ROADMAP EXHIBIT
Testimony Filing References/Excerpts

I. NATIONAL AND STATE RECOGNITION OF THE EXISTENCE OF BARRIER AND THE NEED FOR ITS REMOVAL

I.A <u>The Disincentive or Barrier that Needs to be Removed</u>

I.A.1 What is the disincentive or barrier that needs to be removed?

BLM Direct (Lines 137 - 157)

Q. What is the disincentive or barrier that needs to be removed?

A. The current rate design does not allow the Company to collect its fixed costs when there is a decline in customer usage, and customer usage has been declining for many years. QGC Exhibit 1.4 is a graph showing declining Utah GS-1 temperature-normalized usage per customer from 1980 through 2005. It shows that average usage per customer has declined about 36% over this period. The current rate design recovers the majority of distribution non-gas costs (O&M, depreciation, payroll, taxes, interest expense and return on investment) in a volumetric rate. However, these distribution non-gas costs do not vary as sales volumes go up or down. This is illustrated by QGC Exhibit 1.5. When customer usage is increasing, the Company collects more revenue per customer than the Commission allowed when rates were approved. When customer usage is declining (i.e. less than what was used to set rates), the Company cannot collect the revenue per customer that the Commission allowed when rates were approved. Only when usage is stable does the revenue per customer match that which was allowed by the Commission. The fact that the Company earned 9.06% on equity in 2002, 10.94% on equity and in 2003 and 10.05% on equity in 2004 is at least in part attributable to this effect. In the absence of a mechanism similar to the proposed Conservation Enabling Tariff, the current rate design is a barrier to the Company in promoting Demand-Side Management. Instead, it provides an incentive for the Company to encourage customers to use more natural gas rather than aligning customers' and Company interests in finding ways to conserve gas.

I.B <u>National Momentum for States to Adopt Programs that Remove the Barrier</u>

I.B.1 Many states have engaged in or are studying alternatives designed to remove the barrier.

Application (Paragraph 2)

2. Many state and national energy policy groups have engaged in, and are continuing with, discussions of alternative rate designs or tariffs designed to promote energy efficiency and conservation to help address high wholesale natural gas prices and remove disincentives to natural gas public utilities to implement demand-side management programs while recovering their costs.

I.B.2 Examples of programs adopted in other states.

BLM Direct (Lines 72 - 84)

Q. Please describe briefly the kinds of programs adopted in other states.

A. Innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" have been approved for Northwest Natural Gas in Oregon, Baltimore Gas & Electric and Washington Natural Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina. Fixed-variable rate designs that recover most distribution system costs in a monthly fixed charge have been approved for Northern States Power in North Dakota and Atlanta Gas Light in Georgia. QGC Exhibit 1.3 is a chart providing summary information about the decoupling rate mechanisms that have been adopted or are currently proposed in other states. All of these programs attempt to completely remove the financial disincentive that makes it difficult for gas distribution companies to actively promote Demand-Side Management. These programs all involve full decoupling, which means they go far beyond just recovering lost revenue attributable to Demand-Side-Management programs. Several of these programs were adopted outside general rate cases.

I.B.3 Experience with other states implementing decoupling mechanisms.

RC/NRDC Surrebuttal (Lines 252 - 345)

Q. Is there relevant recent experience with comparable mechanisms in other states?

A. The most extensive recent activity with which I am familiar is in California, Oregon, Idaho, Maryland, North Carolina, Wisconsin and Washington. Four of those states have adopted gas decoupling mechanisms; in the other three, Commissions have indicated specific interest in acting and proceedings are underway or imminent. Ken Costello's recent Briefing Paper for NRRI lists four other states with pending decoupling filings (Indiana, New Jersey and Ohio, in addition to Utah). More specifically:

California has embraced a true-up policy for all its investor-owned utilities, covering fixed costs of delivering both electricity and natural gas; in California today, utilities' recovery of fixed costs is completely independent of retail sales. Not coincidentally, California utilities are conducting the nation's most aggressive energy efficiency programs (measured in savings as a percentage of retail electric and gas use).

Oregon's PUC adopted a true-up mechanism for PacifiCorp in 1998, covering fixed costs of electricity distribution. Initial rate impacts of the Oregon "Alternative Form of Regulation" were extremely modest for all classes, and (as predicted) adjustments went in both directions; the largest annual rate increase for any class was 1.9%, the largest annual rate reduction was 0.83%, and out of a total of fifteen true-ups from 1999 – 2001, seven resulted in rate reductions and eight resulted in rate increases. More recently (in 2002), the Oregon PUC also adopted a modified true-up mechanism for Northwest Natural Gas; an independent evaluation concluded in March 2005 that the mechanism was "effective in altering Northwest Natural's incentives to promote energy efficiency" and should be retained, although the authors recommended removing some rather complex features that were not relevant to the mechanism's primary purpose. The Commission adopted an order in August 2005 adopting a stipulation that simplified the mechanism and extended it for another four years. The State's other major gas distributor, Cascade Natural Gas, secured its own decoupling mechanism recently when the Oregon Commission approved its May 18, 2006 tariff filing.

The **Wisconsin** Public Service Commission determined in July 2005 that utilities' financial disincentives were inappropriately constraining statewide energy efficiency development, and that "the time is right to fully explore true-up mechanisms and performance-based incentives." Those efforts are now underway as Alliant, one of the state's principal utilities, convenes multi-party workshops to seek consensus on proposals to present to the Commission.

In May 2004, the **Idaho** Public Utilities Commission opened a proceeding to address financial disincentives for Idaho Power's energy efficiency investments and performance-based incentives tied to the utility's success in delivering cost-effective savings. Subsequent workshops yielded a report to the Commission, embraced by all participants, which included the conclusions that "the workshop participants agreed that material financial disincentives to the implementation of DSM programs do exist," and called for detailed retrospective and prospective financial analyses "to evaluate incorporation of a true-up mechanism into the [Company's next] rate filing," along with pilot testing of a performance-based DSM incentive. That process is now complete, and the Company's decoupling application is now pending at the Commission.

In November 2005, the **North Carolina** Utilities Commission approved a three-year test of a decoupling mechanism for residential and commercial customers, citing the joint statement of NRDC and AGA and the need to eliminate "an inherent conflict between the interests of the Company and its customers with respect to conservation." The Commission conditioned its approval on "a substantial and effective initiative by the Company to assist its residential and commercial customers with conservation."

Ken Costello's recent NRRI Briefing Paper lists **Maryland** among the states that have embraced gas decoupling, and cites evidence that the mechanism has operated effectively and met expectations there. Costello also notes that in one case (involving the Baltimore Gas and Electric Company), the Maryland Commission included in its decoupling order a 50 basis point reduction in the company's authorized return on equity "to reflect reduced revenue risk for the utility." However, in a more recent (December 2005) BG&E rate case order, the Commission decided that rate of return adjustments based on that same decoupling mechanism were not appropriate.

Washington's Utilities and Transportation Commission approved a revenue cap mechanism for Puget Power in 1991. As the Commission determined at that time:

[T]he revenue per customer mechanism does not insulate the company from fluctuations in economic conditions, because a robust economy would create additional customers and hence, additional revenue. Furthermore, the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor. The company would have an incentive to artificially inflate estimates of sales reductions while actually achieving little conservation.

The Commission implemented Puget's revenue-per-customer cap by "set[ting] up a deferred account allowing a reconciliation of revenue and expenses that would be subject to hearing and review." In its initial review of the mechanism that it had adopted two years earlier, the Commission in 1993 "accept[ed] the parties representations" that the revenue-per-customer cap had "achieved its primary goal – the removal of disincentives to conservation investment," and concluded that "Puget has developed a distinguished reputation because of its conservation programs and is now considered a national leader in this area." Based on these findings, the Commission granted a three-year extension of the revenue-per-customer cap. In 1995, as part of a litigation settlement proposal intended to create no precedent, Puget and several other parties filed a request with the Commission to terminate a complex system of rate adjustment mechanisms that included the revenue-per-customer cap (along with, e.g., a controversial approach to allocating risks of hydropower fluctuations). The Commission approved that request, but the proposal itself expressly reserved the right of all parties to bring forward in the future "other rate adjustment mechanisms, including decoupling mechanisms, lost revenue calculations, [and] similar methods for removing or reducing utility disincentives to acquire conservation resources." In 2004, the Commission invited PacifiCorp and other stakeholders to begin discussions regarding the design of such a mechanism, in its order approving a settlement proposal by NRDC, the Commission staff, and PacifiCorp.

I.B.4 Decoupling has attracted broad industry interest in the last two years.

RC/NRDC Surrebuttal (Lines 408 - 428)

Q. Why don't more states have true-up mechanisms in place to eliminate disincentives for utility investment in demand-side resources?

A. A strong trend in that direction was interrupted in the mid-1990s by a stampede toward an industry restructuring model (pioneered in California) that denied utilities any substantial role in resource planning or investment. On that theory, there was no reason to worry about utilities' energy efficiency incentives, because utilities would be transferring their resource management responsibilities to unregulated participants in wholesale and retail electricity markets. The Western electricity and natural gas crisis of 2000-2001 has discredited that model, which in any case never took hold in Utah. Most states are now restoring full or at least significant utility responsibility for resource portfolio management, and I can attest from frequent appearances at regulatory and utility forums that interest in true-up mechanisms is reviving. But natural gas decoupling has only attracted broad industry interest and support in the last two years; for example, NRDC and the American Gas Association issued their widely cited joint statement in support of decoupling at NARUC's summer 2004 meeting, and it was just last November that NARUC passed a resolution encouraging all state commissions to "review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices."

I.B.5 The Washington Commission did not "reject decoupling".

RC/NRDC Surrebuttal (Lines 347 - 359)

Q. But Witness Dismukes says that the Washington Commission rejected decoupling in 2006; what's your response?

A. As a witness in that case, I can attest that the Commission emphatically did not "reject decoupling." It rejected a specific proposal by the Company and NRDC, principally because (as indicated in the passage quoted by Mr. Dismukes, p. 29) continuing disputes over multi-state allocation of the company's fixed-cost revenue requirement made it impossible to calculate Washington's share of that revenue requirement, a prerequisite for any decoupling mechanism. In addition, unlike the Company in this proceeding, PacifiCorp had not made a public commitment to expand its conservation efforts. I expect soon, on behalf of NRDC, to file a new joint decoupling proposal with PacifiCorp in Washington, and I am confident that the Commission will approve it. I note also that both Puget Energy Services and Avista have natural gas decoupling proposals pending at the Washington Commission.

