**Exhibit QGC 1.0R**

**BEFORE THE**
**PUBLIC SERVICE COMMISSION OF UTAH**

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| Questar Gas Company | ) | Docket No. 02-057-02 |

**REBUTTAL TESTIMONY OF**
**ALAN K. ALLRED**
**ON BEHALF OF QUESTAR GAS COMPANY**

October 4, 2002

**Q. Please state your name and business affiliation.**

A. Alan K. Allred. I am Senior Vice President of Questar Gas Company. I hold the same position with Questar Pipeline Company and Questar Regulated Services (QRS).

**Q. Have you previously submitted direct prepared testimony in this case?**

A. Yes.

**Q. What areas will your rebuttal testimony address?**

A. I will discuss some of the issues raised by the other parties that deal with important policy matters and have a significant effect on the financial and operational aspects of Questar Gas Company.

I must note at the outset that my rebuttal testimony, as well as that of the other Company witnesses, is oriented around the previously filed positions of the parties. The Company has had extensive discussions with the Division and the Committee concerning their positions and the Company's. I am hopeful that these discussions will result in a substantial narrowing of the apparent gaps among the parties. Therefore, although there are encouraging signs of eliminating some issues or reducing the distance between the parties on others, it is necessary for this rebuttal case to address the issues as originally presented by the parties direct cases.

**Q. Now that you have reviewed the recommendations submitted by the Division of Public Utilities (Division) and the Committee of Consumer Services (Committee), what is your general reaction to their proposals?**

A. Although a part of the Division's approach provides a foundation for a more even-handed treatment of determining rates for the Company's utility services—particularly its adoption of a year-end 2002 test year—the overall position filed by the Division would put the Company financially further behind in its ability to serve customers and earn a fair return for its investors.

Worse, however, are the Committee's overall filed proposals which, if adopted, would drive any rational investor—either current or prospective—running for the nearest exit. They would cripple the Company's ability to serve existing customers and make it impossible to attract the capital to serve Utah's growth. The Committee's essentially unadjusted historic 2001 test year uses data that will be 12-18 months out of date by the commencement of the 2003 rate-effective period; this is completely contrary to foundational principles of utility ratemaking. It is preposterous to suggest that mid-2001 conditions reasonably represent the conditions currently facing QGC—much less the conditions in 2003.

In my view, the Committee has made no effort to make a connection between its test-year proposals, the conditions the Company will be facing in 2003, and the effects their positions would have on Questar Gas's ability to serve customers. They appear to have chosen an average historic test year because, for a utility such as Questar Gas, this approach produces lower rates, not because it fairly represents the conditions that the Company will face during the rate-effective period.

I believe it is completely out of line to propose a "remedy" that would reduce the utility's annual revenues by $11-14 million when the Company is *currently* earning financial returns at or below 9% on equity. The Committee's position simply would not produce enough revenues for the Company to provide adequate service to Utah customers.

**Q. Please elaborate on your general view of the Division's position.**

A. The Division does acknowledge the need to change the test-year practice in this case and has employed the same 2002 end-of-year test period that the Company has proposed. The Division's position represents real progress on this issue, and I urge the Commission adopt this test year.

However, with this step forward, the Division's case-in-chief advocates a revenue-requirement outcome that approximates the same level of revenues that was reflected in the Commission's decision in the 1999 rate case. Although less draconian than the Committee's position, it falls far short of providing the revenues necessary to match costs that will occur during 2003.

For example, the Division advocates including revenues from Geneva Steel Corporation based on information that Geneva is attempting to resume operations in 2003. Recognizing that there is no current gas usage at the Geneva plant, the Division argues that the Commission should base its final determination on what is known by the time the order is issued in this case—presumably in November or December. The same Division witness who suggests this approach also advocates that *mid-year* 2002 usage-per-customer levels be used to set rates for 2003. If the most current information on Geneva is to be used by the

Commission, shouldn't the most current information on usage per customer also be used? There should not be one standard for items that increase the revenue requirement and a different standard for items that decrease the revenue requirement.

