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

September 15, 2008

Via Electronic and U.S. Mail

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision
Docket No. UE 197

Dear Filing Center:

On behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket, enclosed please find an original and five copies of:

- Surrebuttal Testimony and Exhibits of Dr. Alan Rosenberg (filed on behalf of ICNU).

Thank you for your assistance regarding this matter.

Sincerely yours,

/s/ Brendan E. Levenick
Brendan E. Levenick

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing documents on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid.

Dated at Portland, Oregon, this 15th day of September, 2008.

/s/ Brendan E. Levenick
Brendan E. Levenick

PORTLAND GENERAL ELECTRIC
DOUGLAS C TINGEY
121 SW SALMON 1WTC13
PORTLAND OR 97204
doug.tingey@pgn.com

PORTLAND GENERAL ELECTRIC
RATES & REGULATORY AFFAIRS
PATRICK HAGER **(C)**
121 SW SALMON ST 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com

JIM DEASON
ATTORNEY AT LAW
1 SW COLUMBIA ST, SUITE 1600
PORTLAND OR 97258-2014
jimdeason@comcast.net

JESSE D. RATCLIFFE **(W)**
ASSISTANT ATTORNEY GENERAL
1162 COURT ST NE
SALEM OR 97301-4096
jesse.d.ratcliffe@doj.state.or.us

BOEHM KURTZ & LOWRY
KURT J BOEHM **(C)**
MICHAEL L KURTZ
36 E SEVENTH ST - STE 1510
CINCINNATI OH 45202
kboehm@bkllawfirm.com
mkurtz@bkllawfirm.com

DEPARTMENT OF JUSTICE
JASON JONES **(C)**
MICHAEL WEIRICH **(C)**
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST NE
SALEM OR 97301-4096
jason.w.jones@state.or.us
michael.weirich@doj.state.or.us

PUBLIC UTILITY COMMISSION
JUDY JOHNSON **(C)**
PO BOX 2148
SALEM OR 97308-2148
judy.johnson@state.or.us

COMMUNITY ACTION DIRECTORS OF OREGON (W)
JIM ABRAHAMSON **(C)**
PO BOX 7964
SALEM OR 97301
jim@cado-oregon.org

JANET L PREWITT
1162 COURT ST NE
SALEM OR 97301-4096
janet.prewitt@doj.state.or.us

LEAGUE OF OREGON CITIES
SCOTT WINKELS
PO BOX 928
SALEM OR 97308
swinkels@orcities.org

FISHER SHEEHAN & COLTON (W)
ROGER D. COLTON
34 WARWICK RD
BELMONT MA 02478
roger@fsconline.com

OREGON ENERGY COORDINATORS ASSOC (W)
JOAN COTE **(C)**
2585 STATE ST NE
SALEM OR 97301
cotej@mwvcaa.org

CITIZENS' UTILITY BOARD OF OREGON (W)
ROBERT JENKS **(C)**
OPUC DOCKETS
610 SW BROADWAY - STE 308
PORTLAND OR 97205
dockets@oregoncub.org
bob@oregoncub.org

OREGON DEPARTMENT OF ENERGY (W)
KIP PHEIL (**C**)
625 MARION ST NE – STE 1
SALEM, OR 97301-3737
kip.pheil@state.or.us

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision	)
	)

MARGINAL COST OF SERVICE STUDY/REVENUE ALLOCATION

SURREBUTTAL TESTIMONY OF DR. ALAN ROSENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

September 15, 2008

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alan Rosenberg, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in St. Louis, Missouri.

Q. ARE YOU THE SAME ALAN ROSENBERG WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. My qualifications were described in Exhibit ICNU/201.

Q. WHAT IS THE SUBJECT MATTER OF YOUR SURREBUTTAL TESTIMONY?

A. I will respond to the testimony of Staff witness Dr. George Compton regarding his recommendations on a new rate design for Schedule 89 and also to the rebuttal testimony of the Portland General Electric Company ("PGE" or the "Company") panel witnesses on Cost of Service (Kuns, Cody, Lynn). I would also note that my failure to address any particular statement or recommendation of the Staff, or of PGE, should not be construed as necessarily agreeing with those assertions or positions.

<u>SURREBUTTAL TO STAFF</u>

Q. WHAT IS DR. COMPTON'S PROPOSAL REGARDING SCHEDULE 89?

A. Dr. Compton is proposing to differentiate the on-peak and off-peak energy rates between the Summer season (which Dr. Compton defines as the months of July, August and September) and the remaining nine months of the calendar year. He also proposed to add a third "super-peak" in the summer months so that there would be three rate periods as follows:

Super Peak	Noon to 8 PM, Monday through Saturday
On-Peak	6 AM to Noon and 8 PM to 10 PM, Monday through Saturday
Off-Peak	All Other Hours

Q. WHAT IS DR. COMPTON'S STATED RATIONALE FOR INTRODUCING THESE CHANGES?

A. Dr. Compton observes that "the eight-hour period from noon to 8 p.m. in the summer time has significantly higher costs than the rest of the standard sixteen hour 'on-peak' period."[1/] He further notes that marginal energy costs in the summer are significantly higher than the comparable cost in the other nine months of the year. Dr. Compton therefore reasons that his proposal would:

- Be more cost based than the current rate design;
- Be fairer and more equitable; and
- Promote load shifting from high cost periods to low cost periods.

