ROCKY MOUNTAIN
POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

September 3, 2008

VIA OVERNIGHT DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 07-035-93
In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge

Rocky Mountain Power hereby submits for filing an original and fifteen copies of the Cost of Service Rebuttal Testimony and Exhibits in the above referenced docket. Enclosed for electronic filing is a CD containing an electronic copy of the testimony and exhibits in the file formats in which they were created. The rebuttal testimony and exhibits in this filing reflect the $36.164 million rate increase ordered in this docket by Public Service Commission of Utah in its phase 1 erratum order on revenue requirement issued August 21, 2008.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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

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

Informal inquiries may be directed to Dave Taylor at (801) 220-2923.

Sincerely,

Jeffrey Larsen /

Jeffrey K. Larsen
Vice President, Regulation

Enclosures
cc: Service List in Docket No. 07-035-93

CERTIFICATE OF SERVICE

I hereby certify that on this 3rd day of September, 2008, I caused to be mailed overnight, postage prepaid, a true and correct copy of a CD containing the Cost of Service Rebuttal Testimony and Exhibits of Rocky Mountain Power in Docket No. 07-035-93 to the following:

F. Robert Reeder
William J. Evans
Vicki M. Baldwin
Parsons Behle &, Latimer
201 South Main Street, Suite 1800
Salt Lake City, Utah 84111
bobreeder@parsonsbehle.com
bevans@parsonsbehle.com
vbaldwin@parsonsbehle.com

Paul Proctor
Utah Committee of Consumer Services
Heber M. Wells Bldg., Fifth Floor
160 East 300 South
Salt Lake City, UT 84111
pproctor@utah.gov

Dennis Miller
William Powell
Philip Powlick
Division of Public Utilities
Heber M. Wells Building
160 East 300 South, 4th Floor
Salt Lake City, UT 84111
dennismiller@utah.gov
wpowell@utah.gov
philippowlick@utah.gov

Rick Anderson
Kevin Higgins
Neal Townsend
Energy Strategies, Inc.
215 South State Street, Suite 200
Salt Lake City, UT 84111
randerson@energystrat.com
khiggins@energystrat.com
ntownsend@energystrat.com

Cheryl Murray
Dan Gimble
Michele Beck
Committee of Consumer Services
160 East 300 South, 2nd Floor
Salt Lake City, UT 84111
cmurray@utah.gov
dgimble@utah.gov
mbeck@utah.gov

Gary A. Dodge
Hatch James & Dodge
10 West Broadway, Suite 400
Salt Lake City, UT 84101
gdodge@hjdlaw.com

Michael Ginsberg
Patricia Schmid
Assistant Attorney General
Utah Division of Public Utilities
Heber M. Wells Bldg., Fifth Floor
160 East 300 South
Salt Lake City, UT 84111
mginsberg@utah.gov
pschmid@utah.gov

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
Ph: 513-421-2255 Fax: 513-421-2764
mkurtz@bkllawfirm.com
kboehm@bkllawfirm.com

Arthur F. Sandack
Attorney for Petitioner IBEW Local 57
8 East Broadway, Ste 510
Salt Lake City, Utah 84111
Telephone: (801) 532-7858
asandack@msn.com

Roger J Ball
1375 Vintry Lane
Salt Lake City, Utah 84121
(801) 277-1375
ball.roger@gmail.com

Roger Swenson
US Magnesium LLC
238 North 2200 West
Salt Lake City, Utah 84116
Roger.swenson@prodigy.net

Stephen F. Mecham
Callister Nebeker & McCullough
10 East South Temple, Suite 900
Salt Lake City, UT 84133
sfmecham@cnmlaw.com

Betsy Wolf
Utah Ratepayers Alliance
Salt Lake Community Action Program
764 South 200 West
Salt Lake City, Utah 84101
bwolf@slcap.org

Craig Cox
Executive Director
Interwest Energy Alliance
P.O. Box 272
Conifer, Colorado 80433
cox@interwest.org

Stephen R. Randle
Stephen R. Randle P.C.
Attorney for Utah Farm Bureau Federation
664 N Liston Cir.
Kaysville, UT 84037
s.randle@yahoo.com

Steven S. Michel
Western Resource Advocates
2025 Senda de Andres
Santa Fe, NM 87501
smichel@westernresources.org

Mike Mendelsohn (Email Only)
Penny Anderson (Email Only)
Western Resource Advocates
2260 Baseline Rd, Suite 200
Boulder, CO 80302
mmendelsohn@westernresources.org
penny@westernresources.org

Sarah Wright
Executive Director
Utah Clean Energy
1014 2nd Avenue
Salt Lake City, UT 84103
sarah@utahcleanenergy.org

Gerald H. Kinghorn
Jeremy R. Cook
Parsons Kinghorn Harris, P.C.
111 East Broadway, 11th Floor
Salt Lake City, UT 84111
ghk@pkhlawyers.com
jrc@pkhlawyers.com

Peter J. Mattheis
Eric J. Lacey
Brickfield, Burchette, Ritts & Stone, P.C.
1025 Thomas Jefferson Street, N.W.
800 West Tower
Washington, D.C. 20007
pjm@bbrslaw.com
elacey@bbrslaw.com

Ronald J. Day, CPA
Central Valley Water Reclamation Facility
800 West Central Valley Road
Salt Lake City, UT 84119
dayr@cvwrf.org

Holly Rachel Smith, Esq.
Russell W. Ray, PLLC
6212-A Old Franconia Road
Alexandria, VA 22310
holly@raysmithlaw.com

Mr. Ryan L. Kelly
Kelly & Bramwell, PC
Attorneys at Law
11576 South State Street Bldg. 203
Draper, UT 84020
ryan@kellybramwell.com

Todd R. Bingham
Randy Parker
Utah Farm Bureau Federation
V.P. Public Policy
9865 South State Street
Sandy, Utah 84070-3205
Todd.Bingham@fbfs.com
rparker@fbfs.com

Dale F. Gardiner
Van Cott, Bagley, Cornwall & McCarthy
36 South State Street, Suite 1900
Salt Lake City, Utah 84111
E-mail: dgardiner@vancott.com

Janee Briesemeister
AARP
98 San Jacinto Blvd. Ste. 750
Austin, TX 78701
E-mail: jbriesemeister@aarp.org

Steve W. Chriss
Wal-Mart Stores, Inc.
2001 SE 10th Street
Bentonville, AR 72716-0550
stephen.chriss@wal-mart.com

Carrie Meyer

Carrie Meyer
Coordinator, Administrative Services

William R. Griffith

Rocky Mountain Power
Docket No. 07-035-93
Witness: William R. Griffith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of William R. Griffith

Rate Spread and Rate Design

September 2008

Q. Are you the same William R. Griffith who has previously testified in this proceeding?

A. Yes I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to:

- Provide an updated rate spread and rate design proposal that reflects the Commission's ordered revenue requirement issued in its Erratum Report and Order on Revenue Requirement on August 21, 2008 in Phase I of this docket.
- Address issues raised in this docket concerning the Company's proposed marginal cost-based pricing proposal, Schedule 500.
- Recommend that the proposed street lighting changes sponsored in the direct testimony of Mr. Daren H. Dixon go into effect.

Updated Rate Spread and Rate Design Exhibit

Q. Please explain Exhibit RMP___(WRG-1R-COS).

A. Exhibit RMP___(WRG-1R-COS) contains the proposed rate spread and rate design for all rate schedules in this case that reflect the Commission-ordered revenue requirement of $36.16 million.

Rate Spread

Q. What modifications has the Company made to its rate spread proposal and methodology filed in your direct and supplemental direct testimony in this docket?

A. The Company had proposed for rate schedule classes falling within four percentage points of the overall proposed rate change, that a uniform percentage increase be applied. The Company also, based on cost of service results, supported an increase of two times the overall average for Schedule 10 and a smaller increase than other rate schedules for Schedule 6. However, based on the size of the increase ordered in this case, Rocky Mountain Power believes that a uniform percentage increase across all tariff schedules as ordered by the Commission in Phase I and implemented through Schedule 97 of this docket is reasonable and should continue to apply. With the level of this price change, any deviations from the equal percentage rate spread ordered in Phase I would have minimal impacts on overall rate levels and would do little to reconcile any subsidization across customer classes.

Rate Design Update

Q. What modifications has the Company made to its rate design proposals as a result of the Commission's order in Phase I of this docket?

A. Based on the Commission's order in Phase I of this docket, the Company proposes that the present Tariff Rate Rider, equal to 2.72 percent of the monthly charges of the customer's applicable schedule, continue to be applied and that no further rate design changes be ordered in this case.

Q. Please explain why the Company has changed its rate design proposals for residential customers.

A. With the ordered revenue requirement in this case, the Company's original rate design proposals for residential customers cannot be implemented without creating unintended consequences that will not send proper price signals to customers. In my direct and supplemental testimony the Company proposed a residential Monthly Customer Charge equal to $4.00 per month based on the Utah Public Service Commission's methodology for determining a customer charge. Using the updated cost of service study results prepared by Mr. C. Craig Paice and filed in his rebuttal testimony, a $4.00 customer charge is still fully supported based on the Utah Public Service Commission's methodology for determining a customer charge. However, based on the ordered revenue requirement in this case, implementation of a $4.00 customer charge would result in an overall reduction in residential energy charges. During a period of rising costs, we do not believe that reducing energy charges overall is the appropriate price signal to send to customers.

Q. Please explain the Company's updated proposal for the Customer Load Charge and residential energy charge rate design.

A. Similar to the Monthly Customer Charge results discussed above, based on the ordered revenue requirement in this docket, implementation of the proposed Customer Load Charge would lead to reductions in residential energy charges overall. The Company withdraws the Customer Load Charge along with the proposed changes to residential energy charge rate design from this docket and will address those in the next general rate case.

Alternative Pricing Proposal for New Large Loads

Q. Does the Company have a response to other parties' testimonies concerning the Company's proposed tariff for new large loads, Schedule 500?

A. Yes. As stated in my direct testimony, we expected that this proposal would generate a high level of interest and that it would be controversial. Indeed, the

Schedule 500 proposal generated significant interest and controversy among the parties. Given the wide range of opinions expressed, and the importance of these issues for the Company and our customers, we agree with the DPU, CCS and others who recommend that the Commission set up a collaborative process to study load growth and marginal cost-based pricing issues. We are currently engaged in a collaborative process in Wyoming and believe that this approach can be worthwhile.

Proposed Street Lighting Changes

Q. What does the Company recommend concerning the proposed street lighting changes sponsored in the direct testimony of Mr. Dixon?

A. As Mr. Dixon indicated in his direct testimony, there is no revenue impact of his proposed changes for existing services being delivered. Given that no party filed any objections to his proposals in this docket, the Company recommends that Mr. Dixon's proposed changes be approved by the Commission as filed.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Rocky Mountain Power
Exhibit RMP___(WRG-1R-COS)
Docket No. 07-035-93
Witness: William R. Griffith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of William R. Griffith

Table A – Estimated Effect of Proposed Changes

September 2008

Rocky Mountain Power
Estimated Effect of Proposed Changes
on Revenues from Electric Sales to Ultimate Consumers in Utah
Historical Test Period 12 Months Ending June, 2007
Forecast Test Period 12 Months Ending December 2008

Line No.	Description (1)	Pre. Sch No. (2)	Pro. Sch No. (3)	No. of Customers Forecast (4)	MWh Forecast (5)	Present Revenues ($000) (6)	Proposed Revenues ($000) (7)	Change (8) (7)-(6)	(%) (9) (8)/(6)	Avg ¢/kWh (10) (7)/(5)
	Residential									
1	Residential	1,3	1,3	707,670	6,554,695	$539,434	$554,102	$14,668	2.72%	8.45
2	Residential-Optional TOD	2	2	392	3,215	$259	$266	$7	2.72%	8.28
3	Residential-Mobile Homes	25	25	11	11,203	$756	$776	$21	2.72%	6.93
4	AGA/Revenue Credit	--	--			$27	$27	$0	0.00%	
5	**Total Residential**			708,073	6,569,113	$540,476	$555,172	$14,695	2.72%	8.45
	Commercial & Industrial [1]									
6	General Service-Distribution	6	6	12,751	5,530,768	$358,286	$368,028	$9,742	2.72%	6.65
7	General Service-Distribution-Energy TOD	6A	6A	1,925	263,939	$22,382	$22,990	$609	2.72%	8.71
8	General Service-Distribution-Demand TOD	6B	6B	16	5,383	$372	$382	$10	2.72%	7.10
9	*Subtotal Schedule 6*			14,692	5,800,090	$381,039	$391,400	$10,361	2.72%	6.75
10	General Service-Distribution > 1,000 kW	8	8	260	2,018,303	$114,861	$117,984	$3,123	2.72%	5.85
11	General Service-High Voltage	9	9	149	4,199,353	$167,830	$172,393	$4,563	2.72%	4.11
12	General Service-High Voltage-Energy TOD	9A	9A	10	50,543	$2,599	$2,670	$71	2.72%	5.28
13	*Subtotal Schedule 9*			159	4,249,896	$170,429	$175,063	$4,634	2.72%	4.12
14	Irrigation	10	10	2,335	169,587	$9,248	$9,500	$251	2.72%	5.60
15	Irrigation-Time of Day	10TOD	10TOD	244	13,541	$746	$766	$20	2.72%	5.66
16	*Subtotal Irrigation*			2,579	183,128	$9,994	$10,266	$272	2.72%	5.61
17	Electric Furnace	21	21	5	3,543	$298	$306	$8	2.72%	8.64
18	General Service-Distribution-Small	23	23	68,927	1,284,629	$97,624	$100,278	$2,654	2.72%	7.81
19	Back-up, Maintenance, & Supplementary	31	31	4	17,085	$1,162	$1,194	$32	2.72%	6.99
20	Special Contracts	--	--	4	2,390,115	$76,797	$76,797	$0	0.00%	3.21
21	AGA/Revenue Credit	--	--			$2,716	$2,716	$0	0.00%	
22	**Total Commercial & Industrial**			86,630	15,946,789	$854,921	$876,005	$21,084	2.47%	5.49
23	**Total C & I (excl. Special Contracts & AGA)**			86,626	13,556,674	$775,407	$796,491	$21,084	2.72%	5.88
	Public Street Lighting									
24	Security Area Lighting	7	7	8,637	13,717	$3,067	$3,150	$83	2.72%	22.97
25	Street Lighting - Company Owned	11	11	1,130	22,151	$5,983	$6,146	$163	2.72%	27.74
26	Street Lighting - Customer Owned	12	12	493	10,473	$1,096	$1,126	$30	2.72%	10.75
27	Traffic Signal Systems	12	12	2,039	4,718	$400	$410	$11	2.72%	8.70
28	Metered Outdoor Lighting	12	12	310	10,375	$731	$751	$20	2.72%	7.24
29	Decorative Street Lighting	13	13	353	41,473	$2,883	$2,961	$78	2.72%	7.14
30	*Subtotal Public Street Lighting*			12,963	102,907	$14,159	$14,544	$385	2.72%	14.13
31	Security Area Lighting-Contracts (PTL)	--	--	70	275	$21	$21	$0	0.00%	7.51
32	Street Lighting-Contracts (66, 77)	--	--	2	141	$17	$17	$0	0.00%	12.31
33	AGA/Revenue Credit	--	--		--	$5	$5	$0	0.00%	
34	**Total Public Street Lighting**			13,034	103,323	$14,202	$14,587	$385	2.71%	14.12
35	**Total Sales to Ultimate Customers**			807,738	22,619,224	$1,409,599	$1,445,763	$36,164	2.57%	6.39
36	**Total Sales to Ultimate Customers (excluding special contracts, AGA)**			807,662	20,228,694	$1,330,016	$1,366,180	$36,164	2.72%	6.75

1. Includes OSPA.

Rocky Mountain Power
Docket No. 07-035-93
Witness: C. Craig Paice

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of C. Craig Paice

Cost of Service

September 2008

Q. Are you the same C. Craig Paice who has previously testified in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony I present PacifiCorp's 2008 Class Cost of Service Study based on the twelve month future test period ending December 31, 2008 that has been updated to correspond with the revenue requirement ordered by the Utah Public Service Commission on August 13, 2008. Additionally, I respond to the testimony of CCS witness Mr. Paul Chernick, UIEC witness Mr. Maurice Brubaker, UAE witness Mr. Kevin Higgins, and WRA/UCE witness Mr. Richard Collins.

Summary of Results

Q. Please identify Exhibit RMP___(CCP-1R-COS) and explain what it shows.

A. Exhibit RMP___(CCP-1R-COS) is the summary table from PacifiCorp's December 31, 2008 Class Cost of Service Study for the State of Utah. It is based on PacifiCorp's revised annual results of operations for the State of Utah presented in the rebuttal testimony of Company witness Steven McDougal as modified by the Commission's final revenue requirement order in this case. Page 1 of Exhibit RMP___(CCP-1R-COS) presents results at the Company's December 2008 rate of return assuming current rate levels. Page 2 shows the results using the return provided by the Commission ordered price increase of $36.2 million. It also reflects changes to the distribution substations peaks per the analysis presented by Company witness Mr. Lowell E. Alt.

Q. Please identify Exhibit RMP___(CCP-2R-COS) and explain what it shows.

A. Exhibit RMP___(CCP-2R-COS) shows the cost of service results in more detail by class and by function. Page 1 summarizes the total cost of service summary by class and pages 2 through 6 contain a summary by class for each major function.

Rebuttal of Mr. Paul Chernick & Mr. Maurice Brubaker

Q. Do you agree with Mr. Chernick that the cost of service study filed in this docket understates the energy-related cost of generation?

A. No, I do not. The cost of service study employs the Utah Public Service Commission approved 75 percent demand and 25 percent energy classification methodology for generation and transmission costs. No generation related costs (including seasonal resources) are classified 100 percent demand-related as Mr. Chernick claims. Exhibit RMP___(CCP-3S), Tab 1, Page 8 explains in detail the use of the 75 percent demand and 25 percent energy methodology to classify generation and transmission costs and Tab 4, Pages 1-18 of the same exhibit identifies all the allocation factors employed in the cost of service study.

Q. Mr. Brubaker also argues for a change in the classification of generation and transmission costs. Do you agree with his recommendation that generation and transmission fixed costs should be classified as 100 percent demand related?

A. No. PacifiCorp's generation portfolio includes different types of resources including coal fired steam plants, hydro facilities, simple and combined cycle gas combustion turbines, wind turbines, and purchases. Although it may be reasonable to classify the fixed costs of simple cycle combustion turbines and other peaking resources 100 percent demand related (which are designed to run during peak load hours only) such a classification would not be appropriate for the majority of PacifiCorp's portfolio. The Company's resource fleet is heavily skewed toward base load plants that were constructed not only to meet peak load, but also to produce low cost kilowatt-hours 24 hours per day, 7 days per week as needed to provide the energy requirements of all customers. The capital investment of a coal fired steam plant and other base load plants is greater than the capital investment of a peaking turbine. This additional investment was made, not to meet the peaking needs of the Company, but to generate lower cost kilowatt hours. Therefore, it would seem reasonable that some of the additional capital investment be classified as energy related.

