Q. Please state your name and business address.

A. My name is Lowell E. Alt, Jr. My address is 1396 Wheelwright Court, Mesquite, Nevada, 89034

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Rocky Mountain Power Company (the Company), a division of PacifiCorp.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Electrical Engineering and a Master of Business Administration degree from West Virginia University where I became a member of the electrical engineering honorary society Eta Kappa Nu. I am a Registered Professional Engineer licensed in Pennsylvania and a member of the Institute of Electrical and Electronics Engineers (IEEE). I have attended numerous conferences and seminars on various aspects of utility regulation. I retired in December 2005 as Executive Staff Director of the Utah Public Service Commission after a twenty-five year career in Utah utility regulation. I served as Director of the Utah Division of Public Utilities from March 2001 to August 2003, Manager of the Energy Section from October 1995 to March 2001, Chief Engineer from 1983 to 1995 and Rate Engineer from 1980 to 1983. I have testified before the Utah Public Service Commission in numerous electric, natural gas and telecommunication cases on various topics including cost-of-service, rate design, customer charges, interim rates, rate case stipulations, mergers, service extensions and return on equity. I was the Division's witness on class cost of service and rate design for every Utah Power rate case from 1983 to 1998. I have completed numerous cost-of-service studies of various utilities including Utah Power, U.S. West Communications, several rural electric cooperatives and two water companies. I previously worked for Pennsylvania Power and Light Company from 1968 to 1980. My last positions there were Distribution Senior Engineer-Substations and Senior Tariff Analyst. Since my retirement in 2005 I published a book, *Energy Utility Rate Setting*, and have done some utility consulting. In April I attended the IEEE 2009 Rural Electric Power Conference, including an all-day seminar on "Critical Elements in the Operation, Installation and Maintenance of Power Transformers" conducted by Waukesha Electric Systems.

Q. Since this case deals with the classification and allocation of distribution costs, please elaborate on your utility experience in distribution.

A. I worked as a distribution substation engineer for ten years. During that time my work included calculating substation power transformer thermal loading capabilities; performing factory inspections of new substation power transformers; inspecting failed substation power transformers; preparing substation transformer (and other equipment) operation and maintenance instructions for substation field people; teaching transformer theory, operation and maintenance at substation repairman apprentice programs; and assisting in the development of planning philosophies, major equipment purchases and engineering designs.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address classification and allocation issues regarding distribution costs raised in the direct testimony of Mr. Paul Chernick on behalf of the Office of Consumer Services (the Office).

Q. Please provide a brief summary of your testimony.

A. I explain the role of classification and allocation in class cost of service studies. I give a brief history of the Company's Distribution Cost Allocation Study and the classification and allocation of distribution costs. I describe the Company's use of engineering standards and load data in making distribution transformer and conductor investment decisions and how it relates to classification and allocation of distribution costs. I explain why the Commission-approved classification and allocation methods for distribution costs are still reasonable.

Q. Mr. Chernick's position in his direct testimony is that the current Commission approved method of allocating distribution costs does not reasonably reflect cost causation. Do you agree?

A. No. In order to explain why I do not agree, I will discuss classification and allocation in cost of service studies, how the current approved classification and allocation of distribution costs came about and why they are still reasonable.

Role of Classification and Allocation in Cost of Service Studies

Q. What is the purpose of classification and allocation in cost of service studies?

A. Most of PacifiCorp's costs of providing utility service are joint costs. Joint costs are the costs of shared facilities such as distribution substations and lines that serve multiple customers. These joint costs must be allocated among customer classes using the facilities. In order to make the allocation step easier and more accurate, a classification step is done first. Utility costs are booked into functional accounts such as distribution station equipment (substations) and overhead and underground lines. Classification is the further division of these functional costs into categories bearing a relationship to a measurable cost-defining service characteristic. Measurable means the service characteristic data is available for use in the allocation step. Cost-defining means a cost-causal relationship exists between the service characteristic and the utility costs to be allocated. Electric utilities traditionally use the classification categories of customer, energy, and demand. Once the costs are classified, they can be allocated to customer classes. Allocation is the apportionment of joint costs among rate classes based on each class's relative share of a measurable cost-defining service characteristic such as kilowatt-hours or peak demand in kilowatts. Costs classified as customer-related are allocated on the number of customers, often weighted by some cost information. Energy-related costs are allocated on relative energy usage. Demand-related costs are allocated on relative demands.

