		1,055,610,407	1,159,825,082	1,117,065,444	-	1,117,065,444					269,363,588	289,947,711	279,298,011	279,298,011
Net Power Cost		1,134,719,692	1,100,545,210	1,095,399,869	(64,224,820)	1,031,175,049					289,515,263	272,967,396	272,364,884	256,395,751
													24.864%	
NPC in Rates from UE-199		1,043,323,002									266,835,529			

6,131,867	5,529,355	(10,439,778)	Increase Absent Load Change

Oregon-allocated NPC Baseline in Rates from UE 199 $	266,835,529
2009 MWH (excluding Schedule 33)	14,026,969
$/MWH in Rates	19.02
2010 MWH (excluding Schedule 33)	13,267,901
2010 Recovery of NPC in Rates $	252,395,751

20,571,846	19,969,133	4,000,000	Increase With Load Change
		(16,571,845)	Variance from Original Filing

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ORDER NO. 09-432

Docket UE 207

STIPULATION OF JOINT PARTIES

Exhibit B

NPC Baseline

September 25, 2009

PacifiCorp

Exhibit B

Net Power Cost Analysis

$

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	12,010,268	1,000,814	964,930	1,012,151	996,213	1,002,313	985,430	1,022,631	1,011,434	990,484	1,009,832	993,458	1,020,579
BPA Wind	2,748,457	344,454	288,814	279,631	217,271	205,016	166,318	124,735	118,197	155,395	227,090	286,056	335,480
Hurricane Sale	985,499	82,125	82,126	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125	82,125
LADWP (IPP Layoff)	25,490,589	2,164,955	1,955,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
PSCO	32,536,058	2,708,780	2,486,509	2,676,610	2,613,730	2,676,610	2,635,664	2,837,461	2,837,461	2,743,873	2,711,705	2,770,195	2,837,461
Salt River Project	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD	12,964,800	1,505,900	547,600	-	162,800	-	-	1,476,300	1,824,100	1,665,000	1,935,100	1,790,800	2,057,200
UAMPS s404236	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II	9,769,272	603,875	571,475	603,875	593,075	603,875	948,920	1,811,625	1,425,145	806,582	603,875	593,075	603,875
Total Long Term Firm Sales	96,504,943	8,410,903	6,896,895	6,819,347	6,760,329	6,734,894	6,913,573	9,519,832	9,463,416	8,538,575	8,734,682	8,610,824	9,101,675
Short Term Firm Sales													
COB	68,026,380	9,530,480	8,487,360	9,360,240	4,305,600	4,140,000	4,305,600	5,114,200	5,114,200	4,917,500	4,305,600	4,140,000	4,305,600
Four Corners	22,386,220	2,957,110	2,475,720	2,682,030	1,285,160	1,454,260	1,285,160	1,726,920	1,726,920	1,684,800	1,716,670	1,674,800	1,716,670
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	18,520,800	3,968,100	3,747,600	4,198,500	1,456,000	1,400,000	1,456,000	774,800	774,800	745,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	65,690,490	7,557,950	6,829,800	7,562,550	6,539,980	6,713,030	6,539,980	3,877,150	3,877,150	3,761,000	4,186,700	4,058,500	4,186,700
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	19,895,525	2,503,845	2,190,510	2,353,107	2,372,520	2,323,512	-	-	-	-	2,742,378	2,602,778	2,806,875
STF Trading Margin	4,782,179	398,515	398,515	398,515	398,515	398,515	398,515	398,515	398,515	398,516	398,516	398,516	398,515
Adjustment to STF Sales Revenue	(4,392,436)	(474,041)	(364,024)	(364,244)	(290,091)	(284,736)	(249,565)	(373,071)	(345,459)	(406,879)	(438,379)	(411,935)	(410,012)
Total Short Term Firm Sales	194,909,158	26,441,959	23,765,481	26,190,698	16,067,684	16,164,582	13,735,690	11,518,513	11,546,126	11,099,936	12,911,483	12,462,658	13,004,348
System Balancing Sales													
COB	74,453,281	6,391,006	6,915,062	6,651,700	5,567,328	4,324,314	3,554,527	5,108,553	6,248,009	5,517,331	6,327,998	7,959,334	9,888,122
Four Corners	141,499,635	16,026,152	12,111,980	8,659,764	9,732,154	8,761,362	7,373,663	13,566,018	13,531,619	10,692,761	15,811,656	14,072,279	11,160,227
Mid Columbia	95,596,444	9,805,869	2,568,497	3,456,971	761,072	50,475	311,111	11,178,559	8,657,473	18,720,382	14,666,423	12,896,121	12,523,473
Mona	17,180,121	1,915,760	549,490	1,504,818	1,273,191	1,316,467	1,218,340	984,162	1,258,992	1,973,558	1,631,421	1,648,806	1,905,116
Palo Verde	65,586,532	3,009,702	2,921,623	2,397,675	5,512,995	4,895,774	7,284,718	7,690,030	5,099,566	6,576,925	7,457,615	6,220,012	6,519,900
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	394,316,013	37,148,509	25,066,651	22,670,927	22,846,739	19,348,391	19,742,359	38,527,321	34,795,658	43,480,956	45,895,112	42,796,551	41,996,836
Adjustment to Secondary Sales Revenue	55,979,012	6,041,377	4,639,270	4,642,072	3,697,043	3,373,690	3,180,563	4,754,577	4,402,676	5,185,428	5,586,888	5,249,871	5,225,357
Total Special Sales For Resale	741,709,126	78,042,748	60,368,297	60,323,044	49,371,795	45,621,758	43,572,184	64,320,243	60,207,875	68,304,895	73,128,166	69,119,903	69,328,218

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	9,756,544	162,936	668,998	1,066,246	1,528,815	1,568,035	2,096,447	1,217,641	385,060	442,197	277,524	166,696	176,149
Blanding Purchase	19,725	1,675	1,513	1,675	1,621	1,675	1,621	1,675	1,675	1,621	1,675	1,621	1,675
Combine Hills	3,911,516	374,287	244,282	432,546	304,814	283,008	340,525	326,830	324,299	309,038	331,759	369,943	270,184
Deseret Purchase	32,249,754	2,710,272	2,593,056	2,710,272	2,671,200	2,710,272	2,671,200	2,710,272	2,710,272	2,671,200	2,710,272	2,671,200	2,710,272
Douglas PUD Settlement	1,894,200	95,756	92,645	125,479	174,570	266,088	280,849	221,857	172,811	103,279	125,616	116,398	118,851
Gemstate	2,716,400	222,200	219,500	224,300	215,100	215,100	215,100	215,100	221,500	215,100	265,600	265,600	222,200
Georgia-Pacific Camas	7,280,700	618,361	558,520	618,361	598,414	618,361	598,414	618,361	618,361	598,414	618,361	598,414	618,361
Grant County 10 aMW purchase	6,971,139	571,459	463,808	514,203	534,854	585,061	593,363	750,640	782,483	621,574	488,377	457,778	607,540
Hermiston Purchase	92,817,337	8,868,670	8,273,028	8,875,968	6,365,705	3,878,410	3,875,084	8,609,605	8,621,202	8,533,469	8,718,884	9,041,141	9,156,170
Hurricane Purchase	328,501	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375	27,375
Idaho Power P278538	777,066	23,580	41,253	25,037	40,625	42,501	55,780	159,536	109,732	65,706	105,796	46,461	61,057
IPP Purchase	25,490,589	2,164,955	1,955,441	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955	2,164,955	2,095,115	2,164,955	2,095,115	2,164,955
Kennecott Generation Incentive	8,211,540	-	-	445,008	503,561	498,523	303,486	1,875,336	2,122,795	1,717,516	745,316	-	-
LADWP 491303-4	1,161,570	-	-	-	-	-	199,840	387,190	387,190	187,350	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	1,755,360	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280	146,280
Morgan Stanley p189046	10,683,600	870,000	835,200	939,600	904,800	870,000	904,800	904,800	904,800	870,000	904,800	870,000	904,800
Morgan Stanley p272153-6-8	1,485,000	-	-	-	-	-	495,000	495,000	495,000	-	-	-	-
Morgan Stanley p272154-7	1,572,000	-	-	-	-	-	524,000	524,000	524,000	-	-	-	-
Nucor	4,610,400	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200	384,200
P4 Production	16,193,520	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460	1,349,460
PGE Cove	252,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000	21,000
Rock River	5,041,868	614,835	485,591	490,707	384,510	367,683	277,559	197,878	239,001	310,441	444,855	605,219	623,409
Roseburg Forest Products	8,767,111	740,873	674,107	747,821	723,250	740,873	723,250	744,347	744,346	719,775	744,347	719,776	744,347
Small Purchases east	570,556	67,645	52,765	46,480	44,319	37,967	35,152	32,262	36,915	32,677	89,197	43,403	51,774
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	10,935,525	-	-	-	-	-	1,183,705	1,054,534	1,080,289	1,421,602	1,785,496	2,005,586	2,404,313
Tri-State Purchase	11,267,375	947,372	875,545	854,630	949,669	903,037	899,905	981,755	1,019,304	953,741	925,205	966,408	990,803
Weyerhaeuser Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek	9,748,726	722,591	570,183	1,135,230	1,093,009	1,065,499	830,533	810,703	760,900	707,747	612,757	801,036	638,537
Long Term Firm Purchases Total	276,469,441	21,705,782	20,533,751	23,346,833	21,062,067	18,745,364	21,129,043	26,932,591	26,355,207	24,505,875	23,989,107	23,770,109	24,393,712
Seasonal Purchased Power													
Morgan Stanley p244840	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p244841	-	-	-	-	-	-	-	-	-	-	-	-	-
UBS p268850	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	4,026,592	387,407	465,359	612,482	697,499	700,649	513,945	157,972	74,754	62,334	58,899	87,379	207,914
QF Idaho	4,477,649	298,760	267,681	340,095	381,922	511,157	556,164	442,079	348,334	324,812	350,831	340,163	315,651
QF Oregon	19,440,841	1,864,969	1,749,989	1,957,540	2,038,618	1,933,090	1,632,405	1,333,552	1,225,909	1,272,968	1,303,729	1,404,423	1,723,649
QF Utah	705,089	52,109	59,151	58,425	67,055	70,420	68,201	58,369	54,041	52,715	65,080	56,660	42,865
QF Washington	1,931,867	160,049	147,934	154,519	161,333	184,376	172,564	174,469	162,340	158,197	152,351	156,319	147,416
QF Wyoming	725,034	15,375	14,501	14,044	38,135	109,333	111,447	119,184	118,964	106,725	47,724	15,152	14,451
Biomass	27,250,062	2,309,276	2,111,600	2,309,276	2,243,384	2,309,276	2,243,384	2,309,276	2,309,276	2,243,384	2,309,276	2,243,384	2,309,276
Chevron Wind QF	2,365,482	162,406	290,658	305,686	100,452	111,340	105,631	113,425	193,751	159,754	266,464	260,825	295,090
Co-Gen II	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas County Forest Products QF	203,637	36,938	30,191	26,914	30,090	23,523	21,853	34,128	-	-	-	-	-
D.R. Johnson	-	-	-	-	-	-	-	-	-	-	-	-	-
Evergreen BioPower QF	3,571,338	317,135	286,061	314,752	305,187	245,621	305,188	316,378	315,508	303,003	319,320	303,003	240,182
ExxonMobil QF	31,569,800	4,446,144	3,830,734	3,537,665	1,589,308	1,358,480	1,408,205	1,052,316	2,618,880	2,057,022	2,125,590	3,401,415	4,144,043
Kennecott QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	8,431,084	1,194,975	766,959	790,896	591,375	496,443	361,689	401,835	538,858	634,302	711,923	830,892	1,110,937
Mountain Wind 2 QF	12,198,479	1,744,137	1,073,230	1,120,541	805,550	864,193	689,661	787,197	837,420	799,895	847,350	1,116,175	1,513,130
Oregon Wind Farm QF	10,337,165	594,602	656,513	841,810	1,032,038	1,043,352	1,213,181	1,235,385	949,001	767,972	780,296	907,034	315,982
Simplot Phosphates	3,796,797	321,520	295,186	321,520	312,742	321,520	312,742	321,520	321,520	312,742	321,520	312,742	321,520
Spanish Fork Wind 2 QF	2,948,260	246,059	193,055	175,077	170,308	154,745	234,248	364,568	374,299	281,621	227,354	233,241	293,685
Sunnyside	24,652,043	2,095,102	1,964,611	1,534,959	2,053,722	2,092,598	2,082,616	2,182,323	2,250,965	2,122,657	1,892,640	2,148,757	2,231,093
Tesoro QF	-	-	-	-	-	-	-	-	-	-	-	-	-
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Weyerhaeuser QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	158,631,218	16,246,963	14,203,413	14,416,201	12,618,717	12,530,114	12,033,122	11,403,976	12,693,819	11,660,101	11,780,346	13,817,563	15,226,883
Mid-Columbia Contracts													
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Chelan - Rocky Reach	4,240,725	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394	353,394
Douglas - Wells	4,812,738	399,793	399,793	399,793	399,793	399,793	399,793	399,793	399,793	403,598	403,598	403,598	403,598
Grant Displacement	12,134,859	872,382	815,628	849,200	1,143,931	1,197,604	999,476	1,170,453	963,543	954,228	990,197	1,049,234	1,128,984
Grant Reasonable	(14,406,120)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)	(1,200,510)
Grant Surplus	1,790,608	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217	149,217
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	8,572,811	574,276	517,522	551,094	845,825	899,498	701,371	872,347	665,437	659,927	695,897	754,934	834,683
Total Long Term Firm Purchases	443,673,470	38,527,020	35,254,686	38,314,128	34,526,609	32,174,977	33,863,535	39,208,914	39,714,463	36,825,904	36,465,349	38,342,606	40,455,278

