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

A. My name is David L. Taylor. My business address is 201 South Main, Salt Lake City, Utah, where I am employed as the Manager of Regulatory Affairs for the state of Utah.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a B.S. in Accounting from Weber State College in 1979 and a M.B.A. from Brigham Young University in 1986. I have been employed by Rocky Mountain Power or its predecessors since 1979. At the Company, I have worked in the Accounting, Budgeting, and Pricing and Regulatory areas. From 1987 to the present, I have held several supervisory and management positions in Pricing and Regulation.

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

A. Yes. I have testified on numerous occasions in Utah as well as in California, Idaho, Montana, Oregon, Washington, and Wyoming.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. In my testimony I provide the need and justification for the twelve months ending December 31, 2010 test period proposed by the Company in this case (the "Test Period").

Test Period

Introduction

Q. What test period did the Company use to determine revenue requirement in this case?

A. Rocky Mountain Power proposes to use a twelve month ending December 31, 2010, forecast test period with a thirteen month average rate base in this general rate case. In accordance with the Commission's Order on Motion for Approval of Test Period issued October 30, 2008 in Docket No. 08-035-38, it plans to file other material in the case on or about June 15, 2009.

Q. Why is a forward-looking test period necessary?

A. Robert Hahne, in his book *Accounting for Public Utilities*, states that "[T]he test period, by nature and by design, is a surrogate for conditions of the period of rate use and, to repeat, is presumed to be representative of future conditions." (7-11, Section 7.06.) This objective is captured in Section 54-4-4(3)(a) of the Utah Code which states:

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of evidence, best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.

It is typical for orders in general rate cases to become effective near the end of the statutory 240-day period provided under section 54-7-12(3) of the Utah Code. Based on the anticipated filing date of the full revenue requirement in this case, June 15, 2009, new rates will become effective on or before February 9, 2010. A forecast test period allows for better matching of costs with revenues during the rate-effective period. In order for rates to be based on costs to support

the financial integrity of the Company, it is essential to have rates set on costs that reflect the time period that the rates will be in effect.

A forecast test period is fundamental during a period of major construction and/or rising expenses. In the current environment, a future test period best reflects the costs the Company will necessarily incur in the rate-effective period to provide the level of service required by its customers. Although load growth in the Utah service territory has moderated somewhat in the near term, the Company expects load growth over the long term to continue. Planning to serve growing load requires the Company to acquire new generating resources. Significant new investments in transmission and distribution systems are required to integrate these new resources, connect new customers and ensure continued reliability. During this period of increased capital investment and rate base growth, a historical or near term forecast test period cannot adequately capture the conditions that the Company will experience during the rate-effective period; rather, use of a historical test period or a near term forecast test period would understate the true cost of service.

Q. What is the impact of "regulatory lag" on the Company?

A. "Regulatory lag" refers to the time difference between when costs are incurred and when they are included in rates. More than anything else, regulatory lag can be the result of the rate-making process, including test period selection. If new rates do not reflect the costs being incurred at the time the rates are in effect, regulatory lag is created.

Regulatory lag is a serious problem for the Company when rates are based on a time period other than the anticipated rate-effective period, especially when the Company is experiencing a steady upward trend in investments. Basing rates on a test period that doesn't reflect the true costs to serve customers during the rate-effective period gives poor price signals to customers while also effectively denying the Company a reasonable opportunity to recover the costs of providing service, including the opportunity to earn the return on investment authorized by the Commission.

Factors in Selection of Test Period

Q. Why did the Company choose the year ending December 31, 2010, as the Test Period?

A. As previously discussed, the primary objective of determining a test period is to develop normalized results of operations based on a period of time that will best reflect the conditions during which time the new rates will be in effect. Many factors must be considered to determine which test period best reflects those expected conditions. This Commission previously identified eight such factors,[1] including:

(1) the general level of inflation;
(2) changes in the utility's investment, revenues, or expenses;
(3) changes in utility services;
(4) availability and accuracy of data to the parties;
(5) ability to synchronize the utility's investment, revenues, and expenses;
(6) whether the utility is in a cost increasing or cost declining status;
(7) incentives to efficient management and operation; and
(8) the length of time the new rates are expected to be in effect.