Q. How is a cost-causal link established?

A. A cost-casual link between customer service characteristics and utility costs is established when costs are allocated using service characteristics that are the same or similar to that used by utility engineers in making investment decisions. Sometimes the data used by engineers is not available by rate class or schedule, so surrogate data must be used.

Q. What is the difference between energy and demand costs?

A. Demand-related costs are a function of a customer's maximum demand (measured in kilowatts). This maximum demand is related to the electrical capacity of the customer's connected appliances, since the maximum demand would occur when all appliances are used at the same time. A utility must size the parts of its system to handle the simultaneous peak demand from all its customers at any given hour. Energy-related costs are a function of a customer's duration of use (measured in kilowatt-hours) of any connected appliances. For example, a portable electric heater rated at 1000 watts (equal to 1 kilowatt) would impose an electrical demand of 1 kilowatt on the electric system each time it is turned on. If the heater is left on for two hours, the energy use would be 1 kilowatt (demand) times 2 hours (duration) or 2 kilowatt-hours.

Distribution Cost Classification and Allocation Background

Q. What is the current Commission approved classification and allocation of distribution plant?

A. 1. Substation equipment and primary lines are classified as demand and allocated with a factor based on the 12 monthly distribution coincident peaks weighted by the number of distribution substations peaking in each month.

2. Line transformers and secondary lines are classified as demand and allocated with a factor based on schedule annual non-coincident peak (NCP) times the design coincidence factor (which takes into account load diversity for schedules with multiple customers on a single transformer).

3. Service drops are classified as customer-related and allocated using average service drop cost (for each rate schedule) times the number of customers.

4. Meters are classified as customer-related and allocated using average meter cost (for each rate schedule) times the number of customers.

Q. How long has the current classification of distribution costs been approved by the Commission?

A. Since January 16, 1980 (over 29 years) when the Commission in Utah Power Case No. 78-035-14 ordered distribution costs to be classified as demand-related (meter and service drops were classified as customer-related).

The Commission reaffirmed that classification of distribution costs in its April 12, 1982 order in Utah Power Case No. 79-035-12 and again in its March 7, 1983 order in Utah Power Case No. 81-035-13 when it adopted for future use the Division's classification of distribution costs. The Commission stated its intent of the 1983 order is to provide guidelines and policies for future cost of service studies. The Commission further ordered, "…any party who proposes alternative methods, except those specified in this Order for further study, will have the burden to demonstrate that the methods adopted in this Order are unreasonable".

Q. How long has the current allocation of distribution costs been approved by the Commission?

A. Since February 9, 1990 (more than 19 years) when, in Utah Power Case No. 89-035-10, the Commission adopted the Company's Distribution Cost Allocation Study allocation methods.

History of the Distribution Cost Allocation Study

Q. What prompted the Company's Distribution Cost Allocation Study?

A. In Utah Power Case No. 81-035-13 the Division recommended further study to determine proper allocation methods for distribution costs. The Commission in its March 7, 1983 Order in that case stated, "The Company shall develop in consultation with the Division an allocation method that takes into account the design characteristics of the distribution system."

Q. What happened next?

A. In Utah Power Case No. 83-035-01, the allocation of distribution costs was still unresolved with the Division again recommending further study. The Commission in its January 30, 1984 Order directed the Company to conduct a study to determine the proper allocation of distribution costs and to submit the study by January 1985.

The Company filed its "Distribution Cost Allocation Study" on January 15, 1985. Although the Commission's directive was to determine the proper "allocation" of distribution costs, the Company also addressed the "classification" of distribution costs and confirmed the Commission's 1980, 1982 and 1983 classification decisions.

