ORDER NO. 12 493

ENTERED: DEC 20 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision	ORDER

DISPOSITION: PARTIAL STIPULATION ADOPTED; REQUEST FOR TARIFF RIDER GRANTED; REQUEST FOR PCAM GRANTED WITH MODIFICATION; RATE RECOVERY FOR COAL PLANT INVESTMENTS ALLOWED IN PART

I. INTRODUCTION

In this order, we address the request of PacifiCorp, dba Pacific Power, for a general rate revision. We adopt the partial stipulation filed by the parties on July 12, 2012. We grant Pacific Power's request for a separate tariff rider to recover its investment in the Mona-to-Oquirrh transmission line, and grant with modification Pacific Power's request for a power cost adjustment mechanism. Finally, we grant partial approval of Pacific Power's request to include in rates its investment in upgrades to its coal fleet.

II. PROCEDURAL HISTORY

Pacific Power is a public utility providing electric service in the State of Oregon within the meaning of ORS 757.005, and is subject to the Commission's jurisdiction with respect to the prices and terms of service for its Oregon retail customers. Pacific Power provides electric service to approximately 580,000 retail customers in Oregon.

On March 1, 2012, Pacific Power filed its request for a general rate revision under ORS 757.205 and ORS 757.220, seeking a revenue requirement increase of $38.4 million, or 3.2 percent. After resetting Schedule 299, its Rate Mitigation Adjustment, to reflect forecast customer loads by rate schedule, the proposed increase to net rates was revised to $41.2 million, or 3.5 percent. In its filing, Pacific Power used an historical base period of the 12 months ending June 2011, with normalizing and *pro forma* adjustments to calculate a 2013 calendar year future test period ending December 31, 2013.

On March 14, 2012, we suspended Pacific Power's tariff filing for investigation under ORS 757.215(1).[1]

[1] Order No. 12-093 (Mar 14, 2012).

On March 19, 2012, a prehearing conference was held and a procedural schedule was established. During the course of the proceedings, the following were granted leave to intervene as parties: Industrial Customers of Northwest Utilities (ICNU); Portland General Electric Company (PGE); Fred Meyer Stores and Quality Food Centers, divisions of the Kroger Company (Kroger); Sierra Club; Northwest Energy Coalition; Renewable Northwest Project; and the Klamath Water and Power Agency. The Citizens' Utility Board of Oregon (CUB) intervened as a matter of right under ORS 774.180.

The parties conducted discovery, filed several rounds of testimony, and engaged in settlement discussions. On July 12, 2012, Commission Staff, Pacific Power, CUB, ICNU, and Kroger filed a partial stipulation of contested issues. Pacific Power filed three rounds of testimony, and intervenors and Commission Staff filed two rounds of testimony, prior to the hearing held on October 15, 2012. Parties filed simultaneous briefs, with one round filed before and one round filed after the hearing. Oral argument was held before the Commission on November 20, 2012.

II. DISCUSSION

A. Procedural Issues

We resolve here the prudence of Pacific Power's investment in upgrades to its coal fleet, including its investments in Unit 3 of its Jim Bridger plant. Because Idaho Power Company is a co-owner of the Jim Bridger plant, Idaho Power's general rate case before the Commission, docket UE 233, also addresses the prudence of investments to Jim Bridger Unit 3. In this order, we address only the prudence of Pacific Power's investment.

B. Legal Standard

In a general rate proceeding, we must balance the interests of the utility investor and ratepayers in establishing fair and reasonable rates.[2] To protect ratepayers, the rates must be set at a level sufficiently low to avoid unjust and unreasonable exactions. To protect the utility investor, the rates must provide sufficient revenue not only for operating expenses, but also for the capital costs of the business.

As the petitioner in this rate case, Pacific Power has the burden of proof on all issues. As provided in ORS 757.210(1)(a), "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just and reasonable." This burden is borne by the utility throughout the proceeding and does not shift to any other party.

With regard to the recovery of capital investments, Pacific Power must make two showings. First, it must show that the investment is presently used for providing utility

[2] ORS 756.040(1).

service.[3] Second, it must show that the investments were prudently made, based on the information that it knew or should have known at the time.[4]

III. STIPULATED ISSUES

On July 12, 2012, most of the active parties filed a partial stipulation resolving certain issues in this docket. Parties supporting the stipulation are: Pacific Power, Staff, CUB, ICNU, and Kroger. No party objected to the partial stipulation.

A. Partial Stipulation

The partial stipulation addressed ten issues. We summarize each separately, followed by our resolution:

1. Revenue Requirement

Stipulating parties agree to a revenue requirement increase of $20.7 million, representing a settlement of contested revenue requirement issues. The calculation of the $20 million increase in rates is attached to the stipulation as Exhibit A. The parties agreed to an overall base price increase of $20.7 million, effective January 1, 2013.

2. Effective Date

Stipulating parties agree that rates to recover the stipulated revenue requirement will go into effect January 1, 2013, as modified by the Commission's resolution of the prudence of Pacific Power's environmental control investments.

3. Rate of Return

Stipulating parties do not agree on values for the components of capital costs and structure, but do agree that Pacific Power's overall rate of return (ROR) and notional values of individual costs of capital components used to derive the ROR are as reflected in the table at page 4 of the stipulation.

4. Carbon-Accelerated Depreciation

Stipulating parties do not oppose Pacific Power's request to include in Oregon rates the accelerated depreciation and decommissioning costs for the early retirement of Pacific Power's Carbon thermal generation plant in 2015, as reflected in Exhibit B to the stipulation.

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[3] ORS 757.355(1).

[4] *See, e.g., In re Portland General Electric Company*, Docket No. UE 102, Order No. 99-033 at 36-37 (Jan 28, 1999). We further discuss the application of the prudence standard in addressing the prudence of Pacific Power's investments in environmental controls at its thermal generation plants.

5. Prudence of Black Cap Solar Resource

Stipulating parties agree that Pacific Power's investment in the Black Cap solar resource is prudent, and should be included in its revenue requirement.

6. Open Access Transmission Tariff (OATT) Revenues

Pacific Power agrees to file a request for deferred accounting to defer Oregon's allocated share of the incremental OATT revenue associated with its pending rate case at FERC beginning January 1, 2013, and continuing until the revenues are included in rates. The deferral will include incremental OATT revenues from all sources, and the intent of the deferral is to credit OATT revenues to customers without offsets.

7. Building of Mona-to-Oquirrh Transmission Line

The stipulating parties agree not to contest the prudence of Pacific Power's decision to build the Mona-to-Oquirrh transmission project, which is scheduled to be placed in service in May 2013. ICNU, CUB, and Staff oppose Pacific Power's request for Commission approval of a tariff rider to include the costs of the project in rate base after January 1, 2013. If the Commission approves Pacific Power's proposed tariff rider, the stipulation provides that all parties will have the opportunity to review Pacific Power's actual costs for the project and challenge any cost as imprudent or exceeding the amount included in the initial filing of this case.

8. Rebalance Rate Mitigation Adjustment (RMA)

Stipulating parties agree that an increase of $2.8 million is required to rebalance the RMA to reflect forecast customer loads by rate schedule, in addition to the $20.7 million revenue requirement increase agreed to in the stipulation.

9. Rate Spread

Stipulating parties do not agree on the cost of service methodology used to determine rate spread, but do agree to the allocation of base and net revenues by rate schedule as presented on page one of Exhibit D to the stipulation. Stipulating parties agree Pacific Power will use the base rate revenues or applicable functionalized revenue requirement allocation factors at page 4 of Exhibit D to the stipulation as the rate spread allocation factors for rate changes, until the Commission approves new functionalized revenue requirement allocation factors in a subsequent general rate case filing. Most customer rate schedules will see a 2.2 percent rate increase under the stipulated rate spread.

10. Rate Design

Stipulating parties agree to the rate design for each rate schedule presented in Exhibit E to the stipulation.

B. Resolution

The Commission will approve stipulations that appropriately resolve issues and result in just and reasonable rates. After reviewing the stipulation, we conclude that the proposed stipulation fairly resolves the contested issues. We adopt the partial stipulation, attached to this order as Appendix A.

IV. DISPUTED ISSUES

Parties filed testimony and briefs on three disputed issues:

1. Pacific Power's proposal to add the Mona-to-Oquirrh transmission line to its rate base through a separate tariff rider when the line goes into service in 2013;

2. Pacific Power's request for a power cost adjustment mechanism; and

3. Pacific Power's request to recover investments in environmental controls at its thermal generation plants.

We address each issue separately, summarizing the parties' arguments followed by our resolution.

A. Inclusion in Rates of Investments to Mona-to-Oquirrh Transmission Line

The Mona-to-Oquirrh transmission project consists of a new high-voltage transmission line and two new substations in Utah. The project originates with a single-circuit 500 kV transmission line that spans from the Clover substation being constructed near Mona, 70 miles north to the future Limber substation in Tooele County. From there, it continues as a double-circuit 345 kV line 30 miles to the existing Oquirrh substation in South Jordan.

Because the project is expected to go into service in May of 2013, midway through the test period, Pacific Power requests approval to make an advice filing for a separate tariff rider for $12.6 million to recover the Oregon-allocated portion of its investment when it goes into service.[5] In their stipulation, the parties stipulated to the prudence of Pacific Power's decision to build the Mona-to-Oquirrh transmission project. As a result, the sole question before us at this time is whether to approve Pacific Power's proposed separate tariff rider.

ICNU, CUB, and Staff oppose Pacific Power's proposed tariff rider. Because their arguments opposing the rider are virtually identical, we refer to ICNU, CUB, and Staff collectively as "opposing parties." The opposing parties raise three primary arguments. First, they contend the rider violates the Commission's used and useful standard. Second,

[5] Pacific Power originally calculated the Oregon-allocated revenue requirement for the project as $13.1 million, and revised it to $12.6 million using the weighted average cost of capital agreed to in the parties' stipulation.

they argue that Pacific Power's proposal undermines the principle of regulatory lag. Finally, they contend the rider constitutes improper "cherry-picking."

1. Used and Useful Standard

ICNU, CUB and Staff argue that Pacific Power's proposed rider violates the intent and purpose of the used and useful standard by allowing rate recovery for a project that will not be in service when rates are approved in this case. The opposing parties cite to precedent from this Commission and the Oregon Supreme Court that a new facility is excluded from rate base "until it actually is placed in service and, even then, the regulators may not allow it in the rate base until the utility established that the property is reasonably necessary to provision of electrical service."[6] The opposing parties note that the underlying purpose of the used and useful statute is to ensure that customers do not pay for costs that are not providing benefits, and the proposed rider would "prevent the Commission from ascertaining the full value of the project or to incorporate other cost savings that may occur if and when the project is completed."[7]

Pacific Power responds that the project complies with ORS 757.355, because it will be both used and useful at the time the tariff rider takes effect. Pacific Power states the project is useful because it is necessary to comply with reliability and performance standards, as well as to strengthen the reliability of the utility's transmission system and support energy demands. Pacific Power notes that its 2007, 2008, and 2011 Integrated Resource Plans (IRPs) evaluated the project for cost-effectiveness and included it as part of the utility's preferred resource portfolio. Because Pacific Power proposes to recover its investment through a tariff rider beginning when the project is placed in service, the utility argues the project will meet the used and useful standard because it will be "presently used for providing utility service to customers" at the time it is included in rates.[8]

2. Regulatory Lag

The opposing parties cite to the principle of "regulatory lag," defined as "the delay between rate cases and within a rate proceeding * * * where rates remain frozen until a new rate is approved."[9] Because a utility carries both the risk and the reward associated with "between rate case" occurrences, the opposing parties argue that Pacific Power has failed to justify extraordinary treatment of its investment that would set it apart from any other "between rate case" occurrence. The opposing parties note that while there are dockets in which this Commission has approved "between rate case" investments to be included in rates, the majority of those dockets were resolved through stipulations, and should not be used as precedent here. ICNU and CUB further note that allowing non-

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[6] *See* Joint ICNU-CUB Prehearing Brief at 4 (Sept 24, 2012), *citing Pac. Power & Light Co. v. Dept. of Revenue*, 308 Or. 49, 53-54 (1989).
[7] *See* ICNU-CUB Joint Posthearing Brief at 11 (Nov 8, 2012).
[8] *See* ORS 757.355(1) ("a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.").
[9] *See, e.g.*, Joint ICNU-CUB Prehearing Brief at 5, citing LEONARD SAUL GOODMAN, THE PROCESS OF RATEMAKING (Vol. I), 44 (Pub. Util. Rpts., Inc. 1998).

operational facilities to go into rates without proper review can lead to significant over-earning, as with the Commission's pre-approved inclusion of Coyote Springs in PGE's 1996 rate case.[10]

Pacific Power responds that "regulatory lag" is not a governing principle of rate regulation, but rather a consequence of traditional rate regulation that fails to match the provision of service with the costs of providing that service. Pacific Power states that by timing the recovery of costs with the customers' receipt of the benefits of service, no regulatory lag is implicated here.

3. *Cherry-Picking*

The opposing parties argue that allowing the tariff rider would constitute "cherry picking," or selecting only those events that are beneficial to the utility and its shareholders for "extra rate case" recognition. The opposing parties note Pacific Power does not propose to pass back to ratepayers any "between rate case" savings, including lower capital costs, that may have occurred in the past or may occur at the time the project is placed in service.

Pacific Power responds that the proposed rider is not being "picked" from an unexamined future period. Pacific Power notes that "[a]ll known, measurable, and reasonably certain expenses and revenues (other than other capital additions not expected to be complete before December 31, 2012) were included in the test year and reviewed by the parties."[11]

4. *Resolution*

We grant Pacific Power's request for a separate tariff rider for the Mona-to-Oquirrh transmission project, with the conditions described below. Under similar circumstances, this Commission has previously allowed utilities to recover in rates the costs of investments placed into service during the test year. We exercise our discretion and find Pacific Power's request for similar rate treatment of this project reasonable because we previously acknowledged the line as part of the utility's IRP process and other parties have stipulated to the prudence of the investment. Further, we believe that a five-month lag is a sufficiently short period of time to minimize the opposing parties' concerns.

At the outset, we agree with Pacific Power that the proposed rider does not violate the terms of ORS 757.355(1), because at the time the cost of the investment will be included in rates, it will be "presently used for providing utility service." We decline the opposing parties' request that we interpret ORS 757.355(1) to restrict the Commission's consideration of whether to allow recovery of investments to only those placed in service prior to the start of the test year. So long as the investment is used and useful at the time it is included in rates, the provisions of ORS 757.355(1) are satisfied. Further, we note that under the terms of the parties' stipulation, the final costs of the transmission line will be reviewed for prudence before being included in rates. As a result, we will not be barred from analyzing and ascertaining the full value of the project.

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[10] *See* Joint ICNU-CUB Prehearing Brief at 7, citing *In Re Portland General Electric Company*, Docket No. UE 100, Order No. 96-306, Appendix A, 2 (Nov 26, 1996).

[11] Pacific Power Prehearing Brief at 57 (Sept 24, 2012).

With regard to regulatory lag and "cherry-picking," the opposing parties are correct that utilities typically bear the risk of increased costs between rate cases.[12] The opposing parties acknowledge, however, that this principle is not binding, and this Commission has permitted utilities to include in rates costs of investments that began operation during the relevant test year.[13] Here, the Mona-to-Oquirrh transmission project has been acknowledged as part of the IRP process and deemed prudent by the opposing parties. Moreover, the final costs of the project will be subject to further review before being included in rates. We do not believe that the expected five-month period is a sufficiently long time to trigger serious concerns about regulatory lag and "cherry-picking," and adopt conditions below to address any possible delays beyond that period.

We grant Pacific Power's request for a tariff rider to recover the Oregon-allocated portion of its investment, with the following conditions. Our decision regarding the tariff rider will prevail as long as the Mona-to-Oquirrh transmission project becomes operational by May 31, 2013. With the proposed tariff rider, Pacific Power will need an attestation by a corporate officer that the project is complete and has been released for operation. We will review for prudence the final costs of the transmission project before they are included in rates. As provided by the partial stipulation, which we adopt in this order, Pacific Power will facilitate the parties' audit and review of the utility's final costs of the project, and any party may challenge costs as imprudent or exceeding the amount initially requested by Pacific Power.

If the transmission project becomes operational after May 31, 2013, but within 60 days of that date, Staff and intervenors will have 20 days from the online date to establish sufficient cause to warrant the reopening of this docket to determine whether any cost reductions to Pacific Power's test year expenses should be used to off-set, in part, costs associated with the new transmission project. If the transmission project becomes operational more than 60 days after May 31, 2013, Pacific Power must make a new filing with the Commission under ORS 757.210 to add the project to rate base when it meets the used and useful standard.

B. Proposed Power Cost Adjustment Mechanism

Pacific Power proposes a Power Cost Adjustment Mechanism (PCAM) to operate in conjunction with the utility's Transition Adjustment Mechanism (TAM), to collect or credit the differences between actual net power costs (NPC) and the forecasted net power costs approved in the TAM and recovered in rates. Staff recommends we adopt a PCAM that mirrors the structure of the PCAM we adopted for PGE, with a deadband, earnings test, and sharing provision. ICNU and CUB oppose a PCAM for Pacific Power, but if we choose to adopt a PCAM, the parties generally agree with the PCAM proposed by Staff.

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[12] *See, e.g., In Re PacifiCorp*, Docket Nos. UM 995, UE 121, UC 578, Order No. 01-420 at 29 (May 11, 2001).

[13] *See* Pacific Power Prehearing Brief at 54-55, *citing In re Idaho Power Company*, Docket No. UE 248, Order No. 12-358 at 4 (Sept 20, 2012) (adopting a stipulation allowing Idaho Power's Langley Gulch power plant investment to be included in rates seven months after the beginning of the relevant test period); *In re Portland General Electric Company*, Docket Nos. UE 180, UE 184, Order No. 07-015 at 50 (Jan 12, 2007 (adopting process for review and approval of PGE's Port Westward natural gas plant after start of test year; no additional review was required if the plant became operational by May of the test year).

Finally, Kroger opposes adopting a PCAM that does not include a sharing of the power cost variances between the company and customers.

1. PCAM

a. Parties' Positions

i. Pacific Power

Pacific Power contends that the proposed PCAM is needed to address the utility's dramatic under-recovery of NPC, caused in large part by the passage of Senate Bill 838 (SB 838), which established a renewable portfolio standard (RPS) for electric utilities and electricity service suppliers.[14] Pacific Power claims its under-recovery of NPC in Oregon rates is due primarily to the inability to accurately forecast wind generation and factors associated with integrating a new, large fleet of renewable resources whose generation fluctuates widely. Because customers must bear all prudently incurred RPS compliance costs—including the variable NPC impacts associated with integrating renewable energy sources—Pacific Power seeks a PCAM without deadbands, earning bands, sharing percentages, or any other feature that would deprive the utility of dollar-for-dollar recovery of any under-recovery of NPC.[15] Pacific Power relies on the provisions of ORS 469A.120(1), which address recovery of compliance costs.[16]

Pacific Power adds that in 2007, the Commission established the Renewable Adjustment Clause (RAC) to allow the utility to recover the fixed capital costs of compliance with ORS 469A.180(2).[17] At the time, Pacific Power intended that the RAC would provide for recovery of its fixed capital costs, and the utility's annual TAM filing would allow for timely recovery of the NPC impact of its renewable generation resources. Pacific Power states that it has now become clear that the utility is significantly under-recovering NPC in Oregon rates. Pacific Power estimates that, since SB 838 was enacted in 2007, the utility has under-recovered its NPC by $134 million on an Oregon basis.

Pacific Power contends deadbands, sharing mechanisms, and earnings bands do not provide incentives for the effective management of NPC, but rather function to arbitrarily reward or penalize the utility for factors that it cannot control. Without proof that these features provide an incentive for the utility to procure fuel and power at a lower cost, Pacific Power argues there is no rational basis to impose such mechanisms and deny the

[14] Codified in ORS Chapter 469A.

[15] Pacific Power notes that neither SB 838 nor the Commission's rules define the terms "integrate, firm or shape," but that in their ordinary usage, the terms refer to "the actions the Company must take on a real-time basis to balance its system to address large amounts of new intermittent renewable resources." Pacific Power Prehearing Brief at 31.

[16] That statute provides: "Except as provided in ORS 469A.180(5), all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric company, including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs, above-market costs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers."

[17] *Id.* at 31, *citing In Re Pacific Power*, Docket No. UM 1330, Order No. 07-572 at 3 (Dec 19, 2007) (establishing Pacific Power's RAC).

utility a reasonable opportunity of recovering its costs of serving customers. Pacific Power also disputes ICNU's and CUB's claim that a PCAM without these features is "unprecedented." Pacific Power states that its proposal is consistent with the majority of PCAMs in the country, and states that PGE is the only utility in Pacific Power's cost of capital peer group with a PCAM that includes all three components. Pacific Power adds that, although the utility's PCAMs in other states have sharing bands, none have deadbands.[18]

If the Commission chooses to adopt a deadband, Pacific Power argues the deadband should be modified to address its unique circumstances. Pacific Power opposes the use of an asymmetric deadband adopted for PGE. That deadband did not change rates when excess power cost were less than the equivalent of 150 basis of authorized ROE or when power cost savings were less than the equivalent of 75 basis points of the utility's authorized ROE. Pacific Power notes that the use of such a large deadband would have provided Pacific Power with zero percent recovery of its unrecovered NPC over the last five years, even though its unrecovered NPC was more than $25 million in four of the five years. Moreover, because that deadband was set through a basis points calculation, the deadband increases as the utility's rate base expands to incorporate new renewable resources required by SB 838.

More generally, Pacific Power argues the deadband in PGE's PCAM was set prior to the passage of SB 838 and does not reflect the changed business risk resulting from the RPS requirements. Pacific Power acknowledges that PGE's PCAM was later modified to include a dollar-defined deadband, but argues that a similar deadband would still be too large. If the Commission adopts a dollar-defined deadband, Pacific Power recommends one that is half of that adopted for PGE, because the utility's Oregon NPC are approximately half those of PGE's.

