BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders	Docket No. 05-057-T01

SURREBUTTAL TESTIMONY OF BARRIE MCKAY

FOR QUESTAR GAS COMPANY

August 14, 2006

QGC Exhibit SR 1

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Q. Please state your name and business address.

A. My name is Barrie L. McKay. My business address is 180 East First South Street, Salt Lake City, Utah.

Q. Are you the same Barrie L. McKay that filed direct testimony in this docket?

A. Yes, I am.

Q. Would you please provide an overview of the Joint Application?

A. The Joint Applicants have requested that the Commission allows the Company to aggressively pursue energy efficiency by approving the Conservation Enabling Tariff and Demand-Side Management Pilot Program. National, state and local support for accelerating adoption of programs to promote energy efficiency has continued to gain momentum subsequent to filing the Joint Application. The Joint Applicants ask the Commission to remove the barrier that discourages the Company from aggressively pursuing energy efficiency. The effect of the Conservation Enabling Tariff and energy-efficiency savings provides a net benefit to all customers. This is a direct result of the current and projected high market prices for natural gas. The Joint Applicants believe that following approval of the Conservation Enabling Tariff and Demand Side Management Pilot Program the Commission and the Division will have the requisite tools to perform their regulatory roles.

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. The purpose of my surrebuttal testimony is to respond to eight major areas discussed in rebuttal testimony or raised by Commission Staff in this docket. The eight areas are:

1) Demand-Side Management (DSM) – How the Joint Applicants' proposal will work and why it is in the public interest;
2) Full Decoupling – Why this was chosen by the Joint Applicants as the preferred option;
3) Return on Equity (ROE) – Why any adjustment to the Company's allowed ROE is not appropriate in this proceeding;

4) New Options – The Committee of Consumer Services' (Committee) witness Mr. Dismukes presents three "new" options. These options were considered and rejected by the Allocation and Rate Design Task Force or the Working Group that continued to meet following the Task Force Report[1] (For purposes of my testimony, my references to "Task Force" include the Working Group);

5) The "minimum requirements" of the Committee's "alternative recommendation" – These requirements have already been addressed by the Joint Application and should not be adopted;

6) Miscellaneous issues raised by the various parties;

7) Response to the Commission Staff's questions asked in the June 7, 2006, Technical Conference; and

8) Summary.

1. DEMAND-SIDE MANAGEMENT

a. Overview

Q. Based on the filed testimony in this proceeding, does it appear that all parties support DSM?

A. Yes. The Joint Applicants are proposing to implement DSM programs in conjunction with the Conservation Enabling Tariff (CET) as part of a three-year Pilot Program (Pilot Program). Committee witness David Dismukes, Utah Ratepayers Alliance (URA) witness Elizabeth Wolf and, to a lesser extent, Utah Association of Energy Users (UAE) witness Kevin Higgins, all express support for cost-effective energy-efficiency programs.

While these rebuttal witnesses appear eager to support the concept of DSM, they seem unwilling to take the steps necessary to really achieve the savings that cost-effective DSM

[1] The Task Force met from January 2003 until June 2004 when the Task Force Report was filed. From June 2004 through December 2005 the Company, Division, Committee and other interested stakeholders continued to meet and produced several White Papers.

programs will provide customers. My direct testimony and the Joint Application presented annual gas-cost savings of $18-20 million that can be realized for the benefit of all customers as a result of cost-effective DSM. No party in this docket has contested these potential savings. Those opposing the Pilot Program are trying to divert the Commission's attention to the minor issues related to non-gas revenue. My testimony will show that a 1% per year reduction in customer usage over five years will result in net gas-cost savings for sales customers of over $32 million in the fifth year after reflecting projected non-gas-cost amortization of DSM program costs and the CET, with an aggregate savings of $86 million over the five-year period. My testimony will refute the objections raised by other parties to the Pilot Program. The Company urges the Commission to weigh the benefits of immediate savings to customers and the regulatory safeguards inherent in the use of a pilot program, and approve the CET.

b. Criticisms of Joint Applicants' DSM Proposal

Q. Do the three rebuttal witnesses support the Joint Applicants' proposal for DSM programs?

A. No. While the rebuttal witnesses appear to support DSM, witnesses Dismukes and Wolf both criticize the Joint Applicants for not having a more definitive DSM plan. While the State of Utah, the U.S. Department of Energy, the DSM Task Force and other interested stakeholders advocate removing the barrier to promoting energy efficiency, Mr. Dismukes and Ms. Wolf are the only ones that argue for implementation of DSM prior to removing the barrier.

Q. Do you believe that these are valid criticisms?

A. No. The Company is proposing to implement a meaningful level of funding for DSM programs this year and then ramp up funding over the course of the Pilot Program to levels that will provide significant energy-efficiency programs to customers. The steps required to achieve this objective will require the Company to dedicate significant resources in terms of time, funding and expertise. The Company's commitment to DSM is evidenced by its role in leading the DSM Working Group; the assignment of a full-time experienced Questar Gas employee to coordinate the Company's efforts; and contracting with Nexant, Inc., an industry leader in DSM evaluation and implementation. The DSM Working Group will propose specific cost-effective DSM programs for Commission approval. The Company has also proposed to transfer funds from its research and development account to jump-start DSM programs. Additionally, it is proposing to increase annual contributions to the Low-Income Weatherization Assistance Program (LIWAP).

c. DSM Working Group

Q. What is the DSM Working Group?

A. The Company, in December 2005, organized the DSM Working Group, made up of Utah Clean Energy, Southwest Energy-Efficiency Project (SWEEP), the Division, Committee, URA, Governor's Office, LIWAP, Department of Natural Resources, Commission Staff and Rocky Mountain Power to address natural gas DSM. The Company has received extensive input from many parties during the DSM Working Group meetings. Utah Clean Energy, a Joint Applicant in this docket, and their industry partner SWEEP have brought expertise and experience to the process that has been invaluable. The Committee and Division have DSM experience through their involvement in the PacifiCorp Demand-Side Resource (DSR) process and have also made significant contributions. Ms. Wolf, with URA, has been an active participant in demand-side issues in Utah for many years. The State of Utah has been an active participant via the involvement of Dr. Laura Nelson, Office of the Governor; Mike Johnson, Utah Low Income Weatherization Assistance Program; and Philip Powlick, Utah State Department of Natural Resources. Commission staff members have been actively involved, and their experience and support for DSM are much appreciated. Finally, Rocky Mountain Power has been supportive of the Company's efforts.

Q. Why is Rocky Mountain Power involved?

A. Rocky Mountain Power has expressed an interest in partnering with the Company on programs where combined efforts would result in higher customer participation, more comprehensive programs, lower program costs, and greater customer satisfaction. Rocky Mountain Power sent a letter to the Commission on January 20, 2006, regarding the Company's efforts in this docket. Some of the most effective DSM programs deal with incentives to home builders and home owners to build more energy-efficient homes, including more energy efficient appliances. Implementation of these programs affects use of both natural gas and electricity. Participation of both utilities can also create synergies. Therefore, it is important to coordinate efforts between the Company and Rocky Mountain Power.

d. Customers' Desires for DSM

Q. Do you believe Utah customers are ready to implement energy efficiency?

A. Yes. Last winter's gas prices raised Questar Gas customers' interest in efficient energy use. The Company wanted to find out more about customers' desires in this high-price environment and the potential for greater energy efficiency in Utah. The Company employed Dan Jones & Associates to conduct a customer survey. A random sample of 415 customers was surveyed in June 2006.

Q. What were the results of the survey?

A. Ninety-four percent of those surveyed believe energy conservation is important. Seventy-three percent of our customers would like Questar Gas to provide energy-conservation information and programs to help reduce energy consumption in their home. Seventy-eight percent would like to receive this information in their monthly bill or by mail. The margin of error for the survey results is +/-5%. The results provide reassuring evidence that the Pilot Program is timely and in the public interest. The survey results are attached as QGC Exhibit SR 1.1.

e. Implementation and Funding Levels of Energy-Efficiency Measures Including DSM

Q. Please explain in more detail what Nexant has been doing.

A. The Company contracted with Nexant to prepare a market-characterization and delivery-evaluation report (Nexant Report). The objective of the report was to build upon the work performed in 2004 by GDS Associates, Inc. for the Natural Gas DSM Advisory Group.[2] The Nexant Report provides findings and recommendations for natural gas DSM and energy efficiency in Utah. Nexant's work included the following steps:

1) review measures list from the GDS Report,
2) evaluate natural gas DSM best practices,
3) identify vendors for each targeted end-use measure,
4) conduct vendor surveys,
5) estimate the impact of program savings,
6) assess incentive levels,
7) recommend program-delivery mechanisms,
8) prepare a final market-characterization report, and
9) estimate design, administration, marketing and incentive costs for prescriptive programs.

A copy of the Nexant Report is attached as QGC Exhibit SR 1.2.

Q. What other actions has the Company taken to move energy efficiency and DSM forward in Utah?

A. With input from the DSM Working Group[3], the Company has developed a preliminary roadmap for implementing energy efficiency in Utah (Energy-Efficiency Roadmap). I have attached this as QGC Exhibit SR 1.3.

Q. What does the Company's Energy-Efficiency Roadmap include?

A. The Energy-Efficiency Roadmap is a working document that brings focus to the DSM and

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[2] The Utah Natural Gas DSM Advisory Group was formed as a result of a Commission Order in Docket No. 02-057-02 to study DSM programs.

[3] The DSM Working Group is the group of interested stakeholders, including the Committee, that has continued to meet to explore DSM options for the Company.

energy-efficiency collaborative process for Questar Gas. It provides an overview for how the collaborative effort will develop and manage energy-efficiency programs. It provides an objective for the Company's DSM initiative, estimates for annual funding for program development during the Pilot Program, measurement and evaluation criteria, and implementing schedules for developing natural-gas energy-efficiency programs in Utah.

Q. The Roadmap identifies accelerating market transformation as a long-term goal. What do you mean by accelerating market transformation?

A. Market transformation is achieving a long-term shift in customer attitudes, habits, purchasing decisions and overall practices regarding energy equipment and usage. The ultimate aim is to maximize energy efficiency and conservation technology and practices across the entire customer base. DSM is an essential, but not the only, factor to accomplishing market transformation. Also included in market transformation will be increased energy efficiency and conservation education and awareness; Company, government and trade-ally partnerships; weatherization information; occupant behavior education; energy-auditing assistance; short-term quick-response conservation programs that respond to transient market conditions; and leadership roles in improving energy building codes and standards.

