BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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

REBUTTAL TESTIMONY OF RUSSELL A. FEINGOLD
TO SUPPORT THE CONTINUATION OF THE CONSERVATION ENABLING TARIFF FOR QUESTAR GAS COMPANY

August 8, 2007

Q. Please state your name and business address.

A. My name is Russell A. Feingold and my business address is Four PPG Place, Pittsburgh, Pennsylvania 15222.

Q. By whom are you employed and in what capacity?

A. I am a Managing Director of Navigant Consulting, Inc. ("NCI") and co-leader of the Litigation, Regulatory & Markets Group within the firm's Energy Practice.

Q. Please describe in more detail the business activities of NCI.

A. NCI has served the electric and natural gas industries since 1983. We offer a wide range of consulting services related to information technology, process/operations management, business strategy development, and marketing and sales designed to assist our clients in a business environment of changing regulation, increased competition and evolving technology. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over thirty-two (32) years of experience in the utility industry, the last twenty-nine (29) years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. I have prepared and presented expert testimony before the Federal Energy

Regulatory Commission ("FERC") and several state and provincial regulatory commissions and have spoken widely on issues and activities dealing with the pricing and marketing of gas utility services. Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in QGC Exhibit 1-YR 3.1.

Q. Please summarize your specific experience with revenue decoupling concepts for gas and electric utilities.

A. With the recent growing interest in the application of revenue decoupling concepts to the utility ratemaking process, I have been actively involved with the evaluation and development of revenue decoupling mechanisms for gas and electric utilities. Specifically, over the past five years, I have worked closely with utilities, regulatory staffs, and other interested parties to evaluate the utility operating conditions that support revenue decoupling (or other revenue stabilization techniques) as a viable ratemaking solution, to develop the conceptual underpinnings and specific details of the desired ratemaking mechanism, and to support the utility's specific ratemaking proposal before its regulatory body. In addition, I have been active in the natural gas industry with revenue decoupling concepts and their importance in addressing the critical business challenges facing gas distribution utilities. A summary listing of my recent industry presentations and appearances on the topics of revenue decoupling mechanisms and energy efficiency initiatives is provided in QGC Exhibit 1-YR 3.2.

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

A. The purpose of my rebuttal testimony is to respond to certain of the criticisms raised by Dr. David E. Dismukes, witness for the Utah Committee of Consumer Services (the "Committee") in this proceeding, concerning the currently-effective Conservation Enabling Tariff ("CET") of Questar Gas Company ("Questar" or the "Company"). Specifically, I will respond to Dr. Dismukes' portrayal of the recent trends in industry-wide activities, and his conclusion based on these activities that revenue decoupling as a concept has been rejected or viewed negatively, and to the risk shifting and risk reducing claims he makes in conjunction with the operation of the Company's CET.

I. Industry-Wide Activities Related to Revenue Decoupling

Q. Do you agree with Dr. Dismukes' portrayal of the recent industry-wide activities as they relate to revenue decoupling mechanisms similar to the Company's CET?

A. Absolutely not. Dr. Dismukes' portrayal of the recent trends in industry-wide activities is biased and misleading. His associated conclusion that such activities have rejected, or otherwise viewed negatively, ratemaking mechanisms similar in purpose and structure to the Company's currently-effective CET is incorrect. Quite the contrary, revenue decoupling mechanisms are being embraced by a growing number of state legislators and regulators across the U.S. in recognition of the business challenges faced by utilities and the energy efficiency and conservation initiatives that are being pursued by utilities for the benefit of their customers. His presentation of industry-wide activities does not provide this Commission with a balanced view that properly captures the latest thinking of utilities, regulators, and public officials on the appropriateness of revenue decoupling as an important ratemaking solution.

Q. Please comment on Dr. Dismukes' CCS Exhibit 1.2 indicating that there are only ten (10) states that have adopted revenue decoupling as either a permanent or pilot mechanism for electric and/or gas utilities.

