STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

The Application of Rocky Mountain Power for Authority To Increase Retail Electric Rates	))))	**Docket No. 09-035-23**

SURREBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH OFFICE OF CONSUMER SERVICES

Resource Insight, Inc.

NOVEMBER 30, 2009

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I. Introduction

Q: Please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Are you the same Paul Chernick who filed Direct and Rebuttal Testimony in this case?

A: Yes.

Q: What is the purpose of your surrebuttal testimony?

A: I will respond to certain cost-allocation issues raised in the rebuttal testimony of Messrs Thornton, Paice and Alt on behalf of RMP, Joseph Mancinelli on behalf of the Division, Maurice Brubaker on behalf of the Utah Industrial Energy Consumers (UIEC), and Kevin C. Higgins on behalf of the Utah Association of Energy Users.

Q: What issues do you address?

A: I address the following seven groups of issues raised by these witnesses:

- The changes in load data presented by Mr. Thornton and Mr. Paice.
- The arguments of Mr. Higgins, Mr. Brubaker, Mr. Swenson and perhaps Mr. Thornton to the effect that certain kinds of loads should be penalized with higher cost allocations.
- The arguments of Mr. Higgins, Mr. Mancinelli and Mr. Paice that traditional allocation methods should not be changed, because they are traditional.
- The arguments of Mr. Brubaker, Mr. Swenson and Mr. Paice that my improvements should be rejected because more complicated analyses may be appropriate, even though the witnesses do not conduct or propose any specific analyses.

- Allegations of Mr. Brubaker, Mr. Swenson, Mr. Paice, and Mr. Mancinelli regarding the rationale for the peaker method and my computation of the energy-related portion of plant.
- Mr. Mancinelli's confusion regarding the capacity-factor and AED allocation methods.
- Assertions of Mr. Paice and Mr. Swenson regarding my improved allocation method for purchases.
- The rebuttal of Mr. Alt on distribution allocations.

II. Changes in Load Data

Q: Why did RMP replace the peak load data used in its original filing in this case with new peak load data in its rebuttal?

A: According to RMP Witness Thornton, the Company has changed its method for estimating class contributions to PacifiCorp system peaks (that is, class 12 CPs). Mr. Thornton (Rebuttal, p. 7) explains that in the Company's original method, matching 2008 dates to forecast test year dates distorted the data:

> summarizing the [2008] load data based on forecast dates and times, presented us with situations where the forecast peak date didn't necessarily align with a historical peak date. As such, we were losing the relationship between the classes that would be expected under a true, peak day scenario.

Thus, it appears that the new class 12 CPs are based on 2008 actual dates and times of the peaks, rather than test year forecasted peak dates and times. Table 1 summarizes the dates and times of coincident peaks assumed in the Company's application and rebuttal.

Table 1: Coincident Peaks in the Application and Rebuttal COS Studies

	Rebuttal		Application	
Month	**Date**	**Time**	**Date**	**Time**
Jul-09	9	18:00	20	17:00
Aug-09	14	18:00	27	17:00
Sep-09	8	17:00	10	17:00
Oct-09	1	17:00	30	09:00
Nov-09	5	19:00	25	19:00
Dec-09	15	19:00	16	19:00
Jan-10	24	09:00	22	09:00
Feb-10	5	09:00	4	09:00
Mar-10	5	09:00	30	09:00
Apr-10	1	09:00	1	09:00
May-10	19	17:00	19	16:00
Jun-10	30	15:00	24	16:00

Q: Have you been able to review fully the derivation of RMP's new load data?

A: No. The schedule for the filing of surrebuttal testimony has not provided adequate time to review all of the steps undertaken by the Company to derive the new data (provided in response to OCS Set 25) and identify where they differ from the original methodology. For my evaluation, I have relied mainly on the explanations of RMP witnesses Mr. Thornton and Mr. Paice and the load data provided on Tab "Demand Factors" of the Original and Rebuttal COS Study spreadsheets.

Q: Does RMP's new approach to modeling coincident peaks provide a reasonable guide to allocating test-year costs?

A: No. The forecasts of test year energy, peak loads and NPC are intended to represent a typical year, based on data from the past 10–20 years. (Eelkema Direct pp. 4–8) In its rebuttal case, RMP proposes to base Utah class contributions to system peak demand entirely on data from 2008, without any analysis to confirm that 2008 was a particularly representative year in terms of the timing of peak loads or of the coincidence of Utah and system peaks.

As shown in Table 2, the largest increases in the estimate Utah loads occur in the shoulder months of May and October, followed by September and June.

Table 2: Composition of Utah Peak Load Changes, Original to Rebuttal Data

Month	MW	% of Total
July	73.5	2%
August	240.7	7%
Sept	559.4	17%
Oct	733.3	22%
Nov	285.9	9%
Dec	6.1	0%
Jan	56.5	2%
Feb	(155.9)	-5%
March	246.8	8%
April	61.7	2%
May	707.3	22%
June	457.0	14%
Total	3,272.3	100%

Q: Have you identified any additional problems with RMP's new load data?

