STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

The Application of Rocky Mountain	**)**	
Power for Authority To Increase Retail	**)**	**Docket No. 07-035-93**
Electric Rates and for Approval of a	**)**	
New Large-Load Surcharge	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH COMMITTEE OF CONSUMER SERVICES

Resource Insight, Inc.

JULY 21, 2008

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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 CSS Exhibit (PLC-8D.1).

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 Committee of Consumer Services ("the Committee") 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.

I also assisted the Committee 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 Committee.

Q: What issues does your testimony address?

A: I evaluate the following proposals of Rocky Mountain Power ("RMP" or "the Company"):

- The classification and allocation factors in the Cost of Service Study ("COS Study");
- The irrigator-load-research study;
- The Company's reliance on its Cost of Service Study as the basis for its class rate spread proposal;
- Proposed rate design changes to Residential Schedule 1, in particular the introduction of the Customer Load Charge ("CLC") for usage over 1000 kWh in the summer months.

Q: Prior to hearings on the revenue-requirement phase of the case in early June 2008, RMP reduced its rate request from approximately $99 million (7.5%) to $74.5 million (5.6%) (excluding special contract customers). What COS Study and proposed rate schedules do you address?

A: I evaluated the COS Study and proposed rate schedules presented in Exhibits RMP__(CCP-3S) and RMP__(WRG-1S through 4S), which are both linked to the 7.5% rate increase request. The Company did not update its proposed rate schedules to comport with its lower 5.6% revenue requirement request.

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 fundamental principle of the process is that allocation based on cost causation results in an equitable sharing of embedded costs. As Company Witness William Griffith explains in his Direct Testimony (at 3), the COS Study process "recognize[s] the way a utility provides electrical service and assigns cost responsibility to the groups of customers for whom those costs were incurred."

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 COS Study be the basis of rate design as well as rate spread?

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

A: No. Considerations of marginal cost and incentive effects, not embedded cost, should be the primary basis for design of rates for individual classes.

Q: Should the Commission expect 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;
- energy and regulatory policy.

A. Reasonableness of Classification and Allocation Factors

Q: Does RMP's COS Study reasonably reflect cost causation?

A: No. I have identified a number of problems with the Company's classification and allocation decisions that are likely to overstate the net costs incurred to serve the residential, small commercial and irrigation classes. In particular, RMP's COS Study

- understates the energy-related costs of generation, especially coal and wind resources;
- understates the energy-related portion of firm power purchase costs;
- almost certainly understates the energy-related costs of transmission;
- misallocates monthly off-system firm sales revenues to rate classes, in that the Study ignores individual class contributions to supporting the resources from which off-system sales are made and the extent to which class loads allow PacifiCorp to make those sales;
- minimizes the effects of energy use on distribution costs;

- ignores the sharing of service drops by residential customers in multi-family dwellings.

1. The Classification of Generation Plant

Q: How is generation plant classified?

A: The COS Study classifies "seasonal" generation plant (including combustion turbines) as 100% demand-related and baseload and intermediate generation plant as 75% demand-related and 25% energy-related. This 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 the 75-25 demand-energy classification split for generation?

A: As I understand the history of this classification split, 75-25 split was initially a compromise between the Pacific Power and Light's 50-50 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 demand-energy classification:

> Citing both past operating experience and future resource planning, the Division notes that resources with higher energy availability are chose 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: 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. 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 a pricing model similar to the peaker method, which are even more weighted to energy. For example,

- The New York ISO and 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 New England ISO sets capacity prices through a forward auction. The initial starting price for the auction, as well as minimum and maximum prices, are determined by the cost of a new peaker, net of energy revenues.

- 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: 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 contemporaneous peaker (generally a simple-cycle combustion turbine) times the rated capacity of the unit. The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.[2]

