STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

The Application of Rocky Mountain	**)**	
Power for Authority To Increase its	**)**	**Docket No. 10-035-124**
Retail Electric Utility 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

Witness OCS – D9 (COS/RD)

Resource Insight, Inc.

JUNE 2, 2011

TABLE OF CONTENTS

TABLE OF EXHIBITS

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 more than two hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies.

Q: Have you testified previously before the Commission?

A: Yes. I testified on behalf of the Utah Office of Consumer Services ("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.
- Dockets 07-035-93 and 09-035-23, on the reasonableness of RMP's Cost-of-Service study. I also assisted the Office in the development of its rate design proposal.

- Docket 09-35-15, on the need for RMP's proposed Energy Cost Adjustment Mechanism.

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?

A: I evaluate the Cost-of-Service Study ("COS Study" or "COSS") and the Marginal Cost Study ("MC Study") filed by Rocky Mountain Power ("RMP" or "the Company") and recommend certain improvements be made to the Company's analyses in the next rate case filing. I pay particular attention to the calibration of the COS Study load data introduced by RMP in this proceeding and to certain classification and allocation methods. In addition, I address RMP's reliance on these COSS and Marginal Cost studies for its revenue spread and residential rate design proposals.

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.[1] A

[1] There are also cost-allocation implications for certain special contract customers due to pricing provisions in their respective contracts.

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. Its reliability is also affected by limits on the accuracy of the load data. For these reasons, 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. A 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
- energy and regulatory policy.

Q: What COS Study issues does your testimony address?

A: My testimony on the COS Study addresses two basic areas:

- the reliability of the Company's load data, and
- specific classification and allocation factors.

A. Evaluation of the Load Data

Q: What load data issues does your testimony address?

A: My testimony addresses the following issues:

- the introduction of a calibration process to reduce a so-called "gap" between the sum of retail class peaks and the Utah jurisdictional peak,
- the unreliability of irrigator load data, and

- the failure to weather normalize retail class peaks.

1. Calibration

Q: What is RMP's justification for the calibration of load data?

A: According to Mr. Thornton's Direct (at 10) "The calibration process is based on the expectation that the sum of base year class loads should equal the total forecast jurisdictional load estimates" at PacifiCorp system monthly peaks. Calibration concerns only the estimation (or re-estimation) of retail loads coincident with PacifiCorp system peaks ("CP").

Q: Please describe RMP's calibration process?

A: RMP follows several steps to develop the COS Study load data. The calibration process (as described in Mr. Thornton's Direct at 10-13 and shown in Attachment OCS 7.2), is by no means a simple and transparent algorithm:

- For the sum of retail class peaks, the process starts with the monthly dates and times of the system peaks in the base year.
- RMP estimates the class contributions to system peaks in the base year, using adjusted load research data.
- RMP forecasts class hourly loads by applying class energy growth factors to the adjusted base year load research data.
- Based on its assumption that class load shapes are constant, RMP sets each monthly class CP at the forecasted hourly load at the time of base year system peaks.
- RMP then sums the forecasted class monthly CP's at the base year dates and times, and compares the results, by month, to the forecasted Utah jurisdictional CP. The jurisdictional CP forecasts are based on a different

methodology and may occur at different dates and times than the class CP's.

- Monthly class loads are adjusted to reduce the "gap." These adjustments are applied to the sampled classes only. The loads of the interval-metered classes are assumed to be 100% certain.
- Where the two Utah forecasts (the sum of class and the jurisdictional peaks, both excluding the interval-metered loads) differ in any month by more than 5%, the sampled class peaks are adjusted in one of two ways: (1) the difference in excess of 5% is spread proportionally over the sampled classes (if the initial difference is between 5% and 10%) or (2) the class peaks are determined at a date and time that is closer to the jurisdictional time of peak and, if necessary, the revised class peaks are adjusted for any excess over 5% (if the initial difference is more than 10%). RMP's choice of new dates and times is based on somewhat of a trial-and-error process.
- RMP also calculated a separate calibration that minimized all monthly "gaps" to 5%. This simpler calibration was not used in the COSS.
- Finally, if necessary, monthly class CP's are adjusted in 0.5% increments to reduce the annual "gap" to 2%. This adjustment was not required.

Q: Is "calibration" considered a valid adjustment to statistical results?

A: No. According to the 1992 NARUC Utility Cost Allocation Manual (p. 179):

> …The sum of the coincident demands for all classes for any hour adjusted for losses will not equal the demand of the utility generated in that hour. This is because of sampling and non-sampling errors.

When the historic test year is coincident with the year the load data was collected, the cost analyst can use the demands as estimated and calculated but usually an adjustment is made to the demands so that they sum to the actual demand of the utility in that hour. Sampling statisticians prefer that no adjustment be made because of the uncertainty as to whether the adjusted demands by class represent more accurately the class's proportion of the total demand than the statistically estimated demands. Some cost analysts have adjusted the estimated demands proportionately of only those classes that are not 100% time-recorded. This procedure, however, ignores the size of the sampling error of the various estimates and the measurement errors present in 100% time-recorded classes.

Q: How does RMP's calibration affect the COSS load data?

A: The calibration increased the relative annual average peak of the Schedules 1 and 23 and reduced the relative peak of Schedule 6. As shown in Table 1, The changes in the current case are small; see Table 1

Table 1: Effect of Calibration on COSS Load Data

	Total Annual		Difference		Percent of Total Class Sum		
Class	Pre-Calib	Calibrated	kW	%	Pre-Calib	Calibrated	Increase
Res 001	15,739,626	15,864,216	124,589	0.79%	35.12%	35.24%	0.10%
Com 006	12,447,653	12,486,511	38,858	0.31%	27.78%	27.74%	−0.05%
Com 023	2,922,563	2,979,568	57,004	1.95%	6.52%	6.62%	0.09%
Irr 010	213,589	213,589	0	0.00%	0.48%	0.47%	0.00%
Sum of Sampled Classes	31,323,432	31,543,883	220,451	0.70%	69.90%	70.07%	0.15%
Total Class Sum	44,810,760	45,031,212	220,452	0.49%			

The algorithms RMP uses to adjust class monthly peaks have different effects on relative class peaks:

- The proportional spread among sampled classes maintains the relationship among those classes, but changes the allocations between large customers and sampled customers.
- Changes in the day and time of peaks changes the allocations among all classes.