A: Yes. The most troublesome issue is that *all* the demand allocators, not just those derived from the class contribution to system peak demand, changed from the original filing to RMP's rebuttal. All three of those demand allocators increased for the residential class, as shown in Table 3.

Table 3: Change in Residential Non-CP Demand Allocators

Residential Allocation Factor	Rebuttal	Application	% Change
12 Weighted Distribution Peaks	0.44570	0.44437	0.3%
Transformers - NCP	0.61637	0.56102	9.9%
Secondary Lines - NCP	0.91279	0.87562	4.2%

Data from Exhibit RMP CCP-9 and CCP-3R.

The Utah distribution peak and the class non-coincident peaks should not be affected by the Company's changing the dates and times of the system peaks, yet RMP has changed the allocators based on those load measures. The Company has not identified any update to load data that would account for those changes in these other allocators, let alone explain or justify them. It is not clear whether the unidentified data adjustments that affected the non-coincident peaks also affected the coincident peaks, nor whether any of those changes were justified. Until RMP explains these inconsistencies, all the rebuttal load data must be considered suspect.

Another inconsistency arises in the changes in the class contributions to the April coincident peak, even though peak date and hour are the same for the test year and for 2008: April 1 at 9:00 am. The Company has not provided any logical explanation for why the class loads for 9 am on April 1, 2008 (grossed up for projected increases in April sales) differ, depending on whether the analysis is reported to be for 2008 or for 2009/2010.

The change to the new load data has disproportional effects on the residential class, as shown in Table 4. Specifically, estimated residential contributions to monthly peaks are higher in eleven out of twelve months, while the total General Service load increases in only six months. As Mr. Thornton notes, net Utah class 12 CPs increased significantly; 85% of this total net increase ends up on the residential class 12 CP.

Table 4: Change in Peak Load From Original to Rebuttal COS Studies (MW)

	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	March	April	May	June	Sum of 12 CP	% of Total
Residential	235.5	389.8	376.7	516.9	107.3	40.5	81.4	-0.3	213.5	66.3	517.0	242.9	2,787.6	85%
Sch 006	-97.2	-165.3	160.8	143.8	111.9	-21.9	-15.8	-38.5	57.2	30.5	92.9	152.6	411.1	
Sch 008	-14.4	-8.9	15.6	27.5	54.9	-1.7	4.2	-10.8	-5.1	-8.2	18.8	15.3	87.2	
Sch 009	-21.4	27.6	30.4	25.2	20.0	-6.3	-18.8	-18.8	4.5	-21.9	29.2	23.6	73.2	
Sch 023	2.3	-15.6	22.0	77.1	10.4	-13.9	3.7	-2.9	-28.1	12.0	67.8	8.0	142.9	
Cust A	-0.2	19.0	0.6	-2.6	-1.6	-3.5	4.7	-3.7	1.2	0.0	-2.4	1.4	12.9	
Cust B	0.0	0.0	0.0	0.3	-3.6	0.0	0.0	-6.1	-12.0	7.0	-0.3	0.0	-14.6	
Cust C	-44.2	-5.3	-66.8	-54.9	-13.5	12.9	-2.9	-74.5	15.5	-24.1	-15.8	-2.4	-276.1	
Gen Service Total	-175.2	-148.5	162.6	216.4	178.6	-34.4	-24.9	-155.5	33.2	-4.6	190.3	198.5	436.4	13%
Irrigation	13.2	-0.6	20.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.6	48.2	1%
Utah Total	73.5	240.7	559.4	733.3	285.9	6.1	56.5	-155.9	246.8	61.7	707.3	457.0	3,272.3	100%

As shown in Table 5, the differences are magnified even further when the Company weights each historical monthly load by the forecast ratio of the monthly peak to the July peak load.

Table 5: Difference in Weighted Peak Load From Original to Rebuttal COS Studies (MW)