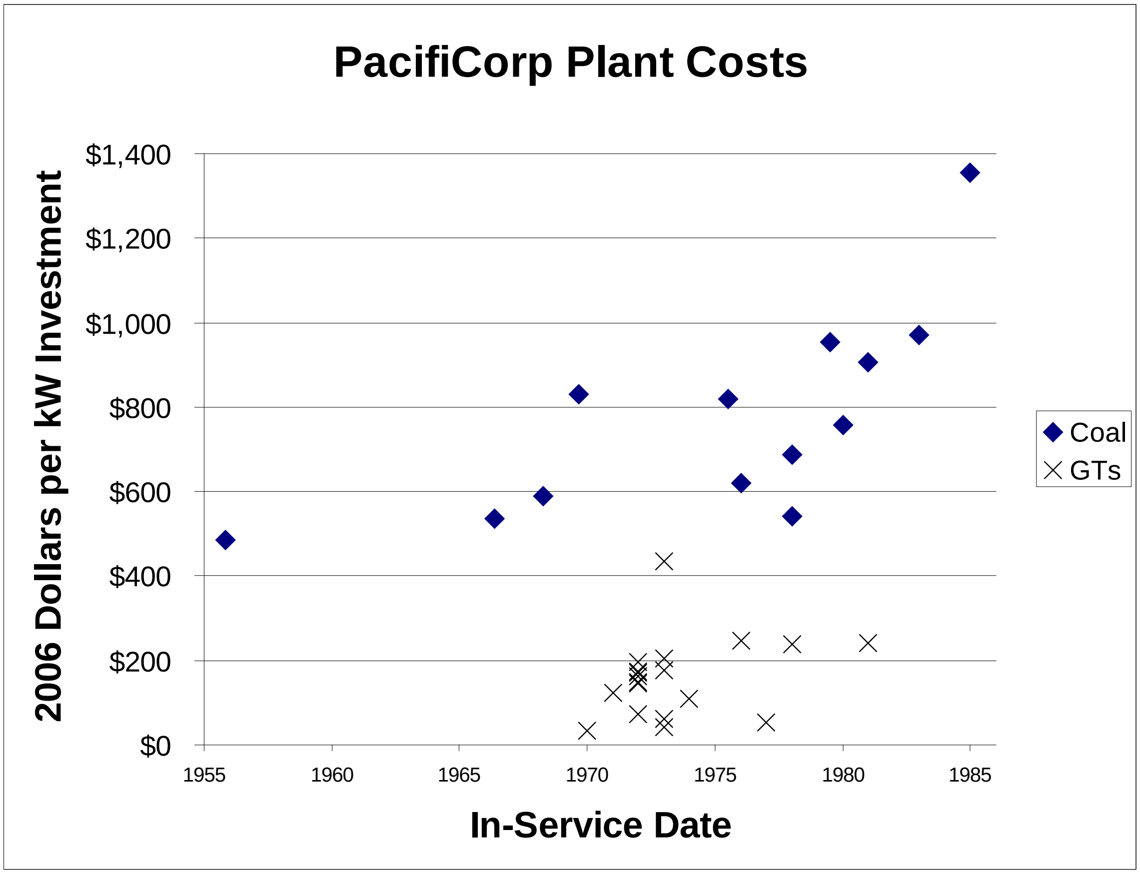
Q: Have you applied the peaker method to PacifiCorp's existing coal plants?

A: Yes. Figure 1, below, shows the gross capital cost per kilowatt at the end of 2006, for each existing PacifiCorp coal plant and for the combustion-turbine plants, sorted by in-service date.[3] The peakers averaged under \$200/kW, compared to \$500–\$1,000/kW for the PacifiCorp coal plants, suggesting that 60% to 80% of the coal plant capital costs are energy-related.

[2]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.

[3]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. PacifiCorp does not own any peakers built in the same period as its coal plants.

Figure 1: PacifiCorp Plant Costs



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

A: Yes. According to the 2007 Integrated Resource Plan ("IRP"), the lowest-cost new coal plant would be a Wyoming supercritical plant, at fixed costs of $217/kW-yr. Netting out the fixed costs of a frame simple-cycle combustion turbine, at $48/kW-year, the energy-related fixed cost of the new coal plant would be $169/kW-year, or 78% of the total fixed cost.

Similar computations indicate that the energy-related fixed costs of a new 2×1 F-class combined-cycle combustion turbine (including the duct firing) would be about 32% of its total fixed cost. Assuming that 0.2 MW of combustion turbine would provide the same reliability contribution as one megawatt of installed wind capacity, the fixed costs of wind are about 95% energy-related.[4]

Q: Would changing the demand-energy classification split for PacifiCorp's generation plant have a significant effect on the cost allocation?

A: Yes. Just changing RMP's Factor 10 (the demand-allocated portion of fixed plant costs) from 75% to 50% shifts about $8.5 million off of Schedules 1, 6, and 23, and about $3.8 million onto Schedules 8 and 9.[5]

Table 1

Schedule	Change in Allocation (Million $)
1	−2.4
6	−4.3
8	0.4
9	3.4
23	−1.8

The demand-related portion of PacifiCorp owned generation, weighted across PacifiCorp's generation mix, may be much lower than 50%, so the effects may be much larger.

2. Allocation of Firm Non-Seasonal Purchases

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

[4]The costs of PacifiCorp's new wind plants, and of the Gadsby peakers, are very similar to the assumptions in the IRP.

[5]This example, and the other examples I present of allocation effects, are based on RMP's 8.19% target return. In addition to the impacts on the major tariffed classes, reducing Factor 10 to 50% would increase the allocation to special contract customers. Regarding subsequent changes in "Factors," the allocation impacts for special contract customers is in the same directions as that in Schedule 9.

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: Has the energy-related portion of firm non-seasonal purchase costs been understated?

