Q. Please state your name, business address, and present position with PacifiCorp dba Rocky Mountain Power ("the Company").

A. My name is Scott D. Thornton. My business address is 1407 W North Temple Street, Salt Lake City, Utah. My present position is Manager, Metered Data Management in the Metering Business Unit.

Q. What does that position entail?

A. I direct the development of all class load profile estimates utilized in cost allocation, rate design, forecasting and special studies. I also direct the design, implementation, and maintenance of all load studies performed by both Rocky Mountain Power and Pacific Power companies. I am responsible for the development of load coincidence factors and for the determination of the distribution system peak for the Company.

Q. Please briefly describe your education and business background?

A. I have B.S. degrees in Accounting and Business Administration/Economics from Westminster College. Additionally, I have an MBA from Brigham Young University. I have over 32 years of experience with the Company, 27 of those years associated with load research activities

Q. Have you appeared as a witness in previous Utah regulatory proceedings?

A. Yes, I have.

Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. My testimony will provide an overview of load research in general, load research processes insofar as they apply to the development of class loads, and the processes surrounding the development of load estimates used in the Company's rate filing.

Q. What is the purpose of load research?

A. In the utility environment, load research provides the data needed for cost allocations and the resulting cost-of-service information. Most demand related costs of production, transmission, and distribution facilities can be allocated to the classes of service based on contribution to system peaks, contribution to distribution peaks, or individual customer demands that are determined from load research data. Load studies are designed to provide information on rate related activities such as demands associated with specific customer classes at specific peak periods (system peak day). These loads are derived by either direct measurement, by sampling for rate groups or by other estimation procedures.

Q. Why are load studies for some classes derived by sampling?

A. For rate groups where load profile meters are not used for billing purposes, direct measurement of customer or class loads is not available. For these customer groups, system peak and other load data is estimated through sampling and statistical analysis.

Samples, by their very nature, are designed to provide information about something that is not otherwise readily available. Our load study samples are designed to estimate loads at the time of the monthly system peaks. This is not information that can be obtained from standard billing meters, and is not stored on a per customer basis in our billing systems.

Q. **Were load studies used to provide load estimates in this rate filing?**

A. Yes. In the state of Utah, sampling is used to provide load estimates for the Residential Class, Schedule 6, Schedule 10 and Schedule 23. Loads reported for all other major rate groups are derived through a full census of direct measurement, where every meter within a particular class is a load profile meter, or by other processes that will be detailed in this testimony.

Sampling Overview

Q. Would you provide a brief overview of load sampling?

A. There are a wide range of sampling options available for estimating load profile characteristics, from simple random to elaborate model-based sampling procedures. The two most widely accepted within the electric industry are simple random sampling and stratified random sampling. Simple random sampling has several advantages: Each unit of the population has the same probability of being selected. Simple random sampling is the easiest sampling technique to perform and the most flexible during analysis. In load research, simple random sampling is used mainly for populations with relatively few customers or for populations where individual units have similar characteristics.

Stratified random sampling is a widely used and accepted technique used to reduce overall sample size. It divides the class of interest into sub-classes of like characteristics. The technique has the effect of reducing the overall variance of the class, thus reducing sample size. This generally results in significant reductions in the sample size required, versus simple random sampling.

Q. Please detail the sampling philosophy employed by Rocky Mountain Power.

A. All samples designed and installed in the state of Utah are based on stratified random samples, and the designs meet, or exceed the standard specified in 1978 by Section 133 of the Public Utilities Regulatory Policy Act ("PURPA") for the variable of interest. The specific parameters of the sample design are outlined in the Code of Federal Regulations ("CFR"), Title 18, Chapter 1, Subchapter K, Part 290.403, Subpart B, which states:

> "**Accuracy Level.** If sample metering is required, the sampling method and procedures for collecting, processing, and analyzing the sample loads, taken together, shall be designed so as to provide reasonably accurate data consistent with available technology and equipment. An accuracy of plus or minus 10 percent at the 90 percent confidence level shall be used as a target for the measurement of group loads at the time of system and customer group peaks."

The PURPA specification has become a load research standard, particularly for samples that will be used to support rate cases or other regulatory requirements.

Q. Is stratified sampling a generally accepted practice for these types of studies?

A. Yes. Stratified sample design is an industry-accepted practice which provides for the installation of dramatically fewer sample points to achieve target precision and confidence levels. This technique is endorsed by both the Association of Edison Illuminating Companies ("AEIC") Load Research Committee, as well as the Western Load Research Association ("WLRA").