	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	March	April	May	June	Sum of 12 CP	% of Total
Residential	235.5	386.6	338.0	393.1	92.9	36.8	74.0	-0.3	172.2	51.3	429.2	229.9	2,439.4	87%
Sch 006	-97.2	-163.9	144.3	109.4	96.9	-19.9	-14.4	-34.0	46.1	23.6	77.1	144.5	312.6	
Sch 008	-14.4	-8.9	14.0	20.9	47.5	-1.5	3.8	-9.5	-4.1	-6.3	15.6	14.4	71.6	
Sch 009	-21.4	27.3	27.3	19.2	17.3	-5.8	-17.1	-16.6	3.6	-16.9	24.2	22.4	63.5	
Sch 023	2.3	-15.5	19.7	58.7	9.0	-12.6	3.4	-2.6	-22.6	9.3	56.3	7.6	112.9	
Cust A	-0.2	18.8	0.5	-2.0	-1.4	-3.2	4.2	-3.3	1.0	0.0	-2.0	1.3	13.9	
Cust B	0.0	0.0	0.0	0.3	-3.1	0.0	0.0	-5.4	-9.7	5.4	-0.2	0.0	-12.7	
Cust C	-44.2	-5.3	-60.0	-41.8	-11.7	11.7	-2.7	-65.7	12.5	-18.6	-13.1	-2.3	-241.1	
Gen Service Total	-175.2	-147.3	145.9	164.6	154.6	-31.3	-22.7	-137.1	26.8	-3.6	157.9	187.9	320.7	11%
Irrigation	13.2	-0.6	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	45.3	2%
Utah Total	73.5	238.7	502.0	557.7	247.5	5.6	51.3	-137.4	199.0	47.7	587.2	432.5	2,805.3	100%

Q: Does the new load data provide a reliable basis for cost allocation?

A: No. For the reasons I have given above, the Commission should reject the Rebuttal COS Study as a basis for rate spread and continue to rely on the COS Study prepared and filed with the Company's Direct Case.

In addition, the difficulty of determining the dates and times of the single monthly peak hours under normal conditions and of estimating class peaks in those twelve hours for the test year makes it important for the Commission to recognize the full portion of generation and distribution costs that are energy-related, and the contribution of distribution loads in many peak hours, not just single peak hours, to demand-related costs.

III. Load Discrimination

Q: Which witness suggests that certain classes should be penalized because of the history of their loads?

A: Mr. Higgins (Rebuttal, pp. 3, 11, 23) asserts that classes responsible for growth should be allocated a larger share of costs.

Q: Is this a standard aspect of cost allocation?

A: No. In general, costs are allocated in proportion to test year usage of the underlying resources. Load growth is not relevant to embedded-cost allocation, other than the effect that growth will have on each class' current energy and peak loads. Mr. Higgins essentially proposes vintaging of resources, which is not widely-accepted cost allocation approach.

In certain rate design situations, vintaging may be appropriate. For example, setting tailblock rates at or near marginal cost and assigning customers some portion of supply at lower historical rates may be used to send more appropriate, cost-based price signals.[1] Mr. Higgins does not provide any evidence demonstrating that any particular classes have tailblock rates below marginal costs.

Q: Does any other witness argue that there is something about the residential load that warrants special allocation of additional costs?

A: Yes. Mr. Brubaker argues that something about temperature-sensitive load (particularly residential load) makes it more expensive to serve than load with similar energy and peak contributions (Rebuttal, pp. 17–18). His

[1] The Utah industrial classes did not appreciate RMP's proposal to implement a vintaged rate design in Docket No. 07-035-93.

assertions are intended to demonstrate that classifying as energy-related 25% or 50% of generation fixed costs under-allocates costs to the residential class.

Q: Does Mr. Brubaker identify any problems with classifying fixed costs as energy-related?

A: No. He does not explain why residential temperature-sensitive load would be more expensive to serve than temperature-sensitive load in other classes, or load that varies for other reasons (such as industrial production schedules). His description of utility planning and operation is muddled; for example, Mr. Brubaker asserts that utilities maintain installed reserves to meet "high-temperature excursions," when reserves are primarily required to cover power-plant outages.

Indeed, his argument actually supports the classification of fixed costs to energy. Mr. Brubaker points out that capacity that is built for peak loads and is not used in many hours must be supported by charges on the peak hours (e.g., demand charges), while capacity that serves load around the clock can be spread over energy use in many hours. That is essentially the rationale for the peaker method.

Q: Does RMP support the positions of Mr. Higgins and Mr. Brubaker?

A: Not explicitly, but Mr. Thornton provides a series of estimated residential peak-day load shapes, for 2002 through 2008, and concludes that these curves "clearly show growth in afternoon and evening Residential loads." (Thornton Rebuttal, p. 4)

Q: Do you agree with Mr. Thornton's interpretation of his data?

A: No. In his graph, residential afternoon loads in 2008 are at or below 2002 and 2005, and evening loads in 2008 are very similar to 2002. The graph does not show a consistent upward trend in the daily residential load shape since 2002, and it is impossible to tell whether the changes in load shapes were due to a secular trend or weather variations.

Q: Do you have any comments on Mr. Swenson's claim that secondary customers' peak line losses must have increased rapidly in recent years, because percentage losses rise as load rises?

A: Mr. Swenson is incorrect about the trend of losses over time. A large share of line losses does vary with the square of load, for a given configuration of the transmission and distribution equipment. However, the ratio of loss to load does not normally increase from one year to the next because RMP adds new capacity to the transmission and distribution system each year, thereby reducing resistance and losses. Secondary customers pay for all the investments in secondary distribution, and pay their load share of investments in other distribution and transmission. There is not reason to assume that losses as a percentage of sales rise from one year to the next.