Q. What are the procedural steps required to implement cost-effective DSM programs?

A. With the approval of the Pilot Program, the Joint Applicants will ask that the Commission institute a new docket to facilitate the regulatory aspects of implementing natural gas DSM. As part of this new docket, the Company should file, within 60 days of the Commission's approval of the CET mechanism, its initial proposal for DSM programs. The Energy-Efficiency Roadmap proposes an aggressive schedule for design and approval of DSM programs. It estimates energy-efficiency funding of $2 million to $5 million in Year 1, $4 million to $8 million in Year 2 and $5 million to $10 million in Year 3. The Company believes that, with the cooperation of the many stakeholders involved, this aggressive schedule is feasible. As mentioned above, the DSM Working Group has been very cooperative in advancing the Energy-Efficiency Roadmap. The Joint Applicants also request the Commission to formally establish a DSM Advisory Group. The existing participants in the DSM Working Group should comprise this group, although stakeholders not yet involved are welcome to participate.

Q. Ms. Wolf advocates that the Company should be required to commit to a substantial level of energy-efficiency expenditures during the life of the Pilot Program. Do you concur?

A. As detailed in the Energy-Efficiency Roadmap, the Company is committed to identifying, developing, proposing and implementing energy-efficiency programs. The projected expenditures in the third year are in line with those advocated by Ms. Wolf.

Q. Why are you proposing to ramp-up to the proposed funding levels over three years?

A. Based on the recommendation of the DSM Working Group, the ramp-up of the funding levels over the course of the Pilot Program will allow sufficient time for the Commission to review programs and approve those in the public interest. We anticipate the process of Commission review and approval of the potential programs may be most efficiently handled in stages. In addition, we anticipate the process will improve with experience.

Q. Why are you proposing a range of funding for energy-efficiency programs rather than fixed targets?

A. The proposed ramp-up of the funding levels is only an estimate. Actual expenditures should be based on the costs associated with programs that the Commission finds are in the public interest. The level of expenditures should not be based on meeting arbitrary targets. The ranges in the Energy-Efficiency Roadmap recognize this issue and the fact that more detailed cost estimates are being developed.

f. Commission Ordered DSM without CET

Q. Mr. Dismukes and Mr. Higgins have both advanced the argument that the Commission

could simply order the Company to implement DSM. Is the Company mandated by statute or IRP guidelines to implement DSM?

A. No. Mr. Dismukes cited Utah Code § 54-3-1 regarding just and reasonable charges of the utility as the support for his claim that "Utah public utilities have a statutory obligation to provide least-cost, reliable, and safe service in return for getting an opportunity to earn a fair return on and of their investments." (Dismukes Rebuttal at lines 305 through 307). Nowhere in the statute does it require public utilities to provide "least-cost" service. In fact, the statute defines just and reasonable rates to "include, but shall not be limited to, the cost of providing service to each category of customer, economic impact of charges on each category of customer, and on the well-being of the state of Utah; methods of reducing wide periodic variations in demand of such products, commodities or services, and means of encouraging conservation of resources and energy." Additionally, the statute provides "[e]very public utility shall furnish, provide and maintain such service, instrumentalities, equipment and facilities as will promote the safety, health, comfort and convenience of its patrons, employees and the public, and as will be in all respects adequate, efficient, just and reasonable."

The Public Utility Code contains further guidance on the meaning of "just, reasonable, and adequate" in Section 54-4a-6(4). That statute makes it clear that "just, reasonable and adequate" includes criteria that balance the interests of shareholders and customers such as "maintain[ing] the financial integrity of the public utilit[y]" and "protect[ing] the long-range interest of consumers in obtaining continued quality and adequate levels of service at the lowest cost consistent with other provisions of Subsection (4)."

Additionally, the Commission's Order in Docket No. 91-057-09, "In the Matter of the Analysis of the Integrated Resource Plan for Mountain Fuel Supply Company," provided that the "Commission will require Mountain Fuel Supply Company to pursue the least-cost alternative for the provision of natural gas energy services to its present and future ratepayers that is consistent with <u>safe</u> and <u>reliable service</u>, the <u>fiscal requirements of a financially</u>

healthy utility, and the long-run public interest." (Order at 1, emphasis added.)

The obligation to pursue the least-cost alternative must be weighed against safe and reliable service, the fiscal requirements of a financially healthy utility and the long-run public interest. The Joint Applicants' proposal offers a "means of encouraging conservation" while considering the cost of providing such service and the safety and reliability of such service. The balancing of shareholder and customer interests required by all of the foregoing cannot reasonably be accomplished by requiring the Company to engage in DSM that is detrimental to the interests of shareholders.

Q. Would it be good policy for the Commission to order the Company to implement DSM without approving the CET?

A. This is not only inconsistent with "adequate, efficient, just, and reasonable" but also contrary to the recommendation of both the recently issued "Utah Policy to Advance Energy Efficiency in the State" and the "Report of the Natural Gas DSM Advisory Group to the Utah Public Service Commission, dated January 2005 (DSM Report)." The recommendations in the DSM Report acknowledged the decline in customer usage experienced by the Company must be addressed if effective Company participation in DSM programs is desired. Without removing the barrier to promoting DSM, the Company would find itself with conflicting incentives. On one hand, it would be required to implement conservation programs that cut revenues. On the other, it would still benefit by promoting higher usage, since volumetric usage drives about 70% of non-gas revenue. Ken Costello in his paper titled "Briefing Paper: Revenue Decoupling for Natural Gas Utilities," dated April 2006, states, "Regulators should not expect a utility to undertake pro-actively energy-efficiency initiatives when shareholder interests deteriorate. A collision course leading to unintended consequences seems inevitable under standard ratemaking from requiring a utility, whose earnings directly relate to the level of sales, to play an independent active role in reducing its sales." (Costello at 20.) Questar Gas agrees with this sound conclusion.

g. Impacts of CET and DSM on Customers

Q. Mr. Dismukes and Ms. Wolf both state that adoption of the Pilot Program will result in some customers paying more than they would pay otherwise because of the amortizations of CET and DSM deferrals. Do you agree with these conclusions?

A. No. All customers will benefit regardless of their actions. The CET ensures the Company will not collect more revenue per customer than the Commission has authorized. These parties fail to recognize the significant gas-cost savings achieved by cost-effective DSM programs. They are overly worried about customers paying their fair share of what the Commission has authorized and are stepping over dollars to pick up dimes.

Q. Have you prepared any exhibits to demonstrate this?

A. I have prepared QGC Exhibit SR 1.4 that shows the benefits to three typical customers given different assumptions about their actions. The exhibit shows the impact of CET amortizations assuming a 1% annual decline in overall usage per customer due to the implementation of DSM programs. In these examples, it is assumed that these reductions in revenue are immediately amortized to customers through CET adjustments even though actual amortizations would lag by about six months. The lag is ignored in these examples for the sake of simplicity.

Q. How is the amortization of DSM costs handled in these examples?

A. The DSM-cost amortization in these examples is based on DSM spending of $3 million in Year 1, $6 million in Year 2 and $8 million in each of Years 3 through 5. To arrive at the DSM cost amortization, these spending levels are divided by GS-1 and GSS Dth sales volumes to arrive at an estimated cost per Dth. The result is multiplied by the typical customer's usage of 115 Dth/year to estimate the DSM-cost amortization per customer per year. The lag on the DSM-cost amortizations under the CET proposal is also ignored in these examples.

Q. What about commodity portions of the bill in this example?

A. As the overall usage per customer declines, the commodity portion of the typical customer's bill will decrease. This is because the Company will not need to purchase as much gas, and cost-of-service gas will make up a greater portion of the portfolio than would otherwise be the case. A 1% decrease in the typical customer's usage results in a decrease of about $12.00 per year. This reduction is also cumulative, such that by Year 5 the annual savings are about $60.00. On a total Company basis, this calculates to $48,000,000 ($60.00 per customer x 800,000 customers) in Year 5. These commodity savings are used in these examples to measure the decrease in overall gas costs that result from a 1% annual decrease in usage per customer.

Q. With these basic parameters established, please explain how a customer, who chooses not to participate in DSM programs, would be impacted by the CET adjustment and DSM costs?

A. Page 1 of QGC Exhibit SR 1.4 shows the impact on a customer who chooses not to (or cannot afford to) adopt any efficiency measures, either through formal DSM programs or on their own. The Pilot Program's financial impact on this customer will be from amortizations of CET adjustments, DSM cost deferrals, and from system-wide gas-cost savings. The green portion of each bar represents the distribution non-gas (DNG) portion of the bill, which does not change over the five years for this customer, since this customers' usage remains the same. The dark blue portion of the bar represents the CET amortization and the pink portion represents the DSM-cost amortization, both of which increase the customer's bill. The light blue portion of the bar represents the commodity portion of the bill. The top of the light blue section represents the total bill. The white portion of the bar represents the net savings to the customer from reduced purchased gas costs, less the increases from CET and DSM cost amortizations. These net savings total $6.00 in the first year and grow to $40.00 in Year 5 ($40 x 800,000 customers = $32,000,000 on a total Company basis). Thus, even the customer who does nothing will benefit from the reduction in purchased gas costs over and above the increased costs from the amortizations. In other words, the net impact of the Pilot

Program will be a benefit to even those customers who do not participate in DSM programs.

Page 2 of this exhibit shows in more detail the comparison of CET and DSM amortizations with the gas-cost savings. Once again the dark blue and pink portions of each bar represent the increases caused by the CET and DSM amortizations, respectively. In this example, they are shown as negative amounts, reducing the savings to customers. The light blue portion of each bar represents the portion of gas-cost savings that offset the increases from the CET and DSM amortizations. The yellow portion of each bar represents the net gas-cost savings realized by the customers who do not participate in DSM.

Q. Ms. Wolf makes the claim that low-income households will not be in a position financially to participate in the DSM programs, but will be required to pay for them nevertheless. Do you agree?

A. No. The discussion above shows that a customer who does nothing receives a net benefit. In addition, the Joint Application proposed an increase in Company funding for LIWAP. This proposal was included in the Joint Application specifically to provide a benefit to low-income customers.

An additional solution for these low-income customers will be to identify and implement DSM programs with low participant costs and broad application. In the Joint Application this was one of two types of programs specifically identified as being desirable in addition to those identified in the GDS study.

Q. How would a customer who participates in DSM measures be impacted?

A. Page 3 of QGC Exhibit SR 1.4 shows the impact on a customer who adopts a moderate level of Company-sponsored DSM programs that result in an annual decrease in usage of 5% per year. Once again, the green represents the DNG portion of the bill, the dark blue represents the CET amortizations, the pink represents the DSM-cost amortization and the light blue represents the commodity portion of the bill. The top of the light blue section represents the total bill. The white portions represent both the decreased commodity and DNG costs resulting from decreased individual usage. As shown, this customer realizes a reduction in Year 5 of $223 (193 + 30) in his bill, even after the inclusion of the DSM and CET amortizations. The cumulative savings for this customer over the five-year period totals $681.