The Division's positions on bad-debt expense, IRC section 29 tax credits, gain on sale of property and depreciation exhibit a similar inconsistent approach that tends to lower the test-year revenue requirement. To the extent they can be reasonably expected to occur, *all* of the conditions the Company will face in 2003 must be fairly incorporated. The Division's position only goes part way in this regard and is, therefore, not adequate.

**Q. What would the effect on QGC's 2003 financial results be if either the Division's or the Committee's position is adopted?**

A. If the Committee's position were adopted, QGC's credit rating would likely be reduced, and the Company's ability to provide quality utility service would be in serious jeopardy. Although not as severe as the Committee's, the Division's position would leave revenues at current levels, but the ongoing decline in usage per customer would continue to erode the level of revenues actually received. In addition, expense increases would further reduce QGC's financial results. As a result, the long-term effects would be similar to, although somewhat less severe than, those resulting from the Committee's position.

**Q. How can this result be avoided?**

A. I believe it is imperative that the Commission re-examine some of its past regulatory policies. The combination of an unadjusted historical test year, low allowed returns on equity and disallowance of necessary business costs have put QGC in the impossible position of being unable to cover the costs of serving customers (including a reasonable return on investment).

**Q. You have previously testified that QGC's previous reaction to these policies has been to reduce costs, increase efficiency and to reduce the array of services it once provided. Why can't this practice continue?**

A. There are limits to how often you can go to that well. Past efforts to increase productivity and reduce costs have reached their practical limits. For example, the Company cannot implement additional employee-reduction strategies without significant service degradation. Further major steps to reduce costs would have significant negative effects on customer service. In setting rates, the crippling effects of the declining usage per customer and increasing investment must be fully taken into account.

**Q. You have previously testified that QGC's returns since the last general rate case in Docket No. 99-057-02 have not been adequate. Please elaborate on this point in view of the Committee's and Division's positions.**

A. First, in discussing the information that investors consider in making their investment decisions, it is important to recognize the distinction between "regulatory return" and "financial return." As required by the Commission, QGC files its Report of Operations on a semi-annual basis. This report contains what is generally referred to as a "regulatory return," which is determined by adjusting the Company's actual operating experience to reflect a variety of regulatory policies. For example, the earned return is calculated by eliminating certain actual costs that the Company incurs, but which the Commission has decided are not entitled to rate coverage. It also includes an adjustment to incorporate average rate base for the prior 12 months, rather than the Company's then-current investment in rate base. And, these reports and returns do not accurately reflect the then-current level of average usage by residential customers, but rather a value that lags actual experience. In recent years, this has caused a distortion in what the Company is actually earning at the time of the report.

"Financial returns," on the other hand, incorporate what the accounting industry considers as generally acceptable asset, revenue and expense reporting. These are the actual returns earned and reported to the investment community at large, and they are what investors consider in making investment decisions. Indeed, it is "real" financial reporting—or the lack of it—that has captured news headlines over the past year. To be fully informed to make rational investment decisions, investors look to the Company's actual financial results and returns; they do not ask if its returns produce acceptable numbers after being adjusted for regulatory policy.

Some may respond to this distinction by claiming that all the Company has to do is conform the actual costs to those allowed in rates. In many cases, this is not possible, because many disallowed costs are actual costs necessary and customary for any business to operate effectively.

**Q. With that background, explain QGC's returns for the years since the last general rate case.**

A. On a regulatory basis using average historical test years, the achieved returns approach within 50 basis points or so of the 11% equity return authorized in Docket No. 99-057-20. However, actual financial returns seen by investors have remained in the 8% to 9% range for 1999 through 2002. Adoption of the main thrusts of the Division or Committee positions would cause QGC profits to continue to languish at levels that are well below that of other companies, including gas LDCs with whom QGC competes for capital. This is unfair not only to QGC but to our customers as well. No utility can continue to provide adequate utility service in this situation. Either investors will take their capital elsewhere or continued cost cutting will cause service to deteriorate to unacceptable levels. I believe that modifying regulatory policy to provide rates that are reflective of costs that will be incurred in the rate effective period and providing a real opportunity to earn a more competitive rate of return is a better solution for customers.