Pacific Power argues that a sharing mechanism is also not appropriate, because it is a misplaced incentive that would only penalize the utility for factors beyond its control. Pacific Power argues nearly all NPC components are out of the utility's control, including wind generation capacity, market prices, variations in customer loads, hydro generation, and the timing of forced outages. Pacific Power notes it currently bears 100 percent of the risk of unrecovered NPC, and despite that incentive, the utility has still underrecovered $134 million of NPC since 2007. Pacific Power argues that this demonstrates it cannot reasonably control large cost exposures which are volatile and inherently out of its control.

Finally, Pacific Power opposes the adoption of an earnings band, which would result in no adjustment if the utility's earnings are within a certain percentage of its authorized ROE. Pacific Power argues that an earnings band would likely result in the disallowance of prudently incurred costs, including those associated with compliance with SB 838. The utility also contends that the earnings band proposed in this case effectively functions as a back-up deadband, increasing the normal business risk assigned to the utility.

[18] Pacific Power notes that out of 55 utilities in its cost of capital peer group, seven have a deadband, four have both a deadband and a sharing band, and one has a deadband, sharing bands, and an earnings review. Pacific Power Prehearing Brief at 39.

ii. Staff

Staff recommends the Commission adopt a PCAM for Pacific Power that mirrors the structure of the PCAM established for PGE. Specifically, Staff recommends a PCAM that contains the following features:

1. Deadband: No adjustment to NPC if variances fall within an asymmetrical dead band defined by 150 basis points of pre-tax ROE in the case of potential collections and 75 basis points of pre-tax ROE in the case of potential refunds.

2. Sharing Mechanism: "90/10" sharing between customers and the utility for amounts outside the deadband.

3. Earnings Test: No refunds or collections if earnings are within 100 basis points of the utility's authorized ROE.

Staff disputes Pacific Power's claims that fluctuations in wind integration costs and under-recovery of NPC justify a pass-through to customers of all differences between forecast and actual NPC. Staff notes wind integration costs are a small part of Pacific Power's overall NPC—less than 2 percent of the 2013 NPC forecast. Staff also notes that costs associated with new wind resources can be reasonably forecast, noting that wind integration studies use methodologies to translate large hour to hour fluctuations into reasonably accurate annual cost estimates. With regard to Pacific Power's under-recovery of NPC, Staff notes the results of 2007 through 2011 may not be representative of results over a longer period of time, and that under-recovered amounts remained within a range that could be absorbed by Pacific Power without unduly affecting earnings.

Staff also defends the use of an asymmetrical deadband to ensure the PCAM is revenue neutral. Staff explains that various components of NPC can go up more than they can go down; consequently, a symmetrical deadband would result in more collections than refunds over a long period of time. Staff opposes Pacific Power's alternate proposal of a PCAM with a deadband half of that adopted for PGE. Staff notes that the modified deadband resulted from a stipulation crafted on the premise that a deadband should be based on a utility's ability to absorb cost variances, not on the size of the utility's NPC. Since Pacific Power's and PGE's rate base are approximately the same size, Staff believes the two utilities' deadbands should be the same size as well.

To provide Pacific Power with an incentive to prudently manage its NPC, Staff proposes 90/10 sharing between customers and the utility for amounts outside the deadband. Under this feature, the utility and its shareholders would be responsible for 10 percent of the difference between forecasted and actual NPC, and the customers would be responsible for the remaining 90 percent. Staff argues that without a sharing percentage, the utility will have no incentive to keep incremental NPC as low as possible when it knows it will be refunding or collecting from customers any NPC differences. Staff implicitly acknowledges there are certain factors affecting NPC that are beyond Pacific Power's control, but argues that the utility can affect costs to a degree with operational decisions, and that the sharing structure ensures that Pacific Power will prudently make those decisions.

Finally, to ensure that the PCAM would impose rate adjustments only for significant NPC variances, Staff's proposes an earnings test that would preclude any refunds or collections if Pacific Power's earnings are within 100 basis points of its authorized ROE. Staff explains that, if actual NPC are greater or less than forecast, Pacific Power may collect from or refund to customers only up to a level at which ROE is 100 basis points more or less than authorized. Thus, under Staff's proposal, no adjustments will be made if earnings are within 100 basis points of authorized ROE; collections are made only up to the point at which earnings are 100 basis points below authorized ROE; and refunds are made only down to the point at which earnings are 100 basis points above authorized ROE.

iii. ICNU and CUB

ICNU and CUB oppose a PCAM for Pacific Power, and argue that the utility has not demonstrated a need for the mechanism. ICNU and CUB claim that Pacific Power has overstated its under-recovery of NPC and the effects of SB 838. ICNU and CUB cite to Staff's calculation that wind integration costs represent less than 2 percent of all NPC, and note that even this amount may be overstated because, on an actual net power cost basis, Pacific Power cannot accurately track and separate its wind integration costs from other power costs. ICNU and CUB also note Pacific Power fails to consider other significant factors that have affected its power costs, such as the economic recession and increased regulation of coal resources. ICNU and CUB conclude Pacific Power has failed to demonstrate that, on a normalized basis, it is unable to recover an appropriate level of NPC in rates under the current regulatory framework.

ICNU and CUB argue that Pacific Power's current regulatory mechanisms allow the utility to recover its prudently-incurred costs associated with renewable resources and other power costs. The parties state wind generation is already included in Pacific Power's rates, and the utility is receiving rate recovery on all of its owned generation resources, including wind generation. ICNU and CUB note Pacific Power's RAC allows it to defer and recover the costs of renewable generation and associated transmission outside of normal ratemaking process. The parties conclude that adopting a dollar for dollar PCAM for all costs to ensure the utility collects a small and fundamentally unverifiable amount of wind integration costs is "overkill." [19]

If the Commission adopts a PCAM, ICNU and CUB contend that it must include a sharing mechanism, deadbands, earning tests, and amortization caps to protect customers and ensure that the utility continues to bear the benefits and risks of normal power cost variations. ICNU and CUB argue that Pacific Power's reliance on SB 838 to support a dollar-for-dollar recovery of NPC variations is misplaced. Although SB 838 allows utilities to recover prudently incurred costs associated with compliance with the renewable portfolio standard, ICNU and CUB contend that an "automatic adjustment clause" or other "method that allows timely recovery of costs prudently incurred" is only

[19] *See* Joint ICNU-CUB Prehearing Brief at 11.

available for fixed costs, such as construction or acquisition costs, and not variable costs, such as NPC.[20]

ICNU and CUB support Staff's proposed deadband and earnings test. They recommend, however, a 75/25 sharing mechanism for costs outside the deadband, with Pacific Power absorbing 25 percent of the costs outside of the deadband and ratepayers absorbing 75 percent. ICNU and CUB argue a larger sharing mechanism is warranted because it will help insulate Oregon customers from subsidizing the outcomes of Pacific Power's services to other jurisdictions. ICNU and CUB also contend the Commission should limit any necessary collections to 6 percent of Pacific Power's revenues for the last calendar year, and that a PCAM should not apply to direct access customers, who already bear the risk of variable power costs through their pricing structure.

iv. Kroger

Kroger joins Staff, ICNU, and CUB in opposing Pacific Power's proposed PCAM with dollar-for-dollar pass-through of annual power cost variance. Kroger states that a 100 percent cost pass-through seriously reduces Pacific Power's incentive to manage its fuel and purchased power costs as well as it would manage them if the utility remained fully responsible for the energy cost risk between TAM filings. Kroger recommends a 70/30 sharing mechanism to provide a more equitable balance between customer and shareholder interests, with 70 percent of the difference between forecasted and actual NPC allocated to customers, and 30 percent allocated to Pacific Power. Kroger notes that such power cost sharing provisions are in place in Pacific Power's Utah and Wyoming jurisdictions. Kroger argues 70/30 sharing meaningfully aligns utility and customer interests through shared benefits and costs.

b. Resolution

In adopting a PCAM for PGE, we articulated general principles that form the basis of a well-designed PCAM: (1) any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility; (2) there should be no adjustments if the utility's overall earnings are reasonable; (3) the PCAM's application should result in revenue neutrality; (4) the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer; and, implicitly, (5) the PCAM should provide an incentive to the utility to manage its costs effectively.[21]

Applying those principles, we adopted a PCAM structure for PGE as follows. First, we established a deadband so that PGE would absorb some normal variation of power costs. If the power cost variation fell within the deadband, there would be no power cost rate adjustment. We concluded a power cost deadband should be calculated based on PGE's overall rate base. To ensure the PCAM was revenue-neutral, we adopted an asymmetric deadband that did not change rates when excess power costs were less than the equivalent

[20] *Id.* at 10, citing ORS 469A.120.

[21] Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26-27 (Jan 12, 2007).

of 150 basis points of authorized ROE or when power cost savings were less than the equivalent of 75 basis points of the utility's ROE.

Second, we adopted a sharing mechanism: for any power costs above or below the deadband, customers will bear 90 percent of the adjustment, and PGE will bear 10 percent of the adjustment. We concluded that the 10 percent share provides PGE "with an incentive to manage its costs effectively, while sharing costs that are beyond normal business risk."[22]

Third, we applied an earnings test to determine whether the utility is earning an acceptable ROE. As noted, an earnings test serves to protect customers from paying for higher-than-expected power costs when the utility's earnings are reasonable, while protecting the utility from refunding power cost savings when it is under-earning. We established an earnings test of +/- 100 basis points around the utility's allowed ROE. Thus, if PGE is earning within +/- 100 basis points of this authorized ROE, then there would be no power cost adjustment for that year. If the utility's earnings are more than 100 basis points below its authorized ROE, then it would be allowed to recover excess power costs, after application of the deadband and 90/10 sharing, up to an earnings level that is 100 basis points less than its authorized ROE. If the utility's earnings are more than 100 basis points above its authorized ROE, then it would be required to refund to customers power cost savings, after application of the deadband and sharing, down to the ROE plus 100 basis points threshold.

Finally, we limited amortization of deferred amounts under the PCAM in any one year to 6 percent of PGE's revenues for the preceding calendar year. Later, we adopted a stipulation that modified PGE's PCAM in one respect—changing the deadband from basis points to a set dollar amount. Under this modification, the negative annual power cost variance deadband was set at $15 million, and the positive annual power cost variance deadband was set at $30 million.[23]

After reviewing the factual record and the parties' arguments in this proceeding, we conclude that our reasoning used to establish a PCAM for PGE remains sound and applies equally with respect to establishing a PCAM for Pacific Power. We note that wind integration costs represent a small portion of all of Pacific Power's NPC, and even that portion is difficult to determine. While we acknowledge that ORS 469A.120(1) provides for recovery of prudently incurred SB 838 compliance costs, we find it unreasonable to adopt a straight dollar-for-dollar PCAM for the totality of Pacific Power's NPC to address appropriate recovery for costs that may amount to far less than 2 percent of that total—particularly when those costs may be difficult to quantify precisely. We find that the most prudent way to accomplish proper recovery is through a well-designed PCAM that complies with the principles we summarized above.

Accordingly, we adopt a PCAM for Pacific Power identical to that adopted for PGE. The PCAM will contain the following features:

[22] *Id.* at 27.
[23] *In the Matter of PGE*, Docket No. UE 215, Order 10-478 (Dec 17, 2010).

1. *Deadband.* We adopt a deadband to require Pacific Power to absorb some normal variation of power costs. If the power cost variation falls within this deadband, there will be no power cost rate adjustment. To ensure the PCAM is revenue neutral, we adopt an asymmetric deadband, with a negative annual power cost variance deadband of $15 million, and a positive annual power cost variance deadband of $30 million. We base our adopted power cost deadband on Pacific Power's authorized rate base, rather than on the utility's net power costs. In determining an appropriate power cost deadband, we look to the size of the utility's rate base and to the utility's authorized ROE. Although Pacific Power's rate base is slightly larger than PGE's we find these amounts to be reasonable for use in the PCAM.

2. *Sharing Mechanism.* To provide Pacific Power the incentive to manage its costs effectively, we adopt a sharing mechanism. For any power cost variance above or below the deadband, customers will bear 90 percent of the adjustment and Pacific Power will bear 10 percent of the adjustment.

3. *Earnings Test.* To protect customers from paying for higher-than-expected power costs when the utility's earnings are reasonable, and to protect Pacific Power from refunding power cost savings when it is under-earning, we adopt an earnings test of +/- 100 basis points around Pacific Power's allowed ROE. If Pacific Power is earning within this range of its authorized ROE, there will be no power cost adjustment for that year.

4. *Amortization Cap.* To be consistent with our prior practice with use of similar mechanisms for other energy utilities, we limit amortization of deferred amounts under the PCAM in any one year to 6 percent of Pacific Power's revenues for the preceding calendar year.

5. *Direct Access.* The PCAM will not apply to direct access customers, because they already bear the risk of variable power costs through their pricing structure.

We conclude that the adoption of this PCAM will result in just and reasonable rates.

2. Transition Adjustment Mechanism

a. Parties' Position

i. Pacific Power

Pacific Power states that the TAM should be preserved. Pacific Power notes a key objective of the TAM is to update forecast NPC to account for changes in market conditions, and that all energy utilities in Oregon have an annual power cost or natural gas update. The utility also notes the TAM is necessary to set accurate and fair transition adjustments for direct access, and that customers pay significantly less than actually incurred NPC since the TAM's adoption. Pacific Power notes the TAM provides customers with advantageous treatment of new resources.

ii. Staff

Staff agrees with Pacific Power that the Commission should preserve annual TAM proceedings, stating that annual filings are necessary to ensure that power cost rates are set to match actual costs as accurately as possible.

iii. ICNU and CUB

ICNU and CUB argue that Pacific Power's TAM is unnecessary to protect cost of service customers and should be eliminated. They argue that the Commission should set transition adjustment credits or charges without resetting net power costs for cost of service customers. The parties argue customers will not lose the ability to get the variable or dispatch benefits of Pacific Power's renewable resources at the same time the fixed costs of those resources go into rates, because the utility could use less harmful mechanisms, such as a renewable adjustment clause or deferred accounting, which could fully pass all the variable benefits of renewable resources to ratepayers.

If the Commission preserves the TAM, ICNU and CUB request we change what the parties claim are the most harmful and one-sided aspects of the TAM. These include removing the final updates when setting power costs for cost of service customers, adding additional revenues associated with higher loads during stand alone TAMs, requiring Pacific Power to fully support all changes to its GRID model, and barring Pacific Power from changing TAM rates unless its earnings are more than 100 basis points above or below its approved ROE.

iv. Kroger

Kroger argues that if that TAM is eliminated, it should be replaced with a viable mechanism that will not impede customers' ability to choose direct access service. Kroger also argues that, if ICNU's proposal to set transition charges or credits in the context of a general rates case is adopted, Schedule 294 and 295 transition adjustments should be annually updated even if cost of service rates are not. Finally, Kroger argues that the direct access program may be more successful if customers are given the option to transition over a five-year period to a cessation of the transition adjustment.

b. Resolution

We decline ICNU's and CUB's request to eliminate or modify the TAM on an *ad hoc* basis for a single utility through a rate case. We will address any issues related to transition adjustment mechanisms globally, such as through a generic docket applicable to both Pacific Power and PGE. Similarly, we decline to address Kroger's recommended changes to Pacific Power's direct access program, because we are addressing issues relating to direct access in docket UM 1587.

C. Investment in Thermal Generation Plants

Pacific Power seeks recovery of the Oregon portion of $661 million for capital investments in emissions control equipment at seven of the 19 coal-fueled generation units owned and operated by the utility: Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3.[24] The investments included projects to reduce emissions of sulfur dioxide (SO_2), nitrous oxides (NOx), and particulate matter (PM). The emission control investments are currently installed and operating and have not yet been considered in a rate case.

Pacific Power argues that the emissions control equipment investments were prudently incurred and should be fully included in rates. Pacific Power contends that all the investments were required to meet existing and anticipated federal and state regulations, and that the utility's analytical path toward compliance with those regulations was comprehensive and reasonable. Staff supports Pacific Power's request, despite identified infirmities in the utility's decision-making processes related to these investments. Sierra Club, CUB, RNP, and NW Energy Coalition oppose Pacific Power's request, and argue that the investments were not prudently incurred.

We divide our discussion into four parts. First, in order to provide context for the parties' arguments, we review the state and federal regulations on which Pacific Power relies. Second, we summarize the parties' arguments and recommendations. Third, we review our prudence standard. Fourth, we provide our resolution.

1. Background

In 1999, the Environmental Protection Agency (EPA) issued its Regional Haze Rule (RHR) in compliance with the Clean Air Act (CAA).[25] The rule addresses regional haze in 156 national parks and wilderness areas across the country, called "Class I areas." In 2005 and 2006, the EPA revised the RHR in response to legal challenges.[26] The goal of the RHR is to eliminate human-caused visibility impairment in national parks and wilderness areas across the country. The EPA requires all states containing sources whose emissions are reasonably anticipated to contribute to regional haze in a Class I area to submit a Regional Haze State Implementation Plan (SIP) that ensures reasonable progress toward the national regional haze goals, including emission limits and schedules of compliance.

The RHR generally requires each state to identify emission sources that are reasonably anticipated to cause or contribute to impairment of visibility. Under 40 CFR § 51.308

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[24] Pacific Power owns or has a partial share in 26 coal fueled units within the states of Wyoming, Utah, Arizona, Colorado and Montana. The utility maintains operational responsibility for 19 of those units; 14 of those units were determined to be BART-eligible units under the RHR. *See* PAC/500, Teply/8 (Mar 1, 2012).

[25] *See* 40 CFR Part 51, 64 FR 35714 (Jul 1, 1999), citing Section 169 of the CCA, 42 USC § 7491(a)(1).

[26] *See* 40 CFR Part 51, 70 FR 39104 (Jul 6, 2005); 71 60612 (Oct 13, 2006).

(Section 308), states must then determine the "Best Available Retrofit Technology" (BART) for each of these sources, and evaluate the need for other control strategies for each source, in order to show that the state's plan will make reasonable progress toward improving visibility in Class I areas. When evaluating potential control technologies to determine their compliance with BART, states must consider: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. A Section 308 Regional Haze SIP must include source-specific BART emission limits and compliance schedules for each source subject to BART. Once a state has made its BART determination for a specific source, the source must install and operate the BART controls as expeditiously as practicable, but no later than five years after the date of EPA approval of the SIP.[27]

As an alternative to compliance under Section 308, and in recognition of the control and cost efficiencies that can be achieved through more flexible trading programs and other alternative measures, 40 CFR § 51.309 (Section 309) allows nine western states whose emissions impact regional haze in 16 Class I areas located on the Colorado Plateau, including Wyoming and Utah, the opportunity to comply with the RHR by developing an alternative regional compliance program that achieves even greater reasonable progress toward the national visibility goal than would be achieved under BART.[28] If the states choose to use this alternative measure provided under Section 309, states are required to compare the degree of visibility improvement expected to be achieved in Class I areas through the application of BART to the degree of improvement expected under the alternative measure. States are further required to adopt rules that are substantively similar to model rules adopted by the EPA in 2003.[29]

Under Section 309, for each of the 16 Class I areas located on the Colorado Plateau, state SIPs must include a projection of improvement in visibility. Rather than requiring source-specific BART controls, Section 309 allows the participating states to establish regional milestone targets for annual SO_2 emissions with a "backstop" SO_2 emissions trading program that is triggered if the milestone targets are exceeded.[30] Using this approach, states must establish declining SO_2 emission milestones for each year of the program through 2018.[31]

[27] 77 FR 28830.

[28] Five states initially exercised this option by submitting plans to the EPA in 2003; at the time that Pacific Power moved forward with upgrades to its coal fleet in 2008 and 2009, participants in the program were Arizona, New Mexico, Utah, and Wyoming. Arizona elected to cease participation in the program in 2010. *See* Western Regional Air Partnership (WRAP) 2009 Regional SO_2 Emissions and Milestone Report (Aug 30, 2011).

[29] Under Section 309, participating states adopt regional haze strategies that are based on recommendations from the Grand Canyon Visibility Transport Commission (GCVTC) for protecting the 16 Class I areas on the Colorado Plateau. In 2000, WRAP, the successor organization to the GCVTC, submitted an annex to the EPA with SO_2 emission reduction milestones and the detailed previsions of a backstop trading program to be implemented automatically if voluntary measures failed to achieve the SO_2 milestones. The EPA codified the annex in 2003 as 40 CFR § 51.309(h). *See* 68 FR 33764.

[30] 77 FR 28829.

[31] 40 CFR 51.309(d).

States are required to submit progress reports in the form of SIP revisions in 2013 and 2019, with evaluations of progress in Class I areas. If a state can show that with the alternative program the distribution of emissions is not substantially different from source-specific BART, and the alternative program results in greater emission reductions than source-specific BART, the alternatives program may be deemed to achieve greater reasonable progress.[32]

Both Wyoming and Utah elected to participate in the Section 309 alternative program for SO_2 emissions. Both states submitted SIPs to the EPA in 2003, and subsequently submitted revised versions. In compliance with the model program rules addressing an SO_2 Milestone and Backstop Trading Program, both states' SIPs require regional yearly emission milestones from 2003 to 2018, calculating the milestones with regard to electric generating units (EGUs), non-EGUs, and new sources.[33] As the EPA recently noted in approving Wyoming's 2011 SIP, state SIPs achieve greater reasonable progress than would be achieved under BART by promoting and sustaining emission reductions as measured against a milestone, as well as encouraging early emissions reductions. Sources "will be actively mindful of the participating states' emissions inventory and operating to avoid exceeding the milestone."[34] In May 2012, EPA likewise approved a portion of Utah's proposed SIP, including its administrative rules adopting an alternative compliance program implemented to comply with Section 309.[35]

2. *Parties' Positions*

a. *Pacific Power*

Pacific Power argues that its investments in emissions controls were necessary to comply with applicable environmental regulations. Pacific Power states the seven units with emissions control investments contested in this case were deemed "subject to BART" under the RHR, and the utility was required to comply with the RHR as expeditiously as practicable, but no later than five years from the date of EPA approval of Wyoming's and Utah's state SIPs. The RHR required state SIP submissions by December 2007, and EPA action on those SIPs was to occur within 18 months of submission. Utah and Wyoming submitted their revised SIPs to the EPA in early 2008, with the underlying assumption of a 2013 compliance deadline. To meet this presumed 2013 compliance deadline for NOx, PM, and SO_2 emissions, Pacific Power states that it worked with state regulators from 2006 to 2009 to determine BART and "Better-than-BART" for the utility's affected units. Pacific Power argues it was required to comply with specific emissions limits for its plants, and that although the Section 309 Backstop Trading Program created regional SO_2 emissions milestones, the intent was to ensure emissions reductions throughout the region by setting emissions limits for each emitting source. Pacific Power also states the

[32] *See* 40 CFR 51.308(e)(3).
[33] Regional milestones are calculated for the combined emissions of the three remaining states participating in the alternative program: Wyoming, Utah, and New Mexico.
[34] 77 FR 30953-01 (May 24, 2012 EPA Approval and Promulgation of State Implementation Plans; State of Wyoming, Regional Haze Rule Requirements for Mandatory Class I Areas).
[35] 77 FR 28825-02 (May 16, 2012 Approval, Disapproval, and Promulgation of State Implementation Plans; State of Utah; Regional Haze Rule Requirements for Mandatory Class 1 Areas).

program was designed to create incentives for early compliance with presumptive unit-by-unit limits.