Q. Mr. Dismukes asserts that DSM can create problems for early adopters of technology and a concern for change in paybacks as a result of DSM in conjunction with adoption of the CET. Is there merit to these assertions?

A. No. Page 4 of QGC Exhibit SR 1.4 shows a customer that implemented conservation measures prior to the implementation of DSM programs and the CET and achieved an annual decrease in usage of 25%. The colors in each bar remain as explained earlier. As can be seen, an "early adopter" customer realizes significant reductions in his bill even before the CET and DSM programs are approved and implemented. These early adopters gain the benefits they presumably expected with no loss of advantage as a result of the Pilot Program. The minimal increase in these customers' bills resulting from amortizations of CET and DSM costs is more than offset by the reduced commodity costs resulting from more widespread implementation of DSM. As a result, they enjoy cumulative savings of about $1,388 with the implementation of the Pilot Program over the 5 years compared to what they would have paid if they had not implemented energy-efficiency measures and the Pilot Program were not implemented.

2. CONSERVATION ENABLING TARIFF

a. Preferred Option

Q. Why did the Joint Applicants ultimately determine that the CET was the preferred option for removing the barrier to the Company's willing participation in DSM?

A. As I described in my direct testimony at pages 5-9, through continued discussion and analysis, the Joint Applicants agreed that the CET was the preferred option to align the interests of the many stakeholders. This conclusion was reached after analyzing numerous other options more fully described in the White Papers attached to the Joint Application as Exhibits 1.6 and 1.7. The Joint Applicants believe the CET is the best alternative to remove the barrier and allow the Company to aggressively pursue DSM while providing the Company an opportunity to earn its allowed rate of return.

b. The DSM Barrier Should Be Removed

Q. Since the filing of your direct testimony, has the State of Utah published an Energy-Efficiency Policy?

A. Yes. On April 25, 2006, the Governor announced the "Utah Policy to Advance Energy Efficiency in the State." A copy of this policy statement is attached as QGC Exhibit SR 1.5. Item number 3 specifically states, "State Government will work with stakeholders to identify and address regulatory barriers to increased deployment of energy efficiency." Adoption of the CET, coupled with the Company's aggressive pursuit of DSM opportunities, will help the State of Utah reach the energy-efficiency goals set by Governor Huntsman.

Q. Are there any other national studies or policies published since the filing of your direct testimony that support removing the barrier to promoting energy efficiency?

A. Yes. In July 2006, the "National Action Plan for Energy Efficiency" was published. This report is a plan developed by more than 50 leading organizations in pursuit of energy savings and environmental benefits through electric and natural gas energy efficiency. It was facilitated by the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA). The executive summary of the report is attached as QGC Exhibit SR 1.6. The full document can be accessed on the EPA's website at www.epa.gov/cleanenergy/actionplan/report.htm. The report's five recommendations are:

1. Recognize energy efficiency as a high-priority energy resource.
2. Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
3. Broadly communicate the benefits and opportunities for energy efficiency.
4. Promote sufficient, timely, and stable program funding to deliver energy

efficiency where cost-effective.

5. Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify rate making practices to promote energy-efficiency investments.

The Pilot Program is a mechanism proposed by the Joint Applicants to implement all five of these recommendations for the State of Utah.

Q. All three rebuttal witnesses argue to some extent that the Company has failed to prove a problem exists. What is the Company's response?

A. I will group their assertions into four categories. Specifically they assert that:

(1) The Company has failed to demonstrate there is a decline in customer usage,

(2) The Company has failed to show it is harmed by declines in customer usage,

(3) The Company can manage expenses to deal with the decline, and it is the Company's responsibility to do just that, and

(4) Customer growth offsets the decline in usage per customer.

Let me address point 1 first. The Company has provided evidence of declining usage per customer for at least 26 years. The impact of the decline has been reviewed by the Division and Committee during the course of the last 26 years. In fact, acceptance of this evidence by all parties was the driving factor behind the Commission-ordered task force in Docket No. 02-057-02 to study separately the possible development of a tracker mechanism for usage per customer.

Q. Would you please address Mr. Dismukes' claim that the Company has not provided back-up for the decline in customer usage shown in QGC Exhibit 1.4, attached to your direct testimony?

A. Yes. His premise seems to be that because the Company could not satisfy his request for back-up data for various weather stations historically used and the resulting temperature-adjusting slopes, the Commission should disregard the Company's exhibit showing the decline in customer usage.

Q. Please explain the derivation of QGC Exhibit 1.4.

A. QGC Exhibit 1.4 in my direct testimony is a graph that shows the historical decline in temperature-adjusted GS-1 usage per customer. The graph displays the final results of the calculation of GS-1 temperature-adjusted usage per customer over a 26-year period. During this 26-year period the Company has: 1) improved the methodology for weather normalization, 2) had to use alternative weather data as source weather station coverage has changed, and 3) developed more sophisticated approaches to all aspects of the weather-normalization process, including the use of multiple weather stations to reflect the diverse geographic nature of our service territory. Although not all of the underlying data and calculations are available for the last 26 years, the usage data is available.

Q. Do you believe not having all the underlying data and calculations is a material problem?

A. Absolutely not. To illustrate, I have prepared a similar graph with two alternative versions overlaid on the original, attached as QGC Exhibit SR 1.7. The new graph of temperature-adjusted usage per customer was created using a temperature-adjusting slope calculated with a regression of GS-1 usage per customer and temperature data from only the Salt Lake Airport Weather Station. While the accuracy of this simplified protocol is technically lower than the procedures followed originally to create the graph, the result is very similar to the original QGC Exhibit 1.4. Also shown on this graph is the unadjusted usage per customer. The unadjusted data demonstrates the same decline, but with greater short-term volatility due to weather variations. The reality captured in QGC Exhibits 1.4 and SR 1.7 depicts the decline in temperature-adjusted usage over the last 26 years. Mr. Dismukes' premise and subsequent arguments seem to acknowledge that the Company is faced with this reality, but he nevertheless advocates that the Commission ignores this fact as it considers the merits of the CET. His concerns regarding QGC Exhibit 1.4 are unfounded and should be given no weight.

Q. Please address the second issue, that the Company has failed to show that it is harmed by the decline in customer usage.

A. The impact of the declining customer usage on the Company's ability to earn its authorized rate of return has been explored in several general rate cases during the past 26 years. More generally, this impact is recognized in the Joint Statement of the AGA and NRDC included as Exhibit 1.1 to the Joint Application and in the briefing paper by Ken Costello that was the starting point for the technical conference held in this docket on June 7, 2006. Nevertheless, to assure that there is no doubt about the validity of this position, I have prepared QGC Exhibit SR 1.8 that shows the cumulative impact on Company DNG revenue of a 1% decline in GS-1 annual usage. As you can see on line 7, column F, the compounded five-year effect of a 1% reduction exceeds $23 million per year. This is an indication of how pursuing DSM may impact Company revenue. Since non-gas costs do not vary directly with reductions in sales, this reduction in non-gas revenue will directly impact the Company's net income. After adjusting for income taxes, the $23 million impact would reduce net income by about $15 million dollars.

Q. Let's turn to point number 3. What has the Company done to manage expenses to deal with the decline in usage?

A. The Company has been dealing with the issue of declining usage per customer since the early 1970s. Company management has used a number of tools and approaches to deal with this challenge. The Company has proposed forward-looking test years, filed numerous requests for rate relief, cut costs, and implemented sound cost-allocation and rate-design methodologies.

Q. Please address these tools and approaches in more detail.

A. One approach is the use of a forward-looking test year in setting rates. While Questar Gas believes using forward-looking test years is entirely appropriate, comments in hearings and technical conferences in other dockets show forward-looking test years are opposed by the same parties that are opposing the CET. In addition, using a forward-looking test year does not remove the disincentive for the Company to engage in DSM. This was explained by Ralph Cavanagh at the June 7, 2006, technical conference in this docket: regardless of the test year used in setting rates, without decoupling, the Company will still benefit from increased sales and would be harmed by decreased usage.

Another approach is the general rate case. General rate cases are costly and time-consuming for all regulatory participants. Additionally, the Company could cut costs but further cost cutting will likely result in unacceptable service reductions. These and other approaches were considered and rejected by the task force that ultimately recommended the CET approach. In summary, the Company has managed to deal with the declining usage per customer, but the tools and approaches to continue to do so produce negative consequences. Therefore, the Joint Applicants proposed the CET.

Q. Let's turn to point 4. Why doesn't the addition of new customers help alleviate the decline in usage?

A. The addition of new customers does not offset the decline in usage per customer. As the Company adds new customers, it also adds rate base and expenses to serve those new customers. In addition, the higher costs required to serve new customers must be recovered over lower volumes per customer because new customers, in general, use less than existing customers.

Q. Can you provide some data to support your claim that new customers add costs beyond what is embedded in rates?

A. The investment for new customers is higher than the average rate base per customer included in existing rates. QGC Exhibit SR 1.9 shows the average investment for new GS-1 customers in calendar year 2005. As can be seen, new customers require an average investment of $1,386 (see page 1, Column C, line 4). Existing rates include an average investment of about $589 (see page 1, Column F, line 4) per GS-1 customer. The second page of QGC Exhibit SR 1.9 shows recent growth rates require the Company to add over $35,000,000 (see Column D, line 19) annually in rate base to serve new customers. The annual revenue requirement resulting from the addition of 25,000 customers (3.125%), assuming a modest O&M expense increase of 2.0% (which is less than the customer growth rate or the rate of cost inflation), shows the Company is not fully compensated by the revenue per customer proposed to be used in the CET (see Column D, line 39).

Q. Is this "negative" return compounded further by the average new customer's natural gas usage?

A. Yes. New customers typically have more energy-efficient appliances and buildings than older customers. That is a primary reason for the declining usage per customer the Company has seen over the past 26 years. A recent Company study of usage per customer for the 12 months ending June 2006 shows that the average GS customer used 112.71 Dth over that period (temperature-adjusted). By comparison, those customers added during the previous 12 months (ending June 2005) used on average only 89.60 Dth, 23 Dth or 20% per customer less!

Q. In his testimony filed June 30, Mr. Dismukes tries to bolster his argument by preparing several exhibits he claims support the idea that the Company is not hurt by declining usage per customer. He attempts to show new customers help the Company's bottom line and with the CET the Company would overearn. Would you please comment?