Load Data Utilized in this filing

Q. Was data derived from load studies utilized in this current filing?

A. Yes. Load estimates for this rate filing are derived from sample data collected during the base year period July 2010 through June 2011. For those schedules where direct measurement is employed, the data represents actual measurements of load for the same base period. Street and area lighting load data is derived from proxy data collected during the same time period.

Q. Please describe the data collected in these load studies.

A. For the rate groups identified, peak load data is estimated from these load samples. Sample participants have specialized load profile metering installed at their site. These meters record usage in hourly or sub-hourly increments for the duration of the load study (96 intervals/day/meter, 2,880 intervals/month/meter, 35,040 intervals/year/meter). Because these meters record and store time-differentiated usage data, we are able to determine usage for the sampled class for any identified date and time (system, jurisdictional, class peaks). This sample usage is the basis for the class load estimates utilized in cost of service studies.

Q. Which Rocky Mountain Power schedules have load profile metering installed?

A. For those samples utilized in this filing, there were 170 such meters installed on residential class customers, 108 meters installed on Schedule 6 customers, 130 meters installed on Schedule 10 customers and 75 load profile meters on Schedule 23 customers. In addition, all Rocky Mountain Power customers with billed demand equal to or greater than 1,000 kW have load profile metering installed. Finally, the PacifiCorp Metering Business Policy manual, Appendix A.3 states:

> "All new revenue loads that are calculated to be seven hundred and fifty kilowatts or greater shall have multifunction, interval data, solid state meters with remote communication access installed."

The table below summarizes these installations:

Utah				
Class/Schedule	Data Source	Design Criteria	Sample Size	Install Date
Sch 001	Stratified random sample	90/5	170	October 2008
Sch 006	Stratified random sample	90/10	108	January 2009
Sch 023	Stratified random sample	90/10	75	October 2008
Sch 010	Stratified random sample	90/10	130	May 2006
Sch 008	Direct Measurement	Census	Census	Ongoing
Sch 009	Direct Measurement	Census	Census	Ongoing
Sch 021	Direct Measurement	Census	Census	Ongoing
Sch 031	Direct Measurement	Census	Census	Ongoing
Street Lights	Estimated	Load estimated from proxy data		

Q. Can you please give an explanation of the table you've just presented?

A. Yes. The first column lists those schedules or breakout of schedules for which time differentiated load estimates are required by the cost-of-service department. The second column, Data Source, identifies how the data is derived. Note that, depending on the schedule, these load estimates may be derived from sample data, direct measurement, or estimated using proxy data. The third column, Design Criteria, indicates the confidence and precision parameters that were used in the sample design. The residential class sample, for example, was designed to achieve ±5 percent precision at the 90 percent confidence level for the variable of interest. More simply put, the sample will provide an estimate that is within ±5 percent of the actual value nine out of ten times. Note that schedules designated as Direct

Measurement indicate a Design Criteria of 100/0. This indicates that 100 percent of the time the loads derived from this group show 0 deviations from actual. The fourth column, Sample Size, indicates the number of load profile meters that were installed on a given schedule to meet the specified Design Criteria. A listing of Census indicates that all customers belonging to that particular group have load profile metering installed. The final column indicates when a given load study was installed. Those schedules from which load estimates are derived by stratified random sampling are replaced every five years. Census metering is only replaced if a given customer moves out of the specified census group. For instance, if a Schedule 8 customer were to be reclassified as a Schedule 6 or Schedule 23 customer, he would be removed from the Schedule 8 group. Because he was reclassified into a group whose loads are determined by sampling, he would not be added to this group except through normal random selection.

Q. According to the Load Research Working Group Report to the Commission, "data that were from sample designs created prior to 2006 were out of date and were not meeting the "PURPA Standard". Was any of the class load data utilized in this filing derived from sample designs created prior to 2006?

A. No, they were not. Data for Utah rate Schedules 001, 006 and 023 were derived from samples that were designed and installed in 2008. Data for Schedule 010 was derived from a sample that was designed and installed in 2006.

Q. Were these load studies designed to meet the "PURPA Standard" for the variable of interest?

A. Yes they were. It should be noted, however, that PURPA does not define what that variable of interest should be. For class load data utilized in this filing, the variable of interest specified in the sample design was the average system peak demand over a 12 month period, four months for irrigation.