Q: Do you have any comment on Mr. Swenson's contention that high-load factor customers should not be allocated any share of the costs associated with new wind resources?

A: Mr. Swenson correctly acknowledges that the benefits of wind resources are mostly energy, but he appears to suggest that certain large industrial customers will not benefit from wind resources and should be exempted from paying for them. Customers classes cannot be allowed to pick and choose the resources for which they pay. Prudently-incurred production costs are allocated to classes in proportion to their use of the resources.

IV. Tradition

Q: Which rebuttal witnesses appeal to tradition rather than cost causation?

A: Mr. Higgins, Mr. Paice and Mr. Alt all make arguments that amount to "The PSC should reject the OCS recommendations because that's not the way we have done it." For example:

- Mr. Higgins expresses concern that in raising single allocation issues, the Division and the OCS "invite others to open up a piecemeal attack on the entire cost allocation methodology" (Higgins Rebuttal, p. 5)
- The 75/25 generation allocation has been validated and long-accepted (Paice).
- "[I]f the historical approach to cost allocation used in Utah is to be changed for one major cost component such as wind plant, others may reasonably argue that it should also be re-examined with respect to other items. I do not believe that major departures from the allocation methodology currently used in this jurisdiction should be undertaken lightly." (Higgins Rebuttal at 21)
- "[T]he classification Mr. Chernick proposes is obviously inconsistent with the manner in which inter-jurisdictional costs are allocated to Utah." (Higgins Rebuttal at 22)
- "The Commission determined that the 75-25 split is appropriate for Utah based on the evidence in the record and the recommendation of DPU, among others." (Higgins Rebuttal at 25)
- Mr. Alt's testimony on distribution relies heavily on the fact that the distribution allocators have remained the same "since February 9, 1990 (more than 19 years) when, in Utah Power Case No. 89-035-10, the Commission adopted the Company's Distribution Cost Allocation Study allocation methods." He then spends about two pages reciting the history of that study. (Alt Rebuttal, pp. 6–8)

The mere fact that RMP has allocated a cost item in a particular manner for twenty years does not mean that the allocation is immutable. Challenging individual items in utility filings whether it be an accounting or allocation matter is standard practice, as demonstrated by all parties in this proceeding.

Q: Is Mr. Paice correct in his testimony on pages 11 and 12 of his rebuttal that the changes you propose to the COS Study would violate the principle of gradualism?

A: No. Gradualism is a principle of rate changes, not COS Study changes. If a methodological or data change in the COS Study indicates that a class is producing much less than its fair share of costs, the gradualism principle implies that increase of rates for that class should be stretched over several rate years, to moderate rate shock in any one year. Gradualism does not require that the Commission ignore the opportunity to change the COS Study so that it allocate costs more fairly.

V. Improvement is Better than the Status Quo

Q: Which rebuttal witnesses argue that your improved allocations should not be adopted, because some other allocation approach might be more appropriate, without proposing specific methods or allocators?

A: Three witnesses make this sort of argument with respect to allocation of generation costs:

- Mr. Swenson (Rebuttal, p. 9) proposes allocation of generation costs based on class energy usage by time period (such as by month, differentiating high-load and low-load hours). His suggestion is not fully fleshed out, but it appears similar to the Probability of Dispatch method, which could produce reasonable results.[2] While RMP or some

[2] Since PacifiCorp's peakers and combined-cycle plants are much more recent than its baseload coal plants, this type of allocation approach would need to correct for the vintage of resources.

parties may want to investigate this approach in the future, Mr. Swenson does not demonstrate that its results would be much different from those of the peaker method.

- Mr. Swenson asserts that a determination of the energy-related portion of generation plant requires comparison of the total resource costs (including fuel), not just capital costs. (Rebuttal, p. 8) Mr. Swenson neither describes how he would perform the required calculation nor demonstrates how such a calculation could be used to determine the energy-related portion of the plant costs.[3]

- Mr. Paice argues that generation classification is a "very complex issue. The complexities involved in determining a proper allocation cannot be underestimated" and "Selection of an appropriate allocation method requires extensive analysis." (pp. 10–11).[4] Rather than enumerating those elements, explaining how (if at all) they would affect the validity of the peaker-method results, or conducting any of the unspecified "extensive analysis" he imagines might be necessary, Mr. Paice simply asserts that nothing can be done.

- Mr. Paice alleges that my analysis of shared residential service drops might be inaccurate, since some other classes might share some service drops, housing mix changes over time, the costs of service drops vary somewhat with load, and some very large residential developments may have multiple service drops.[5] He does not attempt to estimate the effects of any of these factors; indeed, he insists that RMP cannot figure out how to get any usable data on the number of service drops by class

[3] If Mr. Swenson is suggesting that the peaker annual cost be computed including the cost of fuel for the 12 hours that determine the demand portion of RMP's capacity allocator, such a suggestion is reasonable, but inconsequential. Operating a peaker for 12 hours, at a high gas price of $10/MMBtu and a high heat rate of 12,000 Btu/kWh would add about $1/kW-year to the peaker cost.

