Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● mail@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

October 11, 2012

Via FedEx and Electronic Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PACIFICORP 2013 Request for a General Rate Revision
Docket No. UE 246

Dear Filing Center:

Enclosed please find the original and two (2) copies of the re-filed Cross Examination Exhibits on behalf of the Industrial Customers of Northwest Utilities in the above-referenced Docket.

Thank you for your assistance, and please do not hesitate to contact our office if you have any questions.

Sincerely yours,

<u>/s/ Sarah A. Kohler</u>
Sarah A. Kohler

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing the Cross Examination Exhibits on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail where paper service has been waived.

Dated at Portland, Oregon, this 11th day of October, 2012.

/s/ Sarah A. Kohler
Sarah A. Kohler

(W) PACIFIC POWER & LIGHT
SARAH WALLACE
SENIOR COUNSEL
825 NE MULTNOMAH STE 1800
PORTLAND OR 97232
sarah.wallace@pacificorp.com

(W) PACIFIC POWER & LIGHT
R. BRYCE DALLEY
825 NE MULTNOMAH STE 2000
PORTLAND OR 97232
bryce.dalley@pacificorp.com

(W) PACIFICORP
OREGON DOCKETS
825 NE MULTNOMAH STE 1800
PORTLAND OR 97232
oregondockets@pacificorp.com

(W) PUBLIC UTILITY COMMISSION OF OREGON
DEBORAH GARCIA
PO BOX 2148
SALEM OR 97308-2148
deborah.garcia@state.or.us

(W) DEPARTMENT OF JUSTICE
MICHAEL T WEIRICH
BUSINESS ACTIVITIES SECTION
1162 COURT ST NE
SALEM OR 97301-4096
michael.weirich@doj.state.or.us

(W) PORTLAND GENERAL ELECTRIC
RANDY DAHLGREN – 1WTC0702
DOUGLAS C TINGEY – 1WTC13
121 SW SALMON ST
PORTLAND OR 97204
pge.opuc.filings@pgn.com
doug.tingey@pgn.com

(W) BOEHM KURTZ & LOWRY
KURT J BOEHM
JODY KYLER
36 E SEVENTH ST - STE 1510
CINCINNATI OH 45202
kboehm@bkllawfirm.com
jkyler@bkllawfirm.com

(W) CITIZENS' UTILITY BOARD OF OREGON
OPUC DOCKETS
ROBERT JENKS
G. CATRIONA MCCRACKEN
610 SW BROADWAY, STE 400
PORTLAND OR 97205
dockets@oregoncub.org
bob@oregoncub.org
catriona@oregoncub.org

(W) ENERGY STRATEGIES LLC
KEVIN HIGGINS
215 STATE ST - STE 200
SALT LAKE CITY UT 84111-2322
khiggins@energystrat.com

(W) REGULATORY & COGENERATION SERVICES INC
DONALD W SCHOENBECK
900 WASHINGTON ST STE 780
VANCOUVER WA 98660-3455
dws@r-c-s-inc.com

(W) SIERRA CLUB
JEFF SPEIR
85 SECOND ST., 2ND FLR
SAN FRANCISCO CA 94105
jeff.speir@sierraclub.org

(W) SIERRA CLUB LAW PROGRAM
GLORIA D SMITH
85 SECOND STREET
SAN FRANCISCO CA 94105
gloria.smith@sierraclub.org

(W) SYNAPSE ENERGY
JEREMY FISHER
485 MASSACHUSETTS AVE., STE 2
CAMBRIDGE MA 02139
jfisher@synapse-energy.com

(W) ROBERTSON-BRYAN, INC
STUART ROBERTSON
9888 KENT STREET
ELK GROVE CA 95624
stuart@robertson-bryan.com

(W) RENEWABLE NORTHWEST PROJECT
MEGAN WALSETH DECKER
JIMMY LINDSAY
421 SW 6TH AVE #1125
PORTLAND OR 97204-1629
megan@rnp.org
jimmy@rnp.org

(W) NW ENERGY COALITION
WENDY GERLITZ
1205 SE FLAVEL
PORTLAND OR 97202
wendy@nwenergy.org

(W) KLAMATH WATER AND POWER AGENCY
HOLLIE CANNON
735 COMMERCIAL ST STE 4000
KLAMATH FALLS OR 97601
hollie.cannon@kwapa.org

(W) ESLER STEPHENS & BUCKLEY
JOHN W STEPHENS
888 SW FIFTH AVE STE 700
PORTLAND OR 97204-2021
stephens@eslerstephens.com;
mec@eslerstephens.com