Classification of Generation and Transmission Costs

Q. Please explain why the current methodology employed in the Company's cost of service study is appropriate for the state of Utah?

A. This classification issue was one of the first raised at the time of the Utah Power - Pacific Power merger because both companies previously utilized different generation fixed cost classification methodologies. Since the newly merged company created a combined system involving seven states it was necessary to find a common methodology suitable to all parties. Studies were conducted by the Division of Public Utilities (DPU) to determine the cause of production capacity costs with their conclusions being adopted by the Commission staffs of the states served by the Company to allocate jurisdictional costs. This methodology was also used in Docket 90-035-06, the first post-merger case to allocate cost of service. Several years following this docket, the DPU studies were updated and the same conclusions were reached. Since it was first introduced, the mix of 75 percent demand and 25 percent energy has been considered by the Commission to be reasonable. The Commission's position, as stated in Section IV. A.2. of the order issued in Docket 97-035-01, provides the basis for use of this allocation methodology:

> "We conclude that twelve monthly coincident peaks, with a 75 percent demand-related and 25 percent energy-related mix, is the appropriate basis for allocating production and transmission costs to classes in the Utah jurisdiction."

The classification of generation and transmission costs was addressed at length during the Multi-State Process (MSP) discussions. Several approaches were discussed, including those recommended in this case by Mr. Chernick and Mr. Brubaker. As with the earlier PacifiCorp Interjurisdictional Taskforce on Allocations (PITA) analysis, no clearly superior demand/energy classification split emerged from analyses conducted during the Multi-State Process. Because the 75 percent demand and 25 percent energy classification of generation fixed costs currently used by PacifiCorp falls in the middle of the range of reasonable approaches, the Company found no compelling reason to change the approach.

Q. Have changes to the 75 percent demand and 25 percent energy allocation method been proposed in previous rate cases?

A. Yes. In Docket 01-035-01, USEA (United States Executive Agencies) witness Mr. Joseph Herz argued in support of 100 percent demand classification of generation fixed costs. He concluded that the 75 percent demand and 25 percent energy classification was inappropriate "in that a portion of its demand related costs are allocated according to energy use." The Company provided testimony in support of the 75 percent demand and 25 percent energy classification in this same docket. RMP witness Mr. David L. Taylor stated:

> "PacifiCorp classifies production and transmission plant and non-fuel related expenses as 75 percent demand and 25 percent energy related. The Company's goal is to supply the lowest total cost generation resources to meet our customers' needs." (Docket 01-035-01, Taylor rebuttal, page 8).

In addition Dr. George Compton, of the DPU, also responded to Mr. Herz' recommendations and conducted additional analysis on the classification question.

Q. What were the results of Dr. Compton's analysis?

A. The analysis performed by Dr. Compton determined that a portion of the fixed costs associated with generation plants are energy-related and that it is entirely appropriate to allocate some of these costs in proportion to energy consumption. Regarding the quantity of energy-related of fixed costs, Dr. Compton's rebuttal testimony in the aforementioned docket illustrates continued support for the approved methodology where he stated that "… the 25% figure is reasonable." (Docket 01-035-01, Compton Rebuttal, page 3)

Q. Are the peaker and new generation plant approaches presented by Mr. Chernick appropriate methods of determining energy-related generation plant costs?

A. No. The intended objective is to allocate production costs to customer classes consistent with the cost impacts imposed on the system. While classifying some portion of generation fixed as energy-related is appropriate, Mr. Chernick's methods, in my view, reflect a bias toward classifying an excessive portion of generation costs as energy-related. The 1992 *Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Utility Commissioners (NARUC) states that using the peaker method generally results in significant portions (between 40 to 75 percent) of generation costs being classified as energy-related. Mr. Chernick's testimony validates this concern stating that his approaches suggest generation costs should be 32 to 80 percent energy-related.

In addition, neither is appropriate because they apply simple calculations to a very complex issue. The complexities involved in determining a proper allocation cannot be underestimated. Perhaps this is best summarized by Dr. Compton, again in rebuttal testimony in Docket 01-035-01, where he referenced the difficulty involved in calculating an appropriate demand and energy classification mix. His expert opinion provides guidance on this subject:

> "To perform a definitive analysis employing all (or even a large portion of) the elements of the PacifiCorp demand/profile and resources would be horrendously complex." (Docket 01-035-01, Compton Rebuttal, page 3)

Lack of complexity suggests that neither approach presented by Mr. Chernick meets the qualifications of a definitive analysis.

Q. How should we view Mr. Chernick's recommended changes in the energy allocation of generation-related costs?

A. These recommended changes should be rejected for the following reasons:

- This subject has received significant attention throughout the years following the Utah Power - Pacific Power merger. The PacifiCorp Interjurisdictional

Task Force on Allocations (PITA), the Multi-State Process (MSP) and the 2005 Cost of Service and Rate Design Taskforce have all discussed this subject at length with no resulting changes.

- The Utah PSC gave approval for use of this allocation method in cost of service studies.
- Various analyses have been performed validating reasonableness of the 75 percent demand and 25 percent energy allocation.
- Approaches lacking objectivity and based on simple mathematical computations undermine the importance of determining an appropriate generation cost allocation method. Selection of an appropriate allocation method should be based on costs imposed on the system. They should also require extensive analysis as recommended by Dr. Compton.
- Section III.A.1 of Mr. Chernick's testimony references the impact of changing Factor 10 from 75 percent to 50 percent demand causing a shift of "about \$8.5 million off of Schedules 1, 6, and 23 and about \$3.8 million onto Schedule 8 and 9." The final sentence in this same section states "The demand-related portion of PacifiCorp owned generation, weighted across PacifiCorp's generation mix, <u>may be</u> much lower than 50 percent, so the effects may be much larger." It remains evident from these statements that Mr. Chernick's approaches to increase the energy allocation will create significant cost shifts between the various rate schedules. Since the revenue requirement spread to schedules is generally dependent upon cost-of-service information, a large or abrupt change in cost allocations could ultimately produce large rate

variations and would violate the principle of gradualism. The principle of gradualism has been held by the Utah PSC to be significant in order to avoid significant changes in rates within schedules.

Q. What is Mr. Chernick's position regarding the classification of transmission plant?

A. He is also critical of the 75 percent demand and 25 percent energy allocation of transmission-related costs stating it is likely that over half of the Company's transmission revenue requirement is attributable to energy. The basis for this statement is a simple review of PacifiCorp's 2006 FERC Form 1. In addition, he recommends to the Commission that PacifiCorp be required to undertake a comprehensive analysis of the factors driving transmission investment.

Q. Do you agree with his conclusion regarding energy-related classification of transmission plant?

A. No. RMP allocates transmission costs similar to the allocation of generation costs. This practice is consistent with guidelines cited in the NARUC *Electric Utility Cost Allocation Manual* which states:

> "In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other." (page 75).

RMP's position is in concert with this statement. This position plus the aforementioned reasons cited for maintaining use of the 75 demand and 25 energy allocation for generation costs support the current allocation method.

Additionally, the basis of Mr. Chernick's position is a review of the Company's

FERC Form 1 which he admits did not represent a comprehensive analysis of transmission costs.

Q. Should the Utah PSC consider his recommendation for RMP to undertake a thorough analysis of transmission investment?

A. No. This perspective is contrary to the "burden of proof" argument necessary when recommending allocation changes. As explained by Dr. Compton:

> "The burden of 'proof' to come up with some kind of definitive study incorporating the specifics of PacifiCorp's loads and resources would lie with whomever sought to depart from the established 25%/75% ratio." (Docket 01-035-01, Compton Rebuttal, page 5).

As such, the responsibility to prove the necessity of departing from the approved methodology rests with the recommending party.

Allocation of Firm Purchases and Sales

Q. What is the basis for allocating sales for resale revenue and purchased power expenses as presented in the cost of service study?

A. The basis is the *Allocations Task Force Report to the Utah Public Service Commission* (December 16, 1999, page 21) which states:

> "The PSC indicated in their Order in the last PacifiCorp rate case their desire for consistent application of cost-causal principles in both jurisdictional and class allocation studies. Consistency implies that the same methodology would be used in both the jurisdictional allocation and class cost of service models to allocate similar types of costs."

Sales for Resale revenue / Purchased Power expense allocations presented in the cost-of-service study are consistent with allocations presented in the Jurisdictional Allocation Model (JAM) and comports with the Commission's perspective.

Q. Do you agree with Mr. Chernick's position that Sales for Resale revenue and Purchased Power expenses are inappropriately allocated?

A. No. I disagree with Mr. Chernick's positions for at least two reasons. First of all, Mr. Chernick proposes different allocation procedures for Sales for Resale revenues and Purchased Power expenses. Second, his Sales for Resale revenue allocation proposal is inconsistent with his proposal for the allocation of the cost of the resources supporting those revenues. This allocation issue was raised in Docket 97-035-01 and addressed by the Company and the Division at that time. The Allocation Taskforce arising from that case also addressed this issue. Discussion of this subject contained in the *Allocations Task Force Report to the Utah Public Service Commission* (December 16, 1999, page 13) stated:

> "Early in the task force discussions, the parties agreed with the principle that the sales for resale revenue should be allocated on the same basis as the cost of making the sales. The issue then became how this principle would be implemented. The Division's analysis in the last rate case was based on 1997 data. For task force discussion, the Division updated their analysis using 1998 data (see Appendix). In the meantime, the Company had slightly changed the way the sales for resale revenue were allocated in the class cost of service study. The net result was that both the Division's 1998 analysis and the Company's 1998 cost study results were very similar (60/40 versus 63/47demand/energy split respectively). The Division now believes that the Company's current method is reasonable since the results are close and neither method is entirely accurate."

The cost of service study maintains this proportional perspective when comparing the percent of <u>total</u> sales for resale revenues to <u>total</u> purchased power expenses for all classes. Comparison results are:

Schedules	Sales for Resale	Purchased Power	Variance
Sch 1	30.5%	31.0%	0.5%
Sch 6	29.2%	28.9%	-0.3%
Sch 8	9.2%	9.1%	-0.1%
Sch. 7,11,12	0.2%	0.2%	0.0%
Sch 9	17.6%	17.5%	-0.1%
Sch 10	0.6%	0.6%	0.1%
Sch 12	0.0%	0.0%	0.0%
Sch 12	0.0%	0.0%	0.0%
Sch 23	6.6%	6.6%	0.0%
Sch 25	0.1%	0.1%	0.0%
Cust A	0.9%	0.9%	0.0%
Cust B	2.5%	2.5%	0.0%
Cust C	2.5%	2.5%	0.0%

There is a slight difference of 0.5 percent for Residential Schedule 1. A few other schedules show even smaller differences with no variation for most schedules.

Q. **What conclusion can be drawn from this comparison?**

A. Cost of service study results maintain a consistent allocation between sales for resale revenues and purchased power expenses as expected by the Utah PSC. From my analyses I also conclude that as long as the classification and allocation of sales for resale revenues and purchased power expenses are consistent, the methodology will have very little net impact on the cost of service results.

Q. **Why are his approaches for allocating sales for resale revenues particularly inappropriate?**

A. Mr. Chernick proposed to allocate sales for resale revenue in a manner that is totally inconsistent with his proposal for the allocation of the cost of the resources supporting those revenues. In the cost of service study all costs are first allocated to retail customers. Any revenues that the Company receives from sources other than retail customers (revenue credits), such as sales for resale revenues, are then used to reduce the level of costs that are ultimately collected from those retail customers. As such, revenue credits should be allocated to customer classes in a manner consistent with the costs that support those revenues.

Mr. Chernick's approaches, on the other hand, are predicated on the assumption that customer classes have the right to generation resources proportional to their July peak contribution. These approaches may be acceptable if each class were allocated the cost of generation based on only the July peak. However neither RMP's generation allocation method, which utilizes all 12 coincident peaks, nor Mr. Chernick's proposal for generation costs use this method. Mr. Chernick's proposal is a gross mismatch between how the underlying generation costs are allocated among customer classes and how the sales for resale revenues made possible from those resources are allocated. For example Mr. Chernick's "unused energy/peak" method, as shown in the work papers provided in response to RMP DR 1.4, assumes that during the month of February the residential class is entitled to 66 percent, of the Company's generation resources, but is only responsible for 24 percent of the February generation costs.

Q. What other concerns do you have with Mr. Chernick's proposals for the allocation of sales for resale revenues and purchased power expenses?

A. His proposal would create significant shifts among the classes. It appears that incorporating his recommendations would have significant consequences similar to those for generation and transmission costs. His testimony states that by changing the allocation of the firm non-seasonal purchases component of purchased power expenses to 25 percent demand from 75 percent demand results in a shift of approximately $13 million away from Schedules 1, 6, and 23. Then, a review of his three approaches to allocate sales for resale revenues demonstrates large differences from the cost study. The least variable approach would increase allocation of these revenues to Schedule 1 by a net difference of 27.44 percent. The other approaches illustrate even greater variations for this same schedule. He concludes with the observation that significant allocation changes (i.e., cost shifting) would occur and is supported by his final comment that the "effects on other classes could be material." However, there is no analysis presented to illustrate precisely how significantly these changes would impact all customer classes. Also, there is no attempt to determine if the accepted practice of flowing revenue credits to customer classes in proportion to the share of costs would be maintained.

Q. Please summarize your findings regarding current cost of service study allocation methodologies.

A. The cost of service study filed by the Company is a reasonable representation of cost functionalization, classification, and allocation of the Utah revenue requirement. The 75 percent demand / 25 percent energy allocation accepted by the Utah PSC and used in this study is an appropriate methodology which has been significantly discussed and analyzed. The sales for resale revenue allocation flows to customer classes in proportion to the share of generation costs assigned to them. Mr. Chernick's recommended allocation changes to the cost study would induce cost shifts among customer classes potentially creating large rate change variations across classes. No analyses are provided illustrating 1) total potential class revenue requirement shifts or 2) support for consistent allocations between sales for resale revenue and purchased power expenses. Absent cost movement indication it is impossible to ascertain if gradualism would be preserved.

Rebuttal of Mr. Brubaker concerning 12 CP allocation

Q. Do you agree with Mr. Brubaker's observation that because of growth in summer peak compared to loads in other seasons that it is time to revisit the appropriateness of the 12 coincident peaks (CP) allocation?

A. I agree with his observation that summer peak loads are growing. For this reason, the Company introduced modifications to the allocation of generation fixed costs and net power costs (introduced in Docket 06-035-21) to reflect the impact of seasonal costs and load differences. These modifications represent a first step toward meeting the objective of recognizing seasonal load and cost differences in the cost of service study without causing significant cost shifts between customer classes. However, I do not agree with the appropriateness of revisiting the 12 CP cost allocation methodology for two reasons. First, although RMP is a summer-peaking utility, costs are allocated based on the entire integrated system because that is how the system is planned and dispatched. A 12 CP allocation for system demand costs has been used since the Utah Power - Pacific Power merger in 1989 and continues to be used because it represents actual system operations. It recognizes that each of the monthly peaks is important. Second, it is appropriate for allocation methods to be consistent between interjurisdictional and class cost of service allocations. These two positions comport with Utah PSC findings (see order in Docket 97-035-01, Section IV.A.2, 4 respectively). Mr. Brubaker references revisiting the use of 12 coincident peaks to allocate generation among classes but presents no analysis in support of his statement. As discussed earlier in my testimony, deviation from the presently accepted methodology should be accompanied by "definitive analysis" from the recommending party.

Rebuttal of Mr. Kevin Higgins

Q. Do you agree with Mr. Higgins assessment that the Company's treatment of the MSP Rate Mitigation Cap in the class cost of service approach is incorrect?

A. No. While I agree there may be alternative approaches, I do not believe the method employed in our filed study produced a conceptual error. The Company's cost of service treatment of the MSP Rate Mitigation Cap is consistent with our representations before the Utah Commission in the hearing to approve the MSP Stipulation held on July 19, 2004.

Q. Why does Mr. Higgins feel the Company's approach is incorrect?

A. Rather than view the impacts of the Rate Mitigation Cap as a reduction in the Company's return on rate base, he views the Cap as a reduction in the allocation of generation costs to Utah. He recommends that the impact of the Rate Mitigation Cap be reflected as a reduction to generation expense so that the Company return is unaffected.

Q. Do you agree with the way he has portrayed the impact of the Rate Mitigation Cap?

A. No. The Rate Mitigation Cap does not reduce the allocation of costs to Utah.

The MSP Revised Protocol as stipulated by the Utah parties, including those represented by Mr. Higgins, and approved by the Utah Commission is the methodology used to allocate costs to Utah. As such, Utah is allocated its full proportional share of total Company costs. The Rate Mitigation Cap does not limit the allocation of generation costs; it limits the level of revenues the Company is allowed to collect. This lowers the rate of return the Company will actually realize in Utah. The Company's cost of service study reflects the impact of the Rate Mitigation Cap by incorporating the lower "effective" return on rate base it produces.

Q. Are there other alternatives to the cost of service treatment of the Rate Mitigation Cap?

A. Yes. A possible alternative to the current cost of service treatment would be to lower the target return for the generation function only producing a different return for them when compared to the rates of return for other functions. The Company is not opposed to exploring this or other alternatives. Such an approach, however, would be a departure from the Company's traditional view that all business functions are producing the same rate of return.

Planning Margin Adjustment

Q. Mr. Higgins recommends that a portion of costs associated with the Company's planning margin requirement be added to the peak loads for classes that are traditionally temperature normalized. Do you agree with his proposal?

A. No, I do not. Mr. Higgins proposes an adjustment that allocates a percentage of planning margin to the CP for those rate schedules whose loads are traditionally temperature-adjusted by the Company. No data or calculations are presented that support this recommendation. The only basis for his recommendation is that he believes that a planning margin is reasonable. This recommendation has very little foundation and should be rejected.

Rebuttal of Mr. Richard Collins

Q. Do you agree with Mr. Collins that the Commission should order the Division to investigate cost of service based on marginal costs?

A. The Company believes that Mr. Collins' proposal should be investigated in the marginal cost/load growth collaborative proposed by Mr. Griffith in his rebuttal testimony and by other parties in their direct testimonies.

