BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF QUESTAR QUAS COMPANY TO INCRESE DISTRIBTUION NON-GAS RATES AND CHARGES AND MAKE TARIFF MODIFICATIONS	**)))))))))**	**<u>Docket No. 07-057-13</u>** **<u>DPU Exhibit No. 1.0</u>**

Direct Testimony of

Joni S. Zenger, Ph.D.

TEST PERIOD

For the Division of Public Utilities

Department of Commerce

State of Utah

January 28, 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 shows Questar's 2006 Forecasted Results of Operations compared to the Actual Results, as well as the variance.

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 relevant factors that I used in this analysis to come to this recommendation.

Q. What test period does Questar Gas Company propose?

A. In this rate case Questar Gas Company (Questar or the Company) proposes using a fully forecasted test period beginning on July1, 2008 and ending on June 30, 2009 to support its requested rate increase in the amount of $26,966,000.

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, 2008 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 Questar and Rocky Mountain Power rate cases, 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.

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.

[1] Notice and Statement of the Utah Division of Public Utilities Regarding Test Year, Docket No. 07-035-93, January 11, 2008.

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.

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.[2] 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.[3]

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.[4]

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 twelve months starting with July 1, 2008 and ending with June 30, 2009 as the "test period."

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

[2] Order Approving Test Period Stipulation, Docket No. 04-035-042, October 20, 2004. pp. 8-9.
[3] *Id*.
[4] 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 auditors 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. The Company filed, in this general rate case, based on a fully forecasted or forward looking test year.

Q. What is the effect of regulatory lag when determining the appropriate test period?

A. Regulatory lag may be an important consideration. As QGC Exhibit 1.2 illustrates, there is a 240-day standard time period in which it takes to process a rate case from the date of its filing, until the Commission issues an order on the case. Sine it takes the Company an additional several months to gather data and prepare its case, there could conceivably be another five months added to the 240 days before the rate effective period begins. Since the test period is designed to represent the conditions that the utility will face during the rate effective period, the time lag of five to eight months can be significant. The company's conditions could have changed dramatically in that time. For example, if the company plans to invest capital in replacing aging infrastructure, there could potentially be a significant amount of time before the company's investments or expenditures are recognized. When costs are increasing and capital investment is required, a future test year may enhance the likelihood of matching revenues and expenses by minimizing regulatory lag or delay.

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 capital expenditures which 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.

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, where the Company projects material changes expected to take place in 2008 and 2009 both in rising costs and customer growth. The Company will face increased costs to serve projected new GS1 customers estimated to increase by 19,000 each year. In addition, the Company must budget for considerable investment in plant and upgrades to the infrastructure over the next five years. Therefore, cost of service and revenue are likely to be significantly different during the rate effective period than during a historical or mid-period. A future test period narrows the gap between costs and revenue—first, because the costs of new facilities are typically higher than the historical costs of existing facilities. Second, past levels of investment may not reflect future requirements because of future growth or other regulatory or financial constraints.

There are several factors that are especially relevant in this case, including--the need for feeder line replacement and upgrades to capital projects, the growth in the number of customers, along with the corresponding growth in peak-day demand, and the need to maintaining pipeline integrity—all of which justify the use of a future test period. As I discuss below, due to more stringent Department of Transportation pipeline safety requirements and the need for increased capacity, the Company has accelerated the pace of the feeder line replacements projects that have been planned and budgeted for.

In this current environment of changing conditions, projected test period data based on reasonable forecasts should more closely reflect the future conditions that the utility will experience than historic data will. The changing circumstances that the Company appears to face depart from the status quo and necessitate using a future test period in this case.