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Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Storage & Exchange													
APGI/Colockum Capacity Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	1,411,140	116,430	116,430	116,430	116,430	116,430	116,430	118,760	118,760	118,760	118,760	118,760	118,760
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Peaking	47,058,000	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500	3,921,500
BPA So. Idaho Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	3,600,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
PSCO FC III Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line Storage Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
TransAlta p371343/s371344	(1,644,000)	(186,000)	(168,000)	(186,000)	-	-	-	(186,000)	(186,000)	(180,000)	(186,000)	(180,000)	(186,000)
Total Storage & Exchange	50,425,140	4,151,930	4,169,930	4,151,930	4,337,930	4,337,930	4,337,930	4,154,260	4,154,260	4,160,260	4,154,260	4,160,260	4,154,260
Short Term Firm Purchases													
COB	1,634,300	595,550	498,600	540,150	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	36,615,272	-	-	-	-	-	-	13,480,136	13,419,536	9,715,600	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	10,329,900	759,500	694,800	771,900	746,200	759,500	746,200	765,700	765,700	740,000	1,207,700	1,165,000	1,207,700
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	(115,269,391)	(11,807,043)	(11,967,918)	(15,281,015)	(11,582,958)	(13,784,002)	(13,047,330)	(6,838,134)	(5,497,037)	(7,341,140)	(6,366,340)	(6,287,021)	(5,469,454)
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Adjustment to STF Purchase Expenses	1,016,504	47,091	67,903	70,801	85,170	74,835	73,290	201,714	169,046	93,186	32,211	41,675	59,582
Total Short Term Firm Purchases	(65,673,415)	(10,404,902)	(10,706,615)	(13,898,164)	(10,751,588)	(12,949,667)	(12,227,840)	7,609,416	8,857,245	3,207,646	(5,126,429)	(5,080,346)	(4,202,172)
System Balancing Purchases													
COB	9,556,200	521,406	53,073	100,823	252,245	1,183,458	1,245,777	4,147,162	577,868	-	515,544	166,721	792,124
Four Corners	18,303,439	1,648,911	2,334,608	4,005,261	1,740,154	350,261	132,800	599,982	1,403,723	880,965	1,032,736	1,958,868	2,215,190
Mid Columbia	35,446,900	1,258,312	2,131,751	2,989,853	6,526,496	6,440,441	5,977,129	2,431,621	2,194,924	742,247	653,457	1,542,104	2,558,567
Mona	20,709,681	180,931	2,423,530	737,278	1,763,807	1,073,368	1,786,391	5,807,910	4,452,800	496,062	744,340	487,328	755,938
Palo Verde	4,580,471	1,399,487	1,040,417	346,621	378,993	291,846	10,402	28,295	31,268	18,845	199,386	312,183	522,728
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	199,732	-	-	76,503	102,394	14,689	6,147	-	-	-	-	-	-
Adjustment for Condit	(700,000)										(233,333)	(233,333)	(233,333)
Total System Balancing Purchases	88,096,424	5,009,046	7,983,379	8,256,338	10,764,089	9,354,062	9,158,645	13,014,949	8,660,583	2,138,119	2,912,130	4,233,870	6,611,212
Adjustment to Secondary Purchase Expense	(12,954,749)	(600,144)	(865,384)	(902,313)	(1,085,437)	(953,724)	(934,041)	(2,570,732)	(2,154,394)	(1,187,606)	(410,510)	(531,125)	(759,339)
Total Purchased Power & Net Interchang	503,566,870	36,682,951	35,835,997	35,921,920	37,791,603	31,963,578	34,198,229	61,416,808	59,232,157	45,144,323	37,994,800	41,125,265	46,259,239