In the next Utah Power Case No. 84-035-01, parties presented testimony on the Distribution Cost Allocation Study with the Committee claiming that as much as 20 percent of transformer costs should be classified as energy-related and allocated accordingly. The Commission, in its June 7, 1985 Order stated, "The distribution study was also challenged by the Committee of Consumer Services and the Irrigation Pumpers Association. We believe that a strong and sufficient case was made for the reasonableness of the distribution study by the stipulating parties; however, we will permit additional consideration of this issue in a future proceeding."

In Utah Power Case No. 85-035-06, parties reexamined the Distribution Cost Allocation Study. An exchange of ideas in that case, including input from the Committee, and further work on the study resulted in the final version of the Distribution Cost Allocation Study being submitted in October 1989.

Q. When did the Commission finally adopt the Distribution Cost Allocation Study Recommendations?

A. In Utah Power Case No. 89-035-10, the Distribution Cost Allocation Study was again considered. So after 6 years of study and review in multiple cases, the Commission in its February 9, 1990 Order adopted the Distribution Study allocation methods for future cost of service studies. Those allocation methods are the ones used for the past 19 years.

Q. Were you involved in reviewing the Distribution Cost Allocation Study?

A. Yes. I was the Division witness on this issue in all cases that it was considered and testified in support of the final Distribution Cost Allocation Study recommendations regarding distribution cost allocation.

Q. Are you still supportive of the Distribution Cost Allocation Study recommendations regarding distribution cost classification and allocation?

A. Yes. I believe the Distribution Cost Allocation Study was an excellent comprehensive study that involved a significant effort and considerable examination and review by parties and the Commission over a period of 6 years.

Company Distribution Investment Decisions

Q. Although you believe the Distribution Cost Allocation Study was an excellent study, have you recently reviewed how the Company's engineers make distribution investment decisions?

A. Yes. As I stated earlier, the cost-casual link between customer service characteristics and utility costs is established when costs are allocated using service characteristics that are the same or similar to that used by utility engineers in making investment decisions. The classification and allocation of distribution costs should be based on a similar type of analysis. The important information then is what distribution design engineers use in making investment decisions, since that information is the cost-causer.

Even though the burden of proof is on the Office as the party seeking a change in the allocation of distribution costs, I decided to review the current process used by Company engineers in making distribution investment decisions, specifically for transformers and conductors. I reviewed the engineering standards, process and data used by the Company to design the distribution system to determine the importance of energy and demand in design decisions. I also talked with some of the Company's distribution engineers. The purpose was to learn if anything has changed that would affect distribution cost classification and allocation in the 20 years since the final Distribution Cost Allocation Study. I will start with distribution substations in discussing what I learned about the Company's distribution investment decisions.

Distribution Substations

Q. Please describe how customer loads affect distribution substation design?

A. Substations must be designed to handle the maximum simultaneous load of the connected customers. The largest piece of equipment in a distribution substation and also the most costly is the power transformer used to step down transmission voltage to distribution primary line voltage. The Company's cost of a new typical distribution substation transformer (18/24/30 MVA, 138,000 volts to 13,200 volts) in Utah is about $900,000, not including installation. The other substation equipment is then designed to coordinate with the load capability of the power transformer.

The load capability of transformers is limited by the temperature of insulating oil and the hottest spot within the windings, which are a function of the load and ambient temperature. Transformer nameplate capacity (MVA) is based on an average ambient temperature of 30 degrees Celsius (86 degrees Fahrenheit) and represents the continuous load that the transformer can carry and last a normal life of about 40 years. Since transformers rely on air as a heat dissipation medium, higher altitudes with less air density result in reduced thermal capability. So in summation, the load-carrying capability of a transformer is a thermal capability and is primarily dependent on the electrical load, the ambient temperature, and the altitude.

Power transformers are a large mass of metal and oil. It can take a few hours for this mass to reach a steady state temperature once a given load is applied. Each transformer has its own set of characteristics (weight of the mass of metal and oil; no load and load losses; and average winding temperature rise). These characteristics are used, together with load data, in calculating the thermal load capability of a specific transformer. The total energy in kilowatt-hours of the applied load is not an input, because it does not provide the needed information about the peak load or the off-peak load and the respective durations. For calculating the thermal capability of a specific transformer, the key data is the peak load and its duration. Transformer nameplate capacity is stated in either KVA or MVA (measures of demand), not kilowatt-hours.