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

A. Yes. Last year, Questar completed a project that replaced about 14.4 miles of feeder line that had been in service since the late 1940 to 1950s. The pipe had aged, had once been reconditioned, and was finally replaced with a larger, high pressure and higher delivery capacity pipe to meet growing customer demand. This project, called Feeder Line 26, ran from Payson to Orem and took four years to complete. The total cost of this project was $24.9 million.[5]

Next year the company plans to replace another 16 miles of feeder line running across the Salt Lake Valley under 3300 South and 3500 South, as well as two or three other major projects. The Company claims that it will need to spend approximately $45 million annually for the next five years just on feeder line replacements. As a result of these capital requirements, the total capital budget will increase from $95 million to about $135 million

[5] QGC Exhibit 5.14, line 5, Docket No. 07-057-013.

each year for at least the next five years.[6] This is an approximately 40% change to the Company's capital budget. These costs need to be considered on a forward-looking basis, as a historical test period would not adequately match the Company's projected expenditures and revenues to the conditions of the rate effective period beginning in August 2008.

V. THE DIVISION'S ANALYSIS AND FINDINGS

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

A. The Division found that the Company's proposed forecasted test period ending in June 2009 generally complies with Utah's statutes: (1) the test period does not exceed the 20-month date limit; (2) the test period determination appears to be based on evidence which the Division will scrutinize and adjust as necessary; and (3) based on that evidence, the test period best reflects the conditions that the utility will likely encounter during the rate effective period. Of course, the Division believes that the accuracy and reliability of the Company's forecasts is of major significance in predicting the utility's future conditions. Finally, the Division also considered various other economic factors as they applied to this case.

Q. Will you please describe your findings regarding customer growth and customer usage?

[6] QGC Exhibit 2.0, Direct Testimony of Alan K. Allred, pp. 11-12.

A. According to the Company's Master Data Request A.04, the number of Questar customers has grown anywhere from 18,000 to 26,000 and is forecasted to continue grow at the same pace.[7]

	Actual Amounts		Forecast Amounts		
	2005	2006	2007	2008	2009
Customer Additions	30,330	26,095	22,338	18,983	19,476

Using QGC Exhibit 5.13, the number of customers demanding service has increased each year, but as illustrated below, at a decreasing rate since 2005.

Number of Customers Added Each Year[8]

		Change From Previous Year	% Change
2002	18,154		
2003	20,286	2,132	11%
2004	24,217	3,931	16%
2005	29,892	5,675	19%
2006	25,532	-4,360	-17%
2007	22,718	-2,814	-12%

The total number of Questar customers as of December 31, 2007 was 873,000. The Company estimates that at the end of the test period at June 30, 2009, the total customers will have increased to 896,000 in number.[9] Supporting this growth is the fact that Utah's population continues to grow. The Governor's Office of Planning and Budget (GOPB) forecasts Utah's population to reach 2.8 million by the year 2010 or about a 1.7 percent per

[7] QGC Master Data Request A.04.
[8] Direct Testimony of Alan K. Allred, Exhibit 2.2.
[9] Direct Testimony of David M. Curtis, p. 10; also QGC Exhibit 5.13.

year increase between 2008 and 2010.[10] As far as residential customer growth is concerned, one would expect a decrease in the number of new customers in 2007. This is due to the fact that in Utah, only 9,877 building permits were issued for single-family homes along the Wasatch Front—a 36 percent decrease in permits from the previous year. Local builders took out the fewest number of residential construction permits in 14 years. [11] Nevertheless, the Company tends to average between 25,000 to 30,000 new customers each year, which it must plan for.

Q. If the number of customers are increasing at a decreasing rate, then why the increase in customer demand?

A. First, even though new residential customer usage has decreased, the Company has announced plans to add a large industrial customer that will come online during the test period. This will require planning and an adequate supply to serve the new large customer. Although usage is declining per customer, the peak demand of existing and new customers has increased. The Company must meet daily and peak demand for natural gas in every extreme weather condition. According to the Company, demand can vary from 90,000 Dth per day in the summer months to 1,163,000 Dth per day in the winter heating months.[12] As an example, in January 2006, the peak demand for GS1 customers reached 15,142,022 Dth. However, in January 2007, the peak climbed to 17,870,798 Dth.[13]

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

[11] Lee, Jason. Builders took a hit in 2007, Deseret News, January 19, 2008, p. D14.
[12] Direct Testimony of Alan K. Allred, pp. 2-3; also QGC Exhibit 2.1.
[13] Questar Master Data Response MDR A-4.