## TEST YEAR

**Q. In Exhibit CCS 2.0, Hugh Larkin testifies for the Committee that the Commission should adopt an average historical 2001 test year for setting rates in this case. Why do you believe this proposal is improper?**

A. No party has disputed that the rate-effective period in this case will begin about January 1, 2003, and continue until general rates are modified in a subsequent case. Mr. Larkin's proposal to use an average, historical 2001 test year, with little or no adjustment for subsequent "changes reasonably expected" would establishes rates *one and a half years out of date* by the time new rates would be made effective. This position is directly contrary to any rational application of the theory of utility ratemaking. I know of **no** utility regulatory agency in this country that takes this approach.

Because the Committee's average historical test year is so far removed from a legal foundation and practical application of proper utility ratemaking, the Company declines to address the various "adjustments" that the Committee claims to have made to its average historical 2001 test year.

In particular, the Committee has made no attempt to establish that its historical 2001 test year in any way provides a reasonable model or approximation to the conditions that will exist on the Company's system in 2003. Its approach is blind to the conditions of an increasing number of customers, increased need for new investment to serve them properly and customer usage that has already declined materially since mid-2001, with prospects to diminish further.

The Committee ignores this deadly combination and doggedly advances a proposal that is, at best, punitive and quite probably ruinous to the Company. At best, rates based on a historical 2001 test year will almost automatically produce an annual $10 – $15 million shortfall, even at the currently authorized return on equity of 11.0%. This in turn would lead to an equity return 200-300 basis points short of whatever base rate of return on equity that the Commission will authorized. No utility can survive and continue to provide adequate service under such conditions.

**Q. In Exhibit CCS 3.0 and accompanying exhibits, Committee witness Donna DeRonne has proposed a variety of adjustments to the Company's filing under two sets of assumptions: average 2001 test year and partial future 2002 test year. What is QGC's general response to these adjustments?**

A. As I have just noted, the Company rejects in its entirety the Committee's average 2001 test-year approach to setting rates for 2003. Accordingly, we will not address the various individual issues that the Committee raises that are tied to that approach, but rather address the issues that the Committee raises in its discussions of the 2002 test year.

Ms. DeRonne does propose a variety of adjustments to the 2002 test year. The composite result of these proposals would still have the Commission reduce the Company's rates by over $11 million per year. This recommendation simply does not properly reflect the conditions QGC faces and, if implemented, would have one of two effects: Either (a) the Company would be financially crippled, would become an investment pariah, and would be unable to raise necessary capital, or (b) it would be forced to undertake serious reductions to the levels and quality of gas utility service in Utah, or both. In short, it would be a financial disaster for the Company, a service disaster for its customers, and likely the beginning of the end of gas service provided by a long-time Utah company—indeed, the last major Utah-based utility company.

**Q. What is your understanding of the Committee position on the 2002 test year?**

A. Even when Ms. DeRonne focuses on the 2002 test-year period, she proposes a collection of adjustments that produces an unfair, one-sided result that would place QGC in an untenable financial position.

To begin with, even when the Committee focuses on the year 2002, it essentially "rolls back" by six months its determination of the annual revenue requirement by employing an average test year. It compounds the problem by incorporating the usage-per-customer level from the beginning of 2001. This is the equivalent of setting rates for 2003 and possibly beyond on the basis of conditions existing on or before July 1, 2002. Although this improves on use of the 2001 historic test year somewhat, it purposefully ignores currently available information and reasonably expected changes, and it seriously mismodels the conditions expected during the rate-effective period.