Q. Did the Load Research Working Group address the acceptability of average system peak demand as an acceptable variable of interest?

A. Yes they did. It was the general consensus of the group that that average system peak demand might not accurately capture the individual monthly variability inherent in these types of loads. As such, they recommended that the design standard be changed such that “the “PURPA Standard” would be met on a monthly basis. (Exhibit RMP___(SDT-1), page 7). They further recommended that Rocky Mountain Power’s current sample rotation schedule be modified and accelerated (Exhibit RMP___(SDT-1), page 10) to place these new sample designs into production as quickly as possible.

Q. Did the Company accept these recommendations?

A. Yes, we did. Even though the current load studies for Utah Schedules 001 and 006 were less than two years old, new load studies incorporating the revised design standard were put into production on July 1, 2011. Utah Schedules 010 and 023 will be replaced in 2012.

Q. Was data from the newly installed Schedule 001 and Schedule 006 load studies available for this filing?

A. No, it was not. The historical base period utilized in this filing was July 1, 2010 through June 30, 2011. The load studies mentioned weren’t placed into production until July 1, 2011.

Q. For those load studies utilized in this filing, how are sample customers selected?

A. Per standard sampling theory, sample customers are randomly selected. If repeated samples were drawn, you would expect that the location of the sample sites would mirror the location of the target population. For a given individual sample, this would probably not be the case. We do not try to force sample selection to mirror the population as this can potentially introduce bias into the process. We do expect that the sample sites will generally follow population centers. When this is not the case, I will initiate a re-sample of the target population.

Irrigation Load Estimates

Q. Was this the process followed for all load studies?

A. No, it was not. A slightly modified process was followed for irrigation load studies.

Q. Please describe the process used to derive irrigation load estimates.

A. The Load Research Working Group report to the Commission contains an excellent narrative on the process (Exhibit RMP___(SDT-1), page 12). It states "The Company's irrigation customer sample, unlike the residential and small commercial classes, is selected from actively irrigating customers, rather than from all irrigation customers… An important reason for this is that a fairly sizable portion of irrigation customers – over 10 percent – are listed as active but will register zero electricity usage during an irrigation season. When the load research estimates are expanded by the total population, these initial estimates will always be overstated, since this type of expansion assumes usage for the entire customer class. The Company's treatment for this is to adjust this initial load estimate down to the actual billed or forecast energy levels."

Q. **Does this approach provide reliable load estimates?**

A. I believe that it does. The approach is problematic in that normally, billing data is used to gauge the effectiveness of load study estimates. In the case of irrigation, the initial estimates will always be higher than the measured billing data, which is why there is always a downward adjustment. As such, it provides load estimates that are hard to validate against actual, measured usage. For a little over eight months out of the year, the off season, irrigation load estimates are derived from billing energy estimates, assuming a 100 percent load factor. For a little over three months each year, load estimates are derived utilizing the process described above. This process creates a load shape of actively irrigating customers and then adjusts that load shape down to match the billed or forecast energy levels of actively irrigating customers.

Q. Doesn't this process bias the study toward a higher contribution to peak?

A. No, I don't believe it does. Let me offer a simple example which I believe will illustrate the process, as well as highlight why I believe we are not biasing the estimates on the high side. Let's suppose that we have a population of 10 100 watt light bulbs. One of these light bulbs is never turned on. The other nine bulbs are on every hour of every day. What we immediately know about this population is that the total demand at any given hour is 900 watts (100 watts x 9), the average demand per customer is 90 watts (900 watts / 10), the total monthly energy is

657,000 watt hours (900 watts X 730 hours), and the average usage per customer is 65,700 watt hours (657,000 /10). These are all known, measurable usage quantities.

Q. Please describe how a sample of these light bulbs might look.

A. Because there is almost no variance in this group, the sample would be very small and consist of one stratum (simple random sample). As we would not want to install the requisite metering on a customer who never registers usage, we would eliminate the non-usage light bulb from the sample selection process. The math would indicate a sample size of one for this group, but for purposes of this illustration we'll select three.