A. In S.R. Exhibits CCS-2.6, 2.7 and 2.8, Mr. Dismukes presents a series of calculations intended to show that often the growth in customers on the Company's system more than offsets the decline in usage per customer such that total Dth sold and total DNG revenues from the GS-1 class increase over time. He has made some errors in extracting some of the data he uses in his calculations from the data request responses that he was provided, which make the specific results in these exhibits inaccurate. His conclusion, however, is not disputed by the Company. In fact, had he referred to the Company's Integrated Resource

Plan (IRP) that was filed on May 1, 2006, he may have been able to avoid some of his calculations. In Exhibit 3.7 of the May 2006 IRP, the temperature-adjusted throughput from various types of customers is presented from 1986 through 2005, with a forecast through 2016. Although it can be seen that in some years the system GS volumes decline, due to usage per customer declines in excess of usage increases from new customers, the general trend, as well as the forecast show a gentle increase. As the total volumes from these customers increase, the DNG revenues also increase.

Where Mr. Dismukes' argument fails is in the translation of the increased revenue into increased earnings or net income. On lines 267 – 269 he states "If prices and costs are held constant, then earnings will continue to increase if new customer-related usage growth outpaces the decrease in use per customer for existing customers." While this statement is technically correct, the assumption is totally unreasonable. As we have shown in QGC Exhibit SR 1.9, new customers require increases in rate base and expenses that exceed the additional revenue received from them.

S.R. Exhibit CCS-2.9 claims to show the impact on earnings based on Mr. Dismukes' analysis of the net effects of customer growth and usage decline. Page 3 of this exhibit, which attempts to show the financial impact of changes in customers, is incorrect. It fails to take into account increases in depreciation, property tax (taxes other than income taxes) and O&M expenses that are required to serve new customers as the Company has shown on page 2 of QGC Exhibit SR 1.9. As a result of these invalid assumptions, the entire analysis is invalid. SR Exhibit CCS-2.11 which continues his assumption that customer growth results in a net increase in revenues is similarly invalid. As Mr. Dismukes states on lines 275- 276, "All of these relationships are based upon the premise that other factors are held constant." Unfortunately the Company cannot add new customers and hold all other factors constant. His underlying premise is flawed.

Q. Have you reviewed Mr. Dismukes' analysis in SR Exhibit CCS-2.10 that looks at

average and incremental investment trends?

A. Yes. While his conclusion that the investment in new customers is greater than the imbedded investment in existing customers is correct, the analysis presented in QGC Exhibit SR 1.9, page 1, which looks at the isolated investment in mains, service lines and meters for new customers in 2005 versus the investment in existing customers imbedded in current rates (2002), is more accurate.

Q. Can you comment on the conclusions Mr. Dismukes draws from his analysis?

A. On lines 362 – 364, he concludes, "It appears that the real challenge the Company faces is its ability to recover the costs associated with serving new customers. This has nothing to do with DSM, and also has little to do with decreasing use per customers." While he is correct that this is a very real challenge for the Company, his further conclusion that the CET is what the Company is proposing to solve this problem is in error. Again I must refer to QGC Exhibit SR 1.9, page 2. As is shown on line 39, the net impact of additional customers, even with the adoption of the CET, is a shortfall of DNG revenue of about $1 million. In order to recover this shortfall, the Company would likely have to file a general rate case. The CET only compensates the Company for differences in actual revenue per customer as compared to the allowed revenue per customer. Increased expenses and rate base that the Company may experience are not included in the CET formula.

Q. Have you reviewed Mr. Dismukes' Supplemental Rebuttal testimony regarding usage per customer data?

A. Yes, I have. The sole conclusion he reaches is that it may be unreasonable to assume continued large decreases in usage. However, this seems oddly contrary to his sentiment that DSM programs should be adopted.

Q. Do you agree with his conclusion?

A. I find his conclusion to have little relevance. As I have noted elsewhere, the CET is symmetrical in its treatment of changes in usage per customer. If usage per customer increases in the future, the CET will reduce DNG rates per decatherm to reflect this outcome.

If usage declines by a small amount, DNG rates will increase by a very small amount per decatherm. If the effect of Company advocacy, energy-efficiency education and DSM combined with price increases causes a substantial decrease in usage per customer, then there will be an increase in DNG rates per decatherm. I should note that in the absence of the CET, a rate case would result in the same increase in rates, with the additional cost of the proceeding.

c. CET Will Not Remove Need for Rate Cases

Q. Ms. Wolf argues on page 12 of her direct testimony that with implementation of the CET, and no direct order from the Commission to conduct general rate cases on a periodic basis, the Company may not need to file future general rate cases. First of all, if you assume that she is correct, should this concern regulators or customers?

A. No. If the implementation of the CET results in fewer rate cases, the Company sees this as a good thing. In fact, this was identified by the Task Force as one of the "pros" of this alternative. General rate cases are very expensive for the Company, for the State of Utah and for the customers who intervene in them. General rate cases are also very contentious and time-consuming, and typically result in costs going up for customers. The Company is of the opinion that frequent general rate cases are not necessary for effective regulation in the State of Utah.

Q. Is the assumption that future rate cases will not be required if the CET is approved realistic?

A. Not necessarily. Ms. Wolf's contention that the Company will not have to file future rate cases doesn't stand up when the effects of adding new customers discussed above are considered in addition to the effects of general inflation, which is remaining at approximately 2-4%, and increases in labor and medical costs.

Q. What about the ability of regulators to review the Company's books and records?

A. Even with fewer general rate cases, the implementation of the CET does not diminish the

Division's or Committee's ability or opportunity to review the Company's books and records or its business practices and policies or monitor its earnings. In the final order in Docket No. 93-057-01, the Commission ordered the Company to file annual results of operations (Results of Operation). Additionally, the Division has requested that the Company file a mid-year (12-month ending June) report. Copies of these reports are regularly provided to the Division and the Committee. These Results of Operations present the Company's historical results including all regulatory adjustments required by the Commission. They are much like what would be filed in a general rate case, except that the data is for a historical period rather than a forecast of a future period. The Division and Committee regularly review these reports, audit the components and are free to go into the level of detail deemed appropriate.

In addition, during this case, the Division requested that, on an annual basis, the Company provide a forecasted Results of Operations. On April 11, 2006, the Company filed a forecasted Results of Operations for 2006 that was later admitted as an exhibit in the Rate Reduction Stipulation hearing held on May 17, 2006. The Company is willing to continue this practice so the Division and Committee will have not only the Company's historical results, but also a forecast for the coming year. These reports allow them to more closely monitor Company earnings. Also, the Company's IRP process requires that the Company file its annual IRP and hold quarterly meetings with the regulators.

Q. Does approval of the CET prevent other parties or the Company from filing a rate case?

A. No. If it is determined that the Company needs rate relief or is overearning, or if the Commission finds that there is a good reason to investigate the Company's rates, a rate proceeding may be initiated.

d. Company Will Continue to Operate Efficiently

Q. On page 24 of his Direct Testimony, Mr. Dismukes asserts that the implementation of

the CET would substantially reduce any incentive for the Company to aggressively manage costs because regulatory lag has been removed. What is your response to this assertion?

A. First, the incentive to control costs still exists with the CET. The CET only deals with the revenue side of the equation. To achieve its allowed return, the Company will still need to control costs and operate efficiently.

Second, the Company disagrees that regulatory lag should be used as a regulatory tool to provide an incentive for the Company to be efficient and believes that there are much better and more direct regulatory strategies that can be used. One of the reasons for the implementation of the Task Force was to identify such strategies. As pointed out by Mr. Dismukes and others, the Company responded to declining usage per customer over the past 26 years in several ways. One was to file frequent general rate cases. Another response was reducing costs by, among other things, closing region offices, reducing in-home services and reducing the workforce through early retirements and attrition. In the Company's last rate case, some parties including the Committee, felt the Company had gone too far in certain cost-cutting areas. As a result, the Commission established a Service Quality Task Force in the final order to that case. The Service Quality Task Force established service standards that would be used as a management tool and that the Company would be measured against. One of the Joint Applicants' proposals in this case is to bolster the service-quality standards by allowing the Division to initiate an investigation or recommend penalties if certain standards are not met. In addition, the Joint Applicants proposed that a Service Quality Standards Working Group be formed to evaluate other customer-service standards during the Pilot Program. It is the Company's opinion that all of the aforementioned regulatory options, in conjunction with removing the disincentive to promote DSM, should be used instead of regulatory lag.

e. Cart before the Horse

Q. In a related issue, Mr. Dismukes and Ms. Wolf argue repeatedly that the CET should

not be implemented until the Company has implemented DSM. What is your response to this argument?

A. The Joint Applicants believe it is in the best interests of the Company and customers to implement the CET and DSM programs simultaneously. The Company is aggressively working on DSM programs that can be implemented in a timely fashion. I discussed the details of the Energy-Efficiency Roadmap (QGC Exhibit SR 1.3), including proposed funding, goals and performance standards, earlier in my testimony. What is important is that the Company's current rate design is a barrier to implementation of cost-effective DSM programs. The barrier needs to be removed.

f. Revised Annual Allowed Revenue per Customer

Q. On May 26, 2006, the Commission approved the Rate Reduction Stipulation filed in this docket. Can you please explain what the Rate Reduction Stipulation is intended to do?

A. Originally, the Joint Applicants proposed approval of the Pilot Program tied to a $10.2 million rate reduction. Other parties to this docket argued the rate reduction should be severed from the Pilot Program and the rate reduction should be made effective on an interim basis. The parties held numerous settlement conferences and, as a result, agreed upon a $9.7 million rate reduction that would be effective June 1, 2006, on a non-interim basis. In return, the signatories to the Rate Reduction Stipulation agreed that the Joint Applicants' proposed Pilot Program would be heard on its merits during the hearings now scheduled for September 5, 6 and 7.

Q. Now that the Commission has approved the Rate Reduction Stipulation, does the allowed revenue per customer proposed for the CET need to be revised?

A. Yes. Attached as QGC Exhibit SR 1.10, is the new calculation of the proposed annual allowed revenue per customer.

Q. Please explain the differences between the QGC Exhibit 1.7 filed with your direct

testimony and QGC Exhibit SR 1.10.

A. One of the agreements in the Rate Reduction Stipulation was to maintain separate GS-1 and GSS rate classes for the time being. In the original filing, the Joint Applicants proposed to merge the GSS class into the GS-1 class. The revenue on line 1 of page 1 of QGC Exhibit 1.7 reflected the lower revenues resulting from the elimination of the GSS rate premium. In the revised exhibit, SR 1.10, line 1 of page 1 represents the higher revenues received with the GSS rate premium. Line 2 shows the stipulated $9.7 million rate reduction. Line 5 shows the GS-1 and GSS portion of the Utah jurisdictional DNG revenue, which is divided by the 2005 year-end customers to arrive at the new proposed annual allowed revenue per customer of $255.53.

Q. Have you allocated this annual amount to months?

A. Yes. This amount was allocated to months using the same methodology used in the original filing in this case. This methodology was explained in detail by Division witness George Compton in his direct testimony. QGC Exhibit SR 1.10, page 2, shows the annual allowed revenue per customer by month.