Questar forecasts that it will spend $646.8 million in 2008 through 2012 to invest in infrastructure to meet growing demand. To put this into perspective, the Company spent $791 million in all of the years from 1998 through 2007.[14] This is a dramatic departure from historical spending of past periods.

Q. Will you please describe how the general level of inflation might effect the test period selection?

A. The U.S. Department of Labor 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. [15] 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.[16] Questar calculates its forecasted capital budget using an inflation rate of 2.5% on general plant and for most operating expenses.[17] The relevance here is that we face potentially significant inflationary pressures that are not representative of the past and that warrant the need to look to the future for test period consideration.

Q. Does the fact that Questar is in a cost increasing status affect the test period selection?

A. Yes. If the cost status of the company were somewhat steady, then the future rate

[14] Questar Gas Presentation to the Utah Association of Energy Users, January, 2008, p. 4.
[15] "Inflation Hits 17-Year High." Deseret News, January 17, 2008.
[16] Board of Governors of the Federal Reserve System, Press Release, January 22, 2008, http://www.federalreserve.gov/newsevents/press/monetary/20080122b.htm
[17] Questar Master Data Response MDR A-4.

effective period might look similar to the historical or base period. However, in a cost increasing or decreasing industry, the future will not reflect the conditions of the past. Questar claims that the Company's capital expenditures will increase from $95 million per year in 2007 to a forecasted $135 million per year for the next five years.[18] This is a dramatic increase, indicating that the forecasted or future test period would more closely reflect future conditions than a past test period.

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

A. Yes. As described above, the primary driver of the cost increase is the need to replace feeder line. The company has budgeted $45 million per year beginning in 2008 and through 2012 for feeder line replacement projects.[19] In addition, the costs of construction materials, including 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.[20] There have been recent regulatory actions at the federal level that have added significant operating and compliance costs that the Company must incur, although some, but not all, of these costs are placed in a deferred accounting order. First, the Pipeline Safety Improvement Act of 2002 was signed into law on December 17, 2002.[21] The federal legislation mandates new pipeline integrity management programs for transmission pipelines. The law applies to natural gas transmission pipeline companies and requires each pipeline operator to prepare and implement an integrity management program, identify high consequence areas on their systems, conduct risk analyses of these areas, perform baseline integrity assessments of each pipeline segment, and

[18] Direct Testimony of Barry McKay, p. 4, lines 81-83.
[19] Direct Testimony of Alan K. Allred, p. 11, lines 305-306.
[20] Energy Information Administration Annual Energy Outlook (2007), p. 36.
[21] http://ops.dot.gov/library/docs/107_cong_public_laws.pdf

inspect the entire pipeline system according to a prescribed schedule and using prescribed methods. Companies are required to complete necessary remediation plans by December 17, 2008 for high consequence areas and by 2012 for non high consequence segments. This process must be repeated on a seven-year cycle.

Another piece of legislation, The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, was also passed and confirms the federal commitment to the Integrity Management Program and other programs enacted in the 2002 legislation.[22] Questar has, as a result, aggressively accelerated its feeder replacement projects and has also contributed to legislatively mandated multi-agency programs of research, development, demonstration and standardization to enhance the integrity of pipelines. These are all costs that Questar has incurred and will continue to incur as a result of the legislation. Similar federal requirements for distribution lines are also being considered by Congress and the U.S. Department of Transportation.