Q. What did you learn about how the Company sizes distribution substation power transformers and how does it relate to cost allocation?

A. PacifiCorp's Distribution System Planning Study Guide 1E.3.1 under "Substation Transformers" and "New transformer sizing", states "Transformer sizing is subject to an economic evaluation. Often the economic evaluation will result in a transformer at least two standard ratings larger than the projected peak load." The economic evaluation takes into account the expected load growth which may justify a larger transformer size initially rather than replacement a short time later. In this case, even with a load cycle that likely would be projected to be the same, a transformer two sizes larger is selected due to projected peak load growth. Although altitude, average ambient temperature and load cycle are taken into account, it is clear that the projected peak load (including growth) is the key driver in sizing substation transformers and therefore the key cost-driver of substation equipment. Peak load is demand and therefore the current demand classification of distribution substations is reasonable.

In making distribution substation investment decisions, engineers use peak-loading on individual substations that is not available by rate schedule so surrogate data must be used in the allocation step.

The Company has over 300 distribution substations and many more primary lines in Utah with each having its own unique mix of customer types and loads. The substations are geographically diverse with varying ambient temperatures (like Park City and St. George). This means that the loads on individual substations may peak in different seasons, months, days of the week or hours of the day. The substations may have varying load cycles (differing durations and load levels for peak and off-peak periods). The cost of these substations is aggregated in distribution accounts for allocation to rate schedules. The wide variation in the nature of the large number of distribution substations makes developing the ideal cost allocator very difficult.

The Distribution Cost Allocation Study found after evaluating many possible allocators, that a factor based on the 12 monthly distribution coincident peaks, weighted by the number of substations peaking each month, was the best allocator. The 12 monthly coincident distribution peaks are developed from load research data since actual coincident distribution peaks are not measured. The coincident distribution peaks are not used by engineers in substation design, because each substation is a unique subset of the whole distribution system and must be designed to handle the peak loads connected to it. The sum of the 12 coincident distribution peaks developed from load research data is merely an information surrogate that captures the relative peak loads of the different distribution level rate schedules for the aggregated distribution system. The statistical analysis used in the Distribution Cost Allocation Study provided evidence of a strong relationship between the allocator and the simulated equipment peaks in the study. It was this strong relationship together with evidence of good accuracy in matching shares of equipment peaks for each rate schedule that resulted in the allocator's recommendation. The substation weighting factor is based on recent actual measured substation monthly peak loads, like those used by distribution design engineers.

Distribution Primary Lines

Q. What did you learn about the design of distribution primary lines and how does it relate to cost allocation?

A. PacifiCorp's Engineering Handbook, section 1B.10, "Line and Feeder Design Criteria" states on page 3 under the heading "Conductor Sizing", "Main line distribution circuit conductors shall be of adequate size to serve the normal circuit load and shall have a limited reserve capacity margin above the expected peak loading requirements." Also, "Circuit main line conductors shall be scheduled for replacement when normal peak loading, based on forecasts from actual field measurements, exceeds 85 percent of the conductors thermal rating as specified in PacifiCorp's Distribution Construction Standards."

I learned from PacifiCorp's Engineering department that primary line conductor size selection is based on an economic analysis over the estimated 30 year life of the line. I learned the key determinants are the estimated initial peak load (load current in amperes) and the forecast load growth rate. The initial conductor size selection is important because the Distribution System Planning Study Guide 1E.3.1 states, “Costs for reconductoring often are much higher than for constructing a new pole line.” “Reconductoring may involve significant reconstruction of the pole line including replacement, and in some cases relocation of many of the poles.” “When selecting a new conductor, use the economic size, not the minimum size to carry the load. Once the work is required, the lowest total ownership cost for the new line should be the important factor, not the lowest first cost.”