Q: Are there significant problems specific to RMP's calibration process?

A: Yes. There are many problems with RMP's calibration of load research and forecasting results, as follows:

- The calibration process is not a precise algorithm.
- A monthly calibration holds the class load forecasts to a higher reliability standard than the load research data support.
- Before any calibration occurs, the difference between the sums of the monthly class peaks and the monthly Utah jurisdictional peaks is already less than RMP's target of 2%. The selective calibration process used by RMP actually increases this difference.
- Unlike the jurisdictional peak, the class load shapes, class monthly peaks, and the days and times they occur are based on actual loads in a single historical year, rather than a year normalized for weather and other important factors (DPU 3.8). Even when RMP changes the day and time of the monthly peaks, the class loads are still based on an actual year.
- The same adjustment is applied to all sampled classes even though the residential load research study is designed to provide more reliable data than are the load-research samples for the other sampled classes.[2]
- The class CP forecasts and the jurisdictional forecasts are based on different methodologies, another possible cause of the difference between the two forecasts and one that has nothing to do with the varying confidence in various class load studies.

[2] According to Mr. Thornton, the residential class sampling was designed to achieve ±5 percent precision at the 90 percent confidence level, while the load data for the other sampled classes was expected to meet a design criteria of ±10 percent precision at the 90 percent confidence level (Thornton Direct, p. 6)

- Each of the forecast methods contains sources of statistical error that can cause discrepancies between the class and jurisdictional peak loads, and are also independent of the uncertainties in load research data.
- The process incorrectly assumes zero error in historic census data and in the forecasted loads of large customers.
- The calibration method is based on the assumption that all error lies with the class load research and forecasts, ignoring the data and forecasting error in the jurisdictional CP estimates.
- The Company claims to be confident in its load research and statistical analyses. On the other hand, RMP proposes this calibration process as a "fix" to its statistical results. These are inconsistent positions.
- The Utah jurisdictional peaks include some Utah loads that are excluded from the sum of the class peaks reflected in the COSS.
- Losses from wholesale transactions and power transfers through Utah may be inappropriately assigned to the Utah jurisdiction, thereby inflating Utah loads reflected in the jurisdictional model. This was the one of the primary reasons calibration was abandoned by the Company in 2002.

Q: How does the accuracy standard RMP required of its load research study design differ from the calibration tolerances?

A: RMP's calibration standard for sum of sampled peaks in each month is 5% and for the annual total sum of peaks is 2%. That is, RMP adjusts the class peaks (in various ways) until the forecast jurisdictional peak in each month is between 95% and 105% of the sum of class peaks, and the annual average of the forecast monthly jurisdictional peaks is between 98% and 102% of the average of the monthly sum of class peaks. But the load research sampling is designed to meet a much lower level of accuracy: to produce annual average class load estimates within 10% of the actual load, with a confidence level of 90%. (Thornton Direct, p. 4).[3] Furthermore, as the Company itself explains, the design standard applies only to the annual sum of peaks, not to the individual monthly peaks:

> Mr. Thornton's testimony does not assert individual peaks will reflect an "accuracy of plus or minus 10 percent at the 90 percent confidence level." Rather, it states that this is the design standard for the "variable of interest" (lines 73-74). The variable of interest for the load studies referenced is the average demand at the time of the monthly system peaks, as measured over a twelve consecutive month period. (Response to OCS 10.1)

The individual month peaks are not used by RMP's COSS in allocating costs; only an annual average of the monthly peaks is used in allocation, and only that average is important for cost allocation. Errors in individual months may offset one another; accuracy in monthly peaks is not essential for equitable cost allocation.

Q: How close is the annual sum of class peaks to the annual sum of jurisdictional peaks?

A: The difference between the annual sums before calibration far less than RMP's 2% target. As shown in Table 2 below, the calibration actually increases this difference from 0.1% to 0.6%:

Table 2: RMP Estimates of Utah vs. PacifiCorp Peak

		Sum of Class	
	Jurisdictional	Pre-Calib	Calibrated
kW	44,762,224	44,810,760	45,031,212
% Gap		0.1%	0.6%

[3] RMP designed its residential sampling to meet a higher standard: a confidence level of 90% that any particular load estimate is within 5% of the actual load. However, RMP ignores this higher accuracy in its calibration process.

Given that the annual “gap” is almost zero and the monthly peak “gaps” are statistically meaningless, RMP’s calibration process addresses a problem that does not exist.

Q: How do the methodologies used to forecast jurisdictional peaks and class peaks differ?

A: The jurisdictional forecasts are the result of regressions on historical jurisdictional hourly load data, for each hour. The forecast of jurisdictional load shape is normalized through regressions that contain dependent variables for weather.

The COS loads are the result of completely separate regressions. Furthermore, the load shapes and the dates and times of peaks are based on what happened in one actual year only, the base year. There is no attempt to develop a class load shape for a normal year. Only the forecasted class energy growth is normalized for weather through a regression on historic energy use.

There is no reason to expect that the projections resulting from two different methods—using different driving variables, one weather-normalized and the other not—will exactly match; and if they do not match, there is no reason to assume that one projection is right and the other wrong.

Q: What sources of statistical error exist, other than the load research data error?

A: Every regression analysis has a confidence interval around its estimates of the best-fit equation, and an even wider prediction interval around the projection for any particular set of inputs.

In addition, the JAM estimate of Utah’s contribution to system peak (the measure that the DPU assumes is correct) is not even directly the result of the regressions. Rather, the Company separately forecasts hourly state loads (not coincident with the system peak), monthly peak state loads, and monthly energy, all from regression analysis; turns the hourly forecasts into a monthly load duration curve; shifts the curve vertically to fit the state peak and rotates the curve to fit the energy forecast; turns the load duration curve back into hourly loads; adds loads across states and selects the system peak hour.

There are clearly many assumptions and potential errors in this process and they are sources of error in the forecasted jurisdictional peaks as well as the class peaks.

Q: Has the Company acknowledged that there can be error in interval-metered data?