[4] The second quote is actually Mr. Paice's excerpt of testimony by another witness in another docket, but seems to represent Mr. Paice's position.

[5] The latter point would also apply to some large non-residential customers.

without an expensive and time-consuming external study.[6] I used the best available data for the number of customers per service drop; correcting for the variation in service cost would be straightforward.

- Mr. Higgins agrees that "adjusting the cost allocation for service drops to recognize multiple occupancy housing units….may be reasonable," but argues that "before adopting these changes, the Commission should consider the broader perspective" of distribution cost allocation. (Higgins Rebuttal, p. 30) In other words, he argues that no improvement should be considered until some broader analysis is undertaken.

Q: Should the possibility of development of better allocators or of further computations be allowed to delay implementation of identified improvements?

A: Not unless there is some substantial reason to believe that better analysis would produce directionally different results.

VI. The Peaker Method

A. Criticisms

Q: Do you have any response to the criticisms of Witnesses Mancinelli and Higgins (pp. 28-29) of what they describe as your reliance on the allocation of generation costs in competitive markets.

A: Yes. The basis of my proposal for allocating generation plant is the relative cost of peaking and baseload resources, not the performance of competitive markets. I included the discussion of competitive markets as a reality check,

[6] If RMP cannot match account numbers with addresses and with service-drop data from its distribution maps, it has more serious problems than the inability to allocate costs.

because it is commonly held idea that regulation should attempt to mimic the effects of competition, where competitive markets are not in place.

While Mr. Mancinelli criticizes me for discussing competitive markets, he actually finds the peaker method to be reasonable.

Q: Is Mr. Higgins correct in asserting on page 28 of his rebuttal that ISOs sell power "in flat-load blocks"?

A: No. The ISOs set prices hourly in the day-ahead dispatch and more frequently in the real-time market. Each ISO has an "obligation to serve" (in the sense of ensuring sufficient operating reserves and dispatch) and "meet retail load projections," just as Mr. Higgins correctly notes PacifiCorp does.[7] Mr. Higgins's comments on the operation of the restructured wholesale markets are incorrect.

Q: What is Mr. Paice's criticism of the peaker method?

A: Mr. Paice state: "Mr. Chernick's approach reflects a bias toward classifying an excessive portion of generation costs as energy-related." (Paice Rebuttal, p. 10)

One would expect that Mr. Paice would follow up on this claim of bias by demonstrating that allocating 50% of generation capacity costs to energy is beyond the reasonable range. Instead, his next sentence is:

> 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.

[7] The utilities within the ISO also have overlapping obligations, which vary from obligations to purchase power for customers not served by third parties, to more traditional planning responsibilities for the remaining vertically-integrated utilities.

Mr. Paice's testimony actually demonstrates that my proposal of a 50% energy classification is toward the low end of the typical range for this methodology.[8] The NARUC Manual does not describe the peaker method as "biased" or "excessive." So far as I can determine, to the extent that Mr. Paice provides any real evidence on the issue, it supports my proposal.

Q: What are Mr. Brubaker's criticisms of the peaker method and your application of that method?

A: Mr. Brubaker has a number of complaints.

- "The peaker method pretends that it would be possible to serve an entire utility system's demand requirements using only peakers." (Brubaker Rebuttal, p. 15) Mr. Brubaker suggests that reliable service could not be provided with only peakers. He is incorrect. Combustion turbines can operate long hours, if needed, and are run at very high capacity factors in combined-cycle plants and in cogenerators.
- "There is no [all-peaker] utility system in existence, and the fuel costs associated with such a system, if it could ever exist, would not be cost-effective or prudent." (p. 15) Mr. Brubaker is correct that most utility systems have some steam plants or other non-peaking generation, to reduce fuel costs.[9] If a utility actually needed to meet only the 12 hours used in RMP's coincident-peak computation, it would use peakers for that purpose. This criticism of the peaker method is actually a good explanation of its logic.
- Mr. Brubaker claims that the peaker method would be inconsistent with the allocation of fuel costs, which he says are allocated "essentially on an average basis." (p. 16) In fact, the peaker method would allocate fuel-saving fixed costs on energy, just as fuel is allocated, so that classes

[8] I do not know where Mr. Paice found the 40%–75% energy classification. The peaker-method example in the NARUC manual (Tables 4–12 and 4-13) actually shows 80% of generation rate base as energy-related.