Q. In the original filing in this case the Joint Applicants proposed a $3.6 million voluntary rate reduction in conjunction with the CET. What is the current proposal?

A. The $3.6 million voluntary rate reduction was based on data through December 2005 and assumed implementation of the CET on January 1, 2006. QGC Exhibit SR 1.11 shows the entries that would have been entered into the CET deferred account since January 2006 had the CET been approved on that date along with the $9.7 million rate reduction. This exhibit shows that as a result of slightly increasing usage per customer during the first half of 2006, entries into the deferred account would have had the effect of reducing future GS revenues by $1,120,186. This demonstrates the symmetrical aspect of the CET. If the usage per customer increases, the entries into the deferred account reduce GS rates in the same proportion as the rates would be increased during periods of decreasing usage per customer. Since a January 1, 2006 adoption of the CET would have produced a $1.1 million reduction to customers, the Company is proposing to voluntarily provide this reduction now. To effect this revenue reduction, the Company proposes to begin the CET deferred account with a credit balance of $1,120,186 and to begin amortizing this balance through a negative surcharge in rates once the CET is approved.

Q. Please explain the calculations shown in QGC Exhibit SR 1.11.

A. Column A shows the actual customers for the GS rate class for the period from January through June, 2006. Column B shows the DNG revenues for this period restated to include the stipulated $9.7 million rate reduction. Column C is the allowed revenue per customer calculated in QGC Exhibit SR 1.10, page 2, column D. Column D is the product of Column A and Column C. Column E is the difference between the DNG revenues restated at June 1, 2006 rates shown in Column B and the allowed revenues in Column D. The total of these differences for the first 6 months of 2006 is $1,120,186. The Company is proposing to credit this amount to the deferred account if the CET is approved.

3. RISK, RETURN AND REGULATORY PRACTICE

Q. Mr. Dismukes in his Direct Testimony, and again in his Supplemental Rebuttal Testimony, Ms. Wolf and Mr. Higgins all criticize the proposed CET because they claim that risk is shifted or transferred from the Company to customers. Do you agree with this criticism?

A. No. The CET will remove not shift the risk. These witnesses claim the risk of lower revenue per customer has been shifted to customers, but they ignore the other potential outcome of higher revenue per customer. In fact, had the CET been implemented after the last general rate case (Docket 02-057-02), the effect of CET amortizations would have been to reduce non-gas revenue and rates by approximately $2.5 million. For a period of time following that case, GS usage and revenue per customer increased. Since the CET is symmetrical, it would reduce DNG rates per decatherm when revenue per customer increases, just as it would increase DNG rates per decatherm when revenue per customer decreases. As I have just shown, had the CET been approved on January 1, 2006, along with a rate reduction of $9.7 million, an increase in usage per customer during the first six months of 2006 would have resulted in credit entries into the CET deferral account of about $1.1 million. This also illustrates how the risk of higher revenues is removed from the customer just as the risk of lower revenues is removed from the Company.

Another example of how the nature of risk is changed can be seen by examining the Commission's approval of the Weather Normalization Adjustment (WNA), in Docket No. 95-057-02. When reviewing the impact of the WNA, it becomes apparent the risk of warmer or colder weather has not been shifted from the Company to the customers, but, in fact, has been removed from both. The CET operates in a similar fashion. Higher or lower revenues per customer resulting from changes in usage per customer will not increase or decrease the collection of Commission-approved levels of revenue. The CET removes the risk of higher or lower revenues per customer for future periods from both the customers and the Company.

Q. Does the Company believe the reduction in risk experienced by both the Company and its customers is a material change when considering the Company's allowed return on equity?

A. No. The Maryland experience is instructive on this point. The Maryland Commission in Case 9036 initially required a 50 basis point reduction in return on equity in conjunction with its approval of decoupling (Rider 8) for Baltimore Gas & Electric (BGE). It later reversed that finding in Order No. 80460, issued December 21, 2005. The Order provided that, "Staff recommends no reduction in the Company's return on equity to account for any lowered risk due to Rider 8…. [The Company] states that Rider 8 only allows BGE to recover approved revenues and the Company does not see the need for a downward adjustment on return on equity. Based on the reasons provided by Staff and the Company, the Commission declines to order a specific adjustment for Rider 8 effects." (Pages 67-68 of Order No. 80460.)

Q. Do you believe that the Commission must wait to approve the CET in a general rate case?

A. Absolutely not. Delaying the CET implementation until a general rate case delays significant cost savings for customers as I discussed earlier in this testimony. If this matter is delayed for consideration in a future general rate case, opportunities to accelerate customer adoption of energy-efficiency measures will be lost for another heating season.

The evidence on the record shows a general rate case is not needed. The Company's actual reported 2005 Results of Operations and its forecasted 2006 Results of Operations, both of which have been provided to the parties in this case, show Questar Gas' earnings below the authorized level. In addition, the Company is proposing a voluntary reduction that would decrease DNG revenues further and, as just illustrated, implementation of the CET could result in even further decreases in rates should usage per customer increase in the future.

4. THREE ADDITIONAL COMMITTEE OPTIONS

Q. In his supplemental testimony, Mr. Dismukes presents three additional options for the Commission to consider that he claims are superior to the Joint Applicants' proposal. Is it your understanding that these options are being recommended by the Committee?

A. No. Mr. Dismukes makes no claim that these options were being recommended by the Committee. They were given as alternatives to be considered. However, these types of alternatives were considered and rejected by the Task Force. I recommend the Commission reach the same conclusion as the Task Force.

Q. Please explain.

A. The first two options are called incentive-regulation approaches. In reality, both are incentive/penalty approaches. In both cases the details are left for the future. The first would target cost/benefit ratios as the metric to be used for incentives/penalties. Mr. Dismukes admits there is much work to be done prior to implementation and that no other Company has implemented a similar program. It is difficult to comment on this alternative in more detail due to lack of details in his description. The second alternative is also an incentive/penalty approach based on total Dth saved through DSM. Even fewer details are provided by Mr. Dismukes to support this alternative.

Q. Do these alternatives represent viable options for the Commission to consider?

A. These two alternatives may address one minor aspect of the issues addressed by the CET. They do nothing to address the major issues. Specifically they do not remove the barrier to the Company's aggressive pursuit of DSM. They also do not address the new issues to be raised in setting penalty/incentive levels. I suggest the Task Force recommendation regarding incentives be followed. The recommendation is that incentives could be reviewed over the course of the Pilot Program. These two alternatives should therefore be relegated to the category of potential future refinements to the Pilot Program.

Q. Mr. Dismukes' third alternative is characterized as a partial decoupling approach that he refers to as statistical recoupling. What is your understanding of this alternative?

A. It is an econometric approach to modeling sales that proponents argue allows an economist to isolate the effects of various factors on sales levels. Mr. Dismukes lists three classes of factors that must be defined in order to model the impacts. They are: 1) price elasticity of demand, 2) income elasticity of demand and 3) exogenous changes in demand. Depending on the economist designing the program, more or fewer factors could be included. In lay terms, Mr. Dismukes' alternative would first determine the amount of change in usage attributable to retail natural gas rates, then the change attributable to real disposable income and finally the historic trend in usage. Any change in usage not attributed to these three factors would be deemed to have been caused by Company-sponsored DSM.

Q. Was this alternative or similar types of alternatives reviewed by the Task Force?

A. Yes. In addition to incentive ratemaking, statistical decoupling and performance-based ratemaking were also analyzed. The Utah Power 1995 Statistical Decoupling Report was reviewed by the Task Force. Although the group felt the proposal had merit, the consensus was that statistical decoupling was more prone to controversy and was unnecessarily complicated due to the differing results that can be obtained through statistical analysis using different, but valid, methods or assumptions. There were more straight-forward, less controversial alternatives that should be pursued. The Task Force also carefully reviewed the Northwest Natural gas experience in Oregon which ultimately resulted in the same conclusion.

Q. Were there meetings held to analyze performance based ratemaking?

A. Yes. The Company hired Pacific Economics Group with partners Mark Lowry, Ph.D. and Larry Kaufman, Ph.D. They were asked to research and report back to the Task Force the various alternative forms of regulation that were being used across the country. They participated in several meetings by phone and on February 12, 2004, Mark Lowry came and presented their findings. Attached as QGC Exhibit SR 1.12, is the handout to the Task Force that summarizes their findings. This document shows that partial decoupling, full decoupling, performance-based rates, price caps and automatic rate adjustments when ROE was outside of a given band were all alternatives that were considered.

Q. Did the Committee embrace the idea of further analyzing any of these alternatives?

A. Only one, and I quote from the March 11, 2004, minutes where the Committee stated they "felt that most of the examples presented by QGC dealt with companies that offered choice programs or were in the process of unbundling. They felt Northwest Natural's example was possibl[y] the closest example to QGC['s] situation and therefore should be looked at more closely if any of the examples are pursued in the future."

Q. Did the parties review and analyze the Northwest Natural example?

A. Yes. The Task Force analyzed this alternative in detail. At the end of the three-year Northwest Natural pilot program, the Oregon Public Utilities Commission required an independent study regarding the effectiveness of the mechanism. Christensen Associates

Energy Consulting, LLC (Christensen Associates) was retained to perform the evaluation and submitted "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural" on March 31, 2005. The Joint Applicants reviewed this report, and concurred with Christensen Associates' conclusion that full decoupling is the best alternative to remove the barrier.

Q. Does the Committee's current proposal improve the alternative?

A. Not at all. In fact, I am surprised that the Committee seems to have retreated to a position it once criticized. This alternative fails on two major levels. The first problem is the complexity of the proposal. Mr. Dismukes' proposed "statistical" recoupling mechanism requires that three highly controversial factors be agreed upon or determined. In Oregon, only one of these factors, price elasticity was at issue. Price elasticity by itself is very difficult to determine. In its report to the Oregon Public Utility Commission on Northwest Natural's three-year decoupling pilot, Christensen Associates recommended that the price elasticity factor be re-evaluated. This was after a three-year pilot and a substantial effort to evaluate the pilot. Ultimately, the Oregon Commission adopted a stipulation that specified full decoupling. Mr. Dismukes is proposing to triple the level of complexity by not only having a price-elasticity factor, but two others of equal or greater complexity and controversy.

The second problem is fairness. Mr. Dismukes would include the historical trend as a factor that would be eliminated from the statistical recoupling model's compensation for lost revenue. Stated another way, everything that has gone before that is not explained by price or income is attributed to the general trend and that general trend is automatically projected to continue. If the Company's DSM efforts cause the trend in usage per customer to accelerate beyond this level then there would be some compensation for the lost revenue, otherwise no recovery is warranted. Put in perspective, Mr. Dismukes doesn't believe declines in customer usage will continue. If he is right, the Company will be required to pay customers for not continuing to reduce consumption at the historical pace. I can not envision a more patently unfair proposal.