A: Yes. In his Rebuttal Testimony in Docket No. 09-035-23 (at 9), Mr. Thornton stated that "any one of three components (load research data, census data, and/or Utah Border Load data) could have an error …"

Q: Given its recognition that there is error in the census data, what rationale does RMP offer for treating the census data as 100% accurate?

A: RMP seems to take the position that it is appropriate to presume 100% accuracy unless proven otherwise (OCS 10.5):

> …Until the Company becomes aware that a given metering location is NOT working, the presumption will always be that the Company is receiving load data from all members of any of these direct measurement classes.

Q: How would RMP "become aware" that a census meter is malfunctioning?

A: RMP does not provide that information (OCS 10.5).

Q: What steps would RMP take if it discovered that census data were incorrect?

A: That also is unclear. In one instance, RMP included a variable that reflected two incorrect monthly bills in one month for industrial customers in a regression analysis used to predict sales growth. But RMP may not even know the effect of meter error on measured hourly loads and therefore on the forecast peaks of census customers.

Q: What Utah loads are not included in the COS Study retail-class loads?

A: Certain customer loads (electric furnace loads serviced under schedule 21, backup loads serviced under schedule 31, and the partial requirement loads) are reflected in jurisdictional peaks but not in the sum of retail class peaks.

Adding in the omitted loads has a noticeable affect on the monthly "gaps," Table 3 provides a comparison by month, of the Utah jurisdictional peak with the sum of class peaks before calibration including the omitted loads. Negative values indicate months in which the sampled-class loads must be adjusted downward if the total monthly class load is to match the JAM load.

Table 3: The Effect of Omitted Loads on JAM-Class Differentials

	Sum of Class Contributions to System Peak				**JAM-Class Difference as %**	
	COS Classes	Omitted Classes	Total	**JAM Utah**	Excl Omitted	Incl Omitted
Jul-09	4,686	38	4,723	4,723	0.79%	−0.01%
Aug-09	4,759	37	4,796	4,608	-3.29%	−4.09%
Sep-09	4,305	43	4,348	4,240	-1.54%	−2.56%
Oct-09	3,300	135	3,435	2,911	-13.34%	−17.98%
Nov-09	3,571	188	3,758	3,484	-2.49%	−7.87%
Dec-09	3,257	156	3,412	3,716	12.36%	8.17%
Jan-10	3,464	176	3,640	3,573	3.05%	−1.88%
Feb-10	3,350	176	3,526	3,207	-4.45%	−9.94%
Mar-10	3,446	184	3,630	3,066	-12.39%	−18.39%
Apr-10	3,145	170	3,315	2,922	-7.60%	−13.43%
May-10	3,094	122	3,216	3,900	20.67%	17.54%
Jun-10	4,435	113	4,548	4,411	-0.54%	−3.10%
Total	44,811	1,538	46,349	44,762	-0.11%	−3.54%

The average sum of class peaks for the classes included in the COSS is slightly (0.1%) higher than the jurisdictional peak, while the sum of all the class loads (including the loads omitted by the Company) is 3.5% higher than the jurisdictional peak. In addition to the five months that RMP calibrated, using the corrected data with all loads would require the calibration of February as well. For the four months (including February) in which class loads would be adjusted downward, the gaps to be adjusted would increase by 3 to 10 percentage points, while in the two months with upward adjustments, the gaps would decrease by 3 or 4 percentage points. As a result, the loads of the sampled classes would be reduced much more by calibration if the omitted classes are properly included in the computation.

Q: What losses occur within Utah that are not due to Utah retail sales?

A: The sources of these losses include:

- sales to other states,
- municipal and coop loads in Utah,
- power flowing from Arizona or Wyoming, through Utah, to Idaho and beyond.

Q: Has RMP attempted to measure these losses?

A: No. The Company has made no effort to measure these losses. RMP gives the following explanation (OCS 10.12):

> PacifiCorp is unable to provide the requested estimate. While the Company does have Utah-specific loss figures, these are limited to retail uses of the transmission system in Utah. Accordingly, a Utah-specific estimate of losses for third-party wholesale uses of the system cannot be provided from these figures. The Company has transmission system-wide loss figures, but these are not separated into individual state results.

2. Weather Normalization

Q: How do the JAM and COSS peak load forecasting methods differ?

A: While the Company has for some time used weather-normalized load shapes to determine peak loads for the JAM model, it does not weather-normalize the class load data used in the COS Study (DPU 3.8). This discrepancy appears to be one important factor accounting for some of the difference or gap between the jurisdictional and class peak loads.

3. 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: Has the reliability of the irrigator load data used in the current COS Study been improved?

A: No. RMP has not provided any analysis to indicate that the irrigator load data has improved

Q: What has RMP's recent experience been with its irrigator load research data?

A: In the data provided in Company Witness Scott Thornton's Exhibit SDT-1 in the last rate case (Docket No. 09-035-23), there were sizeable discrepancies between estimated and actual monthly usage. The overestimates of irrigation class usage in the summer months (the only months for which RMP uses the irrigation load-research data) ranged from 18% in May to 62% in August. Table 4 summarizes these errors.