[1] Order Approving Test Period Stipulation, Docket No. 04-035-42 (October 20, 2004); Order on Test Period, Docket No. 07-035-93 (February 14, 2008).

In its Order on Test Period issued February 14, 2008 in Docket No. 07-035-93, the Commission also expressed its desire to balance Company and ratepayer interests. The Company is proposing the Test Period in this case after consideration of the current regulatory environment, Utah statutes governing test period development, and the factors identified above by the Commission.

Q. Please describe how the Company considered the factors identified above in choosing the Test Period in this rate case.

A. Below is a brief discussion of the factors identified by the Commission and an explanation of how the Company evaluated its proposed Test Period based on these factors.

- **Level of Inflation** – While inflation is not a significant driver of the case, the Company is striving to absorb cost increases as much as possible. Indeed, certain inflationary pressures still remain and must be reflected in test period cost projections. Based on the latest Global Insight indices, non-labor costs for the utility sector are projected to remain relatively flat between 2008 and 2010. While the final projections for the case are not yet complete, net power costs and non-labor operation and maintenance expenses are anticipated to remain close to the levels reflected in current rates. However, the Company will still experience cost increases in some areas such as labor costs due to negotiated increases in many of its union labor contracts.
- **Changes in Utility Investment, Revenues, and Expenses** – Although load growth in the Utah service territory has moderated somewhat in the near term, Utah, notwithstanding the current economy, continues to grow and long term

load growth is expected to continue. Because of past, current, and future load growth, the Company will have to acquire new resources, impacting not only the level of investment needed to be included in rate base, but also retail revenues, net power costs and operation and maintenance costs. The impact of the Company's capital expenditure program will continue to put pressure on the Company's earnings even with the use of forecasted test periods.

This case includes Utah's portion of approximately three billion dollars in new plant investments the Company has made or will make between the December 31, 2008, historical base year and December 31, 2010, the end of the Test Year. Only a portion of the 2009 investment, and none of the 2010 investment, is included in the rates that will become effective on May 8, 2009. The failure to include this level of investment in rates will understate the cost of serving customers and put significant financial pressure on Rocky Mountain Power. I will provide a more detailed description of the current and projected major capital projects later in my testimony.

- **Changes in Utility Services** – No change in service levels is anticipated, however the Company continues to fund maintenance to allow the provision of safe and reliable electric service and meet our merger commitments.
- **Availability and Accuracy of Data to Parties** – The Company remains open and willing to share information with the parties involved in the case. The Company has agreed to provide, upon the terms of the 2008 general rate case stipulation, answers to Master Data Request A concurrent with filing of the other material and to Master Data Request B within 30 days after the filing of

the other material, with certain power cost information provided earlier than the 30 days. The Company is committed to responding to additional data requests from the parties in a timely manner.

The accuracy of data in our cases is supported by past variance reports which demonstrated that total Company actual non-power cost operations and maintenance expense levels were within 1% of the forecast level in the rate case and that rate base actually exceeded the rate case levels by $380 million. The variance report filed today confirms that the Company's forecasts continue to be very accurate. The table below shows some of the key comparisons from that report.

	2008 Actual Results of Operations		Docket No. 07-035-93	
	Total Company	*Utah Allocated*	*Total Company*	*Utah Allocated*
Dec 2008 Net Electric Plant in Service	11,598,762,742	4,923,524,138	11,214,380,125	4,899,787,009
Net Power Costs	1,120,615,735	460,797,538	1,014,284,026	424,118,555
Non-NPC O&M Expense	967,711,280	399,196,416	960,760,189	409,380,314

***Source: Company variance report filed April 30, 2009.*

There is no good reason to assume that a 12-month forecast would be any more likely to be accurate for that period than an 18-month forecast. The time periods are not significantly different in terms of forecasting. While a case could be made that a one-year forecast would likely be more accurate than a five- or ten-year forecast, the case is not nearly as strong for 12 months versus 18 months.

Even assuming a 12-month forecast would be more accurate than an 18-month forecast, it does not follow that a 12-month forecast would be a better predictor of costs that will be prudently incurred during the rate-effective period than an 18-month forecast. In fact, because we know that

major capital investments will be added during the 18-month period, it is highly likely that a forecast that includes those facilities in rate base during the period of time they are in service will be a more accurate estimation of costs during the rate-effective period than one that does not include them.