Q. Do you believe a lost-revenue approach can be developed that eliminates these major shortcomings?

A. No. It is very difficult to isolate the causes of declines in usage per customer. The controversial regulatory aspects of lost-revenue approaches are well documented. The Christensen Associates report on the Northwest Natural pilot provides an independent summary on the lost revenue approach that is telling. The section on lost revenues is reproduced below in its entirety:

> *5.3.2 Lost Revenue Adjustments*. An alternative to decoupling in general (and DMN in particular) is to compensate the utility for conservation efforts through lost revenue adjustments. For example, lost revenue adjustments as applied to the high-efficiency appliance program would compensate NW Natural for lost margins based on estimated therm reductions for each HEF adoption. This compensation occurs on a case-by-case basis and is not reconciled to actual therm reductions at any point.
>
> There are a number of disadvantages associated with this approach to promoting conservation.
>
> 1. It is administratively burdensome, requiring that energy efficient appliance adoptions be verified, and the energy-saving effects of each adoption estimated through costly program evaluations.
> 2. It addresses only those programs that *can* be verified or are associated with relatively easily counted adoptions. That is, lost revenue adjustments can be applied to high-efficiency furnace programs, but it would be difficult to use this mechanism for a program such as the Energy Trust's Efficient Facility Operations Program, in which a diverse set of actions may be taken to improve energy efficiency.
> 3. Lost revenue adjustments encourage programs that look good on paper, but do not actually deliver therm reductions.
> 4. With only lost revenue adjustments, the utility is discouraged from backing more general conservation efforts, such as pleas from the Governor to reduce consumption during an energy crisis, or proposals to improve energy-efficiency standards embedded in building codes. In addition, to the extent that specific energy-efficiency messages (*e.g.*, promoting the HEF program) can spur

more general conservation efforts, the utility program is left uncompensated by lost revenue adjustments.

5. Lost revenue adjustments do not protect the utility from margin loss due to independent conservation efforts (*i.e.*, conservation efforts undertaken by customers outside of formal programs with the intent of lowering their bill). In times of increasing prices, this can require the utility to file rate cases more frequently, which imposes costs on the regulator and customers (indirectly, to the extent that rate case expenses can be recovered through rates). Conversely, in time of declining prices, lost revenue adjustments do nothing to prevent over-recovery on the part of the utility. (In principle, the elasticity adjustment accounts for this effect. However, its effectiveness is affected by the accuracy of the elasticity parameter, which can be difficult to estimate.)

The principle advantage of lost revenue adjustments relative to decoupling mechanisms is that they limit revenue adjustments to conservation efforts, while decoupling may compensate the utility for consumption declines due to economic or other factors. Our findings in Section 4.3 above, which analyzed the factors that affect residential and commercial use per customer for NW Natural's Oregon customers, indicates that this potential advantage is not relevant in NW Natural's case. That is, we found that the Oregon unemployment rate is not related to use per customer, and that retail prices and heating degree days explain the vast majority of variations in use per customer. Given this, it is unlikely that a significant share of DMN revenue flows can be attributed to customer responses to changing economic conditions.

Taking all of the above into account, our belief is that lost revenue adjustments will not be as effective as decoupling is in changing utility attitudes and actions with respect to promoting energy efficiency and other conservation efforts. (Footnotes deleted)

5. COMMITTEE ALTERNATIVE RECOMMENDATION

Q. In his testimony filed May 16, Mr. Dismukes recommends an "alternative recommendation" if the Commission believes that decoupling is in the public interest. Will you please address the five minimum requirements he identifies?

A. Yes. The *first* "requirement" is that the decoupling mechanism "should be implemented only after properly designed DSM programs are in place and functioning for sufficient time that impacts upon ratepayers and the utility can be measured." On lines 140 to 284 of this surrebuttal testimony, I have addressed this issue of implementing DSM programs prior to the implementation of the CET and outline the progress the Company is making toward having cost-effective DSM measures ready to implement if the Commission approves this application. It is the Company's belief that it is appropriate for the CET and DSM programs to be implemented simultaneously.

On lines 452 to 459 and 572 to 580 of Ralph Cavanagh's surrebuttal testimony, he addresses the issue of implementing the CET only after DSM programs are in place. He quotes the Costello Report stating, "[I]t would seem both unfair and counterproductive to order a utility to promote energy efficiency when detrimental to its shareholders."

Mr. Dismukes' *second* "requirement" is that "[a] cost of capital adjustment should be incorporated into the CET program that accounts for its inherent risk shifting." On lines 795 to 851 of this surrebuttal testimony, I have addressed this issue of a cost-of-capital adjustment. No other jurisdiction approving decoupling has required such an adjustment. The only state where this was done, Maryland, has now reversed course and eliminated the adjustment.

Mr. Dismukes' *third* "requirement" is that "[a] defined three-year set of DSM programs, which match the CET pilot period, should be provided." On lines 162 to 224 of this surrebuttal testimony and in QGC Exhibit SR 1.3, I have provided the Energy-Efficiency Roadmap for implementing DSM in Utah. This has been developed with input from the Division, the Committee and other interested stakeholders. The Company and the DSM Advisory Group should continue to work in harmony to evaluate and propose those programs deemed to be most productive and cost-effective over the Pilot Period and beyond.

Mr. Dismukes' *fourth* "requirement" is that "[t]he Company should define clear reporting requirements and evaluation metrics including annual DSM savings goals for the pilot period." In paragraph 18 of the Joint Application in this docket, the Joint Applicants proposed that "[a]s part of the pilot program, the Division will review the results of the Conservation Enabling Tariff at the end of each quarter for the first year and annually, or more frequently as needed, thereafter, and will submit reports to the Commission that include an analysis of each year's results."

On lines 278 to 296 of his original testimony, Dr. William Powell addressed the Division's responsibility to monitor Questar Gas' DSM performance, the CET tariff and deferral account, and the Company's overall earnings during the Pilot Program. Dr. Powell has provided further discussion of the Division's responsibilities in his surrebuttal testimony.

On lines 227 to 235, he addresses the issue of annual DSM-savings goals. As he points out, the examples used by the Joint Applicants in testimony assumed a 1% annual reduction in natural gas demand from DSM programs. This goal is consistent with other industry goals with respect to DSM programs.

Mr. Dismukes' *fifth* "requirement" is that "[i]f the Company wishes to withdraw from the [CET] program, it must petition the Commission and show that the cost to ratepayers of maintaining the program outweigh its potential benefits." It is the nature of a pilot program that changes can be proposed and the methodology improved prior to the program being permanently adopted. This characteristic was specifically identified as a protective measure for all parties in this case. The Joint Applicants have always understood that any changes to the Pilot Program would have to be proposed to the Commission, supported with evidence and ultimately approved by the Commission. No party can alter or withdraw from a Commission-ordered program without a subsequent order.

Q. Do you believe the five minimum requirements of the Committee's Alternative Recommendation have been included or resolved in the Joint Applicants' proposal?

A. Yes. Four of the five minimum requirements have been shown to be covered by evidence provided in the Joint Applicants' direct or surrebuttal testimony. The other requirement to "adjust the cost of capital" is unnecessary.

6. MISCELLANEOUS ISSUES

a. Amortization Methodology

Q. Mr. Dismukes expressed in his original testimony, some difficulty in understanding the Joint Applicants' proposal. Specifically, he asks about the procedure for amortizing CET balances and the potential for controversy surrounding the use of forecasted sales. In addition he focuses on the question of how to treat an imbalance remaining at the termination of the CET. Can you clarify these issues?

A. Yes. The Joint Applicants proposed the CET balance be amortized semi-annually along with the Company's pass-through applications. This would result in fewer rate changes. However, the Company is agreeable to changing the simultaneous amortization to a different schedule if it is shown to be preferable.

Q. Why did the Company propose to use a sales forecast to calculate the CET amortization?

A. The Company proposed to use a sales forecast to make the CET amortization methodology consistent with its pass-through cases. The Company currently uses a forecast of sales when preparing and filing pass-through applications. The Company is simply proposing to use the same sales forecast to calculate the CET amortizations.

Q. What about the treatment of any balance remaining at the termination of the CET?

A. The Company hopes to make the CET a permanent feature of its tariff. If the Commission decides to terminate the CET, certainly an appropriate amortization of any remaining balance can be determined at that time.

b. Customer Mix

Q. Mr. Higgins and Mr. Dismukes raise the issue of customer mix. Do their concerns have merit?

A. Not really. While they are technically correct that a significant change in customer mix might result in one customer class providing disproportionate support for the Pilot Program or a windfall for the Company, they provide no evidence that customer mix will change. QGC Exhibit SR 1.13 shows the total number of GS customers and the percent of those customers that are residential from 1980 through 2005. As can be seen, even with dramatic customer growth, the percent that are residential in this class has been extremely stable for the last 26 years. Development in our service territory is following stable long-term patterns.

Q. Mr. Dismukes speculates that commercial customers might end up subsidizing the residential sector's DSM costs due to shifts in customer proportions or emphasis on residential DSM to the detriment of commercial DSM. Is there any merit to this concern?

A. No. I have just addressed the customer mix aspect of his concern. To address his second concern, the Company plans to propose DSM programs designed to address each major market segment and expects to achieve similar penetration rates for commercial versus residential DSM programs.

c. CET Evaluation Criteria

Q. Have the Joint Applicants proposed a specific set of evaluation criteria to use in evaluating the performance of the CET mechanism during the Pilot Program?

A. No. However, the Joint Applicants recognize a need to conduct periodic reviews, and suggested that the Division be tasked with this responsibility as outlined in the Joint Application and as discussed above in this surrebuttal testimony.

d Transfer of R&D Funding To DSM

Q. Did the Joint Applicants propose to pay interest on the $1.3 million proposed to be transferred to the DSM deferred account?

A. No. The Joint Application did not propose that interest be paid on this balance. However, after further discussion with our Joint Applicants, the Company would not oppose paying interest on this balance once it has been transferred to the deferred DSM account**.**

7. PSC STAFF QUESTIONS

Q. Commission Staff prepared a document to facilitate the Technical Conference held in this docket on June 7, 2006. This document posed many questions related to the Pilot Program. Have you reviewed this document and the questions contained therein?

A. Yes. I have addressed many of these points in my direct testimony, or elsewhere in this surrebuttal testimony. To the extent I have answered these questions elsewhere, I will provide a specific reference to the lines where the answer can be found. In some cases another Joint Applicant witness has addressed a question. I will provide a reference to the witness in those situations. The Staff's questions are addressed below in the order they appeared in the June 7, 2006 document. **(Note: Commission Staff questions have been italicized).**

Q. What is the direct relationship of use per customer to earnings?

A. Looking at the General Service rate class as a group, a 1% decline in usage per customer translates into a $23,000,000 loss of DNG revenue in the fifth year (see QGC Exhibit SR 1.8). All other things being equal, these lost revenues would result in a direct drop in after-tax earnings of about $15,000,000.