Workpapers

Q. Have you included your workpapers?

A. Yes. Exhibit RMP___(CCP-3R-COS) includes the cost of service study underlying the summary tables in RMP___(CCP-1R-COS). Both of these exhibits are being provided on CD in both PDF and working models.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Rocky Mountain Power
Exhibit RMP___(CCP-1R-COS)
Docket No. 07-035-93
Witness: C. Craig Paice

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of C. Craig Paice

Cost of Service Results

September 2008

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2008
Monthly Wgt Factors
7.38% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M	
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues	
1	1	Residential	539,693,437	7.59%	1.03	536,069,220	281,152,811	25,736,333	204,302,717	22,499,749	2,377,610	(3,624,217)	-0.67%	1
2	6	General Service - Large	381,039,399	8.86%	1.20	364,500,996	249,203,098	22,939,371	86,400,309	4,218,183	1,740,034	(16,538,403)	-4.34%	2
3	8	General Service - Over 1 MW	114,860,522	7.48%	1.01	114,510,482	81,705,979	7,118,150	24,160,993	988,192	537,168	(350,040)	-0.30%	3
4	7,11,12,13	Street & Area Lighting	13,066,659	7.77%	1.05	12,946,640	2,787,992	172,627	9,852,268	93,408	40,345	(120,019)	-0.92%	4
5	9	General Service - High Voltage	170,428,984	6.20%	0.84	175,997,139	159,066,055	14,479,024	778,709	829,647	843,704	5,568,155	3.27%	5
6	10	Irrigation	9,994,195	1.23%	0.17	12,228,333	7,460,890	693,363	3,929,934	90,269	53,878	2,234,138	22.35%	6
7	12	Traffic Signals	399,557	4.80%	0.65	429,942	182,629	15,050	162,271	68,388	1,605	30,385	7.60%	7
8	12	Outdoor Lighting	731,194	42.53%	5.77	403,263	322,971	17,465	49,688	11,553	1,587	(327,931)	-44.85%	8
9	23	General Service - Small	97,623,876	6.17%	0.84	101,410,355	57,718,304	5,600,300	33,429,049	4,197,292	465,411	3,786,479	3.88%	9
10	25	Mobile Home Parks	755,668	8.29%	1.12	734,268	472,545	42,070	218,175	(2,039)	3,516	(21,400)	-2.83%	10
11	SpC	Customer A	8,564,009	3.02%	0.41	9,668,085	8,819,417	712,832	71,208	19,190	45,438	1,104,076	12.89%	11
12	SpC	Customer B	23,253,000	-3.08%	(0.42)	29,555,736	26,429,223	1,499,653	122,594	1,389,221	115,045	6,302,736	27.11%	12
13	SpC	Customer C	22,731,197	4.46%	0.61	24,687,238	22,436,625	1,980,813	104,976	45,462	119,362	1,956,041	8.61%	13
14		Total Utah Jurisdiction	1,383,141,697	7.38%	1.00	1,383,141,697	897,758,538	81,007,050	363,582,890	34,448,515	6,344,704	(0)	0.00%	14

Footnotes :

Column C : Annual revenues based on January 2008 thru December 2008 forecasted data.
Column D : Calculated Return on Ratebase per January 2008 thru December 2008 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Utah Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2008
Monthly Wgt Factors
7.92% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M	
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues	
1	1	Residential	539,693,437	7.59%	1.03	550,660,833	286,483,225	27,851,310	211,297,251	22,619,487	2,409,560	10,967,396	2.03%	1
2	6	General Service - Large	381,039,399	8.86%	1.20	374,257,217	254,089,924	24,871,651	89,330,569	4,199,320	1,765,753	(6,782,182)	-1.78%	2
3	8	General Service - Over 1 MW	114,860,522	7.48%	1.01	117,471,996	83,246,567	7,723,003	24,974,659	982,489	545,279	2,611,474	2.27%	3
4	7,11,12,13	Street & Area Lighting	13,066,659	7.77%	1.05	13,211,685	2,826,638	186,951	10,061,917	95,400	40,778	145,026	1.11%	4
5	9	General Service - High Voltage	170,428,984	6.20%	0.84	180,142,803	161,981,041	15,695,597	782,282	826,029	857,855	9,713,819	5.70%	5
6	10	Irrigation	9,994,195	1.23%	0.17	12,546,703	7,590,906	744,389	4,066,633	90,138	54,637	2,552,508	25.54%	6
7	12	Traffic Signals	399,557	4.80%	0.65	440,288	185,855	16,320	167,625	68,862	1,626	40,731	10.19%	7
8	12	Outdoor Lighting	731,194	42.53%	5.77	411,432	327,546	19,156	51,491	11,625	1,614	(319,762)	-43.73%	8
9	23	General Service - Small	97,623,876	6.17%	0.84	104,158,820	58,868,177	6,057,259	34,567,775	4,193,750	471,859	6,534,944	6.69%	9
10	25	Mobile Home Parks	755,668	8.29%	1.12	754,741	481,598	45,653	225,961	(2,037)	3,567	(927)	-0.12%	10
11	SpC	Customer A	8,564,009	3.02%	0.41	9,890,205	8,977,600	775,002	72,282	19,112	46,208	1,326,196	15.49%	11
12	SpC	Customer B	23,253,000	-3.08%	(0.42)	30,083,881	26,817,878	1,644,269	123,225	1,381,398	117,111	6,830,881	29.38%	12
13	SpC	Customer C	22,731,197	4.46%	0.61	25,275,288	22,852,693	2,150,344	105,634	45,251	121,367	2,544,091	11.19%	13
14		Total Utah Jurisdiction	1,383,141,697	7.38%	1.00	1,419,305,892	914,729,648	87,780,905	375,827,304	34,530,824	6,437,212	36,164,195	2.61%	14

Footnotes :

Column C : Annual revenues based on January 2008 thru December 2008 forecasted data.
Column D : Calculated Return on Ratebase per January 2008 thru December 2008 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Utah Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2008 thru December 2008 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Exhibit RMP___(CCP-2R-COS)

Rocky Mountain Power
Exhibit RMP___(CCP-2R-COS)
Docket No. 07-035-93
Witness: C. Craig Paice

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of C. Craig Paice

Cost of Service – Summary by Function

September 2008

Rocky Mountain Power
Exhibit RMP___(CCP-2R-COS) Page 1 of 6
Docket No. 07-035-93
Witness: C. Craig Paice

PacifiCorp
Cost Of Service By Rate Schedule - All Functions
State of Utah
Monthly Wgt Factors
12 Months Ended Dec 2008

	A DESCRIPTION	B	C Utah Jurisdiction Normalized	D Residential Sch 1	E General Large Dist. Sch 6	F General +1 MW Sch 8	G Street & Area Lighting Sch. 7,11,12	H General Trans Sch 9	I Irrigation Sch 10	J Traffic Signals Sch 12	K Outdoor Lighting Sch 12	L General Small Dist. Sch 23	M Mobile Home Park Sch 25	N Industrial Cust A	O Industrial Cust B	P Industrial Cust C
14	Operating Revenues		2,205,257,437	795,181,753	620,390,362	189,690,743	15,139,303	311,574,923	14,987,022	578,538	955,054	153,542,035	1,196,350	16,127,024	43,147,892	42,746,438
16	Operating Expenses															
17	Operation & Maintenance Expenses		1,606,871,762	551,387,572	438,434,208	139,721,888	8,925,292	255,883,929	11,654,837	501,426	509,738	108,621,779	826,099	13,975,187	40,341,843	36,087,963
18	Depreciation Expense		166,651,846	67,852,721	44,581,810	13,422,174	2,451,099	18,106,318	1,460,025	49,043	35,345	12,832,887	93,435	965,774	2,243,563	2,557,653
19	Amortization Expense		25,290,613	11,368,619	5,989,203	1,815,987	172,229	2,909,546	191,172	15,319	6,484	1,876,787	11,831	155,508	365,545	412,383
20	Taxes Other Than Income		34,283,663	14,081,138	9,139,599	2,772,789	256,356	3,878,716	300,011	10,971	7,851	2,584,039	19,306	207,918	474,199	550,771
21	Income Taxes - Federal		10,283,245	(301,120)	8,015,127	2,029,892	460,868	(3,822,270)	392,167	(66,592)	(12,199)	3,592,627	18,225	(223,784)	798,679	(598,376)
22	Income Taxes - State		2,474,876	279,754	1,424,846	379,165	67,280	(362,433)	63,122	(9,189)	(1,443)	575,765	3,115	(21,974)	136,039	(59,173)
23	Income Taxes Deferred		62,386,622	26,185,785	16,393,671	4,971,093	479,656	6,918,713	542,732	22,492	14,560	4,658,397	34,928	372,041	807,962	984,592
24	Investment Tax Credit Adj		(1,621,963)	(647,369)	(439,989)	(133,662)	(11,638)	(188,715)	(14,272)	(441)	(365)	(123,400)	(919)	(10,099)	(24,343)	(26,750)
25	Misc Revenues & Expense		(5,923,599)	(1,534,285)	(1,849,505)	(579,311)	(13,961)	(1,093,852)	(49,812)	(1,235)	(1,646)	(436,833)	(3,486)	(60,076)	(140,683)	(158,913)
27	Total Operating Expenses		1,900,697,065	668,672,816	521,688,969	164,400,014	12,787,181	282,229,953	14,539,981	521,793	558,327	134,182,048	1,002,535	15,360,495	45,002,805	39,750,151
29	Operating Revenue For Return		304,560,372	126,508,937	98,701,393	25,290,729	2,352,122	29,344,971	447,041	56,745	396,728	19,359,987	193,815	766,529	(1,854,913)	2,996,288
32	Rate Base :															
33	Electric Plant In Service		7,261,861,954	2,921,812,470	1,951,433,588	591,976,219	56,154,604	844,624,443	62,944,598	2,137,604	1,636,296	553,250,336	4,053,088	45,032,490	107,504,191	119,302,027
34	Plant Held For Future Use		3,208,605	1,431,012	1,028,228	303,815	2,884	86,366	41,196	591	346	278,217	2,089	4,844	16,927	12,088
35	Electric Plant Acquisition Adj		29,276,478	9,235,859	8,471,406	2,651,429	62,650	4,985,442	222,845	5,544	7,387	2,004,295	15,642	269,584	631,297	713,100
36	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Prepayments		17,679,962	6,919,529	4,810,832	1,461,885	124,246	2,168,087	150,904	4,885	3,938	1,334,441	9,845	115,473	269,032	306,864
38	Fuel Stock		46,094,797	13,947,065	12,370,581	4,267,381	188,735	8,657,628	377,333	10,083	22,185	2,743,023	23,940	488,493	1,791,240	1,207,110
39	Materials & Supplies		63,952,524	21,925,013	18,129,543	5,615,668	252,462	9,761,638	509,475	13,903	15,415	4,545,747	34,779	526,054	1,230,171	1,392,656
40	Misc Deferred Debits		30,695,841	9,957,692	8,764,012	2,732,076	86,897	5,141,437	236,617	6,116	7,569	2,121,349	16,425	270,202	630,557	724,892
41	Cash Working Capital		39,475,287	14,205,468	10,762,697	3,383,806	355,261	5,658,952	300,435	12,124	11,390	2,776,303	20,500	308,591	882,539	797,223
42	Weatherization Loans		6,496,944	2,023,426	1,834,009	592,513	18,108	1,143,272	51,316	1,293	2,133	425,230	3,437	62,767	177,352	162,088
43	Miscellaneous Rate Base		2,199,318	684,962	620,841	200,575	6,130	387,015	17,371	438	722	143,947	1,163	21,248	60,036	54,869
45	Total Rate Base Additions		7,500,941,710	3,002,142,496	2,018,225,737	613,185,366	57,251,976	882,614,280	64,852,091	2,192,581	1,707,380	569,622,890	4,180,909	47,099,746	113,193,343	124,672,916
47	Rate Base Deductions :															
48	Accum Provision For Depreciation		(2,559,307,704)	(999,131,955)	(692,197,927)	(210,762,278)	(21,499,018)	(316,699,368)	(21,686,716)	(710,525)	(585,990)	(192,703,256)	(1,416,756)	(16,904,282)	(40,267,736)	(44,741,896)
49	Accum Provision For Amortization		(178,008,394)	(87,914,890)	(38,799,268)	(11,624,613)	(1,441,864)	(17,549,815)	(1,323,445)	(135,454)	(46,690)	(13,467,101)	(78,120)	(935,000)	(2,213,589)	(2,478,544)
50	Accum Deferred Income Taxes		(571,387,650)	(229,875,070)	(154,563,985)	(46,892,992)	(3,836,099)	(65,796,614)	(5,041,479)	(155,274)	(127,415)	(43,590,125)	(324,466)	(3,503,798)	(8,387,662)	(9,292,672)
51	Unamortized ITC		(162,865)	(64,945)	(44,236)	(13,429)	(1,146)	(18,981)	(1,430)	(44)	(36)	(12,413)	(92)	(1,012)	(2,420)	(2,682)
52	Customer Advance For Construction		(8,071,613)	(249,304)	(3,901,561)	(1,176,086)	-	(1,745,066)	-	-	-	(999,596)	-	-	-	-
53	Customer Service Deposits		(10,294,490)	(3,951,021)	(2,454,572)	(616,925)	(15,055)	(274,510)	(81,414)	-	-	(2,032,545)	-	-	(868,448)	-
54	Misc Rate Base Deductions		(44,124,606)	(14,741,096)	(12,202,643)	(3,924,120)	(193,341)	(7,137,086)	(363,048)	(9,869)	(14,422)	(2,971,091)	(23,668)	(391,815)	(1,144,722)	(1,007,685)
56	Total Rate Base Deductions		(3,371,357,323)	(1,335,928,281)	(904,164,192)	(275,010,445)	(26,986,524)	(409,221,440)	(28,497,532)	(1,011,167)	(774,553)	(255,776,127)	(1,843,102)	(21,735,906)	(52,884,576)	(57,523,480)
58	Total Rate Base		4,129,584,387	1,666,214,215	1,114,061,545	338,174,921	30,265,452	473,392,840	36,354,559	1,181,414	932,827	313,846,763	2,337,807	25,363,840	60,308,767	67,149,437
60	Calculated Return On Rate Base		7.38%	7.59%	8.86%	7.48%	7.77%	6.20%	1.23%	4.80%	42.53%	6.17%	8.29%	3.02%	-3.08%	4.46%
62	Return On RB @ Jurisdictional Ave.	7.38%	304,560,372	122,884,720	82,162,990	24,940,689	2,232,103	34,913,126	2,681,180	87,130	68,797	23,146,467	172,415	1,870,605	4,447,823	4,952,328
63	Total Operating Expenses		1,900,697,065	668,672,816	521,688,969	164,400,014	12,787,181	282,229,953	14,539,981	521,793	558,327	134,182,048	1,002,535	15,360,495	45,002,805	39,750,151
64	Revenue Credits		(822,115,740)	(255,488,316)	(239,350,963)	(74,830,221)	(2,072,644)	(141,145,939)	(4,992,827)	(178,981)	(223,860)	(55,918,159)	(440,682)	(7,563,015)	(19,894,892)	(20,015,241)
66	Total Revenue Requirements		1,383,141,697	536,069,220	364,500,996	114,510,482	12,946,640	175,997,139	12,228,333	429,942	403,263	101,410,355	734,268	9,668,085	29,555,736	24,687,238
67	Class Revenue		1,383,141,697	539,693,437	381,039,399	114,860,522	13,066,659	170,428,984	9,994,195	399,557	731,194	97,623,876	755,668	8,564,009	23,253,000	22,731,197
69	Increase / (Decrease) Required to															
70	Earn Equal Rates of Return		(0)	(3,624,217)	(16,538,403)	(350,040)	(120,019)	5,568,155	2,234,138	30,385	(327,931)	3,786,479	(21,400)	1,104,076	6,302,736	1,956,041
72	Percent %		0.00%	-0.67%	-4.34%	-0.30%	-0.92%	3.27%	22.35%	7.60%	-44.85%	3.88%	-2.83%	12.89%	27.11%	8.61%
75	Return On Rate Base @ Target ROR	7.92%	326,950,164	131,918,605	88,203,211	26,774,207	2,396,196	37,479,768	2,878,287	93,536	73,854	24,848,082	185,090	2,008,123	4,774,805	5,316,399
76	Total Operating Expenses Adjusted for Taxes		1,914,471,468	674,230,544	525,404,968	165,528,011	12,888,133	283,808,974	14,661,243	525,733	561,438	135,228,897	1,010,333	15,445,097	45,203,967	39,974,130
77	Revenue Credits		(822,115,740)	(255,488,316)	(239,350,963)	(74,830,221)	(2,072,644)	(141,145,939)	(4,992,827)	(178,981)	(223,860)	(55,918,159)	(440,682)	(7,563,015)	(19,894,892)	(20,015,241)
79	Total Target Revenue Requirements		1,419,305,892	550,660,833	374,257,217	117,471,996	13,211,685	180,142,803	12,546,703	440,288	411,432	104,158,820	754,741	9,890,205	30,083,881	25,275,288
80	Class Revenue		1,383,141,697	539,693,437	381,039,399	114,860,522	13,066,659	170,428,984	9,994,195	399,557	731,194	97,623,876	755,668	8,564,009	23,253,000	22,731,197
82	Increase / (Decrease) Required to															
83	Earn Target Rate of Return		36,164,195	10,967,396	(6,782,182)	2,611,474	145,026	9,713,819	2,552,508	40,731	(319,762)	6,534,944	(927)	1,326,196	6,830,881	2,544,091
85	Percent %		2.61%	2.03%	-1.78%	2.27%	1.11%	5.70%	25.54%	10.19%	-43.73%	6.69%	-0.12%	15.49%	29.38%	11.19%

PacifiCorp
Cost Of Service By Rate Schedule - Generation Function
State of Utah
Monthly Wgt Factors
12 Months Ended Dec 2008

