STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of	**)**	
Rocky Mountain Power for Authority	**)**	**Docket No. 09-035-23**
To Increase Its Retail Electric Service	**)**	
Rates In Utah and for Approval of Its	**)**	
Proposed Electric Service Schedules and	**)**	
Electric Service Regulations	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH OFFICE OF CONSUMER SERVICES

Resource Insight, Inc.

OCTOBER 8, 2009

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I. Identification and Qualifications

Q: Mr. Chernick, 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: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further described in OCS Exhibit.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and ninety times on utility issues before various regulatory, legislative, and judicial bodies, including the Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, New Mexico Public Service Commission, New Orleans City Council, New York Public Service Commission, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Utah Public Service Commission, Vermont Public Service Board, Washington Utilities and Transportation Commission, West Virginia Public Service Commission, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

Q: Have you testified previously before the Commission?

A: Yes. I testified on behalf of the Utah Office of Consumer Services[1] ("the Office") in the following dockets:

- Docket No. 98-2035-04, on the proposed acquisition of PacifiCorp by Scottish Power. My testimony addressed proposed performance standards and valuation of performance.
- Docket No. 99-2035-03, on the sale of the Centralia coal plant. My testimony addressed the costs of replacement power, the allocation of plant sale proceeds, and the potential rate impacts on Utah customers of PacifiCorp's decision to sell the plant. I testified that the sale of Centralia was not in the interest of ratepayers and that if the Commission approved the sale it should allocate more of the sale proceeds to Utah to mitigate potentially high replacement power costs. The Commission adopted this latter recommendation as part of approving the sale.
- Docket 07-035-93, on the reasonableness of RMP's Cost-of-Service study, rate spread and residential rate design proposals.

I also assisted the Office in analyzing various issues in the multi-state process. These issues included resource planning, cost allocation of generation-and-transmission plant, regulatory policy and risk analysis.

II. Introduction

Q: On whose behalf are you testifying in this rate case proceeding?

A: My testimony is sponsored by the Office of Consumer Services.

Q: What issues does your testimony address?

[1] Formerly the Utah Committee of Consumer Services.

A: I evaluate the Cost-of-Service Study ("COS Study") filed by Rocky Mountain Power ("RMP" or "the Company") and recommend certain improvements be made to the Company's COS Study in the next rate case filing. I also specifically address the reliability of RMP's load data for the irrigation class and the allocation of residential service lines (i.e., shared services).

III. Evaluation of RMP's Cost-of-Service Study

Q: What is the purpose of the cost-allocation process?

A: The purpose of the cost-allocation process is the fair assignment of the total Utah jurisdictional revenue requirement to the various tariffed rate classes.[2] A fundamental principle of the process is that allocation based on cost causation results in an equitable sharing of embedded costs.

Q: What role should the embedded COS Study play in revenue allocation?

A: Any embedded-cost-based COS Study is approximate and based on judgment. Therefore, it should serve only as a guide to class rate spread.

Q: Should the Commission expect classification and allocation methods to change over time?

A: Yes. The COS Study methodology should not be fixed in stone. It should be updated or revised as needed to address changes in any of the following:

- the conceptual models of cost causation;
- data availability;
- the environment in which utilities operate, such as the structure of wholesale markets and cost patterns;

[2] There are also cost-allocation implications for certain special contract customers due to escalation clauses in their respective contracts.

- energy and regulatory policy.

A. Irrigator Load Data

Q: Does the irrigation class present special load research challenges?

A: Yes. The irrigation loads are diverse, highly variable from year to year, and hard to characterize. Recognizing this variability, RMP used an unusually large sample size.

Q: Does the irrigation customer load data used in the Company's COS Study in this case provide a valid basis for cost allocation?

A: No. As can be seen from the data provided in Company Witness Scott Thornton's Exhibit SDT-1, there are sizeable discrepancies between estimated and actual monthly usage.[3] The overestimates of irrigation class usage in the summer months (the only months for which RMP uses the irrigation load-research data) range from 18% in May to 62% in August; see Table 1.

Table 1: Errors in RMP's Irrigation Load Reconstruction

	Sample MWh	Billing MWh	Adj. Factor	Over-estimate
May	35,079	29,728	0.8475	18.0%
June	48,924	38,702	0.7911	26.4%
July	68,699	44,108	0.6420	55.8%
August	69,803	43,086	0.6173	62.0%
September	44,524	28,760	0.6459	54.8%