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Wheeling & U. of F. Expense													
Firm Wheeling	144,294,464	12,389,524	11,698,210	12,181,651	11,892,221	12,147,383	12,495,050	11,714,671	11,795,722	11,533,973	12,142,376	12,448,215	11,855,471
ST Firm & Non-Firm	274,921	11,169	12,937	2,733	12,912	11,252	41,776	71,838	56,769	23,972	15,658	5,554	8,353
Total Wheeling & U. of F. Expense	144,569,385	12,400,693	11,711,147	12,184,384	11,905,132	12,158,635	12,536,826	11,786,508	11,852,491	11,557,944	12,158,033	12,453,768	11,863,824
Coal Fuel Burn Expense													
Carbon	20,059,572	1,865,436	1,645,362	1,804,669	1,796,637	1,660,440	1,660,479	1,767,053	1,775,422	1,693,836	1,564,839	1,004,453	1,820,945
Cholla	55,207,439	4,917,368	4,401,341	2,527,983	4,761,580	4,803,113	4,664,023	4,923,909	4,948,603	4,765,072	4,929,515	4,695,637	4,869,297
Colstrip	12,944,264	1,137,301	1,028,146	1,139,057	1,102,087	1,137,301	1,102,087	1,138,179	1,138,179	863,248	917,534	1,102,087	1,139,057
Craig	20,838,403	1,793,122	1,620,206	1,650,548	1,619,498	1,786,687	1,731,706	1,792,240	1,793,403	1,732,305	1,789,061	1,735,355	1,794,271
Dave Johnston	52,577,538	4,583,722	4,142,845	4,588,443	4,440,263	4,552,996	4,410,506	4,555,608	4,555,608	4,136,016	3,582,298	4,440,263	4,588,971
Hayden	11,288,166	986,563	891,011	659,639	954,611	986,563	954,611	986,487	986,487	954,611	986,563	954,611	986,411
Hunter	112,775,720	10,136,121	9,050,102	7,362,638	9,082,726	9,484,373	9,147,975	9,790,683	9,854,429	9,472,302	9,658,580	9,635,765	10,100,025
Huntington	96,648,088	8,537,949	7,683,411	8,488,265	4,949,812	8,211,698	8,118,606	8,512,002	8,600,304	8,291,770	8,434,700	8,272,056	8,547,514
Jim Bridger	181,504,009	16,105,798	14,537,415	15,521,233	11,660,347	12,093,715	15,614,565	16,170,819	16,172,158	15,654,736	16,166,073	15,653,998	16,153,153
Naughton	81,873,772	7,161,842	6,439,176	7,125,275	5,119,482	6,691,172	6,906,745	7,139,248	7,142,297	6,907,120	7,135,809	6,937,998	7,167,610
Wyodak	20,144,777	1,784,725	1,618,289	1,791,110	1,727,740	1,772,897	1,700,065	1,714,713	1,720,622	1,700,065	1,492,262	1,329,830	1,792,459
Total Coal Fuel Burn Expense	665,861,747	59,009,947	53,057,302	52,658,860	47,214,781	53,180,954	56,011,369	58,490,941	58,687,510	56,171,082	56,657,233	55,762,053	58,959,714
Gas Fuel Burn Expense													
Chehalis	69,548,930	6,627,676	-	-	-	-	-	8,352,863	12,370,430	11,807,330	13,916,214	8,128,055	8,346,363
Currant Creek	79,283,790	7,168,576	5,567,414	6,083,669	6,076,594	5,108,917	5,703,971	7,718,381	8,429,041	7,322,900	6,341,916	6,397,272	7,365,139
Gadsby	6,297,743	-	-	-	-	-	-	2,163,801	2,565,946	1,567,997	-	-	-
Gadsby CT	9,220,013	1,018,008	549,761	-	-	-	699,040	1,577,850	1,690,013	1,220,438	928,635	647,104	889,165
Hermiston	56,036,843	5,783,821	5,201,302	5,790,874	3,335,026	901,421	898,165	5,530,760	5,542,076	5,456,195	5,637,757	5,923,358	6,036,087
Lake Side	101,444,269	8,992,444	7,020,485	7,580,046	7,663,660	6,710,029	7,615,458	9,334,740	9,929,449	9,407,800	9,808,200	8,264,416	9,117,542
Little Mountain	7,510,350	925,804	839,095	907,996	824,052	803,372	-	80,841	174,256	-	896,778	958,747	1,099,410
Total Gas Fuel Burn	329,341,938	30,516,329	19,178,057	20,362,585	17,899,332	13,523,738	14,916,634	34,759,237	40,701,210	36,782,659	37,529,500	30,318,952	32,853,706
Gas Physical	(45,851)	9,597	8,776	8,938	(23,107)	(23,296)	(21,357)	(17,877)	(16,715)	(15,363)	(20,622)	29,373	35,803
Gas Swaps	81,087,189	7,788,440	6,583,640	7,859,469	7,302,000	7,512,695	6,819,000	9,038,345	8,564,045	7,587,705	5,119,216	4,235,475	2,677,160
Clay Basin Gas Storage	(1,275,691)	(460,309)	(464,226)	(438,714)	52,364	52,364	52,364	52,364	52,364	52,364	52,364	(73,413)	(205,576)
Pipeline Reservation Fees	26,474,459	2,240,920	2,126,411	2,240,920	2,184,634	2,225,534	2,184,634	2,225,534	2,225,534	2,184,634	2,225,534	2,184,634	2,225,534
Additional Fixed Costs	12,123,654	1,315,055	724,549	769,470	694,412	673,924	842,856	1,579,361	1,152,147	1,188,217	420,221	1,246,745	1,516,698
Total Gas Fuel Burn Expense	447,705,697	41,410,032	28,157,207	30,802,667	28,109,635	23,964,958	24,794,131	47,636,963	52,678,584	47,780,216	45,326,213	37,941,767	39,103,325
Other Generation													
Blundell	3,498,000	309,935	279,847	309,753	299,784	309,935	299,784	309,844	309,844	299,784	159,952	299,784	309,753
Wind Integration Charge	7,682,475	733,991	632,977	682,370	623,935	599,565	604,178	551,790	565,296	585,179	647,287	712,056	743,851
Total Other Generation	11,180,475	1,043,926	912,825	992,123	923,719	909,500	903,962	861,634	875,140	884,963	807,239	1,011,840	1,053,604
Net Power Cost	1,031,175,049	72,504,801	69,306,180	72,236,910	76,573,076	76,555,868	84,872,333	115,872,610	123,118,006	93,233,634	79,815,352	79,174,790	87,911,489
Net Power Cost/Net System Load	17.58	13.89	14.76	15.24	17.01	16.77	17.55	21.50	23.02	19.74	17.31	16.80	16.54
Total Adjustment	(64,224,820)	Check	0										

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PacifiCorp

Exhibit B

Net Power Cost Analysis

MWh

12 months ended December 2010		01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
	SG	4,708,940	Condit	(700,000)										
	SE	(68,933,760)												
Adjustments to Load														
Lewis River Hydro Losses		-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Curtailment		(38,516)	(5,896)	-	-	-	-	(6,610)	(6,310)	(6,610)	(6,310)	-	-	(6,780)
Monsanto Curtailment		(42,790)	-	-	-	(295)	(589)	(1,620)	(9,817)	(8,802)	(5,169)	(4,787)	(2,652)	(9,059)
Station Service		70,811	4,141	4,619	6,050	6,195	7,218	6,770	5,966	6,951	5,953	6,234	6,492	4,222
Total Adjustments to Load		(10,495)	(1,755)	4,619	6,050	5,900	6,629	(1,460)	(10,161)	(8,461)	(5,526)	1,447	3,840	(11,617)
System Load		58,674,332	5,222,664	4,691,697	4,735,035	4,495,316	4,559,607	4,838,202	5,398,855	5,357,125	4,729,459	4,610,488	4,709,269	5,326,617
Net System Load		58,663,837	5,220,909	4,696,316	4,741,085	4,501,216	4,566,236	4,836,741	5,388,694	5,348,664	4,723,933	4,611,935	4,713,109	5,315,000
Special Sales For Resale														
Long Term Firm Sales														
Black Hills		362,468	30,203	27,981	30,905	29,918	30,296	29,250	31,554	30,861	29,563	30,762	29,748	31,427
BPA Wind		39,096	4,900	4,108	3,978	3,091	2,916	2,366	1,774	1,681	2,210	3,230	4,069	4,772
Hurricane Sale		13,140	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095
LADWP (IPP Layoff)		613,200	52,080	47,040	52,080	50,400	52,080	50,400	52,080	52,080	50,400	52,080	50,400	52,080
PSCO		464,766	38,681	34,364	38,056	36,835	38,056	37,261	41,180	41,180	39,362	38,738	39,874	41,180
Salt River Project		-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD		350,400	40,700	14,800	-	4,400	-	-	39,900	49,300	45,000	52,300	48,400	55,600
UAMPS s404236		-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II		223,878	13,938	12,588	13,938	13,488	13,938	21,580	41,813	32,893	18,343	13,938	13,488	13,938
Total Long Term Firm Sales		2,066,948	181,596	141,976	140,051	139,226	138,381	141,952	209,396	209,089	185,974	192,142	187,073	200,092
Short Term Firm Sales														
COB		857,200	127,400	112,800	124,200	52,000	50,000	52,000	62,400	62,400	60,000	52,000	50,000	52,000
Four Corners		408,200	51,600	43,200	46,800	22,800	25,800	22,800	32,800	32,800	32,000	32,800	32,000	32,800
Idaho		-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia		268,000	58,600	55,200	61,800	20,800	20,000	20,800	10,400	10,400	10,000	-	-	-
Mona		-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde		1,606,800	184,600	165,600	183,000	169,600	176,000	115,600	70,000	70,000	68,000	136,200	132,000	136,200
SP15		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales		3,140,200	422,200	376,800	415,800	265,200	271,800	211,200	175,600	175,600	170,000	221,000	214,000	221,000
System Balancing Sales														
COB		1,514,223	125,780	145,316	154,314	123,705	108,040	94,497	103,957	113,946	104,549	118,179	148,984	172,955
Four Corners		2,811,532	339,154	262,731	195,408	210,474	214,839	180,751	222,659	197,166	190,654	296,136	288,393	213,168
Mid Columbia		1,837,691	198,474	57,374	90,298	24,087	1,757	10,117	205,750	163,721	338,231	283,228	240,456	224,198
Mona		341,343	41,786	11,628	34,664	27,272	30,298	24,055	14,314	19,112	34,922	31,647	34,566	37,079
Palo Verde		1,275,119	65,461	64,657	58,569	122,930	106,854	128,420	117,501	88,214	119,903	153,931	126,572	122,107
SP15		-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy		-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales		7,779,909	770,655	541,707	533,253	508,468	461,787	437,840	664,182	582,159	788,259	883,121	838,971	769,507
Total Special Sales For Resale		12,987,057	1,374,451	1,060,483	1,089,104	912,894	871,968	790,992	1,049,178	966,848	1,144,233	1,296,263	1,240,044	1,190,599
Total Requirements		71,650,894	6,595,360	5,756,799	5,830,189	5,414,110	5,438,204	5,627,733	6,437,872	6,315,512	5,868,166	5,908,198	5,953,152	6,505,599