(W) WILLIAM GANONG
514 WALNUT AVENUE
KLAMATH FALLS OR 97601
wganong@aol.com

UE 246 - CROSS-EXAMINATION EXHIBITS OF ICNU			
ICNU/300	**R. Bryce Dalley**	**PacifiCorp**	**UE 170 Testimony of Christy Omohundro (PPL/701)**
ICNU/301	**Greg Duvall**	**PacifiCorp**	**UE 246 PacifiCorp Response to ICNU DR 8.1 (PacifiCorp Updated Response to UE 245 ICNU DR 5.1)**
ICNU/302	**R. Bryce Dalley / Pat Reiten**	**PacifiCorp**	**UE 245 - PacifiCorp Response to UE 245 ICNU DR 5.9**

Case UE-170
PPL Exhibit 701
Witness: Christy A. Omohundro

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Christy A. Omohundro

Transition Adjustment

June 2005

Q. Please state your name.

A. My name is Christy A. Omohundro.

Q. Did you previously offer testimony in this proceeding?

A. Yes, I filed testimony in the Company's direct case.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to address the arguments raised by Citizens Utility Board (CUB) witness Bob Jenks and Industrial Customers of the Northwest (ICNU) witness Randall J. Falkenberg against the proposed structure and schedule of the PacifiCorp's Transition Adjustment Mechanism (RVM).

Q. Do you address CUB and ICNU's concerns with regard to the actual calculation of the RVM?

A. No. Mr. Widmer will address the arguments raised by ICNU concerning the calculation of the adjustment and all issues concerning the Company's GRID model.

Q. Please summarize the arguments made by Mr. Jenks and Mr. Falkenberg against the structure and schedule of the Company's proposed RVM.

A. Mr. Jenks argues that PacifiCorp's proposed RVM violates a principle behind Oregon's Direct Access program because it impacts customer classes that are not eligible to participate in the program. The impacts listed by Mr. Jenks include a difficulty to conduct prudence reviews, a mismatch between fixed costs and variable costs, a mismatch between allocation factors, the ability to "game the regulatory system," a shift of additional risk of Utah load growth onto Oregon customers, and increased regulatory burden on all customer classes.

Mr. Falkenberg's arguments are primarily focused on the calculation of the RVM, which, as discussed above, will be addressed by Mr. Mark Widmer. Mr. Falkenberg does, however, raise an issue with PacifiCorp's RVM being modeled after the Resource Value Mechanism (RVM) mechanism currently in place by Portland General Electric (PGE) and argues that an annual net power cost update for all customer classes is not necessary.

Q. Please summarize Staff's position on the Company's proposed RVM.

A. Staff witness Mr. Galbraith supports the Company's proposed mechanism stating that "it provides an accurate accounting of the likely impacts of direct access on PacifiCorp's systems operations and can be expected to result in transition adjustment rates that reasonably balance the interests of retail electricity consumers and utility investors."

CUB's RVM Arguments

Q. Please respond to the assertion made by CUB that the Company's RVM should not impact customers that are not eligible for Direct Access.

A. The calculation and approval of the Company's RVM is an annual process requiring a full procedural schedule that includes testimony, rebuttal, and multiple net power cost updates. With the increasing demands placed on the Company and its stakeholders in the regulatory process, it is imperative that the annual transition adjustment process is as streamlined and straightforward as possible. To develop a calculation that updates net power costs for only a subset of PacifiCorp's customers would create complexity that would be difficult to address in the timeframe required for this mandatory, annual process.

The Company also acknowledges the workload on Staff and intervening parties resulting from the annual transition adjustment process. In an effort to ease this workload, the Company developed a mechanism that is largely mechanical and is conceptually based on the existing mechanism in place for PGE. By proposing a mechanism that mirrors the existing schedule and overall framework of PGE's RVM, the Company avoided the complexities associated with a new, and unfamiliar, mechanism and process. In UM 1081, the Company's transition adjustment was criticized in part because of the confusion to customers resulting from the use of a different approach than PGE's. PacifiCorp received consistent feedback that a mechanism similar in structure to PGE's existing RVM would be preferred.

Q. Please address CUB's concern that the proposed RVM makes prudence reviews difficult.

A. As discussed earlier, the Company has modeled the framework and schedule of its RVM after PGE's RVM. This mechanism, with its schedule of net power cost updates, has already been reviewed and approved by the Oregon Public Utility Commission, and has been in place for three annual cycles.