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	DESCRIPTION		Utah Jurisdiction Normalized	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 12	Outdoor Lighting Sch 12	General Small Dist. Sch 23	Mobile Home Park Sch 25	Industrial Cust A	Industrial Cust B	Industrial Cust C
14	Operating Expenses															
15	Operation & Maintenance Expenses		1,354,083,552	417,967,207	383,441,630	123,881,205	3,852,958	240,785,813	9,700,493	272,884	450,615	87,454,359	719,241	13,177,568	38,375,503	34,004,076
16	Depreciation Expense		78,128,053	25,110,366	22,511,305	7,030,455	197,626	12,999,274	600,754	15,268	19,530	5,393,376	41,908	702,981	1,646,117	1,859,094
17	Amortization Expense		14,051,787	4,562,998	4,009,990	1,254,375	34,982	2,341,826	107,042	3,080	3,592	965,932	7,438	126,643	299,189	334,700
18	Taxes Other Than Income		15,742,535	4,944,534	4,533,058	1,429,061	35,848	2,703,964	120,604	2,993	4,244	1,066,631	8,397	146,732	360,520	385,949
19	Income Taxes - Federal		(26,315,659)	(8,265,420)	(7,577,586)	(2,388,859)	(59,925)	(4,520,021)	(201,605)	(5,003)	(7,094)	(1,783,011)	(14,037)	(245,281)	(602,656)	(645,162)
20	Income Taxes - State		(2,682,543)	(842,553)	(772,438)	(243,513)	(6,109)	(460,758)	(20,551)	(510)	(723)	(181,755)	(1,431)	(25,003)	(61,433)	(65,766)
21	Income Taxes Deferred		28,829,259	9,054,910	8,301,376	2,617,036	65,649	4,951,761	220,861	5,481	7,772	1,953,319	15,378	268,709	660,220	706,787
22	Investment Tax Credit Adj		(765,645)	(240,479)	(220,467)	(69,503)	(1,744)	(131,508)	(5,866)	(146)	(206)	(51,876)	(408)	(7,136)	(17,534)	(18,771)
23	Misc Revenues & Expense		(5,854,439)	(1,846,901)	(1,694,033)	(530,208)	(12,528)	(996,942)	(44,562)	(1,109)	(1,477)	(400,800)	(3,128)	(53,909)	(126,241)	(142,599)
24																
25	Total Operating Expenses		1,455,216,900	450,444,661	412,532,836	132,980,049	4,106,758	257,673,408	10,477,170	292,940	476,251	94,416,175	773,358	14,091,304	40,533,685	36,418,307
26																
27																
28	Rate Base :															
29	Electric Plant In Service		3,447,248,355	1,085,382,086	993,381,315	312,534,165	7,748,800	590,211,899	26,401,685	658,975	913,080	234,290,013	1,838,581	31,998,170	77,594,278	84,295,308
30	Plant Held For Future Use		398,204	120,810	106,777	36,820	1,625	74,598	3,374	87	191	23,665	206	4,208	15,437	10,405
31	Electric Plant Acquisition Adj		29,276,478	9,235,859	8,471,406	2,651,429	62,650	4,985,442	222,845	5,544	7,387	2,004,295	15,642	269,584	631,297	713,100
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		7,484,684	2,384,549	2,154,609	674,135	16,455	1,267,587	56,804	1,514	1,894	512,808	3,977	68,541	160,506	181,305
34	Fuel Stock		46,094,797	13,947,065	12,370,581	4,267,381	188,735	8,657,628	377,333	10,083	22,185	2,743,023	23,940	488,493	1,791,240	1,207,110
35	Materials & Supplies		53,532,765	16,887,996	15,490,176	4,848,204	114,556	9,116,004	407,478	10,137	13,507	3,664,904	28,601	492,941	1,154,342	1,303,920
36	Misc Deferred Debits		15,039,047	4,744,372	4,351,680	1,362,014	32,182	2,560,974	114,473	2,848	3,794	1,029,587	8,035	138,483	324,291	366,312
37	Cash Working Capital		27,983,655	8,637,761	7,924,251	2,560,144	79,626	4,976,109	200,472	5,639	9,312	1,807,342	14,864	272,329	793,073	702,732
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		2,199,318	684,962	620,841	200,575	6,130	387,015	17,371	438	722	143,947	1,163	21,248	60,036	54,869
40																
41	Total Rate Base Additions		3,629,257,304	1,142,025,460	1,044,871,638	329,134,867	8,250,759	622,237,255	27,801,833	695,266	972,072	246,219,586	1,935,010	33,753,996	82,524,500	88,835,062
42																
43	Rate Base Deductions :															
44	Accum Provision For Depreciation		(1,319,792,571)	(415,551,222)	(380,481,895)	(119,653,729)	(2,953,477)	(225,879,735)	(10,103,170)	(251,840)	(348,159)	(89,753,275)	(704,067)	(12,243,337)	(29,603,949)	(32,264,716)
45	Accum Provision For Amortization		(75,494,713)	(23,968,467)	(21,771,114)	(6,821,638)	(174,703)	(12,779,040)	(577,712)	(14,580)	(19,333)	(5,169,533)	(40,343)	(691,510)	(1,640,190)	(1,826,550)
46	Accum Deferred Income Taxes		(262,471,472)	(83,423,338)	(75,207,365)	(23,670,313)	(607,683)	(44,736,130)	(2,005,617)	(53,629)	(70,139)	(17,834,522)	(139,195)	(2,426,121)	(5,909,570)	(6,387,850)
47	Unamortized ITC		(76,880)	(24,198)	(22,148)	(6,971)	(173)	(13,172)	(589)	(15)	(20)	(5,222)	(41)	(714)	(1,737)	(1,881)
48	Customer Advance For Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(33,493,069)	(10,379,051)	(9,363,185)	(3,062,726)	(101,726)	(5,967,337)	(268,256)	(6,790)	(11,978)	(2,153,194)	(17,647)	(329,440)	(988,499)	(843,241)
51																
52	Total Rate Base Deductions		(1,691,328,705)	(533,346,276)	(486,845,707)	(153,215,377)	(3,837,761)	(289,375,414)	(12,955,345)	(326,854)	(449,628)	(114,915,746)	(901,293)	(15,691,121)	(38,143,944)	(41,324,238)
53																
54	Total Rate Base		1,937,928,598	608,679,184	558,025,930	175,919,490	4,412,998	332,861,841	14,846,489	368,412	522,444	131,303,841	1,033,717	18,062,874	44,380,555	47,510,824
55																
56																
57	Return On Rate Base	7.38%	142,923,888	44,890,609	41,154,888	12,974,212	325,462	24,548,845	1,094,941	27,171	38,531	9,683,770	76,238	1,332,152	3,273,104	3,503,964
58	Total Operating Expenses		1,455,216,900	450,444,661	412,532,836	132,980,049	4,106,758	257,673,408	10,477,170	292,940	476,251	94,416,175	773,358	14,091,304	40,533,685	36,418,307
59	Revenue Credits		(700,382,250)	(214,182,459)	(204,484,626)	(64,248,282)	(1,644,229)	(123,156,198)	(4,111,221)	(137,481)	(191,811)	(46,381,642)	(377,051)	(6,604,039)	(17,377,566)	(17,485,646)
60																
61	Total Revenue Requirements		897,758,538	281,152,811	249,203,098	81,705,979	2,787,992	159,066,055	7,460,890	182,629	322,971	57,718,304	472,545	8,819,417	26,429,223	22,436,625
62																
63																
64	Return On Rate Base @ Target ROR	7.92%	153,430,954	48,190,748	44,180,395	13,928,013	349,389	26,353,556	1,175,436	29,168	41,363	10,395,674	81,842	1,430,086	3,513,726	3,761,558
65	Total Op. exp. Adjusted for Taxes		1,461,680,943	452,474,936	414,394,155	133,566,836	4,121,478	258,783,682	10,526,691	294,168	477,994	94,854,144	776,806	14,151,554	40,681,718	36,576,781
66	Revenue Credits		(700,382,250)	(214,182,459)	(204,484,626)	(64,248,282)	(1,644,229)	(123,156,198)	(4,111,221)	(137,481)	(191,811)	(46,381,642)	(377,051)	(6,604,039)	(17,377,566)	(17,485,646)
67																
68	Total Target Revenue Requirements		914,729,648	286,483,225	254,089,924	83,246,567	2,826,638	161,981,041	7,590,906	185,855	327,546	58,868,177	481,598	8,977,600	26,817,878	22,852,693

PacifiCorp
Cost Of Service By Rate Schedule - Transmission Function
State of Utah
Monthly Wgt Factors
12 Months Ended Dec 2008

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	DESCRIPTION		Utah Jurisdiction Normalized	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 12	Outdoor Lighting Sch 12	General Small Dist. Sch 23	Mobile Home Park Sch 25	Industrial Cust A	Industrial Cust B	Industrial Cust C
14	Operating Expenses															
15	Operation & Maintenance Expenses		78,298,756	24,320,723	22,671,069	7,105,524	180,459	13,660,328	561,720	15,239	19,740	5,295,044	41,319	720,396	1,789,702	1,917,493
16	Depreciation Expense		28,378,784	9,047,735	8,070,114	2,519,061	73,353	4,957,402	216,050	5,517	6,991	1,938,959	15,051	252,569	587,435	688,547
17	Amortization Expense		3,088,677	962,214	882,572	276,232	6,527	554,991	23,217	578	770	208,812	1,630	28,271	65,770	77,095
18	Taxes Other Than Income		6,708,033	2,094,426	1,913,504	598,976	14,185	1,204,752	50,531	1,258	1,675	452,519	3,548	61,566	143,210	167,883
19	Income Taxes - Federal		(1,655,449)	(516,875)	(472,226)	(147,819)	(3,501)	(297,316)	(12,470)	(311)	(413)	(111,675)	(876)	(15,194)	(35,342)	(41,431)
20	Income Taxes - State		(233,281)	(72,837)	(66,545)	(20,830)	(493)	(41,897)	(1,757)	(44)	(58)	(15,737)	(123)	(2,141)	(4,980)	(5,838)
21	Income Taxes Deferred		11,152,664	3,482,158	3,181,359	995,847	23,585	2,003,000	84,011	2,092	2,785	752,350	5,899	102,359	238,099	279,120
22	Investment Tax Credit Adj		(317,648)	(99,178)	(90,611)	(28,364)	(672)	(57,049)	(2,393)	(60)	(79)	(21,428)	(168)	(2,915)	(6,781)	(7,950)
23	Misc Revenues & Expense		15,616	4,926	4,519	1,414	33	2,659	119	3	4	1,069	8	144	337	380
24																
25	Total Operating Expenses		125,436,152	39,223,293	36,093,755	11,300,041	293,477	21,986,870	919,026	24,273	31,414	8,499,912	66,288	1,145,055	2,777,449	3,075,298
26																
27																
28	Rate Base :															
29	Electric Plant In Service		1,390,856,523	433,732,547	397,226,118	124,322,024	2,947,387	249,774,814	10,451,609	261,891	346,650	94,038,320	733,426	12,723,871	29,600,931	34,696,935
30	Plant Held For Future Use		69,110	21,802	19,998	6,259	148	11,769	526	13	17	4,731	37	636	1,490	1,683
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		2,687,192	847,267	763,111	238,745	5,868	479,684	20,128	544	672	181,857	1,409	24,434	56,843	66,631
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		3,519,980	1,096,577	1,005,813	314,805	7,438	632,492	26,458	658	877	237,971	1,857	32,219	74,954	87,860
36	Misc Deferred Debits		13,762,714	4,287,487	3,932,612	1,230,851	29,083	2,472,972	103,449	2,574	3,429	930,438	7,261	125,973	293,062	343,524
37	Cash Working Capital		3,527,662	1,095,743	1,021,419	320,131	8,130	615,451	25,308	687	889	238,562	1,862	32,457	80,633	86,390
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																
41	Total Rate Base Additions		1,414,423,182	441,081,422	403,969,070	126,432,816	2,998,055	253,987,181	10,627,479	266,367	352,535	95,631,879	745,851	12,939,591	30,107,914	35,283,024
42																
43	Rate Base Deductions :															
44	Accum Provision For Depreciation		(494,660,676)	(154,102,813)	(141,347,721)	(44,239,815)	(1,045,325)	(88,879,979)	(3,718,229)	(92,500)	(123,248)	(33,442,214)	(260,986)	(4,527,761)	(10,533,358)	(12,346,727)
45	Accum Provision For Amortization		(24,702,084)	(7,760,600)	(7,039,654)	(2,203,425)	(56,629)	(4,396,781)	(186,640)	(4,720)	(6,192)	(1,673,997)	(13,046)	(224,293)	(525,270)	(610,838)
46	Accum Deferred Income Taxes		(116,511,503)	(36,701,921)	(33,101,375)	(10,356,264)	(253,358)	(20,811,538)	(872,764)	(23,481)	(29,125)	(7,883,955)	(61,097)	(1,060,073)	(2,465,697)	(2,890,855)
47	Unamortized ITC		(31,896)	(9,950)	(9,107)	(2,850)	(68)	(5,728)	(240)	(6)	(8)	(2,156)	(17)	(292)	(679)	(796)
48	Customer Advance For Construction		(2,006,037)	(61,959)	(969,654)	(292,293)	-	(433,701)	-	-	-	(248,429)	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(3,005,451)	(935,212)	(854,803)	(270,072)	(6,943)	(539,111)	(22,906)	(572)	(818)	(201,054)	(1,585)	(27,947)	(69,266)	(75,159)
51																
52	Total Rate Base Deductions		(640,917,647)	(199,572,456)	(183,322,316)	(57,364,718)	(1,362,323)	(115,066,837)	(4,800,778)	(121,280)	(159,391)	(43,451,806)	(336,731)	(5,840,367)	(13,594,270)	(15,924,374)
53																
54	Total Rate Base		773,505,536	241,508,966	220,646,755	69,068,097	1,635,732	138,920,344	5,826,701	145,087	193,144	52,180,072	409,121	7,099,224	16,513,644	19,358,650
55																
56																
57	Return On Rate Base	7.38%	57,046,693	17,811,492	16,272,886	5,093,831	120,637	10,245,494	429,724	10,700	14,245	3,848,325	30,173	523,574	1,217,895	1,427,717
58	Total Operating Expenses		125,436,152	39,223,293	36,093,755	11,300,041	293,477	21,986,870	919,026	24,273	31,414	8,499,912	66,288	1,145,055	2,777,449	3,075,298
59	Revenue Credits		(101,475,795)	(31,298,452)	(29,427,270)	(9,275,723)	(241,487)	(17,753,340)	(655,388)	(19,924)	(28,194)	(6,747,937)	(54,390)	(955,797)	(2,495,692)	(2,522,202)
60																
61	Total Revenue Requirements		81,007,050	25,736,333	22,939,371	7,118,150	172,627	14,479,024	693,363	15,050	17,465	5,600,300	42,070	712,832	1,499,653	1,980,813
62																
63																
64	Return On Rate Base @ Target ROR	7.92%	61,240,488	19,120,906	17,469,190	5,468,305	129,505	10,998,693	461,315	11,487	15,292	4,131,235	32,391	562,064	1,307,429	1,532,676
65	Total Operating Expenses Adjusted for Taxes		128,016,213	40,028,856	36,829,731	11,530,421	298,933	22,450,245	938,462	24,757	32,058	8,673,961	67,652	1,168,735	2,832,531	3,139,869
66	Revenue Credits		(101,475,795)	(31,298,452)	(29,427,270)	(9,275,723)	(241,487)	(17,753,340)	(655,388)	(19,924)	(28,194)	(6,747,937)	(54,390)	(955,797)	(2,495,692)	(2,522,202)
67																
68	Total Target Revenue Requirements		87,780,905	27,851,310	24,871,651	7,723,003	186,951	15,695,597	744,389	16,320	19,156	6,057,259	45,653	775,002	1,644,269	2,150,344

PacifiCorp
Cost Of Service By Rate Schedule - Distribution Function
State of Utah
Monthly Wgt Factors
12 Months Ended Dec 2008

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	DESCRIPTION		Utah Jurisdiction Normalized	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 12	Outdoor Lighting Sch 12	General Small Dist. Sch 23	Mobile Home Park Sch 25	Industrial Cust A	Industrial Cust B	Industrial Cust C
14	Operating Expenses															
15	Operation & Maintenance Expenses		119,509,742	63,405,403	29,861,639	8,343,377	4,398,248	859,889	1,207,694	57,044	12,993	11,030,277	62,608	50,534	118,186	101,851
16	Depreciation Expense		59,518,185	33,141,519	13,988,684	3,872,451	2,172,104	148,919	641,005	26,664	8,582	5,451,556	36,467	10,220	10,006	10,008
17	Amortization Expense		4,330,562	2,473,053	1,025,304	284,117	81,879	8,325	47,410	1,951	648	403,480	2,712	566	559	560
18	Taxes Other Than Income		11,684,637	6,674,764	2,796,298	776,468	200,065	3,410	130,449	5,109	1,721	1,086,667	7,430	1,025	602	628
19	Income Taxes - Federal		50,598,525	28,904,042	12,108,938	3,362,375	866,351	14,766	564,890	22,124	7,454	4,705,644	32,175	4,441	2,606	2,720
20	Income Taxes - State		7,130,208	4,073,080	1,706,359	473,817	122,084	2,081	79,603	3,118	1,050	663,107	4,534	626	367	383
21	Income Taxes Deferred		21,442,402	12,248,817	5,131,468	1,424,891	367,138	6,257	239,386	9,376	3,159	1,994,135	13,635	1,882	1,104	1,153
22	Investment Tax Credit Adj		(538,670)	(307,711)	(128,911)	(35,796)	(9,223)	(157)	(6,014)	(236)	(79)	(50,096)	(343)	(47)	(28)	(29)
23	Misc Revenues & Expense		(685,390)	(216,220)	(198,324)	(62,072)	(1,467)	(116,714)	(5,217)	(130)	(173)	(46,922)	(366)	(6,311)	(14,779)	(16,694)
24																
25	Total Operating Expenses		272,990,201	150,396,747	66,291,456	18,439,627	8,197,179	926,775	2,899,205	125,021	35,354	25,237,846	158,851	62,934	118,624	100,581
26																
27																
28	Rate Base :															
29	Electric Plant In Service		2,363,748,480	1,350,139,607	559,453,572	155,023,154	44,687,293	4,536,779	25,871,517	1,066,554	353,628	220,219,192	1,479,595	308,240	304,544	304,806
30	Plant Held For Future Use		2,741,291	1,288,400	901,453	260,735	1,111	-	37,296	491	137	249,820	1,846	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		3,950,623	2,265,807	928,588	257,163	74,513	7,501	43,023	1,844	598	367,627	2,455	508	497	497
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		6,899,779	3,940,440	1,633,554	452,659	130,467	13,142	75,539	3,108	1,032	642,872	4,321	894	875	875
36	Misc Deferred Debits		985,229	562,661	233,257	64,636	18,630	1,877	10,786	444	147	91,797	617	128	125	125
37	Cash Working Capital		7,047,365	3,738,950	1,760,910	492,000	259,360	50,707	71,216	3,364	766	650,444	3,692	2,980	6,969	6,006
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																
41	Total Rate Base Additions		2,385,372,766	1,361,935,865	564,911,335	156,550,347	45,171,374	4,610,005	26,109,378	1,075,806	356,309	222,221,752	1,492,525	312,750	313,011	312,310
42																
43	Rate Base Deductions :															
44	Accum Provision For Depreciation		(741,846,917)	(426,824,106)	(170,312,140)	(46,867,740)	(17,461,759)	(1,936,186)	(7,854,685)	(358,539)	(113,421)	(69,272,679)	(451,662)	(133,162)	(130,407)	(130,431)
45	Accum Provision For Amortization		(37,970,768)	(21,484,429)	(9,016,894)	(2,509,819)	(705,357)	(214,276)	(413,222)	(16,959)	(5,856)	(3,514,108)	(23,682)	(12,643)	(28,702)	(24,821)
46	Accum Deferred Income Taxes		(194,649,411)	(111,601,906)	(46,344,193)	(12,874,742)	(2,981,014)	(284,490)	(2,167,226)	(86,612)	(29,682)	(18,101,354)	(124,175)	(19,268)	(17,108)	(17,640)
47	Unamortized ITC		(54,089)	(30,796)	(12,981)	(3,608)	(906)	(81)	(601)	(24)	(8)	(5,035)	(34)	(6)	(5)	(5)
48	Customer Advance For Construction		(6,065,576)	(187,344)	(2,931,906)	(883,794)	-	(1,311,365)	-	-	-	(751,167)	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		(6,598,091)	(3,102,530)	(1,687,195)	(498,222)	(82,472)	(455,582)	(64,061)	(2,313)	(1,366)	(546,466)	(3,886)	(24,962)	(64,790)	(64,245)
51																
52	Total Rate Base Deductions		(987,184,852)	(563,231,112)	(230,305,309)	(63,637,925)	(21,231,508)	(4,201,981)	(10,499,794)	(464,447)	(150,333)	(92,190,808)	(603,440)	(190,040)	(241,012)	(237,143)
53																
54	Total Rate Base		1,398,187,914	798,704,754	334,606,025	92,912,422	23,939,866	408,024	15,609,584	611,358	205,976	130,030,944	889,085	122,710	71,999	75,166
55			12,524,863	4,999,187	4,568,627	1,131,004	110,497	178,159	120,491	7,838	858	1,398,690	6,247	777	1,339	1,148
56																
57	Return On Rate Base	7.38%	103,117,552	58,905,157	24,677,480	6,852,370	1,765,586	30,092	1,151,220	45,088	15,191	9,589,893	65,571	9,050	5,310	5,544
58	Total Operating Expenses		272,990,201	150,396,747	66,291,456	18,439,627	8,197,179	926,775	2,899,205	125,021	35,354	25,237,846	158,851	62,934	118,624	100,581
59	Revenue Credits		(12,524,863)	(4,999,187)	(4,568,627)	(1,131,004)	(110,497)	(178,159)	(120,491)	(7,838)	(858)	(1,398,690)	(6,247)	(777)	(1,339)	(1,148)
60																
61	Total Revenue Requirements		363,582,890	204,302,717	86,400,309	24,160,993	9,852,268	778,709	3,929,934	162,271	49,688	33,429,049	218,175	71,208	122,594	104,976
62																
63																
64	Return On Rate Base @ Target ROR	7.92%	110,698,251	63,235,577	26,491,648	7,356,123	1,895,383	32,304	1,235,852	48,403	16,308	10,294,895	70,391	9,715	5,700	5,951
65	Total Operating Expenses Adjusted for Taxes		277,653,915	153,060,860	67,407,548	18,749,540	8,277,032	928,136	2,951,272	127,060	36,041	25,671,570	161,817	63,344	118,864	100,831
66	Revenue Credits		(12,524,863)	(4,999,187)	(4,568,627)	(1,131,004)	(110,497)	(178,159)	(120,491)	(7,838)	(858)	(1,398,690)	(6,247)	(777)	(1,339)	(1,148)
67																
68	Total Target Revenue Requirements		375,827,303	211,297,251	89,330,569	24,974,659	10,061,917	782,282	4,066,633	167,625	51,491	34,567,775	225,961	72,282	123,225	105,634