Q. What sort of results would you expect to see from this sample?

A. The average demand per customer would be 100 watts ((100 watts x 3) / 3), higher than what we know the true average per customer demand to be (90 watts). The average usage per customer would be 73,000 watt hours (((100 x 730) x 3) / 3), again higher than what we know the true average to be (65,700 watt hours). These average per customer sample quantities would then be multiplied by the number of customers in the population to determine the initial class usage. This operation would yield the following results: total class demand equal to 1,000 watts (100 x 10) and total usage of 730,000 watt hours. Both of these quantities exceed what we know to be the actual usage quantities. But we don't end the process here. We add one additional step.

Q. What is that additional step?

A. We adjust the load estimates down, always down, to match the billed energy of the historical period, or the forecast energy of the test period.

Q. What effect does this additional step have on the load estimates?

A. Again, I'll use the example above to illustrate. We know that the true amount of usage attributable to this group is 657,000. We know that the sample produced a usage estimate of 730,000 watt hours. Under the adjustment process described above, we would reduce the sample estimates by 10 percent (657,000 / 730,000). This, in turn, reduces the total demand estimate by 10 percent. As such, the sample estimate of 1,000 watts is reduced to 900 watts. Based on my earlier testimony, we know that 900 watts is absolutely the correct level of demand for this group. Even though the initial sample estimates were high, the complete estimation process, which included an adjustment to known quantities, produced the correct answer.

Q. Obviously the situation you've described is simplified. Do you really believe the same process can be applied in loads where greater variance may exist?

A. Yes, I do. The situation described deals with a customer group where the load factor equals 100 percent or, more simply, the peak demand equals the average demand. As such, a one-to-one correlation will exist between demand and energy. Most customer groups will not experience this one-to-one correlation. For them, a given change in energy will result in less of a change to coincident demand. Or, it may result in more of a change. It may even result in a one-to-one exchange. The one thing we do know is that a given change in energy will result in a "same direction" change in demand. Given that, there are some interesting parallels between the irrigation class and my light bulb example.

Q. Please describe these parallels.

A. To begin with, sample load data is only used to estimate irrigation loads during the on-peak irrigation season, May 25th through September 15th. For the other eight plus months of the year, the load is based on a 100 percent load factor applied to billed energy, just like my light bulb example. Additionally, irrigation pumps behave very much like light bulbs. Once turned on, the load really doesn't vary. A 40 kW pump will not vacillate between 20 kW and 60 kW. It stays right around 40 kW. From a sampling standpoint, this makes the irrigation class the most easily stratified group to deal with. There is no migration of customers between strata.

Q. Does this mean that we should expect to see a one-to-one correlation between demand and energy for the irrigation class?

A. No, it does not. Nor should we expect to see a negative correlation, where a downward adjustment of 'X' in energy results in an upward adjustment in demand. In practice, you might expect the demand adjustment to occasionally be less than 'X', occasionally be more than 'X' and occasionally equal to 'X', but the adjustment to demand would always be in the same direction as the adjustment to energy.

Q. What do you perceive to be the major pitfall of the sampling methodology employed for the Utah irrigation class?

A. The exclusion of non-usage customers from the sample selection frame lessens the variability of the load estimates. Reduced variability tends to yield load estimates which result in the class load factor being overstated. This is significant since we already know that the load factor for the irrigation class is calculated at 100 percent for eight plus months of the year. If the class load factor is overstated, the probability that we are understating class contribution to system peak increases.

Q **Do you believe that the load factor for the irrigation class data utilized in this filing is overstated?**

A. Yes, for the over eight months where billing data is utilized to produce demand estimates. No, for the over three months where sample data is used to provide estimates. For that on-season period, I believe the load factor is a reasonably accurate representation of the actual class load factor.

Q. **Did the Working Group provide a recommendation for the irrigation class load data?**

A. No, it did not. As stated in the report (Exhibit RMP___(SDT-1), page 12), "All participants agreed that load research data in this class is problematic. No clear solution was proposed".

Q. **Does the Company have a plan to address the irrigation issue?**

A. Yes it does. The current irrigation load study will be replaced before the 2012 irrigation season begins. This replacement is in line with the revised sample rotation timeline proposed by the Working Group, and will be implemented utilizing the new design standards. Additionally, we intend to include both actively irrigating and active but not irrigating customers in the selection list. My current initial estimate for the size of the load study is 200 customers, up from the current 130. This new irrigation load study will contain more sample customers than any other load study in any of the Company's jurisdictions.