To comply with the RHR and Utah and Wyoming SIPs, Pacific Power argues that it properly assessed regulatory compliance alternatives, cost effectiveness, and benefits associated with the emissions control investments at issue here. Pacific Power states that it first assessed its environmental compliance obligations and the timing of those obligations. It then assessed the overall costs and availability of various emissions control technologies and compliance alternatives. It considered when, whether, and what capital investments to make in environmental controls. As part of its compliance planning efforts, Pacific Power states that it considered the selection of appropriate emissions control technologies as well as alternate compliance options such as idling a unit and replacing it with market power purchases.

Pacific Power states that its analysis for each unit evaluated alternative technologies for their ability to economically achieve compliance and support an integrated approach to control criteria pollutants. Among other considerations, the analyses (1) reviewed available retrofit emissions control technologies, including performance and cost metrics, and (2) reviewed capital costs on a dollars per ton of pollutant removed basis (as required as a part of BART determinations) and costs for projected improvement in visibility. For each unit subject to BART, the respective state regulatory authority identified the appropriate control technology to achieve what the air quality regulators determined were cost-effective emissions reductions. Once the state regulatory authority identified the required BART technology, the utility proceeded with its competitive bidding process.

For each investment, Pacific Power performed a present value revenue requirement differential (PVRR(d)) analysis, which compared the expected costs of installing the proposed emissions control equipment and continuing to operate a plant through the end of its depreciable life against idling or closing the plant and replacing the power with market purchases. In determining the expected costs of continued operation, the utility included known and reasonably anticipated future capital investments in the plant, as well as assumptions regarding national economic conditions, natural gas prices, and future carbon risk. A positive PVRR(d) number supports making the investments and continuing to operate the coal plants.

Pacific Power states it structured its PVRR(d) analysis to be an objective measure of the cost effectiveness of installing emissions control equipment at the unit, without favoring a particular outcome. Pacific Power states that its contemporaneous PVRR(d) analyses showed that maintaining the ability to operate the existing coal units by retrofitting the units with the emissions control equipment represented the least-cost option. The PVRR(d) analyses were usually conducted three to six months before executing contracts but were not reevaluated later because, Pacific Power states, there was no material reason to conduct reevaluations after execution or before beginning construction. Though forward market power prices had begun to decline beginning in early 2009, the utility argues there was no established trend indicating the decline would continue..

With regard to the availability of a broader array of options for analysis, Pacific Power states the PVRR(d) analyses were not intended to analyze the continued operation of the plant against an alternative generating resource. When the PVRR(d) analyses were conducted, the utility had completed the process of working with the state departments of environmental quality to determine what emissions control equipment was necessary to meet compliance obligations and necessary permits had been issued. The intent of the PVRR(d) analysis was to analyze the cost-effectiveness of the emissions control equipment by comparing the costs of continuing to operate the plant through the end of its depreciable life, including known or reasonably foreseeable costs, with market purchases, to find the least expensive alternate source of power. Pacific Power states that, for each generating unit, the PVRR(d) analysis favored making the investment. Pacific Power acknowledges concerns raised by the parties with regard to its analysis, but states that an updated PVRR(d) analysis to address those concerns (modifying the idling date and updating market power price forecasts) still provided a positive benefit for the challenged investments, demonstrating that ratepayers were not harmed by its contemporaneous analysis.

Finally, Pacific Power argues it is unreasonable to impose the Commission's more recent analysis standards on the utility, when those standards did not exist at the time it was acting. For example, Pacific Power argues. There was no awareness at the time of a Boardman-style analysis advocated by CUB in this proceeding. Pacific Power also argues that CUB's phase-out PVRR(d) analyses for some of Pacific Power's plants are fundamentally flawed, because they close the units in 2020 but do not include alternative costs for compliance with the CAA, and do not include any costs for decommissioning the units or a replacement baseload generation resource.

b. Staff

Staff states that Pacific Power, as a load-serving entity, had an obligation to operate its system to meet reliability, quality, and safety standards, and that the utility could have reasonably determined that upgrading its plants was a prudent method for complying with what appeared to be an uncertain environmental compliance future. Staff concludes that Pacific Power's investments were prudent. Staff notes, however, that the utility's decision-making processes related to its environmental investments was deficient or infirm, in the following respects: (1) failure to consider at the time of decision making costs CO_2 emission regulation; (2) failure to include capital cost proxies for compliance with potential coal combustion residuals (CCR), effluent limit, and cooling water intake requirements; (3) failure to update the utility's analyses as significant milestones were reached; (4) use of decision making dates for idling the coal plants rather than state permit compliance dates; and (5) lack of sensitivity analyses for BART compliance costs. With regard to alternative analyses, Staff notes the Boardman-style approach to BART analysis—that is, considering useful life as a permissible variable in the analysis—was not recognized as being beneficial until late 2010, while Pacific Power's PVRR(d) analyses related to those investments had concluded in 2009.

Staff states that with the exception of Units 1 and 2 of the Hunter plant, Pacific Power's PVRR(d) analyses assumed each coal plant unit would be idled in the year of decision making. For the Hunter plant, the idling date used was the end of 2012, approximately three years after the year of the decision making. The result of these assumed idling dates, Staff states, is an overstatement of the PVRR(d) benefit for each coal plant of making the environmental compliance investments. Staff argues that Pacific Power should have used the compliance dates in individual state permits as idling dates for use in analyses. Staff notes that while Pacific Power's initial analysis was flawed, the utility's updated PVRR(d) using a 2014 idling date and March 2009 market power price forecasts still showed a positive benefit to investment. Staff concludes that if updated PVRR(d) analyses show that investment would have been prudent even considering alternatives, Pacific Power's investments should be deemed prudent. Staff notes, however, that it is unable to reconcile the conflicting results achieved by updated analyses conducted by Pacific Power and Sierra Club for the Naughton 1 and 2 units, and that Pacific Power's choice of idling date for these units was not reasonable.

c. Sierra Club

Sierra Club argues that Pacific Power moved forward with plant upgrades long before it was legally required to do so, and that the utility's analysis was superficial and inadequate, resulting in unnecessary expenses. Sierra Club challenges Pacific Power's practices with regard to all its investments, but recommends disallowances only for the utility's upgrades to its Naughton 1 and 2 and Hunter 1 and 2 units.

First, Sierra Club contends that Pacific Power misunderstands or misrepresents the Regional SO_2 Milestone and Backstop Trading Program. Sierra Club explains that this program includes region-wide SO_2 emissions caps or "milestones" that decline over time through the year 2018, and the program is not triggered unless a milestone is exceeded. Sierra Club argues that, contrary to Pacific Power's assertions, the trading program does not require source owners to take any action other than monitoring and reporting their emissions, and that as a result, mere participation in the program did not trigger any specific SO_2 emissions limit or unit-specific pollution controls for Pacific Power. Sierra Club notes part of the SIP submittal under this alternative compliance program is a better-than-BART demonstration, but that this demonstration does not require that each and every unit to adopt emissions controls that are better than BART. Rather, the demonstration is a regional demonstration. Sierra Club states that Pacific Power was not subject to any unit-specific emission limits for SO_2 for the years 2006 to 2009. Sierra Club argued that Pacific Power never considered whether the flexibility inherent in the regional Backstop Trading Program combined with excess or unanticipated reductions from other sources would have allowed it to operate some of its units unscrubbed and still stay below the milestones.

Sierra Club contends that Pacific Power acted prematurely in moving forward with construction plans to upgrade its facilities in Wyoming. Sierra Club notes the Wyoming regulations implementing the BART process, adopted in December 2006, expressly state that any control equipment required under a permit issued pursuant to BART must "be installed and operated as expeditiously as practicable, but in no event later than five years after the US EPA approval of Wyoming's SIP revision for Regional Haze." Sierra Club notes Pacific Power submitted its construction permit for low-NOx burners in January 2007, before any state or federal BART determination and before any deadline existed for complying with the RHR.[36]

[36] Sierra Club Prehearing Brief at 21-22 (Oct 4, 2012), *citing* PAC/1903, Woollums/2 (Sept 5, 2012). Sierra Club notes that in some instances the Wyoming Department of Environmental Quality (WYDEQ)

Sierra Club argues Pacific Power's contemporaneous PVRR(d) analysis was fundamentally inadequate because it was overly narrow in scope, used improper assumptions, and contained errors in methodology. Sierra Club contends that, by only considering immediate shut-down of the units or making the investment upgrades, Pacific Power failed to examine other compliance options, such as a later or phased-out shut down. Sierra Club argues Pacific Power's analysis should have included the option of not installing the pollution control retrofits and, instead, replacing any shortfall in generation with an alternative resource, and should have assessed the costs associated with running the plants uncontrolled until the compliance deadline forced the utility to stop operating and find a replacement resource. Sierra Club also points out errors in Pacific Power's analysis performed for its Naughton units, noting that the utility did not include additional costs related to chimney construction and waste disposal expenses.

Despite the deficiencies of Pacific Power's analysis, Sierra Club contends that the analysis nonetheless raised flags regarding the cost-effectiveness of proceeding with certain investment upgrades that the utility ignored. Sierra Club cites specifically to Pacific Power's analysis regarding retrofits at Naughton units 1 and 2. Sierra Club explains that, in determining whether to move forward with the upgrades, Pacific Power analyzed the investment under a range of estimated future market power prices. That analysis showed that the PVRR(d) value for each Naughton unit was negative under low market price assumptions.[37] Sierra Club contends that, although Pacific Power's own analysis showed that a 20 percent change in market prices would dramatically alter the perceived economic benefit of the proposal and create a liability for customers, the utility never undertook an effort to evaluate whether any other compliance alternatives would have been better for its customers.

Sierra Club concludes that, by failing to fully consider its options, Pacific Power missed a unique opportunity to comprehensively evaluate its entire coal fleet and assess whether removing underperforming units from service was in the best interest of ratepayers where lower-cost resources could meet the fleet-wide tonnage obligations.

d. CUB

CUB similarly argues that Pacific Power's analysis was perfunctory and superficial, and that had the utility considered other options, it would have reduced the cost to ratepayers. It also questions whether certain investments are used and useful. CUB contends that Pacific Power should have brought all the investments into an IRP proceeding for prior review, and specifically challenges the utility's investments in Naughton Units 1 and 2 and Jim Bridger 3.

First, CUB contends that Pacific Power should have performed an analysis similar to that performed by PGE for its Boardman coal plant. That analysis would have tested the flexibility within the state and federal laws governing air quality by considering different closure scenarios. CUB explains that, although PGE faced a 2016 compliance deadline for Boardman, PGE obtained approval to run the plant until 2020 without making all of

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did not anticipate the need to install BART-determined controls until early 2015, based on its assessment that federal compliance was required within five years of approval of a state SIP.

[37] Sierra Club notes that market price forecasts did, in fact, drop dramatically after December 2008.

the investments that would have been required to continue operating Boardman through 2040, because the investments were analyzed over the life of the plant. CUB acknowledges that PGE was required to make some plant upgrades to comply with environmental regulations, but emphasizes that the utility spent far less than it would have to run Boardman until 2040. CUB claims that a modified PVRR(d) analysis using a Boardman-style phase out results in a positive NPV higher than that calculated by Pacific Power using immediate plant closure, and argues that had Pacific Power explored the timing flexibility inherent in the Backstop Trading Program, it could have gained the time to conduct a Boardman-style analysis.[38]

Second, CUB argues Pacific Power's decision to invest in its coal fleet rested on inadequate analysis. Like Sierra Club, CUB notes the marginally positive and marginally negative results of Pacific Power's analysis, and argues that the utility should not have proceeded with investments of this magnitude without additional study. CUB argues utilities have a responsibility to reevaluate their decision-making as conditions change, and that in this case Pacific Power failed both to reevaluate conditions at key points such as at contract signing and prior to beginning construction, and to consider cancellation of its contracts when circumstances changed. For example, CUB notes that Pacific Power modeled an immediate closure for Naughton unit 1 in 2009, even though the utility believed at the time that the primary environmental compliance planning deadline was 2013 under the states' SIPs, and that for modeling purposes a retirement date of 2014 should be used.[39] CUB argues that simply changing the PVRR(d) analysis to delay closure until 2014 results in a negative net present value. CUB notes that with additional time, Pacific Power could have updated its analysis of Bridger 3 and Hunter 1 to conclude that they should be converted to natural gas because the investment in SCR scrubbers was not cost-effective in scenarios with low natural gas prices.

CUB further questions whether certain investments made by Pacific Power are used and useful, and therefore subject to recovery under ORS 757.355(1). CUB explains that, although certain scrubber upgrades have been added to the plant and are being used, Pacific Power needs to also install new selective catalytic reduction systems (SCRs) to work with the scrubbers to meet the RHR. Thus, CUB contends that the scrubbers may not be useful without the SCRs, because the scrubbers do not, by themselves, meet the RHR requirements.

e. RNP and NWEC

RNP and NWEC filed joint briefs arguing that Pacific Power failed to demonstrate that it was required to comply with SO_2 emissions limits or install unit-specific SO_2 pollution controls at certain of its coal plants. RNP and NWEC state that the Backstop Trading Program afforded participants flexibility in determining how best to stay below the SO_2 milestones, and argue that, as the largest participant in the program, Pacific Power was uniquely positioned to take advantage of the program's flexible structure and think creatively about alternatives to simply installing pollution controls at certain units.

[38] CUB Prehearing Brief at 29-30 (Oct 4, 2012)
[39] CUB Posthearing Brief at 20 (Nov 8, 2012), citing PAC/500, Teply/37 (Mar 1, 2012).

The parties contend that Pacific Power could have shut down, converted, or "mothballed" certain coal-fired units and continued operating others without adding costly controls.

3. Resolution

a. Prudence Standard for Utility Investments

Before we turn to the merits of this issue, we take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the Commission applies the prudence standard, particularly with regard to the relevance of the decision-making process that a utility uses to make an investment.

The prudence standard is traditionally used to address the proper valuation of utility investment in rate base. Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance. An example of a modern articulation of the prudence standard is as follows:

> A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company.[40]

Although the Oregon courts have not expressly discussed the applicability of the prudence standard in this state, this Commission has long used the standard when examining utility investments. Through various orders, the Commission has confirmed that prudence of an investment is measured from the point of time of the utility's actions and decisions without the advantage of hindsight,[41] that the standard does not require optimal results,[42] and the review uses an objective standard of reasonableness.[43]

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[40] Phillips, Charles, *Regulation of Public Utilities*, 341 (3d ed 1993).

[41] *See e.g.*, Order No. 99-033 at 36-37 (Jan 27, 1999) (prudence is determined by the reasonableness of the actions "based on information that was available (or could reasonably have been available) at the time."); Order No. 95-322 at 48 (Mar 29, 1995) (a prudence review takes into account the information that was available to decision makers at the time the decision was made. It does not engage in hindsight or second-guessing; to do so would be unfair.); and Order No. 99-697 at 52 (Nov 12, 1999) (we must determine whether NW Natural's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.)

[42] *See e.g.,* Order No. 98-353 at 9 (Aug 24, 1998) (this Commission has applied this prudency standard for many years in deciding whether to include in rate base the full amount of a utility's investment in a new resource (as opposed to a standard that, say, focuses on the outcome of the utility's decisions).); and Order No. 02-469 at 4 (Jul 18, 2002) (in applying this standard, the Commission does not focus on the outcome of the utility's decision.).

[43] *See* e.g., Order No. 09-501 at 5 (Dec 18, 2009) (in a rate case the Commission would apply the "reasonable person" standard); Order No. 95-322 at 48 (Mar 29, 1995) (endorsing an expert witnesses use

In this proceeding, parties have questioned whether the Commission uses a prudence standard that focuses solely on the decision made by the utility, without regard to the decision-making process used to reach that decision. The questions arise from Order No. 02-469, which addressed Pacific Power's request to recover excess NPC. The Commission rejected claims that Pacific Power was entitled to no recovery because it was unable, due to the time that had elapsed, to provide contemporaneous evidence of key decisions relevant to the inquiry. The Commission agreed with the utility that:

> [I]f the record demonstrates that a challenged business decision was objectively reasonable, taking into account established historical facts and circumstances, the utility's decision must be upheld as prudent even if the record lacks detail on the utility's actual subjective decision making process.[44]

That language has raised questions whether our prudence standard focuses solely on the decision made by the utility, without regard to the decision-making process used to reach that decision. In particular, Staff reads the language to mean that, "while a utility's decision process is probative on whether the action itself is prudent, under the Commission's prudence standard, the primary focus is on the reasonableness of the action, not on the process leading up to it."[45]

Although imprecisely worded, the Commission's decision in Order No. 02-469 correctly concluded that a utility does not automatically fail its burden of proof if it is unable to present contemporaneous evidence of its own actions. Prudence is determined by what a utility "knew or should have known" at the time the decision was made. It is possible that the utility may be able to present sufficient information from external sources (what it should have known) to establish that its ultimate decision was prudent—regardless of what internal decision-making process was used (what it knew).

That order should not, however, be interpreted as saying that a utility's decision-making process is not relevant to a prudence determination. Contrary to any implication from the language in docket UM 995, the process used by the utility to make a decision to invest in a plant is highly valuable in determining whether the utility's actions were reasonable and prudent in light of the circumstances which then existed. The prudence standard examines all actions of the utility—including the process that the utility used to make a decision. Although there may be unique circumstances where a utility is able to overcome the inability to explain its internal decision-making processes, a utility's actions are generally a primary consideration in a prudence review.

This clarification as to the importance of a utility's decision-making process is consistent with recent Commission decisions. For example, we recently examined the prudence of certain hedging contracts entered into by Pacific Power. In that proceeding, we explained

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of a reasonable person standard, similar to that commonly employed in utility prudence review proceedings).

[44] *In the Matter of PacifiCorp, dba Pacific Power*, Docket Nos. UM 995, UE 121, UC 578, Order No. 02-469 at 5. (July 18, 2002).

[45] Staff/1500, Colville/2 (Aug 13, 2012).

that the decision-making process used by the utility was crucial in determining whether the hedges were prudent:

> To evaluate the prudence of a hedging contract, we will first examine the utility's hedging strategy. If the strategy is prudently designed (for example, it includes sound hedging goals, methodology, and targets, among other things), we will next examine whether the utility executed its strategy prudently.
>
> If a particular transaction is inconsistent with the strategy, or parties have raised issues that appropriately call the transaction into question, such as lack of market liquidity, we will then examine whether the utility provided adequate and contemporaneous analysis and documentation and a sound justification to support the transaction.[46]

Although that case involved the reasonableness of power costs and not the proper valuation of rate base, it supports the conclusion that the utility's decision-making process may be highly relevant as to whether a capital investment was prudently incurred. It is often central to the inquiry of whether the utility exercised the standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time the decision had to be made.

b. *Prudence of Pacific Power's Investments*

We now turn to the parties' arguments in this case. After reviewing the state and federal regulations applicable to Pacific Power, we conclude that a reasonable utility faced with emerging state and federal regulations would find that some action was required to comply with those rules. At the federal level, the EPA's RHR required states to prepare and submit implementation plans that demonstrated reasonable continuous progress in reducing regional haze in Class I areas. Even if states chose to implement an alternative program under Section 309, that alternative program had to demonstrate, at a minimum, even greater reasonable progress toward national visibility goals than they would otherwise achieve under Section 308. At the state level, both Wyoming and Utah prepared and submitted SIPs that demonstrated progress toward regional visibility goals, with progress reviews to be conducted in 2013 and 2018. Both SIPs contained provisions rewarding early emission reductions.

As the owner of major sources of emissions in both Utah and Wyoming, Pacific Power was required to take action to comply with the mandate that the region achieve reasonable progress toward the RHR's air quality goals. To help meet its obligation to serve its customers and efficiently operate its fleet of generating resources, Pacific Power acted prudently in initiating efforts to address the air quality and emissions regulations that affected its multiple units. Pacific Power states that since 1999 it has worked to reduce power plant emissions through its Comprehensive Air Initiative, and that for the plants at issue here it extensively analyzed its compliance alternatives, developed a long-

[46] *In the Matter of PacifiCorp, dba Pacific Power*, Docket No. UE 227, Order No. 11-435 at 7. (Nov 4, 2011).

term pollution control strategy, and coordinated installation of controls with the utility's existing four-year outage cycle to reduce replacement power costs. We find Pacific Power's initial development of a coordinated and forward-looking response to be reasonable. We decline to find that a prudent utility faced with these state and federal regulations would have simply done nothing and waited to see what additional requirements emerged.

We further find, however, that Pacific Power failed to act prudently in two areas. First, we are not convinced by Pacific Power's claims that there were not legitimate alternative courses of action—both in terms of the mix of compliance actions and, particularly, in the timing of those actions—that could have allowed Pacific Power to meet its air quality requirements at a lower cost and risk to the utility's Oregon ratepayers. The record shows that throughout the period under question, even in response to changing circumstances, Pacific Power did not alter its course of action or consider alternatives of any kind. Second, we find that Pacific Power failed to perform appropriate analyses to determine the cost-effectiveness of the investments. Pacific Power's contemporaneous cost-effectiveness analyses were demonstrably deficient, and did not demonstrate the rigorous review that a prudent utility should have performed prior to making these significant investments.