Q. Do the Joint Applicants assume that declining use per customer always results in declining net revenues?

A. I answer this question with the understanding that "net revenue" means net income. Net income is defined as the remainder after subtracting all costs (expenses, depreciation, interest and taxes) from revenue. Net income is synonymous with earnings. The Company does not make the claim that declining usage per customer always results in declining net income, however, declining usage per customer is a significant factor in causing declining net income and is a phenomenon that the Company has experienced over the years.

Q. ***Are there factors that offset the effect of declining use per customer on earnings?***

A. Yes. Management can attempt to reduce expenses, increase sales revenues, or file for rate relief to mitigate declining customer usage.

Q. ***What does Questar Gas' history tell us about its net revenues (income) between rate cases?***

A. Marginal revenues have not matched marginal costs. The Company's significant decline in usage over the last 26 years and above-average customer growth has overwhelmed management's ability to reduce expenses between rate cases. This is evident by the fact that Questar Gas filed general rate cases in 1989, 1993, 1995, 1999 and 2002.

Q. ***If it is net revenue (income) rather than use per customer that impacts earnings, have the Joint Applicants provided, or do they plan to provide, evidence to support the likelihood and magnitude of declining net revenue (income) attributed to Company-sponsored DSM programs?***

A. The question may assume that the only loss of net income of concern is the loss associated with Company-sponsored DSM which, as I have previously discussed is very difficult to isolate from other factors causing decreases in usage per customer. To quote from the Joint Application at page 8, "The Conservation Enabling Tariff would allow Questar Gas to address the issue of declining usage per customer while removing the disincentives for Questar Gas to implement demand-side management programs." This statement shows that there are two separate but related issues addressed by the CET. The first issue is the revenue impact of declining usage per customer, regardless of cause. The second issue is the barrier to encourage further decline in usage per customer via Company-sponsored DSM and other forms of customer communication (including educational efforts and energy efficiency related advertising.)

With that clarification, I can address Staff's core question. QGC Exhibit SR 1.8 shows that all other factors being equal and an annual decrease in usage per customer from energy-efficiency measures of 1%, the Company will experience a reduction of annual net income-before-taxes of $23,175,000 in Year 5. Assuming any increase in expenses during that same period would result in an even greater decrease in net income.

Q. Is such evidence typically provided in decoupling proceedings?

A. The Company has informally surveyed four companies (Northwest Natural, Baltimore Gas & Electric, Piedmont Natural Gas and Cascade Natural Gas) that have received approval for a decoupling mechanism. All four respondents indicated that evidence supporting the impact of company-sponsored DSM programs on net income was not provided. Therefore, the Company concludes that such evidence may not be typically provided nor required for approval of a decoupling mechanism.

Q. In Ken Costello's NRRI Briefing Paper he states that in addition to promoting energy-efficiency initiatives, the following three conditions would support revenue decoupling:

1. Consumption per customer is likely to decline in the future.
2. The ability to add customers is greatly limited.
3. Expected declining use per customer is not recognized in ratemaking.

If only one of these three conditions exists, is that adequate support for approving revenue decoupling?

A. First, in his briefing paper, Ken Costello concludes there are two separate rationales that can support a decoupling mechanism. The three conditions referenced in Staff's question pertain to the second rationale. By focusing solely on the three conditions associated with the second rationale for revenue decoupling, the reasons for filing the Joint Application are completely overlooked.

The first rationale, which can be found on page 20 of Mr. Costello's paper, matches precisely what the Joint Applicants have filed and what has been provided as evidence in this case.

Specifically Costello states:

> In considering RD, a state commission might first want to consider whether a gas utility should be in the business of selling natural gas and delivery service or, more broadly, of selling energy services, which include energy conservation. If the latter is preferred, then RD becomes a more tenable ratemaking tool. If not, then a commission should assess RD in terms of the "declining gas use per customer" phenomenon. In other words, if a state commission requires a gas utility to promote aggressively energy efficiency, or if there is strong evidence of large benefits from utility-funded energy-efficiency initiatives, RD has definite merits as a ratemaking mechanism.
>
> Regulators should not expect a utility to undertake pro-actively energy-efficiency initiatives when shareholder interests deteriorate. A collision course leading to unintended consequences seems inevitable under standard ratemaking from requiring a utility, whose earnings directly relate to the level of sales, to play an independent active role in reducing its sales. Furthermore, if a commission approves RD, it could require a utility to be committed to promoting aggressively energy efficiency. (Footnotes deleted.)

The Joint Application and testimony have shown that: 1) not only do many third parties and the state of Utah want Questar Gas to "include energy conservation" as one of the services it provides, but more than 90% of Questar Gas' customers believe that energy conservation is important and over 73% would like to receive information and programs from the utility (see QGC Exhibit SR 1.1); 2) Questar Gas has a long and consistent history of the "declining gas use per customer phenomenon"; 3) Questar Gas' shareholder interests will deteriorate if the Company undertakes proactive energy-efficiency initiatives; and 4) the foundation of the Pilot Program is that with decoupling the Company will aggressively pursue energy efficiency.

Q. Why the focus in the first condition on consumption per customer rather than net revenue (income)?

A. The Task Force focused on the first condition (declining usage per customer) because that was the specific direction the Commission gave when it said "study separately" the declining use per customer or usage "tracker mechanism." Another reason for that focus is the basis of the first rationale for revenue decoupling cited in Costello's paper. The Company focuses on usage in the first condition because it is a direct cause (of declining profitability) and would be exacerbated by the proactive DSM programs we are discussing.

Q. The Company recovers DNG costs on a weather-normalized basis, other fixed costs through a fixed monthly charge, and recovers commodity and supplier non-gas costs through a balancing account. How does adoption of these regulatory mechanisms increase or decrease the benefits of revenue decoupling?

A. First, the Company's WNA mechanism removes the risk and volatility of weather variation from the customers' bills for both the Company and its customers. The CET will not diminish this benefit. The Basic Service Fee recovers approximately 23.5% of the fixed costs allocated to the General Service class. This leaves 76.5% of fixed cost recovery to volumetric rates. The fact that the WNA and Basic Service Fee are currently in place for the Company will result in smaller CET deferrals than would be required were they not in place.

The PGA is unaffected by the CET and vice versa, since the CET deals with DNG costs and the PGA deals with commodity and SNG costs. The one example cited by Mr. Dismukes of an LDC without the benefit of a PGA clause (Vermont Gas) is an interesting study in its own right. While I am not completely familiar with the regulatory decisions in Vermont, my understanding is that Vermont Gas has been forced to deal with the lack of a purchased-gas-adjustment tracker by acquiring the bulk of its gas supplies under fixed-price contracts or through hedging-variable priced contracts. As this Commission is well aware, this approach is expensive and increases Vermont Gas' cost of gas substantially. Furthermore, Vermont Gas has pending a request to adopt a purchased-gas-adjustment mechanism.

Q. What information and type of analysis is necessary to determine if the Company would under-earn due to Company-sponsored DSM programs?

A. Please refer to my surrebuttal testimony on lines 491 to 623 and QGC Exhibits SR 1.7, SR 1.8 and SR 1.9.

Q. ***The Joint Applicants request revenue decoupling for the GS rate schedule which includes both residential and commercial customers, and have supported this request by providing a temperature-adjusted usage-per-customer graph in which residential and commercial customers are lumped together. Have other utilities lumped residential and commercial customers together when implementing revenue decoupling?***

A. In its informal survey of four companies that have received approval for a decoupling mechanism, the Company found that this type of analysis for residential and commercial groups was not required, due to the fact that the two groups were already separated by different rate schedules. The decoupling mechanisms approved for each of these four companies, however, applied to both residential and commercial customers.

Q. ***If so have they broken their analyses out to reflect the different customer types?***

A. Refer to previous answer.

Q. ***Is declining use per customer the same for the two customer classes?***

A. Our experience shows the declining usage per customer has declined for both customer classes. QGC Exhibit SR 1.14, page 1 shows that since 1981 residential temperature-adjusted annual usage per customer has declined from 139.80 Dth to 84.64 Dth, a decline of 39.5%. For the same period commercial temperature-adjusted annual usage per customer, shown on page 2 of the exhibit, has declined from 673.83 Dth to 451.31 Dth, a decline of 33%.

Q. ***Regarding the Joint Applicants' graph entitled "Utah GS-1 Temperature-Adjusted Usage Per Customer (QGC Exhibit 1.4 and QGC Exhibit SR 1.7)," how does one identify the individual contribution to the observed declining use per customer due to price impacts, weather impacts, changes to building codes, appliance efficiency standards, customer initiated DSM and the economy?***

A. Other than weather impacts, which have already been removed, it is virtually impossible to determine with certainty the individual impact of each of these various factors on customer usage. It is safe to say that they all have had some impact.

Q. How much will Company-sponsored DSM affect the current trend under a variety of scenarios?

A. The Company's objective is to add an incremental 1% decline to the decline that would have happened in the absence of aggressive Company participation. The Energy-Efficiency Roadmap provides a plan to achieve this.

Q. Can the declining use per customer attributed only to Company-sponsored DSM programs be measured?

A. This would be very difficult to do. It has been a very hotly contested issue in those jurisdictions where it was tried. The effects of education and advertising are virtually impossible to isolate. This is one of the reasons the Joint Applicants chose to propose a pilot program that did not have this controversy.

Q. Can that variable be isolated and tested?

A. No. The effects of education, advertising promotion of better building codes, promotion of research and development for energy efficient appliances, etc. are virtually impossible to measure for specific, short-term periods of time. The continuing trend of declining usage per customer, however, is partially attributable to these Company-sponsored energy-efficiency initiatives. Depending on how much effort and resources one is willing to expend, it may be possible to estimate the declining usage per customer attributable to certain prescriptive approaches.

Q. What is the reasonable level to which consumption per customer can fall?

A. This answer is dependent upon the time frame, future price levels, future building codes and assumed technology expectations. We believe the State of Utah's goal to save 20% over 20 years is aggressive, but achievable. By Commission order we have participated in a DSM

Task Force that commissioned a third-party study that identified $1.5 billion savings over ten years. We have the support of local and national groups who believe 1% per year is possible.

All of these indicators led the Joint Applicants to recommend the Pilot Program to begin capturing possible energy-efficiencies in this market.

Q. Have other utilities provided such an estimate in their revenue-decoupling applications?

A. In its informal survey of four companies that have received approval for a decoupling mechanism, all respondents indicated that this type of estimate was not provided as support for their decoupling applications.