PacifiCorp
Cost Of Service By Rate Schedule - Retail Services Function
State of Utah
Monthly Wgt Factors
12 Months Ended Dec 2008

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	DESCRIPTION		Utah Jurisdiction Normalized	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 12	Outdoor Lighting Sch 12	General Small Dist. Sch 23	Mobile Home Park Sch 25	Industrial Cust A	Industrial Cust B	Industrial Cust C
14	Operating Expenses															
15	Operation & Maintenance Expenses		51,557,018	44,326,549	1,531,702	110,937	467,259	180,158	155,149	155,314	25,646	4,580,262	1,003	5,528	9,195	8,315
16	Depreciation Expense		626,823	553,101	11,707	207	8,015	723	2,216	1,594	242	48,996	9	5	5	5
17	Amortization Expense		3,819,587	3,370,354	71,337	1,262	48,842	4,405	13,504	9,710	1,476	298,562	52	28	28	28
18	Taxes Other Than Income		284,972	414,563	(65,308)	(19,747)	6,895	(12,528)	(452)	1,642	250	(12,262)	5	(269)	(27,085)	(731)
19	Income Taxes - Federal		(14,566,352)	(21,190,359)	3,338,208	1,009,358	(352,457)	640,389	23,114	(83,911)	(12,780)	626,773	(242)	13,757	1,384,452	37,347
20	Income Taxes - State		(2,052,651)	(2,986,088)	470,411	142,236	(49,667)	90,242	3,257	(11,824)	(1,801)	88,323	(34)	1,939	195,093	5,263
21	Income Taxes Deferred		962,298	1,399,900	(220,532)	(66,681)	23,284	(42,306)	(1,527)	5,543	844	(41,407)	16	(909)	(91,461)	(2,467)
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		600,614	523,911	38,333	11,555	-	17,145	(151)	-	-	9,821	-	-	-	-
24																
25	Total Operating Expenses		41,232,309	26,411,929	5,175,858	1,189,128	152,172	878,228	195,109	78,068	13,877	5,599,069	808	20,078	1,470,226	47,758
26																
27																
28	Rate Base :															
29	Electric Plant In Service		60,008,596	52,558,231	1,372,583	96,875	771,123	100,951	219,787	150,183	22,938	4,702,812	1,487	2,210	4,438	4,978
30	Plant Held For Future Use		-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		754	665	14	0	10	1	3	2	0	59	0	0	0	0
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Misc Deferred Debits		518,602	207,231	140,635	42,553	3,995	60,265	4,512	143	113	39,673	292	3,206	7,463	8,520
37	Cash Working Capital		796,985	685,214	23,678	1,715	7,223	2,785	2,398	2,401	396	70,803	16	85	142	129
38	Weatherization Loans		-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																
41	Total Rate Base Additions		61,324,937	53,451,340	1,536,909	141,144	782,351	164,002	226,701	152,729	23,447	4,813,347	1,795	5,501	12,044	13,626
42																
43	Rate Base Deductions :															
44	Accum Provision For Depreciation		(3,007,541)	(2,653,815)	(56,171)	(994)	(38,458)	(3,468)	(10,633)	(7,646)	(1,162)	(235,088)	(41)	(22)	(22)	(22)
45	Accum Provision For Amortization		(39,840,828)	(34,701,395)	(971,606)	(89,731)	(505,175)	(159,719)	(145,871)	(99,194)	(15,310)	(3,109,463)	(1,049)	(6,554)	(19,426)	(16,335)
46	Accum Deferred Income Taxes		2,244,735	1,852,095	88,948	8,327	5,957	35,544	4,128	8,448	1,530	229,706	1	1,664	4,713	3,673
47	Unamortized ITC		-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Customer Advance For Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Customer Service Deposits		(10,294,490)	(3,951,021)	(2,454,572)	(616,925)	(15,055)	(274,510)	(81,414)	-	-	(2,032,545)	-	-	(868,448)	-
50	Misc Rate Base Deductions		(1,027,995)	(324,302)	(297,459)	(93,101)	(2,200)	(175,056)	(7,825)	(195)	(259)	(70,378)	(549)	(9,466)	(22,167)	(25,039)
51																
52	Total Rate Base Deductions		(51,926,119)	(39,778,437)	(3,690,860)	(792,424)	(554,931)	(577,208)	(241,615)	(98,586)	(15,201)	(5,217,767)	(1,638)	(14,378)	(905,350)	(37,724)
53																
54	Total Rate Base		9,398,818	13,672,903	(2,153,951)	(651,280)	227,420	(413,205)	(14,914)	54,143	8,246	(404,420)	156	(8,877)	(893,306)	(24,098)
55																
56																
57	Return On Rate Base	7.38%	693,171	1,008,388	(158,856)	(48,032)	16,772	(30,474)	(1,100)	3,993	608	(29,826)	12	(655)	(65,882)	(1,777)
58	Total Operating Expenses		41,232,309	26,411,929	5,175,858	1,189,128	152,172	878,228	195,109	78,068	13,877	5,599,069	808	20,078	1,470,226	47,758
59	Revenue Credits		(7,476,965)	(4,920,569)	(798,819)	(152,903)	(75,536)	(18,106)	(103,741)	(13,673)	(2,933)	(1,371,951)	(2,859)	(234)	(15,123)	(519)
60																
61	Total Revenue Requirements		34,448,515	22,499,749	4,218,183	988,192	93,408	829,647	90,269	68,388	11,553	4,197,292	(2,039)	19,190	1,389,221	45,462
62																
63																
64	Return On Rate Base @ Target ROR	7.92%	744,129	1,082,520	(170,534)	(51,564)	18,005	(32,715)	(1,181)	4,287	653	(32,019)	12	(703)	(70,725)	(1,908)
65	Total Operating Expenses Adjusted for Taxes		41,263,659	26,457,536	5,168,673	1,186,955	152,931	876,849	195,060	78,249	13,905	5,597,720	809	20,049	1,467,247	47,678
66	Revenue Credits		(7,476,965)	(4,920,569)	(798,819)	(152,903)	(75,536)	(18,106)	(103,741)	(13,673)	(2,933)	(1,371,951)	(2,859)	(234)	(15,123)	(519)
67																
68	Total Target Revenue Requirements		34,530,824	22,619,487	4,199,320	982,489	95,400	826,029	90,138	68,862	11,625	4,193,750	(2,037)	19,112	1,381,398	45,251

PacifiCorp
Cost Of Service By Rate Schedule - Miscellaneous Function
State of Utah
Monthly Wgt Factors
12 Months Ended Dec 2008

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	DESCRIPTION		Utah Jurisdiction Normalized	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 12	Outdoor Lighting Sch 12	General Small Dist. Sch 23	Mobile Home Park Sch 25	Industrial Cust A	Industrial Cust B	Industrial Cust C
14	Operating Expenses															
15	Operation & Maintenance Expenses		3,422,694	1,367,690	928,168	280,846	26,368	397,741	29,781	943	745	261,838	1,929	21,160	49,257	56,229
16	Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Amortization Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Taxes Other Than Income		(136,514)	(47,149)	(37,953)	(11,969)	(639)	(20,882)	(1,120)	(31)	(39)	(9,516)	(74)	(1,136)	(3,048)	(2,958)
19	Income Taxes - Federal		2,222,180	767,492	617,793	194,837	10,400	339,913	18,239	508	635	154,896	1,205	18,493	49,620	48,151
20	Income Taxes - State		313,144	108,153	87,058	27,456	1,465	47,900	2,570	72	89	21,828	170	2,606	6,992	6,785
21	Income Taxes Deferred		-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Investment Tax Credit Adj		-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Misc Revenues & Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																
25	Total Operating Expenses		5,821,503	2,196,186	1,595,065	491,169	37,594	764,672	49,470	1,491	1,430	429,046	3,229	41,123	102,820	108,207
26																
27																
28	Rate Base :															
29	Electric Plant In Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Plant Held For Future Use		-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Electric Plant Acquisition Adj		-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Nuclear Fuel		-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Prepayments		3,556,709	1,421,241	964,510	291,842	27,400	413,314	30,947	980	774	272,090	2,004	21,989	51,186	58,431
34	Fuel Stock		-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Materials & Supplies		-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Misc Deferred Debits		390,249	155,941	105,828	32,021	3,006	45,350	3,396	108	85	29,854	220	2,413	5,616	6,411
37	Cash Working Capital		119,620	47,799	32,439	9,815	922	13,901	1,041	33	26	9,151	67	740	1,721	1,965
38	Weatherization Loans		6,496,944	2,023,426	1,834,009	592,513	18,108	1,143,272	51,316	1,293	2,133	425,230	3,437	62,767	177,352	162,088
39	Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																
41	Total Rate Base Additions		10,563,521	3,648,408	2,936,786	926,192	49,436	1,615,836	86,700	2,414	3,017	736,326	5,728	87,908	235,875	228,895
42																
43	Rate Base Deductions :															
44	Accum Provision For Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Accum Provision For Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Accum Deferred Income Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Unamortized ITC		-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Customer Advance For Construction		-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Customer Service Deposits		-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Misc Rate Base Deductions		-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																
52	Total Rate Base Deductions		-	-	-	-	-	-	-	-	-	-	-	-	-	-
53																
54	Total Rate Base		10,563,521	3,648,408	2,936,786	926,192	49,436	1,615,836	86,700	2,414	3,017	736,326	5,728	87,908	235,875	228,895
55																
56																
57	Return On Rate Base	7.38%	779,069	269,073	216,590	68,307	3,646	119,169	6,394	178	223	54,305	422	6,483	17,396	16,881
58	Total Operating Expenses		5,821,503	2,196,186	1,595,065	491,169	37,594	764,672	49,470	1,491	1,430	429,046	3,229	41,123	102,820	108,207
59	Revenue Credits		(255,868)	(87,649)	(71,622)	(22,308)	(895)	(40,137)	(1,986)	(65)	(65)	(17,940)	(135)	(2,168)	(5,172)	(5,727)
60																
61	Total Revenue Requirements		6,344,704	2,377,610	1,740,034	537,168	40,345	843,704	53,878	1,605	1,587	465,411	3,516	45,438	115,045	119,362
62																
63																
64	Return On Rate Base @ Target ROR	7.92%	836,342	288,854	232,513	73,329	3,914	127,930	6,864	191	239	58,297	453	6,960	18,675	18,122
65	Total Operating Expenses Adjusted for Taxes		5,856,738	2,208,355	1,604,861	494,259	37,759	770,061	49,759	1,500	1,440	431,502	3,248	41,416	103,607	108,971
66	Revenue Credits		(255,868)	(87,649)	(71,622)	(22,308)	(895)	(40,137)	(1,986)	(65)	(65)	(17,940)	(135)	(2,168)	(5,172)	(5,727)
67																
68	Total Target Revenue Requirements		6,437,212	2,409,560	1,765,753	545,279	40,778	857,855	54,637	1,626	1,614	471,859	3,567	46,208	117,111	121,367

Rocky Mountain Power
Exhibit RMP___(CCP-3R-COS)
Docket No. 07-035-93
Witness: C. Craig Paice

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of C. Craig Paice

Functionalized Results of Operations and Cost of Service Detail
Updated 12 Months Ended December 2008

September 2008

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

Rocky Mountain Power
Docket No. 07-035-93
Witness: Lowell E. Alt

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Lowell E. Alt

Classification and Allocation of Distribution Costs

September 2008

Q. Please state your name and business address.

A. My name is Lowell E. Alt, Jr. My address is 1396 Wheelwright Court, Mesquite, Nevada, 89034.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Rocky Mountain Power Company (the Company), a division of PacifiCorp.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Electrical Engineering and a Master of Business Administration degree from West Virginia University where I became a member of the electrical engineering honorary society Eta Kappa Nu. I am a Registered Professional Engineer licensed in Pennsylvania and Utah. I have attended numerous conferences and seminars on various aspects of utility regulation. I retired in December 2005 as Executive Staff Director of the Utah Public Service Commission after a twenty-five year career in Utah utility regulation. I served as Director of the Utah Division of Public Utilities from March 2001 to August 2003, Manager of the Energy Section from October 1995 to March 2001, Chief Engineer from 1983 to 1995 and Rate Engineer from 1980 to 1983. I have testified before the Utah Public Service Commission in numerous electric, natural gas and telecommunication cases on various topics including customer charges, interim rates, rate case stipulations, rate design, cost-of-service, mergers, service extensions and return on equity. I was the Division's witness on class cost of service and rate design for every Utah Power rate case from 1983 to

1998. I have completed numerous cost-of-service studies of various utilities including Utah Power, U.S. West Communications, several rural electric cooperatives and two water companies. I previously worked for Pennsylvania Power and Light Company from 1968 to 1980. My last positions there were Distribution Senior Engineer-Substations and Senior Tariff Analyst. Since my retirement in 2005 I published a book, *Energy Utility Rate Setting,* and have done some utility consulting.

Q. Since this case deals with the classification and allocation of distribution costs, please elaborate on your utility experience in distribution.

A. I worked as a distribution substation engineer for ten years. During that time my work included calculating substation power transformer thermal loading capabilities; performing factory inspections of new substation power transformers; inspecting failed substation power transformers; preparing substation transformer (and other equipment) operation and maintenance instructions for substation field people; teaching transformer theory, operation and maintenance at substation repairman apprentice programs; and assisting in the development of planning philosophies, major equipment purchases and engineering designs.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address classification and allocation issues regarding distribution costs raised in the direct testimony of Mr. Paul Chernick on behalf of the Committee of Consumer Services (the Committee).

Q. Please provide a brief summary of your testimony.

A. I explain the role of classification and allocation in class cost of service studies. I give a brief history of the Company's Distribution Cost Allocation Study and the classification and allocation of distribution costs. I describe the Company's use of engineering standards and load data in the process of sizing distribution transformers and conductors and how it relates to classification and allocation of distribution costs. I explain why the Commission-approved classification and allocation methods for distribution costs are still reasonable.

Role of Classification and Allocation in Cost of Service Studies

Q. What is the purpose of classification and allocation in cost of service studies?

A. Most of PacifiCorp's costs of providing utility service are joint costs. Joint costs are the costs of shared facilities such as distribution substations and lines that serve multiple customers. These joint costs must be allocated among customer classes using the facilities. In order to make the allocation step easier and more accurate, a classification step is done first. Utility costs are booked into functional accounts such as distribution station equipment (substations) and overhead and underground lines. Classification is the further division of these functional costs into categories bearing a relationship to a measurable cost-defining service characteristic. Measurable means the service characteristic data is available for use in the allocation step. Cost-defining means a cost-causal relationship exists between the service characteristic and the utility costs to be allocated. Electric utilities traditionally use the classification categories of customer, energy, and demand. Once the costs are classified, they can be allocated to customer classes. Allocation is the apportionment of joint costs among rate classes based on each class's relative share of a measurable cost-defining service characteristic such as kilowatt-hours or peak demand in kilowatts. Costs classified as customer-related are allocated on the number of customers, often weighted by some cost information. Energy-related costs are allocated on relative energy usage. Demand-related costs are allocated on relative demands.

Q. How is a cost-causal link established?

A. A cost-casual link between customer service characteristics and utility costs is established when costs are allocated using service characteristics that are the same or similar to that used by utility engineers in making investment decisions. Sometimes the data used by engineers is not available by rate class or schedule, so surrogate data must be used.

Q. What is the difference between energy and demand costs?

A. Demand-related costs are a function of a customer's maximum demand (measured in kilowatts). This maximum demand is related to the electrical capacity of the customer's connected appliances, since the maximum demand would occur when all appliances are used at the same time. A utility must size the parts of its system to handle the simultaneous peak demand from all its customers at any given hour. Energy-related costs are a function of a customer's duration of use (measured in kilowatt-hours) of any connected appliances. For example, a portable electric heater rated at 1000 watts (equal to 1 kilowatt) would impose an electrical demand of 1 kilowatt on the electric system each time it is turned on. If the heater is left on for two hours, the energy use would be 1 kilowatt (demand) times 2 hours (duration) or 2 kilowatt-hours.

