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 Utah. 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 customer charges, interim rates, rate case stipulations, rate design, cost-of-service, 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.

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 Committee of Consumer Services (the Committee).

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 the process of sizing distribution transformers and conductors 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.

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

A. I believe since at least April 12, 1982 when the Commission in Utah Power Case No. 79-035-12 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 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 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".

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 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 18 years.

Q. Although the same allocation methods have been used over that period, have implementation changes occurred?

A. Yes. For example, In PacifiCorp Docket No. 97-035-01, the Commission in its March 4, 1999 Order established an Allocations Task Force, that I chaired, to study various unresolved allocation issues. The task force included 19 interested parties and met over an 8 month period. The December 16, 1999 Allocations Task Force Report states agreement was reached on the allocation of service drop costs. Research showed that irrigators had very small service drops, the cost of which was not included in the service drop account. The result was that the irrigation class no longer gets allocated service drop costs in the class cost of service study. This did not change the basic method used to allocate service drops to other classes. I think this type of approach might be a way to deal with the Committee issue of shared service drops which I will address later.

Distribution Classification Issues

Q. Committee Witness Mr. Paul Chernick is critical of the Distribution Cost Allocation Study. What do you perceive are his issues?

A. He says the Distribution Cost Allocation Study is not comprehensive since it limits consideration of energy-related investments, the energy role in distribution plant decisions is understated (specifically with regard to distribution transformers and conductors), the weighting of the allocation factor for the substations and primary conductors does not reflect cost-causation, and the allocation of shared service drops is not cost-based. I will first address his classification issues and in a later section the allocation issues.

Q. Do you agree with his comment that the Distribution Cost Allocation Study was not comprehensive with regard to the energy classification issue?

A. No. Could it have been more comprehensive? Yes, because an issue can always be studied more. But I believe it was comprehensive enough on classification, especially since the Commission directive to the Company was to do an “allocation” study, not a “classification” study as distribution classification had already been decided in 1982 and reaffirmed in 1983. I believe the Distribution Cost Allocation Study was an excellent study that involved a significant effort and considerable examination and review over a period of 6 years. In reviewing the Distribution Cost Allocation Study, I counted about 22 pages, not including supporting exhibits, discussing the rationale supporting the choice of distribution plant classifications. In a similar review of Mr. Chernick’s testimony, I counted about 2 pages of testimony and 2 pages of his exhibit, PLC-8D.2. He offers no alternative comprehensive study, no specific recommendations regarding energy classifications and very little evidence to support his claims of an improper understatement of energy classification.

Q. Do you believe the evidence Mr. Chernick has submitted meets the burden of proof established by the Commission in its March 7, 1983 Order regarding a change in distribution cost classifications?

A. No.

Q. Although you believe the Distribution Cost Allocation Study was excellent and comprehensive enough, 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 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 Committee as the party seeking a change in the classification 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 in the 19 years since the final Distribution Cost Allocation Study.

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

A. The approved Distribution Cost Allocation Study methods break distribution plant into six categories for allocation purposes: substations, primary lines, line transformers, secondary lines, service drops, and meters. Meters and service drops are classified as customer-related. The other plant categories are classified as demand-related.

Q. Let's start with substations. 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 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 (in MVA) is based on an average ambient temperature of 30 degrees Celsius 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. 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?

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.

Engineers use peak-loading on substations that is not available by rate schedule so surrogate data must be used in the allocation step. 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.

Q. What did you learn about the design of distribution primary lines?

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. 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.

Q. What did you learn about the design of distribution line transformers?

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. 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.

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%, 75% & 90% 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-COS) 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.

Q. What did you learn about the design of distribution secondary lines?

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.

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

Q. What do you conclude about distribution cost classifications?

A. In conclusion, the Commission decided the classification of distribution plant about 26 years ago with all distribution costs as demand-related except for meters and service drops. The Commission has not changed that decision. The Commission further placed the burden of proof on any party seeking a change. I do not believe the Committee has met that burden and based on my research of PacifiCorp's distribution investment decision process, I believe the current Commission approved classifications are reasonable.

Distribution Allocation Issues

Q. What are the Commission approved distribution cost allocation methods?

A. The following distribution allocation methods have been approved by the PSC and in use in Utah for the past 18 years.

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.

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).

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

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

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

A. He says the allocation of shared service drops is not cost based and the weighting of the allocation factor for substations and primary conductors does not reflect cost-causation.