CUB specifically takes issue with the Company's scheduled update in October for new market purchase contracts, fuel purchases, and energy transactions. Because the transition adjustment that will be in place for an entire year is set during a one-week window, it is in the best interest of all of PacifiCorp's customers to update relevant data to ensure the final adjustment is as accurate as possible. By updating the Company's net power costs to include new market purchase contracts, fuel purchases, and energy transactions – a limited and verifiable set of data – the RVM will represent the most accurate determination of the value of the displaced power applied to departing customers. This is fair to both Direct Access and non-Direct Access customers.

Q. Will the updates always result in an increase?

A. No. As demonstrated by the Company's RVM updates filed in February and in March of this year, adjustments made to update net power costs go both ways. In fact, the largest single adjustment included in these updates (the "Gas Related Adjustments" filed in this docket as part of the supplemental testimony of Mark T. Widmer in February 2005) reduced net power costs. Additionally, two of the largest adjustments included in the March filing resulted from updated coal prices and the updated forward market price curve. In the event market prices trend downward at some future time, the updates would capture that cost decrease and ensure the RVM was applying the appropriate adjustment to departing customers.

Q. Please respond to CUB's suggestion that the Company's RVM creates a mismatch between fixed costs and variable costs.

A. CUB is correct that the depreciation-related decreases in the fixed costs of existing resources are not updated between rate cases. What CUB has failed to acknowledge, however, is the other side of this argument. The Company is continuously making capital investments in its system for maintenance overhauls, new infrastructure, clean air equipment, and hydro relicensing expenditures, to name a few. These investments are often very large, sometimes in the range of hundreds of millions of dollars. To the extent these expenses are not included in the annual net power cost update and the Company bears the cost of these items between general rate case filings, customers benefit from lower rates. CUB's assertion that the proposed RVM creates a mismatch in variable and fixed costs between rate filings is accurate, but in the current cycle of heavy capital expenditures, and with the impact of inflation, this mismatch will likely benefit customers, not harm them.

For new resources, the Company designed its RVM to treat fixed and variable costs consistently. The Company proposed that both the fixed and variable costs associated with new resources be excluded until the plant is providing utility service as contemplated under ORS 757.355 and the matching fixed costs have been included in the Company's rate base.

Q. What is the Company's response to CUB's assertion that the RVM creates a mismatch between allocation factors?

A. The Company is confused by CUB's assertion of mismatched allocation factors. By regularly updating allocation factors, the RVM actually helps protect Oregon customers from the impacts of Utah's rapidly growing load. When the allocation factors are reset, Oregon customers pay a smaller portion of the variable costs given that Utah customers will be assigned their fair share of the increased costs. CUB's argument that Oregon customers pay a share of ratebase that is too high if fixed costs are not updated for Utah's growing load is irrelevant given that, under the proposed RVM, both the fixed and variable costs of new resources are excluded until the time when both can be included.

Q. Do you agree with CUB's argument that the RVM shifts risk of Utah load growth to Oregon customers?

A. No. First, CUB's statement that Utah's load growth requires additional resources that are more expensive than embedded resources, thus impacting the marginal cost (Jenks page 27, line 10-12) unfairly compares the costs of new resources to existing resources. While it is true that new resources dedicated to serving peak load requirements are more expensive than existing base load resources, updated allocation factors would also assign additional purchased power, transmission costs, system overheads, etc. to more rapidly growing states, benefiting the slower growing states.

Second, CUB has participated actively in the Company's Multi-State Process initiative where the issue of cost shifts to slower growing states was analyzed extensively. Over forty studies were conducted to analyze the cost shifting issue and the conclusion demonstrated Utah was paying 86-127 percent of the incremental revenue requirement associated with their load growth under the traditional Rolled-In allocation methodology. The Revised Protocol, using the Rolled-In methodology as a baseline, also categorizes certain resources as seasonal and carves out the benefits of low-cost hydro resources to the western states, further protecting Oregon ratepayers from Utah's rapidly growing load.

Even with the protections offered under the Revised Protocol, parties were still concerned about cost shifting and an ongoing workgroup dedicated to studying these issues was developed. This workgroup will file a report with the Oregon Commission no later than October 20, 2005.

Q. What is your response to CUB's suggestion that the November forward price curve update presents an opportunity for the Company to game the regulatory system?

A. The Company has a detailed and transparent process in place for calculation of its forward price curve, which has been in place for several years and has been reviewed by all regulatory Commissions overseeing PacifiCorp's operations. PacifiCorp's forward price curve is used for all of the Company's decision-making, both purchases and sales, and skewing it in one direction would inevitably have negative consequences to other transactions modeled by the curve. Consequentially, the Company has every incentive to ensure its forward price curve is as accurate as possible.

Q. Please respond to CUB's argument that the proposed RVM results in increased regulatory burden on all customer classes.