I.B.6 Connecticut regulators didn't rule against decoupling mechanisms.

RC/NRDC Surrebuttal (Lines 361 - 384)

Q. Witness Dismukes also says that Connecticut's regulators "recently ruled against revenue decoupling for its electric and gas utilities" (p.27); is that your understanding?

A. Not exactly. The Commission didn't "rule" on a utility application for a decoupling mechanism (Connecticut's gas utilities are only minimally involved in conservation efforts and are on record in opposition to decoupling). Mr. Dismukes is referring to a report that the Commission filed recently with the state legislature, in which the Commission acknowledged the need to remove financial disincentives for utility support of DSM but expressed a preference for calculating and restoring lost revenues associated with specific gas utility programs. It is worth noting also that the Connecticut Commission's concerns about shifting weather risks as part of decoupling proposals (cited in Mr. Dismukes' testimony at p. 28) are irrelevant to this proceeding, and that the Commission acknowledged specifically that decoupling "removes a disincentive for [utility] companies to promote conservation" (see passage quoted from Commission report at id.). The Connecticut Commission and its natural gas utilities prefer to address this problem by calculating and restoring to utilities lost revenues associated with their (very modest) conservation programs; as indicated earlier, I agree strongly with NRRI's Ken Costello that under this approach "an incentive problem arises where a utility would have an incentive to maximize measured or reported savings but to achieve minimal actual savings from energy efficiency initiatives." I note further that this approach sharply raises the cost to customers of conservation programs, by adding adjudicated lost revenues to the costs of the programs themselves, and that over time these costs escalate sharply as lost revenues from long-lived savings continue to pile up, year after year.

I.B.7 The Arizona Commission chose to defer action on decoupling pending further review.

RC/NRDC Surrebuttal (Lines 386 - 399)

Q. What about the Arizona Commission's reservations about decoupling (Dismukes, pp. 28-29)?

A. Unlike Questar in Utah, which already has participated in extensive informal discussions and workshops on decoupling (most recently on June 7), Southwest Gas's proposal in Arizona included little prior involvement and no support from other parties. The Arizona Commission adopted a proposal by my organization (NRDC) and others to defer action on the company's proposal pending workshops and discussions among interested parties and further review of contentious issues such as "who bears the risk of weather variations;" rather than rejecting decoupling, the Commission directed Southwest gas to "coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties." In this case, of course, Questar has already done precisely what Southwest Gas had neglected to do by way of productive advance consultations among all parties -- as demonstrated in part by my and others' strong support for its proposal.

I.C <u>Governmental Policy Statements or Actions Supporting Removal of the Barrier</u>

I.C.1 AGA and NRDC joint statement to NARUC to consider programs to align the interests.

BLM Direct (Lines 33 - 46)

Q. Is there precedent in other jurisdictions for the Pilot Program proposed in the Joint Application?

A. Yes. Many state and national energy-policy groups are discussing and implementing alternative rate designs or tariffs designed to promote energy efficiency and conservation. These tariffs and rate designs are being adopted to remove financial harm experienced by natural gas utilities when Demand-Side-Management programs are implemented. These programs also help address high gas prices. The American Gas Association and the Natural Resources Defense Council issued a joint statement to the National Association of Regulatory Utility Commissioners (NARUC) recommending that public utility commissions consider "innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders." This statement is Exhibit 1.1 to the Joint Application. The Joint Application requests approval of such an innovative program.

I.C.2 Joint Application notes national momentum and asks Commission to remove the barrier.

BLM Direct 1-YR (Lines 20 - 31)

Q. Would you please provide an overview of the Joint Application for approval of the Pilot Program?

A. The Company, the Division of Public Utilities (Division), and Utah Clean Energy (collectively referred to as the Joint Applicants) requested that the Commission allow the Company to pursue energy efficiency by approving the CET and Demand-Side Management (DSM) Pilot Program (Pilot Program). The Joint Application noted that national, state and local support for adoption of programs to promote energy efficiency was gaining momentum. The Joint Applicants asked the Commission to remove the barrier that discourages the Company from aggressively pursuing energy-efficiency initiatives. The Joint Application explained that the CET and DSM would provide a net benefit to all customers. The Joint Applicants stated that approval of the Pilot Program would not diminish the Commission's or Division's ability to perform their regulatory roles.

I.C.3 NARUC adopted the "Resolution on Energy Efficiency and Innovative Rate Design".

BLM Direct (Lines 47 - 71)

In its 2005 Fall meeting, NARUC adopted the "Resolution on Energy Efficiency and Innovative Rate Design," dated November 16, 2005. NARUC's resolution recognizes that energy conservation and efficiency are, in the short-term, the actions most likely to reduce upward pressure on natural gas prices and that current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers. The resolution further recognizes that:

> Innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), "fixed-variable" rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), other options (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas.

Finally, the resolution provides in pertinent part that NARUC:

> [E]ncourages State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices . . .

A copy of the NARUC Resolution is attached to the Joint Application as Exhibit 1.2.

I.C.4 Energy Policy Act of 2005 supports removing the barrier and aligning the interests.

Application (Paragraph 5)

5. Furthermore, Section 139 of the Energy Policy Act of 2005 provides that NARUC and the National Association of State Energy Officials shall conduct a study of state and regional policies that promote cost-effective programs to reduce energy consumption. In conducting the study, the following criteria shall be taken into consideration:
   (1) performance standards for achieving energy use and demand reduction targets;
   (2) funding sources, including rate surcharges;

(3) infrastructure planning approaches (including energy efficiency programs) and infrastructure improvements;
(4) the costs and benefits of consumer education programs conducted by State and local governments and local utilities to increase consumer awareness of energy efficiency technologies and measures; and
(5) methods of:
  (A) removing disincentives for utilities to implement energy efficiency programs;
  (B) encouraging utilities to undertake voluntary energy efficiency programs; and
  (C) ensuring appropriate returns on energy efficiency programs.

A copy of Section 139 is attached as Exhibit 1.3.

I.C.5 Federal, state and industry calls for actions to remove the barrier; the CET is that action.

BLM Settlement (Lines 317 - 354)

Q. Are there federal, state and industry calls for action that encourage state Commissions to remove utility barriers to promoting DSM programs?

A. Many state and national energy-policy groups are discussing and implementing alternative rate designs or tariffs designed to promote energy efficiency and conservation.

The American Gas Association and the Natural Resources Defense Council issued a joint statement to the National Association of Regulatory Utility Commissioners (NARUC) recommending that public utility commissions consider "innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders." A copy of this statement is attached to the Joint Application as Exhibit 1.1.

In its 2005 Fall meeting, NARUC adopted the "Resolution on Energy Efficiency and Innovative Rate Design," dated November 16, 2005. NARUC's resolution recognizes that energy conservation and efficiency are, in the short-term, the actions most likely to reduce upward pressure on natural gas prices and that current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers.

On April 25, 2006, Governor Jon Huntsman announced the "Utah Policy to Advance Energy Efficiency in the State." This policy sets a goal to reduce energy consumption in Utah by 20% by 2015. As part of the effort, the policy states: "State Government will work with stakeholders to identify and address regulatory barriers to increased deployment of energy efficiency." Adoption of the CET will remove a regulatory barrier to energy conservation and is consistent with Governor Huntsman's policy.

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. 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.

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I.C.6 Additional nationwide momentum since the filing for the CET Pilot Program.

BLM Direct 1-YR (Lines 192 - 205)

Q. Has there been increasing nationwide momentum to remove the barrier for natural gas utilities to promote energy efficiency?

A. Yes. With continued tight supplies of energy and concerns about climate change and CO_2 emissions, energy-efficiency improvements are more important than ever. Governor Huntsman continues to stress the importance of increasing energy efficiency and removing regulatory barriers to promoting energy efficiency. More than 30 states have either allowed or have pending before their state commissions some form of barrier removal. Interestingly, the three approaches analyzed and preferred by the Task Force have been the approaches that have gained traction. The three approaches are: 1) full decoupling; 2) straight-fixed-variable rate designs; and 3) revenue stabilization. QGC Exhibit 1-YR 1.5 is a map of the continental United States showing the status of proceedings regarding these three approaches for natural gas utilities. This represents a significant increase in activity and action since the filing of the Joint Application. Now is not the time for Utah to take a step backward by removing or restricting the Conservation Enabling Tariff.

II. TASK FORCES (3-YEAR PROCESS)

II.A Final Order in Docket No. 02-057-02 Created Task Forces

II.A.1 Final order in Docket No. 02-057-02 created task forces.

Application (Paragraph 8)

8. In Questar Gas' last rate case, Docket No. 02-057-02 (2002 Rate Case) the parties in that case entered into four separate Stipulations and Settlements on four major issues: Revenue Requirement; Allocation and Rate Design; Demand-Side Management; and Service Standards. In the Allocation and Rate Design, Demand-Side Management and Service Standards Stipulations, the parties to the Stipulations in that case recommended to the Commission that task forces be established to further consider issues raised during the 2002 Rate Case and to make recommendations in final reports filed with the Commission on how to proceed in future cases with regard to these issues. In its Order in the 2002 Rate Case, the Commission approved the terms of all four Stipulations and Settlements.

II.A.2 Why were the task forces established?

BLM Direct (Lines 86 - 94)

Q. Why were the Allocation and Rate Design and Demand-Side-Management Task Forces established?

A. The Allocation and Rate Design Task Force was established in the Company's last general rate case. The Task Force was ordered to study and consider rate-design issues that had been raised during that case. The issue of declining customer usage on Questar Gas's collection of non-gas revenue and the resulting disincentive for Questar Gas to support conservation programs was discussed. The Allocation and Rate Design Task Force met 18 times over 18 months. The final report of the Allocation and Rate Design Task Force is included as Exhibit 1.5 to the Joint Application.

II.A.3 Task forces led to extended period of analysis and review of issues.

BLM Direct (Lines 116 - 119)

Q. What does the foregoing process demonstrate?

A. First, this is not something the joint applicants have rushed into. Second, this shows that the joint applicants, as well as other interested stakeholders, have been following the Commission Order and have analyzed this issue over the last three years.

II.A.4 QGC is experiencing a declining usage per customer (UPC).

BLM Surrebuttal (Lines 438 - 488)

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.

II.A.5 QGC is harmed financially from declining UPC.

BLM Surrebuttal (Lines 490 - 504)

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.

II.A.6 QGC's fixed cost recovery is tied to retail sales volumes.