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	222,750	4,950	25,000	36,900	37,050	37,500	37,500	19,350	4,450	6,700	4,450	4,450	4,450
Blanding Purchase	263	22	20	22	22	22	22	22	22	22	22	22	22
Combine Hills	111,503	10,670	6,964	12,330	8,669	8,068	9,707	9,317	9,245	8,810	9,457	10,546	7,702
Deseret Purchase	785,772	66,737	60,278	66,737	64,584	66,737	64,584	66,737	66,737	64,584	66,737	64,584	66,737
Douglas PUD Settlement	68,696	3,479	3,379	4,577	6,323	9,647	10,240	8,083	6,242	3,712	4,554	4,184	4,276
Gemstate	37,448	-	-	-	-	1,467	10,146	13,379	12,456	-	-	-	-
Georgia-Pacific Camas	97,741	8,301	7,498	8,301	8,034	8,301	8,034	8,301	8,301	8,034	8,301	8,034	8,301
Grant County 10 aMW purchase	87,634	6,400	4,992	5,824	7,410	9,346	9,996	10,280	9,560	7,098	5,904	4,734	6,090
Hermiston Purchase	1,568,132	171,603	150,739	171,992	85,476	114	-	162,056	162,504	159,560	165,686	167,452	170,951
Hurricane Purchase	4,380	365	365	365	365	365	365	365	365	365	365	365	365
Idaho Power P278538	15,765	481	897	620	1,023	1,364	1,283	2,927	1,867	1,334	2,014	873	1,082
IPP Purchase	613,200	52,080	47,040	52,080	50,400	52,080	50,400	52,080	52,080	50,400	52,080	50,400	52,080
LADWP 491303-4	23,250	-	-	-	-	-	4,000	7,750	7,750	3,750	-	-	-
MagCorp Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p189046	245,600	20,000	19,200	21,600	20,800	20,000	20,800	20,800	20,800	20,000	20,800	20,000	20,800
PGE Cove	12,000	1,014	942	1,014	990	1,014	990	1,014	1,014	990	1,014	990	1,014
Rock River	142,099	17,329	13,686	13,830	10,837	10,363	7,823	5,577	6,736	8,750	12,538	17,058	17,571
Roseburg Forest Products	153,792	13,062	11,798	13,062	12,640	13,062	12,640	13,062	13,062	12,640	13,062	12,640	13,062
Small Purchases east	8,636	842	652	573	551	472	436	402	458	410	2,655	539	647
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	171,403	-	-	-	-	-	18,553	16,529	16,932	22,282	27,986	31,436	37,685
Tri-State Purchase	170,819	14,598	11,502	10,601	14,697	12,687	12,552	16,080	17,699	14,873	13,643	15,419	16,470
Weyerhaeuser Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek	176,896	13,112	10,346	20,599	19,833	19,334	15,070	14,711	13,807	12,842	11,119	14,535	11,587
Long Term Firm Purchases Total	4,717,779	405,045	375,299	441,028	349,724	271,942	295,141	448,822	432,087	407,155	422,386	428,259	440,892
Seasonal Purchased Power													
Morgan Stanley p244840	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p244841	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	34,066	3,297	4,002	4,561	6,189	6,236	4,473	1,336	587	477	442	706	1,759
QF Idaho	80,665	5,471	4,918	6,235	6,955	9,207	9,987	7,815	6,167	5,807	6,283	6,117	5,704
QF Oregon	229,067	21,916	20,378	22,560	23,588	22,678	19,360	16,066	14,925	15,212	15,446	16,661	20,287
QF Utah	13,466	993	1,081	1,044	1,259	1,416	1,354	1,155	1,091	1,028	1,234	1,013	799
QF Washington	13,136	1,087	999	1,048	1,099	1,268	1,181	1,193	1,103	1,073	1,031	1,060	995
QF Wyoming	11,387	159	147	144	559	1,820	1,834	1,975	1,967	1,741	739	155	148
Biomass	173,449	14,731	13,306	14,731	14,256	14,731	14,256	14,731	14,731	14,256	14,731	14,256	14,731
Chevron Wind QF	44,528	5,154	4,812	4,947	2,528	2,797	2,253	1,602	2,444	2,626	4,829	5,102	5,433
Co-Gen II	-	-	-	-	-	-	-	-	-	-	-	-	-
Douglas County Forest Products QF	5,071	780	684	692	776	734	700	706	-	-	-	-	-
D.R. Johnson	-	-	-	-	-	-	-	-	-	-	-	-	-
Evergreen BioPower QF	67,072	6,004	5,352	5,867	5,695	4,666	5,695	5,935	5,935	5,695	6,004	5,695	4,529
ExxonMobil QF	648,960	71,424	64,512	71,424	46,080	47,616	46,080	19,968	47,616	46,080	47,616	69,120	71,424
Kennecott QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	151,796	19,721	13,198	15,012	12,392	10,117	7,121	6,376	8,227	10,957	13,581	15,787	19,306
Mountain Wind 2 QF	189,638	25,448	16,515	18,403	14,974	15,818	10,747	9,239	10,202	11,715	14,776	18,563	23,239
Oregon Wind Farm QF	161,172	9,177	10,130	12,979	15,974	16,431	18,932	19,466	14,998	12,070	12,181	14,007	4,827
Simplot Phosphates	74,460	6,324	5,712	6,324	6,120	6,324	6,120	6,324	6,324	6,120	6,324	6,120	6,324
Spanish Fork Wind 2 QF	55,562	4,484	3,689	3,500	3,695	3,438	4,611	6,114	6,123	5,203	4,608	4,616	5,480
Sunnyside	385,060	34,700	31,342	19,029	33,581	34,700	33,581	34,700	34,700	33,581	26,865	33,581	34,700
Tesoro QF	-	-	-	-	-	-	-	-	-	-	-	-	-
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Weyerhaeuser QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	2,338,555	230,869	200,776	208,501	195,719	199,996	188,284	154,692	177,141	173,642	176,689	212,559	219,686
Mid-Columbia Contracts													
Canadian Entitlement	(17,528)	(1,456)	(1,344)	(1,512)	(1,456)	(1,456)	(1,456)	(1,512)	(1,456)	(1,456)	(1,456)	(1,456)	(1,512)
Chelan - Rocky Reach	327,226	34,061	24,576	24,070	29,747	33,969	35,082	33,401	25,161	17,271	20,393	23,054	26,441
Douglas - Wells	252,519	26,036	18,601	18,063	23,417	27,901	27,098	26,209	19,434	13,043	15,376	17,361	19,982
Grant Displacement	439,837	29,411	26,744	29,808	42,693	53,655	51,540	46,501	33,187	30,962	31,597	31,347	32,392
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	88,890	12,394	7,118	6,926	7,050	7,477	8,129	8,115	6,444	4,999	5,891	6,688	7,660
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,090,944	100,445	75,696	77,355	101,451	121,545	120,393	112,714	82,769	64,819	71,801	76,993	84,963
Total Long Term Firm Purchases	8,147,277	736,359	651,771	726,884	646,894	593,484	603,819	716,228	691,996	645,615	670,876	717,811	745,541

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Storage & Exchange													
APGI/Colockum Capacity Exchange	(268,153)	(18,608)	(15,579)	(16,877)	(16,445)	(18,608)	(16,445)	(17,743)	(17,743)	(37,310)	(37,743)	(37,310)	(17,743)
APS Exchange	450	142,575	68,850	-	-	(77,900)	(137,970)	(142,380)	(142,490)	(68,780)	77,895	137,895	142,755
BPA Exchange	0	-	-	(50,000)	-	-	133,333	116,667	-	(66,667)	(66,667)	(66,667)	-
BPA FC II Storage Agreement	239	36	(34)	15	(95)	18	(64)	10	22	117	23	158	32
BPA FC IV Storage Agreement	2,229	340	(316)	141	(886)	168	(597)	95	206	1,095	212	1,473	300
BPA Peaking	0	(4,600)	(3,949)	3,125	4,403	(6,385)	(4,149)	9,255	(4,925)	3,801	(5,200)	1,380	7,245
BPA So. Idaho Exchange	39,670	3,921	4,087	3,264	2,979	2,485	3,083	3,170	3,318	2,593	3,034	3,545	4,211
Cowlitz Swift	6,534	774	3,612	(2,220)	3,764	(1,656)	(1,357)	1,212	(3,025)	2,620	2,184	(3,940)	4,566
EWEB FC I Storage Agreement	1,235	160	53	33	(39)	77	(19)	(53)	66	192	260	284	220
PSCo Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III Storage Agreement	(0)	1,240	(1,767)	(2,146)	(2,224)	(1,922)	(1,334)	(2,580)	(1,075)	1,549	3,550	3,854	2,855
Redding Exchange	(55)	11,316	10,184	10,766	10,968	(6,374)	(6,832)	(10,914)	(13,802)	(14,134)	(14,474)	11,298	11,943
SCL State Line Storage Agreement	14,486	1,857	(3,516)	10,718	9,052	(7,771)	4,559	(1,603)	(5,140)	(2,481)	1,374	6,949	490
TransAlta p371343/s371344	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	(203,365)	139,010	61,623	(43,181)	11,478	(117,867)	(27,812)	(44,864)	(184,589)	(177,406)	(35,552)	58,919	156,874
Short Term Firm Purchases													
COB	23,600	8,600	7,200	7,800	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	485,200	-	-	-	-	-	-	177,600	176,800	130,800	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	249,800	18,600	16,800	18,600	18,000	18,600	18,000	18,600	18,600	18,000	29,000	28,000	29,000
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	758,600	27,200	24,000	26,400	18,000	18,600	18,000	196,200	195,400	148,800	29,000	28,000	29,000
System Balancing Purchases													
COB	196,284	11,389	1,279	2,627	6,019	35,166	36,123	64,878	8,191	-	10,311	3,589	16,712
Four Corners	486,408	45,547	67,205	123,021	52,204	10,665	3,865	10,059	29,202	20,130	24,834	46,667	53,009
Mid Columbia	960,991	27,735	47,465	76,278	170,537	218,942	197,650	64,855	46,164	15,585	12,660	32,881	50,239
Mona	447,353	5,221	59,770	21,698	54,141	33,988	43,614	99,880	70,856	12,764	17,573	10,894	16,955
Palo Verde	124,182	36,537	27,499	9,494	11,182	9,277	424	781	840	483	5,303	8,251	14,112
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	4,729	-	-	1,743	2,336	410	240	-	-	-	-	-	-
Total System Balancing Purchases	2,219,947	126,428	203,218	234,862	296,418	308,448	281,915	240,453	155,253	48,962	70,680	102,281	151,027
Total Purchased Power & Net Interchang	10,922,460	1,028,997	940,613	944,965	972,791	802,665	875,921	1,108,017	858,061	665,972	735,005	907,011	1,082,442