Table 4: Errors in RMP's Irrigation Load Reconstruction

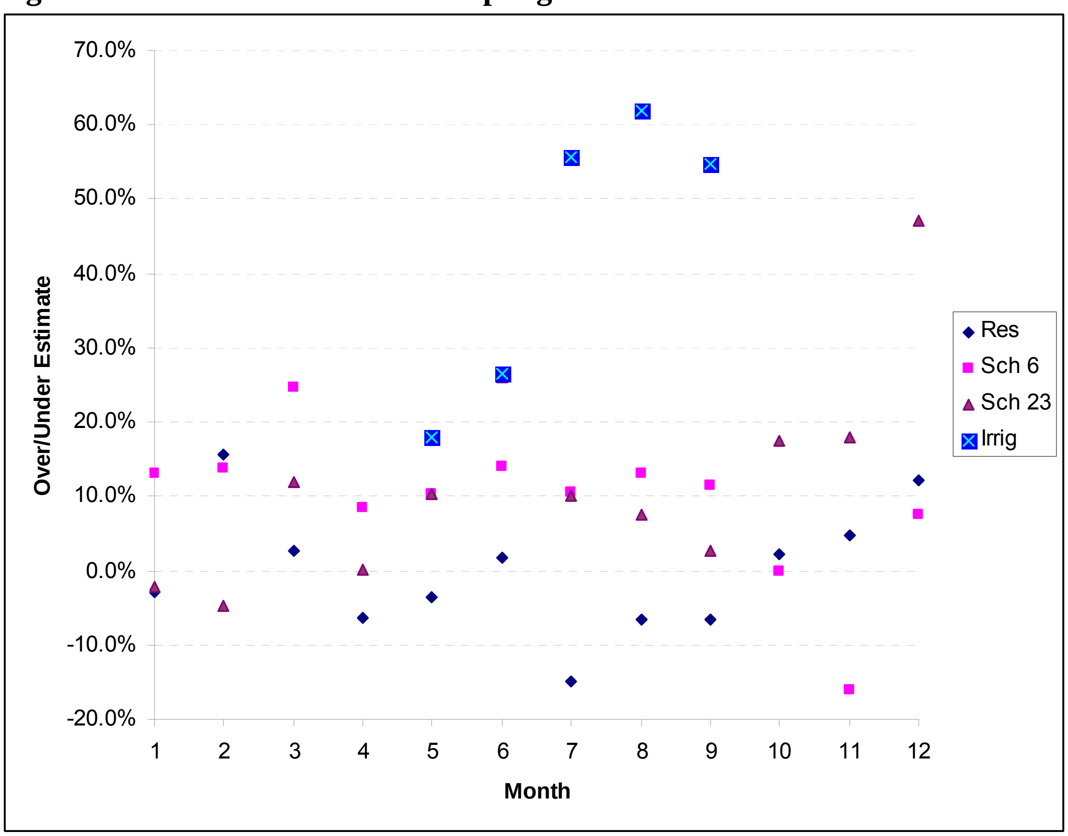
	Sample MWh	Billing MWh	Adj. Factor	Over-estimate
May	35,079	29,728	0.8475	18.0%
June	48,924	38,702	0.7911	26.4%
July	68,699	44,108	0.6420	55.8%
August	69,803	43,086	0.6173	62.0%
September	44,524	28,760	0.6459	54.8%

The load-research data over-predicted actual usage of irrigation customers by 45% in the summer months.

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

A: No. As shown in Figure 1 below, the five months of irrigation load data included 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: 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, 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: Can the current irrigator load data be relied on to support a disproportionate increase in irrigation rates?

A: No. Since the load data for this class has not come close to meeting PURPA standards and has differed sharply from actual class sales, no conclusions can be drawn about the cost of service for the irrigation class. The current irrigator load data should not be relied upon to support a major cost allocation action.

B. Evaluation of Classification and Allocation Factors in the Cost-of-Service Study

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. 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.

- The reliability-based need for generation capacity depends on the relationship between retail load, net wholesale sales and available capacity, not simply upon demand.
- Scrubbers are entirely energy-related investments.
- More than 50% of firm power purchase costs are energy-related.
- Some service drops are shared by two or more customers.

1. The Classification of Generation Plant

Q: How does the COS Study classify generation plant?

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: It was developed for purposes of jurisdictional allocations. 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 Utah Power and Light's 100% demand classification, in place at the time of the PacifiCorp merger.

In Docket No. 97-035-01, the Commission acknowledged that energy needs are a significant driver of generation capital costs. It adopted the Division's *qualitative* argument in support of classification of some generation plant as energy-related and found the 75-25 split to be "reasonable." The Order does not refer to any *quantitative* cost-causation analysis as the basis for the 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 provide any additional guidance in its Order in Docket No. 09- 035-23?

A: Yes. In the Report and Order in the last general rate case, the Commission did indicate that changes to reflect cost causation could meet Commission approval. As 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: Is there a good analytical reason for changing the demand-energy split applied to generation plant?

A: Yes. 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: Has the Commission endorsed your view that more generation plant should be classified as energy-related?

A: No, for at least two reasons. First, the Commission found that a change to the classification of generation would be inconsistent with the JAM method. Second, the Commission believed that the existing 75-25 method is supported by the stress factor analysis.

Q: What is your understanding of the Commission's current view regarding consistency between the JAM and the COSS?

A: The Commission's position is not clear. In its Order in Docket No. 09-035-23, the Commission appeared to raise further obstacles to approval of changes to the COSS that are inconsistent with the JAM methodology:

> Any party who would like to propose an alternative to the approved methods must provide analysis to demonstrate the proposed method is also appropriate and viable at the inter-jurisdictional level. This analysis must include a level of detail to determine the impacts to Utah and other states in the PacifiCorp system of a proposed change in classification and allocation methods

It is not clear what the Commission meant by the term "viable at the inter-jurisdictional level." If that standard requires the proponent of a change to prove that the change would be accepted by all five of the other PacifiCorp states for use in a consensus JAM, it would be nearly impossible to meet. If, on the other hand, the standard is to demonstrate that the proposed change would not seriously disadvantage Utah, or would not excessively burden the majority of states, it may be possible to provide the information the Commission is seeking.

I present an analysis of the energy classification of generation plant, in the event that the Commission clarifies its standard so as to consider allocation factors that are not identical to the current JAM methodology.

Q: Does the stress factor analysis support the 75-25 classification of generation?

A: No. The Company's stress factor analysis determines the hours of load that drive the reliability-based need for capacity. Therefore, it is relevant to the allocation of the demand-related portion of generation plant. In particular, since it shows that hours in all months contribute to the loss-of-load-probability, it supports the 12-CP allocator. It is not relevant to the classification of plant as energy- or demand-related.

Q: How can the energy-related portion of generation plant costs be estimated on a cost-causal basis?

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 found the peaker method to be reasonable?

A: Yes. The Company's current analysis of marginal generation cost is based on the same peaker method. In the case of the marginal cost calculation, a new combined cycle unit (CC) is considered to operate as the baseload unit. The simple cycle combustion turbine (CT) is a proxy for capacity costs. The excess of the cost of the CC over the CT is considered energy-related. (Paice Direct, pp. 12-13).

RMP's support for this methodology is a longstanding one, dating back to its 1989 UP&L Distribution Study at page 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: Please explain how the peaker method would be used to classify generation plant in a COS Study.