A. SB 1149 resulted in an increased regulatory burden on all electric utilities in the state of Oregon, as well as all intervening parties. The transition adjustment requires an accurate determination of the value of a slice of an electric utility's system. This is a difficult and complex task that inevitably results in a time consuming, controversial and resource intensive process for all parties involved.

Q. Do you agree with Mr. Jenks' statement that there is a problem with the Company's RVM because it includes phantom costs that the Company will not actually incur?

A. No. The Company's modeling is consistent with the Commission's previously adopted treatment for resource acquisitions, which is governed by Oregon statute

ORS 757.355.

Q. Please explain.

A. ORS 757.355 prohibits the inclusion of new resources in rates, unless they are in-service prior to the beginning of the rate effective period, because they are not used and useful. Consequently, in the past the Public Utility Commission of Oregon has adopted an approach whereby the new resource is excluded from rates until it is used and useful and in the interim it is assumed that load will be served through system balancing transactions. This is how the Company modeled net power costs in regard to Phase 2 of the Current Creek generation facility. For this reason, Mr. Jenks' phantom cost issue should be disregarded.

ICNU's RVM Arguments

Q. Please address ICNU's suggestion that an annual net power cost update is unnecessary.

A. In this increasingly fluid energy market, regulatory rate setting appears to be moving toward closer alignment of customer rates with the actual costs incurred by the utility to provide electric service. PacifiCorp's proposed RVM, with its annual net power cost update, will better align customer rates with actual costs, benefiting departing Direct Access customers as well as customers remaining on PacifiCorp's system. An annual net power cost update will be important to all of PacifiCorp's customers, as it will require the Company to lower rates if power costs decline. Without this process in place, customers would not benefit from declining power costs until PacifiCorp makes a general rate case filing.

As previously mentioned, developing a calculation that updates net power costs for only a subset of PacifiCorp's customers would create complexity that would be difficult to address in the required timeframe for an annual reset of the RVM. An annual update of all net power costs is the most straightforward, streamlined method for calculating the appropriate adjustment to be applied to departing customers.

Q. What is your response to ICNU's argument that PacifiCorp's RVM should not be modeled after PGE's RVM?

A. As just discussed, attempting to value a portion of an electric utility's system is a complicated undertaking. PacifiCorp doubts that any mechanism proposed would be universally accepted by all interested parties. PGE's RVM has been reviewed and approved by the Oregon Commission and represents a solid model that has generated moderate levels of Direct Access participation in a difficult and volatile market. PacifiCorp is hopeful that adoption of its proposed RVM will help accomplish the objectives of the Direct Access legislation and result in improved levels of customer participation.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ICNU Data Request 8.1

Please provide an updated response to ICNU data request 5.1 in Docket No. UE 245, including the net power costs and rates impact for both indicative November update and the final November update.

Response to ICNU Data Request 8.1

Please refer to Attachment ICNU 8.1.