The Energy Information Agency (EIA) has estimated the cost of legislation's new requirements to natural gas pipeline companies alone to be $11 billion over 20 years.[23] However, because the law allows the Office of Pipeline Safety discretion in the assessment methodologies, the cost of implementation according to its specific rules could be considerably less, although still substantial—about $4.7 billion over the twenty-year period

[22] http://ops.dot.gov/regs/PIPES_Act_of_2006_PL109_468.pdf
[23] http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/pubsafety.html.

or approximately $0.036 per thousand cubic feet for the first-year implementation costs.[24] Similar federal requirements for distribution lines are also being considered by tar:

Q. Have you been able to analyze the Company's investments, revenues and expenses as filed using the Company's proposed June 2009 test year?

A. I have been able to review most of what the Company filed in the Master Data Requests and Application, but have not yet had access to confidential portions DPU Data Requests that I need in order to fully analyze the company's expenditures. The Company's budgeting methodology is based on a top-down approach. The Company prepares a five-year plan, where the first year is based on historical data with known and measurable adjustments. Years two through five are based on forecasts adjusted for general inflation, wage inflation, customer growth, planned projects, etc. For this case, the Company has taken the budgeted amounts developed by managers according to operations, workforce, and capital and spread them into FERC accounts as determined by Questar witness Kelly Mendenhall.

Since feeder line replacement is the largest driver in this case, I have some concerns that I have not yet verified regarding the $45 million estimate for each year going forward five years. According to Data Request 2.03, the replacement costs for completed projects are as follows:

[24] Department of Transportation, Research and Special Programs Administration, Final Rule, Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), Docket No. RSPA-00-7666; Amendment 192-95; RIN 2137-AD54, pp 157 ff.

Years	Pipeline #	Length (Feet)	Location	Cost	Cost per Length
2006 - 2007	12	4,300	West SLC	2,476,645	$576
2006 - 2007	18	12,251	South Weber	2,541,159	$207
2004 - 2007	26	76,061	Utah Co.	24,854,761	$327
2007	7	93,400	SLC State Street	25,074,000	$268
Total		186,012		54,946,565	$295

Since the type of pipe used for each project most likely varies, and the materials and nature of each feeder line is unique, the costs per length of feeder line show no relation. The average cost for the completed projects in this period, however, was $295 per feeder line foot. According to QGC Exhibit 5.14, the projected cost of feeder line projects for the next five years is $45 million annually. The projects are listed by type, but do not identify what “other” means. The forecast for 2008 projects are listed below, with an average cost per foot of $525 (not including “other”):

Years	Pipeline #	Length (Feet)	Location	Cost	Cost per Length
2008	11	64,389	SLC 3500 So.	45,000,000	Cost per Length
	5	13,829	SLC 3500 So.		
	4	7,482	SLC 3300 So.		
	Other				
Total 2008		85,700		45,000,000	$525

The forecast for 2009 projects, excluding “other” are listed below on the next table, showing an average cost per length of $1,252.

Years	Pipeline #	Length (Feet)	Location	Cost	Cost per Length
2009	19	35,948	Ogden	45,000,000	
	11 (Finish)		SLC 3500 So.		
	Other				
Total 2009		35,948		45,000,000	$1,252

Forecasts through 2012 are listed below by project with average cost per length $1,772, $807, and $1,995 for years 2010 through 2012, respectively:

Years	Pipeline #	Length (Feet)	Location	Cost	Cost per Length
2010	12	7,076	West SLC	45,000,000	
	29	732	Brigham, Box Elder		
	18	7,497	South Weber		
	14	10,091	Tooele		
	Other				
Total 2010	**73**	**25,396**		**45,000,000**	**$1,772**
2011	21	1,085	Layton	45,000,000	
	25	54,658	Pleasant Grove		
	Other				
Total 2011		**55,743**		**45,000,000**	**$807**
2012	41	19,040	Middle Canyon	45,000,000	
	35	3,035	Butterfield Canyon		
	28	599	Logan		
	Other				
Total 2012	**104**	**22,674**		**45,000,000**	**$1,985**

Obviously the Division intends to further investigate the costs of the feeder line replacements and how the feeder line costs can vary so dramatically. I have no dispute with the Company's need to invest in the infrastructure over the next five years. The Company is working to comply with federal legislation and to ensure the public interest by providing safe service. However, the

Division has not adequately reviewed the costs or made accounting adjustments to the data. For example, in response to the Division's Data Request 3.01, the Company responded that for the year 2003, Feeder Line 26 had an actual cost of $6,555,780.60 compared to the budgeted amount of $10,000,000.00, a difference of $3,444,219.40.[25] The difference was reported due to a delay in getting the permits needed from the U.S. Forest agency. As we continue to receive responses to data requests, the Division and its auditors will continue to make any adjustments to the data as warranted.