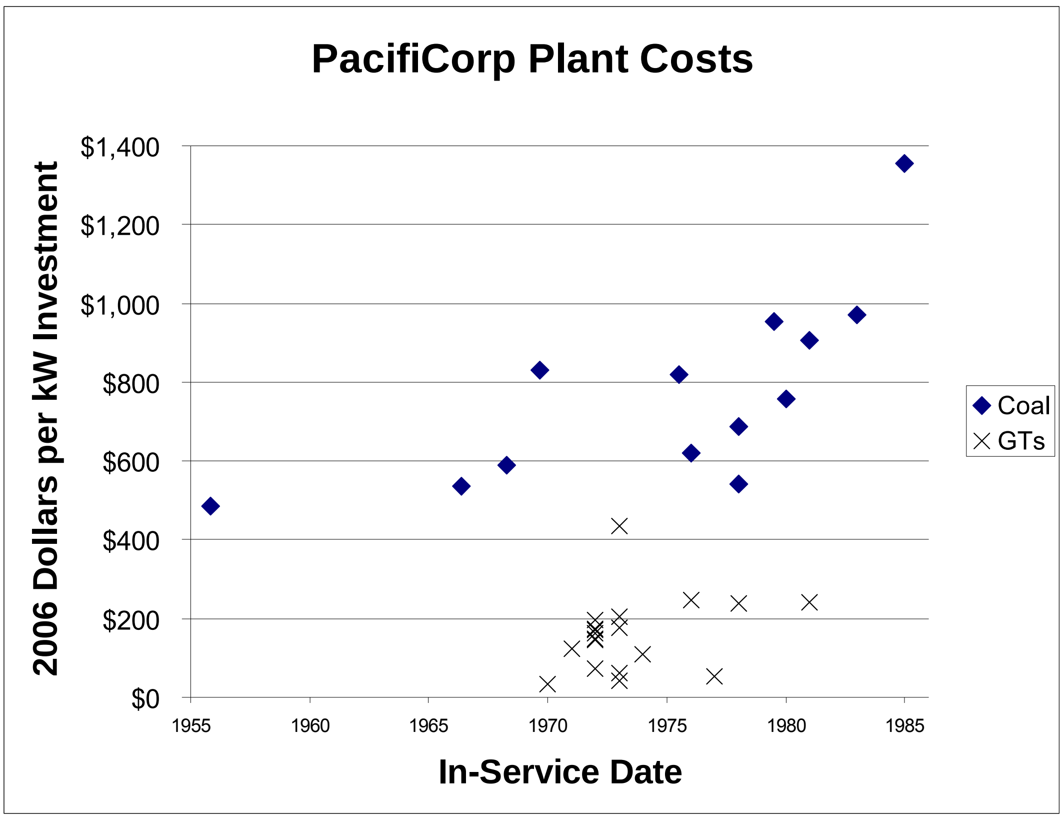
A: For each generation unit, a good initial estimate of the demand- or reliability-related portion of its cost is the cost per kW of a peaker (generally a simple-cycle combustion turbine) installed in the same period times the rated capacity of the unit. The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.[4]

[4]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.

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-turbine plants, sorted by in-service date.[5] 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 CT Plant Costs



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.

[5]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.

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 $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.

In addition, RMP's current Marginal Cost Study indicates that even in the case of combined cycle plants, which are less costly than coal plants, the portion of fixed cost that is energy-related exceeds 25%. Netting out the fixed costs of a frame simple-cycle combustion turbine, at $95/kW-year, this analysis calculates the energy-related fixed cost of a new combined cycle plant would be $49/kW-year, or 34% of the total fixed cost (Attachment OCS 10.19). A comparable computation for a new coal plant, with higher capital and fixed O&M costs, would show much more the 34% of the fixed costs of a new coal plant as being energy-related.

Q: What do you conclude based on your peaker analysis and the Company's Marginal Cost Study?

A; The evidence supports moving in the direction of a 50/50 demand-energy classification of generation plant in future COS studies.

2. Allocation of Demand-Related Generation Plant

Q: How does RMP allocate demand-related generation plant?

A: It uses a weighted 12-CP allocator, where the monthly weights are the ratios of monthly system peaks to the annual system peak. The Company has referred to this factor as a seasonally-weighted CP allocator because the peak month in Utah normally occurs in either July or August.

Q: Is this allocator appropriate?

A: No. It does not reflect cost-causation

Q: Is the weighted 12-CP consistent with JAM allocations?

A: No. The JAM generation allocator uses an unweighted 12-CP.

Q: How does the weighted 12 CP allocator fail to reflect cost causation?

A: The weighting of CP's incorrectly assumes that the need for and cost of capacity is a simple function of the amount of the system monthly peak. The significance of load in any given hour also depends on the following factors:

- The amount of generation capacity that is *available*, not just installed, to meet load in that hour. Because of forced outages, there are many hours that contribute to the system need for capacity.
- The scheduling of maintenance outages. PacifiCorp normally schedules generating-unit outages during the fall or spring months. Thus, it must have generation resources to meet demand when some units are unavailable because of scheduled outages in the shoulder periods.
- The effect of retail load on PacifiCorp's ability to sell capacity in the wholesale market, including in the non-summer months. By reducing PacifiCorp's wholesale sales, the additional load increases net power costs.

3. Classification and Allocation of Scrubbers

Q: Why should new scrubber investment be treated as 100% energy-related?

A: Scrubbers should be treated as a capitalized fuel cost, and therefore 100% energy-related, for the following reasons:

- The purpose of scrubbers is to reduce emissions from coal plants, which is a function of the amount of coal burned.
- The resulting SO_2 Emissions allowances/revenues are allocated 100% on energy in the Company's COSS model (i.e., SE or F30).
- Scrubbers reduce generation plant capacity. They do not serve peak load. Therefore, scrubbers do not serve any demand-related purpose.

Q: Has the issue of the classification of scrubber retrofits been explicitly dealt with in the MSP process or in any Utah proceeding

A: Not to my knowledge. The classification of scrubber retrofits represents a new issue that requires Commission consideration.

4. Treatment of Firm Non-Seasonal Purchases

Q: How does RMP classify and 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 is comprised of all purchases except non-firm and seasonal. It consists of 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 is more energy-related than the COS Study assumes, as discussed above in Section III.B.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 purchases 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.