[9] Some island utilities use entirely CT and diesel peakers.

would pay for the additional costs of baseload plant in proportion to their benefit from low fuel costs. Actually, I have assumed that RMP would continue to allocate the fuel-saving fixed costs on annual energy (as it does currently), while continuing to allocate fuel and purchases on a monthly basis. Classes that use a higher percentage of energy in the low-load months pay a lower average fuel cost and benefit somewhat more from the fuel-saving investments than other classes.

- Mr. Brubaker complains that the peaker method is unrealistic because PacifiCorp did not build peakers contemporaneously with its coal plants, and because the "resource expansion plan in RMP's 2007 IRP does not include any peakers" (Brubaker rebuttal p. 13). Whether PacifiCorp actually plans to build or acquire any peakers is irrelevant to the use of the peaker method; peakers were clearly available if PacifiCorp needed capacity with limited energy requirements. Moreover, Mr. Brubaker needs to examine the Company's current 2008 IRP, in which the preferred resource portfolio includes a 261-MW Eastside peaker.
- Finally, Mr. Brubaker criticizes my use of gross plant, rather than net plant, in establishing the energy-related portion of coal-plant investment. (Rebuttal, p. 13) His criticism seems to be based on multiple confusions. First, while he suggests that using net plant would result in less cost being identified as energy-related, the actual peakers installed in the region are almost certainly more heavily depreciated than the coal plants, so the energy-related portion of net plant would be even higher than the energy-related portion of gross plant. Second, the peaker method is used to derive classification *factors*, not absolute dollar values. I assume that accumulated depreciation, depreciation expense, O&M and all other plant-related costs are proportional to gross plant. This assumption understates the energy-related portion of the plant costs for accumulated depreciation and O&M. A more complicated analysis might produce a much higher estimate of the energy-related portion of costs.

Q: Do you have any response to Mr. Higgins's discussion of the peaker method?

A: Mr. Higgins argues that it would be unreasonable to apply the peaker method with a hypothetical peaker with fuel so expensive that it would not be installed (Higgins Rebuttal, pg 29.) Since I used the costs of peakers that actually were installed in the West in the same period that PacifiCorp was building its coal plants, his critique is irrelevant.[10]

Q: What is the basis for Mr. Higgins's claim that you have engaged in historical revisionism?

A: Mr. Higgins's discussion of history is as follows:

> RMP's coal fleet came on line between 1954 and 1979. Prior to the repeal of the Power Plant and Industrial Fuel Use Act in 1987, electric utilities *could not* just as easily install combustion turbines as other technologies, as the use of natural gas and petroleum for electric power generation was severely restricted under Federal law. Even though that Act allowed an exception for peaking plants, that exception was only permitted through petition to the Secretary of Energy.
>
> Moreover, in the years prior to the adoption of the Power Plant and Industrial Fuel Use Act in 1978, the availability of natural gas supplies for electric power generation had become notoriously unreliable in the United States, as the country was buffeted by natural gas supply shortages – due in large part to a Federal regulatory pricing system that had broken down. In the period during which much of RMP's coal fleet was built, a prudent utility seeking to add reliable capacity needed to plan for a plant that did not rely on natural gas. The most feasible capacity option at that time was coal, particularly in the intermountain west, where coal supplies are abundant. Given the conditions under which RMP acquired its coal fleet, the production plant costs of these units can only reasonably be viewed as primarily capacity-related. (Higgins Rebuttal, pp. 26–27)

Q: Is his historical analysis correct?

A: No. His errors include the following:

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[10] In addition, PacifiCorp later built plants using the same combustion-turbine technology.

- As he admits, the Power Plant and Industrial Fuel Use Act (PIFUA) was adopted in 1978, and had no effect on plants under construction or completed at that time.
- As he admits, PIFUA never prohibited use of gas for peakers.
- Peakers can operate on oil, as well as gas.
- The EIA Form 860 database reports some 6,500 MW of combustion turbines built in 1978–1987, plus another 4,700 MW of turbines installed in the same period that are now part of combined-cycle plants. About 4,600 MW of the combustion turbines and nearly all the combined-cycle plants list gas as their primary fuel.
- Notwithstanding Mr. Higgins's claims regarding the pre-1978 prudence of relaying on natural gas, at least 35,000 MW of combustion turbines were built in that period, at least 20,000 MW of which are gas-fired. A total of 129,000 MW of gas-fired generation was built prior to 1978.[11]
- Mr. Higgins's opinion that gas-fired peakers were imprudent in the intermountain west may come as a surprise to the owners of the 3,100 MW of pre-1988 gas-fired generation and 1,000 MW of pre-1988 combustion turbines (including those at combined-cycle plants) in Montana, Utah, Idaho, Wyoming, Colorado, Nevada and New Mexico.

Mr. Higgins is correct that building mostly coal plants, rather than peakers, made economic sense for PacifiCorp in the 1950s through 1980s. As his testimony makes clear, the coal plants were chosen for their low fuel costs (to serve both retail load and wholesale sales to systems dependent on oil- and gas-fired generation and to energy-short hydro systems), so the incremental costs of the coal plants should be allocated on energy.