Distribution Cost Classification and Allocation Background

Q. How long has the current classification of distribution costs been approved by the Commission?

A. I believe since at least April 12, 1982 when the Commission in Utah Power Case No. 79-035-12 ordered distribution costs to be classified as demand-related (meter and service drops were classified as customer-related).

The Commission reaffirmed that classification of distribution costs in its March 7, 1983 order in Utah Power Case No. 81-035-13 when it adopted for future use the Division's classification of distribution costs. The Commission stated its intent of the order is to provide guidelines and policies for future cost of service studies. The Commission further ordered, "…any party who proposes alternative methods, except those specified in this Order for further study, will have the burden to demonstrate that the methods adopted in this Order are unreasonable".

History of the Distribution Cost Allocation Study

Q. What prompted the Company's Distribution Cost Allocation Study?

A. In Utah Power Case No. 81-035-13 the Division recommended further study to determine proper allocation methods for distribution costs. The Commission in its March 7, 1983 Order in that case stated, "The Company shall develop in consultation with the Division an allocation method that takes into account the design characteristics of the distribution system."

Q. What happened next?

A. In Utah Power Case No. 83-035-01, the allocation of distribution costs was still unresolved with the Division again recommending further study. The Commission in its January 30, 1984 Order directed the Company to conduct a study to determine the proper allocation of distribution costs and to submit the study by January 1985.

The Company filed its "Distribution Cost Allocation Study" on January 15, 1985. Although the Commission's directive was to determine the proper "allocation" of distribution costs, the Company also addressed the "classification" of distribution costs and confirmed the Commission's 1982 and 1983 classification decisions.

In the next Utah Power Case No. 84-035-01, parties presented testimony on the Distribution Cost Allocation Study with the Committee claiming that as much as 20 percent of transformer costs should be classified as energy-related and allocated accordingly. The Commission, in its June 7, 1985 Order stated, "The distribution study was also challenged by the Committee of Consumer Services and the Irrigation Pumpers Association. We believe that a strong and sufficient case was made for the reasonableness of the distribution study by the stipulating parties; however, we will permit additional consideration of this issue in a future proceeding."

In Utah Power Case No. 85-035-06, parties reexamined the Distribution Cost Allocation Study. An exchange of ideas in that case, including input from the Committee, and further work on the study resulted in the final version of the

Distribution Cost Allocation Study being submitted in October 1989.

Q. When did the Commission finally adopt the Distribution Cost Allocation Study Recommendations?

A. In Utah Power Case No. 89-035-10, the Distribution Cost Allocation Study was again considered. So after 6 years of study and review in multiple cases, the Commission in its February 9, 1990 Order adopted the Distribution Study allocation methods for future cost of service studies. Those allocation methods are the ones used for the past 18 years.

Q. Although the same allocation methods have been used over that period, have implementation changes occurred?

A. Yes. For example, In PacifiCorp Docket No. 97-035-01, the Commission in its March 4, 1999 Order established an Allocations Task Force, that I chaired, to study various unresolved allocation issues. The task force included 19 interested parties and met over an 8 month period. The December 16, 1999 Allocations Task Force Report states agreement was reached on the allocation of service drop costs. Research showed that irrigators had very small service drops, the cost of which was not included in the service drop account. The result was that the irrigation class no longer gets allocated service drop costs in the class cost of service study. This did not change the basic method used to allocate service drops to other classes. I think this type of approach might be a way to deal with the Committee issue of shared service drops which I will address later.

Distribution Classification Issues

Q. Committee Witness Mr. Paul Chernick is critical of the Distribution Cost Allocation Study. What do you perceive are his issues?

A. He says the Distribution Cost Allocation Study is not comprehensive since it limits consideration of energy-related investments, the energy role in distribution plant decisions is understated (specifically with regard to distribution transformers and conductors), the weighting of the allocation factor for the substations and primary conductors does not reflect cost-causation, and the allocation of shared service drops is not cost-based. I will first address his classification issues and in a later section the allocation issues.

Q. Do you agree with his comment that the Distribution Cost Allocation Study was not comprehensive with regard to the energy classification issue?

A. No. Could it have been more comprehensive? Yes, because an issue can always be studied more. But I believe it was comprehensive enough on classification, especially since the Commission directive to the Company was to do an "allocation" study, not a "classification" study as distribution classification had already been decided in 1982 and reaffirmed in 1983. I believe the Distribution Cost Allocation Study was an excellent study that involved a significant effort and considerable examination and review over a period of 6 years. In reviewing the Distribution Cost Allocation Study, I counted about 22 pages, not including supporting exhibits, discussing the rationale supporting the choice of distribution plant classifications. In a similar review of Mr. Chernick's testimony, I counted about 2 pages of testimony and 2 pages of his exhibit, PLC-8D.2. He offers no alternative comprehensive study, no specific recommendations regarding energy classifications and very little evidence to support his claims of an improper understatement of energy classification.

Q. Do you believe the evidence Mr. Chernick has submitted meets the burden of proof established by the Commission in its March 7, 1983 Order regarding a change in distribution cost classifications?

A. No.

Q. Although you believe the Distribution Cost Allocation Study was excellent and comprehensive enough, have you recently reviewed how the Company's engineers make distribution investment decisions?

A. Yes. As I stated earlier, the cost-casual link between customer service characteristics and utility costs is established when costs are allocated using service characteristics that are the same or similar to that used by utility engineers in making investment decisions. The classification of distribution costs should be based on a similar type of analysis. The important information then is what distribution design engineers use in making investment decisions, since that information is the cost-causer.

Even though the burden of proof is on the Committee as the party seeking a change in the classification of distribution costs, I decided to review the current process used by Company engineers in making distribution investment decisions, specifically for transformers and conductors. I reviewed the engineering standards, process and data used by the Company to design the distribution system to determine the importance of energy and demand in design decisions. I also talked with some of the Company's distribution engineers. The purpose was to learn if anything has changed that would affect distribution cost classification in the 19 years since the final Distribution Cost Allocation Study.

Q. What is the current approved classification of distribution plant?

A. The approved Distribution Cost Allocation Study methods break distribution plant into six categories for allocation purposes: substations, primary lines, line transformers, secondary lines, service drops, and meters. Meters and service drops are classified as customer-related. The other plant categories are classified as demand-related.

Q. Let's start with substations. Please describe how customer loads affect distribution substation design?

A. Substations must be designed to handle the maximum simultaneous load of the connected customers. The largest piece of equipment in a substation and also the most costly is the power transformer used to step down transmission voltage to distribution primary line voltage. The Company's cost of a new typical distribution substation transformer (18/24/30 MVA, 138,000 volts to 13,200 volts) in Utah is about $900,000, not including installation. The other substation equipment is then designed to coordinate with the load capability of the power transformer.

The load capability of transformers is limited by the temperature of insulating oil and the hottest spot within the windings, which are a function of the load and ambient temperature. Transformer nameplate capacity (in MVA) is based on an average ambient temperature of 30 degrees Celsius and represents the continuous load that the transformer can carry and last a normal life of about 40 years. Since transformers rely on air as a heat dissipation medium, higher altitudes with less air density result in reduced thermal capability. So in summation, the load-carrying capability of a transformer is a thermal capability and is primarily dependent on the electrical load, the ambient temperature, and the altitude.

Power transformers are a large mass of metal and oil. It can take a few hours for this mass to reach a steady state temperature once a given load is applied. Each transformer has its own set of characteristics (weight of the mass of metal and oil; no load and load losses; and average winding temperature rise). These characteristics are used, together with load data, in calculating the thermal load capability of a specific transformer. The total energy in kilowatt-hours of the applied load is not an input, because it does not provide the needed information about the peak load or the off-peak load and the respective durations. The key data is the peak load and its duration. Transformer nameplate capacity is stated in either KVA or MVA (measures of demand), not kilowatt-hours.

Q. What did you learn about how the Company sizes distribution substation power transformers?

A. PacifiCorp's Distribution System Planning Study Guide 1E.3.1 under "Substation Transformers" and "New transformer sizing", states "Transformer sizing is subject to an economic evaluation. Often the economic evaluation will result in a transformer at least two standard ratings larger than the projected peak load." The economic evaluation takes into account the expected load growth which may justify a larger transformer size initially rather than replacement a short time later. In this case, even with a load cycle that likely would be projected to be the same, a transformer two sizes larger is selected due to projected peak load growth. Although altitude, average ambient temperature and load cycle are taken into account, it is clear that the projected peak load (including growth) is the key driver in sizing substation transformers and therefore the key cost-driver of substation equipment. Peak load is demand and therefore the current demand classification of distribution substations is reasonable.

Engineers use peak-loading on substations that is not available by rate schedule so surrogate data must be used in the allocation step. The Distribution Cost Allocation Study found after analyzing several possible allocators, that a factor based on the 12 distribution coincident peaks, weighted by the number of substations peaking each month, was the best allocator.

Q. What did you learn about the design of distribution primary lines?

A. PacifiCorp's Engineering Handbook, section 1B.10, "Line and Feeder Design Criteria" states on page 3 under the heading "Conductor Sizing", "Main line distribution circuit conductors shall be of adequate size to serve the normal circuit load and shall have a limited reserve capacity margin above the expected peak loading requirements." Also, "Circuit main line conductors shall be scheduled for replacement when normal peak loading, based on forecasts from actual field measurements, exceeds 85 percent of the conductors thermal rating as specified in PacifiCorp's Distribution Construction Standards."

I learned from PacifiCorp's Engineering department that primary line conductor size selection is based on an economic analysis over the estimated 30 year life of the line. I learned the key determinants are the estimated initial peak load (load current in amperes) and the forecast load growth rate. The initial conductor size selection is important because the Distribution System Planning Study Guide 1E.3.1 states, "Costs for reconductoring often are much higher than for constructing a new pole line." "Reconductoring may involve significant reconstruction of the pole line including replacement, and in some cases relocation of many of the poles." "When selecting a new conductor, use the economic size, not the minimum size to carry the load. Once the work is required, the lowest total ownership cost for the new line should be the important factor, not the lowest first cost."

The reduction of load losses may affect the conductor size selection, but forecast high load growth may more likely justify a larger conductor size because of the high cost of future reconductoring. Estimates of costs of new line construction and reconductoring are included in PacifiCorp's Engineering Handbook, sections 2P.3 and 2P.4. For example, the estimated total (material & labor) installed cost per mile of new three-phase overhead 4/0 lines under difficult urban circumstances is $265,427. The comparable reconductoring cost per mile is $336,703.

The conclusion is that the sizing of primary lines is likely to be determined by the forecasted initial peak load and the forecasted growth in peak load. Therefore the current demand classification of primary lines is reasonable. The key load data engineers use for sizing primary lines is peak load in amperes on feeders measured at substations. This data is not available by rate schedule so surrogate data must be used in the allocation step. The Distribution Cost Allocation Study found after analyzing several possible allocators, that a factor based on the 12 distribution coincident peaks, weighted by the number of substations peaking each month, was the best allocator.

Q. What did you learn about the design of distribution line transformers?

A. Line transformers step primary voltage down to secondary levels for use by customers. The residential class has an average of about 6 customers per line transformer while most other classes (except small commercial with an average of 2) normally have a single customer connected to a line transformer. Like substation power transformers, line transformers are thermally limited in load carrying capacity, which is affected by the ambient temperature, the electrical load, and the altitude.

PacifiCorp has three engineering standards used in sizing line transformers: General Residential Electrical Demand DA411, Padmounted Transformers-Sizing Criteria GH011, and Overhead Transformers-Sizing Criteria EL021.

Standard DA411 is used to determine the peak demand (in kilowatts) for single family and multiple family dwelling units based on connected electric appliances. Standard DA411 also contains the summer and winter design coincidence factors that account for the diversity of loads when multiple customers are connected to a single line transformer. The coincident peak demand is then used to determine the transformer size using a table with different

KVA sizes and respective load capability based on summer and winter ambient temperatures. The Distribution Cost Allocation Study's recommended allocation factor for line transformers of the annual schedule non-coincident peak times the design coincidence factor is very close to the type of data engineers use and was found by the study to be the best allocator.

Standard GH011 for padmounted transformers refers to Standard DA411 for determination of the peak demand for residential customers and uses the same transformer sizing table. For non-residential loads this standard refers to standard EL021 for overhead transformers for specific sizing guidelines.

Standard EL021 for overhead transformers refers to DA 411 for determination of the peak demand for residential customers and uses the same transformer sizing table. For non-residential, a table is provided with three sets of transformer load capability data for three different preloads (50%, 75% & 90% of nameplate) with each set including load capabilities for different ambient temperatures and peak load periods. These preload levels represent continuous loading exclusive of peak load. Exhibit RMP___(LEA-1R-COS) shows that for a 50 KVA transformer and an 8 hour peak period, increases in the preload have a small effect on the load capability while increases in the ambient temperature have a much larger impact. The difference in average ambient temperature and even altitude for different customers has not been taken into account in allocation of transformer costs even though these parameters affect transformer sizing. I believe the reason is that the key cost driver is peak demand. When sizing a transformer for a bigger preload, a larger size may not be needed depending on the customer's peak load. Further, the exhibit shows that even if the next size line transformer is required, the incremental cost is small. The conclusion is that the key cost driver for line transformer investment is customer peak demand. Therefore the current demand classification of line transformers is reasonable.

Q. What did you learn about the design of distribution secondary lines?

A. Secondary lines are used primarily to serve residential customers since frequently several residential customers are served from the same line transformer (currently an average of 6 per transformer). The secondary lines eliminate the need for the very long service drops that would be needed to connect each customer directly to the shared line transformer. So in essence the secondary lines are an extension of the secondary voltage side of the line transformer and should be classified and allocated the same.

Standard DA411, for determining residential demand, provides several examples of sizing distribution line transformers to serve residential loads. Each example uses common residential appliance demands together with a table of load capabilities for various transformer sizes and ambient temperatures. The standard states that these calculated coincident peak demands are used in determining the transformer "and secondary sizes". So the load data engineers use to size secondary lines is the same as that used to size line transformers, and therefore, using the same classification and allocator is reasonable.

Standard ES001, Overhead Secondary-General Information, states "Overhead single phase secondaries shall be installed when service requirements to one or more customers will require more than one span of low voltage conductors (service drop) or when the maximum allowable length of the service conductors will be exceeded.” (Due to voltage drop) And “When constructing new lines in urban areas where many homes are served from the line, this cable can be an economical method of providing service. Because the economical choice between using secondary cable or using multiple transformers varies in each situation, cost comparisons should be made between the two alternatives before finalizing a cost estimate.” The standard lists several situations that favor the economics of using secondary aerial cable instead of installing additional transformers.

Standard ES001, under the heading, “Conductor Size Selection for Overhead Secondary” lists the first rule as, “Determine customers total peak demands and calculate load current with a possible load growth rate for the next 5 to 10 years.” Then it says to use Table 2 in Standard ES011 (which lists physical characteristics and ampacity for 1/0 and 4/0 conductors) to “…select a secondary conductor to carry this amount of load current.” Expected peak load current is the key cost driver here.

Standard GS001, Underground Secondary and Service-General Information lists steps in selection of cable size. For residential the first step is to use Standard DA411 to determine customer’s peak demand and load factor and then use a graph in Underground Secondary and Service-Residential Economical Service Cable Selection Standard GS041 to determine the economical cable size. A typical residential load with A/C might have 10 to 13 kilowatts of peak demand and an annual load factor of about 40 percent per Standard DA411. For a demand of 10-13 kilowatts, using the graph in Standard GS041, load factor has no impact on the cable size selection. In fact, for a peak demand of 13 kilowatts, the same underground cable size would be selected for the complete range of load factors of 20 to 80 percent. Again the conclusion is that peak demand is the key cost driver for secondary lines, and therefore, the current demand classification for secondary lines is reasonable.

Q. What about service drops?

A. Service drops connect customers either directly to a line transformer or to secondary lines that are connected to a line transformer. Service drops are classified as customer related (even though they are sized based on demands similar to secondary lines) since every customer needs one (although as Mr. Chernick has pointed out some are shared) and allocated using average service drop cost (for each rate schedule) times the number of customers. I believe the current customer classification for service drops is reasonable

Q. What do you conclude about distribution cost classifications?

A. In conclusion, the Commission decided the classification of distribution plant about 26 years ago with all distribution costs as demand-related except for meters and service drops. The Commission has not changed that decision. The Commission further placed the burden of proof on any party seeking a change. I do not believe the Committee has met that burden and based on my research of PacifiCorp's distribution investment decision process, I believe the current Commission approved classifications are reasonable.

Distribution Allocation Issues

Q. What are the Commission approved distribution cost allocation methods?

A. The following distribution allocation methods have been approved by the PSC and in use in Utah for the past 18 years.

Substation equipment and primary lines are classified as demand and allocated with a factor based on the 12 monthly distribution coincident peaks weighted by the number of distribution substations peaking in each month.

Line transformers and secondary lines are classified as demand and allocated with a factor based on schedule annual non-coincident peak (NCP) times the design coincidence factor (which takes into account load diversity for schedules with multiple customers on a single transformer).

Service drops are classified as customer-related and allocated using average service drop cost (for each rate schedule) times the number of customers.

Meters are classified as customer-related and allocated using average meter cost (for each rate schedule) times the number of customers.

Q. What are Mr. Chernick's issues regarding the allocation of distribution costs?

A. He says the allocation of shared service drops is not cost based and the weighting of the allocation factor for substations and primary conductors does not reflect cost-causation.

Q. Do you agree with his concern about shared service drops?

A. If the Utah census information he presented is representative of the magnitude of residential shared service drops in the Company's Utah service area, then a change in the calculation of the service drop allocation factor would be warranted. If multiple residential or commercial customers use a shared service drop, the conductor size would be larger than a normal single customer service drop and some diversity might be taken into account. I would expect the average cost per customer of a shared service drop to be smaller than the average cost per customer of individual service drops. The question is how much smaller? This is an area where some additional study is needed. First, data on the quantity of shared services would be needed (is the census data reflective of the Company's Utah customer base?) and second, the typical number of customers sharing those services, and third, how large are the shared service conductors and the related costs. Depending on the outcome of that study, the service drop allocation factor could be modified.

Q. Do you agree with Mr. Chernick's concern about the weights used in the allocation factor for substations and primary lines?