Q. DO YOU AGREE WITH DR. COMPTON?

A. No. I do not agree with his proposal; however, I do agree with his observation that there are seasonal and diurnal differentials in PGE's marginal energy costs. I also agree that instituting cost-based rates should encourage economic load shifting for those customers with the ability to alter their use. Customers operating at a very high load factor might find it difficult or impossible and costly to shift loads without considerable capital investments in their manufacturing plants. The Commission also should consider the impacts on industry and their employees if industrial customers are forced to add a graveyard shift to their operations. Finally, I agree that cost-based rates are inherently fairer and more equitable than non-cost-based rates. Unfortunately, however, there are several problems with Dr. Compton's proposals.

First, Dr. Compton's proposals are incomplete. For example, I find that the differential between the winter season and spring/autumn season power supply costs is more pronounced than the disparity between the summer and winter power supply costs.

1/ Staff/500, Piro-Tooman/10, line 22 – page 11, line 1.

(This is shown on Exhibit ICNU/206.) Yet, Dr. Compton proposes sharp differentials between summer and winter rates and no difference at all between winter and spring/fall rates.

Second, as even Dr. Compton acknowledges, his proposed rate design may encourage load shifting from summer months to the winter months.[2] While July and August could be considered peak months, the months of November through February are unquestionably peak load months as well. Thus, Dr. Compton's proposal is sub-optimal if the goal is to dampen the need for capacity additions on PGE's system and to reduce the system's total energy costs. Moreover, September, which Dr. Compton classifies as a "peak" month, has a lower system peak demand than any other month except May.

Third, lacking data regarding the distribution of loads between the super-peak and shoulder periods in the summer, Dr. Compton was forced to make certain assumptions to assign loads to these respective time periods. Consequently, there is a question as to whether his proposed rates would collect the appropriate amount of revenue.

Consequently, while I sympathize with Dr. Compton's objectives, I find his proposal to be too simplistic and premature. Furthermore, the policy objectives that he is trying to achieve may not be possible for industrial customers. The result may be to simply penalize the customers who are the least costly to serve. Therefore, on balance, the Commission should reject Dr. Compton's recommendation to modify the rate design of Schedule 89.

---

[2] ICNU/209, Rosenberg/2-3 (from OPUC Staff First Set of Data Responses to ICNU Data Request).

Q. HAVE YOU ANY SUGGESTIONS AS TO HOW PGE AND THE COMMISSION COULD ACHIEVE DR. COMPTON'S OBJECTIVES IN A MORE EFFECTIVE AND APPROPRIATE MANNER?

A. Yes. Based on my experience with large forest products manufacturers, I believe that large industrial customers should be offered the option of taking service on a two-part Real Time Pricing ("RTP") rate. The basic concept of this rate is that the customer is charged a cost-based access fee predicated on operating at a certain baseline load shape, which could be either flat or it could be based on some historic load data adjusted for any known changes. Then the customer is either charged, or credited, for any deviations from that baseline at marginal cost. The advantage of this rate design is that the customer's baseline revenues are anchored in a cost of service rate, but any load shifting is encouraged or discouraged, as the case may be, on the utility's hourly marginal costs. Of course, it may take some effort and collaboration among the utility, the Staff, and the potential participating customers to work out the details of such a tariff.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS OR CONCERNS REGARDING DR. COMPTON'S RATE DESIGN PROPOSAL?

A. Yes. While Dr. Compton recognizes the significance of daily and diurnal differences of generation costs in relation to rate design, he does not seem to be bothered that these same differences are ignored in PGE's cost of service study. I find this ambiguity to be troublesome. While class rate design affects the allocation of costs within a customer class, the cost of service study guides the distribution of the revenue requirement among the classes. Thus, the cost of service study is every bit as important as rate design to the goal of developing cost-based rates. If the Commission wishes to reflect daily and diurnal differences in generation costs, then these costs should be reflected in both rate spread and rate design.

Q. IN HIS RESPONSE TO ICNU DATA REQUEST 1.4[3], DR. COMPTON DISAGREES THAT THESE DIURNAL COST DIFFERENCES ARE NOT REFLECTED. IS DR. COMPTON CORRECT ON THIS SCORE?

A. No. Dr. Compton states in that response that since PGE was in possession of hourly cost estimates, the presumption is that such costs were combined with the loads under each schedule to generate the total peak period energy costs for each schedule. However, it is in the combining, or averaging process, that much of the information gets lost. I will speak to that issue in further detail when I respond to PGE's rebuttal testimony.

<u>SURREBUTTAL TO PGE</u>

Q. IN YOUR DIRECT TESTIMONY, YOU NOTED A NUMBER OF DEFICIENCIES THAT YOU DETECTED IN PGE'S COST OF SERVICE STUDY. DID PGE AGREE WITH YOUR ASSESSMENT OF THE PROBLEMS IN ITS COST OF SERVICE STUDY?

A. PGE agreed with my assessment in part, and disagreed in part. However, I would note that in its rebuttal testimony, PGE presented an alternative cost of service study for the Commission's consideration. This alternative study is a step in the right direction, and demonstrates the validity of my objections to PGE's initial cost of service study.

Q. THE FIRST PROBLEM THAT YOU NOTED WITH PGE'S ORIGINAL COST OF SERVICE STUDY WAS THAT IT WAS TOO BROAD BRUSHED. DID PGE'S RATE PANEL AGREE WITH YOUR ASSESSMENT OF THE PROBLEM?