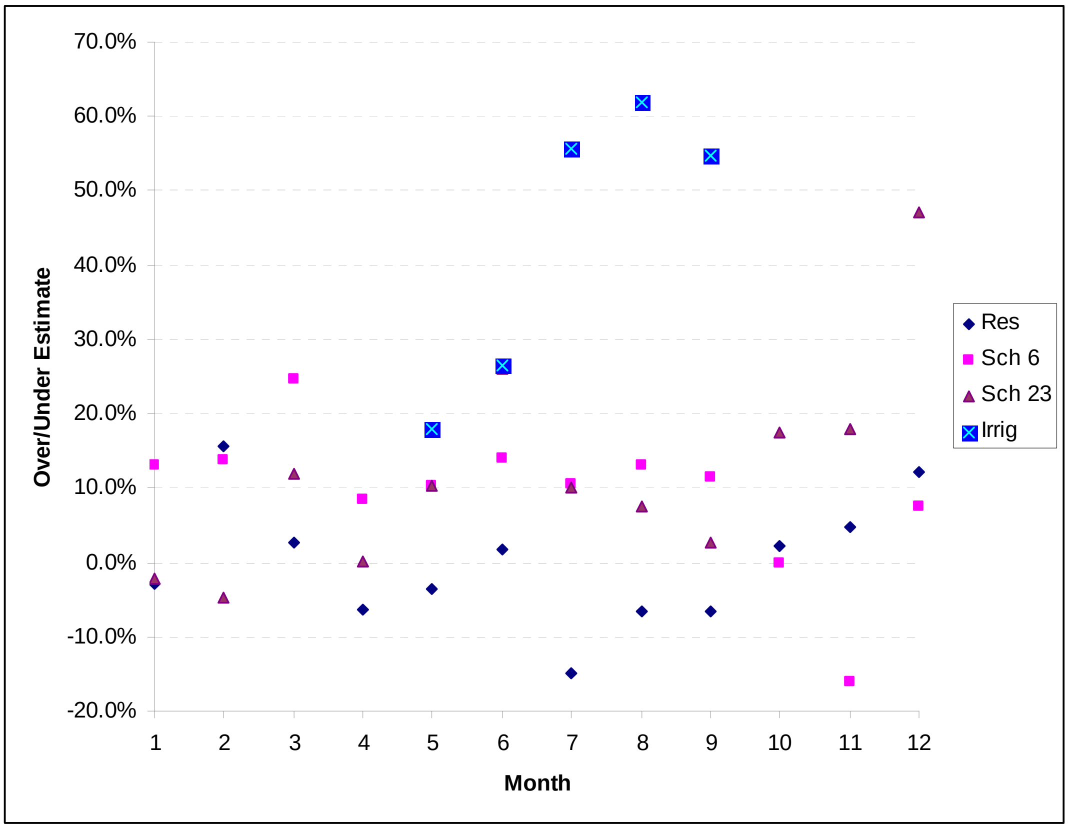
The load-research data over-predict actual usage of irrigation customers by 45% in the summer months. Even including the winter months, for which RMP uses billed sales, not the load-research data, RMP's analysis overstates usage by 41%.

[3] The values that Exhibit SDT-1 reports as annual totals and averages are actually only for July–December.

Q: Are these estimation errors typical for RMP's load-research efforts?

A: No. As shown in Figure 1, the five months of irrigation load data include the three largest errors and five of the seven largest errors, out of the 41 monthly samples in Exhibit SDT-1.

Figure 1: Errors in RMP Load Sampling



Q: Has RMP offered an explanation for the large errors in the irrigation load data?

A: Yes. Mr. Thornton states,

> sample customers are drawn from a pool of the irrigation customers who were actively irrigating in the prior two year period. The effect of this change is that the sample estimates will always be greater than the energy derived from billing records. This is by design. Our intent is to accurately construct the load curve of those customers actively irrigating. We avoid overstating the peak demand of the irrigation class by then adjusting that load curve down to the level of the billed energy. This explains the large downward adjustment factor shown for the irrigation class in Exhibit RMP_(SDT-1). (Thornton Direct at 9)

Q: Does Mr. Thornton's explanation resolve your concerns about the irrigation load study?

A: No, for a couple reasons. First, it is not clear why not "actively" irrigating in the previous two years should exclude a customer from the sample. Considering crop rotations, a farmer may be more likely to irrigate a parcel of land that has been fallow for two years than a parcel of land that has been recently irrigated.

Second, non-irrigation load on the irrigation meter may be significant.[4] The Company assumes that usage by irrigation customers in October through April—which RMP assumes is for non-irrigation purposes—is at a 100% load shape. Irrigation-class sales in the non-irrigating month of April 2008 were 35%–54% of sales in the irrigation months. If RMP's sample excludes a large

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[4]If the 45% estimation discrepancy is due entirely to exclusion from the sample of customers that RMP deemed to not be actively irrigating, and that did not actually irrigate in 2008, more than a third of customers would need to be in that category, in addition to the customers who (1) did not irrigate in 2006–2007, but did in 2008, and (2) irrigated in 2006–2007, but did not irrigate in 2008. This would seem to require quite a large percentage of irrigation customers to be non-irrigating in any particular year.

amount of high-load factor non-irrigating load, it may be grossly understating the aggregate irrigation-class load factor.

Third, in addition to being large on average, RMP's estimation errors for the irrigation class show much greater spread than the other three sampled classes. Table 2 below compares the coefficient of variation (the ratio of standard deviation to the mean) for the monthly adjustment factors computed by RMP for each of the four sampled classes. Since the irrigation class was sampled only for May through September, I performed this computation only for that period. The variability in the required adjustment factors for the irrigation class is about twice that of the residential class and Schedule 23, and about ten times the variation for Schedule 6.

Table 2: Variability in RMP's Adjustment Factors, May–Sept 2008

	Coefficient of Variation in Adjustment Factor
Residential	0.066
Schedule 6	0.015
Schedule 23	0.074
Irrigation	0.146

Finally, even if RMP adjusted its load estimates down by the annual adjustment factor to force the annual average to match sales, each of the adjusted monthly estimates would still vary substantially from the actual sales, ranging from 13% less than actual to 20% more. In three of the five sampled months, the error exceeds 11%, which seems unlikely to comply with RMP's target of 90% of estimates being within 10% of actual loads.