A. No. The approved allocation factor uses the 12 monthly coincident distribution peaks multiplied by a weighting factor based on the number of distribution substations that peak in each of the twelve months. The 12 monthly coincident distribution peaks are developed from load research data since actual coincident distribution peaks are not measured. The substation weighting factor is based on recent actual measured substation monthly peak loads. Mr. Chernick presents two alternative allocation factors for substations and primary lines, which he believes to be more cost causal. He states the first is computed from the ratio of the monthly peak on the substation to the annual peak on the substation, and squared so as to rapidly reduce the contribution as load falls, and summed the squares over the substations to derive the monthly weights. He states, "The second approach is similar, but starts with the ratio of the monthly peak on the substation (in MW) to the substation's capacity (in MVA)."

After reviewing his actual spreadsheet calculations, it appears that the actual calculation of both ratios is somewhat different from the description. The squared ratios are actually multiplied by the summer capacity before calculating the weighting percentages, but the effect of this difference is small. Apparently the capacity is used in the calculation to eliminate his concern about small and large substations being treated equally in the weighting factor calculation.

To examine Mr. Chernick's concern that a small KVA difference in peak load of a substation might have impacted the weighting factor calculation and his concern that small and large substations carry the same weight but have much different costs, I prepared Exhibit RMP___(LEA-2R-COS). In this exhibit, I used Mr. Chernick's spreadsheet (Attachment CCS 10.28) as a starting point to examine the actual substation monthly peak loads for the months of June, July and August. I eliminated all substations for which loads were not available for all twelve months. I sorted all data by peak month. Then I calculated the difference between the load in the peak month and each of the other two months and summed the columns of differences. The results show that the substations that peaked in July had a total load of 159,299 kilowatts in July more than the same substations did in August. The July peaking substations had a total load of 223,675 kilowatts in July more than the same substations did in June.

Next the results for the August peaking substations showed that they had a total load of 12,584 kilowatts more than the same substations did in July and 33,109 kilowatts more than the same substations did in June.

Lastly the results for the June peaking substations showed that they had a total load of 51,976 kilowatts more than the same substations did in July and 76,580 kilowatts more than the same substations did in August.

The conclusions drawn from this actual data mean that July was far more important in terms of cost causing peak load than either June or August. The total numbers are not close. It also means that June is more important than August as its total kilowatts load difference over August was 76,580 kilowatts compared to only 33,109 kilowatts for August over June (a net difference of 43,471 kilowatts).

Mr. Chernick's proposed two new weighting factors would result in August being considered more important than June and much closer to July than the above results would support.

Q. What do you conclude from your analysis of these three summer months?

A. In conclusion, I believe the weighting factors proposed by Mr. Chernick would result in movement away from cost causation, and therefore, does not warrant any change from the current weighting method used with the 12 distribution CP allocation factor for substations and primary lines.

Q. In your analysis of the summer months did you discover an error in the Company's original calculation of the substation weighting factor?

A. Yes. Apparently the spreadsheet function used in the calculations ignored duplicate monthly peaks that occurred for some substations. I recalculated the number of substations that peaked each month. For substations with duplicate peaks, I gave those months an equal fractional share of 1. I also eliminated substations with less than 12 months of data to address concerns of the Committee. The result is shown below:

	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
Original	130	27	11	5	16	19	16	9	3	8	14	58
Revised	120.4	26.9	12.7	4.7	15.5	18.9	17.6	10.4	4.0	9.0	14.7	59.4

Q. Does this correction affect the results of your analysis of the summer months?

A. No. My analysis focused on the total kilowatt load differences between the months and any duplicate peaks would have a zero difference before and after the correction.

Summary

Q. Please summarize your conclusions and recommendations regarding the classification and allocation of distribution costs.

A. I believe no change should be made in the classification or allocation methods for distribution costs for the following reasons:

1. The Commission in its March 7, 1983 Order in Utah Power Case No. 81-035-13 adopted for future use the same classification of distribution costs being used today and put the burden of proof on any party seeking a change. I believe the Committee has not met that burden.
2. The Company's extensive Distribution Cost Allocation Study was developed, refined and thoroughly examined over a 6 year period before the Commission

finally adopted the recommended distribution cost allocation methods in 1990.

3. The Committee has not provided any new study to show results different than the Company's Distribution Cost Allocation Study.
4. My current review of the Company's distribution engineering standards results in the conclusion that peak demand is the key cost driver in distribution transformer and conductor investment decisions.
5. The Committee's proposed two new weighting factors for the allocation factor used to allocate substations and primary lines would result in a movement away from cost causation and therefore no change is warranted in the current method. My mentioned correction of an error in the current weighting calculation is not a method change.
6. I recommend study of shared service drops to determine what modification of the allocation factor calculation is needed. I believe this modification is not a method change, but a refinement in the calculation. The current method uses weighted customers to allocate service drops. I believe a modification to the calculation of the weights might be needed.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(LEA-1R-COS)
Docket No. 07-035-93
Witness: Lowell E. Alt

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Lowell E. Alt

Transformer Loading

September 2008

Effects of Preload Increase and Ambient Temperature on the Load Capability of a 50 KVA line transformer under conditions of an 8 hour peak period

Effect of Increasing Preload @ 86F

			Capability kilowatts	Reduction %
Preload %	50	75		
Load capability kw	64	62	2	3%
Preload %	50	90		
Load capability kw	64	60	4	6%

Effect of Increasing Ambient Temperature

Ambient Temp.	86F	104F		
Preload %	50	50		
Load capability kw	64	59	5	8%
Ambient Temp.	86F	104F		
Preload %	75	75		
Load capability kw	62	56	6	10%
Ambient Temp.	86F	104F		
Preload %	90	90		
Load capability kw	60	51	9	15%

Source:
PacifiCorp 2008 Distribution Construction Standard EL021
Overhead Transformer Sizing Criteria

Average Installed Cost for Different Single Phase Line Transformers
For period March 2003 to April 2005

KVA size	overhead installed avg cost($)	Avg $/KVA		padmount installed Avg cost($)	Avg $/KVA
10	1433	143.30			
25	1557	62.28		2320	92.80
50	1873	37.46		2546	50.92
75	2383	31.77		2792	37.23
100	2759	27.59		3028	30.28
167				3396	20.34

Source:
PacifiCorp Marginal Cost Study

Rocky Mountain Power
Exhibit RMP___(LEA-2R-COS)
Docket No. 07-035-93
Witness: Lowell E. Alt

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Lowell E. Alt

Substation Peaks

September 2008

Analysis of June, July & August Peaks
Utah distribution Substations

July Peaking Substations	Jul-06	Aug-06	Jun-07	Peak kilowatts	kilowatt diff JULY/Aug	kilowatt diff JULY/Jun	Summer Capacity KVA
Cottonwood	64,434	57,488	52,472	64,434	6,946	11,962	74,900
East Bench	26,044	20,366	17,595	26,044	5,678	8,449	30,000
Southeast	33,201	27,914	29,728	33,201	5,287	3,473	22,400
South Ogden	20,215	14,971	12,138	20,215	5,244	8,077	23,900
Milford	6,840	2,131	5,558	6,840	4,709	1,282	14,000
South Jordan	25,705	21,544	22,236	25,705	4,161	3,469	30,000
Dimpledell	33,327	29,186	30,810	33,327	4,141	2,517	30,000
Hoggard	39,810	35,866	36,883	39,810	3,944	2,927	52,400
Dumas	48,877	45,165	44,470	48,877	3,712	4,407	60,000
Quarry	34,593	31,160	31,340	34,593	3,434	3,253	56,900
Hammer	35,714	32,505	33,091	35,714	3,209	2,623	60,000
South Mountain	32,364	29,337	32,312	32,364	3,028	53	30,000
Taylorsville	35,839	32,898	33,138	35,839	2,941	2,701	44,800
Meadowbrook	35,207	32,410	32,365	35,207	2,797	2,842	52,400
Union	38,748	36,019	36,083	38,748	2,729	2,665	50,400
Angel	48,764	46,311	45,152	48,764	2,453	3,611	60,000
Sunrise	32,115	29,678	28,118	32,115	2,437	3,997	60,000
Chapel Hill	21,733	19,352	19,469	21,733	2,381	2,264	30,000
East Layton	28,206	25,979	23,088	28,206	2,227	5,118	30,000
Northeast	20,758	18,760	18,022	20,758	1,998	2,736	29,400
Decker Lake	44,024	42,053	42,312	44,024	1,971	1,712	58,000
Casto	21,519	19,646	20,040	21,519	1,873	1,479	28,000
Fifth West	25,860	23,988	24,025	25,860	1,873	1,835	30,000
Lake Park	40,406	38,544	35,887	40,406	1,862	4,518	58,000
Hunter	19,281	17,492	17,065	19,281	1,788	2,216	22,400
Hogle	16,932	15,148	12,607	16,932	1,784	4,325	19,000
West Roy	21,348	19,628	16,958	21,348	1,720	4,390	23,900
70th South	17,688	15,992	14,799	17,688	1,696	2,889	30,000
Sandy	33,480	31,827	30,936	33,480	1,653	2,544	60,000
Ninetieth South	24,793	23,153	22,534	24,793	1,640	2,259	30,000
Nibley	7,112	5,492	6,703	7,112	1,620	408	14,000
Uintah	20,175	18,611	17,935	20,175	1,564	2,241	37,900
Welby	24,375	22,857	24,081	24,375	1,518	294	38,400
Jordan Park	20,902	19,399	18,205	20,902	1,503	2,697	30,000
Olympus	18,558	17,081	18,520	18,558	1,478	38	22,400
Smithfield	13,369	11,905	11,983	13,369	1,464	1,386	30,000
Altaview	31,355	29,927	30,657	31,355	1,428	697	46,300
Parrish	23,373	21,962	23,029	23,373	1,411	344	30,000
North Bench	22,297	20,908	20,187	22,297	1,388	2,110	23,900
Box Elder	10,779	9,417	10,196	10,779	1,362	584	14,000
Woods Cross	18,173	16,852	17,232	18,173	1,321	941	22,400
Midvale	15,698	14,395	15,603	15,698	1,303	96	23,900
Medical	15,246	13,971	14,686	15,246	1,275	561	34,900
Riverdale	21,278	20,005	18,768	21,278	1,273	2,510	30,000
Thirteenth South	22,105	20,870	21,159	22,105	1,236	947	26,400
Ivins	14,308	13,111	13,048	14,308	1,197	1,260	22,400
Fruit Heights	16,085	14,918	14,630	16,085	1,167	1,455	22,400
Third West	25,145	24,004	19,690	25,145	1,141	5,455	44,800
North Ogden	15,268	14,133	13,811	15,268	1,135	1,456	22,400
Midland	25,475	24,343	24,091	25,475	1,132	1,384	30,000
McClelland	30,229	29,105	27,536	30,229	1,124	2,693	44,800
Pioneer	19,649	18,532	17,253	19,649	1,117	2,397	30,000
Cold Water Cnyn	17,963	16,851	16,192	17,963	1,111	1,771	30,000
Draper	19,042	17,935	15,556	19,042	1,107	3,487	23,400
Parkway	31,878	30,776	30,327	31,878	1,102	1,551	52,400
Cudahy	26,927	25,825	26,734	26,927	1,101	193	30,000
Summit Creek	10,685	9,585	9,960	10,685	1,099	725	14,000
Toquerville	18,696	17,625	14,984	18,696	1,070	3,712	14,000
Magna	20,113	19,076	19,684	20,113	1,036	429	30,000
Layton	22,492	21,484	21,616	22,492	1,008	876	44,800
Pleasant View	11,701	10,698	10,562	11,701	1,003	1,139	14,000

Centennial	32,446	31,456	31,293	32,446	990	1,153	44,800
East Millcreek	14,723	13,738	11,893	14,723	984	2,830	22,400
Clearfield South	49,820	48,860	44,716	49,820	960	5,104	60,000
Morton Court	21,765	20,852	20,331	21,765	913	1,434	28,000
Plain City	12,212	11,311	11,399	12,212	901	814	22,400
Mapleton	9,594	8,717	8,700	9,594	877	895	14,000
Farmington	22,514	21,650	21,163	22,514	864	1,350	30,000
Pine Canyon	17,065	16,204	16,876	17,065	861	189	25,000
Orem	35,127	34,295	33,623	35,127	832	1,504	50,400
Emigration	20,562	19,781	18,086	20,562	781	2,476	28,000
South Weber	10,458	9,687	9,532	10,458	770	925	22,400
Stansbury	16,732	15,980	16,416	16,732	752	317	20,900
Parleys	11,822	11,075	11,475	11,822	748	348	16,800
Cannon	17,206	16,482	15,923	17,206	723	1,283	22,400
118th South	19,875	19,165	10,279	19,875	711	9,596	30,000
Second Street	9,887	9,189	7,236	9,887	698	2,651	12,000
Bear River	8,003	7,309	7,103	8,003	694	900	16,750
North Salt Lake	11,024	10,333	10,256	11,024	691	769	14,000
Marriott	16,890	16,212	16,508	16,890	678	382	22,400
Hale	12,571	11,893	9,714	12,571	677	2,856	14,000
Pelican Point	2,160	1,485	1,593	2,160	675	567	6,250
Rose Park	25,157	24,495	22,472	25,157	663	2,685	40,400
Kensington	5,124	4,489	4,754	5,124	635	370	7,000
Deweyville	3,960	3,366	3,600	3,960	594	360	4,687
West Comm.	13,541	12,951	10,423	13,541	590	3,118	22,400
Manila	17,187	16,598	16,518	17,187	589	668	30,000
Bluffdale	9,520	8,948	9,151	9,520	572	369	14,000
Westfield	15,549	14,978	14,993	15,549	571	555	30,000
Lincoln	18,303	17,777	17,455	18,303	526	848	22,400
Middleton	7,415	6,894	7,223	7,415	521	192	7,000
Havasu	1,062	558	918	1,062	504	144	6,250
Sixth South	16,076	15,576	15,603	16,076	501	474	22,400
Taylor	6,189	5,702	5,703	6,189	487	486	14,000
Lindon	21,053	20,599	19,660	21,053	454	1,393	23,900
Centerville	8,534	8,080	6,405	8,534	454	2,129	16,000
Rattlesnake	2,528	2,087	2,431	2,528	440	96	11,200
Enoch	7,650	7,260	5,380	7,650	390	2,270	12,500
Cherrywood	41,252	40,884	38,872	41,252	368	2,380	58,000
Snarr	26,907	26,577	26,736	26,907	330	171	44,800
Sharon	11,677	11,351	10,925	11,677	326	752	22,400
Kearms	41,812	41,507	39,329	41,812	305	2,483	60,000
Richmond	8,062	7,765	7,438	8,062	298	624	10,500
Valley Center	15,904	15,626	15,048	15,904	278	855	36,400
Vineyard	13,990	13,759	13,750	13,990	231	240	23,900
Mountain Green	3,888	3,672	3,672	3,888	216	216	6,250
Capitol	13,060	12,846	11,742	13,060	214	1,318	22,400
Jordan	6,261	6,055	5,761	6,261	206	500	14,000
Willowridge	9,653	9,456	9,188	9,653	197	465	14,000
Benjamin	1,251	1,071	704	1,251	180	547	2,000
Delta	9,063	8,886	8,326	9,063	177	737	21,900
Cross Hollow	10,531	10,375	7,397	10,531	156	3,134	22,400
Warren	17,864	17,734	15,866	17,864	130	1,998	30,000
Morgan	1,348	1,233	1,147	1,348	115	201	4,687
Mantua	456	380	401	456	77	55	2,300
Fielding	824	750	810	824	74	14	7,000
Promontory	324	288	270	324	36	54	2,000
St John	1.100	0.990	1.100	1.100	0	0	3,750
Ferron	1,476	1,476	1,476	1,476	0	0	7,000
Moore	225	225	223	225	0	2	3,500
Oakley	2,700	2,700	2,700	2,700	0	0	6,250
Skull Valley	1	1	1	1	0	0	2,000
Totals					159,299	223,675	

August Peaking Substations	Jul-06	Aug-06	Jun-07	Peak kilowatts	kilowatt diff AUG/Jul	kilowatt diff AUG/Jun	Summer Capacity MVA
Lone Tree	9,006	11,292	7,806	11,292	2,286	3,486	22,400
Brunswick	21,274	22,859	18,014	22,859	1,585	4,845	67,200
Holladay	24,659	26,209	21,837	26,209	1,549	4,372	36,400
West Ogden	24,190	25,727	23,869	25,727	1,537	1,858	60,000
Pleasant Grove	23,709	25,178	22,699	25,178	1,469	2,479	28,000
Enterprise Valley	7,104	8,104	7,934	8,104	999	170	12,500
Richfield	16,200	16,848	15,768	16,848	648	1,080	24,500
Timp	22,948	23,388	22,562	23,388	440	825	30,000
Highland	28,921	29,356	27,567	29,356	435	1,789	53,900
West Temple	21,742	22,141	20,494	22,141	399	1,647	54,900
American Fork	26,729	27,124	24,673	27,124	395	2,450	30,000
Newgate	15,426	15,652	14,749	15,652	226	903	22,400
East Hyrum	1,593	1,809	1,620	1,809	216	189	6,250
Oakland	19,794	19,913	14,450	19,913	118	5,462	24,700
Dixie Deer	813	913	681	913	100	232	2,000
Winkleman	168	240	124	240	72	116	500
Hiawatha	18	90	1	90	72	89	1,000
LeGrande	72	92	76	92	20	16	1,500
Clive	1,164	1,181	81	1,181	17	1,101	3,800
Ophir	0.01	0.10	0.07	0.10	0.09	0.03	2,500
Totals					12,584	33,109	

June Peaking Substations	Jul-06	Aug-06	Jun-07	Peak kilowatts	kilowatt diff JUNE/July	kilowatt diff JUNE/Aug	Summer Capacity MVA
Terminal	13,113	8,918	20,068	20,068	6,956	11,150	44,000
Bangerter	35,671	33,557	42,185	42,185	6,514	8,628	52,400
West Jordan	16,620	19,744	22,101	22,101	5,480	2,357	28,000
McKay	12,984	13,327	16,816	16,816	3,832	3,490	22,400
West Valley #1	21,776	20,675	24,818	24,818	3,042	4,144	30,000
Gordon Avenue	17,379	16,953	20,200	20,200	2,821	3,247	30,000
Twenty Third St.	6,311	5,947	8,758	8,758	2,447	2,811	14,000
Northridge	5,695	5,562	8,081	8,081	2,386	2,519	14,000
Saratoga	18,714	17,266	20,504	20,504	1,790	3,237	30,000
Coleman	21,406	21,331	23,093	23,093	1,688	1,762	51,900
Syracuse	29,792	29,390	31,219	31,219	1,428	1,829	52,400
North Logan	14,075	13,701	15,457	15,457	1,382	1,757	25,000
Butlerville	48,993	47,968	50,259	50,259	1,267	2,292	82,400
University	22,066	21,629	23,113	23,113	1,047	1,485	54,000
Ridgeland	35,152	35,207	36,033	36,033	881	826	44,800
Redwood	34,369	33,863	35,246	35,246	877	1,383	44,800
Carbonville	2,935	2,938	3,583	3,583	648	646	6,250
Grow	41,434	41,430	42,070	42,070	637	640	74,000
Lewiston	8,136	7,453	8,705	8,705	568	1,251	14,000
Defense Depot of Ogden	3,175	3,470	3,658	3,658	482	187	16,100
Tooele Depot	6,486	6,660	6,956	6,956	470	296	14,000
Melling	214	214	653	653	439	439	5,000
Brooklawn	2,784	2,712	3,216	3,216	432	504	5,000
Gunnison	5,760	5,364	6,120	6,120	360	756	9,375
West Cedar	19,517	18,352	19,874	19,874	358	1,522	30,000
Clinton	34,010	31,944	34,357	34,357	347	2,413	52,400
Grantsville	11,133	10,616	11,476	11,476	343	860	14,000
Snowville	4,036	4,025	4,342	4,342	306	317	6,250
New Harmony	2,232	1,992	2,520	2,520	288	528	5,000
Bush	7,236	6,660	7,524	7,524	288	864	10,500
Willow Creek	1,908	1,872	2,160	2,160	252	288	2,000
Welfare	2,880	2,844	3,132	3,132	252	288	4,687
Tooele	21,056	20,339	21,292	21,292	235	953	23,900
Newton	2,200	1,355	2,432	2,432	232	1,077	5,000
Amalga	2,540	2,504	2,748	2,748	208	244	10,500
Bingham	18,579	14,623	18,743	18,743	163	4,120	22,400
Oquirrh	30,862	28,644	31,020	31,020	158	2,376	30,000

Rasmussen	346	329	495	495	149	167	600
Holden Irrigation	2,448	2,412	2,556	2,556	108	144	3,750
Vickers	1,282	1,316	1,377	1,377	94	61	2,000
Lark	2,640	2,570	2,716	2,716	76	146	6,250
Pariette	463	462	528	528	65	66	3,750
Bothwell	3,286	2,945	3,326	3,326	41	382	3,750
Hamilton Fort	641	612	682	682	41	70	500
Green River	2,874	2,663	2,913	2,913	39	250	5,000
Marysvale	715	247	754	754	39	507	1,500
Burton	4,392	3,600	4,410	4,410	18	810	4,700
Riter	11,387	10,893	11,388	11,388	1	495	22,400
Totals					51,976	76,580	

Rocky Mountain Power
Docket No. 07-035-93
Witness: Scott D. Thornton

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Scott D. Thornton

Load Research

September 2008

Q. Please state your name.

A. My name is Scott D. Thornton.

Q. What is your business address and by whom are you employed?

A. My business address is 1407 W North Temple Street, Salt Lake City, Utah. I am employed by Rocky Mountain Power (the "Company").