Other parties have suggested in prior cases that the most important criteria for test period selection is the accuracy of the data or forecasts during the test period. If this suggestion is taken to its logical extreme, it would always require the use of a historic test period because data from a historic test period is always going to be more accurate than data from a forecast test period. However, such a conclusion misses the point. As Dr. Alfred Kahn noted years ago,

> The fact is … regulatory commissions have always been in the business of projecting, whether they knew it or not. When they used historic test year statistics, fully verifiable and verified, graven in stone, as the basis of future rates, they were in fact projecting. They were assuming that the future would be similar to the past. It is no more speculative, then, to make the best possible estimate of future costs when setting future rates; and honesty compels its.[2]

The issue is not that data for a historic test period may be audited or may be certain. The issue is whether the data for the historic test period is a better predictor of the rate-effective period than a forecast for that period.

- **Ability to Synchronize the Utility's Investment, Revenues, and Expenses**

The synchronization or "matching" of a utility's revenues, expenses and investments in setting rates is a traditional rate making concept; however, it is one that cannot be viewed in isolation without taking into consideration the

rate-effective period. The goal in setting rates should be to set rates that properly reflect the costs that will be incurred by a utility during the period that the rates will be in effect. If the rate-effective period is not considered, then the process of matching revenues, expense and investments may capture interdependent impacts, but the result may not reflect the costs to be incurred during the rate-effective period. For example, a test period based on purely historical information may be properly synchronized between the revenues, expenses and investments included in the test period, but may have very little to do with the costs that will be incurred when new rates go into effect. When the test period does not properly match the rate-effective period, other regulatory tools have been used to adjust the test period to reflect the proper level of costs to be considered in new rates, including, year-end rate base, known and measurable adjustments (often one-sided, non-matching adjustments), and budget levels.

The Company will be proposing a 13 month average rate base for the test period. This is consistent with the Commission's direction in its Order on Motion for Approval of Test Period in Docket No. 08-035-08. The Company believes this is appropriate in this case because the test period corresponds quite closely with the first year of the rate-effective period. The rate-effective period is likely to start about 40 days after the start of the test period.

In the last case, the Company proposed a year-end rate base because its proposed test period did not correspond with the rate-effective period. In

[2] A. Kahn, "Between Theory and Practice: Reflections of a Neophyte Public Utility Regulator," *Public Utilities Fornighty* 29 (Jan. 2, 1975).

that case, the proposed test period was July 1, 2008 through June 30, 2009, but the rate-effective period did not start until March, 2009, (later changed by Commission order to May, 2009).

The important synchronization under the statute is synchronization between the revenue requirement determined for the test period and the costs that will be incurred during the rate-effective period. Notably, section 54-4-4(3)(a) requires the Commission to select a test period that best reflects the conditions that a utility will encounter during the rate-effective period. The purpose of using a test period is simply to attempt to predict the costs that the utility will incur during the rate-effective period. Synchronization of revenues, expense and rate base is only helpful if it achieves that end.

The December 2010 test period is the best way to reflect costs of serving customers and not understate them while providing the Company with an opportunity to recover Utah's share of approximately $600 million of total Company investments that the Company will make between July 2010 and December 2010. In addition, a December 2010 test year will also ensure that customer rates will more fully reflect the costs associated with the $1 billion in total Company investments made between January 2010 and June 2010. If a June 2010 test period is used, however, rates would only reflect between 1/13 and 6/13 of those investments. If that were the case, then additional alternative adjustments such as end-of-period rate base adjustments would need to be included in order to properly reflect the costs to serve customers

and to give the Company an opportunity to earn a reasonable return on those investments.

As previously mentioned, the most important element of matching is that the test period should reflect the costs that the Company expects to incur during the rate-effective period. As stated in *Accounting for Public Utilities* by Robert L. Hahne "If the period forecasted coincides with the period in which the new rates will be in effect, the matching of investment levels to operating results should produce the earnings levels authorized". (Hahne 7-5, Section 7.04).

In this case, the rate-effective period begins in February 2010. By adopting a December 2010 test period, the Commission would be adopting a test period in which approximately 10.5 months are aligned with the rate-effective period. In contrast, by adopting a June 2010 test period, the Commission would be adopting a test period in which only approximately 4.5 months would be aligned. In the 2008 General Rate Case (Docket 08-035-21), the Commission allowed for approximately 8 months of alignment of the forecasted test period with the rate-effective period (December 2009 test period with a May 8, 2009 rate-effective date).