Q: Can RMP's pro rata adjustment to load in all hours provide an adequate correction to the estimated irrigation loads?

A: No. In its derivation of the class hourly load estimates from the sample load data (as explained above), RMP's adjustment holds load shape constant. In other words, RMP assumes that the class demand factors are in constant proportion to energy use and the load profile is unaffected, no matter what the cause of the discrepancy. This is an unrealistic assumption, especially in the case of discrepancies as large as 62%. The factors that significantly alter kWh usage (such as crop rotations, changes in weather, temperature and rainfall, and customer diversity) are likely also to affect load shape.

Q: Mr. Thornton observes that RMP "over-samples the irrigation class relative to other classes." How does RMP's sampling for the irrigation class compare to that of other classes?

A: Mr. Thornton says,

> we over-sample the irrigation class relative to other classes. As an example, the total number of Utah residential class sample customers (170) represent 0.026% of the total residential class. By contrast, the total number of irrigation sample customers (130) represent 6.1 percent of the total class. In doing so, we can afford to lose one or more of the sample customers for the irrigation season without adversely affecting the load estimates. (Thornton Direct at 9)[5]

His characterization of the irrigation class as being "over-sampled" is somewhat misleading. Despite the great variety within the irrigation class, RMP actually meters fewer irrigation customers than residential customers. The number of meters required for the sample depends on the diversity within the class, not on its size. If we knew that all customers used energy in the same time pattern, metering a single customer would be adequate. The 2005 irrigation-sampling study, on which the current cost of service study is still based,

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[5]Mr. Thornton does not explain how he computed that 130 load-research meters are 6.1% of total class, but he seems to have been using the 2,126 customers reported in the 2005 Utah irrigation sampling study (Attachment UEIC 2.1-1). The cost-of-service study reports 2,769 irrigation customers, of which the 130-meter sample would be about 4.7%.

recommended a sample of 123 meters, so the 130 meters are essentially what the sampling study recommended. The 1990 residential sampling study recommended 169 meters, while the 2008 study recommended only 73 meters; if anything, the 2008 study indicates that the residential class has been oversampled.

Q: Does Mr. Thornton argue that his sampled class load data meet the accuracy standards adopted by RMP?

A: He makes that claim for the residential class and Schedule 23:

> These comparisons indicate that, for the year 2008, the residential class and Schedule 23 load samples were providing load estimates that fall within the limits established in the sample design criteria, based on the comparison to the auxiliary variable kWh.[6] (Thornton Direct at 8)

Mr. Thornton implicitly acknowledges that the Schedule 6 data do not meet the standards: "The Schedule 6 comparison, falls outside these limits" (Thornton Direct at 8). He also acknowledges that "there is a substantial difference between the billed and sampled energy for the irrigation class," but argues that the estimation error does not indicate a problem, because "The irrigation class presents a number of challenges from a sampling viewpoint." (Thornton Direct at 8–9) The fact that the irrigation class is difficult to sample accurately does not reduce the accuracy targets.

Q: How far do RMP's load estimates for the irrigation class vary from "the limits established in the sample design criteria" that Mr. Thornton discusses on page 8 of his testimony?

A: That is difficult to determine, but the variance could be very large. The design criteria Mr. Thornton presents are (1) the PURPA standard that "An accuracy of

[6] Mr. Thornton does not define "auxiliary variable kWh," and it is not clear to what that phrase refers.

plus or minus 10 percent at the 90 percent confidence level shall be used as a target for the measurement of group loads at the time of system and customer group peaks" and the Load Research Working Group standard that the sample be "accurate within ±10 percent on 90 percent of the observations" (Thornton Direct at 4).

The only information about accuracy that Mr. Thornton provides is the ratio of annual irrigation billed sales to annual irrigation sales estimated from the sample data. These ratios do not demonstrate that the irrigation load estimates met the standards, for the following four reasons:

- Mr. Thornton reports that actual billed irrigation sales were 15% less than his estimate of irrigation sales, and suggests that this discrepancy may be explained by his exclusion of the customers who had not been irrigating in previous years (Thornton Direct pp. 8–9). But the 15% is the error for January–June, including four months in which RMP reports actual sales for both the actual and estimated sales (Exhibit SDT-1).[7] The error is actually 29% of the estimate and over 40% of actual sales.
- The data compare total energy usage over the year, while the PURPA standard refers to estimates of monthly coincident and class non-coincident peak load. The purpose of the load study is to estimate the class monthly peaks. Therefore, even if Mr. Thornton demonstrated that the irrigation-load sample produces roughly the billed annual energy, that would not demonstrate the peak-load estimates are accurate.
- The standards require a confidence level of 90% that any particular load estimate is within 10% of the actual load. Yet Mr. Thornton compares the actual annual sales (the sum of hourly loads) to the sum of the expected

[7] As I noted above, the totals in Exhibit SDT-1 are totals only for the first half of the year.

values from the load-research sample. In effect, he is testing whether the *average* of his hourly estimates is within 10% of the *average* of the actual loads. His estimates could pass that test even if there were no hour in which the estimate was within 10% of actual load.