The reduction of load losses may affect the conductor size selection, but forecast high load growth may more likely justify a larger conductor size because of the high cost of future reconductoring. Estimates of costs of new line construction and reconductoring are included in PacifiCorp’s Engineering Handbook, sections 2P.3 and 2P.4. For example, the estimated total (material & labor) installed cost per mile of new three-phase overhead 4/0 lines under difficult urban circumstances is $265,427. The comparable reconductoring cost per mile is $336,703.

The conclusion is that the sizing of primary lines is likely to be determined by the forecasted initial peak load and the forecasted growth in peak load. Therefore the current demand classification of primary lines is reasonable. The key load data engineers use for sizing primary lines is peak load in amperes on feeders measured at substations. This data is not available by rate schedule so surrogate data must be used in the allocation step. As discussed under Distribution Substations, there are many more primary lines than substations and they too possess a wide variation in the mix of types of customers and loads. The cost of these primary lines is aggregated in distribution accounts for allocation to rate schedules. The wide variation in the nature of the large number of distribution primary lines makes developing the ideal cost allocator very difficult. The Distribution Cost Allocation Study found after analyzing several possible allocators, that a factor based on the 12 distribution coincident peaks, weighted by the number of substations peaking each month, was the best allocator.

Distribution Line Transformers

Q. What did you learn about the design of distribution line transformers and how does it relate to cost allocation?

A. Line transformers step primary voltage down to secondary levels for use by customers. The residential class has an average of about 6 customers per line transformer while most other classes (except small commercial with an average of 2) normally have a single customer connected to a line transformer. Like substation power transformers, line transformers are thermally limited in load carrying capacity, which is affected by the ambient temperature, the electrical load, and the altitude.

PacifiCorp has three engineering standards used in sizing line transformers: General Residential Electrical Demand DA411, Padmounted Transformers-Sizing Criteria GH011, and Overhead Transformers-Sizing Criteria EL021.

Standard DA411 is used to determine the peak demand (in kilowatts) for single family and multiple family dwelling units based on connected electric appliances. Standard DA411 also contains the summer and winter design coincidence factors that account for the diversity of loads when multiple customers are connected to a single line transformer. The coincident peak demand is then used to determine the transformer size using a table with different KVA sizes and respective load capability based on summer and winter ambient temperatures.

Standard GH011 for padmounted transformers refers to Standard DA411 for determination of the peak demand for residential customers and uses the same transformer sizing table. For non-residential loads this standard refers to standard EL021 for overhead transformers for specific sizing guidelines.

Standard EL021 for overhead transformers refers to DA 411 for determination of the peak demand for residential customers and uses the same transformer sizing table. For non-residential, a table is provided with three sets of transformer load capability data for three different preloads (50 percent, 75 percent & 90 percent of nameplate) with each set including load capabilities for different ambient temperatures and peak load periods. These preload levels represent continuous loading exclusive of peak load. Exhibit RMP___(LEA-1R) shows that for a 50 KVA transformer and an 8 hour peak period, increases in the preload have a small effect on the load capability while increases in the ambient temperature have a much larger impact. The difference in average ambient temperature and even altitude for different customers has not been taken into account in allocation of transformer costs even though these parameters affect transformer sizing. I believe the reason is that the key cost driver is peak demand.

When sizing a transformer for a bigger preload, a larger size may not be needed depending on the customer's peak load. Further, the exhibit shows that even if the next size line transformer is required, the incremental cost is small. The conclusion is that the key cost driver for line transformer investment is customer peak demand. Therefore the current demand classification of line transformers is reasonable. The Distribution Cost Allocation Study's recommended allocation factor for line transformers of the annual schedule non-coincident peak times the design coincidence factor is very close to the type of data engineers use and was found by the study to be the best allocator. Therefore the current allocation method is reasonable.

Distribution Secondary Lines

Q. What did you learn about the design of distribution secondary lines and how does it relate to cost allocation?

A. Secondary lines are used primarily to serve residential customers since frequently several residential customers are served from the same line transformer (currently an average of 6 per transformer). The secondary lines eliminate the need for the very long service drops that would be needed to connect each customer directly to the shared line transformer. So in essence the secondary lines are an extension of the secondary voltage side of the line transformer and should be classified and allocated the same.