Q. Do you believe that using the Company's forecasted test year ending June 2009 in this case will have any material impact on the Company's incentives to efficient management and operation?

A. No, I do not. By setting rates properly, the Company is allowed an opportunity to earn its allowed rate of return. As described many times over in Alan K. Allred's Direct Testimony, the Company has been exemplary in its performance and service benchmarks. The Company has not filed for a rate case since 2002, and it claims that part of the reason for this is due to the Company's efficient operations. If past performance is a reliable predictor of future performance, I would expect that the Company would continue to strive to be efficient and work to improve its operations. 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.

Q. Does the length of time the new rates are expected to be in effect have any bearing on the test period selection in this case?

[25] QGC Response, January 16, 2008 to DPU Data Request 3.01.

A. Only in regard to the fact that the Company's capital expenditures are increasing each year for several years. I have shown how the Company is in a dramatically increasing cost situation for the next several years. If a test period that is not projected out to the full 20 months from the filing date is used, I would expect to see a rate case filed before the end of the current year—2008, which may not be the best use of resources, both for the Company and for regulators and interveners. This is due to the fact that, by the time the rates went into effect for this rate case in August, 2008, the Company would need to immediately file the next rate case in order for the conditions of the utility to match the rate effective period. Otherwise, each case is to be analyzed on its own merits, independent of any other rate case.

In addition, the Pilot Program for the Company's Conservation Enabling Tariff (CET) expires on October 5, 2009; so I would expect to see a rate case filed that would capture the CET tariff or in order for the Company to continue it.[26]

VI. ACCURACY AND RELIABILITY OF FORECASTS

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

A. The Exhibit provided by Questar witness Barry McKay suggests that the company has accurately forecasted system sales and usage from 2002 through 2006.[27] Statistically anything below 5% is considered acceptable. In his results, most of the variances were in the tenths of percentages, with one exception at 2.9%. Mr. Curtis' QGC Exhibit 5.2 also shows that the company's forecast are reasonably close to actual results of operations. The Company has not filed for a general rate increase since 2002. However, I was able to

[26] Commission Order, November 5, 2007, Docket No. 05-057-T01, p. 15.
[27] QGC Exhibit 1.3.

compare the Utah Forecasted Results of Operations for the 12 months ending December 31, 2006 filed by the Company on April 11, 2006 and compare the data to the Actual Results of Operations for the same period filed on April 26, 2007, in order to construct my Exhibit 1.2 and to calculate the variances. This exhibit shows that the Company has been very close in forecasting its results of operations to the actual results. As time goes on and there is actual data that was previously forecasted, the Division will be able to compare the Actual Results of Operations with those forecasted in this case to determine if the results are still relatively close. At this time, the Division's auditors are currently verifying other assumption and adjustments. 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 the Rocky Mountain Power rate case (Docket No. 07-035-93)? 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 Rocky Mountain Power case. In conducting my investigation of the Questar Gas and the Rocky Mountain Power cases, 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 very different in many ways, including the forecasting methodology used and in the applications themselves—one affects only the distributed natural gas portion of a gas company that has operations involving exploration, production, midstream services and interstate transportation, while the other is an investor-owned electricity Company. In the Questar case, only the distribution portion of the gas company pertains to the case; in Rocky Mountain Power's case, 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.[28]

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

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 Questar in this case, irrespective of the Rocky Mountain Powers case.

Q. Does this complete your testimony?

A. Yes it does.