- If Mr. Thornton's test indicates anything about the accuracy of the hourly estimates for irrigation, it might represent an estimate of the average or (assuming a symmetrical distribution) perhaps median error. The average of Mr. Thornton's estimates is 40% greater than the billed sales. But the high end of the 90% confidence interval (the value exceeded in 5% of the hours) may well be 60% or 100% more than actual.

Hence, it seems highly unlikely that the irrigation load-research data really meet RMP's accuracy targets.

Q: Can the current irrigation load data be relied on to support a disproportionate increase in irrigation rates?

A: No. Given the very large disparity between estimated and actual usage for the irrigation class, the load data should not be relied upon to support a major cost allocation action.

B. Allocation of Service Drops

Q: How does RMP allocate service lines?

A: They are allocated on weighted customer number, where the weights are calculated from the cost of a new service by type of customer (Exhibit RMP__(CCP-3), Tab 1, at 9).

Q: Does the allocator reflect any sharing of services?

A: No. It assumes that each residential customer requires its own service line and ignores the sharing of services by customers in multi-family buildings (Paice Direct at 9).

Q: Has the Company acknowledged that its approach overstates the residentials' share of service costs?

A: Yes. In Docket No. 07-035-93, RMP Witness Lowell Alt agreed that the services allocation should be modified to reflect shared services if Utah data is representative of RMP Utah customers:

> If the Utah census information [Chernick] 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. (Alt Rebuttal, Docket No. 07-035-93, at 19–20).

Q: Has the Company agreed with that position in this case?

A: Yes.

> The Company supports Mr. Alt's position regarding services allocation factor derivation as long as modification is based on reasonable data. The data [criteria] he identifies...[are] listed below:
>
> - data reflective of RMP's Utah customer base
> - typical number of customers sharing services
> - size of shared service conductors and related costs (OCS 7.3)

Q: To address the first two criteria listed by RMP, have you revised your analysis to reflect only the census information for the specific counties that RMP serves?

A: Yes. The 2000 Census of Housing indicates that about 29% of housing units in the Utah counties that RMP serves are in multi-family structures.[8] Of those,

[8]In calculating the average mix of housing type, I weighted each county's mix by the number of RMP customers in that county (from Attachment OCS 17.5).

13% of RMP's customers live in housing structures with two to nine units, and 11% live in structures with more than nine units.

Depending on the number of units in each category sharing services, the total number services to residential customers may be 20% less than RMP assumes for allocation purposes (as shown in the Table 3).

Table 3 Estimate of Residential Sharing of Service Drops

Units in Structure	Number of Units	Customers per Service
1-unit, detached	489,360	1.00
1-unit, attached	35,353	0.75
2 units	28,084	0.50
3 or 4 units	34,781	0.29
5 to 9 units	27,265	0.15
10 to 19 units	29,986	0.07
20 to 49 units	22,957	0.03
50 or more	23,074	0.02
Total RMP housing units	690,859	
Number of residential services		547,456.00
Average number of services per residential customer		0.79

Q: Has the Company conducted a study of the number of shared services, as recommended by its witness?

A: No. The Company's efforts consisted of a review of accounting data and confirmation from personnel "that Company records do not contain shared services data" (OCS 17.8 and 17.9).[9] The Company did not attempt to determine the portion of its residential customers that are in multi-family buildings, the number of residential service drops installed and in use, or a process for identifying shared services (OCS 17.6, 17.7, and 17.11). RMP instead seeks to

[9] I find it difficult to believe that RMP cannot identify the service drop that serves each meter, or the number of meters at any given location. Perhaps the Company staff did not consider the diagrams of customer connections to be "shared service drop data."

put the onus on third parties to compile “reasonable” data on RMP’s own customers and installations and propose a “reasonable” allocator:

> Company records do not contain data regarding the number of customers per service drop and unless an alternate allocation method is proposed and deemed reasonable, the cost of service study will continue to allocate these costs assuming a single service per average customer. (Paice Direct at 9)

and

> Subsequent to RMP witness Lowell Alt’s rebuttal testimony recommendation the Company reviewed distribution-related accounting system data. This review reaffirmed that Company records do not contain shared service drop data.... (OCS 7.3)

Q: Is your use of census data to derive the number of shared services a “reasonable” basis for a services allocator?

A: Yes. The use of census housing data is clearly an improvement over RMP’s assumption that every residential customer has its own service drop. However, the Commission should direct the Company to conduct a study of shared services to determine the split of service drops by single and multi-family residential dwellings.

C. Reasonableness of Other Classification and Allocation Factors

Q: Have you identified areas in which RMP’s COS Study should be improved?

A: Yes. I have identified a number of improvements that should be made to the Company’s classification and allocation factors to reflect cost causation better. In particular, future RMP COS Studies should recognize the following realities, each of which I discuss further below:

- At least 50% of generation plant, especially coal and wind resources, is energy-related;
- More than 50% of firm power purchase costs are energy-related;

- The duration of high loads, not just a few single hourly peaks, drive distribution investment; and
- The potential for overloading on substations and feeders, not a simple count of substations peaking in the month, determines the effect of each month's load on distribution costs.

1. The Classification of Generation Plant

Q: How is generation plant classified?

A: The COS Study classifies generation plant as 75% demand-related and 25% energy-related. RMP's approach recognizes that power-production facilities are built both to serve demand (i.e., to meet reliability requirements) and to produce energy economically.