Q. What is your position with Rocky Mountain Power Company and what are your responsibilities?

A. My current position is Manager, Metered Data Management in the Metering Business Unit. I am responsible for the development of all class load profile estimates utilized in cost allocation, rate design, forecasting and special studies. I direct the design, implementation, and maintenance of all load studies performed by both Rocky Mountain Power and Pacific Power Companies. I am responsible for the development of load coincidence factors and for the determination of the distribution system peak for the Company.

Q. What is your educational and work experience?

A. I have Bachelors Degrees in Accounting and Business Administration/ Economics from Westminster College. Additionally, I have a Masters Degree in Business Administration from Brigham Young University. I have over 29 years of experience with the Company, 24 of those years associated with load research activities.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony is in response to the Testimony of UIEC witness Mr.

Maurice Brubaker and CCS witness Mr. Paul Chernick. My rebuttal will focus on the reliability of sample estimates used in this case to support cost allocation recommendations, as well as Mr. Brubaker's assertion that any difference between class load totals and the corresponding jurisdictional loads should be rolled into the sampled rate groups.

Rebuttal of Mr. Maurice Brubaker

Q. In his testimony Mr. Brubaker recommends that the Company's load research data should not be used. What are his primary criticisms?

A. Mr. Brubaker's overall contention is that load research samples are old and they have not been reconciled to Utah jurisdictional loads.

Q. Are these valid reasons to reject the load research data?

A. No, they are not. The sample data are providing load estimates consistent with what we are seeing in the billing system. Indeed, Mr. Brubaker has not provided any evidence that the data are providing inaccurate load estimates. As indicated in the Company's response to UIEC 20-4, these samples are still providing kWh estimates consistent with what we are seeing in the billing system.

Sample Estimates

Q. Do you agree with Mr. Brubaker's representation that the samples for Utah Schedules 001, 006 and 023 are very old?

A. No. While I agree with Mr. Brubaker that the sample designs were prepared a number of years ago, the sample data are current. The Schedule 6 and Schedule 23 designs were constructed in 1990; the residential sample was constructed in 1991. In 1999, both the residential and Schedule 6 designs were re-weighted to reflect population usage at that time. In addition, both of these samples were supplemented with additional sample sites. The Schedule 23 sample, which is based on a robust 3 strata design, was not supplemented.

On the other hand, the sample <u>data</u> used to provide load estimates in this case was collected during the specified test year, January through December 2007 and is very current.

Q. Mr. Brubaker asserts that RMP's load research samples have not shown to be representative of current customers in Utah, because many changes have taken place in the use of appliances (particularly central air conditioning) and in load shapes. Do you agree with this assertion?

A. I do not. The assertion implies that a load study sample represents a static picture of load use at the time of the sample design. This is incorrect. Load profiles derived from samples today in no way reflect what we would have seen in 1992. Our customers are dynamic, ever changing. Older appliances are replaced with newer, energy efficient models. Housing is upgraded with more energy efficient insulation and windows. Evaporative coolers are being replaced with central air conditioning. Our sample group are purchasing home computers and large, flat screen TV's. These appliances are not limited to new construction stock.

We know our customers are doing these things because we see it in their energy consumption. In 1999 the average residential monthly kWh/customer was 637.635 kWh. The sample design was re-weighted based on that level of usage. Sample data collected during 2006 indicates that usage levels increased to 709.46 kWh/month, and in 2007 the estimated usage grew to 735.67 kWh/month. As shown in our response to UIEC 20-4, the 2006 residential sample kWh estimate is within 4.7 percent of the amount shown in billing records for the same period. In 2007, the sample data provided an estimate within 0.8 percent of that recorded in billing records.

The Company's response to UIEC 20-4 presents a comparison of sample estimates vs. billed energy over similar time periods for the three samples identified by Mr. Brubaker. While the 2006 Schedule 6 sample data did not perform as well as the others, in all other cases the samples were very accurate. For the test year 2007, all samples provided acceptable load estimates based on comparisons to billing data.

Load Calibration

Q. Mr. Brubaker has noted that loads used in RMP's class cost of service study are not reconciled to the loads in the jurisdictional study. He recommends that the monthly loads of Schedules 1, 6 and 23 be adjusted such that a bottom up summation of the class loads used in this study match the jurisdictional monthly contribution to system peak. Do you agree that these samples must be adjusted to match the jurisdictional contribution?

A. No. Implicit in Mr. Brubaker's recommendation is the assumption that any difference between the "bottom up" summation of sample loads and the corresponding jurisdictional loads is directly attributable to sample error, therefore any adjustment should be applied only to sample loads.

I offer three reasons why I believe Mr. Brubaker's recommendation should not be adopted:

1. Class loads, both census and sample, are based on load data collected at the customer site. When building up to the jurisdictional load, it is necessary to first adjust the customer data by an appropriate loss factor. Loads prepared by load research are adjusted by a static annual loss factor, differentiated by the service voltage level. That is, the same adjustment is made to every hour of the day, every day of the week, for the entire year. This methodology does not recognize the effects of ambient temperature on losses. As shown in Mr. Brubaker's exhibit UIEC_(MEB-4), the differences between class and jurisdictional loads follows a seasonal pattern which appears correlated to seasonal temperature. During the hot days of summer, losses are greater and during the cold days of winter, losses are less. Losses are applied to all class load studies, not just the samples identified by Mr. Brubaker. If the difference identified by Mr. Brubaker is deemed to be related to losses, any difference should be applied to all customer classes.
2. Losses associated with wholesale sales are reflected in the jurisdictional loads. If all of those losses were assigned to the sampled loads, it would overstate their share of system loads. We have addressed this in data responses in previous cases.
3. On July 1, 2002, the Load Research Working Group, chaired by the Committee of Consumer Services, submitted a report to the Utah Public Service Commission. Among other items in the report, the problems

associated with comparing class load data to jurisdictional loads was addressed. For example, the report states:

> "The general conclusion was that there is something occurring within the Utah Border Load that is more likely the source of the calibration problem than the load research data or the census data. The Working Group agreed that the Company should discontinue the practice of calibrating Utah load research data."

The term "calibration", in this instance, refers to the practice of adjusting sampled loads such that the sum of the class loads is equal to the corresponding jurisdictional load.

Irrigation Sample Accuracy

Q. Do you wish to comment on Mr. Chernick's testimony concerning irrigation sample accuracy?

A. Yes. Attachment DR CCS 10.2 (Tab PricingAdj7) of Mr. Chernick's testimony shows a comparison between the kWh as computed from sample estimates vs. kWh derived from the Company's billing system. For the months of May, June, July, August and September, the table indicates that irrigation sample data is overstated by 26 percent, 26 percent, 7 percent, 30 percent, and 75 percent. Based on this disparity, Mr. Chernick recommends that the sample data not be relied upon to support a major cost allocation action.

Q. Do you agree with Mr. Chernick's recommendation?

A. No, I do not. For any load study, your primary goal is to produce an accurate load curve while secondly you want the sample kWh to compare favorably to billing kWh. Irrigation samples present us with special problems not found with other load studies. In any given year, approximately 30 percent or better of the customers selected to participate in the load study will not be irrigating. This can have a negative effect on the accuracy of the load curve.

For this current irrigation study, we took steps to assure an accurate load curve in order to provide an accurate estimate of irrigation class usage at the times of the monthly system peaks. The customer selection pool was comprised only of those irrigation customers who had measurable irrigation load for two consecutive years. That one change had a huge impact on the number of sample customers who had measurable load during the test period. The reason behind the change was that it was appropriate to sacrifice sample kWh accuracy compared to billing in return for a more accurate load curve. With an accurate load curve one can then scale the magnitude of that curve up or down to match the billed kWh without changing the shape of the curve. In our study we then scaled that load curve down to match actual billed energy which produced a statistically accurate estimate of irrigation class usage at the times of the monthly system peaks.

To summarize, the focus of this latest irrigation load study was to provide an accurate load curve. The magnitude of that curve, utilizing typical mean-per-unit expansion of the data, would have otherwise been overstated but was corrected using billing data, thereby providing a statistically accurate estimate. We believe that these are solid irrigation load estimates, and we recommend the Commission accept them.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

Rocky Mountain Power
Docket No. 07-035-93
Witness: F. Robert Stewart

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of F. Robert Stewart

Changes to Electric Service Regulations

September 2008

Q. **Please state your name, business address and present position with Rocky Mountain Power (the Company), a division of PacifiCorp.**

A. My name is F. Robert Stewart. My business address is 4171 W Lake Park Blvd, Salt Lake City, Utah 84120. My present position is Regulatory Consultant, Customer & Regulatory Liaison in the Customer Services Department.

Q. Are you the same F. Robert Stewart who has previously testified in this proceeding?

A. Yes. However my business address has changed to that just given from when my direct testimony was given.

Q. Do you have any other changes to your direct testimony?

A. Yes, I am withdrawing the proposed change to Regulation No. 3 and the associated testimony given in my direct testimony – from line 30, page 2, through line 78, page 4. Specifically, the Company is withdrawing the proposed changes to Regulation No. 3 to hold former customers responsible for reasonable court costs, attorney's fees and /or collection agency fees incurred in the collection of unpaid debt. Consequently I am also withdrawing Exhibit RMP___(FRS-1) which contained the modified Regulation 3.

Q. Why is this proposal being withdrawn?

A. This withdrawal is being made subsequent to agreement with the AARP and to allow further study of the issue in a more collaborative fashion with interested parties if the Company pursues the issue in the future. There was concern by third parties that this change would pose a burden on low income customers, in particular the low income elderly. In general the elderly are conscientious in payment of their debts and the Company expectation is they would not be burdened. But since the Company's data does not include customer age or income the actual impact on different classes of residential customers could not be projected using current Company data.

Q. Are there other changes to your testimony?

A. No. The Company continues to support the remaining proposed changes and recommends the commission approve them. None of the intervening parties to the case have opposed these changes, and the Company has not received objection from any party to the remaining proposals.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Rocky Mountain Power
Docket No. 07-035-93
Witness: Carol L. Hunter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Carol L. Hunter

Ownership of Environmental Attributes

September 2008

Q. Please state your name, business address and present position with Rocky Mountain Power (the Company), a division of PacifiCorp.

A. My name is Carol L. Hunter. My business address is 201 South Main, Suite 2300, Salt Lake City, Utah 84111. I am Vice President of Communications and Division Services at Rocky Mountain Power ("the Company"). As part of my duties I am responsible for the planning and oversight of the Company's energy efficiency and demand side management initiatives.

Q. What is the purpose of your rebuttal testimony?

A. I will address the UAE and Wal-Mart proposal to eliminate the requirement that a customer transfer to Rocky Mountain Power all "Environmental Attributes" attributable to a Rocky Mountain Power sponsored and funded demand side management program.

Q. Is this rate case the proper forum to address and resolve ownership of renewable energy credits and other environmental attributes?

A. No. These issues should be addressed by a Commission rulemaking docket as prescribed in SB202 and codified in Utah Code Section 54-17-601. However, since the issue has been raised, I will respond to the UAE and Wal-Mart proposal.

Q. How are Rocky Mountain Power demand side management programs funded?

A. Rocky Mountain Power's demand side management and energy efficiency programs are funded by all customers of Rocky Mountain Power through Electric Service Schedule No.193, Demand Side Management (DSM) Cost Adjustment. The DSM Cost Adjustment, which collects just over two percent of each customer's monthly bill, is designed to recover the costs incurred by the Company associated with Commission-approved demand side management expenditures. The revenue received through the DSM Cost Adjustment is used to support cost-effective load management and energy efficiency programs. Customer incentives associated with these programs are designed to influence customers' energy efficient decisions, not to completely compensate customers for their investment.

Q. How do customers benefit?

A. All customers receive benefits from the energy efficiency programs, including customers participating directly and non-participants, through lower net power costs. When traditional embedded cost pricing methods are used to set retail rates in an increasing cost environment, retail consumers receive a significantly dampened price signal regarding the higher incremental cost of new energy resources. Lacking the proper price signal, customers may not choose DSM opportunities even when it would be cost-effective for the total customer base if this decision was made. Ways in which to overcome this inadequate price signal include offering customers DSM programs, educating customers on energy efficiency and encouraging policy makers to adopt energy efficient technologies, codes and standards.

In addition, customers directly participating in energy efficiency programs realize a direct benefit of lower electricity bills and/or improved efficiency.

Q. How are energy efficiency programs and the associated environmental attributes treated in the Company's integrated resource plan?

A. The IRP assumes that carbon based resource options competing against energy efficiency resources carry an additional cost for carbon. As a consequence, energy efficiency resources are given added value in comparison to carbon based alternatives. Since the value ascribed energy efficiency resources within the IRP is the cost to beat in designing DSM programs, it's inappropriate after such an evaluation to transfer the value those carbon offsets to any customer who requires a utilities DSM program to justify the investment in a energy efficiency project.

Q. In his testimony Mr. Steve W. Chriss (UAE-WM Exhibit (COS/RD2) claims it is the participating customer who implements the measure and owns the measure, not the Company? (UAE-WM Exhibit COS/RD2, page 5, line 1)? Do you agree with this representation?

A. I agree the participating customer owns the physical asset, but ownership of the physical assets that result in energy savings is not the question. The question in this case is when an individual customer accepts funds from other customers under the premise the incentive was integral in making the project happen, does the participating customer retain ownership of the environmental attributes or do the environmental attributes belong to all customers.

Q. Mr. Chriss proposes that when a customer such as Wal-Mart accepts an incentive by participating in one of Rocky Mountain Power's demand-side management programs, the participating customer should retain the environmental attributes associated with the energy savings. Is this equitable?

A. No. The value of the environmental attributes has been captured in the design of the demand-side management program and therefore is already reflected in the incentive paid participating customers. Consequently, the value of the environmental attributes should benefit all of Rocky Mountain Power's Utah customers, not merely the participating customer.

Q. In his testimony Mr. Chriss stated the current contractual language requires the transfer of the environmental attributes without any corresponding payment or consideration to the customer. Is this correct?

A. No. As stated earlier, the incentive received by customers reflects the value of the environmental attributes.

Q. Mr. Chriss testifies the transfer of environmental attributes to Rocky Mountain Power serves as an impediment to broader participation in energy efficiency and demand reduction programs. Is this correct?

A. No. Since 2005, when this requirement was placed in our standard contract language, thousands of customers have participated in Company sponsored demand side management projects. To date, Mr. Chriss' client Wal-Mart is the only customer that has insisted that the language be changed.

Q. Mr. Chriss testifies the transfer of environmental attributes to Rocky Mountain Power is inconsistent with the recently enacted Utah Code Sections 54-17-601(10)(e)(i) and 54-17-603(4)(b). Is this correct?

A. No. Sections 54-17-601(10)(e)(i) and 54-17-603(4)(b) do not state customers who own demand side measures have the "right" to the environmental credits or attributes derived from those measures if the measures are the product of funding provided by other customers. That is why contracts between Rocky Mountain Power, acting on behalf of funding customers, and participating customers delineate ownership of environmental attributes, such as renewable energy credits. If the customers funding Rocky Mountain Power's demand-side management programs do not receive the benefits associated with environmental attributes they fund, they should rightly question if the tariff programs should continue as currently constituted.

Q. Who benefits when the "environmental attributes" cited by Mr. Chriss are transferred to Rocky Mountain Power?

A. Rocky Mountain Power's customers, not the Company, are the beneficiaries. Wal-Mart and the Utah Association of Energy Users want to claim the benefits of investments made possible through funds provided by other Rocky Mountain Power customers.

Q. Do you agree with Mr. Chriss' claim that under his proposal the funding customers would receive equitable benefits for financing demand side measures of participating customers?

A. No. I maintain that funding customers should continue to receive the value of "environmental attributes." While the value today or even the future value may not be large, that value should belong to the funding customers to the extent they made the attributes possible. Wal-Mart and other participating customers have the option of installing energy efficiency measures at their cost without an incentive from the funding customers and retaining all the environmental benefits.

Q. What recommendation do you have regarding Mr. Chriss's proposal?

A. I recommend that the Commission reject his proposal.

Q. Does this conclude your rebuttal testimony?

A. Yes.