A. Dr. Dismukes neglected to mention when he discussed CCS Exhibit 1.2 that there are many other states where revenue decoupling mechanisms are currently proposed by utilities, where the concept was recently endorsed by legislators, or where such mechanisms are currently being investigated by utility regulators. Industry-wide support for revenue decoupling mechanisms is growing rapidly, as evidenced by the large number of legislative, regulatory, and utility initiatives that have occurred in just the last six (6) months. Among these developments are:

1. **Illinois –** On March 9, 2007, the Peoples Gas Light and Coke Company and North Shore Gas Company (now Integrys Energy) filed proposals to implement revenue decoupling mechanisms.
2. **New York –** On April 18, 2007, the New York Public Service Commission ordered all gas and electric utilities to file revenue decoupling mechanisms in their next rate cases.
3. **New Hampshire –** On May 14, 2007, the New Hampshire Public Utilities Commission initiated an investigation into revenue decoupling mechanisms.
4. **Ohio** - On May 30, 2007, a bill was introduced in the Ohio House of Representatives that proposes to allow natural gas utilities to apply with state regulators for approval of alternative rate plans, including revenue decoupling mechanisms. In addition, on June 27, 2007, the Public Utilities Commission of Ohio approved a revenue decoupling mechanism for Vectren Energy Delivery of Ohio Inc.
5. **Delaware –** On June 1, 2007, Delmarva Power & Light Company filed in a generic proceeding initiated by the Delaware Public Service Commission a proposal for a Bill Stabilization Adjustment ("BSA"). In addition, on July 6, 2007, Chesapeake Utilities Corporation filed a proposal with the state regulator to implement a revenue decoupling mechanism.
6. **Connecticut –** On June 4, 2007, the Governor signed into law House Bill (H.B.) 7432 which orders the Connecticut Department of Public Utility Control to implement a mechanism designed to decouple electric and gas distribution revenues from sales volumes.
7. **Nevada –** On June 14, 2007, the Governor signed into law amended Senate Bill (S.B) 437, which among its provisions, would allow for the Public Utilities Commission of Nevada to adopt rules for the implementation of natural gas revenue decoupling mechanisms.

8. **Colorado –** On June 18, 2007, the Colorado Public Utilities Commission approved a revenue decoupling mechanism for the gas operations of Public Service Company of Colorado.

9. **Massachusetts –** On June 22, 2007, the Massachusetts Department of Public Utilities initiated an investigation into rate structures that will promote efficient deployment of demand resources, including revenue decoupling mechanisms.

10. **Arkansas** – On July 13, 2007, the Arkansas Public Service Commission approved a settlement in Arkansas Western Gas Company's current rate case that included a Trial Billing Determinant Rate Adjustment ("BDA Tariff"), which is similar to a revenue decoupling mechanism.

Q. Please comment on Dr. Dismukes' conclusion from Attachment 2 included with his direct testimony that revenue decoupling mechanisms for gas or electric utilities have either been rejected by state commissions or withdrawn in eleven (11) states.

A. Dr. Dismukes' conclusion based on Attachment 2 is not reflective of the following recent developments in seven (7) of those eleven (11) states that indicate they have either approved specific revenue decoupling mechanisms or have endorsed the concept:

1. **Washington** – revenue decoupling mechanisms have been approved for Avista Corporation on February 1, 2007 and for Cascade Natural Gas Corporation on January 12, 2007.

2. **Arkansas –** On July 13, 2007, the Arkansas Public Service Commission approved a settlement in Arkansas Western Gas Company's current rate case that included a Trial Billing Determinant Rate Adjustment ("BDA Tariff"), which is similar to a revenue decoupling mechanism. In addition, CenterPoint Energy and Arkansas Oklahoma Gas Corporation filed for various types of revenue decoupling mechanisms on January 16, 2007 and March 8, 2007, respectively.