Q: How did PacifiCorp come to use a demand-energy split of 75-25 for generation?

A: As I understand the history of this classification, the 75-25 split was initially a compromise between Pacific Power and Light's 50-50 demand-energy classification and the Utah Power and Light's 100% demand classification, in place at the time of the PacifiCorp merger. I also understand that PacifiCorp analyzed the demand-energy classification in the early 1990s, as part of the work performed within the PacifiCorp Interjurisdictional Task Force on Allocations process. However, the Utah Commission never ruled on the classification issue until its rate case decision in Docket No. 97-035-01.

Q: What did the Commission decide in that rate case proceeding?

A: Acknowledging that energy needs are a significant driver of generation capital costs, the Commission adopted the Division's *qualitative* argument in support of a 75-25 split:

> Citing both past operating experience and future resource planning, the Division notes that resources with higher energy availability are chosen over those with lower energy availability. Since energy plays a role in the selection of least-cost resources, the Division concludes that some weight needs to be given to energy in planning for new capacity, and the current weight of 25 percent is reasonable. We find the *qualitative argument* offered by the Division to be…convincing. (PSC Order, Docket No. 97-035-01 at 82, emphasis added)

Q: Did the Commission also find in that case that PacifiCorp's inter-jurisdictional and Utah retail class allocations must always be consistent?

A: No. The Commission recognized that the most appropriate retail class allocator may differ from the inter-jurisdictional allocator. In its Report and Order (Docket No. 97-035-01 at 113), the Commission stated,

> We also want to insure that these fundamental cost-of-service decisions are applied consistently at interjurisdictional and class levels…*unless good and sufficient cause shows otherwise* [emphasis added].

Q: Should the inter-jurisdictional allocations be the default for Utah retail class allocations?

A: No, for two basic reasons. First, the 75-25 split was and remains an arbitrary compromise, rather than a result of cost-causality analysis. Second, the 75-25 split understates the portion of generation investment—particularly in coal and wind plants—that is incurred to meet energy needs, rather than peak load.

Q: From a quantitative standpoint, how can the energy-related portion of generation plant costs be estimated?

A: One approach is the *peaker method,* which considers the demand-related portion of production plant to be the minimum cost of providing the current system reliability level, and the remainder to be the energy-related portion.

Q: Has the Company considered the peaker method to be reasonable?

A: Yes. The Company previously endorsed this concept in the 1989 UP&L Distribution Study at 11:

> The increased cost of a baseload unit over a peaking plant represents an investment made to save fuel costs. The additional investment can be classified as energy related.… The generation plants have two equally important ratings, energy and demand.

Q: Is the peaker approach consistent with the current electricity markets?

A: Yes. The Independent System Operators ("ISOs") for restructured markets apply pricing models similar to the peaker method, but even more weighted to energy. Essentially, ISOs structure capacity markets to allow generators to recover the "Cost of New Entry" (CONE), without the withholding of capacity and excess profits. For example,

- The New York ISO ("NYISO") and PJM Interconnection ("PJM") determine the price of capacity from a formula that sets the capacity price near the cost of a peaking unit, net of energy revenues, when installed capacity is close to the required level.

> The CONE revenue requirements are based on the total project capital cost and annual fixed operations and maintenance expenses of a combustion turbine ("CT") simple cycle peaker power plant addition. The plant configuration is the "Reference Resource" prescribed by the PJM Tariff, i.e., two General Electric Frame 7FA combustion turbines with selective catalytic reduction technology, dual fuel capability, inlet air cooling, and a heat rate of 10,500 MMbtu/MWh. (PJM Tariff Amendments submitted to FERC, 12/12/08, at 10)

- The New England ISO sets capacity prices through a forward auction. The initial starting price for the auction, as well as minimum and maximum prices, is determined by the cost of a new peaker, net of energy revenues. In addition, the formula for these energy revenues reflects the characteristics of a combustion turbine. When market energy price is very high, the capacity price is reduced by the "peak energy rent," which assumes a proxy unit operating on ultra-low sulfur No. 2 oil at a heat rate of 22,000 Btu. This pricing prevents over-collection in the capacity and energy markets by

  > Ensur[ing] that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. (New England ISO, Market Rule 1, §III.13.7.2.7.1.1.1(iii))

- Other ISOs, including the California ISO, Midwest ISO, and ERCOT, have no installed-capacity requirements at all, and charge load primarily on time-of-use energy consumption.

Q: For the ISOs that include capacity markets, how have the market capacity prices compared to the cost of new peakers?

A: Most of the capacity auctions have resulted in capacity prices significantly below the cost of a new peaker. Table 4 shows the estimated cost of new peaking capacity and the market price response for the most recent annual auctions for various PJM zones, the NYISO upstate zone, and ISO-NE.[10]

[10] The PJM and ISO-NE auctions are for forward markets, while the NYISO auctions are for one to six months ahead. Since NYISO has not completed the final auction for summer 2009 (which includes October). I use the summer 2008 and winter 2008/2009 results. I do not include the NYISO prices for New York City (which have been regulated) or Long Island (where there is essentially only a single buyer).