A. They did to an extent, but they attempted to minimize the problem. For example, they stated that they "<u>believed</u>" the results would "<u>likely</u>" not be "<u>significantly</u>" different had they used hourly prices instead of monthly on-peak and off-peak prices.[4/] Note however, how heavily they qualify their assertion. Moreover, PGE did not provide any analysis whatsoever that would support their "belief." In fact, when directly asked for any

---

[3] ICNU/209, Rosenberg/1-2 (from OPUC Staff First Set of Data Responses to ICNU Data Request).

[4/] PGE/2000, Kuns-Cody-Lynn/12, lines 15-18.

studies, analyses or investigations that support this "belief," PGE could only respond that this is "an opinion based on the experience of the witnesses."[5/] Consequently, we must take this "opinion" for what it is, namely just speculation.

The PGE panel also noted that the ratio of the highest to the lowest hourly price within MONET is approximately 5.3 to 1, instead of the 100 to 1 ratio that I noted with respect to Mid-C prices. However, that in no way eliminates the problem I identified in my direct testimony. The problem is still there – it is just a question of degree. Consider, for example, the following hypothetical example:

Hourly Prices

Hour	Market Price	Class A Usage	Class A Marginal Cost	Class B Usage	Class B Marginal Cost
1	$20	20	$400	60	$1,200
2	$100	100	$10,000	60	$6,000
3	$50	60	$3,000	60	$3,000
Total		180	$13,400	180	$10,200

Monthly Prices

Period	Market Price	Class A Usage	Class A Marginal Cost	Class B Usage	Class B Marginal Cost
Off-Peak	$20	20	$400	60	$1,200
On-Peak	$78.57	160	$12,571	120	$9,429
Total		180	$12,971	180	$10,629

5/ ICNU/209, Rosenberg/4 (from PGE Tenth Set of Data Responses to ICNU Data Request).

As shown above, there is simply no way, except by sheer accident or coincidence, that an hourly allocation of marginal energy costs would produce the same result as an allocation based on 24 different averages of monthly on-peak and off-peak costs.

Q. THE SECOND PROBLEM THAT YOU NOTED WITH PGE'S ORIGINAL COST OF SERVICE STUDY WAS THAT IT NEGLECTED THE ROLE OF RELIABILITY AND CAPACITY. DID PGE'S RATE PANEL AGREE WITH YOUR ASSESSMENT OF THE PROBLEM?

A. The panel acknowledged that PGE's planning process includes capacity resources and that NERC imposes reserve requirements. However, they claim that because market prices of energy include the cost of operating reserves, these considerations are implicitly included.[6/]

Q. DOES THAT SATISFACTORILY ADDRESS YOUR CONCERN?

A. No. In the first place, operating reserves are ancillary services that are typically recovered through separate, unbundled charges under the requirements of FERC Order No. 888, rather than through market energy prices. Moreover, even if the cost of operating reserves were included in market prices, this would not address the problem. That is because market energy prices in only a relatively few on-peak hours would likely reflect those charges, and PGE's averaging process would mask their impact. Moreover, I would note that PGE's Open Access Transmission Tariff ("OATT"), which sets out the rates for spinning reserves and supplemental reserves, separately charges for these ancillary services on a per kW basis, not an energy basis. Thus, PGE's OATT contradicts the notion that operating reserves are somehow bundled into market energy prices.

6/ PGE/2000, Kuns-Cody-Lynn/13, lines 10-11.

Q. THE THIRD PROBLEM YOU NOTED IS THAT THE COMPANY COST ANALYSIS FAILS TO DISTINGUISH BETWEEN FIXED AND VARIABLE GENERATION COSTS. HOW DID PGE RESPOND TO THIS PARTICULAR ISSUE?

A. PGE acknowledged that a portion of its generation revenue requirement is related to fixed plant, but noted that a large portion of the fixed costs are based on historical considerations and so are not marginal.

Q. DOES THAT OBSERVATION ASSUAGE YOUR CONCERNS?

A. No. The implication here is that because these costs were incurred in the past, from a marginal cost perspective it would be acceptable to ignore how these costs are incurred. There are two problems with this assertion. First, from the perspective of equity, these costs still have to be recovered, and it is unfair to ignore the usage patterns that gave rise to these costs. Moreover, PGE continues to incur fixed generation cost prospectively. For example, just last month, PGE issued an RFP for 50 MW of demand response peak capacity to reduce dependence on supply-side resources. Anticipated growth in peak demand will inevitably lead to higher fixed costs and this reality must be reflected in the cost allocation process in order to properly and fairly assign responsibility for these costs.

Q. WHAT WAS THE FOURTH PROBLEM YOU NOTED WITH THE PGE COST STUDY?

A. I noted that it is unreasonable to assume that PGE's long-term fixed production capital costs are fully reflected in short term on-peak energy prices. Even if such costs were reflected in energy prices to some extent, it would only be for a relatively brief period of time, which would then be lost in the averaging process.

Q. DID PGE AGREE WITH THAT APPRAISAL?

A. It did not disagree and went so far as to acknowledge that PGE was not claiming that the 2009 projected market prices recover long-term fixed production capacity costs.[7/] This admission underscores the fact that PGE's initial cost of service study ignores this important element of the utility's cost structure in assigning customer class responsibility for the incurrence of costs on the PGE system.

Q. HOW DID PGE ASSESS YOUR ALTERNATIVE METHODOLOGY TO REMEDY THE SHORTCOMINGS WITH PGE'S MARGINAL COST METHODOLOGY FOR GENERATION COSTS?