RC/NRDC Surrebuttal (Lines 123 - 133)

Q. What is the basis for your conclusion that Questar's fixed cost recovery is strongly tied to its retail sales volumes?

A. Like most utilities, Questar recovers most of its fixed costs through the rates it charges per therm. In other words, a part of the cost of every decatherm represents the system's fixed charges for existing plant and equipment; the rest collects the cost of the gas commodity itself. After approving a fixed-cost revenue requirement, the Public Service Commission of Utah sets rates based on assumptions about annual retail sales. If sales lag below those assumptions, the Company will not recover its approved fixed-cost revenue requirement. By contrast, if the Company is successful in promoting consumption increases above regulators' expectations, its shareholders earn a windfall in the form of cost recovery that exceeded the approved revenue requirement.

II.A.7 QGC losses from reduced retail sales are substantial.

RC/NRDC Surrebuttal (Lines 209 - 225)

Q. How substantial are potential shareholder losses from reduced retail sales?

A. In his rebuttal testimony, witness Barrie McKay demonstrates that programs saving one percent of systemwide use would reduce the company's fixed-cost recovery by about $1.5 million in the first year. But the losses get even worse in the context of multi-year programs initiated under a long-term resource plan. Mr. McKay's testimony contemplates a five-year program that pursues annual savings equivalent to one percent of retail consumption in the initial year, with each year adding new savings equivalent to the savings achieved during the previous year, and all savings persisting for at least five years. The first year impact on fixed cost recovery is then about $1.5 million, followed by $3 million dollars in the second year (as an equal amount of savings is added), and so on: **the automatic five-year loss to shareholders from this steady-state utility investment program would exceed $23 million dollars**, with shareholder losses continuing to escalate in succeeding years as initial energy savings persisted (with some gradual erosion) and more savings were added. Note that the shareholders would be absorbing these losses even as Utah gained from substituting less costly energy efficiency for more costly natural gas.

II.A.8 QGC has used various tools to deal with declining UPC.

BLM Surrebuttal (Lines 506 - 530)

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.

II.A.9 Addition of new customers does not offset financial harm of declining UPC.

BLM Surrebuttal (Lines 532 - 562)

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!

II.A.10 The task force process led to the filing of the Joint Application.

BLM Settlement (Lines 98 - 141)

Q. Please describe the process that led to the Joint Application.

A. In the Company's general rate case in 2002, Docket No. 02-057-02, questions arose regarding Demand-Side Management programs and the impact on earnings of a continuing decline in usage per customer. The Commission established two task forces to address these issues and directed the parties to attempt to reach accord and resolution of these issues for consideration in subsequent regulatory proceedings.

The Allocation and Rate Design Task Force met 18 times over 18 months. The final report of the Allocation and Rate Design Task Force was included as Exhibit 1.5 to the Joint Application. Although the Task Force was unable to reach consensus, members of the Task Force continued to meet. These meetings resulted in two white papers, one dated November 9, 2004 and one dated November 23, 2005, included as Exhibits 1.6 and 1.7 to the Joint Application. These white papers were distributed among the parties for review and discussion.

The Demand-Side-Management Task Force met numerous times over two years. As part of that process, a study jointly funded by the Company and the Utah Energy Office and conducted by GDS Associates was commissioned to determine the potential for energy conservation in Utah. Based on that study, the Task Force filed a report identifying that the net present value of savings to Questar Gas's residential and commercial customers from implementation of cost-effective natural gas DSM programs is over $1.5 billion in 2004 dollars. Additionally, eight recommendations were made in the DSM report all of which were incorporated in the Joint Application. The executive summary of the DSM Task Force is included as Exhibit 1.4 to the Joint Application.

Q. What did the parties do after the Task Forces filed their reports?

A. The parties continued to meet and to attempt to come to accord on the issues presented to the Task Forces. As noted in the second white paper, the parties had three goals: (1) remove the Company's disincentive to promote demand-side management, (2) reduce contention between regulators and the Company, and (3) provide the Company an opportunity to earn its allowed return during periods of declining usage. They analyzed six methods to achieve these goals. Ultimately, the Company, Division and Utah Clean Energy reached agreement on the Conservation Enabling Tariff and filed the Joint Application.

Q. What conclusions do you draw from the foregoing process?

A. The Settlement Stipulation is not something the Parties have rushed into. It was proceeded by a nearly four-year process with Task Force meetings, analyses and reports, further discussion and analysis among the Parties leading to white papers, the filing of the Joint Application, testimony and argument, discovery and workshops and technical conferences and arms-length negotiations. This lengthy process shows that the Parties, as well as other interested stakeholders, have been following the Commission direction from the 2002 rate case to study the issues and to attempt to reach accord on a resolution of the issues. The Settlement Stipulation is the result of this process.

II.B Final Order in Docket No. 02-057-02 Created the DSM Task Force

II.B.1 The Demand-Side Management Task Force (DSM).

BLM Direct (Lines 94 - 99)

The Demand-Side-Management Task Force was also established in the last general rate case. This Task Force was directed to examine Demand-Side-Management alternatives for resource planning in the Company's Integrated Resource Plan proceedings. The Commission directed the parties to attempt to reach accord and resolution of these issues for consideration in subsequent regulatory proceedings.

II.B.2 The Natural Gas DSM Advisory Group.

Application (Paragraph 9)

9. In the Demand-Side Management (DSM) Stipulation and Settlement, the settling parties agreed that the Commission should approve the DSM Stipulation and should order Questar Gas to examine DSM alternatives for resource planning in its Integrated Resource Plan (IRP) proceedings and further should schedule an initial meeting for all parties interested in the development of natural gas DSM in Utah to form a collaborative work group. The work group was to address DSM issues raised by the Utah Energy Office (UEO) and other interested parties in the 2002 Rate Case. The work group was known as the Natural Gas DSM Advisory Group (Advisory Group) and was co-chaired by representatives from Questar Gas and UEO.

II.B.3 Executive Summary of the GDS Report submitted by Advisory Group.

Application (Paragraph 10)

10. The Advisory Group engaged GDS Associates, Inc. to conduct a study of demand-side management options and to prepare a report (GDS Report). The Advisory Group submitted its final report to the Commission in January 2005. A copy of the Executive Summary from the final report is attached as Exhibit 1.4. Item 4 of the Findings and Recommendations from the Executive Summary states: "The Advisory Group has identified several barriers to the successful implementation of Natural Gas DSM. It is recommended that the Commission address the policy issues that act as barriers. The primary example is the issue of Questar's economic sensitivity to the loss of gas load that increased DSM would foster." Adoption of the Conservation Enabling Tariff is expected to remove the barrier identified by the Advisory Group.

II.B.4 Potential savings to customers in Utah from cost-effective natural gas DSM programs.

BLM Direct (Lines 106 - 115)

Q. Were there savings to customers identified in the recommendation made in the final DSM report to the Commission?

A. Yes. The report identified that the net present savings to Questar's residential and commercial customers from implementation of cost-effective natural gas DSM programs, for natural gas, electricity and water, identified in the GDS Study was over $1.5 billion in 2004 dollars. The projected amount of $1.5 billion, over a ten-year period, based on 2004 prices was identified as potential savings to customers assuming unlimited funding. This projected amount includes savings attributable to conservation of electricity and water, as well as natural gas. Additionally, eight recommendations were made in the DSM report all of which have been incorporated in this Joint Application.

II.C Final Order on Docket No. 02-057-02 Created the Allocation and Rate Design Task Force

II.C.1 The Allocation and Rate Design Task Force.

Application (Paragraph 12)

12. In the Allocation and Rate Design Stipulation and Settlement, the settling parties agreed that several issues raised during the proceedings in the 2002 Rate Case required further study and consideration by a collaborative task force made up of the Company, the Division, the Committee and other interested parties. In the Stipulation, the parties requested the Commission to direct in its final order that a task force engage in a study in 2003 regarding ten issues concerning Questar Gas' rate-design and allocation methodologies. On December 30, 2002, the Commission entered a final order in the 2002 Rate Case approving the Allocation and Rate Design Stipulation and Settlement and directing that a collaborative task force (Allocation and Rate Design Task Force) be established and chaired by a representative of the Division.

II.C.2 The task force directed to study a tracker mechanism for usage per customer.

Application (Paragraph 13)

13. Additionally, the settling parties agreed in the Allocation and Rate Design Task Force to study separately the possible development of a tracker mechanism for usage per customer**.** While the issue of how to address the problems created from declining usage per customer was discussed in several task force meetings, no specific consensus was reached. However, "the Task Force felt it was important to continue discussions in this area into the future after the task force conclude[s]." See Final Task Force Report at page 6. A copy of the final report is attached as Exhibit 1.5.

II.C.3 Three goals used by task force to evaluate options.

Application (Paragraph 15)

15. As discussions with the Division, Committee, and Company progressed, Questar proposed three important goals with regard to the alternatives being analyzed: 1) to remove disincentives for the Company to promote DSM; 2) to reduce contentions between regulators and the Company by using new rate design concepts; and 3) to provide the Company the opportunity to earn its allowed rate of return during periods of declining usage. In the course of these discussions, the Company, Division, Committee and other interested parties explored various options for addressing these three goals.

II.C.4 Primary benefits of the Conservation Enabling Tariff.

BLM Direct 1-YR (Lines 101 - 116)

Q. What are the primary benefits of the Conservation Enabling Tariff?

A. Three primary benefits have been identified. The Conservation Enabling Tariff provides a simple mechanism that: 1) allows the Company to collect the Commission-allowed distribution-non-gas (DNG) revenue; 2) allows the Company to aggressively promote energy efficiency; and 3) aligns the interests of the Company and regulators for the benefit of customers.

Q. Please explain how these benefits were achieved.

A. First, the CET has decoupled DNG revenue collection from customer gas-usage levels. With the CET the Company only collects the Commission-allowed revenue, nothing more, nothing less. Second, once the barrier was removed, the Company, with significant assistance from the DSM Advisory Group, has successfully launched an aggressive campaign to promote increased energy efficiency. Finally, the CET has aligned the interests of the Company and regulators for the benefit of customers by creating an atmosphere where customers no longer receive mixed signals about usage and conservation. The parties are now aligned in a message promoting energy efficiency.

II.D <u>White Papers and Alternatives Analyzed</u>

II.D.1 Further meetings after task force (Working Group) and November 2004 White Paper.

BLM Direct (Lines 120 - 136)

Q. Did the parties continue to meet following the conclusion of the Allocation and Rate Design Task Force and create an additional report?