Standard DA411, for determining residential demand, provides several examples of sizing distribution line transformers to serve residential loads. Each example uses common residential appliance demands together with a table of load capabilities for various transformer sizes and ambient temperatures. The standard states that these calculated coincident peak demands are used in determining the transformer "and secondary sizes". So the load data engineers use to size secondary lines is the same as that used to size line transformers, and therefore, using the same classification and allocator is reasonable.

Standard ES001, Overhead Secondary-General Information, states "Overhead single phase secondaries shall be installed when service requirements to one or more customers will require more than one span of low voltage conductors (service drop) or when the maximum allowable length of the service conductors will be exceeded." (Due to voltage drop) And "When constructing new lines in urban areas where many homes are served from the line, this cable can be an economical method of providing service. Because the economical choice between using secondary cable or using multiple transformers varies in each situation, cost comparisons should be made between the two alternatives before finalizing a cost estimate." The standard lists several situations that favor the economics of using secondary aerial cable instead of installing additional transformers.

Standard ES001, under the heading, "Conductor Size Selection for Overhead Secondary" lists the first rule as, "Determine customers total peak demands and calculate load current with a possible load growth rate for the next 5 to 10 years." Then it says to use Table 2 in Standard ES011 (which lists physical characteristics and ampacity for 1/0 and 4/0 conductors) to "…select a secondary conductor to carry this amount of load current." Expected peak load current is the key cost driver here.

Standard GS001, Underground Secondary and Service-General Information lists steps in selection of cable size. For residential the first step is to use Standard DA411 to determine customer's peak demand and load factor and then use a graph in Underground Secondary and Service-Residential Economical Service Cable Selection Standard GS041 to determine the economical cable size. A typical residential load with A/C might have 10 to 13 kilowatts of peak demand and an annual load factor of about 40 percent per Standard DA411. For a demand of 10-13 kilowatts, using the graph in Standard GS041, load factor has no impact on the cable size selection. In fact, for a peak demand of 13 kilowatts, the same underground cable size would be selected for the complete range of load factors of 20 to 80 percent. Again the conclusion is that peak demand is the key cost driver for secondary lines, and therefore, the current demand classification for secondary lines is reasonable.

In conclusion, the current approved demand classification for secondary lines is reasonable and also the current approved allocation method is reasonable as it is the same as that for line transformers.

Distribution Service Drops

Q. What about service drops?

A. Service drops connect customers either directly to a line transformer or to secondary lines that are connected to a line transformer. Service drops are classified as customer related (even though they are sized based on demands similar to secondary lines) since every customer needs one (although as Mr.

Chernick has pointed out some are shared) and allocated using average service drop cost (for each rate schedule) times the number of customers. I believe the current customer classification for service drops is reasonable. The current allocation factor may need to be modified as new information becomes available.

Distribution Classification and Allocation Issues

Q. What are Mr. Chernick's issues regarding the allocation of distribution costs?

A. He says the monthly weighting factors used in deriving the allocation factor for substations and primary feeders are not cost-based and that the current approved allocation method overlooks many of the ways that periods of high energy use drive distribution investment.

Q. Mr. Chernick, on page 25 of his direct testimony, cites your rebuttal testimony in Docket No. 07-035-93. Has he correctly characterized your testimony?

A. No. He states "Lowell Alt acknowledged that duration of peak, load cycle, and on-peak energy are all cost-causal factors." First, I did not use the phrase "on-peak energy" in my testimony, nor did I use the phrase "cost-causal factors" together with "duration of peak" or "load cycle". Second, my use of "duration of peak" on page 11 referred specifically to information needed in the calculation of the thermal capability of a specific power transformer.

He further quoted my testimony (on page 11) stating "The key data are the peak load and its duration" and said that it was with regard to substation sizing. This is incorrect. This quote specifically related only to the data needed to calculate the thermal capability of a specific power transformer. The relevant statement from my testimony is on page 12 where I draw my conclusions regarding distribution substation investment decisions, “Although altitude, average ambient temperature and load cycle are taken into account, it is clear that the projected peak load (including growth) is the key driver in sizing substation transformers and therefore the key cost-driver of substation equipment”.