Reliability of Load Data

Q. Can a load study sample placed in service several years ago continue to provide reliable load estimates today?

A. Yes. While a sample is selected and load research meters are placed into service for a particular customer class at a single point in time, the meters in the sample continue to provide continuous current load data as long as they remain in service. This is important as our customers are not static and have a tendency to change over time. Because our load study meters are always in place, we capture those changes and, as such, our load estimates will reflect design and appliance changes that occur over time.

Q How do we know these studies are performing as designed?

A. As stated in the AIEC Load Research Manual, 2nd Edition, 2001, pages 7-26-7-27, which is widely accepted by the industry:

> Since population demands are estimated from relatively small samples drawn from the population, a valid concern is how well the samples represent the universe. Actual population demands are unknown, precluding direct comparisons with estimated demands. The representativeness of a sample must, therefore, be judged on the basis of auxiliary variables that are available for both the sample and the total population and correlate well with the variable of interest, class demands. In these respects, energy use per customer is an acceptable proxy for demand.

Energy use of the sample should correspond closely to the target population use (per customer), not only annually but also for each month of the year, after the application of any calendar month adjustments. This data validation is performed on all load study samples by Rocky Mountain Power's load research personnel.

Q. You had previously mentioned estimating loads from proxy data. Would you explain why you would use proxy data rather than either of the methods you've already identified?

A. Yes. There are situations where installing load profile metering is cost prohibitive, or just not practical. Street lights, for instance, represent a prime example. We could install load studies to estimate these loads, but it makes much more economic sense to simply divide the monthly billed energy for the group by the number of burning hours for the given month.

Adjustment of Historical Loads to Forecast Level

Q. Are any adjustments made to the data before it is submitted for use in the cost of service study?

A. Yes. Preparation of these loads includes an adjustment to extrapolate the historical base year loads to properly reflect forecast test year energy sales.

Q. Please describe the method used to adjust base year class load data to test year forecast energy levels.

A. The load research group prepares estimates of average per customer hourly demand for each customer rate class for every hour of the base historical year. We then calculate the base year monthly energy usage for each of these groups. This data is then extrapolated so that the value of the energy associated with these base year load estimates matches the forecast energy level. The data is further adjusted by the appropriate loss factor. Finally, the class load data is extracted and summarized for those dates and times identified as the base year system peaks.

Weatherization of Class Load Data

Q. Does the Company "weather normalize" its load research data?

A. No, not in the classical sense. The Company currently has no systems in place which would allow it to create the necessary, normalized load data. In its stead, forecast load estimates are based on base year load estimates, adjusted to forecast, weather normalized energy levels.

Q. How does this differ from what would be considered a "normal" weatherization process?

A. A more normal scenario might incorporate regressing a number of years (5, 10, 15) of load data against weather variables. You would then forecast class loads forward by incorporating "normal" weather variables into some future period. A simpler solution might involve averaging peaks over a multi-year period and then adjusting them to forecast energy levels.

Q. Did the Working Group provide a recommendation for weather normalizing class load data?

A. No, we did not. As stated in the Working Group Summary (Exhibit RMP___(SDT-1), page 13), "The workgroup was unable to arrive at consensus on this issue". Several individual recommendations were suggested however. The DPU suggested load shapes be averaged over a three to five year time period. The OCS supported using a time period longer than five years. The UIEC and UAE recommended that calibration of a single year of class load data to JAM load data as a better interim solution.

Q. **Did you adopt any of these methods for this current filing?**

A. Yes, we adopted the approach suggested by the UIEC and UAE. Their recommendation provides a process whereby we can immediately bridge current practices into an acceptable solution until such time that the Company can implement an automated system to addresses these issues. This is a short term solution which we will utilize until we can put a process in place to normalize data over multi-year periods. Other proposals put forward would have required the development of software solutions which could not be developed in time to address the Company's immediate needs.

Q. **Have you begun the process of putting such a system in place?**

A. Yes, we have. The Company has completed the RFP process and entered into negotiations for the purchase of such a system. We hope to have a workable solution in place by the end of the second quarter of 2012.