A. PGE raised three substantive objections to my study. First, it said that the fixed cost allocation in my alternative study was done on an embedded basis, rather than a marginal one. Second, PGE stated that the weighted five coincident peaks that I used do not necessarily reflect the periods when PGE may need capacity the most. Third, PGE asserted that by continuing to use monthly on-peak and off-peak prices I have effectively "double counted" the Company's fixed generation capacity costs – once explicitly in allocating the fixed costs and again implicitly by using the on-peak energy prices.

Q. HOW DO YOU RESPOND TO THE FIRST CRITICISM?

A. PGE is correct, as I had already acknowledged in my direct testimony. In fact, that was a key reason why I recommended weighting my alternative study 50/50 with the Company's initial study. This approach would temper the impact of transitioning from a marginal to an embedded cost analysis.

Q. HOW DO YOU RESPOND TO THE SECOND CRITICISM?

A. PGE complains that my use of "100 peak hours" to allocate fixed production costs gives too much emphasis to the winter months, and insufficient weight to the summer months.

[7/] PGE/2000, Kuns-Cody-Lynn/15, lines 4-7.

Of course, I was simply trying to reflect the apparently greater probability that the winter period will be critical to the need for more capacity. In point of fact, in 2007 there were only 110 hours that were within 10% of the annual peak and 92 of those hours occurred in the winter. Nevertheless, I do agree that PGE experiences a secondary peak in the months of July and August, and therefore PGE could, in the future, become a summer peaking utility if this trend continues. Certainly, reasonable people can disagree on what weightings to give to each month in a multiple coincident peak allocation method.

Q. HOW DO YOU RESPOND TO THE THIRD PGE CRITICISM?

A. I disagree that there is a double counting problem. As I noted previously, that objection could conceivably be valid if one were to use an hourly allocation of marginal energy prices and if one were to accept the premise that energy prices adequately reflect generation fixed costs. However, any possible double counting would be masked by the averaging process that PGE employed to develop monthly on-peak and off-peak energy prices. More importantly, I disagree with the assertion that market energy prices implicitly reflect the recovery of the long-run, fixed generation costs that PGE must incur to operate its system in a reliable manner. Therefore, my use of market energy prices does not result in a double counting of fixed generation costs.

Q. PLEASE REFER TO PGE/2000, KUNS-CODY-LYNN/19. THERE PGE STATES ITS BELIEF THAT THE COMMISSION SHOULD BE PRESENTED WITH A COST ANALYSIS THAT IS BOTH MARGINAL AND IS LONG RUN IN NATURE. CAN YOU AGREE?

A. Yes. As long as there is the prospect of the need for additional capacity – and clearly the evidence is that PGE will need to address its capacity considerations – there will be a need to reflect both short-run costs, which by definition ignore capacity, as well as long-run costs in the cost allocation process. This need is all the more important because customers make both short-run energy consumption decisions (such as when to turn up or down a thermostat), as well as decisions with long-run implications, such as whether to install new machinery or whether to insulate their house.

Q. PGE HAS IDENTIFIED A FUTURE NEED FOR CAPACITY RESOURCES AND IT HAS ACKNOWLEDGED THAT IT MAY BE APPROPRIATE TO EXPLICITLY RECOGNIZE CAPACITY COSTS IN THE MARGINAL COST CALCULUS. IS PGE'S PROXY PEAKER PLANT ANALYSIS RESPONSIVE TO THIS NEED?

A. I could accept PGE's proxy peaker plant marginal cost analysis (what PGE refers to as "Method 2" in its rebuttal testimony) as a reasonable alternative to the cost of service study I supported in my initial testimony with one important reservation. PGE relied on FERC "tests" to support the use of a 12 CP method to allocate the marginal cost of capacity. PGE's proxy peaker plant analysis would only be valid if it excluded the six off-peak months. In other words, the methodology should use at most a 6 CP method, rather than a 12 CP method.

Q. WHY ARE YOU RECOMMENDING THAT WE DISREGARD THE SIX OFF-PEAK MONTHS IN THE ALLOCATION OF CAPACITY-RELATED GENERATION COSTS?

A. Precisely because they are off-peak months, as even PGE acknowledges and characterizes as such. If PGE's generation capacity is sufficient to meet the system's needs during the peak months, it is a fortiori sufficient to meet the capacity needs of the off-peak months. Thus, including the six off-peak months in the allocation formula is not only not cost-based (because these off-peak months are irrelevant to additional capacity requirements), but including these extraneous peaks in the allocation formula dilutes the signal that a capacity allocation is intended to provide - namely to discourage demand growth at the time of the system peak.

Q. HOW DO YOU RESPOND TO PGE'S USE OF "FERC TESTS" THAT SUPPOSEDLY SUPPORT THE USE OF A 12 CP METHOD?

A. First, the "FERC tests," to the best of my knowledge, are only applicable to embedded cost of service studies. PGE acknowledged that at least "the majority of the FERC rate cases are based on embedded cost of service study methodologies." Response to ICNU Data Request 10.290.[8] Even if one were to apply the FERC tests in this case, I would note that the PGE data barely passed the first test, which is comparing the average of the 12 monthly peaks with the highest monthly peak. PGE states that the threshold ratio is 84%. For the PGE data, the ratio was 84.7%. But more importantly, there is no evidence that the off-peak months, which average only 77.9% of the annual peak, play any role in PGE's planning process. In PGE's 2007 Integrated Resource Plan, the load forecast was concerned with the Winter Peak and the Summer Peak. There is simply no evidence that the other months are critical to the need for new capacity. I have attached ICNU/207 to this surrebuttal testimony which depicts the monthly peaks on the PGE system. Unless PGE can produce data that would suggest that the Loss of Load Probability or some other reliability index is equally relevant to all months, the prominence of the data clearly shows that no more than 6 CP would be an appropriate measure of demand cost responsibility.