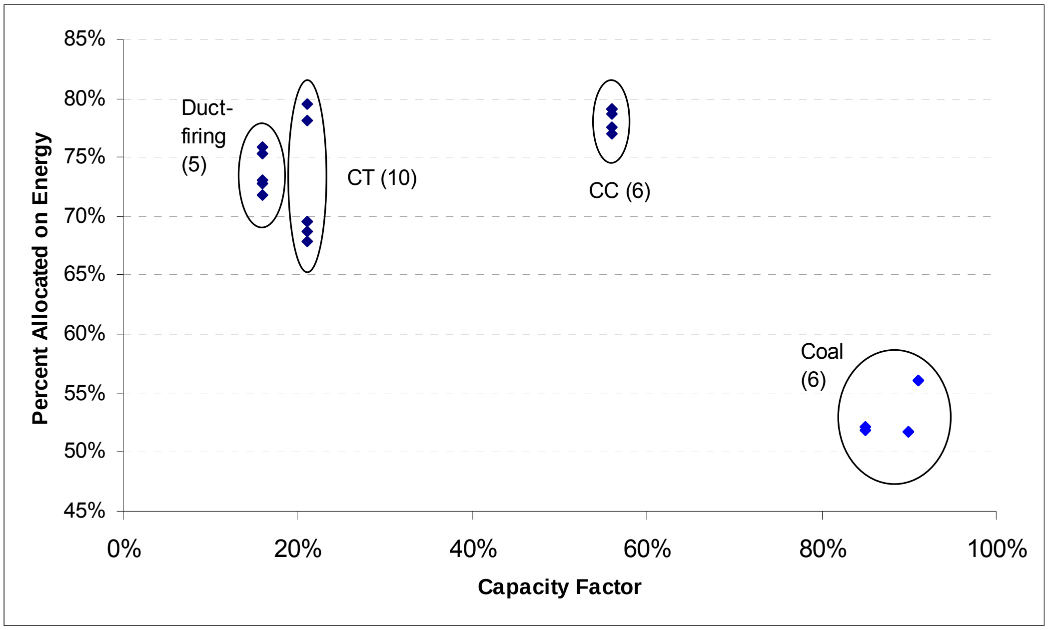
Table 5: Share of Cost Allocated on Energy

	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: 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 (See Figure 3). 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



5. *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 derivation of this allocator take into account all of the important cost factors?

A: No. RMP's derivation of the allocator has at least two problems:

- It ignores the sharing of services by customers in multi-family buildings, and
- It assumes the same average service length (70 feet) for all rate classes.

Q: How does the allocator ignore sharing of services?

A: It assumes that each residential customer requires its own service line (Paice Direct at 8).

Q: Has RMP confirmed that some residential customers share services?

A: Yes. In its response to OCS 7.6, RMP agrees that "the assumption of one service drop per multi-family housing complex is not correct…" However, RMP has not modified the services allocator to correct this error.

Q: What is RMP's explanation for continuing to rely on an invalid assumption?

A: RMP has given several reasons, including:

- It is unable to retrieve from its records enough customer data on shared service drops (OCS 7.4, OCS 7.5).
- Multi-family building service drops are more expensive than single-family services and there are no "clear rules of thumb" for deriving a representative cost figure (OCS 7.6).
- Some general service customers may also share service drops (OCS 7.6).

Q: Have you estimated what the impact of shared services would be on the residential services allocator?

A: Yes, given the data I have available to me. The 2000 Census of Housing indicates that about 29% of housing units in the Utah counties that RMP serves are in multi-family structures.[6] Of those, 13% of RMP's customers live in housing structures with two to nine units, and 11% live in structures with more than nine units.

[6]In calculating the average mix of housing type, I weighted each county's mix by the number of RMP customers in that county (from OCS 7.3).

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 Table 6.

Table 6: Estimate of Residential Sharing of Service Drops

Units in Structure	Number of Units	Customers per Service
1-unit, detached	496,559	1.00
1-unit, attached	35,840	0.75
2 units	28,486	0.50
3 or 4 units	35,313	0.29
5 to 9 units	27,639	0.15
10 to 19 units	30,395	0.07
20 to 49 units	23,267	0.03
50 or more	23,378	0.02
Total RMP housing units	700,872	
Number of residential services		555,474
Average number of services per residential customer		0.79

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.

Q: Could the Company update your estimate of the percentage of customers that reside in multi-family dwellings by using 2010 Census Data as that becomes available?

A: In the absence of more detailed information from the Company about its customers and service drop installations, using 2010 Census Data to update the estimate I provide here is a reasonable approach. Office witness, Dan Gimble, also discusses the issue of shared services in his direct testimony and provides the Office's recommendation.

IV. Marginal Cost Study

Q: What problems have you identified in RMP's Marginal Cost Study?

A: RMP's Marginal Cost Study understates the cost of load growth in at least two ways:

- RMP excludes sizeable future transmission investment that may actually be growth-related; and
- RMP excludes a major portion of distribution by classifying it as "commitment-" or customer-related.

A. Transmission

Q: How does the Company estimate marginal transmission costs?

A: RMP projects that it will make a total of $1,074 million transmission expenditures over five years 2012-2016 to meet a load growth of 647 MW in the same period. (Exhibit RMP_CCP_5_Redacted, Table 9).

Q: What future expenditures are excluded as non-growth-related?

A: Attachment OCS 7.25 provides a list of future transmission investments that were omitted from the estimate of marginal transmission cost as non-growth-related. In the years 2012 through 2016, these expenditures amount to $2,272 million.[7]

Q: Has the Company explained why it omitted these expenditures from its marginal cost study?

A: No, despite a request for this information (OCS 7.25(d)). In fact, Attachment OCS 7.25(d) refers to these expenditures as "Transmission–Increase capacity work 2011-2020" and eighteen of the additions are listed as general investments

7The sum does not include expenditures for transmission to individual new customers for “New Revenue–Transmission Expansion Plan.” It is unclear why RMP has excluded such a large portion of its transmission investments from its marginal cost calculation.

B. Distribution

Q: How did RMP determine the portion of its distribution plant investment that is “commitment-related?”

A: In concept, RMP used minimum-system approaches separate demand- and customer-related distribution costs according to these simple rules:

- The number of units (feet of line, number of transformers and meters) is due to the number of customers.
- The size of units is due to the load.