Calibration of Loads

Q. **Are any other adjustments applied to these data?**

A. Yes, the sample data is subject to an additional calibration adjustment. One of the recommendations made to the Utah commission by the Load Research Working Group was to calibrate load data to more closely mirror reported jurisdictional load forecast estimates. The calibration process is based on the expectation that the sum of base year class loads should equal the total forecast jurisdictional load estimates. The parties in the Group agreed that there are a number of unknowns occurring in the system that will prevent an exact match, losses being the primary example, but the Group felt that these class load totals should certainly fall within

±5 percent of the total. While not all parties to the Group agreed with this process, most parties, including the Division, indicated that the Company should implement a calibration process in its future filings Exhibit RMP___(SDT-1).

Q. Would you describe this calibration process?

A. Yes. The process employs a 10%-5%-2% look at the monthly data. First, if the sum of class loads in any given month differs from the forecast jurisdictional load estimate by more than 10 percent, that month will be subject to further investigation to determine the cause of the variance and necessary adjustments will be made. Second, if a monthly variance lies between 5 percent and 10 percent, the sample load data will be adjusted to a level sufficient to achieve a class load summation that does not exceed 5 percent. Last, if the result of the monthly 10 percent to five percent procedure results in an annual difference greater than two percent, the monthly calibration level will be lowered in an iterative process by 0.5 percent until the annual level of 2 percent is achieved.

Q. Is it possible that a specific month may exceed the 10 percent level even after calibration?

A. Yes it is. If the Company has made all reasonable efforts to determine that cause of a variance level in excess of 10 percent, and the variance is still in excess of 10 percent, the Company will automatically adjust the data to the 5 percent level.

Q. In this current filing, did any months require calibration?

A. Yes. For the 2012/13 test year, four months exceeded allowable percentage levels and required calibration. The four months were June 2012 (-7.4 percent), September 2012 (7.1 percent), October 2012 (-11.7 percent), and May 2013 (15.6

percent). June and September, whose required adjustment fell between 5 percent and 10 percent, were directly adjusted to the five percent level. The other months required a more iterative process.

Q. **Please describe that process.**

A. As each of these remaining months required an adjustment in excess of 10 percent, we first looked at utilizing base year loads on the respective base year system peak day but coincident with the test year peak hours.

Q. **What was the result of this comparison?**

A. The October difference decreased from -11.7 percent to -3.3 percent. This adjustment brought October to within acceptable calibration limits. A similar adjustment for May 2013 increased the difference from 15.6 percent to 16.1 percent. As this latter adjustment fell outside calibration parameters, additional steps were looked at.

Q. **What additional steps were investigated to adjust the May 2013 loads?**

A. I reviewed the relative time of month for the base year system peak occurrences relative to the same information in the test year. For May, the test year peak occurred on 14th, or the second Tuesday of the month. The corresponding base year peak date is May 10, 2011. With this in mind, I compared the base year loads for May 10th at 15:00, the time of the test year peak against the test year loads. The resulting difference was 16.1 percent.

Q. **Were there additional steps taken to resolve the May difference?**

A. Yes. As this comparison still resulted in a difference outside allowable calibration limits, we compared base year loads for May 10th at the time of the base year peak against the test year loads at the time of the test year peak. The resulting difference was 15.9 percent. Having completed what I felt to be all reasonable options at gaining a favorable result, and still falling outside acceptable calibration parameters, system peak day loads coincident to the forecast system peak time were directly calibrated down to the 5 percent level.

Q. You discussed an additional 2 percent adjustment may be required. Did you find it necessary to employ this additional adjustment?

A. No. Additional adjustments are required if the annual difference between the base year class load data and the test year forecast data exceed 2 percent. After applying the adjustments described above, the difference between these two metrics was 0.5 percent.

Q. Do you believe that load estimates prepared by the load research group, and adjusted to encompass the calibration techniques previously described, accurately reflect actual population usage for the Utah customers identified previously?

A. Yes I do. These estimates are prepared and reviewed following industry and the Company's own standard practices, as defined below.

a) All Utah load data samples incorporate stratified random design principles, which are the most commonly used sampling methods within our industry;
b) All Utah load samples are designed to meet or exceed the PURPA standard of ±10 precision at the 90 percent confidence level for the variable of interest, average system peak demand over the 12 month base period.
c) Samples are continuously reviewed to insure ongoing representativeness with the target population group. If samples continuously fall outside the acceptable limits, they are supplemented with additional sample points, or replaced.

All of these steps contribute to the reliability of the load estimates. As such, these estimates reflect a fair and accurate representation of the affected population's usage at the various defined periods of interest.

Q. Does this complete your direct testimony?

A. Yes, it does.