We are not persuaded by Pacific Power's claim that the state and federal implementation of the RHR imposed a binding plant-specific emission limit on each of the utility's plants that had to be implemented at the time the investments were made. Although Pacific Power notes repeatedly that the milestones under the Backstop Trading Program were calculated using plant-specific emission limits, the program milestones established with those limits were, as Sierra Club notes, regional milestones. We similarly are not persuaded by Pacific Power's reliance on construction approval orders and permits that mandate specific SO_2 plant emission limits upon completion of construction. Pacific Power has been unable to present us with documentary evidence demonstrating that the Wyoming and Utah DEQs required Pacific Power to apply for all of the permits at issue here when it did so.

Pacific Power itself states that it began implementing its emission reduction commitments in 2005, "well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP."[47] As cited by Sierra Club, documents from 2005 also show Pacific Power had a strategy of moving forward with air pollution controls that was independent of state or federal action.[48] Moreover, after it began implementing its air quality commitments, Pacific Power was confident enough that its emissions were sufficiently below regional milestones that it sought, in its 2007 IRP, acknowledgement to add two coal-fired resources that would begin operation in 2012 and 2014. In April of 2008, we did not acknowledge those plants.

The evidence also shows the WDEQ acknowledged the flexibility available under the Backstop Trading Program. In Wyoming's BART permit analysis for the Naughton plant, the WDEQ noted that, for SO_2, "the State of Wyoming submitted a [Section] 309

[47] *See* Sierra Club/100, Fisher/21, *citing* Sierra Club/112, PacifiCorp's Emissions Reduction Plan.
[48] *See* Sierra Club Posthearing Brief at 3 (Nov 7, 2012), citing Confidential Sierra Club/115, Fisher/2 (Jun 20, 2012).

SIP as is allowed by the Regional Haze Rule. Part of the SIP submittal is a 'Better than BART' demonstration, required by rule, which does not require that each and every unit demonstrate emission controls that are 'Better than BART.' The demonstration is a regional demonstration."[49]

The yearly Regional SO_2 Emissions and Milestone Reports issued by the Western Regional Air Partnership also provided Pacific Power with notice that yearly emissions were far below the emissions limits established under the Backstop Trading Program. Early on, it was clear that the 2013 regional emissions would be much lower – regardless of Pacific Power's actions – and the limits would be readily met. Those reports showed that:

- The 2008 regional emissions were 20,000 tons lower than the 2013 limit.
- The 2009 emissions were more than 40,000 tons lower than the 2013 limit.
- The 2010 emissions were 54,000 tons less than the 2013 limit and more than 10,000 tons less than the 2018 limit.

We add that the regional milestone for 2013 was achieved before the retrofits at Naughton 1 and 2, Hunter 1 and 2, Bridger 3, and Wyodak were completed. Further, these levels do not include other expected actions that will further limit or reduce emissions in the region, such as the conversion of Naughton 3 to natural gas and the shutdown of the Carbon plants.

In addition to finding that Pacific Power failed to establish that it was required to make each of the disputed investments at the time that it did, we find that the utility conducted inadequate analyses to justify the plant upgrades. As pointed out by the parties, Pacific Power's cost-effective analyses were flawed in a number of ways:

<u>Assumption of Immediate Shutdown</u>: With the exception of the Hunter units, Pacific Power's PVRR(d) analysis compared the expected costs of installing emissions control equipment against immediately replacing the output of the plant with market purchases, even in instances when the utility anticipated a compliance date that would occur several years later. As shown by Sierra Club and CUB in their analyses, the use of a more realistic shut down date by itself significantly alters the economics of the projects.

<u>Lack of meaningful sensitivity and scenario analyses</u>: Major resource decisions should not rely largely on single point forecasts, but should instead be shown to be robust over a wide range of futures/scenarios and input assumptions. As CUB's and Sierra Club's analyses showed, the economics of the utility's projects changed significantly based on changes in the assumptions about single variables such as wholesale prices or closure date. This alone signals that all of the investments should have been stress-tested against a wide range of futures and varied input assumptions and that a second stage of more rigorous analyses were merited for a number of the investments. The *ad hoc* analyses

[49] *See* PAC/2002, Teply/262 (Sept 5, 2012).

that were conducted during this case cannot substitute for the depth and breadth of analyses that should have occurred at the time of the decision.

Failure to incorporate potential costs of known, emerging regulations: As Sierra Club points out, Pacific Power assigned no costs to some known, emerging regulations. In retrospect, the retrofit cost associated with some of those regulations at Pacific Power's units were substantial. Further, Sierra Club notes other legitimate modeling adjustments that Pacific Power failed to make at the time of its analyses .[50]

Failure to update analyses: While we do not expect a utility to engage in a never-ending process of reconsideration of its investment decisions, with major resource investments such as these, a reasonable utility would consider changing conditions that significantly impact the financial viability of the investments. The evidence in the record shows substantial changes in the economics of Pacific Power's investments if assumptions had been updated just prior to the time of at least two significant milestones: contract signing and the start of construction. With updated analyses, Pacific Power would have had more refined estimates of market prices, gas prices, capital costs, and costs of other regulations, among other factors. Sierra Club and CUB have shown substantial changes to the economics of the investments with properly updated analyses. For example, CUB and Sierra Club showed that if Pacific Power had conducted analyses for Naughton Units 1 and 2 before signing a contract in May 2009 to upgrade the units, and before beginning construction in June 2010, on each date the updated results would have shown a substantial negative PVRR(d) result for the proposed retrofits. As CUB and Sierra Club point out, updated analyses for these plants would have raised "red flags" which would have merited a slow-down in decision-making and further analyses.

The inherent limitations of a PVRR(d) analysis: Pacific Power acknowledges that its PVRR(d) analysis is limited by focusing solely on market purchases, rather than a mix of replacement resources. In fact, it justifies its investments in part by arguing that a gas-fired replacement resource would have resulted in more positive PVRR(d) results. Yet, there is nothing in the record that shows it conducted resource portfolio analyses at the time of its decisions that back up any of its assertions.

In addition, if Pacific Power had properly explored the potential flexibility in the timing of its options under the RHR, as we believe it had the opportunity to do, the utility and ratepayers would have benefited from additional information that could have been incorporated into cost-effectiveness analyses. That additional information, at a minimum, could have supported later potential shut down dates for use in the PVRR(d) analysis as suggested by CUB and Sierra Club. Indeed, had Pacific Power planned to delay investments at some of its plants, then the utility would have been clearly aware of the "phase-out" analysis conducted by PGE for its Boardman plant and prompted to evaluate the economics of a similar phase-out. As noted by CUB, that analysis permitted PGE to consider a phase-out of its Boardman plant geared toward shutting the plant in 2020, rather than investing in more costly upgrades necessary to allow the plant to operate past that date. Further, if Pacific Power had altered the timing of some of its investments, the utility and its ratepayers could also have benefited from analyses that

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[50] *See* Sierra Club Prehearing Brief at 6-8.

included the most up-to-date information on the cost of all regulations at its units. In some instances, these additional costs are substantial and significantly alter the cost-effectiveness of retrofits at particular units.

c. *Disallowance*

Based on our findings that Pacific Power failed to reasonably examine alternative courses of action and perform adequate analysis to support its investments, we conclude that a partial disallowance is warranted. Pacific Power's imprudent and inadequate analysis and decision-making put ratepayers at risk. The full costs of the investments resulting from that imprudence should not be recoverable in rates.

Because the purpose of a prudence review is to hold ratepayers harmless from any amount imprudently invested, a disallowance should equal the amount of the unreasonable investment. For example, we recently concluded that a utility had failed to establish that it acted prudently in building a natural gas pipeline years ahead of a demonstrated need for the project. Finding there was no persuasive evidence that the pipeline was needed to serve customers at this time, we excluded the entire amount from rate base.[51]

We are unable to easily calculate the precise amount of a proper disallowance in this case, however. Quantifying the impact of Pacific Power's imprudence has been hindered by the very actions that underlie our finding of imprudence—the utility's inadequate analysis and decision-making. Had Pacific Power reasonably considered other compliance alternatives and performed proper and robust analyses, we would have the information necessary to calculate the harm to ratepayers for the utility's decision to proceed with its investments rather than pursuing other, least-costly, options. Without that information, we are left with determining a disallowance that reasonably penalizes Pacific Power for its imprudence, while acknowledging our inability to assess a precise amount.

CUB recognizes this dilemma and offers three recommendations. First, CUB suggests that we could simply disallow the investments, reasoning that costs incurred from imprudent actions should be eliminated. Alternatively, CUB proposes that we require Pacific Power to perform the analysis it failed to perform so that the economic costs to ratepayers resulting from the utility's actions can be modeled. CUB's final and primary recommendation is to disallow 25 percent of the investments.

We dismiss CUB's first two proposals. With regard to a total disallowance, even CUB acknowledges the difficulty of excluding from rate base investments that enable the affected plants to continue to operate and provide service to customers. Moreover, although Pacific Power failed to reasonably consider other compliance scenarios or timing options, significant investments in its coal fleet were necessary. And while we agree that new analysis to model the impact on ratepayers would provide us additional information to determine a disallowance, the proposal is not possible under the statutory

[51] *In Re Application of Northwest Natural for General Rate Revision,* Docket No. UG 221, Order No. 12-437 at 18. (Nov 16, 2012).

framework governing ratemaking. As the parties are aware, we are restricted to a statutory suspension period to investigate and resolve a proposed rate request.[52] Requiring the additional analysis would take more time than we are allotted. We find merit in CUB's third proposal to adopt a percentage disallowance. Because our finding of imprudence is based on Pacific Power's inadequate analysis and decision-making used for all of its investments, we find a partial disallowance applied to all of its unit upgrades is appropriate.

The question then becomes how much of a percentage to disallow. As noted above, Pacific Power seeks recovery, on a company-wide basis, of approximately $661 million in its emission control investments. The Oregon-allocated share of those investments is approximately $170 million. Accepting the fact that it is impossible, on this record, to precisely quantify the impact of Pacific Power's imprudence, we conclude sufficient evidence exists to support a 10 percent ($17 million) disallowance.

We readily acknowledge that this disallowance is not a precise result. This is not uncommon in ratemaking, however, as "[t]he economic judgments required in rate proceedings are often hopelessly complex and do not admit to a single correct result."[53] Moreover, this imprecision is due to an incomplete evidentiary record caused by Pacific Power's imprudence. Nonetheless, in exercising our discretion in determining rate base, we conclude that a 10 percent disallowance is reasonable in relationship to the potential harm to customers. We further conclude that the effect of this disallowance, combined with the other decisions made in this order, results in rates that are just and reasonable.

Finally, we implement this disallowance as follows. Rather than placing each of these investments in rate base at reduced amounts, we direct Pacific Power to file a tariff rider that credits ratepayers this $17 million disallowance during the upcoming calendar year. This will simplify the tracking of recovery for these investments over their useful lives. The $17 million credit will be credited to the rate classes/schedules in proportion to the generation functionalized revenue requirement allocation factors shown in Exhibit D to the partial stipulation adopted in this proceeding.

d. Used and Useful

We reject CUB's argument that certain scrubber upgrades made by Pacific Power are not useful because of the potential that additional controls will be required in the future to meet the RHR. These investments are placed in service and are useful to ratepayers for purposes under ORS 757.355(1).[54]

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[52] *See* ORS 757.210 *et seq.*

[53] *Duquesne Light Co. v. Barasch*, 488 US 299, 314, 109 S Ct 609, 616, 102 L Ed 2d 646 (1989).

[54] *See In re Pacific Power & Light Company*, Docket UE 21, Order No. 84-898 at 3.

e. Expectations

Because the parties have raised issues about the lack of a full evaluation of these investments in Pacific Power's IRP process, we close with the following clarifications. We expect a utility to fully evaluate all major investments that have implications for the utility's resource mix—including those where the investment will extend the useful life of an asset and where a plant shutdown is an option—in its IRP. [55] Although the IRP process is not a legal prerequisite for a utility to seek recovery of investments in rates, we have repeatedly stated that the IRP process serves as a complement to the rate-making process and reduces the uncertainty of recovery.[56] We give considerable weight to actions that are consistent with an acknowledged IRP, and consistency with the plan is evidence to support favorable rate-making treatment of the action. If a utility seeks rate recovery of a significant investment that has not been included in an IRP, we will hold the utility to the same level of rigorous review required by the IRP to demonstrate the prudence of the project.

Regardless of whether a utility intends to use the IRP process for a resource decision, we expect to be kept informed about anticipated major utility investment. As this case demonstrates, investments made by a utility to serve its customers can significantly impact the rates paid by those customers. The communications between Pacific Power and this Commission with regard to the utility's investments related to its emission reduction plan were not sufficient.

[55] As we recognized in adopting least-cost planning principles in 1989, the IRP process enhances the quality of information available to the utility and leads to better resource decision-making. *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 3. (Apr 20, 1989).

[56] *See, e.g., In Re PacifiCorp, dba Pacific Power, 2008 Integrated Resource Plan*, Docket No. LC 47, Order No. 10-066 at 27 (Feb 24, 2010); *In Re PacifiCorp, dba Pacific Power, 2007 Integrated Resource Plan*, Docket No. LC 42, Order No. 08-232 at 38 (Apr 24, 2008).

V. ORDER

IT IS ORDERED that:

1. The partial stipulation between PacifiCorp, dba Pacific Power; the Staff of the Public Utility Commission of Oregon; the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities; and Fred Meyer Stores and Quality Food Centers, divisions of the Kroger Company, attached to this order as Appendix A, is adopted.

2. Advice No. 12-003 is permanently suspended.

3. Pacific Power is directed to file new tariffs consistent with this order, to be effective January 1, 2013.

Made, entered, and effective DEC 20 2012.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under 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 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

ORDER NO. 12 493

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of PACIFICORP D/B/A PACIFIC POWER'S Request for a General Rate Revision.	**PARTIAL STIPULATION**

Parties to this case enter into this Partial Stipulation for the purpose of resolving certain issues related to PacifiCorp's, d/b/a Pacific Power's, filing for a general rate revision.

PARTIES

1. The initial parties to this Partial Stipulation are PacifiCorp (PacifiCorp or Company), Staff of the Public Utility Commission of Oregon (Staff), the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Co. (Kroger) (collectively the Stipulating Parties). The only other party that filed testimony in this case and actively participated in the settlement conferences—the Sierra Club—does not object to this Partial Stipulation. This Partial Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of the Partial Stipulation.

BACKGROUND

2. On March 1, 2012, PacifiCorp filed revised tariff sheets to be effective March 31, 2012, seeking a base rate increase of approximately $38.4 million or 3.2 percent. As a result of resetting Schedule 299, the Rate Mitigation Adjustment, to reflect forecast customer loads by rate schedule, the proposed increase to net rates was $41.2 million, or 3.5 percent. In its filing, PacifiCorp used an historical base period of the 12 months ended June 2011, with normalizing and pro forma adjustments to calculate a 2013 calendar year

future test period. The Company also included the Mona to Oquirrh transmission line in its filing. Because the transmission line is not projected to be in service until second quarter 2013, the Company proposes to delay implementation of the revenue requirement increase related to the Mona to Oquirrh transmission line ($13.1 million or 1.1 percent on an overall basis) until the plant is in service, and to begin recovery of it through a separate tariff rider at that time.

3. In Order No. 12-093, issued March 14, 2012, the Public Utility Commission of Oregon (Commission) suspended the Company's application for a general rate revision for an additional nine months from the original effective date of the revised tariff sheets. Due to the suspension, the effective date of the revised tariff sheets is now January 1, 2013.

4. Consistent with Chief Administrative Law Judge Michael Grant's Prehearing Conference Memorandum dated March 20, 2012, the parties to this docket convened settlement conferences on May 30, 2012, and June 27-28, 2012. All parties were invited to participate.

5. As a result of the settlement conferences, the Stipulating Parties reached a partial settlement resolving most of the issues in this case. The Stipulating Parties did not settle the following issues, which are discussed in more detail in paragraph 14 of this Partial Stipulation: (1) the prudence of PacifiCorp's investments in environmental controls at its thermal generation plants; (2) PacifiCorp's request for a power cost adjustment mechanism (PCAM), and ICNU's related testimony on the Transition Adjustment Mechanism (TAM); and (3) PacifiCorp's proposal to add the Mona to Oquirrh transmission line to its rate base through a separate tariff rider when the line goes into service in 2013. Collectively, these three specific issues are referred to in the Partial Stipulation as Reserved Issues.

6. Notwithstanding the Reserved Issues, the issues resolved in this Partial Stipulation result in an overall base price increase of $20.7 million, effective January 1, 2013.

AGREEMENT

7. The Stipulating Parties agree to submit this Partial Stipulation to the Commission and request that the Commission approve the Partial Stipulation as presented. The Stipulating Parties agree that this Partial Stipulation will result in rates that meet the standard in ORS 756.040.

8. Revenue Requirement. The Parties agree to a revenue requirement increase of $20.7 million, which in conjunction with the other terms identified below represents a settlement of the revenue requirement issues in this case except the Reserved Issues. The Parties agree to suspend discovery except as necessary for the continued litigation of the Reserved Issues. Exhibit A includes an agreed-upon calculation of the $20.7 million increase in rates based on resolution of adjustments proposed by the Stipulating Parties. The Stipulating Parties agree that the acceptance of these adjustments for purposes of settlement is not binding on parties in future proceedings and does not imply agreement on the merits of the adjustments.

9. Effective Date. The Stipulating Parties agree that rates to recover the stipulated revenue requirement for the issues resolved in this Partial Stipulation will go into effect on January 1, 2013. The rates agreed to in this Partial Stipulation may be modified by the Commission's resolution of the prudence of the Company's environmental control investments at its thermal generating plants included in the Reserved Issues.

10. Rate of Return. The Stipulating Parties do not agree on values for the various components of capital costs and capital structure but do agree that, for Oregon regulatory

purposes, the Company's overall rate of return (ROR) and notional values of individual cost of capital components used to derive this ROR are as reflected in the table below.

Component	Structure	Cost	Weighted Cost
Long-term Debt	47.60%	5.322%	2.533%
Preferred Stock	0.30%	5.427%	0.016%
Common	52.10%	9.800%	5.106%
	100.00%		7.655%

11. Carbon Accelerated Depreciation. The Stipulating Parties do not oppose PacifiCorp's request to include in Oregon rates the accelerated depreciation and decommissioning costs for the early retirement of the Company's Carbon thermal generation plant in 2015 as reflected in Exhibit B.

12. Prudence of Black Cap Solar Resource. The Stipulating Parties agree that the Company's investment in the Black Cap solar resource as presented in the Company's initial filing in this case is prudent and should be included in the Company's revenue requirement. Nothing in this paragraph limits a party's ability to challenge any new costs associated with this resource in a future case.

13. Open Access Transmission Tariff (OATT) Revenues. Upon approval of this Partial Stipulation, PacifiCorp agrees to file a request for deferred accounting to defer Oregon's allocated share of the incremental OATT revenue associated with the Company's pending rate case at the Federal Energy Regulatory Commission (Docket No. ER11-3643-000) beginning January 1, 2013, and continuing until the revenues are included in rates. The deferral will include incremental OATT revenues from all sources, and the intent of the deferral is to credit OATT revenues to customers without offsets.

14. Reserved Issues. The Stipulating Parties agree that the Reserved Issues will be further litigated in this case. The Stipulating Parties agree that the procedural schedule

adopted on May 30, 2012, and amended on June 14, 2012, remains in effect and governs litigation of the Reserved Issues. Nothing in this Partial Stipulation expands or limits the existing rights of the Stipulating Parties with respect to the continued litigation of these issues.

a. Environmental Control Investments. The Company is seeking rate recovery of its investments in environmental controls at the following thermal generation plants: Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3. CUB proposes to disallow 25 percent of the Company's investment in all environmental controls as imprudent or to disallow as not currently used and useful, and the Sierra Club proposes disallowance of the investments in Naughton Units 1 and 2 and Hunter Units 1 and 2 as imprudent. Staff supports the prudence of the Company's investments. ICNU and Kroger did not raise issues related to these investments before settlement, but may address these issues on rebuttal.

b. PCAM/TAM. The Company is proposing that the Commission adopt a PCAM for the Company. Staff, CUB, and Kroger oppose the Company's proposal and recommend alternative PCAM structures. ICNU recommends that no PCAM be adopted for the Company and, if a PCAM is adopted, recommends an alternative structure. ICNU also filed related testimony recommending that the TAM be eliminated or modified if retained.

c. Mona to Oquirrh Tariff Rider. The Mona to Oquirrh transmission line is expected to go into service in second quarter 2013. The Company filed testimony on the prudence of this investment and requested approval to file a separate tariff rider to begin recovery of the investment when it goes into service. No party filed testimony contesting the prudence of this transmission line, but Staff and ICNU filed testimony asserting that the costs should not be included in this case and the use of a tariff rider is inappropriate. CUB and Kroger did not raise issues related to the tariff rider.

(1) The Stipulating Parties agree that they will litigate PacifiCorp's proposal to use a tariff rider to include the Mona to Oquirrh transmission line in rate base after the January 1, 2013 rate effective date in this case.

(2) The Stipulating Parties agree not to contest the prudence of the decision to build the Mona to Oquirrh transmission line in this case, absent material changes in facts that raise new prudence issues. Parties may address the prudence of the total expenditures on the Mona to Oquirrh transmission line.

(3) PacifiCorp agrees to apply the cost of capital included in this Partial Stipulation to calculate the revenue requirement impact of the Mona to Oquirrh transmission line investment, reducing the maximum amount to be included in rates in this case from approximately $13.1 million to approximately $12.6 million as reflected in Exhibit C.

(4) If the Commission approves the tariff rider, the Stipulating Parties will have the opportunity to review for prudency PacifiCorp's actual costs for the Mona to Oquirrh transmission line and challenge costs that are not properly assigned to the project or are imprudent, or costs exceeding the amount included in the initial filing in this case ($380.6 million total company). PacifiCorp agrees to facilitate the Stipulating Parties' audit and review and to provide an update on the costs of the investment as of the close of the third quarter in 2012 and to provide additional updates as requested by any of the Stipulating Parties.

(5) If the Commission approves the tariff rider, the Stipulating Parties agree not to contest the implementation of a tariff rider consistent with the Commission's

order and this Partial Stipulation. The Stipulating Parties are not precluded from seeking reconsideration or appealing the Commission order.