Pacific Power
State of Oregon
UE 246 GRC

	Docket	UE 170 (1)	UE 179 (1) (2)	UE 191	UE 199	UE 207	UE 216	UE 227
	Final Rates Effective	1/1/2006	1/1/2007	1/1/2008	1/1/2009	1/1/2010	1/1/2011	1/1/2012
Initial filing								
Total NPC	$ Millions	$813.9	$863.1	$1,004.1	$1,128.5	$1,100.5	$1,278.2	$1,557.7
Overall Rate Change	($000)	Not	Not	$35,851	$41,161	$20,571	$69,169	$61,645
	Base %	tracked	tracked	4.0%	4.5%	2.2%	7.2%	5.3%
	Net %	separate	separate	3.9%	4.4%	2.1%	7.0%	5.2%
Large General Service Rate Change (Sch 48)	($000)	from GRC	from GRC	$7,755	$8,904	$3,823	$12,230	$13,359
	Base %			5.5%	6.1%	3.0%	9.6%	6.9%
	Net %			5.5%	6.2%	2.9%	9.8%	7.3%
Indicative November Update (3)								
Total NPC prior to settlement adjustments	$ Millions	798.3	$858.8	$980.7	$1,139.9	$1,102.2	$1,290.5	$1,501.1
Impact of Settlement Adjustments	$ Millions	-	(42.1)	(7.6)	(91.2)	(63.6)	(44.8)	(32.3)
Total NPC, Indicative November Update	$ Millions	$798.3	$816.7	$973.1	$1,048.6	$1,038.6	$1,245.7	$1,468.8
Overall Rate Change	($000)	Rate change and rate impacts of indicative NPC not				$6,331	$61,716	$52,473
	Base %	calculated prior to UE 207.				0.7%	6.4%	4.5%
	Net %					0.6%	6.2%	4.5%
Large General Service Rate Change (Sch 48)	($000)					$1,176	$10,896	$10,880
	Base %					0.9%	8.5%	5.9%
	Net %					0.9%	8.7%	6.3%
Final November Update (3)								
Total NPC prior to settlement adjustments	$ Millions	796.5	$875.0	$987.8	$1,134.6	$1,092.3	$1,288.7	$1,496.9
Impact of Settlement Adjustments	$ Millions		(42.1)	(7.6)	(91.2)	(63.6)	(44.8)	(32.3)
Total NPC, Final November Update	$ Millions	$796.5	$832.8	$980.2	$1,043.3	$1,028.8	$1,243.9	$1,464.5
Overall Rate Change	($000)	$2,912	$10,000	$22,422	$9,198	$3,743	$60,881	$51,261
	Base %	0.4%	1.2%	2.5%	1.0%	0.4%	6.3%	4.4%
	Net %	0.4%	1.2%	2.5%	0.9%	0.4%	6.1%	4.4%
Large General Service Rate Change (Sch 48)	($000)	$690	$2,163	$4,850	$2,106	$696	$10,749	$10,643
	Base %	0.5%	1.7%	3.5%	1.3%	0.5%	8.4%	5.8%
	Net %	0.5%	1.7%	3.5%	1.3%	0.5%	8.6%	6.1%
Final Rate Change (4)								
Total NPC	$ Millions	$796.5	$832.8	$980.2	$1,043.3	$1,028.8	$1,237.0	$1,463.1
Overall Rate Change	($000)	No Change	No Change	No Change	No Change	No Change	$59,758	$50,959
	Base %	from Final	from Final	from Final	from Final	from Final	6.2%	4.4%
	Net %	Update	Update	Update	Update	Update	6.0%	4.4%
Large General Service Rate Change (Sch 48)	($000)						$10,541	$10,569
	Base %						8.3%	5.7%
	Net %						8.4%	6.1%
Changes made between final update and actual rate increase:								
Total NPC	$ Millions						$ (6.9)	$ (1.4)
Apply provisions of UM1355							$ (2.6)	
Kennecott price change per new contract							$ (4.3)	
Hourly price scalar updates								$ (1.4)

(1) Prior to 2006, net power cost increases were requested as part of a GRC when a GRC was filed. The TAM adjustment made in November reflects the incremental change only

(2) Final Net Variable Power Costs and final TAM increase were capped as part of an approved settlement.

(3) Indicative and Final November Update total NPC do not include settlement adjustments.

(4) Final November Rate Change total NPC includes settlement adjustments.

ICNU Data Request 5.9

For Oregon, Washington, Utah, Idaho, California, and Wyoming, please provide, on an electronic spreadsheet with all formulae intact, the overall percentage and industrial customer percentages increase in rates that PacifiCorp received for each year since 2000 and provide the specific docket in which the rate increase was authorized.

Response to ICNU Data Request 5.9

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

Please refer to Attachment ICNU 5.9, which provides overall and industrial revenue percentage changes for Oregon, Washington, Utah, Idaho, California, and Wyoming. The attachment includes surcharges and credits.