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.A.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 the table below:

Table 2

Percent Allocated on Energy

	Fixed Costs	*Fuel And Variable Cost*	*Total if Half of Cost*

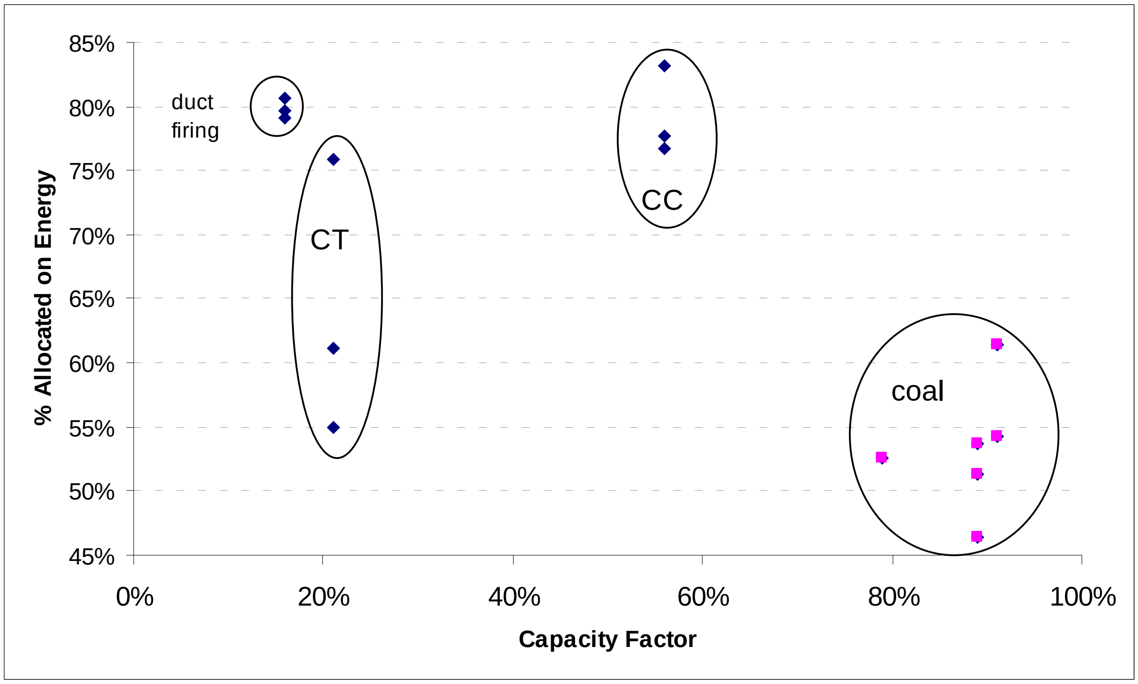
			s	ls Fuel
Plant	25%		100%	62.5%
Non-Seasonal Purchases		25%	25%	25%

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

A: The disparity is quite large. From the 2007 PacifiCorp IRP, 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 for non-seasonal resource, and just variable costs for peakers. The portion of generator costs allocated on energy under RMP's current classification and allocation method ranges from 46% for Wyoming IGCC to

61% for Utah pulverized coal, 55% to 76% for various types of combustion turbines, and 76%–83% for various combined-cycle configurations.

Figure 2: Energy-Related Share of New Resource Costs in RMP's COS Study



Q: Would changing the demand-energy classification split for firm non-seasonal purchases have a significant effect on the cost allocation?

A: Yes. Changing RMP's Factor 87 (the demand-allocated portion of firm non-seasonal purchases) from 75% to 25% shifts about $13 million off of Schedules 1, 6, and 23, and about $5.5 million onto Schedules 8 and 9.

Table 3

Schedule	Change in Allocation (Million $)
1	−2.4
6	−8.0
8	0.3
9	5.2
23	−2.5

3. The Allocation of Firm Sales Revenue

Q: How does RMP allocate firm sales revenue?

A: As with firm non-seasonal purchases, RMP classifies firm sales as 75% demand-related and 25% energy-related. The monthly allocation factors for sales and purchases are the same.[6]

Q: Why is this allocation approach inappropriate?

A: Under this allocator, the greater the rate class's demand and usage during a month, the greater its share of the months' firm sales revenue. The correct allocator would reward a class for having lower demand and usage in the month, thereby leaving generation (and transmission) capacity available to support the off-system sales.[7]

Q: Can you provide an example of the misallocation of firm sales revenues?

A: Yes. The irrigation class is assigned 0.761% of (non-seasonal) production plant, 0.627% of firm non-seasonal purchases and 1.519% of firm seasonal purchases, but receives only 0.58% of the firm sales revenues.

Q: Why are the allocations of costs and revenues so skewed in the case of the irrigation class?

A: In the test year, 96% of irrigation kWh usage occurs in the higher-cost summer months (May–September), but only 35% of the firm sales revenues are made in those months (Excel file COS UT Dec 2008 (MSP).xls, Tabs "Energy Factor" and "NPC Factors"). In the non-summer months, when irrigation kWh use is

[6]The annual allocation factors differ in part because sales and purchases do not follow the same monthly pattern.

[7]The allocator must also recognize that purchases in the current month may also contribute to serving the off-system sales that month.

negligible, firm sales revenue is high; in particular, average sales in January through March exceed the summer average by 64%.

The irrigation class should receive a credit for making its share of capacity available for off-system sales in the winter months.

Q: Have you been able to determine the effect on the class allocation of an improved allocator for firm off-system firm sales?

A: No. The COS Study is not designed to allow a user to change the allocation of sales revenues among months. Furthermore, several factors should be reflected in the allocation of sales revenues, and those should vary with the type of sale (e.g., off-peak, around-the-clock, peak hours).