3. **New York –** On April 18, 2007, the New York Public Service Commission ordered all gas and electric utilities to file revenue decoupling mechanisms in their next rate cases.
4. **Connecticut** – On June 4, 2007, the Governor signed into law House Bill (H.B.) 7432 which requires the Connecticut DPUC to implement a mechanism designed to decouple electric and gas distribution revenues from sales volumes.
5. **Delaware** – On June 1, 2007, Delmarva Power & Light Company filed in a generic proceeding initiated by the Delaware Public Service Commission a proposal for a Bill Stabilization Adjustment ("BSA"). In addition, on July 6, 2007, Chesapeake Utilities Corporation filed a proposal with the state regulator to implement a revenue decoupling mechanism.
6. **Nevada –** On June 14, 2007, the Governor signed into law amended Senate Bill (S.B) 437, which among its provisions, would allow for the PUC to adopt rules for the implementation of natural gas revenue decoupling mechanisms.
7. **Michigan** – On February 9, 2007, CMS Energy proposed a revenue decoupling mechanism in its current gas rate case.

Q. Have you prepared a detailed comparison of the results of Dr. Dismukes' CCS Exhibit 1.2 with the most recent industry-wide activities related to revenue decoupling mechanisms?

A. Yes, I have. QGC Exhibit 1-YR 3.3 presents in tabular form a detailed listing of the most recent industry-wide activities related to revenue decoupling mechanisms, grouped by the categories used by Dr. Dismukes in CCS Exhibit 1.2, so this Commission can see the most recent trends in each state contrasted against the claimed negative industry position on revenue decoupling presented by Dr. Dismukes. To highlight the industry trend towards revenue decoupling, QGC Exhibit 1-YR 3.4 presents a map of the U.S., which depicts the extent to which revenue decoupling has been approved, or is currently being addressed, in the various states. Interestingly, this map is in stark contrast to what a similar map would have looked like only five (5) years ago. As of 2002, there were only three (3) states that had approved revenue decoupling mechanisms for gas utilities – and currently there are eleven (11) states that have approved revenue decoupling, with fourteen (14) additional states currently addressing revenue decoupling issues. I anticipate that over the next 6-12 months, we will see other states added with solid shading on this map indicating state regulatory approval of revenue decoupling mechanisms for other gas utilities.

Q. How do you respond to Dr. Dismukes' conclusion based on CCS Exhibit 1.2 that twenty-one (21) states "have found a way to promote energy efficiency under more traditional ratemaking approaches."

A. Review of the activities in those states as presented in QGC Exhibit 1-YR 3.3 would suggest otherwise. Of the twenty-one (21) states noted by Dr. Dismukes, utility regulators in more than half of those states (12 states) have either ordered all gas utilities to file revenue decoupling mechanisms, approved a revenue decoupling mechanism for a gas utility, have opened an investigation into revenue decoupling concepts, or are considering a revenue decoupling proposal filed by a gas utility. In addition, the Governors of Connecticut and Nevada have signed laws that either order the utility regulator to implement revenue decoupling mechanisms for all utilities or allow the utility regulator to adopt rules to implement revenue decoupling mechanisms for all utilities.

Q. In particular, based on CCS Exhibit 1.4, Dr. Dismukes implies that Vermont Gas does not need a revenue decoupling mechanism "in order to be successful at promoting DSM." Is this a fair characterization of Vermont Gas' current ratemaking situation relative to DSM?

A. No. Just like all other gas utilities, Vermont Gas Systems ("VGS")[1] has experienced revenue losses due to the decline in use per customer caused by the energy efficiency and conservation actions of its customers. Although VGS does not have a revenue decoupling

[1] I have provided a wide range of ratemaking and regulatory consulting assistance to VGS since 1980.