- **Whether the Utility Is in a Cost Increasing or Cost Declining Status** – As discussed above, while some of the pressures of increasing costs on the Company have moderated in recent months, as a result of its capital investment program, the Company is still in a rising cost environment. This is

discussed in greater detail later in my testimony. In addition, the Company faces cost pressures from increasing labor costs and other costs.

- **Incentives to Efficient Management and Operation** – The Company management is continually looking for ways to increase the efficiency of the Company. The Company has reduced many costs related to employees and the overall number of employees; adjustments for these savings will be included in the proposed Test Period. The Company is adding investment to serve load growth and improve reliability and needs the level of investment included in the proposed Test Period. To not allow the proposed Test Period would be a disincentive to the Company in these efforts.

  Some parties have argued that regulatory lag provides an incentive for management efficiency because it forces management to cut costs in order to have the opportunity of recovering the Company's true costs of providing service to customers when rates are based on a period prior to the rate-effective period. The circular logic of this argument is dubious in any circumstances, but is particularly dubious in the context of a case in which the rate increase is sought to recover the costs of new investments which are necessary to provide reliable service to customers. The incurrence of prudent costs of major capital resources cannot be reduced by management efficiency.

- **Length of Time New Rates Are Expected To Be in Effect** – The Company has not made any decision on the length of time the new rates are expected to be in effect. Future rate cases will be filed based on Utah jurisdictional earnings and the Company's ability to get timely recovery of its costs. This

factor is best satisfied by setting rates that are expected to recover the true costs of providing service during the first full year that new rates are in effect.

Q. Should each of these factors be given equal weight by the Commission?

A. No. Certain factors will be more important at a given point in time than other factors. In this case, changes in utility investments should be given predominant weight

Capital Investments - Major Driver of this Case

Q. What is the primary driver of this case?

A. The main driver for this general rate case is the significant level of capital investment the Company is making on behalf of our customers. With this capital investment comes the need for rates to reflect the cost associated with generation, transmission, and distribution plants that will be in service during the rate-effective period. The following table shows, in round numbers, the level of total Company capital investment currently planned for 2009 and 2010.

PacifiCorp Projected Capital Investment	Capital Amount
January to June 2009	$850 million
July to December 2009	$800 million
January to June 2010	$1,000 million
July to December 2010	$600 million

The 2009 investment will be partially included in the rates that go into effect on May 8, 2009. Because a 13 month average rate base is being used in this case, rates based on a June 2010 test period will not reflect full recovery of the June to December 2009 investment that will be in service prior to the February 2010 effective date of new rates in this case. The proposed December 2010 Test Period will ensure that customer rates will more fully reflect the costs associated with the $1 billion in total Company investments made between January 2010 and

June 2010. If a June 2010 test period is used, however, rates would only reflect between 1/13 and 6/13 of those investments. The proposed December 2010 test period is the best way that rates will reflect any of the costs associated with the approximately $600 million of total Company investments to be made between July and December 2010, a period of time included in the first year of the rate-effective period.

Q. Doesn't the newly-enacted section 54-7-13.4 approved in Senate Bill 75 earlier this year remove the need to look forward a full 20 months as allowed by current statute?

A. No. The newly-enacted section 54-7-13.4 provides an alternative cost recovery for major plant additions. It allows a utility to start recovering the cost of a major plant addition at the time it is placed into service. The statute defines a major plant addition as "any single capital investment project of a gas corporation or an electrical corporation that in total exceeds 1% of the gas corporation's or electrical corporation's rate base." For Rocky Mountain Power, the threshold investment level is over $100 million. The table below shows the plant additions in excess of $20 million each scheduled to be in service by December 2010 that are either not included in current rates or, in the case of some past investments, are not fully included in current rates:

PacifiCorp Major Plant Additions	In-Service	Project Total
Glenrock III Wind Plant Project (39 MW)	Jan-09	$90 million
Rolling Hills Wind Project (99 MW)	Jan-09	$210 million
Camp WIlliams SVC Installation	Jun-09	$40 million
Oquirrh New 345-138kV Substation	Jun-09	$25 million
U4-Boiler Economizer/Low Temp SH Upgrade	Jul-09	$25 million
High Plains Wind Plant Project (99 MW)	Oct-09	$245 million
McFadden Ridge I Wind Project (28.5 MW)	Oct-09	$70 million
Chappel Crk 230kV Cimarex Energy 20 MW - Phase 1	Nov-09	$20 million
301 Turbine Upgrade HP/IP/LP (15MW)	May-10	$30 million
Dave Johnston Casper 230kV Rebuild	May-10	$40 million
Pinto 345kV Series Capacitors	May-10	$20 million
DJ U3 SO2 & PM Emission Cntrl Upgrades	May-10	$300 million
St George-Red Butte 138kV Line	May-10	$25 million
Three Peaks Sub: Install 345 kV Sub - Phase 2	Jun-10	$50 million
Ben Lomond - Terminal	Jun-10	$230 million
Huntington U1 Clean Air - PM	Nov-10	$90 million
HTN U1 Turbine Upgrade HP/IP/LP	Dec-10	$30 million

These large projects account for only half of the projected $3 billion investment over this time period. The Company's application in this case will also include other capital investments that are not as significant individually, but that together make up half of the investment that will be incurred prior to the end of 2010 in providing safe, reliable and adequate service to the Company's customers.

Only four of these projects meet the threshold in the major plant addition definition, two in 2009 and two more in 2010. No projects over the threshold level are included in the $600 million in plant investment scheduled to go into service during the July to December 2010 time period.

Q. Does Rocky Mountain Power plan to use the alternative cost recovery for major plant additions in the future?

A. Yes. The second phase of the Populus to Terminal transmission project, Populus to Ben Lomond, is not included in the table. It is scheduled to be completed near the end of 2010. It is not included in the table and will not be included in the application in this case for two reasons: First, the project may not be completed during the proposed test period. Second, the Company anticipates filing an

application under section 54-7-13.4 to start recovering the cost of this investment at the time it is placed into service. If the Company acquires new significant energy resources as part of a continuation of its 2008 Request for Proposals or its 2009 Request for Proposals and any of those resources come on line during the Test Period, the Company will also file an application under section 54-7-13.4 to recover the cost of those resources effective when they are placed in service.

Q. Given these capital investments, what would be the impact of choosing a test period that ends earlier than the Test Period proposed by the Company in this case?

A. Using a test period that ends significantly earlier than December 2010 would assure that customers will not pay and that the Company will not recover its actual costs of providing service during the rate-effective period. As I have previously testified, the driver for this rate case is the capital investments the Company has made and will be making through December 2010 in the facilities needed to serve its customers in Utah. These projects are in process.

For example, the Company has received a certificate of public convenience and necessity from the Commission for the largest of these projects, the Populus to Terminal transmission project. That project is now underway. The Ben Lomond to Terminal segment of the project that will cost approximately $230 million is scheduled for completion in June 2010. It is essential to provide service to Utah customers. Customers should pay and the Company should start recovering the costs associated with this project when it is placed into service. If an earlier test period such as July 2009 through June 2010 is used, only one-

thirteenth of the cost will be included in rate base. Yet, the first phase of the project will be in service for eight months of the first year of the rate-effective period. Thus, if the Commission were to choose a July 2009 through June 2010 test period, customers would underpay and the Company would be improperly denied recovery of over $7 million in revenue during the first year of the rate-effective period and annually thereafter until new rates are set that include the full investment in the Ben Lomond to Terminal transmission line. Conversely, a December 2010 test period would include approximately half of the investment during eight months of the rate-effective period.

Likewise, the Dave Johnston Plant emissions equipment upgrades in the approximate amount of $300 million will be completed and in-service in May of 2010. These upgrades are required to comply with environmental laws and are, therefore, necessary to operating one of the Company's significant generation resources. Use of a July 2009 to June 2010 test period would improperly deny the Company recovery of nearly $9 million during the first year of the rate-effective period and annually thereafter until new rates are set.

Although the sizes of the other individual capital projects are smaller, use of a nearer term test period would have the same effect with regard to recovery of legitimate costs of providing service during the rate-effective period. As shown in the table, $600 million of investment will be made in the last half of 2010. This investment will be in service during a portion of the rate-effective period. In sum, use of a test period ending June 30, 2010 would understate the cost of serving customers.