Q: Can you give the Commission a sense of the potential effect of a more appropriate allocation of off-system firm sales revenue?

A. Yes. I computed three additional sales allocators. The first allocates monthly sales revenues, in excess of July and August sales, in proportion to the difference between the class's contribution to annual coincident peak and the class's contribution to monthly coincident peak. The second allocator allocates each month's sales revenue in proportion to the class's unused energy in that month: its contribution to potential energy (annual coincident peak times the hours in the month) minus the class's energy use in the month. The third allocator is the same as the second, except that the potential energy is increased by a 15% reserve margin. The class results are as follows:

Table 4

		RMP Allocation	Unused Energy Compared to Peak		Unused CP Sales > Summer
			peak + 15%	*peak*	
Residential	Sch 1	30.54%	57.98%	64.84%	91.59%
GS Dist—Large	Sch 6	29.23%	24.34%	23.83%	4.00%
GS Dist—> 1MW	Sch 8	9.18%	6.02%	5.28%	3.43%
GS Trans	Sch 9	17.60%	4.57%	0.97%	-6.17%
Irrigation	Sch 10	0.58%	2.53%	2.91%	6.89%
GS Dist—Small	Sch 23	6.62%	9.19%	10.11%	8.88%

A fully developed allocator for off-system firm sales revenue would probably fall somewhere between RMP's allocator and those I developed. Such an allocator would increase allocation of off-system sales revenue to Schedules 1, 23, and, especially, 10, and decrease sale revenue allocations to Schedules 6, 8, and 9.

Q: Could these changes be significant?

A: Yes. RMP estimates $590 million in off-system sales revenues, so every 1% shift is worth $5.9 million.[8] A $5.9 million change in cost allocation would change the revenue allocated to Schedules 1, 6, and 9 by about 1%–3%; Schedules 8 and 23 by about 5%; and Schedule 10 by about 45%. In addition to the concerns with the irrigator load data discussed later in my testimony, the Commission should note that a small change in the off-system-sales revenue allocation could eliminate the revenue shortfall RMP reports for irrigation. The effects on other classes could also be material.

4. *The Classification of Transmission Plant*

Q: How does the COS Study classify transmission plant?

[8] There may be indirect allocation effects as well.

A: It classifies 75% of transmission costs as demand-related and 25% as energy-related. This classification recognizes that, while peak loads are a major driver of transmission costs, a significant portion of transmission costs are incurred to reduce energy costs. However, RMP has not performed a study of its transmission assets to determine what percentage is energy-serving (RMP Response to CCS DR 40.7).

Q: How is PacifiCorp's transmission system designed to reduce energy costs?

A: PacifiCorp's transmission system design lowers energy costs in at least three ways. First, a large portion of the Company's transmission is required to move power from the remote generators to the load centers and for export. Were generation located nearer to the load centers, the long, expensive transmission lines would not be required (and transmission losses would be smaller). These transmission costs were incurred as part of the tradeoff against the higher operating costs of plants that could be located nearer to the load centers; in other words as a tradeoff against energy-related costs.

Second, PacifiCorp's transmission system is more expensive because it is designed to allow for large transfers of energy between neighboring utilities. Third, PacifiCorp's transmission system is designed to minimize energy losses and to function over extended hours of high loadings. Were the system designed only to meet peak demands, a less costly system would suffice; in some cases lines or circuits would not be required, voltage levels could be lower, and fewer or smaller substations would be needed.

Energy efficiency is clearly a primary purpose of the Company's transmission investment plan, as RMP witness Douglas Bennion explains:

> Rocky Mountain Power must invest in transmission assets to move Company owned generation to substations and load centers. The Company must also build transmission facilities to move power generated by others (i.e. independent power producers) to substations and load centers. In addition, the Company must build facilities that interconnect with other transmission and generation providers as it enters into contracts with customers, generators and shippers that require transmission access. This transmission infrastructure is essential to enhance efficiencies as daily and seasonal loads fluctuate. (Bennion Direct Testimony at 5)

Q: Have you performed a comprehensive analysis of the factors driving RMP's transmission investment?

A: No. Such an analysis is quite data-intensive, involving consideration of the uses of each line, and the effect of energy and long hours of high usage on system design. That analysis would best be undertaken by RMP with input and review by interested parties. I recommend the Commission require such an analysis.

To give the Commission a sense of the possible impact of correcting the transmission classification, I reviewed the transmission-line cost data in PacifiCorp's 2006 FERC Form 1 at 422–423. From PacifiCorp's transmission maps, it appears that the highest-voltage lines (500 kV, 345 kV, and 230 kV) primarily connect PacifiCorp's load with remote baseload generation and would not be needed except to access low-cost energy. Those lines account for 55% of PacifiCorp's gross transmission investment and, since they tend to be newer, probably a higher percentage of PacifiCorp's net transmission investment. Hence, over half of PacifiCorp transmission revenue requirement is likely to be attributable to energy.

5. Distribution Classification and Allocation factors

Q: What is the basis for RMP's distribution cost classification and allocation?