(6) PacifiCorp agrees that if the Mona to Oquirrh transmission line is not in service by November 30, 2013, then PacifiCorp will withdraw its tariff rider.

(7) If the Commission rejects the tariff rider, PacifiCorp agrees not to file a request for deferred accounting to address the delay in rate recovery for the Mona to Oquirrh transmission line.

(8) If the Commission does not conclusively determine the prudence of the investment in the Mona to Oquirrh transmission line in this case and/or rejects the tariff rider, PacifiCorp may file a general rate case to recover its investment. This Partial Stipulation does not prevent the Stipulating Parties from raising any issues in that new proceeding.

15. Rebalance Rate Mitigation Adjustment (RMA). The Stipulating Parties agree that an increase of $2.8 million is required to rebalance the RMA to reflect forecast customer loads by rate schedule. The amount is additive to the $20.7 million revenue requirement increase agreed to in this Partial Stipulation and is unaffected by the resolution of the Reserved Issues.

16. Rate Spread. The Stipulating Parties do not agree on the cost of service methodology used to determine rate spread in this case but do agree to the allocation of base and net revenues by rate schedule as presented on page one of Exhibit D. The Stipulating Parties further agree that the Company will use the base rate revenues or applicable functionalized revenue requirement allocation factors presented on page four of Exhibit D as the rate spread allocation factors for rate changes, including the pending transition

adjustment mechanism case, Docket No. UE 245, until the Commission approves new functionalized revenue requirement allocation factors in a subsequent general rate case filing. As shown on Exhibit D, most customer rate schedules, including residential, large general service, and agricultural pumping service will see a 2.2 percent rate increase.

17. Rate Design. The Stipulating Parties agree to the rate design for each rate schedule presented in Exhibit E.

18. This Partial Stipulation will be offered into the record as evidence under OAR 860-001-0350(7). The Stipulating Parties agree to support this Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Partial Stipulation at hearing, if needed, and recommend that the Commission issue an order adopting the Partial Stipulation.

19. If this Partial Stipulation is challenged by any other party to this proceeding, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Partial Stipulation. The Stipulating Parties reserve the right to cross-examine witnesses and introduce evidence as they deem appropriate to respond fully to the issues presented.

20. The Stipulating Parties have negotiated this Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Partial Stipulation or imposes additional material conditions in approving this Partial Stipulation, any of the Stipulating Parties is entitled to withdraw from the Partial Stipulation or exercise any other rights provided in OAR 860-001-0350(9), including the right to present evidence and argument on the record in support of the Partial Stipulation.

21. By entering into this Partial Stipulation, no Stipulating Party approves, admits, or consents to the facts, principles, methods, or theories employed by any other party in arriving at the terms of this Partial Stipulation, other than as specifically identified in this Partial Stipulation. Except as set forth in paragraphs 10, 11, 12, 13, 14(c)(3) through (8), and 16 of this Partial Stipulation, the Stipulating Parties agree that the provisions of this Partial Stipulation may not be used to resolve issues in any other proceeding.

22. This Partial Stipulation is not enforceable by any party unless and until adopted by the Commission in a final order. Each signatory to this Partial Stipulation avers that they are signing this Partial Stipulation in good faith and that they intend to abide by the terms of this Partial Stipulation unless and until the Stipulation is rejected or adopted only in part by the Commission. The Stipulating Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Partial Stipulation. If the Commission rejects or modifies this Partial Stipulation, the Stipulating Parties reserve the right to seek reconsideration or rehearing of the Commission order under ORS 756.561 and OAR 860-001-0720 or to appeal the Commission order under ORS 756.610.

23. This Partial Stipulation may be executed in counterparts and each signed counterpart will constitute an original document.

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

PACIFICORP	STAFF
By: William R. Griffith	By: ______________________
Date: July 12, 2012	Date: ______________________

21. By entering into this Partial Stipulation, no Stipulating Party approves, admits, or consents to the facts, principles, methods, or theories employed by any other party in arriving at the terms of this Partial Stipulation, other than as specifically identified in this Partial Stipulation. Except as set forth in paragraphs 10, 11, 12, 13, 14(c)(3) through (8), and 16 of this Partial Stipulation, the Stipulating Parties agree that the provisions of this Partial Stipulation may not be used to resolve issues in any other proceeding.

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23. This Partial Stipulation may be executed in counterparts and each signed counterpart will constitute an original document.

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

PACIFICORP	STAFF
By: ______________________	By: Johanna Riemenschneider
Date: ______________________	Date: July 12, 2012

CUB

By: ____________________

Date: 7-12-2012

ICNU

By: ____________________

Date: ____________________

KROGER

By: ____________________

Date: ____________________

CUB

By: ______________________

Date: ______________________

ICNU

By: Irion Sanger

Date: 7/12/2012

KROGER

By: ______________________

Date: ______________________

CUB

By: ______________________

Date: ______________________

ICNU

By: ______________________

Date: ______________________

KROGER

By: KBoehm

Date: 7-12-12

PACIFICORP UE 246
Stipulated Adjustments to Oregon Allocated Results
Year Ending December 31, 2013
($000)

Item	Adjustments	Revenue Requirement Effect ($000)
	Original Filed Revenue Requirement	$38,356
Settlement - 0	Rate of Return - 7.655%	($14,657)
Settlement - 1	Miscellaneous Operation and Maintenance Expense Adjustment Reflects the combined revenue requirement impact of adjustments proposed by Staff and ICNU associated with uncollectible expenses, labor expenses, miscellaneous administrative and general expenses, legal expenses, and operation and maintenance expense escalation.	($2,999)
	Total Adjustments	($17,656)
	Settled Revenue Requirement	$20,700

PACIFICORP UE 246
Results of Operations
Year Ending December 31, 2013
($000)

	UE 246 Oregon Results per Company Filing (1)	Stipulated Adjustments (2)	2013 Adjusted (3)	Stipulated Price Increase (4)	Results at Reasonable Return (5)
1 Operating Revenues					
2 General Business Revenues	837,943	-	837,943	20,700	858,643
3 Interdepartmental	-	-	-		-
4 Special Sales	1,019	-	1,019		1,019
5 Other Operating Revenues	39,568	-	39,568		39,568
6 **Total Operating Revenues**	$878,530	$0	$878,530	$20,700	$899,230
7 Operating Expenses					
8 Steam Production	88,353	(527)	87,826		87,826
9 Nuclear Production	-	-	-		-
10 Hydro Production	12,991	(87)	12,905		12,905
11 Other Power Supply	33,429	(219)	33,210		33,210
12 Embedded Cost Differential	5,971	-	5,971		5,971
13 Transmission	17,513	(111)	17,402		17,402
14 Distribution	70,646	(380)	70,266		70,266
15 Customer Accounting	35,339	(423)	34,916	151	35,067
16 Customer Service & Info	4,062	(15)	4,047		4,047
17 Sales	-	-	-		-
18 Administrative & General	45,485	(1,146)	44,338		44,338
19 Total Operation & Maintenance	$313,790	($2,909)	$310,881	$151	$311,032
20 Depreciation	178,458	-	178,458		178,458
21 Amortization	13,807	-	13,807		13,807
22 Taxes Other Than Income	65,230	-	65,230	728	65,958
23 Income Taxes - Federal	(749)	822	73	6,622	6,696
24 Income Taxes - State	1,999	112	2,111	900	3,011
25 Income Taxes - Def Net	71,515	-	71,515		71,515
26 Investment Tax Credit Adj.	-	-	-		-
27 Misc Revenue & Expense	(346)	-	(346)		(346)
28 Total Operating Expenses	$643,704	($1,975)	$641,729	$8,401	$650,131
29 **Net Operating Revenues**	$234,825	$1,975	$236,800	$12,299	$249,099
30 Average Rate Base					
31 Electric Plant In Service	6,407,405	(0)	6,407,405		6,407,405
32 Plant Held for Future Use	-	-	-		-
33 Misc Deferred Debits	22,573	-	22,573		22,573
34 Elec Plant Acq Adj	11,261	-	11,261		11,261
35 Nuclear Fuel	-	-	-		-
36 Prepayments	7,666	-	7,666		7,666
37 Fuel Stock	50,783	-	50,783		50,783
38 Material & Supplies	54,123	-	54,123		54,123
39 Working Capital	27,888	(40)	27,848		27,848
40 Weatherization Loans	(1)	-	(1)		(1)
41 Misc Rate Base	-	-	-		-
42 Total Electric Plant	$6,581,698	($40)	$6,581,658	$0	$6,581,658
43 Less:					
44 Accum Prov For Deprec	(2,198,381)	-	(2,198,381)		(2,198,381)
45 Accum Prov For Amort	(140,098)	-	(140,098)		(140,098)
46 Accum Def Income Tax	(960,764)	-	(960,764)		(960,764)
47 Unamortized ITC	(1,116)	-	(1,116)		(1,116)
48 Customer Adv For Const	(11,392)	-	(11,392)		(11,392)
49 Customer Service Deposits	-	-	-		-
50 Misc Rate Base Deductions	(15,987)	-	(15,987)		(15,987)
51 Total Rate Base Deductions	($3,327,739)	$0	($3,327,739)	$0	($3,327,739)
52 **Total Average Rate Base**	$3,253,959	($40)	$3,253,919	$0	$3,253,919
53 Rate of Return	7.217%	0.061%	7.277%	0.378%	7.655%
54 Implied Return on Equity	8.865%	0.209%	9.075%	0.725%	9.800%

PACIFICORP UE 246
Stipulated Adjustments to Oregon Results
Year Ending December 31, 2013
($000)

	Rate of Return Adjustment	Misc. O&M Adjustment	Total Stipulated Adjustments
	Settlement - 0	Settlement - 1	
1 **Operating Revenues**			
2 General Business Revenues	0	0	0
3 Interdepartmental	0	0	0
4 Special Sales	0	0	0
5 Other Operating Revenues	0	0	0
6 **Total Operating Revenues**	$0	$0	$0
7 **Operating Expenses**			
8 Steam Production	0	(527)	(527)
9 Nuclear Production	0	0	0
10 Hydro Production	0	(87)	(87)
11 Other Power Supply	0	(219)	(219)
12 Embedded Cost Differential	0	0	0
13 Transmission	0	(111)	(111)
14 Distribution	0	(380)	(380)
15 Customer Accounting	0	(423)	(423)
16 Customer Service & Info	0	(15)	(15)
17 Sales	0	0	0
18 Administrative & General	0	(1,146)	(1,146)
19 **Total Operation & Maintenance**	$0	($2,909)	($2,909)
20 Depreciation	0	0	0
21 Amortization	0	0	0
22 Taxes Other Than Income	0	0	0
23 Income Taxes - Federal	(150)	972	822
24 Income Taxes - State	(20)	132	112
25 Income Taxes - Def Net	0	0	0
26 Investment Tax Credit Adj.	0	0	0
27 Misc Revenue & Expense	0	0	0
28 **Total Operating Expenses**	($170)	($1,805)	($1,975)
29 **Net Operating Revenues**	$170	$1,805	$1,975
30 **Average Rate Base**			
31 Electric Plant In Service	(0)	0	(0)
32 Plant Held for Future Use	0	0	0
33 Misc Deferred Debits	0	0	0
34 Elec Plant Acq Adj	0	0	0
35 Nuclear Fuel	0	0	0
36 Prepayments	0	0	0
37 Fuel Stock	0	0	0
38 Material & Supplies	0	0	0
39 Working Capital	(3)	(36)	(40)
40 Weatherization Loans	0	0	0
41 Misc Rate Base	0	0	0
42 **Total Electric Plant**	($3)	($36)	($40)
43 Less:			
44 Accum Prov For Deprec	0	0	0
45 Accum Prov For Amort	0	0	0
46 Accum Def Income Tax	0	0	0
47 Unamortized ITC	0	0	0
48 Customer Adv For Const	0	0	0
49 Customer Service Deposits	0	0	0
50 Misc Rate Base Deductions	0	0	0
51 **Total Rate Base Deductions**	$0	$0	$0
52 **Total Rate Base**	($3)	($36)	($40)
53 **Revenue Requirement Effect**	($14,657)	($2,999)	($17,656)

PACIFICORP UE 246
Cost of Capital
Year Ending December 31, 2013

Filed Cost of Capital (Refer to Page 2.1 of Exhibit PAC/1102)

	Capital Structure	Embedded Cost	Weighted Cost
DEBT%	46.90%	5.372%	2.519%
PREFERRED %	0.30%	5.427%	0.016%
COMMON %	52.80%	10.200%	5.386%
	100.00%		**7.921%**

Settlement Cost of Capital

	Capital Structure	Embedded Cost	Weighted Cost
DEBT%	47.60%	5.322%	2.533%
PREFERRED %	0.30%	5.427%	0.016%
COMMON %	52.10%	9.800%	5.106%
	100.00%		**7.655%**

ORDER NO. 12 493

Docket UE 246
Partial Stipulation Exhibit B
Page 1 of 1

PACIFICORP UE 246
Results of Operations
Year Ending December 31, 2013
Partial Stipulation, Paragraph 11, Carbon Plant

		8.15 Carbon Plant Closure	Reference
1	Operating Revenues:		
2	General Business Revenues	-	
3	Interdepartmental	-	
4	Special Sales	-	
5	Other Operating Revenues	-	
6	Total Operating Revenues	$0	
7			
8	Operating Expenses:		
9	Steam Production	-	
10	Nuclear Production	-	
11	Hydro Production	-	
12	Other Power Supply	-	
13	Embedded Cost Differential (ECD)	-	
13	Transmission	-	
14	Distribution	-	
15	Customer Accounting	-	
16	Customer Service & Info	-	
17	Sales	-	
18	Administrative & General	-	
19			
20	Total O&M Expenses	$0	
21			
22	Depreciation	$10,606,153	Exhibit PAC/1102, page 8.15
23	Amortization	-	
24	Taxes Other Than Income	-	
25	Income Taxes - Federal	$75,202	
26	Income Taxes - State	$10,219	
27	Income Taxes - Def Net	($4,025,141)	Exhibit PAC/1102, page 8.15
28	Investment Tax Credit Adj.	-	
29	Misc Revenue & Expense	-	
30			
31	Total Operating Expenses:	$6,666,433	
32			
33	Operating Rev For Return:	($6,666,433)	
34			
35	Rate Base:		
36	Electric Plant In Service	$388,186	Exhibit PAC/1102, page 8.15
37	Plant Held for Future Use	-	
38	Misc Deferred Debits	-	
39	Elec Plant Acq Adj	-	
40	Nuclear Fuel	-	
41	Prepayments	-	
42	Fuel Stock	-	
43	Material & Supplies	-	
44	Working Capital	$1,719	
45	Weatherization Loans	-	
46	Misc Rate Base	-	
47			
48	Total Electric Plant:	$389,905	
49			
50	Rate Base Deductions:		
51	Accum Prov For Deprec	($13,300,096)	Exhibit PAC/1102, page 8.15
52	Accum Prov For Amort	-	
53	Accum Def Income Tax	$4,025,141	Exhibit PAC/1102, page 8.15
54	Unamortized ITC	-	
55	Customer Adv For Const	-	
56	Customer Service Deposits	-	
57	Misc Rate Base Deductions	-	
58			
59	Total Rate Base Deductions	($9,274,955)	
60			
61	Total Rate Base:	($8,885,050)	
62			
63			
64	TAX CALCULATION:		
65	Operating Revenue	($10,606,153)	
66	Other Deductions	-	
67	Interest (AFUDC)	-	
68	Interest	($225,082)	
69	Schedule "M" Additions	$10,606,153	Exhibit PAC/1102, page 8.15
70	Schedule "M" Deductions	-	
71	Income Before Tax	$225,082	
72			
73	State Income Taxes	$10,219	
74	Taxable Income	$214,864	
75			
76	Federal Income Taxes + Other	$75,202	
77			
78	Revenue Requirement Impact	$9,933,005	Note 1

Note:
(1) The revenue requirement impact is calculated using the stipulated rate of return.

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	ALLOCATED	REF#
May 2013 In Service							
Adjustment to Plant in Service:							
Transmission Plant - Capital Addition	355	3	380,613,978	SG	25.7772%	98,111,455	Page 3
Adjustment to Depreciation Reserve:							
Transmission Plant - Capital Addition	108TP	3	(3,896,866)	SG	25.7772%	(1,004,501)	Page 3
Adjustment to Depreciation Expense:							
Transmission Plant - Capital Addition	403TP	3	7,194,213	SG	25.7772%	1,854,464	Page 3
Adjustment to O&M Expense:							
Mona to Oquirrh	571	3	150,000	SG	25.7772%	38,666	
Adjustments to Tax:							
Schedule M Adjustment	SCHMDT	3	15,809,183	SG	25.7772%	4,075,158	Page 4
Deferred Income Tax Expense	41010	3	5,999,743	SG	25.7772%	1,546,563	Page 4
ADIT Balance	282	3	(2,858,818)	SG	25.7772%	(736,922)	Page 4

Description of Exhibit:

This exhibit adds the Mona to Oquirrh transmission capital project to rate base, as discussed in detail in Exhibit PAC/700. The figures above represent the capital investment, depreciation expense, accumulated depreciation, O&M, and tax impacts associated with the segment of the line that will be placed into service in May 2013. The total Oregon-allocated annual revenue requirement associated with this segment of the transmission line is shown on page two.

PacifiCorp
Oregon General Rate Case
Revenue Requirement: Mona to Oquirrh Project

	Mona - Oquirrh Addition (May 2013)			
	Total Company	Oregon Allocated	Price Change	Results with Price Change
Operating Revenues:				
General Business Revenues	-	-	12,646,187	12,646,187
Interdepartmental	-	-		
Special Sales	-	-		
Other Operating Revenues	-	-		
Total Operating Revenues	-	-	12,646,187	12,646,187
Operating Expenses:				
Steam Production	-	-		
Nuclear Production	-	-		
Hydro Production	-	-		
Other Power Supply	-	-		
Embedded Cost Differential	-	-		
Transmission	150,000	38,666		38,666
Distribution	-	-		
Customer Accounting	-	-	62,360	62,360
Customer Service & Info	-	-		
Sales	-	-		
Administrative & General	-	-		
Total O&M Expenses	150,000	38,666	62,360	101,025
Depreciation	7,194,213	1,854,464		1,854,464
Amortization	-	-		
Taxes Other Than Income	-	-	300,979	300,979
Income Taxes - Federal	(10,900,086)	(2,809,195)	4,103,822	1,294,627
Income Taxes - State	(1,481,141)	(381,723)	557,641	175,918
Income Taxes - Def Net	5,999,743	1,546,563		1,546,563
Investment Tax Credit Adj.	-	-		
Misc Revenue & Expense	-	-		
Total Operating Expenses:	962,730	248,774	5,024,803	5,273,577
Operating Rev For Return:	(962,730)	(248,774)	7,621,385	7,372,610
Rate Base:				
Electric Plant In Service	380,613,978	98,111,455		98,111,455
Plant Held for Future Use	-	-		
Misc Deferred Debits	-	-		
Elec Plant Acq Adj	-	-		
Nuclear Fuel	-	-		
Prepayments	-	-		
Fuel Stock	-	-		
Material & Supplies	-	-		
Working Capital	-	(63,429)		(63,429)
Weatherization Loans	-	-		
Misc Rate Base	-	-		
Total Electric Plant:	380,613,978	98,048,026		98,048,026
Rate Base Deductions:				
Accum Prov For Deprec	(3,896,866)	(1,004,501)		(1,004,501)
Accum Prov For Amort	-	-		
Accum Def Income Tax	(2,858,818)	(736,922)		(736,922)
Unamortized ITC	-	-		
Customer Adv For Const	-	-		
Customer Service Deposits	-	-		
Misc Rate Base Deductions	-	-		
Total Rate Base Deductions	(6,755,684)	(1,741,423)		(1,741,423)
Total Rate Base:	373,858,295	96,306,603		96,306,603
Return on Rate Base		-0.26%		7.66%
Return on Equity		-5.39%		9.60%
TAX CALCULATION:				
Operating Revenue	(7,344,213)	(1,893,129)	12,282,848	10,389,719
Other Deductions	-	-		-
Interest (AFUDC)	-	-		-
Interest	9,470,847	2,439,708		2,439,708
Schedule "M" Additions	-	-		-
Schedule "M" Deductions	15,809,183	4,075,158		4,075,158
Income Before Tax	(32,624,244)	(8,407,995)	12,282,848	3,874,853
State Income Taxes	(1,481,141)	(381,723)	557,641	175,918
Oregon/Utah State Tax Credits	-	-	-	-
Total State Income Taxes	(1,481,141)	(381,723)	557,641	175,918
Taxable Income	(31,143,103)	(8,026,272)	11,725,207	3,698,935
Federal Taxes Before Credits	(10,900,086)	(2,809,195)	4,103,822	1,294,627
Renewable Energy Tax Credit	-	-	-	-
Federal Income Taxes	(10,900,086)	(2,809,195)	4,103,822	1,294,627

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

Depreciation Rate (Transmission SG)	1.890%

Mona - Oquirrh Project
In Service: May 2013

	Capital Addition Pieces		Depreciation Pieces (Capital)	
Month	Addition Per Month	Capital Addition Balance	Depreciation Expense	Depreciation Reserve
May-13	380,613,978	380,613,978	299,759	(299,759)
Jun-13	-	380,613,978	599,518	(899,277)
Jul-13	-	380,613,978	599,518	(1,498,794)
Aug-13	-	380,613,978	599,518	(2,098,312)
Sep-13	-	380,613,978	599,518	(2,697,830)
Oct-13	-	380,613,978	599,518	(3,297,348)
Nov-13	-	380,613,978	599,518	(3,896,866)
Dec-13	-	380,613,978	599,518	(4,496,383)
Jan-14	-	380,613,978	599,518	(5,095,901)
Feb-14	-	380,613,978	599,518	(5,695,419)
Mar-14	-	380,613,978	599,518	(6,294,937)
Apr-14	-	380,613,978	599,518	(6,894,454)
May-14	-	380,613,978	599,518	(7,493,972)
Total	380,613,978	380,613,978	7,194,213	(3,896,866)
		13 Month Average	Annual Level	13 Month Average
		Ref. Page 1	**Ref. Page 1**	**Ref. Page 1**