OR UE 245
ICNU 5.9

Oregon Docket/Advice No.	Filing	Rate Effective Date	Net Change Total %	Net Change Industrial %
00-008	AFOR, DSM & Decoupling	7/1/00	1.8	1.1
UE 111	General	10/1/00	1.8	0.4
00-017	Y2K, Centralia Credit & Merger Credit	1/1/01	(4.0)	(4.9)
UE 121/01-002	Deferred Accounting Adj.	2/21/01	3.0	4.2
01-014	AFOR	7/1/01	1.0	(0.2)
UE 116	General	9/10/01	0.6	(3.0)
UE 116	Public Purpose	3/1/02	3.0	3.0
UE 135/02-003	SB 1149 Implementation Costs	3/6/02	0.3	0.7
02-009	Merger Credit Revision	4/2/02	0.2	0.2
UE-134	Base, PCS, Hermiston & Trail Mountain (UE-134)	6/1/02	2.0	1.8
02-015	AFOR	7/17/02	(0.2)	(0.1)
02-022	Decoupling - Commercial	8/7/02	0.3	0.0
UE 127/01-021	Deferred Accounting Adj.	8/8/02	2.8	3.7
02-023	Decoupling - Industrial	9/4/02	(0.1)	(0.6)
02-026	Decoupling - Residential	10/10/02	(1.3)	0.0
03-001	Merger Credit Revision	2/5/03	0.1	0.1
UE 148/03-004	SB 1149 Revision	5/21/03	0.1	0.2
03-006	Removal of Hermiston and Excess NPC Surcharges	7/16/03	(1.9)	(2.7)
UE 147	General	9/1/03	0.8	(0.0)
04-002	SB 1149 Adjustment Revision	4/9/04	0.1	0.2
04-004	SBC Elimination	6/1/04	(2.8)	(3.0)
04-006	Merger Credit Elimination	7/6/04	0.5	0.5
04-012	Sale of Halsey Credit Elimination	10/6/04	0.4	0.1
05-002	SB 1149 Adjustment Revision	3/23/05	0.1	0.1
05-007	Deferred Accounting Adj. Cancellation	7/25/05	(5.8)	(7.8)
UE 170	General	10/4/05	3.2	4.2
05-014	Cancel Centralia Credit	11/9/05	3.4	4.8
UE 170	TAM	1/1/06	0.4	0.5
06-002	Cancel Y2K Surcharge	2/22/06	(0.0)	(0.1)
UE 170/06-011	Klamath Basin Irrigation Year 1	4/17/06	0.2	0.2
06-008, 06-010	SB1149 Phase VI plus Shopping Incen. Surcharge	5/12/06	0.3	0.5
UE 170	GRC reconsideration	7/21/06	0.8	1.0
06-015	BPA Credit Reduction	10/1/06	0.9	0.0
UE 179, 06-016	GRC, TAM and Transaction and Def. Tax Adj.	1/1/07	5.6	5.8
07-004	Misc. Deferred Accounts Credit Elimination	2/28/07	0.2	0.3
07-005	SB1149 Phase VII	3/15/07	0.2	0.6
07-010, 07-013	Intervenor Funding and BPA Credit Suspension	6/1/07	6.5	0.5
07-015	Cancel Trail Mine Surcharge	8/23/07	(0.3)	(0.4)
UE 191	TAM	1/1/08	2.5	3.5
07-022, 07-026	ECC and Transaction and Def. Tax Adj. Elimination	1/25/08	0.7	(0.1)
08-004	Klamath Irrigation Year 3 and Large SB1149 Adj. Elim.	4/17/08	(0.8)	(2.3)
UE 177, 08-008	Income Tax Adjustment and Intervenor Funding	6/1/08	2.9	4.4
08-011	BPA Credit Return	11/1/08	(2.2)	(0.0)
08-016	Residential & Small SB1149 Adj. Elimination	11/26/08	(0.2)	0.0
UE 199, UE 200, 08-019, 08-017, 08-01	TAM, RAC, Renew Def, Ind. Evaluator, Property Sales	1/1/09	4.8	6.5
09-001	RAC Revision	1/21/09	0.6	0.8
09-004, 09-005	Intervenor Funding and Shopping Incen. Surcharge	2/25/09	(0.2)	(0.4)
09-006	Klamath Irrigation Year 4	4/17/09	0.0	(0.1)
UE 177	Income Tax Adjustment	06/09	(0.8)	(1.1)
09-013	BPA Credit Increase	10/09	(0.7)	(0.0)
UE 207, 09-015, 09-017	TAM, RAC Deferral, ECC	1/10	1.0	(0.2)
UE 210	General	2/10	4.8	5.4
UE 219	Klamath Dam Removal Surcharges	3/10	1.7	2.0
10-004	Shoping Incentive Surcharge Cancellation	3/10	(0.0)	0.0
09-018	ECC	4/10	0.1	0.0
10-006	RAC Deferral	4/10	0.1	0.2
10-011	Income Tax Adjustment	6/10	(1.5)	(2.1)
10-015, 10-014	Prop. Sales and Trans. Plan-Oregon Cancellation	8/10	(0.1)	(0.1)
UE 217, UE 216, 10-015, 10-021	GRC, TAM, Property Sales, RAC Deferral	1/11	13.8	15.8
11-010	Independent Evaluator	5/11	(0.1)	(0.1)
11-009	Income Tax Adjustment	6/11	1.0	1.4
11-014	BPA Credit Change	10/11	0.5	0.0
11-017	RAC Deferral	11/11	(0.4)	(0.6)
UE 227, 11-019, 11-020, 11-021	TAM, OSIP, ECC, 2010 Protocol Adj.	1/12	4.5	5.9
12-006	Klamath Irrigation Year 7	4/12	0.0	(0.2)
12-009	MEHC CIC Adj Cancelation	5/12	(0.2)	(0.3)
12-010	Income Tax Adjustment Cancelation	5/12	(1.3)	(1.8)