A: The Company relies on UP&L's October 1989 Distribution Cost Allocation Study (provided as an attachment to DR CCS 38.3). The Study (at 11) attempts to reflect the distribution design guidelines in the selection of classification and allocation factors:

> We need to discover the chief characteristics of each of the physical sub-systems in order to effect an appropriate cost classification. To do this we will examine the design process for the distribution system. The rationale behind this approach is that costs are not driven directly by service characteristics but by the design engineer's response to those service characteristics.

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. In RMP's view, "there are no significant energy related costs associated with the distribution system." (Exhibit RMP___(CCP-3S), Tab 1, at 8.)

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. In the case of line transformers,

> The allocation factor, F21, is based on the maximum monthly class NCP. This may be a different month for each class. For classes of customers where transformers are shared by more than one customer, the NCP is weighted by the appropriate coincidence factor from the Company's Job Designer's Manual to recognize the diversity of load at the transformer. (Exh. RMP (CCP-35), Tab 1, at 9)

Secondary lines are allocated to the residential and small General Service classes only, using a similar "weighted non-coincident peak" allocator.

Q: How does RMP allocate services and meters?

A: Services and meters are allocated based on weighted customer number, weighted by the current installed cost of the 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 in which energy usage drives distribution investment.
- The weighting factors used in deriving the F20 allocator (for substations and primary feeders) are not cost based and overweight the July peak.
- It ignores the sharing by smaller customers of service drops.

a) Energy-Related Distribution Costs

Q: In what ways does energy use affect distribution costs?

A: Energy use, especially in high-load hours and in off-peak hours on high-load days, 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 (marginal line losses due to another kWh of load generally exceed the average loss percentage in that hour).

CSS Exhibit (PLC-8D.2) provides a more detailed explanation of the effect of energy on the cost and sizing of transformers.

Q: Does the 1989 UP&L study consider the effect of energy use on distribution costs?

A: Yes, but it concludes that the energy-related portion of distribution is negligible.

Q: Is the UP&L study comprehensive?

A: No. The study

- limits the category of “energy-related” investments to those that are specifically made to reduce energy load losses, namely, certain increases in the sizing of conductors and transformers. [9]

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

- credits energy loss reductions with fuel-savings only, assuming that only demand-loss reductions can avoid generation, transmission and distribution capacity costs.[10]
- relies on an out-of-date 1983 estimate of fuel-savings, which is likely to be much less than current marginal fuel costs and market prices. The lower the value of fuel-savings from increased capacity of lines and transformers, the smaller the portion of plant that will be considered energy-related.

In addition, UP&L performed few actual calculations to quantify the energy-related portion of distribution. Apparently, its conclusion was based on a cost comparison for only two transformer ratings and a single manufacturer, which UP&L acknowledged (in its 1989 Distribution Study at 21) "cannot be extrapolated to all transformers.…" There were no calculations of the energy-related portion of conductor costs.

Q: Do the Company's distribution guidelines and COS Study support the UP&L Distribution Study methodology and conclusions?

A: No, for the following reasons:

- Utah Power & Light's assumption that reduction in energy losses saves only fuel costs is inconsistent with the Company's own cost allocation approach. The COS Study assumes that 25% of generation plant, transmission plant and firm purchase costs are driven by energy use.

…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.

[10]This also appears to have been a problem with the 1983 version of "Distribution Specification No. L-100: Distribution Transformer Loss Evaluation," on which UP&L's distribution-cost allocation relied. Presumably, the Company has revised its transformer purchase practices to take into account the current power market and value of reducing energy usage.

- The Study misinterprets the distribution design guidelines.
- The Study overlooks the effect of energy use on the need for replacement and the failure rate of distribution equipment, also recognized in the distribution guidelines.
- The Study does not reflect the current condition of the RMP distribution system.

Q: Can you provide some examples from the distribution design guidelines that demonstrate that energy use is a driving factor in distribution capacity costs?

A: Yes. The Study identifies a number of ways in which expected energy use, especially in hours close to peak in load or time, affects both 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) Coincident Distribution Peak Weighting Factors

Q: Why are the distribution weighting factors invalid?

A: RMP's approach produces illogical results. The only two months with weights greater than 10% are July (41%) and June (18.4%). The Utah distribution peak actually occurs in August, but receives a weight of only 8.5% (Excel file COS UT Dec 2008 (MSP).xls, Tab "Dist. Factors").

Weighting by the number of substations peaking in a 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.
- A small substation has as much effect on a month's weighting factor as a large substation does.

Q: Are there more reasonable distribution weighting factors the Commission should consider adopting?

A: Yes. I looked at two methods that recognize the size of individual substations and the effect of multiple peaks on substation sizing.[11] For the first method, I computed the ratio of the monthly peak on the substation to the annual peak on the substation, from Attachment CCS 10.28, squared the result so as to rapidly reduce the contribution as load falls, and summed the squares over the substations to derive the monthly weights. The second approach is similar, but starts with the ratio of the monthly peak on the substation (in MW) to the substation's capacity (in MVA). The resulting monthly weights are as follows:

[11]In both cases, I omitted substations for which PacifiCorp provided less than twelve months of data.