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

Mona-Limber-Oquirrh Project - (May 2013 Portion)					
	Tax Depreciation		Book Depreciation		Accumulated
Month	Book-Tax Difference	Deferred Income Tax	Book-Tax Difference	Deferred Income Tax	Deferred Income Tax
01/31/2013	0	0	0	0	0
02/28/2013	0	0	0	0	0
03/31/2013	(4,694,571)	1,781,637	1,798,553	(682,569)	(1,099,068)
04/30/2013	0	0	0	0	(1,099,068)
05/31/2013	0	0	0	0	(1,099,068)
06/30/2013	(4,694,571)	1,781,637	1,798,553	(682,569)	(2,198,136)
07/31/2013	0	0	0	0	(2,198,136)
08/31/2013	0	0	0	0	(2,198,136)
09/30/2013	(4,694,571)	1,781,637	1,798,553	(682,569)	(3,297,204)
10/31/2013	0	0	0	0	(3,297,204)
11/30/2013	0	0	0	0	(3,297,204)
12/31/2013	(4,694,569)	1,781,636	1,798,553	(682,569)	(4,396,271)
01/31/2014	0	0	0	0	(4,396,271)
02/28/2014	0	0	0	0	(4,396,271)
03/31/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(7,098,811)
04/30/2014	0	0	0	0	(7,098,811)
05/31/2014	0	0	0	0	(7,098,811)
06/30/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(9,801,351)
07/31/2014	0	0	0	0	(9,801,351)
08/31/2014	0	0	0	0	(9,801,351)
09/30/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(12,503,891)
10/31/2014	0	0	0	0	(12,503,891)
11/30/2014	0	0	0	0	(12,503,891)
12/31/2014	(8,919,684)	3,385,109	1,798,553	(682,569)	(15,206,431)
Book-Tax Differences	(23,003,395)	8,730,019	7,194,212	(2,730,276)	
	Ref. Page 1	Ref. Page 1	Ref. Page 1	Ref. Page 1	

Monthly Rollfoward of Accumulated Deferred Income Tax Liability: Internal Revenue Code Regulations				
Month Ended	Beg. Bal	Provision	Accum. Provision	Ending Balance
05/31/2013	(1,099,068)	0	0	(1,099,068)
06/30/2013	(1,099,068)	(1,011,745)	(1,011,745)	(2,110,813)
07/31/2013	(2,110,813)	0	(1,011,745)	(2,110,813)
08/31/2013	(2,110,813)	0	(1,011,745)	(2,110,813)
09/30/2013	(2,110,813)	(734,719)	(1,746,464)	(2,845,532)
10/31/2013	(2,845,532)	0	(1,746,464)	(2,845,532)
11/30/2013	(2,845,532)	0	(1,746,464)	(2,845,532)
12/31/2013	(2,845,532)	(457,693)	(2,204,157)	(3,303,225)
01/31/2014	(3,303,225)	0	(2,204,157)	(3,303,225)
02/28/2014	(3,303,225)	0	(2,204,157)	(3,303,225)
03/31/2014	(3,303,225)	(459,062)	(2,663,219)	(3,762,287)
04/30/2014	(3,762,287)	0	(2,663,219)	(3,762,287)
05/31/2014	(3,762,287)	0	(2,663,219)	(3,762,287)
13-Month Average				(2,858,818)
				Ref. Page 1

Monthly Period Ended	06/30/2013 Accrual	09/30/2013 Accrual	12/31/2013 Accrual	03/31/2014 Accrual	Forecast Period
6/1 - 6/30/2013	1	0	0	0	30
07/31/2013	31	0	0	0	31
08/31/2013	31	0	0	0	31
09/30/2013	30	1	0	0	30
10/31/2013	31	31	0	0	31
11/30/2013	30	30	0	0	30
12/31/2013	31	31	1	0	31
01/31/2014	31	31	31	0	31
02/28/2014	28	28	28	0	28
03/31/2014	31	31	31	1	31
04/30/2014	30	30	30	30	30
05/31/2014	31	31	31	31	31
Days In Forecast Per.	336	244	152	62	365
% Days in Forecast Per.	92.0548%	66.8493%	41.6438%	16.9863%	100.0000%

PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

BOOK BASIS					
		AFUDC			
Description	Cost	Debt	Equity	Total	Total
Land	0	0	0	0	0
Land Rights	0	0	0	0	0
Non-Land	351,766,345	10,052,596	18,795,037	28,847,633	380,613,978
Total	351,766,345	10,052,596	18,795,037	28,847,633	380,613,978

TAX BASIS										
		Less: AFUDC						Tax Depreciation		
Description	Book Basis	Debt	Equity	Total	Cost	Add: Avoided Costs	Tax Basis	Method	Convention	Recovery Period
Land	0	0	0	0	0	0	0	Non -Depreciable		
Land Rights	0	0	0	0	0	0	0	Straight-Line	Mid-Month	84-Years
Non-Land	380,613,978	(10,052,596)	(18,795,037)	(28,847,633)	351,766,345	23,799,297	375,565,642	MACRS	Half-Year	15-Years
Total	380,613,978	(10,052,596)	(18,795,037)	(28,847,633)	351,766,345	23,799,297	375,565,642			

TAX DEPRECIATION			
MACRS / 15-Years			
	Cost	Avoided Costs	Tax Basis
Month	351,766,345	23,799,297	375,565,642
01/31/2013	1,465,693	99,164	1,564,857
02/28/2013	1,465,693	99,164	1,564,857
03/31/2013	1,465,693	99,164	1,564,857
04/30/2013	1,465,693	99,164	1,564,857
05/31/2013	1,465,693	99,164	1,564,857
06/30/2013	1,465,693	99,164	1,564,857
07/31/2013	1,465,693	99,164	1,564,857
08/31/2013	1,465,693	99,164	1,564,857
09/30/2013	1,465,693	99,164	1,564,857
10/31/2013	1,465,693	99,163	1,564,856
11/30/2013	1,465,693	99,163	1,564,856
12/31/2013	1,465,694	99,163	1,564,857
Total 2013	17,588,317	1,189,965	18,778,282
01/31/2014	2,784,817	188,411	2,973,228
02/28/2014	2,784,817	188,411	2,973,228
03/31/2014	2,784,817	188,411	2,973,228
04/30/2014	2,784,817	188,411	2,973,228
05/31/2014	2,784,817	188,411	2,973,228
06/30/2014	2,784,817	188,411	2,973,228
07/31/2014	2,784,817	188,411	2,973,228
08/31/2014	2,784,817	188,411	2,973,228
09/30/2014	2,784,817	188,411	2,973,228
10/31/2014	2,784,817	188,411	2,973,228
11/30/2014	2,784,817	188,411	2,973,228
12/31/2014	2,784,816	188,412	2,973,228
Total 2014	33,417,803	2,260,933	35,678,736

MACRS Depreciation Table: Half-Year Convention	
Recovery Year	Recovery Period 15-Year
1	5.00%
2	9.50%
3	8.55%
4	7.70%
5	6.93%
6	6.23%
7	5.90%
8	5.90%
9	5.91%
10	5.90%
11	5.91%
12	5.90%
13	5.91%
14	5.90%
15	5.91%
16	2.95%
	100.00%

Mona-Limber-Oquirrh Project - (May 2013 Portion)

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PacifiCorp
Oregon General Rate Case - December 2013
Mona to Oquirrh Project

SG Allocation Factor	25.7772%
Federal Tax Rate	35.0000%
State Tax Rate	4.54%

Capital Structure and Cost			
	%	**Cost**	**Weighted Cost**
Debt	47.600%	5.322%	2.533%
Preferred	0.300%	5.427%	0.016%
Common	52.100%	9.800%	5.106%
			7.655%

Revenue Sensitive Items	
Operating Revenue	100%
Operating Deductions	
Uncollectable Accounts	0.493%
Taxes Other - Franchise Tax	2.300%
Taxes Other - Revenue Tax	0.00%
Taxes Other - Resource Supplier	0.080%
Taxes Other - Gross Receipts	0.00%
Sub-Total	97.127%
State Income Tax @ 4.54%	4.410%
Sub-Total	92.717%
Federal Income Tax @ 35.00%	32.451%
Net Operating Income	60.266%

ORDER NO. 12 495

UE 246 Stipulated GRC Price Change - Updated Table 1303-1

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2013

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	479,457	5,400,866	$564,491	$12,962	$577,453	$581,948	$8,426	$590,374	$17,457	3.1%	$12,921	2.2%	1
2	**Total Residential**		479,457	5,400,866	$564,491	$12,962	$577,453	$581,948	$8,426	$590,374	$17,457	3.1%	$12,921	2.2%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	75,333	1,093,926	$120,069	($1,442)	$118,627	$114,206	$5,625	$119,831	($5,863)	-4.9%	$1,204	1.0%	3
4	Gen. Svc. 31 - 200 kW	28	9,818	1,986,600	$161,266	$7,928	$169,194	$168,786	$4,194	$172,980	$7,520	4.7%	$3,786	2.2%	4
5	Gen. Svc. 201 - 999 kW	30	815	1,303,689	$98,119	$2,348	$100,467	$99,921	$1,801	$101,722	$1,802	1.8%	$1,255	1.3%	5
6	Large General Service >= 1,000 kW	48	208	3,003,510	$201,084	($9,613)	$191,471	$202,883	($7,242)	$195,641	$1,799	0.9%	$4,170	2.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	5	50,204	$3,585	($177)	$3,408	$3,716	($134)	$3,582	$131	0.9%	$174	2.2%	7
8	Agricultural Pumping Service	41	8,090	210,342	$24,940	($3,282)	$21,658	$23,188	($1,044)	$22,144	($1,752)	-7.0%	$486	2.2%	8
9	**Total Commercial & Industrial**		94,269	7,648,271	$609,063	($4,238)	$604,825	$612,700	$3,200	$615,900	$3,637	0.6%	$11,075	1.8%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,850	9,710	$1,298	$257	$1,555	$1,222	$238	$1,460	($76)	-5.9%	($95)	-6.1%	10
11	Street Lighting Service	50	250	8,845	$1,022	$221	$1,243	$963	$202	$1,165	($59)	-5.8%	($78)	-6.3%	11
12	Street Lighting Service HPS	51	733	18,680	$3,433	$732	$4,165	$3,234	$693	$3,927	($199)	-5.8%	($238)	-5.7%	12
13	Street Lighting Service	52	50	599	$73	$16	$89	$69	$14	$83	($4)	-5.3%	($6)	-6.7%	13
14	Street Lighting Service	53	260	9,579	$621	$147	$768	$585	$127	$712	($36)	-5.8%	($56)	-7.3%	14
15	Recreational Field Lighting	54	103	1,189	$104	$22	$126	$98	$20	$118	($6)	-5.8%	($8)	-6.4%	15
16	**Total Public Street Lighting**		8,246	48,602	$6,551	$1,395	$7,946	$6,171	$1,294	$7,465	($380)	-5.8%	($481)	-6.1%	16
17	**Total Sales to Ultimate Consumers**		581,972	13,097,739	$1,180,105	$10,119	$1,190,224	$1,200,819	$12,920	$1,213,739	$20,714	1.8%	$23,515	2.0%	17
18	**Employee Discount**			17,195	($445)	($10)	($455)	($459)	($6)	($465)	($14)		($10)		18
19	**Total Sales with Employee Discount**		581,972	13,097,739	$1,179,660	$10,109	$1,189,769	$1,200,360	$12,914	$1,213,274	$20,700	1.8%	$23,505	2.0%	19
20	AGA Revenue				$2,716		$2,716	$2,716		$2,716	$0		$0		20
21	**Total Sales with Employee Discount and AGA**		581,972	13,097,739	$1,182,376	$10,109	$1,192,485	$1,203,076	$12,914	$1,215,990	$20,700	1.8%	$23,505	2.0%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

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UE 246 Stipulated Updated Table 1303-2
PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2013

Line No.	Description	Sch No.	Prop. Sales 96 ($000)	Tax Adj 102 ($000)	MEHC Sev 194 ($000)	Grid West 195 ($000)	Sol. Incty. 204 ($000)	2010 Prtcl. 291 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) PRE	(10) PRO	(11) PRE	(12) PRO
	Residential											
1	Residential	4	($1,458)	$6,373	$864	$162	$378	($1,026)	$7,669	$3,133	$12,962	$8,426
2	**Total Residential**		($1,458)	$6,373	$864	$162	$378	($1,026)	$7,669	$3,133	$12,962	$8,426
	Commercial & Industrial											
3	Gen. Svc. < 31 kW	23	($295)	$1,291	$175	$33	$77	($207)	($2,516)	$4,551	($1,442)	$5,625
4	Gen. Svc. 31 - 200 kW	28	($536)	$2,345	$318	$60	$139	($377)	$5,979	$2,245	$7,928	$4,194
5	Gen. Svc. 201 - 999 kW	30	($352)	$1,539	$209	$39	$91	($234)	$1,056	$509	$2,348	$1,801
6	Large General Service >= 1,000 kW	48	($811)	$3,544	$481	$90	$211	($511)	($12,617)	($10,246)	($9,613)	($7,242)
7	Partial Req. Svc. >= 1,000 kW	47	($14)	$59	$9	$2	$4	($9)	($228)	($185)	($177)	($134)
8	Agricultural Pumping Service	41	($57)	$248	$34	$6	$15	($38)	($3,490)	($1,252)	($3,282)	($1,044)
9	**Total Commercial & Industrial**		($2,065)	$9,026	$1,226	$230	$537	($1,376)	($11,816)	($4,378)	($4,238)	$3,200
	Lighting											
10	Outdoor Area Lighting Service	15	($3)	$11	$1	$0	$0	($1)	$249	$230	$257	$238
11	Street Lighting Service	50	($2)	$10	$1	$0	$1	($1)	$212	$193	$221	$202
12	Street Lighting Service HPS	51	($5)	$22	$3	$1	$2	($4)	$713	$674	$732	$693
13	Street Lighting Service	52	$0	$1	$0	$0	$0	$0	$15	$13	$16	$14
14	Street Lighting Service	53	($3)	$11	$2	$0	$0	($1)	$138	$118	$147	$127
15	Recreational Field Lighting	54	$0	$1	$0	$0	$0	$0	$21	$19	$22	$20
16	**Total Public Street Lighting**		($13)	$56	$7	$1	$3	($7)	$1,348	$1,247	$1,395	$1,294
17	**Total**		($3,536)	$15,455	$2,097	$393	$918	($2,409)	($2,799)	$2	$10,119	$12,920
18	**Employee Discount**		$1	($5)	($1)	$0	$0	$1	($6)	($2)	($10)	($6)
19	**Total Sales with Employee Discount**		($3,535)	$15,450	$2,096	$393	$918	($2,408)	($2,805)	$0	$10,109	$12,914

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UE 246 Stipulated Updated Table 1303-3
PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2013

Line No.	Description	Sch No.	Prop. Sales 96 ¢/kWh	Tax Adj 102 ¢/kWh	MEHC Sev 194 ¢/kWh	Grid West 195 ¢/kWh	Sol. Inctv. 204 ¢/kWh	2010 Prtcl. 291 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) PRE	(10) PRE	(11) PRE	(12) PRO	(13) PRO	(14) PRO
	Residential													
1	Residential	4	(0.027)	0.118	0.016	0.003	0.007	(0.019)	0.142			0.058		
	Commercial & Industrial													
2	Gen. Svc. < 31 kW	23	(0.027)	0.118	0.016	0.003	0.007	(0.019)	(0.230)	(0.230)		0.416	0.416	
3	Gen. Svc. 31 - 200 kW	28	(0.027)	0.118	0.016	0.003	0.007	(0.019)	0.301	0.301		0.113	0.113	
4	Gen. Svc. 201 - 999 kW	30	(0.027)	0.118	0.016	0.003	0.007	(0.018)	0.081	0.081		0.039	0.039	
5	Large General Service >= 1,000 kW	48	(0.027)	0.118	0.016	0.003	0.007	(0.017)	(0.329)	(0.411)	(0.509)	(0.267)	(0.334)	(0.413)
6	Partial Req. Svc. >= 1,000 kW	47	(0.027)	0.118	0.016	0.003	0.007	(0.017)	(0.329)	(0.411)	(0.509)	(0.267)	(0.334)	(0.413)
7	Agricultural Pumping Service	41	(0.027)	0.118	0.016	0.003	0.007	(0.018)	(1.659)	(1.659)		(0.595)	(0.595)	
	Lighting													
8	Outdoor Area Lighting Service	15	(0.027)	0.118	0.016	0.003	0.006	(0.017)	2.575			2.365		
9	Street Lighting Service	50	(0.027)	0.118	0.016	0.003	0.006	(0.015)	2.393			2.183		
10	Street Lighting Service HPS	51	(0.027)	0.118	0.016	0.003	0.009	(0.023)	3.819			3.609		
11	Street Lighting Service	52	(0.027)	0.118	0.016	0.003	0.007	(0.018)	2.450			2.240		
12	Street Lighting Service	53	(0.027)	0.118	0.016	0.003	0.003	(0.008)	1.440			1.230		
13	Recreational Field Lighting	54	(0.027)	0.118	0.016	0.003	0.005	(0.013)	1.800			1.590		

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PACIFIC POWER
STATE OF OREGON
UE 246 Stipulated Functionalized Revenue Requirement Allocation Factors

Line	Description	Total	(A) Residential (sec)	(B) General Service Sch 23 (sec)	(C) General Service Sch 23 (pri)	(D) General Service Sch 28 (sec)	(E) General Service Sch 28 (pri)	(F) General Service Sch 30 (sec)	(G) General Service Sch 30 (pri)	(H) Large Power Service Sch 48T (sec)	(I) Large Power Service Sch 48T (pri)	(J) Large Power Service Sch 48T (trn)	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
	Generation	100.00%	42.83%	8.37%	0.01%	15.64%	0.14%	9.24%	0.67%	4.64%	11.41%	5.30%	1.61%	0.12%
	Transmission	100.00%	44.45%	8.41%	0.01%	16.22%	0.14%	9.04%	0.68%	4.56%	10.74%	4.34%	1.39%	0.02%
	Distribution	100.00%	63.81%	12.68%	0.01%	10.59%	0.06%	4.10%	0.27%	1.80%	2.48%	0.00%	3.57%	0.64%
	Ancillary Service	100.00%	42.83%	8.37%	0.01%	15.64%	0.14%	9.24%	0.67%	4.64%	11.41%	5.30%	1.61%	0.12%
	Customer - Billing	100.00%	84.82%	12.41%	0.01%	1.78%	0.01%	0.14%	0.01%	0.07%	0.06%	0.00%	0.55%	0.12%
	Customer - Metering	100.00%	73.97%	14.59%	0.35%	4.94%	0.40%	0.99%	0.39%	0.22%	0.74%	1.36%	2.03%	0.01%
	Customer - Other	100.00%	83.93%	12.75%	0.01%	2.04%	0.01%	0.26%	0.02%	0.11%	0.09%	0.01%	0.66%	0.12%
	Embedded DSM - (MWh)	100.00%	41.83%	8.30%	0.01%	15.28%	0.15%	9.27%	0.68%	4.65%	11.97%	3.99%	1.70%	0.16%
	Regulatory & Franchise	100.00%	48.47%	10.10%	0.01%	13.76%	0.12%	7.73%	0.57%	3.77%	9.00%	4.00%	2.24%	0.22%

PACIFIC POWER
State of Oregon

UE 246 Stipulated Base Rates

Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,607,431,415	5,544,795,299	5,400,866,473	kWh	0.414 ¢	$22,359,587	0.378 ¢	$20,415,275
Distribution Charge								
Basic Charge, per month	5,716,077	5,716,077	5,753,484	bill	$9.00	$51,781,356	$9.00	$51,781,356
Three Phase Demand Charge, per kW demand	18,062	18,062	17,593	kW	$2.20	$38,705	$2.20	$38,705
Three Phase Minimum Demand Charge, per month	1,529	1,529	1,539	bill	$3.80	$5,848	$3.80	$5,848
Distribution Energy Charge, per kWh	5,607,431,415	5,544,795,299	5,400,866,473	kWh	3.266 ¢	$176,392,299	3.826 ¢	$206,637,151
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	4,099,028,935	4,053,241,935	3,948,030,052	kWh	2.754 ¢	$108,728,748	2.559 ¢	$101,030,089
Second Block kWh (> 1,000)	1,508,402,480	1,491,553,364	1,452,836,421	kWh	3.761 ¢	$54,641,178	3.494 ¢	$50,762,105
Subtotal	5,607,431,415	5,544,795,299	5,400,866,473	kWh		$413,947,721		$430,670,529
Populus to Terminal Adjustment (80), per kWh	5,607,431,415	-5,544,795,299	5,400,866,473	kWh	-0.040 ¢	($2,160,347)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	4,099,028,935	4,053,241,935	3,948,030,052	kWh	0.024 ¢	$947,527	0.000 ¢	$0
Second Block kWh (> 1,000)	1,508,402,480	1,491,553,364	1,452,836,421	kWh	0.033 ¢	$479,436	0.000 ¢	$0
Subtotal						$413,214,337		$430,670,529
Schedule 201								
First Block kWh (0-1,000)	4,099,028,935	4,053,241,935	3,948,030,052	kWh	2.550 ¢	$100,674,766	2.550 ¢	$100,674,766
Second Block kWh (> 1,000)	1,508,402,480	1,491,553,364	1,452,836,421	kWh	3.483 ¢	$50,602,293	3.483 ¢	$50,602,293
Total	5,607,431,415	5,544,795,299	5,400,866,473	kWh		$564,491,396		$581,947,588
							Change	$17,456,192
Schedule No. 4 - Employee Discount								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	17,653,331	17,653,331	17,195,095	kWh	0.434 ¢	$71,188	0.378 ¢	$64,997
Distribution Charge								
Basic Charge, per month	13,922	13,922	14,013	bill	$9.00	$126,117	$9.00	$126,117
Three Phase Demand Charge, per kW demand	86	86	84	kW	$2.20	$185	$2.20	$185
Three Phase Minimum Demand Charge, per month	12	12	12	bill	$3.80	$46	$3.80	$46
Distribution Energy Charge, per kWh	17,653,331	17,653,331	17,195,095	kWh	3.266 ¢	$561,592	3.826 ¢	$657,884
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	11,790,524	11,790,524	11,484,472	kWh	2.754 ¢	$316,282	2.559 ¢	$293,888
Second Block kWh (> 1,000)	5,862,807	5,862,807	5,710,623	kWh	3.761 ¢	$214,777	3.494 ¢	$199,529
Subtotal	17,653,331	17,653,331	17,195,095	kWh		$1,290,187		$1,342,646
Populus to Terminal Adjustment (80), per kWh	17,653,331	17,653,331	17,195,095	kWh	-0.040 ¢	($6,878)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	11,790,524	11,790,524	11,484,472	kWh	0.024 ¢	$2,756	0.000 ¢	$0
Second Block kWh (> 1,000)	5,862,807	5,862,807	5,710,623	kWh	0.033 ¢	$1,885	0.000 ¢	$0
Subtotal						$1,287,950		$1,342,646
Schedule 201								
First Block kWh (0-1,000)	11,790,524	11,790,524	11,484,472	kWh	2.550 ¢	$292,854	2.550 ¢	$292,854
Second Block kWh (> 1,000)	5,862,807	5,862,807	5,710,623	kWh	3.483 ¢	$198,901	3.483 ¢	$198,901
Total	17,653,331	17,653,331	17,195,095	kWh		$1,779,705		$1,834,401
Schedule 201 Employee Discount						($122,939)		($122,939)
Total Employee Discount						($444,926)		($458,600)