**Q. Summarize your view of the Committee's general approach to determining the revenue requirement in this case.**

A. The Committee has made no showing that either its average 2001 test year or its average 2002 test year reasonably approximates the conditions that will be in effect in 2003 and beyond. To the contrary, its analysis is designed to retard the Company's ability to generate enough revenues during the rate-effective period to meet its commitments to its customers, employees and investors. Continued application of this approach under today's conditions will invariably set rates below the levels of costs that are, in the terms of the Utah statute, "reasonably likely to occur" during the test year. This, I believe, is neither a proper nor legal approach to setting utility rates.

## GAIN ON SALES OF PROPERTY

**Q. Division witness Tom Peel and Committee witness Ms. DeRonne have proposed adjustments to the 2002 test year to include as utility revenues (above-the-line) the gain from certain properties that were sold in 2001—$313,000 and $617,000, respectively. Do you agree with these adjustments?**

A. No, for two reasons.

First, as a matter of fundamental utility regulation, I believe that property the Company purchases to provide utility service belongs to the Company's owners. Although the utility has an obligation to acquire and utilize the property prudently and in the public interest, it generally has the right to dispose of its property as it sees fit when it is no longer used and useful for utility service.

In that regard, the Company's customers do not have ownership rights to the property any more than I have any ownership in Ford Motor Company's assets just because I buy a Crown Victoria. The prices of the products or services we buy from both companies will generally include the same kinds of cost components: O&M, taxes, return *of* capital (depreciation) and *on* capital (for investors), etc.

So far as I know, the Commission has never issued an order in a QGC or Mountain Fuel general rate proceeding in which the Company was required to reflect the gain on sale of assets as an above-the-line item to be credited to rates, nor—conversely—to incorporate any loss on a sale of property as a ratemaking element that would increase rates.

But, in this case, even if I were to be wrong about this history, many of the gains included by the Division and Committee do not belong in the 2002 test year. They were sales made in 2001. Had they been recorded above the line, the Company would have justifiably removed them as one of the normal adjustments to be made to the basic 2001 results to make them conform to the 2002 condition.

Only if the Company had made, or planned to make, similar such sales in 2002 on an ongoing, regular basis would their inclusion be proper for the 2002 test year. To put it another way, to the extent that these sales occurred in 2001 and 2001 data form the basis for the 2002 test year, they would have been routinely removed as not "reasonably expected" to occur in the test year.

The basis of Mr. Peel's adjustment is in his statement: "When there is a rate case, only the gains realized during the test year would be included for ratemaking." (Exhibit DPU 4.0, page 8.) He goes on to claim that gains should be amortized over a three-year period as a way to share the gain between customers and the Company.

The Division's analysis and presentation is founded on the *2002* test year. And, under Mr. Peel's theory, only gains occurring during the test year should be included. Even under Mr. Peel's share-the-gain approach, "Between rate cases, realized net gains accrue fully to the benefit of the shareholders." The 2001 sales were between the test years for the two rate cases.

## USAGE PER CUSTOMER

**Q. Both the Division and the Committee have proposed that the revenues for the 2002 test year be adjusted to reflect higher GS class usage per customer than is reflected in the Company's case. First, outline these proposals relative to the Company's position.**

A. QGC based its 2002 test-year revenue deficiency in part on a projection of average GS class usage per customer to the end of 2002. This was a partial projection that was obtained by considering actual average usage per customer through March 2002 and projecting this index to the end of the year. Mr. Robinson's direct testimony describes the process by which the Company calculated that annual usage per customer will be 116.16 Dth by year end. (Exhibits QGC 4.0, page 23; QGC 4.5, page 2.)

More recent usage-per-customer information through June 2002, which has been delivered to the parties in the case through data request responses, corroborates the Company's original projection of 116.16 Dth.

The Committee's approach to the 2002 test year, through the testimony of Mr. Larkin and Ms. DeRonne, incorporates a usage per customer of 120.64 Dth. This is, in effect, the level of usage per customer that the Company was experiencing at the end of 2001—a full year before the end of the 2002 test year. The Division, through Mr. Peel, has used the figure of 117.0, which is the actual value of annual usage per customer for June 2002.

**Q. What is your understanding of the justification for the use of the mid-2002 or end-of-year 2001 figures?**

A. In general, that the recent decline in gas costs will result in a smaller decline in usage per customer in the future.

**Q. Do you agree with this reasoning?**

A. Yes, but it is already included in the Company's position on this issue. This can be seen from looking at my Exhibit QGC 1.9. This exhibit shows that the Company's projection of year-end 2002 usage per customer reflects a significantly lower rate of decline than a straightforward projection of the results of between 1999 and 2001 would produce. The decline in gas costs was a major factor that the Company's projection took into account. If any gas-cost increase were to occur in the future, the inclusion of this factor likely *overstates* the level of usage per customer.

**Q. What is the effect of the Division's and Committee's positions on the determination of the Company's revenue requirement in this case?**

A. The Division's adjustment from 116.16 to 117.0 translates to a reduction of about $1 million in the annual revenue deficiency. The Committee's adjustment from 120.6 produces a swing of over $4 million.

Thus, the "sensitivity" of the annual revenue requirement to this variable is approximately $1.3 million per Dth. This emphasizes the importance of using the best information available at the time rates are established to prevent wide variations in actual revenues relative to the test-year revenues.

**Q. Are there other aspects of the usage-per-customer issue?**

A. Yes. David Nichols has testified on behalf of the Utah Energy Office (UEA) concerning demand-side management (DSM) issues. Mr. Nichols directly raises the issue of fair treatment of a utility that would be involved in implementing DSM programs. Clearly, when a utility's rates are fixed on the basis of a specified average usage per customer, a "successful" DSM program will produce a revenue shortfall for the utility company, and the company will be penalized for participating in what would have been set forth as a desirable public-policy goal.

There is, therefore, a common thread that connects the Division's, Committee's and UEA's proposals: If customers do not achieve the usage per customer that is built into the determination of rates, there will be a major shortfall in revenues to the Company.

**Q. What has been the magnitude of this issue over the past several years?**

A. As shown above, the Company's revenues are extremely sensitive to determining the usage per customer accurately. One of the reasons for the Company's inability to achieve acceptable financial returns over the past four years is that the usage per customer curve has been in sharp decline after the establishment of rates in the Company's last two major rate proceedings (Docket No. 95-057-02 and 99-057-20). Exhibit QGC 1.12R shows the results for the past four years with a comparison of usage per customer as incorporated in the then-effective rates with the actual usage per customer experienced by QGC.

For successive six-month intervals, the table shows the annualized shortfall in GS revenues attributable solely to the departure of actual usage per customer from the value used to determine rates. Because of generally declining usage, the shortfall builds up until rates are reset, and then begins to grow again as average usage resumes its downward trend.

Exhibit QGC 1.12R shows that the failure of actual average usage to agree with the value used to set rates has resulted in a combined three-year revenue shortfall of **$31 million**.

**Q. What do you propose to deal with the usage-per-customer adjustments proposed by the Division and the Committee and by the UEA's DSM issue?**

A As Exhibit QGC1.12R dramatically shows, the Company's poor revenue performance the last several years can be attributed in major part to the continued decline of usage per customer after rates have been set. The Company has regularly sought to reflect this downward trend when rates are determined, but in the last two cases, the continued slide of this key ratemaking element has put the Company behind in its ability to recover its costs.

QGC's near-term projections have generally been quite close to what actual results have turned out to be. As I discussed above, the latest data substantiate the projection that was incorporated in the May 3 filing. Nevertheless, it is not always possible to predict usage per customer with precision. To the extent that projections do vary substantially from actual results, there can be major variation from test-year revenues. Yet, in a general rate case, the use of a historic value is itself a *prediction* that the same level of usage will occur in the rate-effective period. Recently, this has been detrimental to the Company, although under other circumstances, the swing could go in the Company's favor.

Because of this volatility and the occurrence of usage-per-customer trends that are difficult to predict, QGC supports Mr. Nichols's suggestion of a tracking mechanism, and it strongly recommends the implementation of a "usage tracker" that would neutralize these effects. This would include a specification of the average GS usage ("normal" usage) for each of the 12 months of a calendar year.

Mr. McKay describes such a usage tracker in his rebuttal testimony.

**Q. In summary, what do you see as the major features of a usage "tracker?"**

A.

- It removes the determination of the average usage per GS customer as a rate-case hot-button issue that generates a fairly high level of emotion and, often, hostility. As such, it allows the Company to focus on the aspects of utility service over which it has control and where true efficiency gains can result in rewards for both customers and shareholders.
- It protects the customers from the possibility that usage-per-customer

trends may suddenly reverse and provide a major revenue benefit to the Company.

- It protects the Company from the serious financial problem that occurs when the regulatory process does not adequately forecast and implement a reduction in average usage per customer.

- It removes a major disincentive for the Company to engage in DSM programs if or when those become a desirable public policy. Without such a tracker, a utility would, in effect, be cutting its own throat to encourage reduced usage under the current ratemaking regime.

## RETURN ON EQUITY

**Q. The Committee is recommending a 10% allowed return on equity, the division is at 10.5%. How do you view these returns?**

A. These recommendations, as well as those of Professor Williamson, are based in large part on similar financial models. But, it is actual outside investors who must provide the investment capital necessary for Questar Gas to continue to meet the growing needs of customers. They will make the decisions on where and at what rate they will invest. Those investors have choices, and I believe it is instructive to look at some of those choices.

Q. **What have other state commissions recently authorized as equity returns for the LDCs they regulate?**

A. There are a significant number of gas LDCs with allowed returns on equity in the 11–13% range. Exhibit QGC 1.13R lists such LDCs and shows that the average of recent authorized equity returns is 11.32%. In addition many of these companies have a demonstrated ability to actually earn their allowed returns.

Let me add a few details on a couple of companies. Alabama Gas has an allowed ROE of 13.15% to 13.65%, just established in June 2002. It also has the benefit of a gas-cost pass-through mechanism, weather normalization and an annual adjustment that changes rates up or down each year to insure that the actual earned return stays within the 13.15-13.65% range. In Wisconsin, Wisconsin Gas just received a general rate case order that set the allowed return at 12.3%. In many states, gas LDCs are regularly allowed to exceed the established return if they can do so by operating efficiently.

**Q. What are the allowed returns established by the FERC for interstate natural gas pipelines?**

A. The allowed returns for interstate pipelines established by the FERC are currently in the 12% to 13% range. This is significant because the straight fixed-variable (SFV) rate design approved by the FERC recovers nearly all costs, including the allowed return, in the demand component of rates. This is in sharp contrast to QGC, where 94% of its non-gas costs are fixed costs, but over 70% of total costs are collected through usage-based rates.

**Q. What significance does this information have in this case?**

A. Although some may argue that pipelines have risks that LDCs do not, LDCs have risks that pipelines do not. It is still an important general comparison to make, because it illustrates the options available to an investor who is looking for a regulated return on equity investment.

Given this choice of investment opportunities, the equity returns recommended by the Committee and the Division fall short of the return available to investors in other gas LDCs and pipelines. Why would a rational investor choose to invest in Questar Gas Company if the Commission adopts either the 10.0% or 10.5% recommendations? Higher returns with comparable risk are readily available elsewhere. In that regard, I believe that both the Division and the Committee positions fail the *Hope* and *Bluefield* tests.

**Q. What about claims that QGC is less risky than other LDCs?**

A. The investment community does not agree. They are concerned about Questar Gas's ability to earn a competitive return. The single-digit financial returns on equity over the past three years speak far louder to the investment community than the arguments advanced by the Division and Committee witnesses. Investors may not understand the devastating inter-workings of declining usage per customer, historic test years and increasing investment requirements of serving new customers, but they do understand the poor financial results those factors produce. They are not willing to remain for a repeat performance of the past few years. They are looking for a change in the regulatory procedures that provide a reasonable return and a fair opportunity to actually earn that return. Their expectation is for higher not lower achieved returns. Recent commission decisions in other states are starting to show this trend, as shown in Exhibit QGC 1.13R.

## RATE DESIGN

**Q. Some witnesses in this case have proposed that more costs than are in QGC's allocation proposal be shifted to large-volume industrial customers. Do you agree with these proposals?**

A. Generally, I do not. Although I believe that costs should ordinarily be assigned or allocated to the customers who cause those costs to be incurred, one must also be aware of the possible negative effects of pricing some customers out of the market.

In our case, shifting more costs to the industrial transportation customers may well cause them to find cheaper alternate ways to deliver gas to their operations.

**Q. Do you have any experience with proposals to shift more costs to the large-volume customers?**

A. Yes. In the early 1970s, total sales to large-volume interruptible customers in Questar Gas's (then Mountain Fuel's) Wyoming service territory significantly exceeded the residential and small commercial load. Cost allocation methodologies then were similar to those now used by QGC in Utah. Those customers made significant revenue contributions to cover distribution system costs in Wyoming. In general rate cases before the Wyoming PSC, various parties proposed changes in cost allocation that shifted significant costs to the interruptible classes. The Company argued vigorously against such cost shifting, because it knew that these customers had other energy choices and that residential and small commercial rates would be subject to higher rates if the industrial customers left the system. Despite these concerns, the Wyoming Commission increased the costs assigned to the interruptible rate schedules.

Q. **What happened?**

A. The customers left the system by directly connecting to intrastate or interstate pipelines or by building their own pipelines. In 1974 these customers purchased about 18 million Dth from Mountain Fuel. By 1988, that load had fallen to less than 500,000 Dth. It rebounded somewhat from 1990-95, but has remained less than one million Dth since 1997. Exhibit 1.14R shows these volumes. As a result, nearly all costs of the system are now borne by the residential and small commercial class. The interruptible load that remains is a small fraction of what was once served. The attempt to lower residential rates by assigning more costs to interruptible customers failed, and the residential/commercial share of costs actually increased as a result of the interruptible load that was lost.

**Q. How does that experience apply to Utah?**

A. Although I believe there is the potential for the same result. The large-volume interruptible transportation customers in Utah have other alternatives. Many of the largest customers could by-pass Questar Gas by connecting directly to interstate pipelines. Attempts to shift substantial costs to these customers will ultimately result in higher costs for residential and small commercial customers just as it did in Wyoming.

## SUMMARY

**Q. Please summarize the outcome that Questar Gas Company seeking in this case.**

A. In order to continue to serve customers at proper levels of service, Questar Gas Company needs a change in regulatory practice. As I explained in my direct testimony, the combination of declining usage per customer, the need to increase investment to serve new customers, and rates set on out-of-date cost and revenue elements threaten the financial viability of Questar Gas and its ability to continue to provide safe, reliable gas service. The Company cannot maintain its ability to provide gas service to customers if equity investors continue to see single-digit returns. The practice of purposely imposing regulatory lag through the use of historic test years, the disallowance of legitimate business costs, and failure to recognize the huge revenue impact of declining usage per customer puts Questar Gas in an impossible position. This problem is compounded by the practice of setting the authorized equity return at or near the low end of the reasonable range expected by investors, while higher-yield investments are available in other regulated utilities.

The needed rate relief is modest. A increase of less than 5% in total rates, or about $2.75 per month per residential customer, will allow Questar Gas to continue utility service at the levels customers deserve and provide reasonable returns to investors. No one wants to increase rates, but a rate increase is necessary to allow utility service to continue.

**Q. Does that conclude your rebuttal testimony?**

A. Yes.