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Washington Docket/Advice No.	Filing	Rate Effective Date	Net Change Total %	Net Change Industrial %
UE-991832 - Year 1	GRC Year 1, Def. Rev. Adj, SBC, Centralia & Merger Credits	1/01	1.1	1.2
UE-991832 - Year 2, Advice 01-017	GRC Year 2, Def Rev Adj Rev, & BPA	1/02	(9.3)	1.9
Advice 02-001	SBC Change	2/02	2.1	2.4
UE-991832 - Year 3	GRC	1/03	(0.1)	(0.7)
Advice 04-05	Merger Credit Elimination	9/04	1.9	1.7
UE-032065	GRC	11/04	8.7	8.2
Advice 05-001	SBC Change	2/05	0.8	0.7
Advice 05-004	SBC Change	4/05	0.3	0.3
Advice 05-005	Centralia Credit Termination	6/05	3.0	2.8
Advice 06-005&006	BPA & SBC Reductions	11/06	1.0	(1.0)
Advice 7-04	BPA Elimination	6/07	7.6	0.0
UE-061546	GRC	6/07	6.1	6.5
UE-061546-reconsideration	GRC and MEHC Credit	8/07	(0.3)	(0.3)
Advice 08-04	MEHC Credit Elimination	7/08	0.3	0.3
UE-080220	GRC and Hydro Deferral	10/08	8.4	8.6
Advice 08-05	BPA Credit Reinstated	11/08	(1.8)	0.0
Advice 09-03	BPA Credit Change	10/09	(1.4)	0.0
Advice 09-05	SBC Change	10/09	1.7	1.7
UE-090205	GRC	1/10	5.2	5.1
UE-100749	GRC/REC	4/11	10.4	11.4
Advice 11-02	BPA Credit Decrease	10/11	0.2	0.0

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Utah Docket/Advice No.	Filing	Rate Effective Date	Net Change Total %	Net Change Industrial %
Advice 99-03	Merger Credit	1/00	(2.0)	(1.8)
99-035-10	GRC	5/00	2.5	1.0
99-035-10	GRC Reconsideration	10/00	0.0	0.0
01-035-01 interim	GRC Interim	2/01	10.4	10.3
Advice 01-05	Merger Credit Reduction	4/01	0.8	0.8
01-035-01	GRC	11/01	(3.9)	(3.2)
03-2035-02 interim	GRC Interim	11/01	3.6	3.5
Advice 02-06	Merger Credit Removal	5/02	1.0	1.0
03-2035-02	GRC	4/04	3.7	4.0
02-2035-T12	DSM	4/04	3.0	3.0
04-035-42	GRC	3/05	4.7	4.2
Advice 06-06	DSM	8/06	(0.8)	(0.8)
06-035-21 interim credit	GRC Phase I	12/06	7.2	7.4
06-035-21	GRC Phase II	6/07	2.4	2.5
07-035-93	GRC Phase I	8/08	3.0	2.7
08-035-38	GRC Phase II	5/09	3.3	3.9
Advice 09-08	DSM	9/09	2.5	2.4
09-035-23	GRC	2/10	2.3	3.0
10-035-13/14/89, Advice 10-13	MPA and DSM	1/11	2.5	3.0
Advice 11-08	MPA Deferral Ending	9/11	(1.5)	(1.8)
10-035-124	GRC and REC	9/11	6.7	7.6
Advice 11-13	DSM Decrease	2/12	(0.5)	(0.5)

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Idaho Filing	Rate Effective Date	Net Change Total %	Net Change Industrial %
Merger Credit	01/00	(1.9)	(1.7)
BPA	06/00	3.9	0.0
BPA	02/02	(34.7)	0.0
Power Cost	6/02	28.6	4.0
BPA	2/03	6.8	0.0
Power Cost, Second Year	6/03	(9.2)	0.0
RMA 3rd Year, Power Cost/Tax, BPA reduction	6/04	(2.0)	(0.0)
BPA Reduction	1/05	8.1	0.0
GRC	9/05	2.2	1.7
Customer Efficiency Serv Rate Adj	5/06	2.0	1.5
Rate Change for Irrg. and Spcl Contr.	1/07	2.4	0.0
BPA	2/07	3.9	0.0
BPA Elimination (non-irrigation)	6/07	11.8	0.0
BPA Elimination (Irrigation)	7/07	10.9	0.0
GRC	1/08	3.7	0.0
Customer Efficiency Serv Rate Adj	5/08	2.2	2.2
GRC	4/09	3.1	5.9
ECAM	4/10	1.4	2.0
Customer Efficiency Serv Rate Adj	7/10	1.0	1.0
GRC and DSM	12/10	4.1	5.8
ECAM	4/11	5.8	8.6
GRC Reconsideration	4/11	0.2	0.3
BPA	12/11	(1.9)	0.0
GRC	1/12	7.4	7.0