A. Yes. At the conclusion of the Allocation and Rate Design Task Force, the Division and the Company continued to meet to discuss various alternative regulatory options. In November 2004, the Company circulated a draft "white paper" to the Division, the Committee, and other interested parties that presented an in-depth overview of how customer usage can impact utility revenues. The 2004 White Paper analyzed five options that could potentially address the decline in customer usage. A copy of the November 2004 White Paper is attached as Exhibit 1.6 to the Joint Application.

Q. What were the goals that the parties were trying to achieve?

A. Three important goals were proposed with regard to the alternatives being analyzed: 1) to remove disincentives for the Company to promote Demand-Side Management; 2) to reduce contention between regulators and the Company by using new rate design concepts; and 3) to allow the Company an opportunity to earn its authorized rate of return during periods of declining usage. Following the November, 2004 White Paper, the Company, Division, Committee, and other interested parties explored various options for addressing these three goals.

II.D.2 Six main alternatives discussed by Working Group.

BLM Direct (Lines 158 - 169)

Q. Were there alternatives discussed in the ongoing task force meetings that would help remove this disincentive?

A. Yes. Over several months, the Company, with the input of the Division and Committee, analyzed the following six alternatives: 1) use of provisions in recent legislation that allow 20-month forecasted test years; 2) filing annual, abbreviated rate cases using projected test years; 3) including a calculation of "lost revenues" associated with reductions in usage in rate case proceedings; 4) implementing rate-design changes designed to recover a higher percentage of the fixed costs through fixed charges and/or higher low-volume initial blocks in a declining-block rate structure; 5) implementing a decoupling mechanism; and 6) filing annual rate cases with a banded rate of return on equity (ROE) with quarterly monitoring and automatic rate changes when the actual ROE falls outside the band.

II.D.3 Three preferred alternatives (2005 White Paper).

BLM Direct (Lines 170 - 183)

Q. Did the parties narrow the list of alternatives?

A. Yes. Initially the parties narrowed the list to two alternatives: 1) Revenue Stabilization (this alternative would require annual rate cases, banded ROE and quarterly reviews); and 2) Rate Design (this alternative would use the collection of fixed costs through a monthly delivery charge that recovers the distribution non-gas costs). However, in October 2005, at the Committee's recommendation the list was expanded to include a third option: 3) Conservation Enabling Tariff (this alternative would decouple distribution non-gas revenue collection from volumetric sales). In November 2005, Questar Gas refined the 2004 White Paper to include an in-depth analysis of the three preferred alternatives. A copy of the 2005 White Paper is attached as Exhibit 1.7 to the Joint Application. The Commission held a technical conference on November 9, 2005, to discuss the three alternatives. Ultimately, through continued discussions and analysis, the joint applicants agreed that the Conservation Enabling Tariff was the preferred option to align the interests of the many stakeholders involved.

II.E <u>The Conservation Enabling Tariff (CET) Pilot Program</u>

II.E.1 The CET proposed by Joint Applicants as a 3-year Pilot Program.

Application (Paragraph 18)

18. 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. The Parties propose jointly that the Conservation Enabling Tariff be adopted by the Commission as a three-year pilot program.

As 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. At any time during the Pilot Program, any party can recommend to the Commission that the Pilot Program be modified or discontinued.

II.E.2 Why the CET was proposed as a Pilot Program.

BLM Direct (Lines 209 - 228)

Q. Why does the Joint Application propose that the Conservation Enabling Tariff and Demand-Side Management be implemented as a Pilot Program?

A. The Joint Applicants recognized the adverse impact of declining usage per customer on the Company is a serious long-term problem. However, they also recognized that there may be unexpected results from any new program. Therefore, the Joint Applicants recommend that this proposal be implemented as a Pilot Program.

From the Company's perspective, approval of the Pilot Program allows the Conservation Enabling Tariff to be implemented now so that customers and the Company can begin enjoying the benefits. The ultimate goal of all participants wanting to pursue real solutions to these long-term problems should be to refine and perfect the Conservation Enabling Tariff and the Demand-Side-Management program during the three-year Pilot Program with the intention of making them permanent features of the Company's tariff.

Q. Will the Pilot Program be reviewed during the three-year period?

A. Yes, the Division will review the results of the Conservation Enabling Tariff and the cost/benefits of Demand-Side Management at the end of each quarter for the first year and then annually thereafter, or more frequently as needed, and will submit reports to the Commission that include an analysis of each year's results.

Q. Could the Pilot Program be modified during the three-year period?

A. Yes. At any time during the three-year period any party can recommend to the Commission that the Pilot Program be modified or discontinued.

II.E.3 Brief overview of the CET.

BLM Direct (Lines 230 - 239)

Q. Please give a brief overview of the proposed Conservation Enabling Tariff.

A. The Conservation Enabling Tariff is a rate mechanism designed to ensure that the Company only collects from GS-1 customers the Commission-authorized revenue per customer. The Conservation Enabling Tariff applies only to the GS-1 rate schedule. It operates as a distribution non-gas (DNG) revenue balancing account for that rate schedule.

Q. Is this the same as the gas balancing account used for the passthrough of gas costs?

A. No. The gas balancing account includes both expenses and revenues. These expenses and revenues are matched or netted against each other and any over- or under-collection is amortized into the Company's gas-cost rates typically twice a year. Thus, increases or decreases in costs are flowed through to customers directly.

II.E.4 1-YR Review of the CET Pilot Program.

BLM Settlement (Lines 245 - 284)

Q. Does the Settlement Stipulation define a schedule for review of the CET aspect of the Pilot Program?

A. Yes. The Settlement Stipulation states "During the first year of the Pilot Program, the Parties request that a Commission proceeding be held at which Parties will have the opportunity to propose alternatives to the CET to be in effect during the balance of the Pilot Program." This review is called the 1-year Review.

Q. What is the purpose of the 1-year Review?

A. The 1-year Review allows the CET to go into effect for approximately one year so that parties can review the effects of full decoupling and continue to study and develop proposals on possible alternatives. The Parties agreed that it was beneficial to implement DSM now in advance of the winter 2006-2007 heating season rather than waiting for an additional period of time while parties study and refine alternative proposals. During the 1-year Review, any party may propose an alternative or alternatives or advocate continuance of the CET with or without limitations. The Company will provide available data with respect to the CET as requested by any other Party. Parties have agreed to cooperate in good faith with the provision of data, and the scheduling of proceedings to facilitate review of the CET and the proposal of other alternatives.

Q. Does the Settlement Stipulation provide dates by which certain events are to take place in connection with the 1-year Review?

A. The Settlement Stipulation proposes that the Commission schedule a technical conference on or about April 18, 2007, so that the parties and the Commission can review the status of potential alternatives or proposals to continue the CET. This will allow parties to learn whether other parties plan to file written testimony or positions statements on alternatives to or continuation of the CET. The Settlement Stipulation provides that any party wishing to do so must file written testimony or position statements on alternatives to or continuation of the CET by June 1, 2007. If no party makes such a filing, the Settlement Stipulation provides that the CET will be discontinued on September 30, 2007.

Assuming one or more parties files written testimony or position statements by June 1, 2007, the Settlement Stipulation provides that the Company will request that the Commission schedule a procedural conference within ten days following the filing of the first of such filings. The parties agree to cooperate in scheduling proceedings resulting from the filing or filings so that all evidence and argument is presented and the matter can be submitted to the Commission for decision not later than September 14, 2007. The parties agree to cooperate in good faith to expedite the process. The Parties anticipate that the hearings in this proceeding would take place near the beginning of September 2007, so that a decision from the Commission could be made by the end of September for how to proceed for years 2 and 3 of the Pilot Program.

II.E.5 Review of the CET Settlement Stipulation and implementation date.

BLM Direct 1-YR (Lines 62 - 90)

Q. Would you please provide an overview of your Settlement Testimony?

A. The purpose of my Settlement Testimony was to describe the Settlement Stipulation and to explain why the Settlement was just and reasonable and why its adoption by the Commission was in the public interest.

Q. Please briefly review the terms of the Settlement Stipulation.

A. The Settlement Stipulation provided the Pilot Program would go into effect on the first day of the month following Commission approval. The parties agreed the Company would make an initial credit to the CET balancing account of $1.1 million as though the CET had been in effect from January 1, 2006, through June 30, 2006. The parties agreed the Company would amortize that credit (through a reduction in rates) in conjunction with the Company's fall 2006 pass-through filing. The parties agreed amortization of other accruals to the CET starting with July 2006 would take place in subsequent semiannual pass-through filings. The parties agreed to limitations on both the accruals to and amortization of CET balances during the first year of the Pilot Program.

The parties agreed that there would be a 1-year review of the CET Pilot Program starting with a technical conference in April 2007 and the filing of testimony or position statements advocating continuation, changes or alternatives to or discontinuance of the CET by June 1, 2007. This testimony is filed pursuant to that portion of the Settlement Stipulation. The parties agreed that they would cooperate in scheduling a proceeding so that the Commission could issue an order on the future operation of the CET by the end of September 2007.

The parties agreed the Company would file an application requesting approval of DSM programs within sixty days of Commission approval of the Settlement Stipulation. The parties also agreed the Commission should formally recognize the DSM Advisory Group that had been meeting unofficially since December 2005.

Q. When did Questar Gas implement the Conservation Enabling Tariff?

A. The CET was implemented November 1, 2006, the first month following approval of the Settlement Stipulation. However, as previously discussed, it was effectively implemented on January 1, 2006, through the initial $1.1 million credit accrual and monthly CET entries made for the July – October period.

II.E.6 Division of Public Utilities to review CET during the Pilot Program.

BLM Surrebuttal (Lines 1140 - 1144)

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.

III. CET REMOVES BARRIER AND ALIGNS INTERESTS OF THE COMPANY, CUSTOMERS AND REGULATORS

III.A <u>Decoupling / Conservation Enabling Tariff (CET) Removes the Barrier</u>

III.A.1 Pilot Program benefits customers.

BLM Direct 1-YR (Lines 33 - 39)

Q. Would you please provide an overview of your Direct Testimony filed in support of the Joint Application?

A. Yes. The purpose was to explain the proposed Pilot Program. The Pilot Program consisted of two components: 1) the DSM programs; and 2) the CET. I explained the operation of the CET and discussed the benefits of the Pilot Program. I also provided a description of the components of the requested $10.2 million rate reduction and addressed other proposed changes.

III.A.2 CET was the preferred option by Joint Applicants for removing the barrier.

BLM Surrebuttal (Lines 396 - 404)

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.