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Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Coal Generation													
Carbon	1,188,418	111,011	97,723	107,134	106,883	97,729	98,020	104,558	105,099	100,151	93,092	58,840	108,180
Cholla	2,873,922	256,058	229,102	131,607	247,929	249,898	242,678	256,363	257,680	248,090	256,659	244,387	253,472
Colstrip	1,157,417	101,684	91,932	101,856	98,548	101,684	98,548	101,770	101,770	77,254	81,969	98,548	101,856
Craig	1,357,993	116,857	105,589	107,534	105,586	116,424	112,843	116,795	116,875	112,886	116,581	113,092	116,933
Dave Johnston	5,897,343	514,145	464,705	514,699	498,073	510,672	494,710	510,977	510,977	463,764	401,791	498,073	514,757
Hayden	633,786	55,396	50,030	36,997	53,601	55,396	53,601	55,391	55,391	53,601	55,396	53,601	55,386
Hunter	8,042,046	724,728	646,557	526,117	647,893	674,214	649,897	697,805	702,686	674,955	687,284	687,920	721,989
Huntington	6,656,495	588,126	529,228	584,636	341,097	565,603	558,722	586,208	592,507	571,194	580,558	569,816	588,798
Jim Bridger	10,294,306	913,290	824,286	880,503	661,104	685,646	885,565	917,292	917,376	888,041	917,007	887,996	916,201
Naughton	5,392,539	471,698	424,055	469,211	337,269	441,159	454,832	470,143	470,348	454,858	469,907	456,966	472,092
Wyodak	2,203,844	195,393	177,228	196,149	189,159	193,991	185,879	187,092	187,793	185,879	163,332	145,642	196,309
Total Coal Generation	45,698,110	4,048,384	3,640,435	3,656,442	3,287,143	3,692,416	3,835,295	4,004,393	4,018,501	3,830,672	3,823,575	3,814,880	4,045,974
Gas Generation													
Chehalis	1,607,195	145,347	-	-	-	-	-	210,852	305,638	288,541	333,798	164,129	158,889
Currant Creek	2,044,347	182,246	140,839	157,686	168,551	139,610	155,616	207,020	222,121	191,512	169,005	152,185	157,956
Gadsby	96,696	-	-	-	-	-	-	33,559	39,530	23,606	-	-	-
Gadsby CT	126,469	12,863	6,925	-	-	-	9,362	24,260	25,740	17,484	12,730	7,644	9,460
Hermiston	1,568,132	171,603	150,739	171,992	85,476	114	-	162,056	162,504	159,560	165,686	167,452	170,951
Lake Side	2,760,047	241,805	188,416	206,864	227,526	194,777	217,457	263,013	275,965	258,222	272,941	208,309	204,750
Little Mountain	83,357	10,371	9,367	10,371	10,036	9,630	-	884	1,920	-	10,371	10,036	10,371
Total Gas Generation	8,286,241	764,235	496,286	546,912	491,590	344,131	382,436	901,646	1,033,419	938,926	964,530	709,754	712,376
Hydro Generation													
West Hydro	3,727,038	472,123	439,440	386,912	410,519	340,238	281,848	182,298	173,310	217,453	159,926	267,746	395,225
East Hydro	308,123	17,301	17,095	30,231	30,539	37,018	35,738	42,039	36,171	19,642	12,909	13,577	15,861
Total Hydro Generation	4,035,162	489,424	456,535	417,143	441,058	377,257	317,586	224,337	209,481	237,095	172,836	281,323	411,086
Other Generation													
Blundell	181,827	16,111	14,547	16,101	15,583	16,111	15,583	16,106	16,106	15,583	8,314	15,583	16,101
Blundell Bottoming Cycle	86,961	7,705	6,957	7,700	7,453	7,705	7,453	7,703	7,703	7,453	3,976	7,453	7,700
Total Blundell	268,787	23,816	21,504	23,801	23,036	23,816	23,036	23,809	23,809	23,036	12,291	23,036	23,801
Foote Creek I	102,699	12,892	10,506	10,105	7,611	7,605	5,865	4,253	4,466	6,260	9,075	11,269	12,794
Glenrock Wind	332,471	36,809	28,625	30,312	27,213	22,675	22,529	19,189	20,690	24,548	29,268	32,442	38,172
Glenrock III Wind	124,409	13,846	10,745	11,363	10,181	8,432	8,385	7,094	7,676	9,169	10,960	12,182	14,375
Goodnoe Wind	266,887	13,956	18,183	31,076	22,609	24,419	28,225	27,556	23,970	18,281	23,542	20,857	14,214
High Plains Wind	309,370	35,480	27,001	29,176	25,636	26,751	20,556	16,976	17,585	20,555	22,727	31,025	35,902
Leaning Juniper 1	305,473	16,176	17,454	29,577	23,680	31,823	33,873	35,958	30,532	25,784	24,369	18,181	18,066
Marengo I	393,136	32,850	33,648	35,285	35,941	33,338	32,512	31,293	30,373	29,681	32,407	31,668	34,139
Marengo II	187,226	25,913	18,628	19,890	13,929	12,361	15,227	12,975	13,096	12,325	12,202	16,669	14,013
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	349,596	43,929	30,606	36,878	26,476	25,496	21,961	17,024	19,928	21,606	29,584	35,802	40,304
Seven Mile II Wind	68,862	8,653	6,029	7,264	5,215	5,022	4,326	3,353	3,925	4,256	5,827	7,052	7,939
Total Wind Generation	2,440,129	240,504	201,425	240,925	198,492	197,921	193,459	175,670	172,242	172,465	199,961	217,147	229,919
Total Other Generation	2,708,917	264,319	222,929	264,726	221,528	221,737	216,494	199,479	196,050	195,501	212,251	240,183	253,720
Total Resources	71,650,889	6,595,359	5,756,799	5,830,189	5,414,109	5,438,205	5,627,732	6,437,871	6,315,512	5,868,166	5,908,198	5,953,151	6,505,598

APPENDIX A
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Exhibit B

Net Power Cost Analysis

"The Rack"

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Fuel Burned (MMBtu)													
Carbon	13,707,576	1,274,733	1,124,348	1,233,209	1,227,721	1,134,650	1,134,677	1,207,505	1,213,223	1,157,472	1,069,323	686,387	1,244,331
Cholla	31,062,195	2,766,734	2,476,389	1,422,352	2,679,078	2,702,448	2,624,189	2,770,418	2,784,313	2,681,046	2,773,573	2,641,976	2,739,681
Colstrip	12,493,832	1,097,726	992,369	1,099,420	1,063,737	1,097,726	1,063,736	1,098,573	1,098,572	833,209	885,607	1,063,736	1,099,420
Craig	13,720,601	1,180,645	1,066,789	1,086,768	1,066,322	1,176,408	1,140,204	1,180,063	1,180,829	1,140,598	1,177,970	1,142,607	1,181,399
Dave Johnston	65,560,713	5,715,593	5,165,856	5,721,474	5,536,704	5,677,297	5,499,613	5,680,547	5,680,552	5,157,337	4,466,905	5,536,707	5,722,129
Hayden	6,708,726	586,329	529,541	392,033	567,339	586,329	567,340	586,284	586,284	567,339	586,329	567,340	586,239
Hunter	85,290,013	7,665,752	6,844,410	5,568,210	6,869,079	7,172,836	6,918,428	7,404,499	7,452,706	7,163,712	7,304,600	7,287,333	7,638,448
Huntington	66,687,515	5,891,208	5,301,579	5,856,937	3,415,381	5,666,100	5,601,868	5,873,309	5,934,241	5,721,354	5,819,966	5,707,750	5,897,822
Jim Bridger	107,557,665	9,544,145	8,614,748	9,197,746	6,909,820	7,166,636	9,253,058	9,582,680	9,583,470	9,276,863	9,579,861	9,276,422	9,572,218
Naughton	56,269,979	4,922,173	4,425,497	4,897,041	3,518,498	4,598,688	4,746,848	4,906,643	4,908,741	4,747,106	4,904,279	4,768,329	4,926,137
Wyodak	26,460,995	2,344,308	2,125,686	2,352,694	2,269,455	2,328,764	2,233,121	2,252,346	2,260,111	2,233,121	1,960,138	1,746,786	2,354,466
Chehalis	11,492,394	1,041,235	-	-	-	-	-	1,505,714	2,191,962	2,066,790	2,385,127	1,168,567	1,133,001
Currant Creek	15,075,127	1,354,154	1,047,997	1,171,946	1,249,036	1,040,440	1,139,427	1,515,783	1,626,404	1,395,347	1,237,040	1,128,238	1,169,318
Gadsby	1,178,755	-	-	-	-	-	-	410,904	478,846	289,005	-	-	-
Gadsby CT	1,683,545	186,011	100,104	-	-	-	135,001	299,633	315,384	224,945	175,173	110,488	136,806
Hermiston	11,308,218	1,235,151	1,087,884	1,236,934	616,069	823	-	1,171,176	1,174,037	1,152,324	1,198,231	1,204,287	1,231,303
Lake Side	19,147,811	1,684,930	1,310,828	1,448,389	1,562,577	1,355,513	1,509,019	1,818,462	1,900,480	1,778,185	1,897,779	1,445,797	1,435,851
Little Mountain	1,362,832	169,164	152,789	169,155	163,700	158,135	-	15,352	32,519	-	169,164	163,700	169,155
Burn Rate (MMBtu/MWh)													
Carbon	11.534	11.483	11.506	11.511	11.487	11.610	11.576	11.549	11.544	11.557	11.487	11.665	11.502
Cholla	10.808	10.805	10.809	10.808	10.806	10.814	10.813	10.807	10.805	10.807	10.806	10.811	10.809
Colstrip	10.795	10.795	10.795	10.794	10.794	10.795	10.794	10.795	10.795	10.785	10.804	10.794	10.794
Craig	10.104	10.103	10.103	10.106	10.099	10.105	10.104	10.104	10.103	10.104	10.104	10.103	10.103
Dave Johnston	11.117	11.117	11.116	11.116	11.116	11.117	11.117	11.117	11.117	11.121	11.117	11.116	11.116
Hayden	10.585	10.584	10.584	10.596	10.585	10.584	10.585	10.584	10.584	10.585	10.584	10.585	10.585
Hunter	10.606	10.577	10.586	10.584	10.602	10.639	10.645	10.611	10.606	10.614	10.628	10.593	10.580
Huntington	10.018	10.017	10.018	10.018	10.013	10.018	10.026	10.019	10.015	10.016	10.025	10.017	10.017
Jim Bridger	10.448	10.450	10.451	10.446	10.452	10.452	10.449	10.447	10.447	10.446	10.447	10.446	10.448
Naughton	10.435	10.435	10.436	10.437	10.432	10.424	10.436	10.436	10.436	10.436	10.437	10.435	10.435
Wyodak	12.007	11.998	11.994	11.994	11.998	12.005	12.014	12.039	12.035	12.014	12.001	11.994	11.994
Chehalis	7.151	7.164	0.000	0.000	0.000	0.000	0.000	7.141	7.172	7.163	7.145	7.120	7.131
Currant Creek	7.374	7.430	7.441	7.432	7.410	7.452	7.322	7.322	7.322	7.286	7.320	7.414	7.403
Gadsby	12.190	0.000	0.000	0.000	0.000	0.000	0.000	12.244	12.113	12.243	0.000	0.000	0.000
Gadsby CT	13.312	14.460	14.456	0.000	0.000	0.000	14.419	12.351	12.252	12.866	13.761	14.455	14.462
Hermiston	7.211	7.198	7.217	7.192	7.207	7.242	0.000	7.227	7.225	7.222	7.232	7.192	7.203
Lake Side	6.937	6.968	6.957	7.002	6.868	6.959	6.939	6.914	6.887	6.886	6.953	6.941	7.013
Little Mountain	16.349	16.311	16.311	16.311	16.311	16.421	0.000	17.360	16.941	0.000	16.311	16.311	16.311
Average Fuel Cost ($/MMBtu)													
Carbon	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463	1.463
Cholla	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777	1.777
Colstrip	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036	1.036
Craig	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519	1.519
Dave Johnston	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802	0.802
Hayden	1.683	1.683	1.683	1.683	1.683	1.683	1.683	1.683	1.683	1.683	1.683	1.683	1.683
Hunter	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322	1.322
Huntington	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449	1.449
Jim Bridger	1.688	1.688	1.688	1.688	1.688	1.688	1.688	1.688	1.688	1.688	1.688	1.688	1.688
Naughton	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455	1.455
Wyodak	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761	0.761
Chehalis	5.929	6.365	6.147	5.549	5.274	5.322	5.424	5.547	5.644	5.713	5.835	6.956	7.367
Currant Creek	5.266	5.294	5.312	5.191	4.865	4.910	5.006	5.092	5.183	5.248	5.127	5.670	6.299
Gadsby	5.444	5.473	5.492	5.368	5.034	5.080	5.178	5.266	5.359	5.425	5.301	5.857	6.499
Gadsby CT	5.444	5.473	5.492	5.368	5.034	5.080	5.178	5.266	5.359	5.425	5.301	5.857	6.499
Hermiston	3.992	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	4.173	4.173
Lake Side	5.309	5.337	5.356	5.233	4.904	4.950	5.047	5.133	5.225	5.291	5.168	5.716	6.350
Little Mountain	5.444	5.473	5.492	5.368	5.034	5.080	5.178	5.266	5.359	5.425	5.301	5.857	6.499