Q. Are there any studies which evaluate how much the natural gas price spike in the last couple of years has contributed to decreased usage per customer?

A. The price spike was too recent to have been studied extensively. The California experience with their 10/20 program may give some insight. This program offered a 20% rebate for customers reducing usage by more than 10%. The 10/20 program resulted in 21% of the customers saving an average of 28% in the three-month period.

Q. Since the commodity gas costs and supplier non-gas costs are recovered through a balancing account, some fixed costs are collected through a fixed monthly charge, and the DNG costs (pretty much everything else) would be in the new CET balancing account, then over time the utility has a government guaranteed recovery of all prudent costs incurred. Given this type of recovery, what financial risk does the Company face over time?

A. This question is based on an erroneous assumption. The CET does not guarantee that the Company will recover 100% of all prudent DNG costs. The CET does not even have costs as a component in the equation. The Company continues to face the possibility that costs will exceed those included in rates. As shown by QGC Exhibit SR 1.9, the average rate base for new customers exceeds the average that is in rates. If costs exceed revenues by an excessive amount the Company can be expected to file for rate relief, as is current practice.

The change expected by the CET is not as characterized by this question. A full discussion of risk, return and regulatory practice can be found in this surrebuttal testimony beginning at line 795.

Q. Does the provision of gas service become a "cost-plus" contract? If so, what is a reasonable cost of capital to assign? A T-Bill rate? Utah State Government rate?

A. Absolutely not. As stated above, and on lines 690 to 718 in this surrebuttal testimony, the Company's risks with respect to costs are not mitigated by the implementation of the CET.

Q. Under a full decoupling approach to cost recovery the ratepayers assume most of the risk of price movement, and the further additional risk that Questar's behavior and incentives would change; what benefits do customers receive to compensate them for this increased risk?

A. I need to comment on the premise of the question that customers assume most of the risk of price movement under full decoupling. Customers are only at risk to pay the Commission authorized non-gas cost of service. From the Company's perspective, it is allowed to collect on an average-per-customer basis, only what the Commission has already found to be just and reasonable. As stated earlier in this testimony, full decoupling has little to do with the risk of price movement.

Customers receive many benefits from adoption of the CET, such as: reduced price volatility, assistance with energy efficiency, stabilized DNG costs, and greater management focus on achieving the lowest long-run cost of service, potentially lower financing costs due to a better credit rating, lower gas cost via the avoidance of high-cost gas purchases, reduced gas cost due to reductions in demand leading to reductions in market prices and lower supplier non-gas costs as reduced demand allows for deferment of facility expansions.

Q. The proposed CET appears to fully decouple DNG decatherm sales from collection of DNG revenues. Remaining commodity and supplier non-gas costs are currently collected

through a balancing account and remaining fixed costs through a fixed monthly charge rather than a volumetric charge. With these regulatory mechanisms in place governing all natural gas service costs, what incentive remains for the utility to be economically efficient?

A. The CET is an accounting tool that enables the Company to collect from customers only what the Commission has authorized. No expenses are included in the calculation. Therefore, as explained on lines 690 through 718 of this testimony, the Company's incentive to control costs and be efficient is not diminished by implementing the CET.

Q. Intervenor testimony raises the question as to why an incentive is needed for Questar Gas to pursue DSM when it is already obligated by Commission Order to pursue the least-cost alternative for the provision of natural gas energy services to its present and future ratepayers. Exhibit 9.23 of Questar Gas Company's May 2, 2005, Integrated Resource Plan shows Company implementation of DSM programs would reduce Company costs and customer rates. Is it prudent for the Company to forego implementation of these programs in the absence of an approved CET?

A. Three points need to be recognized in response to this question. First, as previously stated, Commission Order in Docket No. 91-057-09, provided that it "will require Mountain Fuel Supply Company (MFS or Company) to pursue the least-cost alternative for the provision of natural gas energy services to its present and future ratepayers that is consistent with <u>safe</u> and <u>reliable service</u>, the <u>fiscal requirements of a financially healthy utility</u>, and the <u>long-run public interest</u>." (Order at 1, emphasis added.)

Second, the parties to that docket, including the Committee and the Division, agreed to modified guidelines in 1998 which provided the following additional clarifications on page 1: "This [IRP] process should result in the selection of the optimal set of resources given expectations relating to costs, risk, uncertainty and technical feasibility."

Third, intervenor testimony either failed to focus on the demand-side resource section of the

IRP Report or chose to ignore it. But on page 8-3 of the May 2005 IRP Report the eight recommendations of the DSM Group Report are summarized. Recommendation #4 states that barriers to successful implementation of DSM should be addressed by this Commission. The primary example of a barrier was identified in the report as "Questar's economic sensitivity to the loss of gas load that increased DSM would foster." Recognizing that significant gas-cost savings are possible, a prudent utility would do exactly what the Joint Application requests: remove the barrier so the Company is not harmed when it aggressively pursues DSM. (I should note that the other seven recommendations in the DSM Report/IRP Report have also been addressed with this Joint Application.)

Q. Given that State law offers the option of a future test period for rate cases - which if done correctly will match revenues to costs on average - are there some other benefits to a decoupling approach (other than cost recovery and energy efficiency) that argue for its adoption?

A. Yes. Assuming that a future test period is used that correctly matches revenues to costs, the Company will continue to benefit from increased sales between rate cases. This does not align the interest of the Company with those of its customers. The Task Force analyzed the pros and cons of the "future test period" and felt that the CET was the better option for aligning the Company's interests with that of its customers and should be implemented as a pilot program.

Q. When compared to a program that would only compensate Questar Gas for its direct DSM costs and any under-recovery of fixed costs determined to be caused by those DSM programs, what are the advantages and disadvantages of both the decoupling approach and the future test year approach?

A. Compared to a direct lost-revenue approach, decoupling as proposed in the CET is far superior. Calculating lost revenues strictly attributable to DSM programs would be contentious and complex. Please refer to the discussion of lost revenues at lines 957 to 1025. Instead, the time, money and effort would be much better spent on more DSM programs. For a comparison of regulation alternatives, see QGC Exhibit SR 1.15.

The future-test-year approach does not remove the barrier. A future test year would be used in the context of a general rate case and therefore suffers from the problems mentioned above. That said, if the Company is going to have a rate case, then a forecasted test year is preferred.

Q. Is there a decoupling mechanism that addresses only the impact of Company-sponsored DSM programs on declining use per customer (or net revenues (income) should this be the relevant factor affecting earnings)?

A. While some may claim that there are decoupling mechanisms that can address only company-sponsored DSM programs, my testimony has demonstrated that these mechanisms have significant problems. In addition, simply providing an incentive to promote DSM was not the purpose of the Joint Application. The purpose is to remove the barrier to the Company from aggressively pursuing DSM and allowing the Company an opportunity to collect its allowed revenue during periods of declining customer usage regardless of the cause.

Q. Are there any other regulatory mechanisms besides the decoupling proposal or the current use of a future test year that should be considered in this case?

A. I think it is very important for the Commission to understand the alternative approaches that were considered and rejected. The Joint Application was the culmination of a three-year process following the Company's general rate case in Docket No. 02-057-02. Other regulatory mechanisms including forecasted test year, annual abbreviated rate cases, lost revenue/partial decoupling, delivery charge/straight fixed variable, revenue stabilization and full decoupling were analyzed by the Joint Applicants, and others. The analysis is summarized in Exhibits 1.6 and 1.7 attached to the Joint Application in this docket.

8. SUMMARY

Q. Would you please recap your testimony in this docket?

A. This process was initiated through the creation of three task forces at the conclusion of the Company's 2002 rate case. The Company has continued this collaborative process both prior to and following the filing of the Joint Application. I have reviewed the historical backdrop to the Joint Application, including the Allocation and Rate Design Task Force, the DSM Task Force, and the work growing directly from these efforts that led to the filing in this docket by the Joint Applicants. I have provided a long-term perspective on the experience the Company has had with declining usage and its effects on the Company's finances. I have clearly shown that the Company is ready, willing and able to aggressively pursue energy-efficiency measures once the barrier to doing so is removed. I have explained how the CET will provide benefits for all customers.

Q. Why should the Commission approve the Joint Applicant's Pilot Program?

A. There is clear and unambiguous support nationwide for improved energy efficiency, most recently evidenced by the National Action Plan for Energy Efficiency. As noted above, the Company is ready to be a leader in this effort once the barrier has been removed. Governor Huntsman's state energy-efficiency policy calls for regulatory barriers to the adoption of energy-efficiency programs to be identified and removed. The CET will effectively remove the barrier in a fair manner. The Commission has sufficient evidence on the record to determine that the Company's rates are just and reasonable. The Commission has the tools available to continue monitoring the ongoing just and reasonableness of future rates.

Q. The rebuttal witnesses have raised numerous issues regarding the Pilot Program. They all argue that the Joint Applicants' Pilot Program should be rejected. Have the issues raised by the rebuttal witnesses been addressed by the Joint Applicants?

A. The rebuttal witnesses' substantive issues have been addressed. Specifically, energy-efficiency measures can and should be encouraged and the Company is best in the position to lead this effort. The barrier to the Company's willing participation is real and should be removed. The CET mechanism proposed to remove the barrier has been shown to be effective and fair. The $9.7 million rate reduction implemented June 1, 2006 and the $1.1

million credit to the CET balance proposed herein will result in rates that are just and reasonable. The Results of Operations Report is an effective tool for monitoring the Company's financial performance and should continue to ensure that rates remain just and reasonable.

Finally, the three-year Pilot Program provides an opportunity to fully evaluate the Company's performance in pursuing energy-efficiency and the effect of the CET on the Company's earnings.

Q. In your opinion is the Pilot Program as proposed by the Joint Applicants a step in the right direction in terms of regulatory policy?

A. Absolutely. The Pilot Program provides the Company, its customers and regulators with a mechanism that will allow the benefits of energy-efficiency to begin accruing in the near term. In addition, since the implementation of the CET and DSM is proposed as a Pilot Program, any unanticipated problems can be addressed on a going-forward basis. The Commission will have continuing opportunities to exercise its role in overseeing the justness and reasonableness of the Company's rates.

Q. Does this conclude your testimony?

A. Yes.

State of Utah)
) ss.
County of Salt Lake)

I, Barrie L. McKay, being first duly sworn on oath, state that the answers in the foregoing written testimony are true and correct to the best of my knowledge, information and belief. Except as stated in the testimony, the exhibits attached to the testimony were prepared by me or under my direction and supervision, and they are true and correct to the best of my knowledge, information and belief. Any exhibits not prepared by me or under my direction and supervision are true and correct copies of the documents they purport to be.

____
Barrie L. McKay

SUBSCRIBED AND SWORN TO this 14th day of August 2006.

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Notary Public