III.A.3 Decoupling mechanism is the preferred option of NRDC for removing the barrier.

RC/NRDC Surrebuttal (Lines 239 - 248)

Q. If you oppose higher fixed charges, how would you propose to remove the financial disincentives described in earlier sections of your testimony?

A. To eliminate a powerful disincentive for energy efficiency, I support Questar's proposal to use modest, regular true-ups in rates to ensure that its authorized fixed-cost recovery is not held hostage to sales volumes. This mechanism involves a simple comparison of actual sales to authorized fixed cost recovery during the period under review. The difference is then either refunded to customers or restored to the Company. Note that the true-up can go in either direction, depending on whether actual retail sales are above or below that allowed by the Commission.

III.A.4 CET removed the barrier and allowed the Company to pursue DSM.

BLM Direct 1-YR (Lines 151 - 157)

Q. Do you believe the CET has been effective in removing the barrier the Company has faced in promoting energy efficiency?

A. Yes. As evidenced by the first-year results, the CET has decoupled the link between customer usage (volumetric sales) and DNG revenue collection. The Company has aggressively pursued the implementation of energy-efficiency programs and the market-transformation initiatives. Our customers are responding positively to the new energy-efficiency campaign.

III.A.5 Use of Future Test Year does not remove the barrier to pursue DSM.

RC/NRDC Surrebuttal (Lines 135 - 145)

Q. Couldn't this problem be solved by using a forward test year and incorporating the impacts of the Company's energy-efficiency programs in the forecast of sales?

A. No. The utility's ongoing incentive to promote increased use and discourage efficiency is almost wholly unaffected by the test year and forecasting methodology chosen. Whether consumption ultimately ends up above or below whatever forecast is adopted, every reduction in sales from efficiency improvements yields a corresponding reduction in cost recovery, to the detriment of shareholders. The Company loses less in aggregate if the Commission adopts a low sales forecast rather than a high sales forecast, but the incentive at the margin is the same: reduced sales are always adverse to shareholders' financial interests if all that changes is the forecast used to set rates.

III.A.6 The Company is motivated to pursue DSM in order to maintain the CET.

BLM Direct 1-YR (Lines 185 - 190)

Q. The Company has made substantial progress in a short period of time. Is this a result of the Conservation Enabling Tariff?

A. Yes. Obviously the removal of the barrier through the implementation of the CET has been a major factor, but the aggressive approach the Company has pursued goes well beyond simple barrier removal. The Company is motivated to maintain the CET. This should help explain the extensive initial response of the Company in implementation of energy efficiency.

III.A.7 Utah state policy is to remove regulatory barrier for the Company to pursue DSM.

BLM Surrebuttal (Lines 407 - 414)

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.

III.A.8 United States Dept. of Energy policy is to align utility incentives with the pursuit of DSM.

BLM Surrebuttal (Lines 416 - 436)

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.

III.A.9 Limitations on the CET result in barrier not completely being removed.

BLM Settlement (Lines 382 - 399)

Q. In your two foregoing answers, you have qualified statements regarding whether the Settlement Stipulation removes the barrier to Questar Gas's disincentive to implement energy-efficiency programs. Please elaborate.

A. The limitations on CET accruals and amortization in the Settlement Stipulation could continue to provide a disincentive to Questar Gas to whole-heartedly promote conservation programs. If customer usage falls by more than one percent of GS revenues, the limitations will prevent Questar Gas from recovering the full amount of distribution non-gas costs that the Commission has found reasonable. However, the limitations were necessary compromises to make certain other parties feel comfortable with the Pilot Program during its first year. As noted in my prior answer, the Company believes that even with the limitations, it will have adequate incentives to promote energy-efficiency programs during the first year of the Pilot Program. Following the first year, the Company is hopeful that others will recognize that the substantial savings to customers available from reduced commodity costs from cost-effective DSM programs overwhelm the possibility that increased distribution non-gas rates might be necessary to allow the Company to recover expenses previously found just and reasonable by the Commission. The Company is willing to go forward in good faith based upon the terms and conditions of the Settlement Stipulation.

III.A.10 Limitations on the CET should be removed.

BLM Direct 1-YR (Lines 221 - 229)

Q. The initial approval of the CET Pilot Program included limits to the accruals and amortizations. Is it necessary to continue to limit accruals and amortizations?

A. No. The implementation of the CET and the resulting accruals have shown the limits are not necessary. The Company is receiving mixed signals resulting from decoupling with limited accruals and amortizations. These mixed signals suggest a limited approach to energy efficiency is preferred over an aggressive one. The Company has aggressively implemented energy efficiency even with the limitations in an effort to demonstrate its good faith and commitment. However, continuing the limitations is counterproductive and inconsistent with removal of the barrier.

III.A.11 High gas prices make "now" the time to remove the barrier and pursue DSM.

BLM Direct (Lines 192 - 207)

Q. Why is this the time to act on the interrelated issues of high gas prices, conservation and the adverse impact of conservation on the Company?

A. Simply put, high gas prices provide a window of opportunity to achieve a win/win situation. High prices increase customers' willingness to take action to reduce energy use. QGC Exhibit 1.6 shows usage per customer from 1980 through 2005 and average annual customer bills for the same period. It shows that as gas prices increase usage per customer decreases. Questar Gas wants to more actively encourage conservation, but, as customers use less gas, the ability to recover fixed costs in rates erodes as demonstrated on QGC Exhibit 1.5. The Company is also offering to reduce its rates in this process in conjunction with the approval of the Conservation Enabling Tariff mechanism. Once the proposals made in the Joint Application are approved, Utah natural gas customers will receive an immediate rate reduction and cost-effective Demand-Side-Management programs will be pursued. Utah natural gas customers will receive real help from the Company in pursuing permanent and effective energy-efficiency efforts. The Company, regulators, and other interested stakeholders need to commit to a long-term sustained effort to identify, design and deliver cost-effective energy-efficiency programs.

III.A.12 High prices not sufficient to motivate customers to pursue energy efficiency.

RC/NRDC Surrebuttal (Lines 165 - 198)

Q. Describe the evidence that market failures continue to block highly cost-effective energy savings.

A. Overwhelming evidence has been marshaled in recent years by the National Research Council of the National Academy of Sciences, the U.S. Congress's Office of Technology Assessment, the National Association of Regulatory Utility Commissioners, and the national laboratories, among many others. Although "[t]he efficiency of practically every end use of energy can be improved relatively inexpensively," "customers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years . . . The phenomenon is not only independent of the customer sector, but also is found irrespective of the particular end uses and technologies involved." Typically, customers are demanding rates of return of 40-100+%, and such expectations differ sharply from those of investors in utility assets. Utilities' returns on capital average 12% or less. The imbalance between the perspectives of consumers and utilities invite large, relatively low-return investments in natural gas supplies that could be displaced with more lucrative energy efficiency. These widely documented market failures generate "systematic underinvestment in energy efficiency," resulting in energy consumption at least 20-40% higher than cost-minimizing levels.

There are many explanations for the almost universal reluctance to make long-term energy efficiency investments. Decisions about efficiency levels often are made by people who will not be paying the utility bills, such as landlords or developers of commercial office space. Many buildings are occupied for their entire lives by very temporary owners or renters, each unwilling to make long-term improvements that would mostly reward subsequent users. And sometimes what looks like apathy about efficiency merely reflects inadequate information or time to evaluate it, as everyone knows who has rushed to replace a broken water heater or furnace.

Market failures like these mean that energy prices alone are a grossly insufficient incentive to exploit even the most inexpensive savings: NARUC analysts have determined, for example, that electricity customers who insist on two-year paybacks and see average rates of 7 cents/kWh "can be expected to forego demand-side measures with costs of conserved energy of more than 0.9 cents/kWh." That is, energy prices would have to increase about eightfold to overcome the gap that typically emerges in practice between the perspectives of investors in energy efficiency and production, respectively.

III.A.13 CCS, SLCAP and UAE appear to support DSM but criticize QGC's Pilot Program.

BLM Surrebuttal (Lines 47 - 92)

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 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).

III.B Decoupling / CET Aligns the Interests

III.B.1 The CET and rate reduction will align interests of Company, customers and regulators.

Application (Paragraph 1)

1. Questar Gas Company (Questar Gas or Company), the Division of Public Utilities (Division), and Utah Clean Energy (collectively the Parties) request the approval of tariff changes that would implement a Conservation Enabling Tariff (or CET) Pilot Program (Pilot Program) and that would result in a rate decrease in the non-gas portion of customers' rates. The Parties believe that this rate reduction, if implemented on a timely basis, could help reduce customers' bills this heating season. At a time when customers are bearing the burden of higher energy costs, the Pilot Program represents a real opportunity to align the interests of the Company, customers, regulators, and other interested parties and utilize conservation as an effective means to save energy and reduce costs. The Parties also request the approval of various accounting orders necessary for the implementation of the Conservation Enabling Tariff and rate decrease.

III.B.2 The Joint Application aligns the interests of Company, customers and regulators.

BLM Direct (Lines 12 – 20)

Q. Why did the Company join in the Joint Application?

A. The Joint Application achieves an important goal. The Conservation Enabling Tariff aligns the interests of the Company, customers, regulators, and other interested parties to effectively use conservation to save energy and reduce customer costs. This is particularly important at a time when customers are bearing the burden of higher energy costs. The Conservation Enabling Tariff allows the Company to support cost-effective Demand-Side-Management programs that benefit customers because it removes the financial harm that the Company experiences when customers' usage declines. In addition, customers will receive a modest reduction in rates.

III.B.3 The CET has been effective in aligning interests.

BLM Direct 1-YR (Lines 208 – 213)

Q. Has the CET been effective in aligning the interests of the Company and stakeholders?

A. Yes. The CET, as noted earlier, has been effective in removing the barrier to promoting energy efficiency. With the CET in place, the Company has no reason to limit its efforts to promote energy efficiency. The Company's DSM Pilot Program has progressed at a pace that reflects the advantage gained when interested stakeholders fully cooperate to attain a common goal—in this case, helping customers to achieve greater energy efficiency.

III.C CET Calculations, Accruals and Amortizations

III.C.1 The formula for accruing amounts into the CET balancing account.