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Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Peak Capacity (Nameplate)													
Blundell	23	23	23	23	23	23	23	23	23	23	23	23	23
Blundell Bottoming Cycle	11	11	11	11	11	11	11	11	11	11	11	11	11
Carbon	172	172	172	172	172	172	172	172	172	172	172	172	172
Cholla	387	387	387	387	387	387	387	387	387	387	387	387	387
Colstrip	148	148	148	148	148	148	148	148	148	148	148	148	148
Craig	166	166	166	166	166	166	166	166	166	166	166	166	166
Dave Johnston	762	762	762	762	762	757	757	757	757	757	757	762	762
Hayden	78	78	78	78	78	78	78	78	78	78	78	78	78
Hunter	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,118	1,118	1,123	1,123	1,123	1,123
Huntington	895	895	895	895	895	895	895	895	895	895	895	895	895
Jim Bridger	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413	1,413
Naughton	700	700	700	700	700	695	695	695	695	695	695	700	700
Wyodak	280	279	280	280	279	277	274	267	268	274	278	280	280
Chehalis	529	529	528	524	522	514	509	500	500	507	520	527	529
Currant Creek	549	549	549	548	547	543	539	533	534	540	545	548	549
Gadsby	231	231	231	231	231	231	231	231	231	231	231	231	231
Gadsby CT	123	123	123	123	121	121	121	117	117	121	121	123	123
Hermiston	248	248	246	246	241	237	235	232	232	237	241	246	248
Lake Side	584	584	577	569	561	576	572	568	569	574	557	570	580
Little Mountain	14	14	14	14	14	13	13	12	12	13	14	14	14
Capacity Factor													
Blundell	90.2%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	94.1%	48.6%	94.1%	94.1%
Carbon	78.9%	86.7%	84.5%	83.7%	86.3%	76.4%	79.2%	81.7%	82.1%	80.9%	72.7%	47.5%	84.5%
Cholla	84.8%	88.9%	88.1%	45.7%	89.0%	86.8%	87.1%	89.0%	89.5%	89.0%	89.1%	87.7%	88.0%
Colstrip	89.3%	92.3%	92.4%	92.5%	92.5%	92.3%	92.5%	92.4%	92.4%	72.5%	74.4%	92.5%	92.5%
Craig	93.7%	94.9%	94.9%	87.3%	88.6%	94.6%	94.7%	94.9%	94.9%	94.7%	94.7%	94.9%	95.0%
Dave Johnston	88.6%	90.7%	90.8%	90.8%	90.8%	90.7%	90.8%	90.7%	90.7%	85.1%	71.3%	90.8%	90.8%
Hayden	92.8%	95.5%	95.4%	63.8%	95.4%	95.5%	95.4%	95.4%	95.4%	95.4%	95.5%	95.4%	95.4%
Hunter	81.8%	86.7%	85.7%	63.0%	80.1%	80.7%	80.4%	83.9%	84.5%	83.5%	82.2%	85.1%	86.4%
Huntington	84.9%	88.3%	88.0%	87.8%	52.9%	84.9%	86.7%	88.0%	89.0%	88.6%	87.2%	88.4%	88.4%
Jim Bridger	83.1%	86.9%	86.8%	83.7%	65.0%	65.2%	87.0%	87.2%	87.2%	87.3%	87.2%	87.3%	87.1%
Naughton	88.3%	90.6%	90.1%	90.1%	66.9%	85.3%	90.9%	90.9%	91.0%	90.9%	90.9%	90.7%	90.6%
Wyodak	91.1%	94.1%	94.2%	94.2%	94.2%	94.1%	94.2%	94.2%	94.2%	94.2%	79.0%	72.2%	94.2%
Chehalis	35.5%	36.9%	-	-	-	-	-	56.7%	82.2%	79.0%	86.3%	43.3%	40.4%
Currant Creek	42.9%	44.6%	38.2%	38.7%	42.8%	34.6%	40.1%	52.2%	55.9%	49.3%	41.7%	38.6%	38.7%
Gadsby	4.8%	-	-	-	-	-	-	19.6%	23.1%	14.2%	-	-	-
Gadsby CT	11.9%	14.1%	8.4%	-	-	-	10.8%	27.9%	29.6%	20.1%	14.2%	8.6%	10.3%
Hermiston	74.4%	93.0%	91.2%	94.0%	49.3%	0.1%	-	93.9%	94.1%	93.5%	92.4%	94.5%	92.7%
Lake Side	55.1%	55.7%	48.6%	48.9%	56.3%	45.5%	52.8%	62.2%	65.2%	62.5%	65.9%	50.8%	47.4%
Little Mountain	71.0%	99.6%	99.6%	99.6%	99.6%	99.6%	-	9.9%	21.5%	-	99.6%	99.6%	99.6%
Foote Creek I	35.9%	53.1%	47.9%	41.6%	32.4%	31.3%	25.0%	17.5%	18.4%	26.7%	37.4%	48.0%	52.7%
Glenrock Wind	38.3%	50.0%	43.0%	41.2%	38.2%	30.8%	31.6%	26.1%	28.1%	34.4%	39.7%	45.5%	51.8%
Glenrock III Wind	36.4%	47.7%	41.0%	39.2%	36.3%	29.1%	29.9%	24.4%	26.5%	32.7%	37.8%	43.4%	49.5%
Goodnoe Wind	32.4%	20.0%	28.8%	44.4%	33.4%	34.9%	41.7%	39.4%	34.3%	27.0%	33.7%	30.8%	20.3%
High Plains Wind	35.7%	48.2%	40.6%	39.6%	36.0%	36.3%	28.8%	23.0%	23.9%	28.8%	30.9%	43.5%	48.7%
Leaning Juniper 1	34.7%	21.6%	25.8%	39.6%	32.7%	42.6%	46.8%	48.1%	40.8%	35.6%	32.6%	25.1%	24.2%
Marengo I	32.0%	31.4%	35.7%	33.8%	35.6%	31.9%	32.2%	30.0%	29.1%	29.4%	31.0%	31.3%	32.7%
Marengo II	30.4%	49.6%	39.5%	38.1%	27.6%	23.7%	30.1%	24.8%	25.1%	24.4%	23.4%	33.0%	26.8%
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	40.3%	59.6%	46.0%	50.1%	37.1%	34.6%	30.8%	23.1%	27.1%	30.3%	40.2%	50.2%	54.7%
Seven Mile II Wind	40.3%	59.6%	46.0%	50.1%	37.1%	34.6%	30.8%	23.1%	27.1%	30.3%	40.2%	50.2%	54.7%