Table 5

	Method for Assigning Substation Costs to Months	
	Squared % of Annual Peak	*Squared % of Capacity*
January	7.1%	7.1%
February	6.4%	6.4%
March	6.0%	5.9%
April	6.8%	6.7%
May	8.1%	8.2%
June	11.6%	11.9%
July	12.8%	12.8%
August	11.6%	11.9%
September	9.4%	9.5%
October	5.9%	5.9%
November	7.1%	6.7%
December	7.4%	7.0%

Unfortunately, I do not have the data necessary to incorporate the number of high-load hours in each month into the allocation.

Q: How much would these monthly weights change the allocation of RMP costs?

A: Substituting either of these weights would shift about $16.4 million off of Schedules 1 and 10, and about $16.2 million onto Schedules 6, 8, and 23.

Table 6

	Schedule	**Change in Allocation** (Million $)
Residential	1	−15.4
GS Dist—Large	6	12.4
GS Dist— > 1MW	8	2.0
GS Trans	9	0.0
Irrigation	10	−1.0

GS Dist—Small	23	1.8

In addition, the allocation of distribution costs should reflect the extent to which energy use affects distribution costs.

c) Sharing of Service Drops

Q: How does RMP allocate service drops?

A: They are allocated based on customer number, weighting by the cost of a new service for each type of customer (Exhibit RMP__(CCP-3S), Tab 1, at 9).

Q: Has RMP considered the sharing of service drops in developing the service allocator?

A: No. It assumes that each residential customer requires its own service drop (RMP Response to CCS DR 10.14) and ignores the sharing of services by customers in multi-family buildings. The Company has not estimated the number of shared services or portion of its residential customers that are in multi-family buildings or the number of service drops installed (RMP Response to CCS DRs 10.11, 10.13).

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

A: No. RMP does not have data on the mix of housing types and the number of customers per service in its Utah jurisdiction. However, census information indicates about 23% of housing in Utah is multi-family. According to the 2000 Census of Housing in Utah, 12.9% of the customers are in multi-family housing with two to nine units, and 10.3% in multi-family housing with more than nine units, as follows:

Table 7

Units in Structure		
1-unit, detached	520,101	71.5%
1-unit, attached	37,902	5.2%
2 units	29,243	4.0%
3 or 4 units	36,998	5.1%
5 to 9 units	27,677	3.8%
10 to 19 units	30,357	4.2%
20 or more units	44,848	6.2%
Total housing units	727,126	100.0%
Units in multi-family housing	169,123	23.3%

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

Q: Would similar adjustments apply to other classes?

A: No. Other than multi-family residential customers on the residential rate, relatively few customers are likely to share services.[12]

B. Irrigation Class Load Study

Q: What does the new load study indicate for Irrigation customers?

A: The Company's current COS Study, which relies on this new load data, indicates that bringing the class to the Company average ROR would require at least a 30% increase to Schedule 10. The Company is proposing an increase of twice the jurisdictional average request for Schedule 10.

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

[12]In some cases, small commercial customers in a strip mall or office building will share a service.

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: Please explain the derivation of the irrigation load estimates from the sample data.

A: The Company metered the hourly loads of 120 (out of 2,000) irrigation customers for the period July 1 through September 15, 2006 and May 25 through June 30 2007. It extrapolated from the sample to the entire class in the following five steps (as documented in CCS 23.4 and Attachment DR CCS 10.2):

1. In each strata, computed the average sample load in each hour;
2. Calculated a weighted sum of the hourly kWh over the strata to give an estimate of total class load in that hour, weighting the loads in a given strata by the percentage of the total population that fall in that strata;
3. Summed the class estimated hourly loads over all hours to produce an estimated total class load in each month;
4. Computed the ratio of the actual to the estimated total class load by month;
5. Adjusted each estimated hourly load by the ratio computed in the previous step to provide the load assumptions used in the COS Study.

In the off-peak months, RMP calculated the CP (and all other hourly loads) as the total kWh usage for the month divided by the number of hours in the month, assuming that in their low usage months, they have 100% load factors.

Q: Does the irrigation customer load data provide a valid basis for cost allocation?

A: No. As can be seen from the ratios provided in Attachment DR CCS 10.2 (Tab PricingAdj7), there are sizeable discrepancies between estimated and actual monthly usage. The excess of estimated over actual usage in the summer months range from 7% in July to 75% in September:

Table 8

	May	June	July	August	September
Load Research (kWh)	44,565	48,669	39,758	44,099	33,430
Pricing (kWh)	35,418	38,735	37,081	33,885	19,062
Adj. Factor	0.79	0.80	0.93	0.77	0.57
Overestimate	26%	26%	7%	30%	75%

The load research data over-predicts actual annual usage of irrigation customers by 24%.

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 25–75%. 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: Does the COS Study support RMP's proposed disproportionate increase in Irrigation rates?

A: No. RMP's irrigation load study represents a serious research effort, but since there is such a large disparity between sample and actual usage, the data should not be relied upon to support a major cost allocation action. As discussed earlier in my testimony, the problem is compounded by the significant under-allocation of off-system firm sales revenue to this class.