Impact of Economic Uncertainty

Q. Do you acknowledge that we are in a period of economic uncertainty?

A. Yes. There can be no debate that the current situation facing the economy in Utah, in the United States and in the world is very unusual and that this is a period of economic uncertainty.

Q. Does this economic uncertainty impact the Company's proposal to use a 2010 calendar-year test period in this rate case?

A. No. As I have previously testified, the driver for this rate case is the capital investments the Company has made and will be making through December 2010 in the facilities needed to serve its customers in Utah. These projects are either in process or will be in process regardless of any current uncertainty in economic conditions. A prime example is the portion of the Populus to Terminal transmission project that will be included in the case. That project is now underway. It is essential to provide service to Utah customers even if load does not grow during the next year or so.

The Company's major capital projects have long lead times. For example, the Populus to Terminal transmission project was first announced as part of the Energy Gateway project in May 2007. Even assuming the current recession continues through the first part of 2010 as some economists predict, it would be imprudent and unwise to cancel or defer the project.

The same reasoning applies to the other capital projects that are included in the 2010 test period. The current economic uncertainty does not affect the need for these resources.

Q. What about the potential uncertainty in customer loads based on current economic uncertainty?

A. The Company believes that its forecast of loads during the test period will be reasonable. The Company is carefully considering the current economic uncertainty in making its projection of loads during the Test Period. It is currently anticipated that those loads will be essentially flat. This will be explained more fully in the testimony that will be filed with the other material in the rate case.

Regardless, the impacts of potential incorrect forecasts with regard to load growth are relatively insignificant. When loads differ from those forecasted both revenue and costs change. In the case of a reduction in loads, lower electric sales would result in lower revenues collected which, when holding all other components constant, would increase the Company's revenue requirement. However, this is offset by the reduction in net power costs incurred by the Company. If the Company sells less electricity, its net power costs will go down as it does not have to produce or acquire the incremental electricity.

Q. Some parties have suggested in the past that the Company has complete discretion to make capital investments, implying that given the current economic downturn and the corresponding declining costs and load growth, the Company could choose to cut back. Would you like to comment?

A. The Company is making substantial capital investments for the future. In addition, the decision to acquire the current capital projects was made long ago, before anyone knew that we would be in this type of economic downturn. But

had the Company had a crystal ball, it would have continued planning for growth. We all know that just like there are economic recessions, there are long periods of economic growth. This area of the country, in particular, will continue to grow and the Company must be prepared for that growth. Granted that we have curbed our capital spending plan somewhat, but whenever it makes sense to continue to acquire projects, the Company will do so. It is short-sighted to allow temporary economic conditions to dictate your capital spend plan. The Company has to make responsible decisions.

Q. Would use of a historic test period be better given the economic uncertainty?

A. No. Use of a historic test period assumes that the conditions the Company will face during the period rates will be in effect in the future will be the same as those encountered during the historic period. Because of the major capital investments that have gone into service and will go into service by the end of 2010, we know that historic conditions do not represent the conditions that will be in effect from and after February 2010, when new rates resulting from this case go into effect. Therefore, there is no reason to assume that just because past costs can be known with certainty that they predict costs during the rate-effective period better than a forecast. Economic uncertainty does not impact this conclusion.

Q. Would use of a forecast test period extending only 12 months be more accurate than one extending 18 months during a period of economic uncertainty?

A. No. Just as we know a historic test period will not accurately reflect the rate-effective period because it does not include capital investments that will be in

service during the rate-effective period, a June 30, 2010 forecast test period will not include capital investments that will be in service during the rate-effective period. These investments will not be affected by economic uncertainty.

Conclusion

Q. What do you conclude?

A. The Company's proposed twelve months ending December 31, 2010 test period is the Test Period that is most likely to represent conditions during the period the rates set in this case will be in effect. The major driver of the Company's need for a rate increase is the capital investments the Company has made and will make through December 2010 to serve customers. These capital investments must be included in rates if the Company is to have a reasonable opportunity to recover its costs of providing service to customers including a reasonable return on its investments.

Q. Does this conclude your direct testimony?

A. Yes.