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California Filing	Rate Effective Date	Net Change Total %	Net Change Industrial %
Interim Surcharge	6/02	9.3	0.0
General	12/03	4.5	0.0
General	1/07	10.6	7.5
CARE Surcharge	1/07	1.1	1.8
CPUC Surcharge	7/07	0.1	0.2
ECAC	1/08	7.0	10.7
PTAM Attrition	1/08	1.6	1.4
DSM	2/08	1.2	1.0
Klamath Transition Rate	4/08	1.0	0.0
PTAM Cap. Adds.	8/08	0.8	0.7
Intervenor Funding	9/08	0.4	0.5
PTAM Cap. Adds.	11/08	1.2	1.0
ECAC, PTAM Att., CARE/LIEE	1/09	7.2	9.6
PTAM Cap Adds.	03/09	1.5	1.2
Klamath Transition Rate	04/09	0.9	0.0
Cancel Intervenor Funding	7/09	(0.3)	(0.5)
PTAM Cap Adds.	11/09	0.6	0.5
ECAC, PTAM Attrition	1/10	(4.2)	(6.5)
Klamath Transition Rate (to Standard Tariff)	4/10	0.9	0.0
PTAM Cap Adds.	5/10	0.7	0.6
GRC, ECAC, PTAM Cap Adds., CEMA	1/11	17.3	22.5
Solar Incentive	5/11	1.1	1.2
LIEE	5/11	(0.8)	(0.8)
DSM	10/11	(1.1)	(1.0)
PTAM Cap. Adds.	12/11	0.3	0.3
PTAM Attrition, Cancel CEMA	1/12	(0.4)	0.2
Klamath Dam Removal Surcharge	1/12	1.8	2.0
ECAC	3/12	1.6	2.4

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		Net Change	
		Total	Industrial
Wyoming East Territory Filing (2000-2005)	**Rate Effective Date**	%	%
General Year 1 of 2	5/00	4.8	3.6
Partial Requirements Svc.	7/00	0.6	1.2
Centralia Credit	10/00	(3.4)	(4.0)
Centralia Change	7/01	(0.6)	(0.7)
General Year 2 of 2	8/01	3.6	4.0
Centralia Elimination	8/02	3.9	3.6
General	3/03	2.9	2.5
General	3/04	7.2	7.4
Power Cost Adjustment	9/04	2.7	2.7

		Net Change	
		Total	Industrial
Wyoming West Territory Filing (2000-2005)	**Rate Effective Date**	%	%
General Year 1 of 2	5/00	1.6	1.0
Partial Requirements Svc.	7/00	0.0	0.0
Centralia Credit	10/00	(3.0)	(3.8)
Centralia Change	7/01	(0.5)	(0.7)
General Year 2 of 2	8/01	(2.1)	(2.1)
Centralia Elimination	8/02	3.8	4.3
General	3/03	(13.0)	(12.8)
General	3/04	9.4	9.9
Power Cost Adjustment	9/04	2.7	2.7

		Net Change	
		Total	Industrial
Wyoming Filing (2006-present)	**Rate Effective Date**	%	%
General-Phase I	3/06	4.1	3.8
General-Phase II	7/06	2.6	3.0
PCAM Deferred NPC	4/07	0.7	0.9
PCAM Deferred NPC	7/07	(0.1)	(0.0)
PCAM Deferred NPC	4/08	7.9	9.5
General	5/08	5.0	6.9
PCAM Deferred NPC	10/08	(0.5)	(0.6)
CESC Charge	01/09	0.9	0.5
PCAM NPC Base & Deferred	04/09	1.4	1.6
Rate Case	05/09	3.7	4.6
PCAM NPC Base & Deferred	09/09	0.0	(0.0)
PCAM Deferred NPC	04/10	(3.7)	(4.3)
Rate Case	07/10	5.0	5.8
CESC Charge	07/10	(0.1)	(0.0)
CESC Charge	01/11	(0.8)	(0.4)
Rate Case - Phase II	02/11	1.9	2.2
PCAM Deferred NPC	04/11	2.0	2.2
Rate Case	09/11	7.7	8.1
PCAM Deferred NPC	11/11	(0.4)	(0.5)
DSM Category 2	03/12	0.2	0.0
DSM Category 1 and 3	03/12	0.5	0.4
PCAM Deferred NPC	04/12	(2.0)	(2.3)
REC & SO2 Adj	05/12	0.2	0.2

ECAM Deferred NPC	05/12	4.8	5.8