BLM Direct (Lines 240 - 249)

Q. What does the Conservation Enabling Tariff balancing account include?

A. The Conservation Enabling Tariff balancing account only includes GS-1 DNG revenues. The Company will record monthly over- or under-recoveries of authorized GS-1 DNG revenue in the Conservation Enabling Tariff balancing account. The allowed GS-1 DNG revenue for a given month is equal to the allowed GS-1 DNG revenue per customer for the month times the actual number of GS-1 customers billed in that month. The monthly accrual (positive or negative) is determined by calculating the difference between the actual billed GS-1 DNG revenue and the allowed DNG revenue for that month. The formula is:

Allowed GS-1 DNG Revenue – Actual GS-1 DNG Revenue = CET Accrual

III.C.2 Example of entries into the CET balancing account.

BLM Direct (Lines 278 - 287)

Q. How are entries made into the Conservation Enabling Tariff deferred balancing account?

A. On a monthly basis, the monthly-allowed GS-1 DNG revenue per customer is multiplied by the actual number of GS-1 customers. The product is compared to the actual GS-1 DNG revenue that has been billed to customers using the then-effective block and basic-service-fee rate structure. Any difference, positive or negative, is booked into the deferred-balancing account (Account 191.9). An example showing how this would be done for January 2006 is provided on Page 3 of QGC Exhibit 1.7. Interest will accrue and will be booked into Account 191.9 as currently approved by the Commission for Account 191 and described in the Utah Tariff, Section 2.10.

III.C.3 Description of the CET accruals and amortizations.

Application (Paragraph 19)

19. The Conservation Enabling Tariff methodology consists of the following three steps:

a. First, the allowed GS-1 distribution non-gas (DNG) revenue per customer per month is calculated. The revenue requirement and the year-end customers are allocated to the calendar months based on historical patterns. The monthly revenue requirement is then divided by the monthly number of customers to arrive at the allowed revenue per customer per month. Exhibit 1.8 shows an example of the calculated revenue per Utah GS-1 customer proposed to be implemented in the Conservation Enabling Tariff beginning in January 2006. The proposed revenue per customer will be based on projected year-end 2005 customers and the revenue collected from these customers using the rates proposed to be effective on January 1, 2006. These rates include a reduction in total Utah Jurisdictional Revenue Requirement of $10.2 million as explained in Paragraph 34.

b. Second, on a monthly basis, the allowed GS-1 DNG revenue per customer each month is multiplied by the actual number of GS-1 customers. The product is compared to the actual GS-1 DNG revenue and any difference, higher or lower, is booked into a balancing account (Account 191.9). Interest will accrue and will be booked into Account 191.9 as currently approved by the Commission for Account 191 and described in the Utah Tariff, Section 2.10 (See Exhibit 1.9.)

c. Third, on a schedule of not less than twice per year, the Company will file for a percentage adjustment to the GS-1 DNG block rates in an amount to amortize the balance of Account 191.9 over the projected sales for the upcoming 12 months. It is anticipated that these filings will be in conjunction with the Company's regular pass-through rate cases, but may occur separately. The Commission-approved amortization will increase or decrease the volumetric DNG rates for the GS-1 rate schedule on a prospective basis.

III.C.4 Amortization of the CET balancing account.

BLM Direct (Lines 288 - 294)

Q. How will the balance in the account be amortized?

A. On a schedule of not less than twice per year, the Company will file for a percentage adjustment to the GS-1 DNG block rates to amortize the balance of Account 191.9 over the projected sales for the upcoming 12 months. The Company anticipates that these filings will be made contemporaneously with its regular passthrough filings. The Commission-approved amortization will increase or decrease the volumetric DNG rates for the GS-1 rate schedule on a prospective basis.

III.C.5 Amortization of the CET balancing account.

BLM Surrebuttal (Lines 1097 - 1117)

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.

III.C.6 Calculation of allowed revenue per customer to be used in the CET.

BLM Direct (Lines 260 -277)

Q. Please explain how the Conservation Enabling Tariff will actually work.

A. I have prepared QGC Exhibit 1.7 to illustrate how the tariff works. First, the allowed annual DNG revenue is determined. This is done by calculating the current level of Commission-approved DNG revenues using actual 2005 usage per customer, year-end customers and current DNG rates. The result of this calculation, shown on Page 1, Line 1, of QGC Exhibit 1.7, is $224,465,426. This amount is then reduced by the proposed rate reduction of $10,218,684, as shown on Line 2, resulting in $214,246,742 as shown on Line 3. The portion of this revenue attributable to GS-1 customers is $203,196,646 as shown on Line 5. This amount is divided by 2005 year-end customers to arrive at the proposed allowed annual DNG revenue per customer. This amount is $254.23 as shown on Line 7.

As shown on Page 2, Column D, of QGC Exhibit 1.7, the $254.23 is then spread to months based on the pattern of Utah GS-1 revenues per customer in 2005, adjusted for DNG rate changes that occurred during the year. This pattern is shown in Columns B and C. Assuming the Commission approves the requested decrease of $10.2 million, the amounts shown in Column D of Page 2 are the monthly allowed DNG revenue per Utah GS-1 customer proposed to be implemented in the Conservation Enabling Tariff beginning in January 2006.

III.C.7 Revised Calculation of allowed revenue per customer to be used in the CET.

BLM Surrebuttal (Lines 732 - 765)

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.

III.C.8 Proposed revision to monthly spread of CET allowed revenue per customer.

BLM Direct 1-YR (Lines 231 - 247)
Q. Does the Company have a recommendation regarding a revised monthly spread of the revenue per customer?
A. Yes. The Company recommends that effective on January 1, 2008, the month-to-month spread be modified to reflect the average monthly DNG revenue per customer experienced in the immediately preceding 36-month period. QGC Exhibit 1-YR 1.6 shows the month-to-month spread of the Commission-allowed DNG revenue using 2005 and 2006 data. The recommended month-to-month spread will include 2007 data and will be used to calculate the CET accruals beginning with the January 2008 accrual. The Company will work with the Division to review the revenue-per-customer data and to calculate the revised month-to-month spread.

Q. Will this revised monthly spread change the total amount the Company is authorized to collect in DNG revenue per customer?
A. No. Column I, line 13, of Exhibit 1-YR 1.6 shows a net difference of zero over the full year. The recommended month-to-month spread simply reallocates the same annual amount based on more recent experience.

III.C.9 CET tariff sheets.

BLM Direct 1-YR (Lines 249 - 256)
Q. Have you prepared proposed tariff sheets that incorporate the Company's recommendations?
A. Yes. QGC Exhibit 1-YR 1.7 provides tariff sheets 2-17 and 2-18 reflecting the changes required to implement the Company's proposals as described herein in both legislative and proposed format. When data becomes available for 2007, revised tariff sheets will be prepared and reviewed by the Division and filed with the Commission to reflect the monthly spread of DNG revenue per customer. As noted earlier, this revised month-to-month spread will be effective for January 2008.

III.C.10 CET accruals for January 2006 – June 2006.

BLM Surrebuttal (Lines 767 - 792)

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.

III.C.11 CET accruals for January 2006 – June 2006 and going forward.

BLM Settlement (Lines 197 - 230)

Q. Please describe the initial accruals to the CET balancing account and the DSM deferral account?

A. The Settlement Stipulation provides for an initial credit to be made to the CET balancing account in the amount of $1.1 million. This amount was calculated as though the CET had been in effect from January 1, 2006, through June 30, 2006. This credit is proposed to be amortized (through a reduction in rates) in conjunction with the Company's fall pass-through filing.

The Settlement Stipulation also provides that the Company will transfer $1.3 million from unexpended funds included in rates for research and development to the DSM deferral account effective with the Commission order approving the Settlement Stipulation.

Q. Will interest accrue on balances in the CET balancing account and DSM deferral account?

A. Yes. Interest will accrue on the CET balancing account and the DSM deferral account at the rate approved for Account 191 balances.

Q. When will the CET be effective?

A. The Settlement Stipulation provides that the Company will implement the CET effective on the first of the month following Commission approval of the Settlement Stipulation. The Company is hopeful that the Commission might be able to approve the Settlement Stipulation prior to the end of September so that the CET may be implemented on October 1, 2006.

Q. How will additional accruals be made to the CET balancing account?

A. The CET balancing account will initially reflect the $1.1 million credit referenced above. Thereafter, accruals will be made as if the CET had been effective starting July 1, 2006 and will be made monthly after the effective date. However, in accordance with the terms of the Settlement Stipulation, only the $1.1 million credit will be amortized during the first semiannual amortization of the balance in the CET balancing account. The accruals for July and subsequent months will not be amortized until the second semiannual amortization. The Company will make amortized filings concurrently with future pass-through filings.

III.C.12 CET accruals for January 2006 – April 2007.

BLM Direct 1-YR (Lines 119 - 147)

Q. What did the CET mechanism accomplish in the first year?

A. During the first year, including the first six months of 2006 when the CET accruals were effectively implemented through a single entry, usage per GS customer increased slightly. The total CET accruals reflected this by crediting to the deferral account approximately $1.75 million in "over collection" of Commission-allowed DNG revenue. This demonstrates the symmetrical nature of the mechanism and has resulted in lower DNG rates for GS customers than would have been the case without the CET. QGC Exhibit 1-YR 1.1 shows the accruals booked in 2006.

Q. Is it important to look at 12-month periods when considering CET results?

A. Yes. The CET is designed to ensure that the Company only collects the annual DNG revenue per customer allowed by the Commission. The allowed DNG revenue to be collected per customer is spread over 12 months. Any month-to-month volatility in the CET accruals is removed when 12 months are considered in aggregate.

Q. Do you believe the CET is working as expected?

A. Yes. The accruals resulting from the CET make sense. When usage per customer has increased, the CET accruals reflect over collection of revenues. When usage has declined, the CET accruals have reflected the under collection. The Company can no longer increase revenues by encouraging customers to increase gas usage. Instead the incentive for the Company is to focus on managing operations with an eye to efficient, safe and reliable service.

Q. Have you prepared an exhibit that shows the balance for the CET deferral account through the end of April 2007?

A. Yes. QGC Exhibit 1-YR 1.2 shows the monthly accruals for the first 16 months of the CET, the interest entries and the amortizations that have occurred through April 30, 2007. The amortization of the initial CET balance has reduced customer bills by $870,699. The balance in the account as of April 30, 2007, is $3,241,969.

III.C.13 Limitations on accruals to and amortization of the CET balancing account.

BLM Settlement (Lines 233 - 242)

Q. Are there limitations on the accruals to the CET balancing account?

A. Yes. Through August 2007, accruals to the CET balancing account are capped at a cumulative 12-month total equal to 1% of the Company's total GS revenue (GS-1 and GSS).