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Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13-12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,125,411,853	1,128,427,446	1,092,594,951	kWh	0.409 ¢	$4,468,713	0.361 ¢	$3,944,268
Distribution Charge								
Basic Charge								
Single Phase, per month	711,057	711,057	697,562	bill	$18.70	$13,044,409	$17.95	$12,521,238
Three Phase, per month	209,808	209,808	205,865	bill	$27.90	$5,743,634	$26.80	$5,517,182
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	925,557	925,557	897,096	kW	$1.30	$1,166,225	$1.25	$1,121,370
Demand Charge, the first 15 kW of demand				kW	No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	478,010	478,010	463,326	kW	$4.34	$2,010,835	$4.17	$1,932,069
Reactive Power Charge, per kvar	80,694	80,694	78,843	kvar	65.00 ¢	$51,248	65.00 ¢	$51,248
Distribution Energy Charge, per kWh	1,125,411,853	1,128,427,446	1,092,594,951	kWh	2.730 ¢	$29,827,842	2.622 ¢	$28,647,840
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	882,298,260	884,661,260	856,570,502	kWh	3.208 ¢	$27,478,782	2.877 ¢	$24,643,533
All additional kWh, per kWh	243,113,593	243,766,186	236,024,449	kWh	2.381 ¢	$5,619,742	2.135 ¢	$5,039,122
Subtotal	1,125,411,853	1,128,427,446	1,092,594,951	kWh		$89,411,430		$83,417,870
Populus to Terminal Adjustment (80), per kWh	1,125,411,853	1,128,427,446	1,092,594,951	kWh	-0.039 ¢	($426,112)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	882,298,260	884,661,260	856,570,502	kWh	0.028 ¢	$239,840	0.000 ¢	$0
All additional kWh, per kWh	243,113,593	243,766,186	236,024,449	kWh	0.021 ¢	$49,565	0.000 ¢	$0
Subtotal						$89,274,723		$83,417,870
Schedule 201								
1st 3,000 kWh, per kWh	882,298,260	884,661,260	856,570,502	kWh	2.971 ¢	$25,448,710	2.971 ¢	$25,448,710
All additional kWh, per kWh	243,113,593	243,766,186	236,024,449	kWh	2.204 ¢	$5,201,979	2.204 ¢	$5,201,979
Total	1,125,411,853	1,128,427,446	1,092,594,951	kWh	0.000 0	$119,925,412		$114,068,559
							Change	($5,856,853)
Schedule No. 23/723 - Composite General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	1,348,277	1,348,277	1,330,980	kWh	0.396 ¢	$5,271	0.351 ¢	$4,672
Distribution Charge								
Basic Charge								
Single Phase, per month	321	321	315	bill	$18.70	$5,891	$17.95	$5,654
Three Phase, per month	251	251	258	bill	$27.90	$7,198	$26.80	$6,914
Load Size Charge								
≤ 15 kW				kW	No Charge		No Charge	
per kW for all kW in excess of 15 kW	5,508	5,508	5,611	kW	$1.30	$7,294	$1.25	$7,014
Demand Charge, the first 15 kW of demand				kW	No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	2,234	2,234	2,237	kW	$4.22	$9,440	$4.05	$9,060
Reactive Power Charge, per kvar	2,812	2,812	2,920	kvar	60.00 ¢	$1,752	60.00 ¢	$1,752
Distribution Energy Charge, per kWh	1,348,277	1,348,277	1,330,980	kWh	2.644 ¢	$35,191	2.548 ¢	$33,913
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	853,168	853,168	836,443	kWh	3.107 ¢	$25,988	2.796 ¢	$23,387
All additional kWh, per kWh	495,109	495,109	494,537	kWh	2.306 ¢	$11,404	2.075 ¢	$10,262
Subtotal	1,348,277	1,348,277	1,330,980	kWh		$109,429		$102,628
Populus to Terminal Adjustment (80), per kWh	1,348,277	1,348,277	1,330,980	kWh	-0.038 ¢	($506)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	853,168	853,168	836,443	kWh	0.028 ¢	$234	0.000 ¢	$0
All additional kWh, per kWh	495,109	495,109	494,537	kWh	0.020 ¢	$99	0.000 ¢	$0
Subtotal						$109,256		$102,628
Schedule 201								
1st 3,000 kWh, per kWh	853,168	853,168	836,443	kWh	2.878 ¢	$24,073	2.878 ¢	$24,073
All additional kWh, per kWh	495,109	495,109	494,537	kWh	2.136 ¢	$10,563	2.136 ¢	$10,563
Total	1,348,277	1,348,277	1,330,980	kWh	0.000 0	$143,892		$137,264
							Change	($6,628)

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Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units	Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite							
Large General Service - (Secondary)							
Transmission & Ancillary Services Charge							
per kW	6,768,502	6,768,502	6,629,746 kW	$1.20	$7,955,695	$1.12	$7,425,316
Distribution Charge							
Basic Charge							
Load Size ≤ 50 kW, per month	54,876	54,876	53,753 bill	$15.00	$806,295	$20.00	$1,075,060
Load Size 51-100 kW, per month	41,602	41,602	40,722 bill	$28.00	$1,140,216	$37.00	$1,506,714
Load Size 101-300 kW, per month	22,797	22,797	22,283 bill	$67.00	$1,492,961	$88.00	$1,960,904
Load Size > 300 kW, per month	438	438	428 bill	$96.00	$41,088	$125.00	$53,500
Load Size Charge							
≤50 kW, per kW	2,104,760	2,104,760	2,057,029 kW	$0.95	$1,954,178	$1.25	$2,571,286
51-100 kW, per kW	2,889,797	2,889,797	2,828,186 kW	$0.75	$2,121,140	$1.00	$2,828,186
101-300 kW, per kW	3,425,109	3,425,109	3,360,475 kW	$0.45	$1,512,214	$0.60	$2,016,285
>300 kW, per kW	183,478	183,478	180,103 kW	$0.30	$54,031	$0.40	$72,041
Demand Charge, per kW	6,768,502	6,768,502	6,629,746 kW	$3.31	$21,944,459	$4.32	$28,640,503
Reactive Power Charge, per kvar	599,342	599,342	595,353 kvar	65.00 ¢	$386,979	65.00 ¢	$386,979
Distribution Energy Charge, per kWh	2,004,166,036	2,004,166,036	1,960,069,773 kWh	0.326 ¢	$6,389,827	0.425 ¢	$8,330,297
Energy Charge - Schedule 200							
1st 20,000 kWh, per kWh	1,435,479,865	1,441,165,865	1,409,538,253 kWh	3.040 ¢	$42,849,963	2.838 ¢	$40,002,696
All additional kWh, per kWh	568,686,171	570,944,867	558,266,695 kWh	2.959 ¢	$16,519,112	2.763 ¢	$15,424,909
Subtotal	2,004,166,036	2,012,110,732	1,967,804,948 kWh		$105,168,158		$112,294,676
Populus to Terminal Adjustment ($0), per kW	6,768,502	6,768,502	6,629,746 kW	($0.12)	($795,570)	$0.00	$0
TAM Adj for Other Revs (205)							
1st 20,000 kWh, per kWh	1,435,479,865	1,441,165,865	1,409,538,253 kWh	0.027 ¢	$380,575	0.000 ¢	$0
All additional kWh, per kWh	568,686,171	570,944,867	558,266,695 kWh	0.026 ¢	$145,149	0.000 ¢	$0
Subtotal					$104,898,312		$112,294,676
Schedule 201							
1st 20,000 kWh, per kWh	1,435,479,865	1,441,165,865	1,409,538,253 kWh	2.816 ¢	$39,692,597	2.816 ¢	$39,692,597
All additional kWh, per kWh	568,686,171	570,944,867	558,266,695 kWh	2.739 ¢	$15,290,925	2.739 ¢	$15,290,925
Total	2,004,166,036	2,012,110,732	1,967,804,948 kWh		$159,881,834		$167,278,198
						Change	$7,396,364
Schedule No. 28/728 - Composite							
Large General Service - (Primary)							
Transmission & Ancillary Services Charge							
per kW	65,682	65,682	65,892 kW	$0.87	$57,326	$1.00	$65,892
Distribution Charge							
Basic Charge							
Load Size ≤ 50 kW, per month	99	99	96 bill	$17.00	$1,632	$24.00	$2,304
Load Size 51-100 kW, per month	163	163	158 bill	$29.00	$4,582	$41.00	$6,478
Load Size 101-300 kW, per month	355	355	341 bill	$69.00	$23,529	$97.00	$33,077
Load Size > 300 kW, per month	35	35	34 bill	$99.00	$3,366	$139.00	$4,726
Load Size Charge							
≤50 kW, per kW	3,294	3,294	3,251 kW	$0.95	$3,088	$1.35	$4,389
51-100 kW, per kW	12,248	12,248	12,246 kW	$0.80	$9,797	$1.10	$13,471
101-300 kW, per kW	61,575	61,575	61,812 kW	$0.45	$27,815	$0.65	$40,178
>300 kW, per kW	14,953	14,953	14,881 kW	$0.25	$3,720	$0.35	$5,208
Demand Charge, per kW	65,682	65,682	65,892 kW	$3.37	$222,056	$4.72	$311,010
Reactive Power Charge, per kvar	25,905	25,905	25,889 kvar	60.00 ¢	$15,533	60.00 ¢	$15,533
Distribution Energy Charge, per kWh	18,807,080	18,807,080	18,795,139 kWh	0.032 ¢	$6,014	0.074 ¢	$13,908
Energy Charge - Schedule 200							
1st 20,000 kWh, per kWh	9,645,695	9,645,695	9,685,033 kWh	2.817 ¢	$272,827	2.737 ¢	$265,079
All additional kWh, per kWh	9,161,385	9,161,385	9,110,106 kWh	2.741 ¢	$249,708	2.663 ¢	$242,602
Subtotal	18,807,080	18,807,080	18,795,139 kWh		$900,993		$1,023,855
Populus to Terminal Adjustment ($0), per kW	65,682	65,682	65,892 kW	($0.08)	($5,271)	$0.00	$0
TAM Adj for Other Revs (205)							
1st 20,000 kWh, per kWh	9,645,695	9,645,695	9,685,033 kWh	0.025 ¢	$2,421	0.000 ¢	$0
All additional kWh, per kWh	9,161,385	9,161,385	9,110,106 kWh	0.024 ¢	$2,186	0.000 ¢	$0
Subtotal					$900,329		$1,023,855
Schedule 201							
1st 20,000 kWh, per kWh	9,645,695	9,645,695	9,685,033 kWh	2.609 ¢	$252,683	2.609 ¢	$252,683
All additional kWh, per kWh	9,161,385	9,161,385	9,110,106 kWh	2.539 ¢	$231,306	2.539 ¢	$231,306
Total	18,807,080	18,807,080	18,795,139 kWh		$1,384,518		$1,507,844
						Change	$123,526

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Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,449,320	3,449,320	3,412,157	kW	$1.34	$4,572,290	$1.24	$4,231,075
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	261	261	250	bill	$385.00	$96,298	$499.00	$124,696
Load Size 201-300 kW, per month	2,516	2,516	2,413	bill	$115.00	$277,493	$149.00	$359,534
Load Size > 300 kW, per month	6,780	6,780	6,496	bill	$301.00	$1,955,389	$391.00	$2,540,057
Load Size Charge								
≤ 200 Kw, per kW	1,381	1,381	1,359	kW	No Charge		No Charge	
201-300 kW, per kW	652,734	652,734	643,173	kW	$1.35	$868,284	$1.75	$1,125,553
>300 kW, per kW	3,359,038	3,359,038	3,320,260	kW	$0.65	$2,158,169	$0.85	$2,822,221
Demand Charge, per kW	3,449,320	3,449,320	3,412,157	kW	$3.43	$11,703,699	$4.46	$15,218,220
Reactive Power Charge, per kvar	660,592	660,592	667,305	kvar	65.00 ¢	$433,748	65.00 ¢	$433,748
Energy Charge - Schedule 200								
Demand Charge, per kW	3,449,320	3,449,320	3,412,157	kW	$1.25	$4,265,196	$1.28	$4,367,561
1st 20,000 kWh, per kWh	184,180,535	190,454,535	187,732,515	kWh	2.950 ¢	$5,538,109	2.645 ¢	$4,965,525
All additional kWh, per kWh	1,043,739,698	1,046,231,467	1,026,570,446	kWh	2.558 ¢	$26,259,672	2.294 ¢	$23,549,526
Subtotal	1,227,920,233	1,236,686,002	1,214,302,961	kWh		$58,128,257		$59,737,716
Populus to Terminal Adjustment (80), per kW	3,449,320	3,449,320	3,412,157	kW	($0.13)	($443,580)	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	184,180,535	190,454,535	187,732,515	kWh	0.030 ¢	$56,320	0.000 ¢	$0
All additional kWh, per kWh	1,043,739,698	1,046,231,467	1,026,570,446	kWh	0.026 ¢	$266,908	0.000 ¢	$0
Subtotal						$58,007,905		$59,737,716
Schedule 201								
1st 20,000 kWh, per kWh	184,180,535	190,454,535	187,732,515	kWh	3.096 ¢	$5,812,199	3.096 ¢	$5,812,199
All additional kWh, per kWh	1,043,739,698	1,046,231,467	1,026,570,446	kWh	2.685 ¢	$27,563,416	2.685 ¢	$27,563,416
Total	1,227,920,233	1,236,686,002	1,214,302,961	kWh		$91,383,520		$93,113,331
							Change	$1,729,811

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	276,534	276,534	273,642	kW	$1.32	$361,207	$1.16	$317,425
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	4	4	4	bill	$367.00	$1,426	$468.00	$1,819.00
Load Size 201-300 kW, per month	100	100	97	bill	$117.00	$11,309	$148.00	$14,306.00
Load Size > 300 kW, per month	540	540	517	bill	$303.00	$156,734	$383.00	$198,116.00
Load Size Charge								
≤200 Kw, per kW	0	0	0	kW	No Charge		No Charge	
201-300 kW, per kW	27,421	27,421	26,699	kW	$1.25	$33,374	$1.60	$42,718
>300 kW, per kW	302,291	302,291	299,138	kW	$0.65	$194,440	$0.80	$239,310
Demand Charge, per kW	276,534	276,534	273,642	kW	$3.39	$927,646	$4.28	$1,171,188
Reactive Power Charge, per kvar	28,785	28,785	29,465	kvar	60.00 ¢	$17,679	60.00 ¢	$17,679
Energy Charge - Schedule 200								
Demand Charge, per kW	276,534	276,534	273,642	kW	$1.25	$342,053	$1.28	$350,262
1st 20,000 kWh, per kWh	12,726,135	12,726,135	12,534,699	kWh	2.892 ¢	$362,503	2.580 ¢	$323,395
All additional kWh, per kWh	78,261,768	78,261,768	76,851,297	kWh	2.500 ¢	$1,921,282	2.230 ¢	$1,713,784
Subtotal	90,987,903	90,987,903	89,385,996	kWh		$4,329,653		$4,390,002
Populus to Terminal Adjustment (80), per kW	276,534	276,534	273,642	kW	($0.13)	($35,573)	$0.00	$0
TAM Adj for Other Revs (205)								
1st 20,000 kWh, per kWh	12,726,135	12,726,135	12,534,699	kWh	0.029 ¢	$3,635	0.000 ¢	$0
All additional kWh, per kWh	78,261,768	78,261,768	76,851,297	kWh	0.025 ¢	$19,213	0.000 ¢	$0
Subtotal						$4,316,928		$4,390,002
Schedule 201								
1st 20,000 kWh, per kWh	12,726,135	12,726,135	12,534,699	kWh	3.061 ¢	$383,687	3.061 ¢	$383,687
All additional kWh, per kWh	78,261,768	78,261,768	76,851,297	kWh	2.647 ¢	$2,034,254	2.647 ¢	$2,034,254
Total	90,987,903	90,987,903	89,385,996	kWh		$6,734,869		$6,807,943
							Change	$73,074

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Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Composite								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	199,445,302	199,445,302	209,714,409	kWh	0.324 ¢	$679,475	0.293 ¢	$614,463
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	6,321	6,321	6,157	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per customer	1,925	1,925	1,867	bill	$360.00	$672,120	$320.00	$597,440
Three Phase Load Size > 300 kW, per customer	64	64	63	bill	$1,400.00	$88,200	$1,250.00	$78,750
Total Customers	8,310	8,310	8,087	bill				
Monthly Bills	38,775	38,775	37,822					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	71,521	71,521	75,256	kW	$17.00	$1,279,352	$15.00	$1,128,840
Three Phase Load Size 51-300 kW, per kW	118,789	118,789	124,944	kW	$11.00	$1,374,384	$10.00	$1,249,440
Three Phase Load Size > 300 kW, per kW	17,983	17,983	18,805	kW	$7.00	$131,635	$6.00	$112,830
Single Phase, Minimum Charge	569	569	564	bill	$60.00	$33,840	$55.00	$31,020
Three Phase, Minimum Charge	1,603	1,603	1,576	bill	$105.00	$165,480	$95.00	$149,720
Distribution Energy Charge, per kWh	199,445,302	199,445,302	209,714,409	kWh	4.168 ¢	$8,740,897	3.708 ¢	$7,776,210
Reactive Power Charge, per kvar	132,215	132,215	140,166	kvar	65.00 ¢	$91,108	65.00 ¢	$91,108
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	1,759,731	1,759,731	1,842,166	kWh	4.206 ¢	$77,482	3.975 ¢	$73,226
Winter, All additional kWh, per kWh	1,717,135	1,717,135	1,796,594	kWh	2.867 ¢	$51,508	2.709 ¢	$48,670
Summer, All kWh, per kWh	195,968,436	195,968,436	206,075,649	kWh	2.867 ¢	$5,908,189	2.709 ¢	$5,582,589
Subtotal	199,445,302	199,445,302	209,714,409	kWh		$19,293,670		$17,534,306
Populus to Terminal Adjustment (80), per kWh	199,445,302	199,445,302	209,714,409	kWh	-0.031 ¢	($65,011)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
Winter, 1st 100 kWh/kW, per kWh	1,759,731	1,759,731	1,842,166	kWh	0.037 ¢	$682	0.000 ¢	$0
Winter, All additional kWh, per kWh	1,717,135	1,717,135	1,796,594	kWh	0.025 ¢	$449	0.000 ¢	$0
Summer, All kWh, per kWh	195,968,436	195,968,436	206,075,649	kWh	0.025 ¢	$51,519	0.000 ¢	$0
Subtotal						$19,281,309		$17,534,306
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	1,759,731	1,759,731	1,842,166	kWh	3.897 ¢	$71,789	3.897 ¢	$71,789
Winter, All additional kWh, per kWh	1,717,135	1,717,135	1,796,594	kWh	2.655 ¢	$47,700	2.655 ¢	$47,700
Summer, All kWh, per kWh	195,968,436	195,968,436	206,075,649	kWh	2.655 ¢	$5,471,308	2.655 ¢	$5,471,308
Total	199,445,302	199,445,302	209,714,409	kWh		$24,872,106		$23,125,103
							Change	($1,747,003)
Schedule No. 41/741								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	604,026	604,026	627,888	kWh	0.314 ¢	$1,972	0.285 ¢	$1,789
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	2	2	2	bill	No Charge		No Charge	
Three Phase Load Size 51 - 300 kW, per customer	0	0	0	bill	$350.00	$0	$310.00	$0
Three Phase Load Size > 300 kW, per customer	1	1	1	bill	$1,360.00	$1,360	$1,210.00	$1,210
Total Customers	3	3	3	bill				
Monthly Bills	20	20	20					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	10	10	10	kW	$17.00	$170	$15.00	$150
Three Phase Load Size 51-300 kW, per kW	0	0	0	kW	$11.00	$0	$10.00	$0
Three Phase Load Size > 300 kW, per kW	618	618	642	kW	$7.00	$4,494	$6.00	$3,852
Single Phase, Minimum Charge	1	1	1	bill	$60.00	$60	$55.00	$55
Three Phase, Minimum Charge	0	0	0	bill	$100.00	$0	$90.00	$0
Distribution Energy Charge, per kWh	604,026	604,026	627,888	kWh	4.037 ¢	$25,348	3.603 ¢	$22,623
Reactive Power Charge, per kvar	1,141	1,141	1,186	kvar	60.00 ¢	$712	60.00 ¢	$712
Energy Charge - Schedule 200								
Winter, 1st 100 kWh/kW, per kWh	7,949	7,949	8,263	kWh	4.073 ¢	$337	3.863 ¢	$319
Winter, All additional kWh, per kWh	42,997	42,997	44,696	kWh	2.777 ¢	$1,241	2.633 ¢	$1,177
Summer, All kWh, per kWh	553,080	553,080	574,929	kWh	2.777 ¢	$15,966	2.633 ¢	$15,138
Subtotal	604,026	604,026	627,888	kWh		$51,660		$47,025
Populus to Terminal Adjustment (80), per kWh	604,026	604,026	627,888	kWh	-0.030 ¢	($188)	0.000 ¢	$0
TAM Adj for Other Revs (205)								
Winter, 1st 100 kWh/kW, per kWh	7,949	7,949	8,263	kWh	0.036 ¢	$3	0.000 ¢	$0
Winter, All additional kWh, per kWh	42,997	42,997	44,696	kWh	0.025 ¢	$11	0.000 ¢	$0
Summer, All kWh, per kWh	553,080	553,080	574,929	kWh	0.025 ¢	$144	0.000 ¢	$0
Subtotal						$51,630		$47,025
Schedule 201								
Winter, 1st 100 kWh/kW, per kWh	7,949	7,949	8,263	kWh	3.774 ¢	$312	3.774 ¢	$312
Winter, All additional kWh, per kWh	42,997	42,997	44,696	kWh	2.571 ¢	$1,149	2.571 ¢	$1,149
Summer, All kWh, per kWh	553,080	553,080	574,929	kWh	2.571 ¢	$14,781	2.571 ¢	$14,781
Total	604,026	604,026	627,888	kWh		$67,872		$63,267
							Change	($4,605)