Table 4: Recent Capacity Market Prices

			Dollars per kW-yr		
ISO	**Zone**	**Year Starting**	*Cost of New Peakers (Estimated)*	*Market Capacity Price*	**Price: Peaker Ratio**
PJM	RTO	Jun-12	$115	$6	5%
	MAAC	Jun-12	$113	$49	43%
	EMAAC	Jun-12	$122	$51	42%
	PSEG-North	Jun-12	$122	$68	55%
	DPL-South	Jun-12	$122	$81	66%
NYISO	ROS	May-08	$105	$25	23%
ISO-NE	All	Jun-11	$90	$37	42%

The ISO-NE price for the year starting June 2011 was set by the price floor for the auction; the same was true for the previous year. The price floor will be lower for the year starting June 2010, and the price is expected to fall further.

Q: Please explain how the peaker method would be used to classify generation plant in a COS Study.

A: For each generation unit, a good initial estimate of the demand- or reliability-related portion of its cost is the cost per kW of a peaker (generally a simple-cycle combustion turbine) installed in the same period times the rated capacity of the unit. The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.[11]

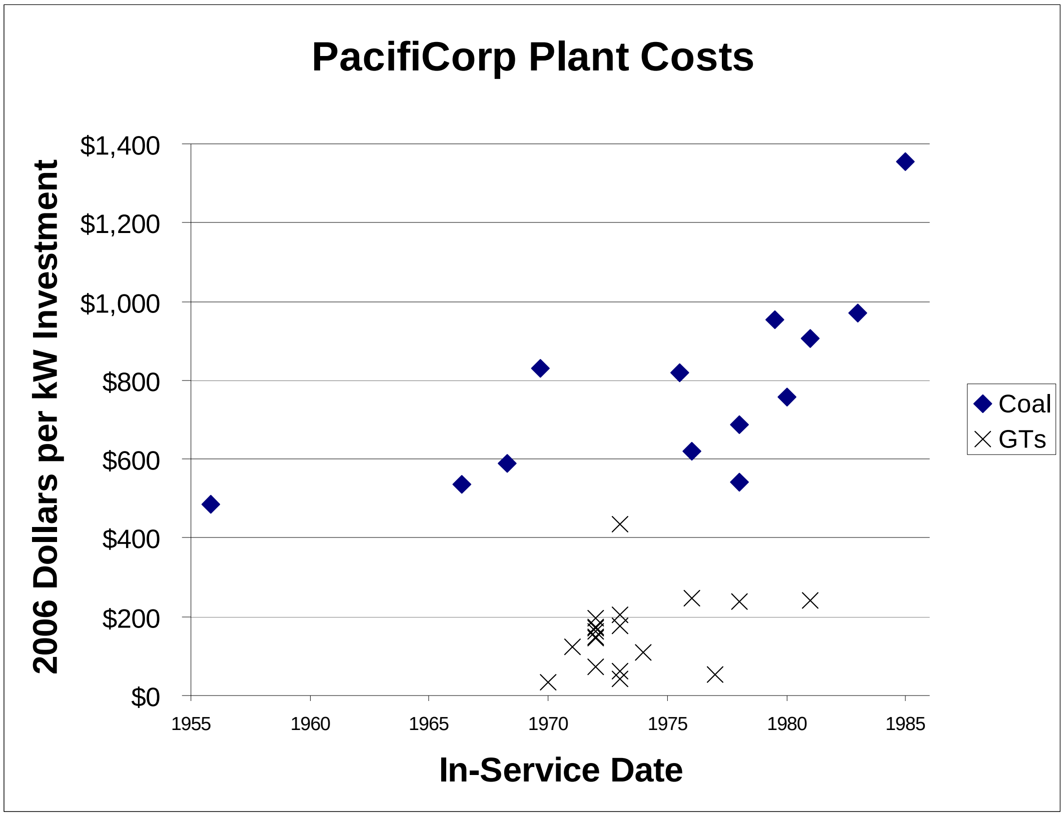
Q: Have you applied the peaker method to PacifiCorp's existing coal plants?

A: Yes. I compared the gross capital cost per kilowatt, in year-end 2006 dollars, for each existing PacifiCorp coal plant and for contemporaneous combustion-

[11]This calculation overstates the reliability-related portion of plant cost: it assumes steam plant supports as much firm demand as would be supported by the same capacity of combustion turbines. Higher forced outage rates, large maintenance requirements, and the size of large units all tend to reduce the contribution of large units to system reliability.

turbine plants, sorted by in-service date.[12] The peakers averaged under $200/kW, compared to $500–$1,000/kW for PacifiCorp's coal plants, suggesting that 60% to 80% of the coal plant capital costs are energy-related. See Figure 2 below.

Figure 2: PacifiCorp Coal Plant Costs versus GT Plant Costs



Q: Do PacifiCorp's projections of new generation plant costs support your findings from existing plant data?

A: Yes. According to the 2008 Integrated Resource Plan, the lowest-cost new coal plant would be a Utah pulverized coal plant, at fixed costs of $291/kW-yr. Netting out the fixed costs of a frame simple-cycle combustion turbine, at

[12]Since PacifiCorp does not own any peakers built in the same period as its coal plants, I used as proxies, peakers built in the relevant period in areas contiguous to PacifiCorp's service territories. The peakers are those owned by investor-owned utilities in Arizona, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington, and were all built during the period 1970–1981.

$69/kW-year, the energy-related fixed cost of the new coal plant would be $222/kW-year, or 76% of the total fixed cost.