1. Minimum System Methods

Q: Are these minimum-system rules based on a realistic view of an electric distribution system?

A: No. This view is overly simplistic, for four reasons. First, much of the cost of a distribution system is required to cover an area, and is not really sensitive to either load or customer number. For example, serving many customers in one multi-family building is no more expensive than serving one commercial customer of the same size, other than metering. The distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers.

Second, load levels help determine the *number* of units, as well as their size. As load grows, utilities add distribution feeders and transformers in parallel with existing equipment, such as adding a transformer to serve one end of a block, as load grows beyond the capability of the transformer originally serving the block (See OCS 7.19, OCS 7.21). Indeed, large customers may be served by multiple transformers to increase reliability.

In general, more small electric customers than large customers can be served from one transformer. Higher loads require larger service drops and secondary wires, so more transformers are added to reduce the length of the wires. This multiplication of transformer number is expensive because (1) transformers show large economies of scale in dollars of investment per kVA of capacity and (2) dispersed transformers have lower diversity than transformers serving many customers, increasing the total installed kVA required to meet customer load.

Third, load can determine the type of equipment installed, in addition to size and number. Electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, increasing the costs of equipment (e.g., insulation requirements for transformers and lines).

Fourth, increases in peaks and duration of high energy use on the so-called "commitment-related" investment increases the need for repairs and replacements, decreases its expected operating life, increases the carrying costs, and therefore increases the lifetime costs of the equipment (See OCS 7.22).

Q: Please explain how increases in peaks and duration 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 in the ability of lines and transformers to survive brief load spikes on the same day.

Q: How is the cost of the "minimum distribution system" generally derived?

A: The most common methods used are:

- The Minimum-System Method,
- The Zero-Intercept Method.

Q: Please describe the Minimum-System Method.

A: A minimum-system analysis attempts to calculate the cost (in constant dollars) of the utility's installed units (transformers, poles, conductor-feet, etc.), were each of them the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis attempts to determine how much would it have cost to install the same number of units (poles, conductor-feet, transformers), but with the size of the units installed limited to the current minimum unit normally installed. This cost will be customer-related, and the remaining cost will be demand-related.

The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

Q: Please describe the Zero-Intercept Method.

A: The Zero-Intercept Method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load, as in 0-kVA transformers, or the smallest units legally allowed (as 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The idea is that this procedure identifies the amount of equipment required to connect existing customers, even if they had virtually no load.

Q: Is either method successful in separating customer-related from demand-related investment?

A: No, for the following reasons:

- Minimum-system analyses overlook the smaller sizes installed in the past, but not currently on the system. The current minimum system is sized to carry expected demand. Consequently, as demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less-expensive small equipment because rising demand has resulted in very rare use of the small equipment and the cost of maintaining stock became no longer warranted.
- Minimum-system analyses usually ignore the effect of loads on the *number* of units installed, or the *type* of equipment installed. Hence, a portion of the costs allocated to customer number is really driven by demand.

- Minimum-system methods ignore the effect of loads on the rate of repair and replacement of minimum-system equipment.
- Minimum systems analyses fundamentally assume that all area-spanning investment is caused by the number of customers. As discussed above, this is not true.

Q: How should the number of units installed be categorized as customer or demand-related?

A: A piece of equipment (e.g., conductor, pole, service drop, or meter) should be considered customer-related only if the removal of one customer eliminates the unit. The number of meters and, for the most part, services (although not the size) are customer-related, while feet of conductor and number of poles should be largely demand-related, especially in non-rural areas.

Reducing the number of customers, without reducing the demand in an area, will:

- sometimes eliminate a span of secondary conductor, if the customer is the furthest one from the transformer on that secondary;
- rarely eliminate a pole, if the customer is at the end of the primary line. In many situations, additional conductors are added to increase capacity, rather than to reach an additional customer.

Q: Can the zero-intercept method be relied on to determine the customer-related portion of plant?

A: No. The determination of the number of units required for a zero-demand system are far from simple. A system designed to connect customers but provide zero load would look very different from the existing system. A zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. A system with very low loads would use a single distribution voltage, which eliminates many conductor-feet, reduces the required height of many poles, and eliminates the need for line transformers.

The zero-intercept method is so abstract that it can be interpreted in many ways, and can produce a wide range of results. Any use of this method must be grounded in a firm understanding of the purpose and conceptual framework for defining a zero-intercept.

2. Poles and Conductors

Q: What portion of pole and conductor investment does the Marginal Cost Study treat as "commitment-related?"

A: The Study classifies 43% of pole costs and 22% of conductor costs as "commitment-related" ((Exhibit RMP_CCP_5_Redacted, Table 4). For the residential class, the customer-related portion is higher: 58% of pole costs and 34% of conductor costs.

Q: Does RMP rely upon either of the minimum-system approach you describe to estimate the commitment-related poles and conductor costs?

A: It is not clear from the Company's testimony and responses to data requests submitted by parties. RMP constructs a hypothetical circuit from which it estimates marginal costs and classifies them as commitment- or demand-related. However, RMP does not provide a detailed explanation of the basis for this classification.

Q: Is it likely that RMP's Distribution Circuit Model has the same problems as the minimum-system methods you discussed above?

A: Yes.

3. Transformers

Q: What portion of transformer investment does the Marginal Cost Study treat as "commitment-related?"

A: The Study estimates that 80% of transformer installation costs are "commitment-related" ((Exhibit RMP_CCP_5_Redacted, Table 4).

Q: What minimum system approach does RMP rely upon to estimate the commitment-related line transformer cost?

A: RMP applies the Zero-Intercept Method.

Q: Have you identified specific problems with RMP's marginal transformer cost analysis?

A: Yes. The regression analysis (documented in Attachment OCS 7.7) that RMP used to estimate the zero intercept has at least the following problems:

- The regression is based on a synthetic data, rather than the actual installed cost of actual individual transformer equipment.
- The results do not make sense. The zero-intercept exceeds the cost of a third of the transformers actually installed in 2009. RMP's estimate of the commitment-related portion of marginal transformer costs assumes that the hypothetical utility would install zero-capacity transformers to serve zero-load customers that cost 18% more than 10 kVa transformers and 4% more than non-pad-mounted 25 kVa transformers (Attachment OCS 7.17).
- The regression analysis looks at only transformer sizes installed in 2009, not at all transformers currently on the system. Transformers currently on the system range in size from 5 kVa to 25,000 kVa.