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Wind Integration Charge													
Foote Creek I	102,699	12,892	10,506	10,105	7,611	7,605	5,865	4,253	4,466	6,260	9,075	11,269	12,794
Glenrock Wind	332,471	36,809	28,625	30,312	27,213	22,675	22,529	19,189	20,690	24,548	29,268	32,442	38,172
Glenrock III Wind	124,409	13,846	10,745	11,363	10,181	8,432	8,385	7,094	7,676	9,169	10,960	12,182	14,375
High Plains Wind	309,370	35,480	27,001	29,176	25,636	26,751	20,556	16,976	17,585	20,555	22,727	31,025	35,902
Marengo I	393,136	32,850	33,648	35,285	35,941	33,338	32,512	31,293	30,373	29,681	32,407	31,668	34,139
Marengo II	187,226	25,913	18,628	19,890	13,929	12,361	15,227	12,975	13,096	12,325	12,202	16,669	14,013
McFadden Ridge Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Rolling Hills Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Seven Mile Wind	349,596	43,929	30,606	36,878	26,476	25,496	21,961	17,024	19,928	21,606	29,584	35,802	40,304
Seven Mile II Wind	68,862	8,653	6,029	7,264	5,215	5,022	4,326	3,353	3,925	4,256	5,827	7,052	7,939
Combine Hills	111,603	10,670	6,964	12,330	8,689	8,068	9,707	9,317	9,245	8,810	9,457	10,546	7,702
Rock River	142,099	17,329	13,686	13,830	10,837	10,363	7,823	5,577	6,736	8,750	12,538	17,058	17,571
Three Buttes Wind	171,403	-	-	-	-	-	18,553	16,529	16,932	22,282	27,986	31,436	37,685
Wolverine Creek	176,896	13,112	10,346	20,599	19,833	19,334	15,070	14,711	13,807	12,842	11,119	14,535	11,587
BPA FC II Generation	5,650	709	578	556	419	418	323	234	246	344	499	620	704
BPA FC IV Generation	52,734	6,619	5,394	5,189	3,908	3,905	3,012	2,184	2,293	3,214	4,660	5,786	6,569
EWEB FC I Generation	27,563	3,460	2,820	2,712	2,043	2,041	1,574	1,141	1,198	1,680	2,436	3,024	3,434
PSCo FC III Generation	79,101	9,929	8,092	7,783	5,862	5,857	4,517	3,276	3,439	4,822	6,990	8,680	9,854
Long Hollow	333,438	38,586	34,980	29,681	28,391	22,034	22,320	13,777	17,963	21,051	27,716	34,649	42,273
State Line generation	491,423	45,306	35,245	47,394	42,627	40,883	49,269	39,940	41,770	35,906	39,256	38,482	35,346
-	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	44,528	5,154	4,812	4,947	2,528	2,797	2,253	1,602	2,444	2,626	4,829	5,102	5,433
Mountain Wind 1 QF	151,796	19,721	13,198	15,012	12,392	10,117	7,121	6,376	8,227	10,957	13,581	15,787	19,306
Mountain Wind 2 QF	189,638	25,448	16,515	18,403	14,974	15,818	10,747	9,239	10,202	11,715	14,776	18,563	23,239
Oregon Wind Farm QF	161,172	9,177	10,130	12,979	15,974	16,431	18,932	19,466	14,998	12,070	12,181	14,007	4,827
Spanish Fork Wind 2 QF	55,562	4,484	3,689	3,500	3,695	3,438	4,611	6,114	6,123	5,203	4,608	4,616	5,480
Subtotal Wind Generation	4,062,274	420,075	332,237	375,187	324,374	303,183	307,194	261,639	273,383	290,673	344,680	401,001	428,649
Generation subject to BPA Wind Integration Charges (included in wheeling)													
Goodnoe Wind	266,887	13,956	18,183	31,076	22,609	24,419	28,225	27,556	23,970	18,281	23,542	20,857	14,214
Leaning Juniper 1	305,473	16,176	17,454	29,577	23,680	31,823	33,873	35,958	30,532	25,784	24,369	18,181	18,066
Total Generation (MWh)	4,634,634	450,207	367,874	435,840	370,663	359,424	369,291	325,153	327,886	334,737	392,592	440,039	460,929
Wind Integration Charge $/MWh		1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
BPA Wind Integration Charge per kW-month		1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Company Wind Integration Charge	4,671,615	483,086	382,072	431,465	373,030	348,660	353,273	300,885	314,391	334,274	396,382	461,151	492,846
Goodnoe Wind	1,455,120	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260	121,260
Leaning Juniper 1	1,555,740	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645	129,645
Total Wind Integration Charge ($)	7,682,475	733,991	632,977	682,370	623,935	599,565	604,178	551,790	565,296	585,179	647,287	712,056	743,851
Additional Fixed Costs													
Gadsby	496,359	-	-	-	-	-	-	178,747	167,049	150,563	-	-	-
Gadsby CT	226,355	32,197	24,587	-	-	-	18,392	18,120	18,439	19,071	22,165	30,338	43,046
Chehalis	2,149,521	381,912	-	-	-	-	-	515,911	84,653	154,249	-	438,202	574,595
Additional O&M	-	-	-	-	-	-	-	-	-	-	-	-	-
Startup Fuel	2,149,521	381,912	-	-	-	-	-	515,911	84,653	154,249	-	438,202	574,595
Currant Creek	3,995,259	374,425	290,898	319,785	288,599	280,084	342,649	360,153	366,563	359,218	315,818	323,423	373,645
Additional O&M	-	-	-	-	-	-	-	-	-	-	-	-	-
Startup Fuel	3,995,259	374,425	290,898	319,785	288,599	280,084	342,649	360,153	366,563	359,218	315,818	323,423	373,645
Lake Side	5,256,160	526,521	409,064	449,685	405,813	393,840	481,815	506,429	515,444	505,117	82,238	454,782	525,412
Additional O&M	-	-	-	-	-	-	-	-	-	-	-	-	-
Startup Fuel	5,256,160	526,521	409,064	449,685	405,813	393,840	481,815	506,429	515,444	505,117	82,238	454,782	525,412
Total Fixed Costs	12,123,654	1,315,055	724,549	769,470	694,412	673,924	842,856	1,579,361	1,152,147	1,188,217	420,221	1,246,745	1,516,698

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PacifiCorp

Exhibit B

Net Power Cost Analysis

Mills / kWh

ORDER NO. 09-432

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	33.13	33.14	34.48	32.75	33.30	33.08	33.69	32.41	32.77	33.50	32.83	33.40	32.47
BPA Wind	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30	70.30
Hurricane Sale	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
LADWP (IPP Layoff)	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57
PSCO	70.01	70.03	72.36	70.33	70.96	70.33	70.74	68.90	68.90	69.71	70.00	69.47	68.90
Salt River Project	-	-	-	-	-	-	-	-	-	-	-	-	-
SMUD	37.00	37.00	37.00	-	37.00	-	-	37.00	37.00	37.00	37.00	37.00	37.00
UAMPS s404236	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II	43.64	43.33	45.40	43.33	43.97	43.33	43.97	43.33	43.33	43.97	43.33	43.97	43.33
Total Long Term Firm Sales	46.69	46.32	48.58	48.69	48.56	48.67	48.70	45.46	45.26	45.91	45.46	46.03	45.49
Short Term Firm Sales													
COB	79.36	74.81	75.24	76.36	82.80	82.80	82.80	81.96	81.96	81.96	82.80	82.80	82.80
Four Corners	54.84	57.31	57.31	57.31	56.37	56.37	56.37	52.65	52.65	52.65	52.34	52.34	52.34
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	69.11	67.72	67.89	67.94	70.00	70.00	70.00	74.50	74.50	74.50	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	40.88	40.94	41.24	41.33	38.56	38.14	56.57	55.39	55.39	55.31	30.74	30.75	30.74
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	62.07	62.63	63.07	62.99	60.59	59.47	65.04	65.60	65.75	65.29	58.42	58.24	58.84
System Balancing Sales													
COB	49.17	50.81	47.59	43.10	45.00	40.03	37.62	49.14	54.83	52.77	53.55	53.42	57.17
Four Corners	50.33	47.25	46.10	44.32	46.24	40.78	40.79	60.93	68.63	56.08	53.39	48.80	52.35
Mid Columbia	52.02	49.41	44.77	38.28	31.60	28.74	30.75	54.33	52.88	55.35	51.78	53.63	55.86
Mona	50.33	45.85	47.26	43.41	46.68	43.45	50.65	68.76	65.88	56.51	51.55	47.70	51.38
Palo Verde	51.44	45.98	45.19	40.94	44.85	45.82	56.73	65.45	57.81	54.85	48.45	49.14	53.39
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Sales	50.68	48.20	46.27	42.51	44.93	41.90	45.09	58.01	59.77	56.16	51.97	51.01	54.56
Total Special Sales For Resale	57.11	56.78	56.93	55.39	54.08	52.32	55.09	61.31	62.27	59.69	56.41	55.74	58.23

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	43.80	32.92	26.76	28.90	41.26	41.81	55.91	62.93	86.53	66.00	62.36	37.46	39.58
Blanding Purchase	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Combine Hills	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08	35.08
Deseret Purchase	41.04	40.61	43.02	40.61	41.36	40.61	41.36	40.61	40.61	41.36	40.61	41.36	40.61
Douglas PUD Settlement	27.57	27.52	27.42	27.42	27.61	27.58	27.43	27.45	27.69	27.82	27.59	27.82	27.79
Gemstate	72.54	-	-	-	-	146.63	21.20	16.08	17.78	-	-	-	-
Georgia-Pacific Camas	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49	74.49
Grant County 10 aMW purchase	79.55	89.29	92.91	88.29	72.18	62.60	59.36	73.02	81.85	87.57	82.72	96.70	99.76
Hermiston Purchase	59.19	51.68	54.88	51.61	74.47	34,124.91	-	53.13	53.05	53.48	52.62	53.99	53.56
Hurricane Purchase	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00	75.00
Idaho Power P278538	49.29	49.02	45.99	40.38	39.71	31.16	43.48	54.51	58.77	49.25	52.53	53.22	56.43
IPP Purchase	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57	41.57
LADWP 491303-4	49.96	-	-	-	-	-	49.96	49.96	49.96	49.96	-	-	-
MagCorp Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p189046	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50	43.50
PGE Cove	21.00	20.71	22.29	20.71	21.21	20.71	21.21	20.71	20.71	21.21	20.71	21.21	20.71
Rock River	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
Roseburg Forest Products	57.01	56.72	57.14	57.25	57.22	56.72	57.22	56.99	56.99	56.94	56.99	56.94	56.99
Small Purchases east	66.07	80.37	80.93	81.09	80.49	80.49	80.66	80.31	80.53	79.76	33.59	80.58	80.00
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	63.80	-	-	-	-	-	63.80	63.80	63.80	63.80	63.80	63.80	63.80
Tri-State Purchase	65.96	64.90	76.12	80.62	64.62	71.18	71.69	61.05	57.59	64.13	67.82	62.68	60.16
Weyerhaeuser Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-
Wolverine Creek	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11	55.11
Long Term Firm Purchases Total	58.60	53.59	54.71	52.94	60.22	68.93	71.59	60.01	61.00	60.19	56.79	55.50	55.33
Seasonal Purchased Power													
Morgan Stanley p244840	-	-	-	-	-	-	-	-	-	-	-	-	-
Morgan Stanley p244841	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