2. Allocation of Firm Non-Seasonal Purchases

Q: How does RMP allocate firm non-seasonal purchases?

A: The Company classifies firm non-seasonal purchases as 75% demand-related and 25% energy-related and allocates each month's cost separately based on class coincident peak and kWh usage in that month.

Q: What costs does RMP's COS Study include in the category of "firm non-seasonal purchases?"

A: As shown in the COS Study Model sheet labeled "NPC," the category comprises all purchases except non-firm and seasonal. It comprises the following transactions:

- Long-term firm purchases,
- Short-term firm purchases,
- Storage & Exchange,
- System Balancing Purchases.

The last two transaction categories are clearly 100% energy-related.

Q: Does RMP's COS Study understate the energy-related portion of long term firm purchase costs?

A: Yes, in two important ways. First, the non-seasonal purchases are likely to reflect RMP's mix of non-seasonal generation plant, which are more energy-related than the COS Study assumes, as discussed above in Section III.C.1.

Second, RMP allocates purchases and generation inconsistently. In the case of its own generation plant, RMP treats fuel costs and plant costs separately, and classifies fuel as 100% energy-related, and plant as 75% demand–25% energy-related. But in the case of firm non-seasonal purchases, RMP does not attempt to separate the variable and fixed components and instead treats all purchase costs as fixed plant costs. As a result, RMP allocates only 25% of all purchase costs, including fuel costs, on energy. This difference is illustrated in Table 5.

Table 5: Share of Cost allocated on Energy

	Fixed Costs	Fuel and Variable Costs	Total if Half of Cost Is Fuel
Plant	25%	100%	62.5%
Non-Seasonal Purchases	25%	25%	25.0%

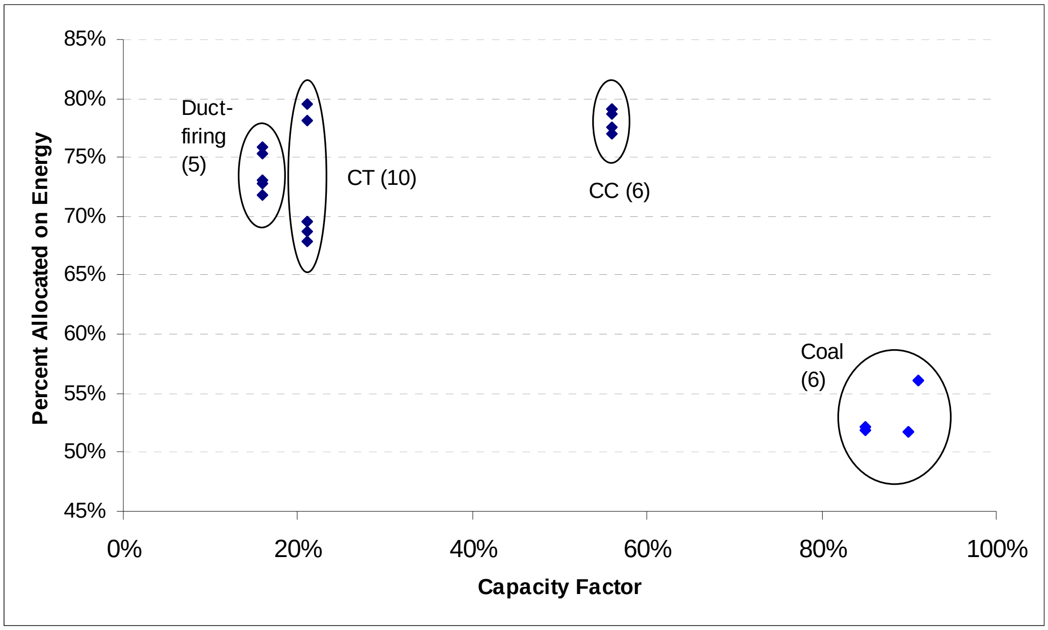
Q: Have you estimated the percentage of firm purchase costs that are variable charges or otherwise energy-related?

A: Yes. Energy charges are about $431 million—or about 83%—of the $522 million of short-term firm and long-term contract costs projected in RMP's GRID run for this proceeding.

Q: How significant is the disparity between RMP's classification of purchases and generation?

A: The disparity is large. From PacifiCorp's' 2008 Integrated Resource Plan, I computed the portion of total costs that RMP would allocate on energy for each potential new resource. The energy-related portion of the costs is the sum of variable costs plus 25% of fixed costs. The portion of generator costs allocated on energy under RMP's current classification and allocation method ranges from 52% for pulverized coal with carbon capture and sequestration to 56% for coal without carbon capture, 66% to 81% for various types of combustion turbines, and 77%–83% for various combined-cycle configurations.

Figure 3: Energy-Related Share of New Resource Costs under RMP's COS Study Approach



3. Distribution Classification and Allocation Factors

Q: How does RMP's COS Study classify distribution?

A: The Company classifies substations, primary lines, line transformers, and secondary lines as demand-related. The remaining distribution plant, services and meters, are classified as customer-related.

Q: How does RMP's COS Study allocate demand-related distribution plant?

A: The COS Study treats distribution costs as follows:

- Substations and primary lines are allocated based on weighted monthly coincident distribution peaks:

> The coincident distribution peak is the simultaneous combined demand of all distribution voltage customers at the hour of the distribution system peak. These monthly values are weighted by the percent of substations that achieve their annual peak in each month of the year. (Exh. RMP (CCP-35), Tab 1, at 9)

- Line transformers and secondary lines are allocated based on weighted non-coincident peaks, where the "weighting" adjusts for the diversity of load on shared distribution equipment.

Q: Does RMP's allocation of distribution costs reasonably reflect cost causation?

A: No. The Company's approach has the following problems:

- It overlooks many of the ways that periods of high energy use drive distribution investment.
- The monthly weighting factors used in deriving the allocator for sub-stations and primary feeders are not cost-based.

a) Effect of Energy and Duration of Peak on Distribution Costs

Q: Does RMP acknowledge that energy (that is, duration of peak) affects distribution costs?

A: Yes. In his Rebuttal Testimony in Docket No. 07-035-93, Company Witness Lowell Alt acknowledged that duration of peak, load cycle, and on-peak energy are all cost-causal factors. For example, regarding substation sizing, he stated "The key data are the peak load and *its duration* (at 11, emphasis added)." In the same Rebuttal Testimony, however, Mr. Alt endorsed RMP's allocation assumption that peak demand alone drives distribution costs.

Q: In what ways do periods of high energy use affect distribution costs?

A: Duration of high load affects distribution investment and outage costs in the following ways:

- The number of high-load hours determines risk of load loss following equipment failure, and hence drives investment in redundant equipment to improve distribution system reliability.

- The number and extent of overloads determines the life of the insulation on lines and in transformers (both in substations and in line transformers), and hence the life of the equipment. A transformer that is very heavily loaded for a couple of hours a year, and lightly loaded in other hours, may well last 40 years or more, until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but to many smaller overloads in each year, may burn out in 20 years.
- All energy in high-load hours, and even all hours on high-load days, adds to heat buildup and results in (1) sagging of overhead lines, which often defines the thermal limit on lines; (2) aging of insulation in underground lines and transformers; and (3) a reduction the ability of lines and transformers to survive brief load spikes on the same day.
- Line losses depend on load in every hour (as marginal line losses due to another kWh of load generally exceed the average loss percentage in that hour). UP&L's October 1989 Distribution Cost Allocation Study recognizes that "energy-related" distribution investments are made to reduce energy load losses, namely, certain increases in the sizing of conductors and transformers.[13]

Q: Do the Company's distribution design guidelines indicate that periods of high energy use and duration of peak load are driving factors in distribution costs?

[13]In the case of conductors, the UP&L study (at 14) specifies that Company selects the conductor size at the point at which

> the incremental savings in capitalized energy losses from switching to the next larger conductor are equal to the incremental cost of installing the larger conductor. Thus the conductor selected is the most economical one to use for the initial loading of the circuit.

A: Yes. The Distribution Guidelines identify a number of ways in which expected energy use, especially in hours close to peak in load or time, affects both the design standards and investment. For example, the sizing of new conductors and transformers is determined by the expected hours of high use as well as by the single peak. Figure 4 of the Guidelines sets out the maximum design loading without damage assuming four hours of usage and maximum emergency usage limited to 8 hours with some risk of equipment damage. So the greater the number of hours of maximum loading, the larger the conductor installed. Similarly, the Study (at 12) recognizes that heat buildup may limit the capacity of a substation transformer.

b) Distribution Monthly Peak Weighting Factors

Q: Why are the distribution weighting factors invalid?

A: Weighting each month by the number of substations that peak in that month does not reflect cost causality. Under this weighting scheme, for example,

- The month with the most large substations seriously overloaded could be the highest-cost month, yet not receive the highest weight.
- A month would receive a weight of 100% whether each substation's maximum load were (1) only 1 kVA more than its maximum in every other month, or (2) four times its maximum in every other month. High loads in other months that are near the substations' annual peaks can cause excessive wear and tear. For example, August receives twice the weight that July does, even though both months experience high loads.
- A small substation has as much effect on a month's weighting factor as a large substation does.
- RMP's approach can produce illogical results. For example, in Docket No. 07-035-93, the only two months with weights greater than 10% were July

(41%) and June (18.4%). The Utah distribution peak actually occurred in August, but received a weight of only 8.5% (Excel file COS UT Dec 2008 (MSP).xls, Tab "Dist. Factors").

Monthly weighting factors should recognize the size of individual substations and the effect of multiple peaks and the duration of peaks on substation sizing.

IV. Recommendations

Q: Please summarize your recommendations.

A: I recommend that the Commission give no weight to the COS Study results for the irrigation class in this proceeding, due to the large errors in the irrigation class load estimates. I also recommend the Commission direct the Company to conduct a study of shared services to determine the split of service drops by single and multi-family residential dwellings. Lastly, I recommend that the Commission order the Company to implement improvements in its next COS Study to meet the following goals:

- recognize the sharing of service drops by residential customers in multi-family dwellings;
- classify a greater percentage of generation plant as energy-related;
- classify a greater percentage of non-seasonal purchases as energy-related;
- allocate demand-related distribution costs based on class contribution to loads in the many high-load hours that determine the duration of peak loads;
- revise the monthly weights for the primary distribution allocator to more reasonably reflect monthly distribution demand.

Q: Does this conclude your testimony?

A: Yes.