Q. HAVE YOU REPLICATED PGE'S MORE COMPLETE MARGINAL COST METHODOLOGY THAT USES 6 CP INSTEAD OF 12 CP IN THE ALLOCATION OF MARGINAL CAPACITY COSTS?

A. Yes. The results are shown in ICNU/208. This Exhibit also compares the 6 CP Study (Columns 4 and 5) with PGE's original marginal cost analysis that ignores any long-run

[8] ICNU/209, Rosenberg/5 (from PGE Tenth Set of Data Responses to ICNU Data Request).

or capacity cost considerations (Columns 2 and 3). (The latter is what PGE terms "Method 1" in its rebuttal testimony.)

Q. COULD YOUR VERSION OF THE COMPLETE MARGINAL COST ANALYSIS BE IMPROVED UPON?

A. Yes. PGE used a single annual marginal energy cost to derive the class responsibilities for the energy-related component of the marginal cost, i.e., the short-run marginal cost. However, the fact is that short-run marginal costs can, and do, vary from hour to hour, depending upon the running (i.e., variable) cost of the last (and typically the most expensive) generating unit needed to meet the load. Using a single marginal cost for every hour ignores that reality.

Q. WHAT IS THE PRACTICAL RESULT OF USING A SINGLE ANNUAL SHORT-RUN MARGINAL ENERGY COST INSTEAD OF RECOGNIZING THESE HOURLY FLUCTUATIONS IN PGE'S MARGINAL ENERGY COST?

A. The end result is that the cost analysis summarized in ICNU/208, Column 4, understates the cost of the weather sensitive classes, such as Rate Schedule 7, and overstates the cost of the classes with relatively constant loads, such as Rate Schedule 89. This is due to the fact that relatively constant loads consume a larger proportion of their total energy consumption during off-peak hours, when short-run marginal energy costs tend to be relatively low. Nevertheless, the 6 CP Study is still a huge improvement over PGE's Method 1 cost analysis.

Q. IF THE COMMISSION DETERMINES THAT REFLECTING LONG-RUN MARGINAL COSTS IN THE COST STUDY IS APPROPRIATE, THEN PGE FAVORS AN ALLOCATION PROCESS THAT GIVES EQUAL WEIGHT TO METHOD 1, WHICH IGNORES LONG-RUN MARGINAL COST, AND TO METHOD 2, WHICH ENCOMPASSES THESE REAL COSTS. DO YOU AGREE?

A. No. The reasons that PGE gives for this 50/50 weighting of the two methods are: (1) it helps to mitigate rate impacts; and (2) that weighting is consistent with my own recommendation. However, this reasoning does not hold up to scrutiny.

First, it is Method 1, not Method 2, which is in need of mitigation. Method 1 is indicating the need for some classes to receive increases of almost twice the system average. (I am ignoring Schedule 47 and Schedule 49, which would require a Customer Impact Offset ("CIO") regardless of the cost methodology chosen. There is no dispute on the appropriateness of implementing a moderation for these two classes.) In contrast, Method 2 (even with the 6 CP application) indicates at most, an increase of less than 1.3 times the system average. Consequently, if PGE did not deem it necessary to moderate Method 1, it is hard to see why Method 2 would require any tempering. Again, I am ignoring the CIO for Schedule 47 and Schedule 49. Thus PGE's "logic" on this issue is simply wrong.

Second, although I did recommend a 50/50 weighting of Method 1 and an alternate cost method in my direct testimony, that reasoning is not applicable in this case. In my direct testimony, I was weighting a marginal cost study with the indications of an embedded study, and I was making a concession to that effect. In this case, both studies are unquestionably marginal, so that is no longer necessary.

Third, in my direct testimony, I did note the need for rate moderation. However, that was because the alternative study (which I proposed to be weighted with the

Method 1 study), did indicate some rate schedules receive increases that were nearly two times the system average increase. Therefore, I felt there was a need for rate moderation. As I have already noted, however, that is no longer a concern with the Method 2 study.

Finally, in my direct testimony, I validated the use of a 50/50 weighting of my alternative cost study and the Method 1 study by noting that the 50/50 weighting produced a result that was very close to the classic peaker deferral method. However in this case, Method 2 is <u>already</u> a peaker deferral method. Thus, the reasoning that led me to recommend a 50/50 weighting of two studies is simply inapplicable in this case.

Q. IS THE COST ANALYSIS THAT APPEARS IN THIS SURREBUTTAL TESTIMONY DIRECTLY COMPARABLE TO THE COST STUDIES YOU SUBMITTED IN YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. No. PGE changed a number of inputs to the study in its rebuttal testimony. Consequently, the analysis in this exhibit was designed to comport with those changes.

Q. COULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. Yes. My first recommendation is reject Dr. Compton's proposal to redesign Schedule 89. While Dr. Compton's motives are sound, the mechanics of his design are incomplete and premature. Instead, I suggest that work get started on designing an optional two-part RTP rate that would provide accurate signals to increase or decrease load each hour.