mechanism, it received regulatory approval in April 2007 to implement a ratemaking mechanism that provides similar rate treatment. Before that time, however, VGS was forced to file rate cases on a regular basis to be able to adjust its base rates to reflect, among other things, the decreases in sales volumes (i.e., its billing determinants). VGS also secured regulatory approval to implement a Lost Revenue Adjustment ("LRA") to provide some added financial relief from the impact of DSM. In April 2007, VGS implemented an Alternative Regulatory Plan ("ARP") and eliminated its LRA. The ARP consists of an earnings sharing mechanism and rate cap indexed to inflation that creates an annual change in its base rates due to a number of financial factors including operating expenses, income taxes, and return on projected rate base. VGS will file each year with its regulator a projection of its revenue requirement for the next 12-month period, using projected revenue requirements and billing determinants, to reset its base rates. In addition, if there is a shortfall in its earnings in a particular year, VGS can reflect a portion of that loss in its future rates. Through this ARP, VGS has some of the same opportunities it would have under a revenue decoupling mechanism. The annual rate filing component enables VGS to reset its billing determinants periodically to track <u>any</u> changes in sales volumes and the earnings sharing component provides some rate relief from under earnings due to a decline in revenue per customer caused by <u>any</u> factor, including DSM. Clearly, VGS is not immune to the ratemaking challenge of declining use per customer and its regulator has appropriately recognized that challenge, and the failure of traditional ratemaking, by approving a ratemaking solution that addresses some of the same factors addressed by revenue decoupling.

Q. Dr. Dismukes suggests that consumer groups are particularly concerned about the adoption of revenue decoupling mechanisms and the implications they have for customer bills. Do you share Dr. Dismukes' industry-wide perspective on this topic?

A. No. I believe Dr. Dismukes' industry-wide viewpoint on this topic is biased. In states such as Arkansas, Indiana, and Colorado, State Attorney Generals and other consumer groups have signed onto utility rate case settlements that proposed revenue decoupling mechanisms. In addition, the former New York Attorney General (Elliot Spitzer) was supportive of revenue decoupling in its comments in the New York Public Service Commission generic proceeding on the subject that led to the ordering of all gas and electric utilities in the state to file revenue decoupling proposals. Furthermore, the utility consumer advocates in the states of Colorado, Indiana, Ohio, and Wyoming (with the states of California and Massachusetts abstaining) voted against the National Association of State Consumer Advocates ("NASUCA") Resolution urging utility regulators not to adopt revenue decoupling concepts. Finally, the Connecticut Office of Consumer Counsel and the Office of the Ohio Consumers' Counsel endorsed the recommendations of the National Action Plan for Energy Efficiency – which included as one of its recommendations to encourage state utility regulators to consider revenue decoupling mechanisms.

Q. Is Dr. Dismukes correct in his suggestion that because revenue decoupling creates negative incentives for monitoring and verification of energy efficiency programs, many states have used as an alternative method third-party administrators for the promotion and development of energy efficiency programs?

A. No. Dr. Dismukes' claim on this point is misleading in his continuing attempt to cast a negative light on revenue decoupling. While certain states have decided to rely upon a third-party administrator to implement energy efficiency and conservation programs for the utility's customers, this decision has no bearing whatsoever on the appropriateness of approving a revenue decoupling mechanism for the utilities that operate in the states indicated in CCS Exhibit 1.16. In fact, three of the four states he includes in CCS Exhibit 1.16 also have approved revenue decoupling mechanisms for the gas utilities operating in these states. These states are New Jersey, Ohio, and Oregon. In fact, Oregon was one of the first states in the U.S. to approve a revenue decoupling mechanism for a gas utility – Northwest Natural Gas. This evidence strongly suggests that these states never viewed the use of a third-party administrator as a substitute for implementation of a revenue decoupling mechanism.

Q. Please comment on Dr. Dismukes' observation that over the last three years "revenue neutrality programs" have been considered in at least 15 rate case proceedings rather than in rate design only proceedings like the one in Utah.

A. While that may be Dr. Dismukes' experience on the subject, my experience in this area is different. Over the last five years, I am aware of at least 11 "revenue neutrality programs" (besides the Company's current CET) that were considered and approved by utility regulators in stand-alone, rate design only proceedings rather than in general rate cases.

Q. What is your opinion concerning the relative level of review and evaluation of "revenue neutrality programs" that occurs in rate design only proceedings compared to general rate cases?