[11] Some of that generation originally burned primarily oil or coal.

B. Alternatives

Q: What is Mr. Mancinelli's position on alternatives to the peaker approach.

A: Mr. Mancinelli accepts the validity of the peaker approach, but he also proposes an elaboration of the approach I used and discusses a couple of other allocation methods.

Q: What elaboration of the peaker approach does Mr. Mancinelli propose?

A: Mr. Mancinelli proposes that the energy-related portion of costs be determined for each type of resources. That is a reasonable elaboration on the approach I proposed; indeed I have conducted plant-specific classifications in other cases, reflecting capital and operating costs.

The Company already classifies some peaking capacity as seasonal resources, and allocates their costs based on loads only in the season in which they are used.

Q: What alternatives to the peaker approach does Mr. Mancinelli discuss?

A: Mr. Mancinelli discusses two very simple load-based classification approaches for fixed plant costs. Neither approach directly reflects cost, and each has some serious problems.

First, Mr. Mancinelli describes a capacity-factor approach to classification, which would "consider each unit's approximate capacity factor in the determination of demand-related and energy-related costs" (p. 12). In this method, "classifying baseload costs between demand and energy can be done simply by looking at the unit's annual capacity factor. A baseload unit with a 70% annual capacity factor may be classified as 70% energy-related and 30% demand-related." (p. 5). It is not clear whether Mr. Mancinelli would use projected test-year capacity factor, a long-term average capacity factor, or something else. This method makes sense directionally, but has a number of practical problems, such as that

- Wind resources (with a capacity factor of 25%–35%) would be primarily allocated on demand (which Mr. Mancinelli agrees is illogical).
- Baseload plants with poor reliability would be more heavily allocated to demand.
- The classification of a plant would be independent of its cost. The capacity-factor approach would treat all plants operating at 70% capacity factor as 70% energy related, regardless of whether they cost 110% as much as a peaker, 400%, or 800% more.
- Unit capacity factors can vary quite a bit from year to year, depending on load levels; planned and unplanned plant outages at the unit in question, other PacifiCorp units and other plants in PacifiCorp market areas; supply of wholesale purchases and demand for wholesale sales; and gas prices.

Second, Mr. Mancinelli describes what he calls the Average and Excess Demand (AED) method. (Mancinelli Rebuttal pp. 9–11) I believe he is actually describing the Average and Peak method, which allocates on energy the fraction of the plant cost equal to the system capacity factor and the remainder on non-coincident class peak, while the AED (as described in the NARUC Manual and everyplace else I recall having seen it) allocates the remainder on the excess of class NCP over average load. The classic AED method is essentially equal to an NCP allocator; indeed, the AED uses the NCPs because, if it were computed on CP, it would be exactly the same as the 100% demand CP allocation.[12]

[12] While Mr. Mancinelli equates his version of the AED approach with the AED advocated in Mr. Brubaker's direct, I believe that Mr. Brubaker was referring to the classic AED.

The classic AED method does not really classify any fixed generation costs as energy-related, and uses the non-coincident class peaks, which have no particular significance in resource planning or cost causation. Mr. Mancinelli's Average and Peak approach is a major improvement over the classic AED, but it shares the problem of using the irrelevant NCPs and being insensitive to the mix of generation resources. Mr. Mancinelli's approach would classify 72% of the generation plant as energy, regardless of whether PacifiCorp's plants were all baseload coal and nuclear, or all gas-fired steam and peakers.

VII. Purchases

Q: What is Mr. Swenson's position on the allocation of purchase costs?

A: Swenson mischaracterizes my testimony as proposing that purchases be classified as 100% energy-related:

> Mr. Chernick also discusses the nature of energy costs associated with firm electric purchases and attempts to compare them to fuel costs. The full thrust of his argument (on pages 22-23) is unclear, but he appears to be suggesting that firm contracts should be allocated on energy. His argument seems to be that fuel is related only to energy so firm electric purchases also relate only to energy. (Swenson, p. 8)

Q: What is your response to his testimony?

A: I think my argument is very clear: the non-seasonal contracts fill the same functions as PacifiCorp-owned generation, and the total cost of the contracts should be similarly classified to be consistent with the classification of PacifiCorp generation. I point out that 83% of the contract cost is billed on energy, and that 52% to 83% of the costs of the new resources described in the 2008 IRP would be allocated on energy. I never suggested allocating 100% of the firm contracts on energy.

Q: What issues does Mr. Paice raise with respect to your proposed treatment of firm non-seasonal purchases?

A: Mr. Paice raises three issues on page 13 of his rebuttal.