My second recommendation is to adopt PGE's "Method 2" study, with but one modification, as the sole guide for the distribution of any rate increase in this proceeding. That modification is to use 6 monthly coincident peaks (instead of 12) in the allocation of the marginal capacity costs. Such a study would satisfactorily redress the problems that I identified to PGE's "Method 1" study. Moreover, of all the marginal studies presented in this case, it would do the best job of accurately portraying the manner in which customer consumption patterns give rise to PGE's cost of generation and supply.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision	)
	)

ICNU/206

PGE's 2009 Average Power Costs
Marginal Power Supply Cost Estimates - By Month and Season

September 15, 2008

PORTLAND GENERAL ELECTRIC COMPANY

PGE's 2009 Average Power Costs
Marginal Power Supply Cost Estimates - By Month and Season

		On-Peak		Off-Peak		Total	
Line	Month	MWh	$/MWh	MWh	$/MWh	MWh	$/MWh
		(1)	(2)	(3)	(4)	(5)	(6)
	Summer Season						
1	July	937,158	88.17	596,279	56.41	1,533,437	75.82
2	August	958,749	95.18	578,815	70.37	1,537,564	85.84
3	September	888,399	89.74	509,238	66.84	1,397,637	81.40
4	Wtd Avg.		**91.08**		**64.36**		**81.01**
	Spring, Autumn Seasons						
5	April	892,669	61.02	555,087	44.59	1,447,756	54.72
6	May	909,678	56.17	523,999	35.96	1,433,677	48.78
7	June	879,228	52.39	522,505	34.89	1,401,733	45.87
8	October	922,208	78.49	554,495	62.04	1,476,703	72.31
9	March	1,022,235	73.69	591,763	61.54	1,613,998	69.24
10	Wtd Avg.		**64.71**		**48.27**		**58.58**
	Winter Season						
11	November	1,005,386	84.74	584,915	72.83	1,590,301	80.36
12	December	1,095,884	87.72	680,662	78.53	1,776,546	84.20
13	January	1,112,689	82.89	674,574	73.16	1,787,263	79.22
14	February	959,590	78.57	575,377	69.90	1,534,967	75.32
15	Wtd Avg.		**83.61**		**73.79**		**79.92**
16	Summer to Winter		**1.089**		**0.872**		**1.014**
17	Winter to Spring, Fall		**1.292**		**1.529**		**1.364**

The current, year-round "on-peak" is defined as 6 a.m. - 10 p.m., Mon. - Sat.
Data Source: PGE 1200 Work Papers 49.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

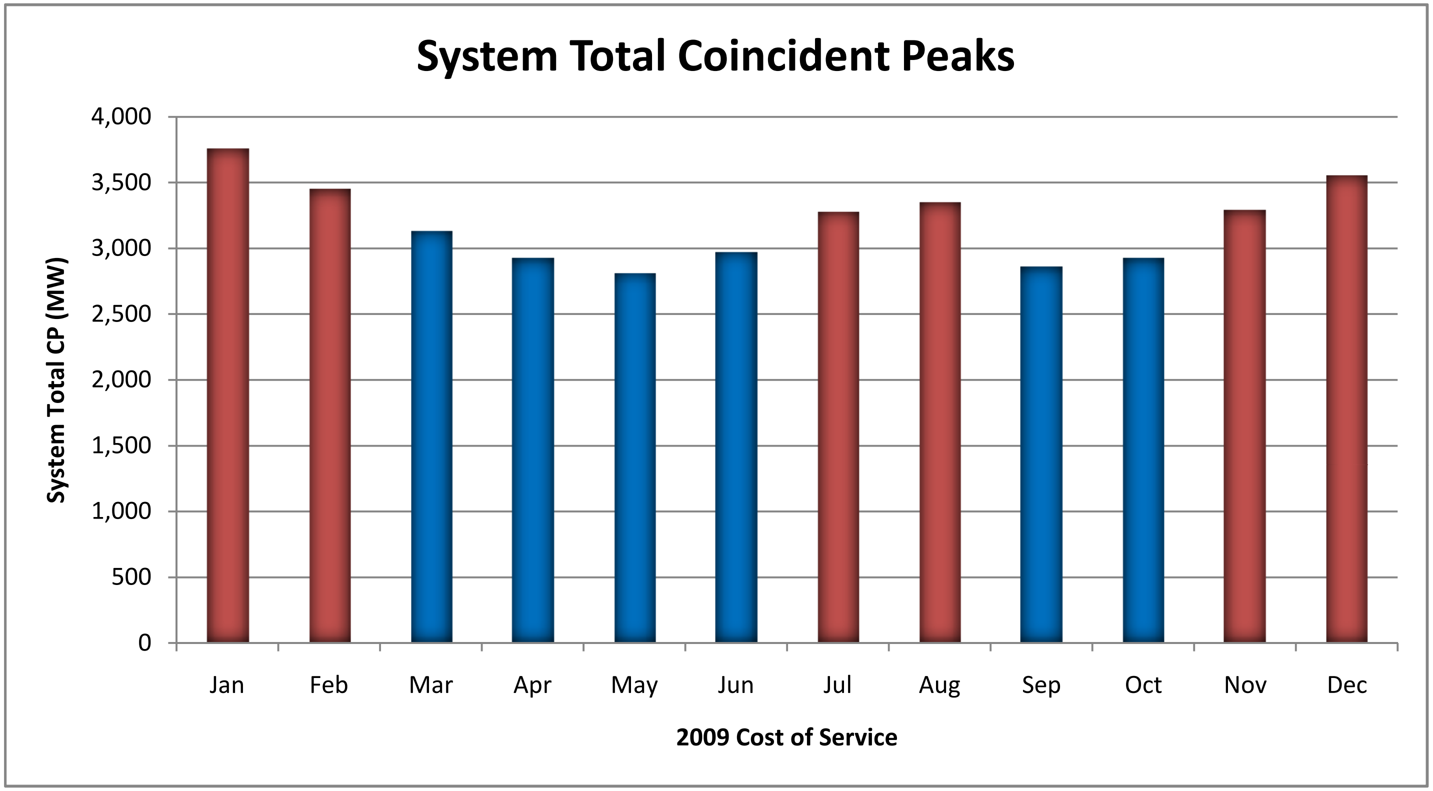
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
	)