Q. Do you agree with his concern about shared service drops?

A. If the Utah census information he presented is representative of the magnitude of residential shared service drops in the Company's Utah service area, then a change in the calculation of the service drop allocation factor would be warranted. If multiple residential or commercial customers use a shared service drop, the conductor size would be larger than a normal single customer service drop and some diversity might be taken into account. I would expect the average cost per customer of a shared service drop to be smaller than the average cost per customer of individual service drops. The question is how much smaller? This is an area where some additional study is needed. First, data on the quantity of shared services would be needed (is the census data reflective of the Company's Utah customer base?) and second, the typical number of customers sharing those services, and third, how large are the shared service conductors and the related costs. Depending on the outcome of that study, the service drop allocation factor could be modified.

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 12 monthly coincident distribution peaks are developed from load research data since actual coincident distribution peaks are not measured. The substation weighting factor is based on recent actual measured substation monthly peak loads. Mr. Chernick presents two alternative allocation factors for substations and primary lines, which he believes to be more cost causal. He states the first is computed from the ratio of the monthly peak on the substation to the annual peak on the substation, and squared so as to rapidly reduce the contribution as load falls, and summed the squares over the substations to derive the monthly weights. He states, "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)."

After reviewing his actual spreadsheet calculations, it appears that the actual calculation of both ratios is somewhat different from the description. The squared ratios are actually multiplied by the summer capacity before calculating the weighting percentages, but the effect of this difference is small. Apparently the capacity is used in the calculation to eliminate his concern about small and large substations being treated equally in the weighting factor calculation.

To examine Mr. Chernick's concern that a small KVA difference in peak load of a substation might have impacted the weighting factor calculation and his concern that small and large substations carry the same weight but have much different costs, I prepared Exhibit RMP___(LEA-2R-COS). In this exhibit, I used Mr. Chernick's spreadsheet (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).

Mr. Chernick's proposed two new weighting factors would result in August being considered more important than June and much closer to July than the above results would support.

Q. What do you conclude from your analysis of these three summer months?

A. In conclusion, I believe the weighting factors proposed by Mr. Chernick would result in movement away from cost causation, and therefore, does not warrant any change from the current weighting method used with the 12 distribution CP allocation factor for substations and primary lines.

Q. In your analysis of the summer months did you discover an error in the Company's original calculation of the substation weighting factor?

A. Yes. Apparently the spreadsheet function used in the calculations ignored duplicate monthly peaks that occurred for some substations. I recalculated the number of substations that peaked each month. For substations with duplicate peaks, I gave those months an equal fractional share of 1. I also eliminated substations with less than 12 months of data to address concerns of the Committee. The result is shown below:

	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07
Original	130	27	11	5	16	19	16	9	3	8	14	58
Revised	120.4	26.9	12.7	4.7	15.5	18.9	17.6	10.4	4.0	9.0	14.7	59.4

Q. Does this correction affect the results of your analysis of the summer months?

A. No. My analysis focused on the total kilowatt load differences between the months and any duplicate peaks would have a zero difference before and after the correction.

Summary

Q. Please summarize your conclusions and recommendations regarding the classification and allocation of distribution costs.

A. I believe no change should be made in the classification or allocation methods for distribution costs for the following reasons:

1. The Commission in its March 7, 1983 Order in Utah Power Case No. 81-035-13 adopted for future use the same classification of distribution costs being used today and put the burden of proof on any party seeking a change. I believe the Committee has not met that burden.
2. The Company's extensive Distribution Cost Allocation Study was developed, refined and thoroughly examined over a 6 year period before the Commission

finally adopted the recommended distribution cost allocation methods in 1990.

3. The Committee has not provided any new study to show results different than the Company's Distribution Cost Allocation Study.
4. My current review of the Company's distribution engineering standards results in the conclusion that peak demand is the key cost driver in distribution transformer and conductor investment decisions.
5. The Committee's proposed two new weighting factors for the allocation factor used to allocate substations and primary lines would result in a movement away from cost causation and therefore no change is warranted in the current method. My mentioned correction of an error in the current weighting calculation is not a method change.
6. I recommend study of shared service drops to determine what modification of the allocation factor calculation is needed. I believe this modification is not a method change, but a refinement in the calculation. The current method uses weighted customers to allocate service drops. I believe a modification to the calculation of the weights might be needed.

Q. Does this conclude your rebuttal testimony?

A. Yes.