Q: In what way is the regression analysis based on a synthetic data set?

A: The “data set” does not consist of actual cost data. Rather, it consists of 26 numbers, which are the average installed cost by size of transformer for all transformers installed in 2009. By reducing the cost of 6,800 transformers into 26 numbers, the data set has removed most of the cost variation that is supposed to be dealt with in a statistical analysis.

Then, without actually adding pertinent information, RMP increases the number of “observations” from 26 to 6830. It does so by treating each of the 26 “data points” as though it represents many transformers of a single size at the same cost.

Q: Does RMP’s Marginal Cost Study provide any useful guidance for rate design?

A: Yes. Since the study is likely to have understated the cost of load growth, RMP’s marginal energy plus demand cost estimates provide a reasonable minimum target for the tail block charges of non-demand rate schedules. The estimate of marginal customer costs, on the other hand, is not valid and should not be relied upon in setting the level of the residential customer charge

V. Residential Rate Design

Q: Please describe RMP’s proposal for the residential rate, Schedule 1.

A: The Company proposes to increase the customer charge from $3.75 to $10.00 per month. In the Company’s view, fixed charges should be increased to recover additional costs it regards as customer-related.

Q: What is the Commission’s current policy on setting the customer charge?

A: Customer charges are based on only the costs of services, meters and billing.

Q: What additional costs has RMP proposed to reflect in the customer charge?

A: The Company would like to increase the customer charge to reflect its estimates of the distribution costs that RMP considers to be related to "commitment" (by which RMP means something like "spanning the service territory") and "retail" costs, such as customer service.

Q: What is RMP's rationale for increasing the residential charge?

A: RMP makes the following assertions (Griffith Direct, pp. 5-6):

- Its marginal cost study, in particular its determination that a large portion of transformer costs should be treated as "committed" costs, supports the inclusion of additional costs in the calculation of the customer charge.
- Underpricing customer costs gives the utility an incentive to encourage growth.
- Raising customer charges will result in more accurate price signals.
- Raising customer charges will reduce the Company's revenue volatility.

Q: Is RMP's marginal cost study a reliable basis for its proposal to increase customer charges substantially?

A: No, RMP's determination of the commitment-related portion of distribution investment is not valid, as discussed in Section IV.B.

Q: Has RMP identified ways in which it would pursue load growth if the customer charge were set below marginal cost?

A: No.

Q: Does RMP have incentives to encourage load growth, based on other cost components?

A: Yes. The more energy that RMP sells, and the higher its customers' billing demands, the more revenue it receives, from rates set to support distribution, transmission and generation investments. This effect remains strong under most circumstances, for all customer classes, with any plausible level of customer charges.

Q: Would increasing the customer charge provide more accurate price signals to customers?

A: No, for two reasons. First, higher customer charges require lower energy charges, which would reduce important price signals regarding the cost of using additional electricity. RMP's proposed residential energy charges are significantly below the sum of marginal energy and demand costs, according to RMP's own marginal-cost analysis.[8]

Second, unlike energy charges, a customer charge is not a price signal. Few if any customers decide whether to add a new meter and service drop in a manner that might be affected by the customer charge. Customers will not forego electric service because of high customer charges. Nor will they discontinue service due to the customer charge.

Q: Do higher customer charges reduce RMP's revenue volatility?

A: Yes. I expect that would be the major attraction of higher customer charges to RMP. That convenience to RMP hardly justifies the inefficiency of reducing energy charges.

Q: Has RMP used the appropriate costs in its justification of the customer charge?

A: As I describe in Section IV.B, the marginal-cost analysis grossly overstates the so-called commitment costs. In addition, the estimate of the service-drop cost for the minimum-size customer is overstated by RMP's failure to recognize the

[8] In addition, as I explain above, RMP's marginal-cost analysis is likely to understate the marginal cost of load growth.

sharing of services in multi-family buildings, and use of the average cost of a single-family residential service, rather than the cost of a minimal service. The longest, highest-cost services are likely to be installed for higher-use customers. In particular, the assumption in the marginal cost of a 70-foot service length is excessive for the smallest residential customers, which should be the basis for the service charge. Longer service lines are likely to be serve larger homes on larger lots, as well as non-residential customers.[9]

VI. Recommendations

Q: Please summarize your recommendations regarding the load data used in the Company's COS Study

A: I recommend that the Commission order the Company to eliminate its calibration of load data. Instead of calibration, I recommend that the Company modify its load research methods to reduce inconsistencies in its approach to forecasting jurisdictional and retail-class peaks. In particular, RMP should:

- Base both the jurisdictional and the retail class energy and peak forecasts on weather-normalized load data;
- Provide data on the load included in Utah for the JAM that is omitted from the retail class loads in the COSS;
- Estimate the losses included in Utah for the JAM that may be due to wholesale transactions and interstate transfers.

In addition, I recommend that the Commission not rely on the current irrigator load data to support a disproportionate rate increase to this class.

[9] It is not clear that the average residential service drop is really as long as the 70 feet that RMP assumes.

Q: Please summarize your recommendations regarding COS Study classification and allocation.

A: I recommend that the Commission order the Company to implement improvements in its next Cost-of-Service Study to meet the following goals:

- classify a greater percentage of generation plant as energy-related,
- classify the costs associated with environmental control technologies as 100% energy-related,
- allocate demand-related generation plant based on an unweighted 12-CP factor,
- classify a greater percentage of non-seasonal purchases as energy-related,
- recognize the sharing of service drops by residential customers in multi-family dwellings and require the Company to file a compliance filing to correct this allocation error, as discussed in the testimony of Office witness Gimble.

Q: Please summarize your recommendations concerning residential rate design.

A: The marginal energy plus demand cost estimates included in the Company's marginal cost study provide a reasonable minimum target for the tail block charge for the residential class. However, the Company's estimate of marginal customer costs is not valid and should not be relied upon in setting the level of the residential customer charge.

Q: Does this conclude your testimony?

A: Yes.