PACIFIC POWER
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Billing Determinants
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Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	191,967	191,967	110,285	kW	$0.97	$106,976	$0.82	$90,434
credit per kW of on-peak demand (OATT)	0	0	0	kW	($0.97)	$0	($0.82)	$0
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$360.00	$0	$510.00	$0
Facility Capacity > 4,000 kW, per month	30	30	35	bill	$640.00	$22,400	$910.00	$31,850
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$0.75	$0	$0.75	$0
Facility Capacity > 4,000 kW, per kW	212,521	212,521	123,882	kW	$0.70	$86,717	$0.70	$86,717
Demand Charge, per kW of on-peak demand	191,967	191,967	110,285	kW	$2.81	$309,901	$4.43	$488,563
Reactive Power Charge, per kvar	34,139	34,139	11,379	kvar	60.00 ¢	$6,827	60.00 ¢	$6,827
Reactive Hours, per kvarh	15,759,610	15,759,610	12,168,738	kvarh	0.080 ¢	$9,735	0.080 ¢	$9,735
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	212,521	212,521	123,882	kW	$0.27	$33,448	$0.27	$33,448
Supplemental Reserves, per kW of Facility Cap.	212,521	212,521	123,882	kW	$0.27	$33,448	$0.27	$33,448
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	191,967	191,967	110,285	kW	$1.15	$126,828	$1.18	$130,136
On-Peak, per on-peak kWh	39,678,341	39,678,341	18,845,893	kWh	2.605 ¢	$490,936	2.289 ¢	$431,382
Off-Peak, per off-peak kWh	20,194,321	20,194,321	8,192,094	kWh	2.555 ¢	$209,308	2.239 ¢	$183,421
Unscheduled Energy, per kWh	1,250,186	1,250,186	1,245,206	kWh		$42,844		$42,844
Subtotal	61,122,848	61,122,848	28,283,199	kWh		$1,479,368		$1,568,805
Populus to Terminal Adjustment (80), per kW	191,967	191,967	110,285	kW	($0.15)	($16,543)	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	39,678,341	39,678,341	18,845,893	kWh	0.025 ¢	$4,711	0.000 ¢	$0
Off-Peak, per off-peak kWh	20,194,321	20,194,321	8,192,094	kWh	0.025 ¢	$2,048	0.000 ¢	$0
Subtotal						$1,469,584		$1,568,805
Schedule 201								
On-Peak, per on-peak kWh	39,678,341	39,678,341	18,845,893	kWh	2.663 ¢	$501,866	2.663 ¢	$501,866
Off-Peak, per off-peak kWh	20,194,321	20,194,321	8,192,094	kWh	2.613 ¢	$214,059	2.613 ¢	$214,059
Total	61,122,848	61,122,848	28,283,199	kWh		$2,185,509		$2,284,730
							Change	$99,221

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	288,240	288,240	42,610	kW	$1.43	$60,932	$1.23	$52,410
credit per kW of on-peak demand (OATT)	0	0	0	kW	($1.43)	$0	($1.23)	$0
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	12	12	8	bill	$580.00	$4,640	$960.00	$7,680
Facility Capacity > 4,000 kW, per month	24	24	17	bill	$1,070.00	$18,190	$1,780.00	$30,260
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	18,320	18,320	1,013	kW	$0.80	$810	$1.15	$1,165
Facility Capacity > 4,000 kW, per kW	326,400	326,400	44,721	kW	$0.80	$35,777	$1.15	$51,429
Demand Charge, per kW of on-peak demand	288,240	288,240	42,610	kW	$2.54	$108,229	$4.47	$190,467
Reactive Power Charge, per kvar	7,048	7,048	490	kvar	55.00 ¢	$270	55.00 ¢	$270
Reactive Hours, per kvarh	1,048,000	1,048,000	57,976	kvarh	0.080 ¢	$46	0.08 ¢	$46
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	344,720	344,720	45,734	kW	$0.27	$12,348	$0.27	$12,348
Supplemental Reserves, per kW of Facility Cap.	344,720	344,720	45,734	kW	$0.27	$12,348	$0.27	$12,348
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	288,240	288,240	42,610	kW	$1.16	$49,428	$1.19	$50,706
On-Peak, per on-peak kWh	80,894,447	80,894,447	13,246,613	kWh	2.569 ¢	$340,305	2.207 ¢	$292,355
Off-Peak, per off-peak kWh	51,385,488	51,385,488	8,216,785	kWh	2.519 ¢	$206,981	2.157 ¢	$177,236
Unscheduled Energy, per kWh	3,069,297	3,069,297	457,463	kWh		$11,205		$11,205
Subtotal	135,349,232	135,349,232	21,920,861	kWh		$861,509		$889,923
Populus to Terminal Adjustment (80), per kW	288,240	288,240	42,610	kW	($0.19)	($8,096)	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	80,894,447	80,894,447	13,246,613	kWh	0.024 ¢	$3,179	0.000 ¢	$0
Off-Peak, per off-peak kWh	51,385,488	51,385,488	8,216,785	kWh	0.024 ¢	$1,972	0.000 ¢	$0
Subtotal						$858,564		$889,923
Schedule 201								
On-Peak, per on-peak kWh	80,894,447	80,894,447	13,246,613	kWh	2.539 ¢	$336,332	2.539 ¢	$336,332
Off-Peak, per off-peak kWh	51,385,488	51,385,488	8,216,785	kWh	2.489 ¢	$204,516	2.489 ¢	$204,516
Total	135,349,232	135,349,232	21,920,861	kWh		$1,399,412		$1,430,771
							Change	$31,359

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Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13-12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.032	$0	$0.030	$0
Primary	0	0	0	kW	$0.038	$0	$0.032	$0
Transmission	0	0	0	kW	$0.056	$0	$0.048	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.101	$0	$0.166	$0
Primary	0	0	0	kW	$0.109	$0	$0.173	$0
Transmission	0	0	0	kW	$0.099	$0	$0.174	$0
Schedule No. 48/748 - Composite								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,630,687	1,630,687	1,663,005	kW	$1.37	$2,278,317	$1.30	$2,161,907
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	1,338	1,338	1,287	bill	$340.00	$437,580	$470.00	$604,890
Facility Capacity > 4,000 kW, per month	24	24	24	bill	$630.00	$15,120	$880.00	$21,120
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,774,246	1,774,246	1,813,453	kW	$1.35	$2,448,162	$1.35	$2,448,162
Facility Capacity > 4,000 kW, per kW	192,839	192,839	186,796	kW	$1.25	$233,495	$1.25	$233,495
Demand Charge, per kW of on-peak demand	1,630,687	1,630,687	1,663,005	kW	$2.58	$4,290,553	$4.26	$7,084,401
Reactive Power Charge, per kvar	444,823	444,823	465,249	kvar	65.00 ¢	$302,412	65.00 ¢	$302,412
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,630,687	1,630,687	1,663,005	kW	$1.14	$1,895,826	$1.17	$1,945,716
On-Peak, per on-peak kWh	387,025,545	393,198,545	399,171,764	kWh	2.667 ¢	$10,645,911	2.374 ¢	$9,476,338
Off-Peak, per off-peak kWh	213,669,561	216,123,195	218,871,139	kWh	2.617 ¢	$5,727,858	2.324 ¢	$5,086,565
Subtotal	600,695,106	609,321,740	618,042,903	kWh		$28,275,234		$29,365,006
Populus to Terminal Adjustment (80), per kW	1,630,687	1,630,687	1,663,005	kW	($0.13)	($216,191)	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	387,025,545	393,198,545	399,171,764	kWh	0.026 ¢	$103,785	0.000 ¢	$0
Off-Peak, per off-peak kWh	213,669,561	216,123,195	218,871,139	kWh	0.026 ¢	$56,906	0.000 ¢	$0
Subtotal						$28,219,734		$29,365,006
Schedule 201								
On-Peak, per on-peak kWh	387,025,545	393,198,545	399,171,764	kWh	2.766 ¢	$11,041,091	2.766 ¢	$11,041,091
Off-Peak, per off-peak kWh	213,669,561	216,123,195	218,871,139	kWh	2.716 ¢	$5,944,540	2.716 ¢	$5,944,540
Total	600,695,106	609,321,740	618,042,903	kWh	0.000	$45,205,365		$46,350,637
							Change	$1,145,272
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,585,123	3,585,123	3,756,978	kW	$1.51	$5,673,057	$1.36	$5,109,490
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	783	783	758	bill	$360.00	$272,880	$510.00	$386,580
Facility Capacity > 4,000 kW, per month	372	372	352	bill	$640.00	$225,280	$910.00	$320,320
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,454,948	1,454,948	1,484,689	kW	$0.75	$1,113,517	$0.75	$1,113,517
Facility Capacity > 4,000 kW, per kW	2,997,862	2,997,862	3,170,630	kW	$0.70	$2,219,441	$0.70	$2,219,441
Demand Charge, per kW of on-peak demand	3,585,123	3,585,123	3,756,978	kW	$2.81	$10,557,108	$4.43	$16,643,413
Reactive Power Charge, per kvar	842,451	842,451	892,857	kvar	60.00 ¢	$535,714	60.00 ¢	$535,714
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,585,123	3,585,123	3,756,978	kW	$1.15	$4,320,525	$1.18	$4,433,234
On-Peak, per on-peak kWh	937,707,001	937,707,001	982,307,452	kWh	2.605 ¢	$25,589,109	2.289 ¢	$22,485,018
Off-Peak, per off-peak kWh	580,241,052	580,241,052	607,639,708	kWh	2.555 ¢	$15,525,195	2.239 ¢	$13,605,053
Subtotal	1,517,948,053	1,517,948,053	1,589,947,160	kWh		$66,031,806		$66,851,780
Populus to Terminal Adjustment (80), per kW	3,585,123	3,585,123	3,756,978	kW	($0.15)	($563,547)	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	937,707,001	937,707,001	982,307,452	kWh	0.025 ¢	$245,577	0.000 ¢	$0
Off-Peak, per off-peak kWh	580,241,052	580,241,052	607,639,708	kWh	0.025 ¢	$151,910	0.000 ¢	$0
Subtotal						$65,865,746		$66,851,780
Schedule 201								
On-Peak, per on-peak kWh	937,707,001	937,707,001	982,307,452	kWh	2.663 ¢	$26,158,847	2.663 ¢	$26,158,847
Off-Peak, per off-peak kWh	580,241,052	580,241,052	607,639,708	kWh	2.613 ¢	$15,877,626	2.613 ¢	$15,877,626
Total	1,517,948,053	1,517,948,053	1,589,947,160	kWh		$107,902,219		$108,888,253
							Change	$986,034

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Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 – Composite								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	699,014	699,014	1,172,561	kW	$1.97	$2,309,945	$1.77	$2,075,433
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	30	30	30	bill	$580.00	$17,400	$960.00	$28,800
Facility Capacity > 4,000 kW, per month	27	27	38	bill	$1,070.00	$40,660	$1,780.00	$67,640
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	40,406	40,406	39,523	kW	$0.80	$31,618	$1.15	$45,451
Facility Capacity > 4,000 kW, per kW	692,502	692,502	1,139,311	kW	$0.80	$911,449	$1.15	$1,310,208
Demand Charge, per kW of on-peak demand	699,014	699,014	1,172,561	kW	$2.54	$2,978,305	$4.47	$5,241,348
Reactive Power Charge, per kvar	115,299	115,299	128,402	kvar	55.00 ¢	$70,621	55.00 ¢	$70,621
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	699,014	699,014	1,172,561	kW	$1.16	$1,360,171	$1.19	$1,395,348
On-Peak, per on-peak kWh	251,374,000	251,374,000	448,520,508	kWh	2.569 ¢	$11,522,492	2.207 ¢	$9,898,848
Off-Peak, per off-peak kWh	399,510,000	199,510,000	346,999,262	kWh	2.519 ¢	$8,740,911	2.157 ¢	$7,484,774
Subtotal	450,884,000	450,884,000	795,519,770	kWh		$27,983,572		$27,618,471
Populus to Terminal Adjustment (80), per kW	699,014	699,014	1,172,561	kW	($0.19)	($222,787)	$0.00	$0
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	251,374,000	251,374,000	448,520,508	kWh	0.024 ¢	$107,645	0.000 ¢	$0
Off-Peak, per off-peak kWh	199,510,000	199,510,000	346,999,262	kWh	0.024 ¢	$83,280	0.000 ¢	$0
Subtotal						$27,951,710		$27,618,471
Schedule 201								
On-Peak, per on-peak kWh	251,374,000	251,374,000	448,520,508	kWh	2.539 ¢	$11,387,936	2.539 ¢	$11,387,936
Off-Peak, per off-peak kWh	199,510,000	199,510,000	346,999,262	kWh	2.489 ¢	$8,636,812	2.489 ¢	$8,636,812
Total	450,884,000	450,884,000	795,519,770	kWh		$47,976,458		$47,643,219
							Change	($333,239)

PACIFIC POWER
State of Oregon

UE 246 Stipulated Base Rates

Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units	Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 15 - Composite							
Outdoor Area Lighting Service							
No. of Customers	7,208	7,208	6,850				
Transmission & Ancillary Services Charge per kWh	10,398,287	10,398,287	9,709,823 kWh	0.069 ¢	$6,528	0.060 ¢	$6,105
Distribution Charge — Distribution Charge, per kWh	10,398,287	10,398,287	9,709,823 kWh	7.995 ¢	$776,284	7.821 ¢	$759,427
Energy Charge - Schedule 200 per kWh	10,398,287	10,398,287	9,709,823 kWh	2.620 ¢	$254,343	2.046 ¢	$198,295
Subtotal	10,398,287	10,398,287	9,709,823 kWh		$1,037,155		$963,827
Populus to Terminal Adjustment (80), per kWh	10,398,287	10,398,287	9,709,823 kWh	-0.007 ¢	($680)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	10,398,287	10,398,287	9,709,823 kWh	0.025 ¢	$2,427	0.000 ¢	$0
Subtotal					$1,038,902		$963,827
Schedule 201 per kWh	10,398,287	10,398,287	9,709,823 kWh	2.664 ¢	$258,367	2.664 ¢	$258,367
Total	10,398,287	10,398,287	9,709,823 kWh		$1,297,269		$1,222,194
						Change	($75,075)
Schedule No. 50							
Mercury Vapor Street Lighting Service							
No. of Customers	251	251	250				
Transmission & Ancillary Services Charge per kWh	9,273,884	9,273,884	8,845,474 kWh	0.069 ¢	$5,908	0.060 ¢	$5,648
Distribution Charge — Distribution Charge, per kWh	9,273,884	9,273,884	8,845,474 kWh	6.916 ¢	$611,713	6.791 ¢	$600,680
Energy Charge - Schedule 200 per kWh	9,273,884	9,273,884	8,845,474 kWh	2.363 ¢	$209,325	1.845 ¢	$162,969
Subtotal	9,273,884	9,273,884	8,845,474 kWh		$826,947		$769,297
Populus to Terminal Adjustment (80), per kWh	9,273,884	9,273,884	8,845,474 kWh	-0.007 ¢	($619)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	9,273,884	9,273,884	8,845,474 kWh	0.021 ¢	$1,858	0.000 ¢	$0
Subtotal					$828,186		$769,297
Schedule 201 per kWh	9,273,884	9,273,884	8,845,474 kWh	2.190 ¢	$193,380	2.190 ¢	$193,380
Total	9,273,884	9,273,884	8,845,474 kWh		$1,021,566		$962,677
						Change	($58,889)
Schedule No. 51/751, 55							
Street Lighting Service, Company-Owned System							
No. of Customers	701	701	733				
Transmission & Ancillary Services Charge per kWh	18,551,166	18,551,166	18,679,735 kWh	0.069 ¢	$12,811	0.060 ¢	$11,905
Distribution Charge — Distribution Charge, per kWh	18,551,166	18,551,166	18,679,735 kWh	11.096 ¢	$1,072,713	10.883 ¢	$2,032,840
Energy Charge - Schedule 200 per kWh	18,551,166	18,551,166	18,679,735 kWh	3.732 ¢	$696,812	2.914 ¢	$543,989
Subtotal	18,551,166	18,551,166	18,679,735 kWh		$2,782,335		$2,588,735
Populus to Terminal Adjustment (80), per kWh	18,551,166	18,551,166	18,679,735 kWh	-0.007 ¢	($1,308)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	18,551,166	18,551,166	18,679,735 kWh	0.033 ¢	$6,164	0.000 ¢	$0
Subtotal					$2,787,191		$2,588,735
Schedule 201 per kWh	18,551,166	18,551,166	18,679,735 kWh	3.456 ¢	$645,497	3.456 ¢	$645,497
Total	18,551,166	18,551,166	18,679,735 kWh		$3,432,688		$3,234,231
						Change	($198,456)
Schedule No. 52/752							
Street Lighting Service, Company-Owned System							
No. of Customers	55	55	50				
Transmission & Ancillary Services Charge per kWh	788,080	788,080	599,203 kWh	0.069 ¢	$413	0.060 ¢	$360
Distribution Charge — Distribution Charge, per kWh	788,080	788,080	599,203 kWh	6.606 ¢	$39,585	6.557 ¢	$39,292
Energy Charge - Schedule 200 per kWh	788,080	788,080	599,203 kWh	2.860 ¢	$17,137	2.233 ¢	$13,380
Subtotal	788,080	788,080	599,203 kWh		$57,136		$53,032
Populus to Terminal Adjustment (80), per kWh	788,080	788,080	599,203 kWh	-0.007 ¢	($42)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	788,080	788,080	599,203 kWh	0.025 ¢	$150	0.000 ¢	$0
Subtotal					$57,244		$53,032
Schedule 201 per kWh	788,080	788,080	599,203 kWh	2.647 ¢	$15,861	2.647 ¢	$15,861
Total	788,080	788,080	599,203 kWh		$73,105		$68,892
						Change	($4,213)

PACIFIC POWER
State of Oregon

UE 246 Stipulated Base Rates

Billing Determinants
Actual 12 Months Ended June 30, 2011
Forecast 12 Months Ended December 31, 2013

Schedule	Actual 7/10-6/11 Units	Normalized 7/10-6/11 Units	Forecast 1/13 - 12/13 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	255	255	260					
Transmission & Ancillary Services Charge								
per kWh	9,548,236	9,548,236	9,578,780	kWh	0.069 ¢	$6,609	0.060 ¢	$5,747
Distribution Charge								
Distribution Charge, per kWh	9,548,236	9,548,236	9,578,780	kWh	4.062 ¢	$389,107	3.969 ¢	$380,199
Energy Charge - Schedule 200								
per kWh	9,548,236	9,548,236	9,578,780	kWh	1.221 ¢	$116,957	0.953 ¢	$91,286
Subtotal	9,548,236	9,548,236	9,578,780	kWh		$512,673		$477,232
Populus to Terminal Adjustment (80), per kWh	9,548,236	9,548,236	9,578,780	kWh	-0.007 ¢	($671)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	9,548,236	9,548,236	9,578,780	kWh	0.011 ¢	$1,054	0.000 ¢	$0
Subtotal						$513,056		$477,232
Schedule 201								
per kWh	9,548,236	9,548,236	9,578,780	kWh	1.130 ¢	$108,240	1.130 ¢	$108,240
Total	9,548,236	9,548,236	9,578,780	kWh		$621,297		$585,472
							Change	($35,825)
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,138,574	1,138,574	1,189,338	kWh	0.069 ¢	$821	0.060 ¢	$714
Distribution Charge								
Basic Charge, Single Phase, per month	822	822	813	bill	$6.00	$4,878	$6.00	$4,878
Basic Charge, Three Phase, per month	427	427	423	bill	$9.00	$3,807	$9.00	$3,807
Distribution Energy Charge, per kWh	1,138,574	1,138,574	1,189,338	kWh	3.871 ¢	$46,039	3.849 ¢	$45,778
Energy Charge - Schedule 200								
per kWh	1,138,574	1,138,574	1,189,338	kWh	2.100 ¢	$24,976	1.640 ¢	$19,505
Subtotal	1,138,574	1,138,574	1,189,338	kWh		$80,521		$74,682
Populus to Terminal Adjustment (80), per kWh	1,138,574	1,138,574	1,189,338	kWh	-0.007 ¢	($85)	0.000 ¢	$0
TAM Adj for Other Revs (205), per kWh	1,138,574	1,138,574	1,189,338	kWh	0.019 ¢	$226	0.000 ¢	$0
Subtotal						$80,664		$74,682
Schedule 201								
per kWh	1,138,574	1,138,574	1,189,338	kWh	1.947 ¢	$23,156	1.947 ¢	$23,156
Total	1,138,574	1,138,574	1,189,338	kWh		$103,820		$97,838
							Change	($5,982)
TOTAL OREGON	13,091,819,591	13,057,536,168	13,097,739,985			$1,180,103,926		$1,200,818,012
Employee Discount						($444,926)		($458,600)
TOTAL OREGON (WITH EMPLOYEE DISCOUNT)						$1,179,659,000		$1,200,359,412