IV. Rate Design Proposal for Residential Schedule 1

Q: Were you asked by the Committee to address certain issues relating to RMP's residential rate design proposals?

A. Yes. My testimony addresses (1) concerns with the Company's Customer Load Charge proposal, (2) whether RMP's proposed increase in the customer charge may over-recover costs from small residential customers in multi-family buildings with shared services, and (3) the level of the summer tail-block charge.

Q: What are your general concerns with regard to RMP's residential rate design proposals?

A: Variable energy charges are better at signaling energy-related costs than a fixed charge that customers cannot avoid. The Company's proposal to collect approximately 83% of the residential class increase in fixed charges (customer charge and CLC) will reduce customer control over bills, reduce savings from DSM investments, and therefore reduce incentives for customers to conserve. Raising fixed charges is the wrong direction to go especially during a time of rising energy costs and ongoing concerns about Utah load growth.

1. Customer Load Charge

Q: Please explain RMP's Customer-Load-Charge ("CLC") Proposal.

A: Under RMP's CLC Proposal, a $72 charge would be triggered when monthly usage in the May through September billing months exceeds 1,000 kWh in more than one month. The CLC would appear in bills as a $6/month fee for continuous months upon issuance of the Commission's final order in this case.

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

A: Company Witness William Griffith claims (at 9–11) that the Company's proposal will improve residential rate design by providing the following benefits:

- a signal "to large customers about the costs of their above-average usage,"
- a more effective price signal,
- a "strong and persistent" price signal that will appear in every bill rather than solely in the month in which the kWh usage occurred,
- an easily understandable charge,
- smaller rate increases to the smaller residential customers.

Q: Has RMP provided any studies or reports to support these claims?

A: No. RMP has provided no evidence to support its claim that the CLC will provide an effective pricing signal. RMP acknowledges (in response to CCS 10.39) that it has not prepared or obtained any of the following analyses or data:

- any study of the relative effectiveness of CLCs versus tail block energy charges,
- any estimate of the effect of the CLCs on the residential class contribution to summer peak usage,
- any survey of customers' understanding or acceptance of CLCs,
- any survey of other utilities' experience with CLCs,
- any estimate of effect of CLCs on customers' peak usage.

Q: Did RMP properly assess the bill impacts of the CLC?

A: No. The Company's bill-impact analysis ignores several of the CLC's effects, particularly by computing the bills only for a customer whose usage is the same from month to month. As a result, the bill-impact analysis adds the CLC to all bills over 1,000 kWh, and to others. In reality, the CLC would be added to some small bills (e.g., 400 kWh) and not to some large bills (e.g., 2,000 kWh).

Do you believe that the CLC could provide an effective pricing signal?

A: No, for the following reasons:

- The charge is not cost-based. Usage during high-load periods is a primary driver of costs. Yet, customers incur the same $72 annual cost whether (a) they consume 2,000 kWh in all four summer months or (b) reach 1,100 kWh in only June and July and use 750 kWh in the other two months. In the extreme, a customer could end up paying $72 for a single kWh. On the other hand, a customer with very high usage in only one month (e.g., 4,000 kWh in the peak summer month) will not incur the $72 penalty. The CLC is inequitable, assigning the highest penalty per kWh to the customers with the lowest increment above 1000 kWh.
- Once incurred, the CLC will provide no incentive to conserve, even at peak times.
- Shifting revenues onto fixed charges will reduce energy charges and encourage increased summer electric use.
- If the CLC does provoke a response, it is more likely to come from the customers nearer the 1,000-kWh breakpoint. A small percentage reduction in load would be enough to avoid the charge, providing a significant reward for a relatively small effort. But for a 2,000 kWh residential customer with a very high air conditioning usage, a savings of $72 would probably not be worth the effort required to reduce usage by 50%.
- The CLC cannot be easily explained to customers, especially since it violates fundamental cost and fairness principles. Customers will have difficulty accepting fixed charges in winter bills that are in payment for high summer consumption.
- The CLC will be difficult to avoid. Determining whether to reduce usage is inherently difficult, since the customer must know (1) the start and stop date of the billing month and (2) its summer monthly usage. In addition,

the customer must on a daily basis (1) monitor usage so far in the billing month and (2) forecast usage in the remaining days of the billing month, under normal and various alternative operating conditions. In fact, in its survey RMP found that at least 67% of its residential customers do not know their billing cycle or their monthly usage—information that would be crucial to customer success at avoiding the CLC trigger.

- The CLC would be difficult, if not impossible, to implement. The kWh billing determinants in a given month are not entirely under customers' control. Customers are placed into one of 21 different billing cycles (RMP's Response to AARP DR 4.1). Some of the electric bills are calculated based on estimated rather than actual billing data because of missed meter readings, meter reading errors, and meter failures. On the other hand, a summer meter reading (and bill) can reflect anywhere from 26 to 34 days' electric use with no adjustment for the length of the billing period (RMP's Responses to AARP DR 4.2, 4.3). These factors are not generally a problem under the current residential rate, because the bills are self-correcting. When the actual kWh reading is billed, any prior misestimates are netted out in the following bill. On the other hand, the CLC is a spike in price that is fixed once incurred. When a small error in billing can result in a permanent $72 overcharge, there will be considerable customer frustration and billing disputes.