First, he states that my approach of allocating these purchases as if they were generation resources would be inconsistent with the allocation of sales. Since the allocation of sales is already inconsistent with the allocation of PacifiCorp-owned resources, and with the amount of resources available to make off-system sales, the solution is to improve the allocation of sales, rather than continue ignoring the fuel-displacing value of purchases.

Second, Mr. Paice asserts that my "only support for" the conclusion "that non-seasonal generation plant is more energy-related than is shown in the cost of service" is my "discussion regarding use of a peaker method to allocate generation costs." (Paice Rebuttal, p. 13) In fact, the peaker method has nothing to do with my proposed correction to the generation classification. I provide three lines of evidence: the existing allocation of PacifiCorp-owned generation costs, the share of purchases billed on capacity versus energy, and the share of new-plant costs that would be allocated on energy. None of those analyses use the peaker method.

Third, he asserts that Company personnel who operate GRID have determined that there is no way to separate variable from fixed costs.[13] Mr.

[13] Oddly, Mr. Paice says that I "assert that the Company does not attempt to separate the variable and fixed components of firm non-seasonal purchases and treats all purchase costs as fixed plant costs" (p. 13), as if that were just my opinion, and then says that RMP cannot extract that information from its own GRID model.

Paice's point in this passage is difficult to discern. He does not state that my computations are incorrect, nor does he offer any improved estimates from GRID or any other source. Since RMP puts the NPC data into GRID, its analysts should be able to identify the capacity charges they specified. Indeed, in DR OCS 17.16, which requested the "demand and energy unit charges under each contract" and "total contract demand charges and total energy (variable) charges by month under each contract," RMP replied that "The requested information is in the GRID model." Now that we have found the data where RMP said we would find it, RMP claims the data are not there.

VIII. Distribution

Q: What issues does Mr. Alt raise with respect to your proposal to the allocation of demand-related distribution should recognize the effect of the duration of high loads on costs?

A: Mr. Alt (Rebuttal, p. 4, 9) makes several arguments, which for the most part follow the approach and conclusions of the UP&L's 1989 Distribution Cost Allocation Study and his Rebuttal Testimony in Docket No. 07-035-93. First, he asserts that the load information on which the engineers base distribution investment decisions is the "cost-causer" (regardless of the actual effect of class loads on distribution costs) and that the only load information that distribution design engineers take into account are projected peaks on equipment.

Second, Mr. Alt cites design procedures for substations, primary conductors, line transformers and underground secondary lines as support for his position that duration of peak has little or no effect on the sizing of equipment and classification as 100% demand-related is reasonable.

Third, Mr. Alt claims that I mischaracterized his Rebuttal Testimony in Docket No. 07-035-93 as acknowledging that duration of peak as well as peak drive distribution costs.

Q: What is your response to Mr. Alt's rebuttal testimony?

A: First, Mr. Alt's Rebuttal does not even address the section of my Direct Testimony (pp. 25–27) where I explain how duration of high load affects distribution investment and outage costs, with references to RMP's distribution guidelines.

Second, according to Mr. Alt's own explanations, distribution design procedures take into account peak duration and other hours of high load. For example,

- In the case of substations, Mr. Alt (Rebuttal, p.11) states that "[f]or calculating the thermal capability of a specific transformer, the key data is the peak load and *its duration*." The thermal capability of a specific transformer determines its load-carrying capability.
- Mr. Alt concedes that its demand allocators for substations and primary lines are not ideal because the peak loading for each occurs at different times under different conditions:

> The Company has over 300 distribution substations and many more primary lines in Utah with each having its own unique mix of customer types and loads. The substations are geographically diverse with varying ambient temperatures (like Park City and St. George). This means that the loads on individual substations may peak in different seasons, months, days of the week or hours of the day. The substations may have varying load cycles (differing durations and load levels for peak and off-peak periods).

In other words, even if the Company were correct that a substation's peak loading alone determines its sizing and cost, the allocation of substation plant should recognize that there are as many as 300 load hours per month that drive substation costs.

- Mr. Alt cites a guideline that demonstrates that the sizing of transformers takes into account the expected hours of high use as well as the single peak.

> For non-residential, a table is provided with three sets of transformer load capability data for three different preloads (50 percent, 75 percent & 90 percent 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) compares of the effects of ambient temperature and the preload on transformer sizing. Mr. Alt concludes from his exhibit that since ambient temperature has a greater effect on sizing, preloads should be ignored in allocations. Mr. Alt's comparison is misleading. Ambient temperature is not within the customers' control and therefore irrelevant to cost allocation and the relative importance of duration of peak on transformer costs.

Third, Mr. Alt's assertion that I have mischaracterized his testimony is simply a matter of semantics. He claims that his statement that "The key data are the peak load and its duration" "related only to the data needed to calculate the thermal capability of a specific power transformer." Since the thermal capability of a power transformer determines its load-carrying capability, Mr. Alt is attempting to make a distinction where there is none.

Q: Does this conclude your surrebuttal testimony?

A: Yes.