Q. Are there limitations on the amortization of the CET balancing account?

A. Yes. During the first year of the CET, amortizations of the CET balancing account are capped at a cumulative 12-month total equal to ½ of 1% of the Company's total GS revenues. Any remaining balance in the account will carry forward and will be amortized in subsequent years.

III.D <u>Decoupling is Consistent with Current Billing Practices and Traditional Regulation</u>

III.D.1 Billing process doesn't change under the CET.

BLM Direct (Lines 295 - 301)

Q. Will customers be billed in a different way under the Conservation Enabling Tariff?

A. No. Page 1 of QGC Exhibit 1.8 is a copy of the currently effective GS-1 rate schedule. Page 2 reflects implementation of the Conservation Enabling Tariff, including the effect of the $10.2 million rate reduction. The same components currently included in the DNG portion of the bill will continue to be included in the DNG portion of the bill following adoption of the Conservation Enabling Tariff. The form and components of the bill will not change in any way.

III.D.2 Decoupling is consistent with traditional regulation.

RC/NRDC Surrebuttal (Lines 433 - 441)

Q. Does this proposal represent a significant departure from the way that traditional utility regulation handles distribution non-gas revenues?

Decoupling has a 25-year history and is entirely consistent with traditional regulation. It uses the Commission's adjudicated fixed cost revenue requirement, employs the same regular true-ups that have been adopted for a host of other purposes, and (as Mr. Dismukes himself acknowledges) performs basically the same function as a very traditional fixed charge, without in the process requiring a change in existing rate structures.

III.D.3 Decoupling is not a higher fixed charge in disguise.

RC/NRDC Surrebuttal (Lines 556 - 563)

Q. Is decoupling really a higher fixed charge in disguise, as Mr. Dismukes contends (pp. 40-41)?

A. On the contrary, as Mr. Dismukes appears to recognize, the great strength of decoupling is that it yields the benefits to utilities of fixed charges without reducing customers' rewards for saving natural gas; Mr. Dismukes inexplicably says that "the fact that these charges are applied volumetrically is a difference without a distinction," when in fact this difference is at the heart of the distinction between decoupling and fixed-charge increases.

III.D.4 Decoupling is not a fundamental change in ratemaking philosophy.

RC/NRDC Surrebuttal (Lines 657 - 664)

Q. Do you agree with witness Higgins that decoupling represents "a fundamental and unwarranted change in ratemaking philosophy, because it makes the non-fuel portion of base rates variable (p. 6)?

A. I think he's got it backwards here. The non-fuel portion of base rates is effectively variable <u>without</u> decoupling, because actual recovery goes up and down in lockstep with gas sales; assuming this should be avoided (as I do), decoupling is crucial to the solution, not a contributor to the problem.

III.D.5 Decoupling is not a hazardous undertaking akin to single-issue ratemaking.

RC/NRDC Surrebuttal (Lines 666 - 680)

Q. Address witness Higgins's concern that decoupling is "a hazardous undertaking that is akin to single-issue ratemaking," in that it could create rate increases at times when rates might actually deserve to be reduced if all relevant variables were considered (p. 12).

A. Traditional ratemaking makes ample provision for "trackers" and/or true-ups associated with, <u>e.g.,</u> weather and fuel costs; the Company's proposal is no different in its "single issue" implications, and the public interest justification is at least as compelling. Ken Costello of the National Regulatory Research Institute has investigated whether decoupling mechanisms meet the traditional tests justifying state utility regulators' use of "tracking mechanisms that adjust rates and revenues whenever sales deviate from their targeted level," and has concluded that "[u]nless a state commission faces legal restrictions in implementing a 'sales tracker' or has a built-in policy of limiting trackers in general, [revenue decoupling] would seem to meet the regulatory threshold for a tracker." I agree.

IV. BENEFITS OF CET AND DSM PILOT PROGRAM

IV.A Expected Savings for Customers

IV.A.1 Expected customer savings from implementation of energy-efficiency measures.

BLM Direct (Lines 302 - 334)

Q. Can you provide an illustration of the impact of conservation on a typical GS-1 customer's bill?

A. Yes. QGC Exhibit 1.9 provides an illustration. Using the proposed rates, a typical customer using 115.0 Dth annually would be billed $1,273.43, $1000.34 for the commodity portion of the bill and $273.09 for the DNG portion, as shown on Column B, Lines 1-4. Assuming the customer decreases annual usage through conservation by only two percent to 112.7 Dth, the commodity portion of the bill would decrease to $980.23 (Line 6), a savings of $20.11 (Line 10). The DNG portion of the bill would decrease to $268.83 (Line 7), a savings of $4.26 (Line 9). The $4.26 would be accrued in the Conservation Enabling Tariff balancing account to be amortized at a later date to all GS-1 customers.

Q. How would this same level of conservation affect the entire GS-1 customer group?

A. QGC Exhibit 1.10 provides the calculation on a total customer class basis. Annual savings to customers in reduced bills would be over $16 million, or $20.11 per customer, (Column B, Line 11).

Q. Would there by any other effects?

A. Yes. As shown on Line 6, Column B of QGC Exhibit 1.10, there would be a savings of $19 million in purchased gas costs at current prices. Thus, there would be an additional savings to customers as shown on Line 7 of $3,246,000 ($19,394,000 - $16,148,000) in future gas cost passthroughs. In addition, there would be reductions in future gas costs over the longer term as a result of declining demand. I have not attempted to estimate this longer term savings.

Q. How does the additional $3.2 million savings in future passthroughs affect an individual customer?

A. It nearly offsets the amortization of the Conservation Enabling Tariff accrual of $4.26 discussed previously. As shown on QGC Exhibit 1.10, Line 8, the $3,246,000 passthrough savings translates to $4.04 per customer for a total realized savings per customer of $24.15, as shown on Line 10.

Q. Are there additional savings that a customer will realize?

A. Yes. As a result of the $10.2 million rate reduction proposed in the Joint Application, customers will receive an additional annual savings of $13.93. This is shown on Column F, Line 13 of Exhibit 1.10 of the Joint Application. In total, this results in savings to customers of approximately $38 on an annual basis.

IV.A.2 Examples of expected savings to various QGC customers.

BLM Surrebuttal (Lines 287 - 392)

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.

IV.A.3 Benefits of the CET Pilot Program.

BLM Settlement (Lines 182 - 194)

Q. Please describe the benefits of the Pilot Program that will result from implementation of the Settlement Stipulation.

A. The Settlement Stipulation achieves at least two important goals. First, the Conservation Enabling Tariff aligns the interests of the Company, customers, regulators, and other interested parties to effectively promote cost-effective conservation measures to save energy and reduce customer costs. My Exhibit SR 1.4 summarizes the savings that will result from a 1% annual reduction in usage over a five-year period. Year five shows a net savings for customers of $32 million. This is particularly important at a time when customers are bearing the burden of higher energy costs. The Conservation Enabling Tariff allows the Company to support cost-effective Demand-Side-Management programs that benefit customers because it removes the financial harm that the Company experiences when customers' usage declines. Second, customers will receive direct benefits from the CET and DSM and a modest reduction in rates.

IV.B <u>Process for Reviewing Proposed DSM Programs</u>

IV.B.1 Proposal for DSM programs and the Natural Gas DSM Advisory Group.

Application (Paragraph 23)

23. With a conservation enabling tariff, the Company commits to developing and implementing cost effective gas DSM programs for its residential and non-residential customers using the GDS Report as a guide. The Parties request that the Commission order the creation of a Natural Gas DSM Advisory Group to evaluate and propose specific cost effective natural gas DSM programs and to provide implementation guidance to the Company. The Natural Gas DSM Advisory Group will include representatives from the Company, the Division, the Committee, the Governor's Energy Advisor, Utah Clean Energy and Southwest Energy Efficiency Project (SWEEP). Input from other interested parties will be solicited and given due consideration by the Natural Gas DSM Advisory Group.

IV.B.2 DMS program cost-effectiveness criteria.

Application (Paragraph 24)

24. In designing these programs, the Company shall seek and consider input from the Natural Gas DSM Advisory Group. The programs will be developed and implemented in a timely manner and will seek to maximize gas savings and net economic benefits for customers. All programs and other related costs must pass the cost effectiveness

criteria established by the Utah Public Service Commission and be subject to approval by the Commission. Promotion of ENERGY STAR products and buildings and a pilot program involving education and provision of low-cost efficiency measures to a large number of low-income households will be among the programs considered by the Company.

IV.B.3 The DSM Working Group.

BLM Surrebuttal (Lines 95 - 122)

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.

IV.B.4 All customers expected to benefit from DSM initiatives.

BLM Surrebuttal (Lines 287 - 351)

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.

IV.C Demand-Side Management Initiatives

IV.C.1 Review of proposed DSM initiatives in Joint Application.

BLM Direct (Lines 342 - 367)
Q. Please review the proposed Demand-Side-Management initiatives the Joint Application is proposing.
A. The Joint Application describes the efforts of the Demand-Side Management Advisory Group that was established by Commission Order in the 2002 rate case and the report developed by GDS Associates, Inc. on Natural Gas Demand-Side Management in Utah (GDS Report). The Joint Application recommends that a task force be created to evaluate and propose specific cost-effective natural gas Demand-Side-Management programs using the GDS Report as a guide. Some of the potential programs described in the GDS Report include encouraging installation of set-back thermostats, water heater blankets, high efficiency furnaces and Energy Star appliances. The Joint Application recommends that two other initiatives be considered by the Advisory Group: 1) the adoption of a program designed to pursue education and provision of low-cost efficiency measures to a large number of low-income households and 2) an effort to grow the capabilities of the Low- Income Weatherization Assistance Program (LIWAP) to extend beyond the low-income population.

The Natural Gas DSM Advisory Group will include representatives from the Company, the Committee, the Governor's Energy Advisor, Utah Clean Energy, Southwest Energy Efficiency Project (SWEEP) and other interested parties. The Advisory Group will make recommendations regarding Demand-Side Management to the Commission for approval.

Q. Please explain the proposed increase in funding for LIWAP.
A. LIWAP's current level of funding for health and safety measures from Questar Gas is $250,000. The Joint Application proposes to increase this level of funding to $500,000. LIWAP health and safety measures include inspection, adjustments, and, if necessary, replacement of furnaces. A funding increase of this magnitude is well below the increase of $625,000 recommended by the GDS Report in the portion titled Optimal Level of Funding for Utah Weatherization Program.

IV.C.2 Increased funding for Low-Income Weatherization Assistance Program.