Q: Please explain why billing cycles can cause problems.

A: Suppose there are two customers A and B that have the same daily load profile but are billed on two different billing cycles X and Y. Billing cycle X includes ten hot days in each of two months, and Y includes 15 hot days in the first month and five days in the second month. Customer A has an 1,200 kWh bill in the first month but only 900 kWh in the second, while Customer B has two 1050 kWh in both months. As a result, only Customer B must pay the CLC.

2. Customer Charge Increase

Q: What is the Company's basis for doubling the customer charge to $4 per month?

A: The Company proposes to set the customer charge to recover the embedded costs of meters, service drops, meter reading, and billing for residential customers (Griffith Direct at 6–7). Exhibit RMP___(WRG-3S) derives an average cost per residential customer from the COS Study.

Q: Is it appropriate to set the customer charge at the average cost of the components you listed in the previous response?

A: Only if those costs are independent of the size of the customer (Commission Order, Docket No. 06-035-21, p. 30). Costs that vary with usage should be in the energy charge. Only the costs of serving the smallest customers should be in the customer charge. Otherwise, small customers would subsidize large customers.

Q: Do any of the components of RMP's calculation of the customer charge overstate the cost of serving small customers?

A: Yes. The smallest residential customers are likely to live in multi-family housing. Those smaller customers would likely share a service drop with other customers in an apartment building. The cost of the service drop varies with the load of the building, not with the number of customers, and therefore does not belong in the customer charge.

Meter reading costs that are also included in the customer charge vary with the size and type of customer. In an apartment building, a single meter in a bank of meters is likely to require much less meter reading time than a single family home.

Q: Have you estimated a customer charge reflecting only the costs of minimum-size residential customers in multi-family housing?

A: Yes. To estimate the customer costs for customers living in multi-family dwellings, I made just one change in RMP's calculation: I removed the costs of service drops. This change alone (without any adjustment to the meter reading cost estimates) results in a customer charge of $2.40 per month.

3. Summer Tail Block Charge

Q: How do you recommend that the revenue increase be recovered from residential customers, if not through a CLC and increase in the customer charge?

A: This cost should be recovered in the energy charges, with the longer-term goal of moving the tail block to marginal cost.

Q: What is the cost of serving the summer tail-block load?

A: Additional summer load incurs the following costs, among others:

- summer energy costs, much of it in high-load, high-cost hours, especially for customers in the tail block;
- a large portion of the cost of peaking generation capacity, including reserves;
- a large portion of the incremental costs of transmission and distribution;
- line losses.

Q: Can you quantify those costs at this time?

A: In part. As of early June, the forward prices for third-quarter energy at Palo Verde and Mid-Columbia in 2009 and 2010 were running about 11¢/kWh on-peak and 7¢/kWh off-peak. Even for a nearly flat load shape, with 60% of the energy in the peak period, the average summer market value of the power is about 9¢/kWh. [13] For a real residential load shape, the energy costs would be greater. Peaking capacity, at $48/kW-year for a frame combustion turbine (in 2006 dollars, from the 2007 IRP), to meet peak plus a 12% reserve margin, spread over 1,400 summer kWh per kW of peak, would add another 1¢–2¢/kWh.[14] Including even 10% marginal losses, the total generation cost would be between 11¢ and 12¢/kWh. Marginal load-related T&D costs would add another couple cents per kWh.[15]

Q: Please summarize your recommendations.

A: On the cost-of-service study, I recommend in Section III.A improvements in classifications and allocations, specifically:

- classifying a greater percentage of fixed non-seasonal generation costs as energy-related,
- classifying a greater percentage of non-seasonal purchases as energy-related,
- classifying a greater percentage of transmission costs as energy-related,
- allocating firm sales revenues in a more realistic manner,
- classifying a portion of distribution costs as energy-related,

[13] About 57% of hours are in the peak period.

[14] I assume that a flat energy forward would provide capacity value at the average load level; peaking would be required to make up the difference.

[15] On the other hand, some of the generation capacity is attributable to months outside the summer.

- recognizing the sharing of service drops by small residential customers,
- revising the monthly weights for the primary distribution allocator.

My recommended changes to the classifications and allocations should be addressed in an appropriate forum and implemented in the Company's next COS Study.

In setting the rate spread, the Commission should recognize that the deficiencies in the COS allocations and in the irrigation load study bias the COS results and in particular tend to overstate the costs of Schedule 1, 10, and 23. Since the COS Study is flawed in a number of areas, it should not be relied on for determining rate spread until these problems are corrected. In his testimony, Mr. Gimble discusses the Committee's rate spread proposals in greater detail.

In residential rate design, the Commission should reject RMP's proposed CLC and customer charge increase, and use the revenues to raise energy charges, especially in the summer tail block.

Q: Does this conclude your testimony?

A: Yes.