ORDER NO. 09-432

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ORDER NO. 09-432

PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Qualifying Facilities													
QF California	118.20	117.51	116.29	134.28	112.70	112.36	114.90	118.20	127.28	130.63	133.13	123.73	118.22
QF Idaho	55.51	54.61	54.42	54.54	54.92	55.52	55.69	56.57	56.49	55.93	55.84	55.61	55.33
QF Oregon	84.87	85.10	85.88	86.77	86.43	85.24	84.32	83.06	82.14	83.68	84.41	84.29	84.96
QF Utah	52.36	52.49	54.69	55.98	53.27	49.73	50.38	50.53	49.55	51.29	52.76	55.93	53.62
QF Washington	147.06	147.18	148.12	147.48	146.86	145.35	146.17	146.29	147.14	147.42	147.75	147.49	148.21
QF Wyoming	63.67	96.63	98.86	97.36	68.21	60.08	60.76	60.36	60.48	61.30	64.56	98.05	97.70
Biomass	157.11	156.76	158.70	156.76	157.36	156.76	157.36	156.76	156.76	157.36	156.76	157.36	156.76
Douglas County Forest Products QF	40.15	47.39	44.17	38.90	38.79	32.04	31.21	48.32	-	-	-	-	-
Evergreen BioPower QF	53.25	52.82	53.45	53.65	53.59	52.65	53.59	53.31	53.16	53.20	53.19	53.20	53.03
ExxonMobil QF	48.65	62.25	59.38	49.53	34.49	28.53	30.56	52.70	55.00	44.64	44.64	49.21	58.02
Kennecott QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	55.54	60.59	58.11	52.68	47.72	49.07	50.79	63.02	65.50	57.89	52.42	52.63	57.54
Mountain Wind 2 QF	64.32	68.54	64.99	60.89	53.80	54.64	64.17	85.20	82.08	68.28	57.35	60.13	65.11
Oregon Wind Farm QF	64.14	64.80	64.81	64.86	64.61	63.50	64.08	63.46	63.27	63.63	64.06	64.75	65.46
Simplot Phosphates	50.99	50.84	51.68	50.84	51.10	50.84	51.10	50.84	50.84	51.10	50.84	51.10	50.84
Spanish Fork Wind 2 QF	53.06	54.88	52.33	50.02	46.09	45.01	50.80	59.62	61.13	54.12	49.34	50.53	53.59
Sunnyside	64.02	60.38	62.68	80.66	61.16	60.31	62.02	62.89	64.87	63.21	70.45	63.99	64.30
Tesoro QF	-	-	-	-	-	-	-	-	-	-	-	-	-
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Weyerhaeuser QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	67.83	70.37	70.74	69.14	64.47	62.65	63.91	73.72	71.66	67.15	66.67	65.01	69.31
Mid-Columbia Contracts													
Canadian Entitlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Chelan - Rocky Reach	12.96	10.38	14.38	14.68	11.88	10.40	10.07	10.58	14.05	20.46	17.33	15.33	13.37
Douglas - Wells	19.06	15.36	21.49	22.13	17.07	14.33	14.75	15.25	20.57	30.94	26.25	23.25	20.20
Grant Displacement	27.59	29.66	30.50	28.49	26.79	22.32	19.39	25.17	29.03	30.82	31.34	33.47	34.85
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	20.14	12.04	20.96	21.54	21.17	19.96	18.36	18.39	23.16	29.85	25.33	22.31	19.48
Grant - Wanapum	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	7.86	5.72	6.84	7.12	8.34	7.40	5.83	7.74	8.04	10.18	9.69	9.81	9.82
Total Long Term Firm Purchases													
COB	69.25	69.25	69.25	69.25	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	75.46	-	-	-	-	-	-	75.90	75.90	74.28	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	41.35	40.83	41.36	41.50	41.46	40.83	41.46	41.17	41.17	41.11	41.64	41.61	41.64
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	(86.57)	(382.53)	(446.11)	(526.45)	(597.31)	(698.22)	(679.32)	38.78	45.33	21.56	(176.77)	(181.44)	(144.90)
System Balancing Purchases													
COB	48.69	45.78	41.48	38.38	41.91	33.65	34.49	63.92	70.55	-	50.00	46.46	47.40
Four Corners	37.63	36.20	34.74	32.56	33.33	32.84	34.36	59.64	48.07	43.76	41.59	41.98	41.79
Mid Columbia	36.89	45.37	44.91	39.20	38.27	29.42	30.24	37.49	47.55	47.62	51.62	46.90	50.93
Mona	46.29	34.66	40.55	33.98	32.58	31.58	40.96	58.15	62.84	38.86	42.36	44.73	44.59
Palo Verde	36.88	38.30	37.83	36.51	33.89	31.46	24.52	36.25	37.21	39.04	37.60	37.84	37.04
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	42.24	-	-	43.88	43.83	35.84	25.66	-	-	-	-	-	-
Total System Balancing Purchases	39.68	39.62	39.28	35.15	36.31	30.33	32.49	54.13	55.78	43.67	41.20	41.39	43.77

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PacifiCorp

Exhibit B

Net Power Cost Analysis

12 months ended December 2010	01/10-12/10	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Thermal Resources													
Blundell	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01	13.01
Carbon	16.88	16.80	16.84	16.85	16.81	16.99	16.94	16.90	16.89	16.91	16.81	17.07	16.83
Cholla	19.21	19.20	19.21	19.21	19.21	19.22	19.22	19.21	19.20	19.21	19.21	19.21	19.21
Colstrip	11.18	11.18	11.18	11.18	11.18	11.18	11.18	11.18	11.18	11.17	11.19	11.18	11.18
Craig	15.34	15.34	15.34	15.35	15.34	15.35	15.35	15.35	15.34	15.35	15.35	15.34	15.34
Dave Johnston	8.92	8.92	8.92	8.91	8.91	8.92	8.92	8.92	8.92	8.92	8.92	8.91	8.91
Hayden	17.81	17.81	17.81	17.83	17.81	17.81	17.81	17.81	17.81	17.81	17.81	17.81	17.81
Hunter	14.02	13.99	14.00	13.99	14.02	14.07	14.08	14.03	14.02	14.03	14.05	14.01	13.99
Huntington	14.52	14.52	14.52	14.52	14.51	14.52	14.53	14.52	14.52	14.52	14.53	14.52	14.52
Jim Bridger	17.63	17.63	17.64	17.63	17.64	17.64	17.63	17.63	17.63	17.63	17.63	17.63	17.63
Naughton	15.18	15.18	15.18	15.19	15.18	15.17	15.19	15.19	15.19	15.19	15.19	15.18	15.18
Wyodak	9.14	9.13	9.13	9.13	9.13	9.14	9.15	9.17	9.16	9.15	9.14	9.13	9.13
Total Coal Expenses	14.57	14.58	14.57	14.40	14.36	14.40	14.60	14.61	14.60	14.66	14.82	14.62	14.57
Chehalis	43.27	45.60	-	-	-	-	-	39.61	40.47	40.92	41.69	49.52	52.53
Currant Creek	38.78	39.33	39.53	38.58	36.05	36.59	36.65	37.28	37.95	38.24	37.53	42.04	46.63
Gadsby	65.13	-	-	-	-	-	-	64.48	64.91	66.42	-	-	-
Gadsby CT	72.90	79.14	79.39	-	-	-	74.66	65.04	65.66	69.80	72.95	84.66	93.99
Hermiston	35.73	33.70	34.51	33.67	39.02	7,931.32	-	34.13	34.10	34.20	34.03	35.37	35.31
Lake Side	36.75	37.19	37.26	36.64	33.68	34.45	35.02	35.49	35.98	36.43	35.94	39.67	44.53
Little Mountain	90.10	89.27	89.58	87.56	82.11	83.42	-	91.42	90.78	-	86.47	95.53	106.01
Total Thermal Resources	54.03	54.18	56.74	56.32	57.18	69.64	64.83	52.83	50.98	50.89	46.99	53.46	54.89

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Docket UE 207

STIPULATION OF JOINT PARTIES

Exhibit C

Rate Calculation

September 25, 2009

Exhibit C

UE 207 STIPULATION
PACIFIC POWER & LIGHT COMPANY
DEVELOPMENT OF TAM ADJUSTMENT FOR JANUARY 1, 2010
FORECAST 12 MONTHS ENDED DECEMBER 31, 2010

					Stipulated TAM Adjustment				
Line No.	Description	Sch No.	kWh[1]	January 1, 2010 Sch 200 Present Revenue	Net Power Cost Increase Revenue	Final Upate[2] Revenue	Growth/ Loss Adjustment Revenue	Total Adjustment Revenue	Total Adjustment Cents\kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (5)+(6)+(7)	(9) (8)/(3)
	Residential								
1	Residential	4	5,435,845,633	$226,599,972	($4,403,546)	$0	$6,090,764	$1,687,218	0.031
2	**Total Residential**		5,435,845,633	$226,599,972	($4,403,546)	$0	$6,090,764	$1,687,218	
	Commercial & Industrial								
3	Gen. Svc. < 31 kW	23	1,013,940,497	$42,927,417	($834,214)	$0	$1,153,843	$319,629	0.032
4	Gen. Svc. 31 - 200 kW	28	2,045,065,385	$84,830,155	($1,648,515)	$0	$2,280,144	$631,628	0.031
5	Gen. Svc. 201 - 999 kW	30	1,378,646,160	$55,560,675	($1,079,718)	$0	$1,493,411	$413,694	0.030
6	Large General Service >= 1,000 kW	48	2,643,901,271	$99,835,377	($1,940,113)	$0	$2,683,468	$743,354	0.028
7	Partial Req. Svc. >= 1,000 kW	47	565,102,620	$20,957,166	($407,263)	$0	$563,306	$156,043	0.028
8	Agricultural Pumping Service	41	136,791,880	$5,648,605	($109,770)	$0	$151,828	$42,058	0.031
9	**Total Commercial & Industrial**		7,783,447,813	$309,759,395	($6,019,593)	$0	$8,326,000	$2,306,407	
	Lighting								
10	Outdoor Area Lighting Service	15	10,467,219	$238,234	($4,630)	$0	$6,403	$1,774	0.017
11	Street Lighting Service	50	10,738,031	$203,271	($3,950)	$0	$5,464	$1,514	0.014
12	Street Lighting Service HPS	51	16,084,697	$480,611	($9,340)	$0	$12,918	$3,579	0.022
13	Street Lighting Service	52	1,185,726	$27,141	($527)	$0	$730	$202	0.017
14	Street Lighting Service	53	9,316,113	$91,112	($1,771)	$0	$2,449	$678	0.007
15	Recreational Field Lighting	54	815,719	$13,729	($267)	$0	$369	$102	0.013
16	**Total Public Street Lighting**		48,607,505	$1,054,098	($20,484)		$28,333	$7,849	
17	**Total Sales to Ultimate Consumers**		13,267,900,951	$537,413,465	($10,443,624)	$0	$14,445,097	$4,001,474	
18	**Employee Discount**			($197,897)	$3,846	$0	($5,319)	($1,474)	
19	**Total Sales with Employee Discount**		13,267,900,951	$537,215,568	($10,439,778)	$0	$14,439,778	$4,000,000	

[1] Excludes unscheduled energy