Q. Does the Distribution Cost Allocation Study discuss how the current substation weighting factors method came about?

A. Yes. The October 21, 1989 Distribution Cost Allocation Study report states on page 39:

> A suggestion was made by a consultant for Committee of Consumer Services that the number of equipment peaks by season be used to weight the CDP’s (Coincident Distribution Peaks) to capture seasonal variation. The only equipment peaks available from normal records were the substation peaks shown in Table No. 5. These figures show considerable variation by location as well as by season. The use of the substation peaks produce a very practical weighting which accounts for both geographic variance and seasonal factors. In addition, since the weighting factor can be measured easily each year, shifts in loading patterns are captured. Finally, they offer a good surrogate for the equipment peaks which approximate the “ideal allocator.

The report went on to say that ten formulations of the CDP were ranked using the r^2 statistic, the percent error, and the allocation fraction measures and that the monthly substation weighted formulation was best over all.

Q. When you were the Division witness in the 1989 case, what were your reasons for supporting the substation weighted 12 coincident distribution peaks allocator for substations and primary lines?

A. Following is my October 23, 1989 filed testimony in Case No. 89-035-10 on that question:

Cost causation is the guiding principle in selecting allocators. In this Case we met with some of the Company's distribution engineers and discussed the key information used by them in making distribution plant capacity decisions. We learned that coincident demands on distribution circuits (as measured at distribution substations) are the key data used in making capacity change decisions. We also learned that distribution circuits and substations may peak in any month. Since actual load data is not available by rate schedule, load research data has been used by the Company to develop coincident distribution demands by rate schedule. The next step in selecting an allocator is determining which form of the available load data best matches the load data used by the design engineers. This is where the Company's Distribution Study is important. The Distribution Study basically used actual data from a previous transformer study to simulate with a computer the peak loads on distribution substations, circuits and line transformers. In Case No. 85-035-06, the Company presented testimony and exhibits that used three criteria for selecting the allocator that best matched the computer simulated equipment peaks in the Distribution Study. These criteria were the R^2 (coefficient of determination), the absolute error and the percentage error. I selected the monthly substation weighted 12 coincident distribution peaks method for four reasons. First because I believed it was similar to the load data used by distribution design engineers. Second, it had a high R^2 value when regressed against the Distribution Study equipment peaks. Using the Company's Exhibit SLW-1R.2 in Case No. 85-035-06, the range of R^2 values for the ten distribution allocators developed by Mr. Walton was 0.9729 to .9997 (maximum=1.0). The R^2 value indicates the significance of an independent variable in explaining variations in the dependent variable. These values are all quite high and nearly equal and suggest that another method be used to select the best allocator. Third and more important, the highest average ranking based on the percentage error criterion was for the monthly substation weighted 12 coincident distribution peaks. Fourth the monthly substation weighted 12 coincident distribution peaks includes both the summer and winter seasons as well as the remaining off season months. I believe the use of the number of monthly substation peaks as weights is reasonable as it decreases the weight given the off-season months while still including them.

Q. Do you agree with Mr. Chernick's concern about the weights used in the allocation factor for substations and primary lines?

A. No. The approved allocation factor uses the 12 monthly coincident distribution peaks multiplied by a weighting factor based on the number of distribution substations that peak in each of the twelve months. The substation weighting factor is based on recent actual measured substation monthly peak loads.

With over 300 distribution substations in Utah, small changes would not impact the overall weighting. The sum of the 12 monthly coincident distribution peaks basically weights each of the 12 months the same. By using the substation weights, peak months get additional weighting and off-peak months less. The month of the coincident distribution peak is really not relevant in substation investment decisions, because each substation must be considered on its own. The relevant task is to select an allocator that is reasonably accurate, using surrogate data (since actual data by rate schedule does not exist) to allocate the aggregated costs. As I explained earlier, developing an ideal allocator for the aggregated costs of over 300 unique substations and far more primary lines is difficult. This is one of the reasons as a Division witness I originally recommended that the issue be studied. I think the comprehensive analysis done in the Distribution Cost Allocation Study, and the related review and refinement over a 6 year period, accomplished that.