ICNU/207

System Total Coincident Peaks

September 15, 2008

PORTLAND GENERAL ELECTRIC



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
	)

ICNU/208

Comparison of Method 1 and Method 2
Using 6 CP

September 15, 2008

PORTLAND GENERAL ELECTRIC

Comparison of Method 1 and Method 2
Using 6 CP

Line No.	Schedule	Current Revenues (1)	Method 1 Proposed Revenues (2)	Method 1 Percent Change (3)	Method 2 Proposed Revenues (4)	Method 2 Percent Change (5)
1	7	$ 764,344	$ 863,152	12.9%	$ 891,346	16.6%
2	15	$ 4,323	$ 4,517	4.5%	$ 4,505	4.2%
3	32	$ 143,924	$ 160,095	11.2%	$ 155,060	7.7%
4	38	$ 7,103	$ 8,099	14.0%	$ 7,202	1.4%
5	47	$ 2,253	$ 2,831	25.6%	$ 2,831	25.6%
6	49	$ 4,821	$ 6,057	25.6%	$ 6,057	25.6%
7	83-S	$ 411,732	$ 461,137	12.0%	$ 453,017	10.0%
8	83-P	$ 21,052	$ 23,965	13.8%	$ 23,252	10.4%
9	89-S	$ 49,228	$ 56,058	13.9%	$ 54,818	11.4%
10	89-P	$ 117,427	$ 135,558	15.4%	$ 128,815	9.7%
11	89-T	$ 74,757	$ 87,469	17.0%	$ 82,036	9.7%
12	91	$ 16,968	$ 17,869	5.3%	$ 17,840	5.1%
13	92	$ 365	$ 446	22.4%	$ 419	15.0%
14	93	$ 86	$ 97	12.8%	$ 96	10.9%
15	94	$ 7	$ 9	22.4%	$ 8	13.6%
16	Total	$ 1,618,388	$ 1,827,359	12.9%	$ 1,827,301	12.9%

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision	)
	)

ICNU/209

PGE Data Responses to ICNU Data Requests

OPUC Staff Data Responses to ICNU Data Requests

September 15, 2008

Response:
As shown in the lower right-hand corner of Staff/504, Dr. Compton's rate design will produce revenues of $251.7 million (assuming the sales quantities indicated), as opposed to the $250.9 million produced by the Company's rate design, as shown in the lower right-hand corner of page 8 of PGE Exhibit 1203. Once the Schedule 89 revenue requirement is established, naturally all candidate rate designs should and undoubtedly will be constructed to produce that established amount of revenues. Caveat: PGE was unable, within its data response time constraint, to provide a breakout of the Schedule 89 energy quantities by season and type of peak. Dr. Compton is confident that such data can ultimately be produced so as to assure "revenue neutrality" between the Staff rate design proposal and the Company's. (Projected quantities for the peak period and off-peak periods of every day and month in the future test period were developed by PGE in order for it to allocate energy production costs among the schedules.)

Request:
1.4 Mr. Compton states that rates should reflect costs. Staff/500 at 7, lines 12-14. Mr. Compton also recognizes that there is a super-peak period during the day when power supply prices are measurably higher than at other times. Staff/500 at 11, lines 10-11. He also notes that even within a month, loads and prices can vary significantly depending upon how hot the day is. Staff/500 at 15, lines 17-18.

a. Does Mr. Compton believe that these daily and diurnal differences are reflected in PGE's cost of service study? If so, where specifically in PGE's model does he believe those differences are reflected?
Response:
Since PGE was in possession of hourly cost estimates, the presumption is that such were combined with schedule hourly volumes to generate the total peak period energy costs for each schedule. Consequently, each schedule's cost allocation could/would/should incorporate the hourly prices/marginal costs.

b. Assuming that these daily and diurnal differences are not reflected, or not adequately reflected in the cost study, would Mr. Compton agree that the Company study is not a reliable guide for revenue allocation? If not, please explain why.
Response:
Dr. Compton would not agree.
Even if PGE could only use average peak-period prices (instead of breaking out super-peak period prices and quantities), the fact that different schedules have different weightings of peak and off-peak consumption, combined with the fact that the average prices differ between the peak and off-peak periods, mean that the Company's cost allocation approach is more reliable than the former approach, which ignores peak versus off-peak price differences. (It should be noted that comparatively high-load-factor schedules benefit from PGE's breaking energy costs into peak and off-peak averages,

and allocating costs accordingly.) And even if super-peak versus shoulder-peak period distinctions are not made in the cost allocations, since those distinctions are well known they can still be incorporated in rate design construction, per se.

Request:

1.5 Referring to page 6, lines 10-23 of Staff/500, Mr. Compton states that PGE's cost allocation approach is reasonable. Please explain why diurnal, daily and seasonal variations in costs should not be reflected in cost allocations.

Response:

It is not clear that such were not reflected in the cost allocations. (Refer to the answer to 1.4.a.) If they in fact were not this time, they should be reflected in the future cost allocations.

Request:

1.6 Mr. Compton's proposals on rate design seem focused on market supply costs, as opposed to PGE's owned generation.

a. Does Mr. Compton agree that this is a fair characterization of his testimony? If not, please explain why it is not fair and cite to any evidence for such disagreement.
Response:
It is fair, but incomplete (see below).

b. Does Mr. Compton agree that PGE owns regulated generation resources?
Response:
He agrees.

c. Assuming that PGE does own regulated generation, does Mr. Compton agree that the cost of that generation ought to be reflected somehow in rates? If not, please explain why not.
Response:
Own-generation costs are "somehow" reflected in the rates in the sense that the rates are designed to recover embedded production costs, which consist of the costs of PGE's own resources combined with its purchase costs. Even if cost allocations did not, or only imperfectly incorporated marginal costs, rate design should reflect marginal costs as much as possible/feasible.

Request:

1.7 Does Mr. Compton agree that adoption of his rate design proposals may shift load from the three summer months to the winter period? If not, please explain why not?

Response:

There could be a limited amount of seasonal load shifting on the part of industrial customers who possessed the desire and ability to build up some additional production stockpile prior to the commencement of the summer peak season. Summer-period-pricing-induced conservation practices by residential and commercial customers (e.g., to increase their insulation in order to reduce their air-conditioning costs) will have the effect of reducing non-summer loads as well as the summer loads.

Request:

1.8 Assuming that load is shifted from summer period to the winter period, does Mr. Compton agree that this could hasten and/or exacerbate PGE's need for additional capacity to maintain adequate reserve margins? If not, please explain why not.

Response:

The combination of limited load shifting and the induced effects of off-season conservation is unlikely to have an appreciable effect on PGE's reserve margin situation. Even if it did, costs are low enough in the seasons surrounding the summer to enable an economical adaptation, the costs of which should be well within the costs avoided by shrinking loads in the high-cost summer period.

Request:

1.9 Assuming that Mr. Compton's rate design proposals for Schedule 89 are adopted, how many customers would experience rate increases greater than 15%?

Response:

Unknown. (Refer to next.)

How many would experience rate increases greater than 20%?

Response:

Unknown. Comment: Even the proposed super-peak price is well below the marginal energy cost averaged for the entire peak period. In other words, the highest proposed energy prices are well within marginal cost reasonableness bounds.

Please provide all analysis prepared by or reviewed by Mr. Compton regarding the customer impacts of his rate design proposal.

Response:

Staff/505 consists of the analyses prepared by Dr. Compton regarding customer impacts.

Request:

1.10 Staff/505 shows that in Mr. Compton's illustrated bills, for any given size, the percentage increase rises as the load factor rises. (For example, for Schedule 89 Secondary, at 20 MW, the increases for 30%, 50%, 70% and 90% load factor customers are 11.27%, 11.57%, 11.72% and 11.81% respectively.) Please explain how such increases would encourage greater efficiency.

Response:

There is a slight tendency for PGE's proposal for Schedule 89 to possess that same slight characteristic. (See particularly Primary 3 phase service, PGE Exhibit 1202 at 12.) The shared tendency is an artifact due to both PGE's and Staff's proposals placing a slightly larger emphasis on per-kWh rate increases than on per-kW increases. Efficiency, in the sense of customers receiving a

September 3, 2008

TO: Brad Van Cleve
Industrial Customers of NW Utilities

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to ICNU Data Request 10.280
Dated August 19, 2008
Question No. 280

Request:

On page 12 of their rebuttal testimony Messrs. Kuns and Cody and Ms. Lynn state that they "believe" that the generation allocation results likely would not deviate significantly even if PGE were to use estimates of the hourly load shape of every individual rate schedule combined with the hourly energy prices provided in PGE's power cost model MONET. Please provide all studies, analyses or investigations that support this belief, including but not limited to any computer spreadsheets used or relied upon for these analyses. Also, please explain the extent of the load sampling relied upon by PGE in performing this analysis.

Response:

The statement on page 12 of PGE's testimony is an opinion based on the experience of the witnesses. The statement is made in response to ICNU's assertion that the ratio between the highest and the lowest price period can be in the neighborhood of 100 to 1, perhaps more. [ICNU Exhibit 100, Page 4]

September 3, 2008

TO: Brad Van Cleve
Industrial Customers of NW Utilities

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 197
PGE Response to ICNU Data Request 10.290
Dated August 19, 2008
Question No. 290

Request:

On pages 21-22 of their rebuttal testimony, Messrs. Kuns and Cody and Ms. Lynn refer to three tests used by FERC in prior proceedings on whether or not to use a 12 CP allocation or a subset of the twelve coincident peaks. Do Messrs. Kuns and Cody and Ms. Lynn acknowledge that those FERC tests were established in the context of using embedded cost of service studies? If not, please provide relevant citations to any FERC Orders, Decisions or Rulemakings that refer to those tests in the context of marginal cost of service studies.

Response:

PGE acknowledges that the majority of the FERC rate cases are based on embedded cost of service study methodologies. PGE does not have information regarding whether or not this is universal.