Application (Paragraph 25)

25. Questar Gas will work with the Utah State Division of Housing and Community Development to design and implement an energy efficiency program targeted at the residential gas market (irrespective of household income). This is the state agency that currently receives $250,000 per year from Questar Gas to fund the Low Income Weatherization Assistance Program (LIWAP). The Parties recommend that Questar increase its funding for LIWAP to $500,000. The program may involve audits, promotions, and/or financial incentives, and the program may be modeled after the LIWAP.

IV.C.3 Initial funding for QGC DSM initiatives.

BLM Direct (Lines 368 - 380)

Q. How will the Company fund new Demand-Side-Management efforts?
A. The Joint Application proposes to establish a Demand-Side-Management deferred account to account for authorized Demand-Side-Management expenditures. The balance in this account will be amortized periodically in conjunction with the Conservation Enabling Tariff balancing account. The Joint Application also proposes to establish the Demand-Side-Management deferred account with an initial credit balance of $1.3 million.

Q. What is the source of the initial funding?
A. In past cases, the Commission authorized the Company to collect revenue earmarked for Research and Development (R&D). Currently, the Company has $1.3 million available to transfer from R&D to Demand-Side Management. The Joint Application proposes to spend these dollars on Demand-Side Management rather than R&D. Amortization of the Demand-Side-Management deferred account will not begin until $1.3 million has been expended for approved Demand-Side-Management programs.

IV.C.4 QGC customers are ready for energy-efficiency programs.

BLM Surrebuttal (Lines 125 - 139)

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.

IV.C.5 The Nexant Report (market-characterization and delivery-evaluation study).

BLM Surrebuttal (Lines 143 - 160)

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. 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.

IV.C.6 The Energy-Efficiency Roadmap.

BLM Surrebuttal (Lines 162 - 224)

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, 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 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.

IV.C.7 Process for development of DSM initiatives.

BLM Settlement (Lines 287 - 307)
Q. Please describe the DSM aspects of the Pilot Program.
A. The Parties agree that the Natural Gas DSM Advisory Group (DSM Advisory Group) will collaborate with the Company in its filing an application no later than 60 days following the date the Settlement Stipulation is approved requesting expedited approval of DSM Programs. The Parties will work in good faith as members of the DSM Advisory Group to recommend DSM Programs that will have an immediate benefit to customers in the winter 2006-2007 heating season. In anticipation of Commission approval of these DSM Programs, the Company will take all necessary and reasonable steps to be able to execute such DSM Programs upon receiving Commission approval. The Parties, as members of the DSM Advisory Group, also agree to continue to collaborate with the Company in its filing for Commission approval of additional cost-effective DSM Programs as soon as reasonably possible after Commission approval of the first set of DSM Programs. The Company agrees to propose DSM Programs during the first year with anticipated costs from $2 to $5 million. The Settlement Stipulation provides that the DSM aspect of the Pilot Program will run for the entire three-year period of the Pilot Program.

Q. Will the Commission review and approve DSM programs and expenditures?
A. Yes. The Company, with input from the DSM Advisory Group, will seek Commission approval of DSM programs and expenditures. No DSM programs will be initiated without prior Commission approval.

IV.C.8 Application for approval of six initial energy-efficiency programs (Dec. 5, 2006).

BLM Direct 1-YR (Lines 91 - 96)
Q. Did the Company file an application within 60 days following the Commission's order ?
A. Yes. The Company, with significant input from the DSM Advisory Group, filed an application on December 5, 2006, requesting approval of six initial energy-efficiency programs. These programs support the Company's comprehensive market-transformation initiative. I will provide an overview of the status of the DSM Pilot Program later in this testimony.

IV.C.9 Review of initial participation levels in ThermWise Programs.

BLM Direct 1-YR (Lines 166 - 183)

ROADMAP EXHIBIT
Testimony Filing References/Excerpts

Q. Are the participation levels since the program launch in line with projected participation rates?
A. Yes. As can be seen on QGC Exhibit 1-YR 1.4, the ThermWise Programs are on track. We are three months into the first year. The ThermWise Appliance Rebates are at 26% of annual target levels. ThermWise Weatherization Rebates are at 33% of annual target levels. ThermWise Business Rebates are at 26% of annual target levels. ThermWise Home Energy Audits are at 16% of annual target levels. The ThermWise Builder Rebate Program is just beginning. Builders have shown an unexpected level of interest in building Energy Star® Homes. Early indications show that builders intend to build 4,651 Energy Star® Homes this year. This is 279% of our annual target. These participation levels indicate we are meeting our energy-efficiency goals.

Q. Are the energy-efficiency programs being well received by the Company's customers?
A. Yes. The initial response has been very good in terms of direct participation from customers, home builders and other trade allies. Customers are providing positive feedback on the entire campaign, including ease of participation with the rebate programs and awareness and understanding of the energy-efficiency message. The Division, with input from the Advisory Group, is making progress on defining a protocol for program evaluation.

V. ADDITIONAL REBUTTAL OF DISMUKES, HIGGINS AND WOLF

V.A Assertions of CCS, SLCAP and UAE Witnesses

V.A.1 QGC is not hurt by declining usage per customer.

BLM Surrebuttal (Lines 564 - 639)

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.

V.A.2 The CET will reduce QGC's incentive to manage expenses.

BLM Surrebuttal (Lines 691 - 717)

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.

V.A.3 The CET will reduce QGC's incentive to manage expenses.

RC/NRDC Surrebuttal (Lines 528 - 532)

Q. Does decoupling reduce a utility's incentive to pursue cost efficiencies, by assuring fixed revenues per customer for a utility with a growing customer base (Dismukes, p. 25)?

A. No. Under both the status quo and decoupling, cost efficiencies between rate cases yield identical bottom line benefits, and cost inefficiencies come out of shareholders' pockets.

V.A.4 With the CET, risk is shifted from the Company to customers.

BLM Surrebuttal (Lines 796 - 836)

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.)

V.A.5 Dr. Dismukes' Supplemental Testimony, three additional options.

BLM Surrebuttal (Lines 854 - 879)

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.

V.A.6 Dr. Dismukes' Supplemental Testimony, third alternative – Statistical Recoupling.

BLM Surrebuttal (Lines 881 - 954)

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.

V.A.7 Dr. Dismukes' Supplemental Testimony regarding lost-revenue approach.

BLM Surrebuttal (Lines 956 - 1024)

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)

V.A.8 Dr. Dismukes' Supplemental Testimony "Alternative Recommendation".

BLM Surrebuttal (Lines 1028 - 1092)

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.

V.A.9 Changes in customer mix could bias the impact of the CET on customers.

BLM Surrebuttal (Lines 1120 - 1137)

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.

V.A.10 The CET vs. a Lost Revenue Adjustment; use of Future Test Years.

BLM Surrebuttal (Lines 1455 - 1500)

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.

V.A.11 Adoption of CET should be conditioned on a reduction to allowed ROE.

RC/NRDC Surrebuttal (Lines 461-475)

Q. Should approval of the Company's proposal be conditioned on a cost of capital adjustment to reflect reduced financial risks to shareholders?

A. I disagree with both the conclusion and the premise on which it rests. It is important to recognize (as Mr. Dismukes himself clearly does) that the gas industry has only limited experience with this mechanism, and that it creates both upside and downside exposure for company shareholders (they will no longer under-recover authorized fixed costs if sales drop below expectations, but they also will lose their longstanding opportunity for gains from sales increases). Whether the net result is a material change in the company's risk profile cannot be determined without company-specific and capital market experience. This is particularly true for a mechanism, like this one, which is framed as a pilot program that does not in any way affect current allocation of weather-related risks. Finally, if the goal is to encourage the company to devote more management resources and creativity to energy efficiency, the simultaneous imposition of a reduction in shareholder returns would be wholly counterproductive.

V.A.12 The CET is like using a steam roller to crack a peanut.

RC/NRDC Surrebuttal (Lines 477 - 490)

Q. How do you respond to the contention that the decoupling proposal "makes the Company whole for revenue losses that go beyond any revenue losses caused by energy efficiency per se...[it] is like using a steam roller to crack a peanut" (Dismukes, p. 8)?

A. Potential revenue losses from a robust conservation program are clearly material, as I showed earlier in describing the calculation of potential $23 million in automatic shareholder losses to Questar from a five-year systemwide conservation initiative. Peanut-sized conservation initiatives are what we will continue to get if Mr. Dismukes' advice is accepted. Also, note that mechanisms focused solely on conservation-driven revenue losses guarantee both regular rate increases and costly adjudication; by contrast, the company's proposal envisions adjustments that could go either up or down following a simple calculation based on easily ascertainable empirical data (customer count, actual non-gas revenues and authorized revenue per customer).

V.A.13 The CET will eliminate QGC's incentive to promote economic development.

RC/NRDC Surrebuttal (Lines 534 - 541)

Q. Do you agree that Questar's decoupling proposal will eliminate its incentive to promote economic development in Utah (Dismukes, p. 36)?

A. No. Mr. Dismukes is effectively equating economic development with increased fuel use; that kind of thinking undercuts energy efficiency progress and efforts to reduce Utahns' exposure to fossil fuel price risks. The right kind of economic development incentive links utilities' fixed cost recovery to growth in the customer base, rather than the use of natural gas, and that is precisely what the company is proposing.

V.A.14 The CET will remove the need for future rate cases.

BLM Surrebuttal (Lines 642 - 688)

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.

V.A.15 The CET assures profitability, eliminates need for rate cases.

RC/NRDC Surrebuttal (Lines 582 - 590)

Q. Respond to witness Wolf's contention that the Company's proposal would "virtually assure its profitability" and eliminate any need for it to file rate cases.

A. The Company's proposal does not guarantee, "virtually" or otherwise, any level of profitability; it simply prevents fluctuations in gas use from affecting the Company's ability to recover previously approved revenue requirements unrelated to gas use. This reform should not affect the frequency of rate cases (which will be driven, as always, primarily by changes in the company's costs of operations); what will change is the company's incentives to promote reductions in systemwide gas needs between rate cases.

V.A.16 The CET unfairly shifts costs and burdens to ratepayers.

RC/NRDC Surrebuttal (Lines 592 - 598)

Q. Do you agree with witness Wolf that the Company's proposal unfairly shifts costs and burdens to ratepayers?

A. No, because the proposed mechanism adds no new costs or burdens, and rates could go either up or down (very modestly) as a result of its regular true-ups. On the other hand, without these true-ups and the associated changes in the Company's incentives, ratepayers are unlikely to see the substantial benefits associated with creative large-scale energy efficiency programs.