Q. Mr. Chernick states that the substation weighting method can produce illogical results. Do you agree with his example?

A. No. He cites data from Docket No. 07-035-93 saying June and July had higher weights than August even though August was the month of the coincident distribution peak. I addressed this same issue in that docket with an exhibit which I have included here as Exhibit RMP___(LEA-2R). In this exhibit, I used Mr. Chernick's spreadsheet from that docket (Attachment CCS 10.28) as a starting point to examine the actual substation monthly peak loads for the months of June, July and August. I eliminated all substations for which loads were not available for all twelve months. I sorted all data by peak month. Then I calculated the difference between the load in the peak month and each of the other two months and summed the columns of differences. The results show that the substations that peaked in July had a total load of 159,299 kilowatts in July more than the same substations did in August. The July peaking substations had a total load of 223,675 kilowatts in July more than the same substations did in June.

Next the results for the August peaking substations showed that they had a total load of 12,584 kilowatts more than the same substations did in July and 33,109 kilowatts more than the same substations did in June.

Lastly the results for the June peaking substations showed that they had a total load of 51,976 kilowatts more than the same substations did in July and 76,580 kilowatts more than the same substations did in August.

The conclusions drawn from this actual data mean that July was far more important in terms of cost causing peak load than either June or August. The total numbers are not close. It also means that June is more important than August as its total kilowatts load difference over August was 76,580 kilowatts compared to only 33,109 kilowatts for August over June (a net difference of 43,471 kilowatts).

Q. Do you agree with Mr. Chernick's concerns that the current approved allocation method overlooks many of the ways that periods of high energy use drive distribution investment?

A. No. In my review of the Company's distribution engineering standards, process and data used, I found, as discussed earlier, that all distribution plant, except meters and service drops, should be classified as demand and that the key driver in the investment decisions was peak demand. He says the number of high load hours drives investment in redundant equipment, but provides no evidence. I found no evidence of this in my review of the engineering standards. He says all energy in high-load hours adds to heat buildup and results in a reduction of the ability of transformers to survive brief load spikes on the same day. As I discussed earlier, substation power transformers are a huge mass of metal and oil that results in a time lag of hours before the effect of "brief load spikes" even take effect. He says that distribution investments, such as increases in the sizing of transformers, are made to reduce energy load losses. I found no evidence to support this statement in the Company's current engineering standards. The cost of load and no-load losses in transformers are taken into account in the evaluation of bids during purchase decisions.

Summary

Q. What do you conclude from your analysis of Mr. Chernick's distribution cost classification and allocation issues?

A. The bottom line here is that the Distribution Cost Allocation Study was a comprehensive study that extensively analyzed numerous possible distribution allocation factors before settling on the recommended allocators as the best. It was reviewed by many parties, including the Committee (Office), and refined over several years before being approved by the Commission. Mr. Chernick has completed no such comprehensive analysis, but only suggests there is a better way. The Distribution Cost Allocation Study Report contains 42 pages plus extensive exhibits. Mr. Chernick presents about 3 pages of discussion of why the current allocation methods should be changed. He offers no alternative comprehensive study, no specific recommendations regarding alternative allocation methods and very little evidence to support his claim that the current methods do not reasonably reflect cost causation. My review of the Company's use of engineering standards and load data in making distribution transformer and conductor investment decisions indicates that peak demands are clearly the key driver in those decisions. This establishes a cost-causal link between customer peak demands and distribution costs. Therefore I conclude that the current Commission approved classification and allocation of distribution costs is reasonable and need not be changed. The Commission decided the classification of distribution plant over 29 years ago with all distribution costs as demand-related except for meters and service drops. The Commission decided the allocation of distribution plant over 19 years ago. The Commission has not changed those decisions. The burden of proof is on any party seeking a change. I do not believe the Office has met that burden and based on my research of PacifiCorp's distribution investment decision process, I believe the current Commission approved distribution classifications and allocation methods are reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes.