BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power For Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge	**)))))))))**	**Docket No. 07-035-93** **DPU Exhibit No. 1.0**

Direct Testimony of

Joni S. Zenger, Ph.D.

TEST PERIOD

For the Division of Public Utilities

Department of Commerce

State of Utah

January 25, 2008

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Direct Testimony of Joni S. Zenger, Ph.D.

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Joni S. Zenger. I am employed by the Division of Public Utilities of the Utah Department of Commerce as a Technical Consultant.

Q. What is your business address?

A. Heber M. Wells Office Building, 160 East 300 South, Salt Lake City, Utah, 84114.

Q. On whose behalf are you testifying?

A. The Division of Public Utilities ("Division").

Q. Do you have any attachments that you are filing that accompany your testimony?

A. Yes. Exhibit 1.1 lists the previous dockets and dates in which I have testified in Utah. Exhibit 1.2 documents the increased growth in residential usage and thus the need for new generation. Exhibit 1.3 identifies the plant additions that the Company has forecasted in the mid- and forecasted test periods. Exhibits1.4 and 1.5 shows the projected Company expenses and revenues forecasted for each test period in Utah and system-wide. Exhibits 1.6 and 1.7 show the increase in demand and energy, as well as the variance between the Company's actual and forecasted demand.

Q. Please describe your education and work experience.

A**.** I graduated with my Bachelor's degree and Master's degree Cum Laude from the University of Utah, both in economics. I began working for the Division of Public Utilities in the fall of 2000 and completed my Doctorate degree in economics from the University of Utah in early 2001. In addition, I have taught various economics and statistics courses for a ten-year period from 1996 through 2006, first at the University of Utah, and then at the University of Phoenix.

Q. Have you previously testified before the Commission?

A. Yes. I have testified on numerous occasions for the Division. As mentioned above, please see Exhibit 1.1 for a complete listing and dates.

II. PURPOSE AND RECOMMENDATION

Q. What is the purpose of your testimony that you are now filing?

A. My testimony presents the Division's position regarding the test period that should be used in this case. I also explain the principles, criteria, and factors that I used in this analysis to come to this recommendation. Finally, I discuss some additional safeguard issues regarding forecasting and reporting conditions should the forecasted test year be used in this or in upcoming rate cases.

Q. What test period does Rocky Mountain Power (the Company) propose?

A. In this rate case Rocky Mountain Power (the Company) proposes using a fully forecasted test period ending in June 2009 to support its requested rate increase of $161.2 million.

Q. What test year does the Division recommend be used for this rate case?

A. The Division has no objections to the use of the test period recommended by the Company ending June 30, 2009, subject to the conditions explained below. On the basis of the evidence in this particular case, we find the Company's proposed future test period is the most defensible test period to be used in this case, and it best reflects the conditions that the Company will encounter when the rates will be in effect.

Q. Notwithstanding the above, does the Division think that there may be instances when this test period must be adjusted by its auditors?

A. Yes. The Division believes that its auditors and other staff can appropriately adjust the test period proposed by the Company for any appropriate reason, including, but not limited to, forecasting issues. This could include bringing the expenses or rate base back to an earlier time period than proposed by the Company in the event of a forecasting error or due to a lack of sufficient evidence presented by the Company that would support the expense proposed.

Q. On January 11, 2007 the Division filed a pleading with the Commission indicating that it preferred waiting until the revenue requirement phase to present any arguments or evidence on the appropriate test year. Is the Division changing its position on this matter?

A. Not exactly. In our January 11 filing, the Division stated that we did not have sufficient time to make a full test year determination.[1] Due to the unique simultaneous filing of the PacifiCorp and Questar rate case and the somewhat novel nature of an *ex ante* test year determination in Utah, we did not think that we could present enough evidence to the Commission in this short of a period. Even having one rate case takes a considerable amount time to read through the entire filing and then to present data requests to the Company, let alone investigate and audit the data that we do have. Therefore, the Division thought it best to leave the test year determination until the revenue requirement phase of these proceedings, after we have analyzed more of the data provided by the Company.

[1] Notice and Statement of the Utah Division of Public Utilities Regarding Test Year, Docket No. 07-035-93, January 11, 2007.

However, the Division does not object to the test period being decided up front and is ready to present the evidence that time has allowed us to assemble. Additionally, the Division recognizes (and values) the benefits to the auditors and others working on the case to have that decision now.

III. BASIS FOR DETERMINING THE APPROPRIATE TEST PERIOD

Q. What is the basis for the Division's recommendation of a June 2009 test period in this case?

A. In determining the appropriate test period, the Division first identified certain principles that need to be considered: the outcome must balance the need to ensure that rates are just and reasonable while allowing the Company the opportunity to earn its allowed rate of return. Second, the appropriate test period must comply with Utah's statutes and previous Utah Public Service Commission (the Commission) orders. Considering the former, Section 54-4-4(3) of the Utah Code Annotated states the following:

> (a) 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, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.
>
> (b) In establishing the test period determined in Subsection (3)(a), the commission may use:
>
> (i) a future test period that is determined on the basis of projected data not exceeding 20 months from the date a proposed rate increase or decrease is filed with the commission under Section 54-7-12;
> (ii) a test period that is:
> (A) determined on the basis of historic data; and
> (B) adjusted for known and measurable changes; or
> (iii) a test period that is determined on the basis of a combination of:

(A) future projections; and
(B) historic data.

(c) If pursuant to this Subsection (3), the commission establishes a test period that is not determined exclusively on the basis of future projections, in determining just and reasonable rates the commission shall consider changes outside the test period that:
(i) occur during a time period that is close in time to the test period;
(ii) are known in nature; and
(iii) are measurable in amount.

Q. What other regulatory guidelines directed the framework for your analysis in this case?

A. The Commission issued an Order on October 20, 2004, as part of PacifiCorp's 2004 General Rate Case, approving the test period stipulation in that case (Docket No. 04-035-42).[2] In the 2004 Order, the Commission identified several factors that need to be considered in selecting a test period. The Division considered the factors identified in the Commission's Order, which are listed below:

- The general level of inflation;
- Changes in the utility's investment, revenues or expenses;
- Changes in utility services;
- Availability and accuracy of data to the parties;
- Ability to synchronize the utility's investment, revenues and expenses;
- Whether the utility is in a cost increasing or cost declining status;
- Incentives to efficient management and operation;
- Length of time the new rates are expected to be in effect.

[2] Order Approving Test Period Stipulation, Docket No. 04-035-042, October 20, 2004.

IV. IMPORTANCE OF PROPER TEST YEAR SELECTION

Q. Will you please explain your interpretation of the meaning of "test period" versus "test year?"

A. Yes. I have found that many people at times use these two terms interchangeably.[3] In the previously mentioned Commission Order, the Commission defined the test period as follows (bold added):

> A test period as used in traditional rate base, rate-of-return regulation is a twelve-month period of utility operations used in setting rates that, **when properly adjusted** will afford the utility a reasonable opportunity to earn its allowed rate of return.[4]

Another helpful explanation of the test period is described below by Lowell Alt, former Executive Staff Director of the Utah Public Service Commission:

> Since the revenue requirement is an annual figure, the data (costs, revenues and usage) used in its determination is based on a twelve-month period. This twelve-month period is termed the test period for a rate case.[5]

Once you have selected the test period that you will be using, then you have what results in the "test year." As I understand the difference then, the "test year" represents a measure of the operations and investment from some specified 12-month period. The test period is a measure of (or representative of) conditions during the period of new rates. In this case, the Company has proposed using the months starting with July 2008 and ending with June 2009 as the "test period" in this case.

Q. How does the selection of the test period affect the ratemaking process?

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[3] *Id*, see pp. 8-9.
[4] *Id*.
[5] Alt, Lowell E. *Energy Utility Rate Setting,* p. 25.

A. The selection of the test period is significant in ratemaking because, as stated above, the data used to determine the revenue requirement comes from whichever test period is selected. In Mr. Alt's definition above, I stressed the importance of "when properly adjusted" because these numbers are just the starting point. The Division's accountants will make adjustments beginning with the historical period and going through the forecasted test period.

Q. Are there alternative test periods that could be selected?

A. Yes, as stated above, the Company can select a test period based on historical results with known and measurable adjustments, or a fully forecasted test year, or a combination of the two. In the current environment of changing conditions, projected test year data based on reasonable forecasts should consistently come closer to expressing future conditions than historic data will. Many jurisdictions, including FERC, have recognized this fact and have adopted a forward view in evaluating revenue requirements.

The Company could have selected any 12-month period along the continuum of the dates that it filed up until the 240 days for the rate case to be completed, as long as the period did not exceed 20 months out from the date of filing. Those possibilities include, the mid-period (July 2007 – June 2008), or any of the following: (August 2007-July 2008), (September 2007-August 2008), (October 2007 – September 2008), (November 2007-October 2008), (December 2007-January 2008), (January 2008 -December 2008), (February 2008-January 2009), (March 2009 –February 2009), …etc. through the full twenty months, which the Company did file as the Future Test Period (July 2008-June 2009). The Division only has the data that the Company filed, and it would have exceeded the regulatory time frame to complete the case to look at every alternative. Therefore, we looked at what was filed in this case: the historical with adjustments, the mid-Period (ending June 2008), and the Forecasted Test Period (ending June 2009

Q. Do you consider regulatory lag an important issue to consider when determining the appropriate test period?

A. Yes, it can be an important consideration. First, it takes the Company several months to gather data and prepare a rate case. This could be approximately five months or more from the end of a historical test period to when the case is filed. Then, by the time the rate case is filed, according to the 240-day standard rate case calendar, much time has elapsed, and there can be a significant time lag before new investments are recognized, yet already paid by the Company. A future test year may enhance the likelihood the matching of revenues and expenses.

Q. Wouldn't regulatory lag or delay also affect ratepayers negatively?

A. Ratepayers might be disadvantaged if projects encounter some type of delay, resulting in ratepayers paying for projects not yet built or for which capital expenditures have not yet been made. Regulatory delay or lag can also adversely affect the public interest by hampering the progress and efficiency of the utility Company or by preventing ratepayers from receiving their share of the benefits flowing from progress and efficiency. For example, both consumers and the companies are harmed when the introduction of a new or improved service or technology is postponed or if the company is not allowed to operate efficiently because capital projects cannot be funded.

Q. What are the conditions in this case that warrant the use of a future test period?

A. A forecasted test period is appropriate in this case because jurisdictions such as Utah are experiencing high rates of growth in the demand for service, and therefore cost of service and revenue are likely to be significantly different during the rate effective period than during a historical or mid-period. In the next section, I present Utah's increased growth both in population, as well as residential customer demand and usage.

Q. Will you please provide an example of where increasing cost of service warrants using a forecasted test period?

A. For example, the demonstration IGCC plant (called FutureGen), which PacifiCorp partnered with the U.S. Department of Energy (DOE) and others, was initially estimated to cost $950 million. However, because construction and labor costs are now higher, with inflation, the project's price has increased to $1.7 billion.[6] In addition, the DOE found that prices for wind turbines increased by nearly 60 percent between 2002 and 2006.[7] There have also been dramatic increases in the cost of transmission projects, due to material costs, with the price of copper increasing by 160 percent, core steel by 70 percent, and concrete by 45 percent.[8]

V. THE DIVISION'S ANALYSIS AND FINDINGS

Q. After establishing the principles and criteria for the appropriate test year analysis, please summarize the work and findings of the Division.

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[6] Chupka, Marc and Basheda, Gregory, Rising Utility Construction Costs: Sources and Impacts, September 2007, p. 11.
[7] U.S. Department of Energy, Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2006, p. 16.
[8] Chupka, Marc and Basheda, Gregory, Rising Utility Construction Costs: Sources and Impacts, September 2007, p. 11.

A. First, the Division found that the Company's proposed forecasted test year ending in June 2009 generally complies with Utah's statutes: the test period does not exceed the 20-month date limit; the test period determination appears to be based on evidence which the Division will scrutinize and adjust as necessary; and based on that evidence, the test period best reflects the conditions that the utility will encounter during the rate effective period. Next, the Division looked at each factor that the Commission identified in its 2004 Order, as stated above, and applied them to this analysis.

Q. Will you please describe your findings with respect to the general level of inflation?

A. We face potentially significant inflationary pressures that warrant the need to look to the future for test period consideration. The U.S. Department of Labor has reported the Consumer Price Index (CPI) for December 2007 as well as for all of 2007. According to the report, consumer prices rose by 4.1 percent in 2007, the largest increase in 17 years. Core inflation, which excludes energy and food, rose 2.4 percent, down from the 2.6 percent increase in 2006. [9] Additionally, the Federal Reserve recently announced its decision to lower the Federal Funds rate by 75 basis points or ¾ of a percent in an attempt to ward off what it sees as a pending recession. In announcing this action, which is designed to "pump" money into the economy, the Federal Reserve acknowledged the potential inflationary pressures of its policy.[10]

Q. This question ties to another factor the Commission ordered to be considered when selecting the proper test period--whether the utility is in a cost increasing or cost declining status. Will you please comment on this?

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[9] "Inflation Hits 17-Year High." Deseret News, January 17, 2007.
[10] Board of Governors of the Federal Reserve System, Press Release, January 22, 2008, http://www.federalreserve.gov/newsevents/press/monetary/20080122b.htm

A. Yes. In fact electricity prices are outpacing inflation, much as they did in the 1970s, when the price of electricity was rising faster than prices in general. Interestingly, the reasons cited then for the increasing cost of providing electricity included inflation, rising fuel cost, increasing construction cost, and growth in peak demand—the same factors affecting today's electricity sector.[11] In Utah, we have seen a growth in peak demand, formerly in the winter months, but now during the summer cooling months. The table below comes from the Division's Data Request #1.3 and illustrates Utah's growth in peak demand. Peak demand in June 2006 was 3,788 MW and in June 2007 increased to 3,991 MW.

Month/Year	**Peak Demand (MW)**	**Month/Year**	**Peak Demand (MW)**
October-05	2,453	(continued)	
November-05	3,222	September-06	3,698
December-05	3,268	October-06	2,696
January-06	3,056	November-06	3,490
February-06	2,874	December-06	3,464
March-06	2,626	January-07	3,200
April-06	2,642	February-07	3,112
May-06	3,575	March-07	3,112
June-06	3,788	April-07	3,166
July-06	3,890	May-07	3,173
August-06	3,998	June-07	3,991

Q. Can you provide substantive data regarding the increasing costs?

A. Yes. To illustrate the changing costs that we currently face, the Energy Information Administration (EIA) estimated that average residential electricity prices will rise by 2.9 percent in 2007 and by 2.4 percent in 2008. Long-term estimates suggest that prices will also

[11] Uhler, Robert. The Rate Design Study: Helping Evaluate Load Management, "Public Utilities Fortnightly," Vol. 104, No. 8, October 11, 1979.

remain high due to the cost of fuels to power plants, including fuel oil, natural gas, LNG, and coal. The costs of construction materials used heavily in building new power projects, including steel, cement, concrete, and iron, have also increased sharply over the last few years. The prices for iron and steel have increased from 9 percent from 2002 to 2003, 9 percent from 2003 to 2004, and 31 percent from 2004 to 2005.[12] In addition, capital must be spent on new technologies such as customer information systems and automated meter readings. PacifiCorp anticipates the Company will spend approximately $42 million in both the mid- and future test periods in order to implement the automated meter reading technology.[13]

Environmental mitigation costs are and will continue to be greater than what was required historically. Inasmuch as our state produces the majority of our electricity by coal-fired generation, the state will be greatly affected by the yet unknown cost of meeting clean air regulations.

Q. You mentioned several times the customer growth and population growth that has created this demand for energy. What data do you have to confirm this growth?

A. The continued robust population growth in our state demands the need for system expansion. The following table contains a summary sheet on population growth from the Governor's Office of Planning and Budget (GOPB). Included are state population and projections from 2000 to 2010. The GOPB forecasts Utah's population to reach 2,833,337 by the year 2010. As of July 1, 2007, GOPB reports the current population at 2,699,554. Hence, the percent

[12] EIA's Annual Energy Outlook (2007), p. 36.
[13] SRM Exhibit 8.10.

increase between 2007 and 2010 is approximately 4.96 percent or about 1.7 percent per year between 2008 and 2010.[14]

Utah Population, 2000 – 2007

Data Type	Year	Population	% Change
Actual	2000	2,246,553	
Actual	2001	2,305,652	2.6%
Actual	2002	2,358,330	2.3%
Actual	2003	2,413,618	2.3%
Actual	2004	2,469,230	2.3%
Actual	2005	2,547,389	3.2%
Actual	2006	2,615,129	2.7%
Actual	2007	2,699,554	3.2%
Estimate	2008	2,744,148	1.7%
Estimate	2009	2,789,479	1.7%
GOPB Forecast	2010	2,833,337	1.7%

Total Population Projections (As of July 1, 2007)

Year	Total	Growth Rate
2000	2,246,553	
2010	2,833,337	2.3%
2020	3,486,218	2.1%
2030	4,086,319	1.6%
2040	4,701,369	1.4%
2050	5,368,567	1.3%

PacifiCorp has stated in its Integrated Resource Plan (IRP) that it needs to build additional generation, distribution, and transmission to keep up with the increased demand

[14] Governor's Office of Planning and Budget, 2005 Baseline Projections. Also, Utah Population Estimates Committee, http://governor.utah.gov/dea/UPEC/AllUPECData071115.xls

for electricity as well as the increase in the coincident peak demand. Exhibit 1.2 shows the increased residential customer use, with a 13.6% change from 2006 to 2007 based on the average of summer and winter usage. The average summer usage is increasing at a faster face than the winter average use by residential customers. On an energy basis, the Company forecasted a system–wide average load growth of 2.5 percent per year from 2007 through 2016. Utah load is projected to grow at an average rate of 3 percent per year.[15] Exhibit 1.3 illustrates the Company's projected plant additions through June 2009. This includes $1.9 million in generation, distribution and transmission plant during the mid-period, and another $1.3 million during the forecasted test period ending in June 2009.

Population growth implies both increased energy and demand. At the national level according to the EIA, electricity peak demand increased 65,529 MW from 2000 to 2005. Peak demand in 2007 was expected to rise to 760,840 MW in the United States—an increase of about 12 percent from 2000 to 2007.[16] In Utah the system peak occurs in the summer and is predicted to average 2.9 percent per year from 2006 through 2016.[17]

As far as load growth at the national level is concerned, U.S. electricity output in 2007 increased 2.8 percent over 2006, for the first time, surpassing 4 million GWh in a given year since the Edison Electric Institute (EEI) began compiling reports 75 years ago.[18] Utah's data reflect the same upward trend. For demand, the average demand for the 12 months through September 2006 is 3,258 MW, while the average demand for the 12 months through

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[15] PacifiCorp 2007 Integrated Resource Plan, p. 61.
[16] Energy Information Association, Electric Power Annual (2006), Table ES1, North American Electric Reliability Council, 2007, Table 32, and NERC, "2007 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2007), p. 11.
[17] PacifiCorp 2007 Integrated Resource Plan, p. 63.
[18] Edison Electric Institute, Press Release, January 4, 2008. www.snl.com

September 2007 is 3,514 MW. That is a 7.9 percent growth in year-to-year average demand. For energy, the total energy for the 12 months through September 2006 is 22,471,572 MWh, while the total energy for the 12 months through September 2007 is 23,833,218 MWh. That is a 6.1 percent growth in year-to-year total energy.[19]

Q. Will you please describe the changes in the utility's services as they pertain to test period selection?

A. I have noticed a great turn around in the type of service that is being used to provide electricity to our homes. The Company has announced plans to drop the coal-fired generation plant that it had previously planned to build to provide electricity.[20] The Company has also announced many wind projects that are either under way or will be in the near term.[21] The change is a shift away from supplying power via sources that emit greenhouse gases, to providing service using renewable or clean energy. Apparently, in part as a result of these changes, the IRP process faced considerable delays, as has the formal Request for Proposals process.[22] The Company is actively pursuing demand side management programs as well as energy efficiency programs. Again, the changing circumstances that the Company faces warrant a forecasted test period in this case.

Q. Have you been able to demonstrate how the utility's investment, revenues and expenses are synchronized using the Company's June 2009 test year?

[19] Using the most recent 24 months of actual, historical data (source: Tab 11 in June 2007 Semi-Annual report and DPU data request 2.5 spreadsheet) we are able to examine both demand (in MW) and energy (in MWh). The comparison we make is to examine the growth from year October 2005-September 2006 to year October 2006-September 2007.

[20] "Deseret News," January 20, 2007, p. G5.

[21] Presentation by Rick Walje, December 14, 2007, Utah Association of Energy Users.

[22] Memo to the Commission, from the Division of Public Utilities, January 23, 2007.

A. To a limited degree thus far. This is tied to another area of concern identified by the Commission in its 2004 Order approving a stipulation—the availability and accuracy of data to the parties. I have been able to review most of what the Company filed in the Master Data Request and Application. Again, the Company's forecasts will need to match up reasonably close to the actual results in order to validate the Company's data going forward. Exhibits 1.3 and 1.4 illustrate the Company's projected expenses and revenues both in Utah and system-wide, respectively. However, none of these results have been adjusted by the Division's accountants. Therefore, I would expect these numbers to change.

Q. There are two remaining factors from the Commission's Order that you have not discussed: (1)incentives to efficient management and operation and, (2) length of time the new rates are expected to be in effect. Will you please comment on each of these?

A. Yes, as previously mentioned, the Company will have its own self-interest served if it performs efficiently and if the Company's operational expenses are close to, or less than, the data that has been filed in this case as forecasted operations.

As far as the length of time the new rates are expected to be in effect, that could be anyone's guess. I have shown how the Company is in a dramatically increasing cost situation for the next several years. By supporting the Company's 20-month out test period, the Company can get the financing it needs to invest large amounts of capital into our aging infrastructure. The Company has inherent incentives to operate efficiently, cut costs where possible, and complete projects as forecasted in the event that, at some future time, the Company again files a general rate case using a forecasted test period.

VI. ACCURACY AND RELIABILITY OF FORECASTS

Q. Can you verify the accuracy and reliability of the Company's forecasts?

A. At this time, I have not verified every assumption or projection. However, I have been able to verify the accuracy of the Company's projections of Demand and Energy. Using the June 2007 Semi-Annual Report Tab 11 "CCS-DPU Reporting Commitments" (Tab 10) and the response from the Company to DPU Data Request #5, I created Exhibits 1.6 and 1.7 which shows the forecasted demand and energy compared to the actual demand and energy for both Utah and system-wide. The Company's forecasts were accurate within 3 percent in all instances, unless there was a weather-related event that caused the variance to be higher than projected. However, I would offer a word of caution. Although the variances between actual and forecasted demand and energy are small, the dollar effect may be quite large. As mentioned above, these issues can be addressed going forward through other auditing and analytical work that will be done.

VII. CONCLUSION AND RECOMMENDATION

Q. What is your recommendation in this case regarding test period issues?

A. Based on the principles and statutes, analysis to date, and the changes the Company is currently facing as described above, the July 2008-June 2009 forecast test period most closely reflects the conditions that the Company will encounter during the rate effective period. In order that regulators and interveners will have the opportunity to evaluate future projects and plans and to suggest alternatives, we will need access to the Company's forecasts and actual data going forward. The Division's policy witness will address this issue further in the revenue requirement phase of the case.

Q. Finally, are you also the Division's test year witness in Questar's rate case (Docket No. 07-057-13)? How is your testimony in this related to the Questar Testimony that you have filed?

A. I am the Division's test year witness in the Questar Gas case. In conducting my investigation of the PacifiCorp and the Questar Gas case, I referred to Utah's statutes which apply to both cases. In addition, basic forecasting principles apply to both cases. However, I considered each case independently of each other. The two dockets are completely different—one is an investor-owned electricity Company, the other affects only the distributed natural gas portion of a gas company that has operations involving exploration, production, midstream services and interstate transportation. To begin with, Questar Gas uses an entirely different forecasting methodology (a top-down approach) than the methodology as described by Steven R. McDougal in this docket. The electric and gas utilities have entirely different plant additions—in the Questar Gas case, only the distribution portion of the gas company pertains to the case; in this docket, generation, transmission and distribution plant all represent capital expenditures. There are numerous other differences in the two cases, which are mostly obvious. The cases are similar in that both represent increasing cost industries, yet each has entirely different projections and assumptions. The Commission's 2004 Order gave further insight into instances such as the current situation where the Division is investigating two simultaneous rate cases:

> Each case needs to be considered on its own merits and the test period selected should be the most appropriate for that case. The

> test period selected for a utility in a particular case may not be appropriate for another utility or even the same utility in a different case.[23]

Q. Did you select the appropriate test period for the RMP case on its own merits?

A. Yes, the forecasted test year ending June 2009 is the most appropriate test year for this RMP case irrespective of the Questar Gas case.

Q. Does this complete your testimony?

A. Yes it does.

[23] Order Approving Test Period Stipulation, Docket No. 04-035-042, October 20, 2004.