A. In my opinion, a rate design only proceeding provides for a greater level of scrutiny of a utility's "revenue neutrality program" compared to what can occur in a general rate case. In a rate design only proceeding, by its very name, the parties are singularly focused on the ratemaking proposal of the utility. In a general rate case, the parties also must address the appropriate determination of the utility's total revenue requirement, which includes the review and evaluation of a multitude of expense and rate base components that comprise the utility's total revenue requirement. By contrast, in a rate design only proceeding, the parties are able to spend a greater amount of time considering the ratemaking alternatives, the appropriate design elements, and the degree to which these alternatives can satisfy the desired ratemaking objectives. With the increased industry-wide importance being placed on the development of energy efficiency and conservation programs for utility customers, I believe this type of focused regulatory proceeding is conducive to addressing the fundamental ratemaking changes that are consistent with, and supportive of, such initiatives.

Q. Based on your review of the evidence presented in this proceeding, how would you characterize the level of scrutiny that the concepts underlying the Company's current CET were subjected to during the case's history including the three-year process?

A. In my opinion, the entire process followed addressed more ratemaking options, with a greater level of scrutiny, than I have seen in most utility rate design only or general rate cases. In fact, in many respects, the type of review and evaluative activities undertaken in this proceeding with regard to the development of the Company's CET were very similar to the process in which key ratemaking issues are addressed in generic regulatory investigations initiated by regulators in other jurisdictions. With the important ratemaking goals established by the parties in this proceeding, I believe that a rate design only proceeding was the best venue to fully address and agree upon a preferred ratemaking approach that best satisfied those goals.

Q. Please summarize your conclusions regarding the status of revenue decoupling in the natural gas industry.

A. It is my view that the concept of revenue decoupling in the natural gas industry is being embraced more broadly across the country than it was in the recent past. The growing number of utility proposals and regulatory initiatives that I discussed above underscores the recognized importance of this ratemaking concept with the increased offering of energy efficiency and conservation programs to utility customers. In my opinion, the continuation of the Company's CET is consistent with, and supportive of, these industry-wide initiatives.

II. <u>Risk-Shifting Under the Company's CET Mechanism</u>

Q. Do you agree with Dr. Dismukes' conclusion that the Company's current CET shifts business risk to its customers?

A. No. I do not believe that outcome has occurred under the Company's CET. The Company's business risks are not shifted to its customers under the CET mechanism for the following reasons:

1. The Company's CET does not change the fundamental weather related or economy related costs of the utility – it will only affect how and when revenues are collected to cover the regulator-approved level of costs.

2. If a customer's gas consumption increases due to a variety of factors, and it overpays for gas delivery service, the Company's CET remedies this situation equally for both the Company and its customers by adjusting the revenues of the Company and the level of rates charged to its customers for delivery service.
3. Commodity risk is not shifted to customers under the Company's CET because customers will continue to respond to the market risk associated with gas commodity prices, as embodied in measures of price elasticity.
4. The Company, as explained in Mr. McKay's testimony, has shown by its actions that it is committed to promoting energy efficiency and conservation programs that will have the effect of reducing commodity price risk to the customer.
5. Contrary to Dr. Dismukes' claim, the Maine experience with revenue decoupling in the 1990s, under the Electric Revenue Adjustment Mechanism ("ERAM") program, does not serve as an example of how a revenue decoupling mechanism failed.
6. My conclusions on the absence of risk shifting under the Company's CET is supported empirically by DPU witness Dr. Daniel G. Hansen of Christensen Associates Energy Consulting, LLC in his company-specific report (the "Hansen Report").

Q. What is the nature of your fundamental disagreement with Dr. Dismukes assertion that the Company's current CET shifts risk from the Company to its customers?

A. Very simply, Dr. Dismukes has painted the operation of the Company's current CET as extremely one-sided because he highlights only the resulting higher rates that he alleges customers experience under the CET mechanism. The reality is that the symmetry considered in the design of the CET mechanism preserves the relative risk relationship between the Company and its customers, as I will demonstrate below, and provides a much more balanced ratemaking result than what is alleged by Dr. Dismukes.

Q. Please explain more specifically why risk will not be shifted to customers under the Company's current CET.

A. The Company's current CET mechanism will not shift volume risk to customers because of the symmetrical treatment of the variation in volumes and associated margin revenue caused by factors other than weather. For example, under current rates, when the Company over-recovers DNG revenues due to higher than expected revenue per customer (like what happened in 2006), and its customers overpay for delivery service ($1.7 million in 2006), the current CET remedies that situation equally for both the Company and its customers by adjusting the DNG revenues recoverable by Questar and the level of rates charged to their customers for delivery service. Therefore, customers no longer will have the risk of overpaying for delivery service under the CET. Next, the approval and implementation of the Company's CET does not guarantee it will achieve the financial performance currently allowed by this Commission in Questar's most recently completed rate case. As such, any suggestion that customers somehow will absorb risks related to the Company's ability to achieve enhanced financial performance under this decoupling mechanism is simply unfounded.

Q. The premise for Dr. Dismukes risk shifting argument seems to be that he believes customers should have the opportunity to avoid a portion of their distribution non-gas charges if they use less gas, and that under the Company's CET, this opportunity has been eliminated. Do you agree with his premise?

A. Absolutely not. The problem with Dr. Dismukes' premise is that it is based on a faulty ratemaking assumption. Essentially, he assumes that customers should have the opportunity to reduce their distribution non-gas charges and pay less fixed delivery costs whenever their gas usage declines. This is despite the fact that the costs incurred by the Company to provide delivery service do not change when customer usage declines. In essence, Dr. Dismukes' argument amounts to him suggesting that it is sound regulatory policy to use the Company's current rate design (with the volumetric recovery of fixed delivery costs) to allow customers to avoid responsibility for the fixed costs that are incurred to provide them with delivery service. His perspective is simply regressive in nature and in direct conflict with the concept of cost-based rates. On this basis alone, Dr. Dismukes' claim of risks being shifted to customers under the Company's CET should be rejected.

Q. Dr. Dismukes claims that because weather influences the sales of the Company's customers, under the CET mechanism weather risk would be shifted to customers. How do you respond to this specific claim?

A. I disagree with this specific claim for the simple reason that any sales variability experienced by the Company's customers due to weather already has been accommodated in its previously approved Weather Normalization Adjustment ("WNA"). Therefore, even if the weather factor raised by Dr. Dismukes was an appropriate consideration in assessing the potential for change to the relative risks between the Company and its customers, the CET is not relevant to its consideration.

Q. Are economic risks shifted to the Company's customers under the CET as argued by Dr. Dismukes?

A. No. Dr. Dismukes' claim is incorrect that under the CET, customers will be required to make the utility whole for possible losses during economic downturns, whereas under traditional regulation, this would not have been the case. Under traditional regulation, the utility would have the ability to file a rate case to reset its base rates to reflect the lower sales level and the associated increase in those rates required to adequately recover its fixed costs of delivery service. Those costs do not change even with an economic downturn of the type suggested by Dr. Dismukes. I would note that Dr. Hansen reached a similar conclusion that there is no shifting of economic risks to the Company's customers under its CET based on his statistical analysis of the prevailing economic conditions in Questar's service area.[2]

Q. **Dr. Dismukes cites a "real world" example of how a revenue decoupling mechanism created serious problems during an economic contraction. Do you share his view that the example he cites demonstrates a problem with revenue decoupling as a concept?**

A. No. Contrary to Dr. Dismukes' claim, the Maine experience with revenue decoupling in the 1990s that he cites does not serve as an example of how a revenue decoupling mechanism

[2] The economic conditions analyzed in the Hansen Report included the Utah unemployment rate, Utah gross

failed. While the Maine ERAM was not deemed a success, this had little to do with the concept of revenue decoupling and more to do with the construct of the recovery mechanism that was established. In the EPA's National Action Plan for Energy Efficiency, it identified the deferred recovery process as a source of the problem with this experience – and not the revenue decoupling mechanism itself.

In mid-1991, the Maine Public Utilities Commission approved the ERAM for Central Maine Power Company ("CMP") on a three-year trial basis. This revenue decoupling mechanism adjusted CMP's rates annually based on its previously approved revenue level and the actual sales levels of its customers. Due to the ensuing economic downturn in New England, sales levels declined early in the ERAM trial period causing revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in late 1991 that would have increased rates at the time, but likely would have caused lower revenue deferrals under the ERAM. However, that rate case was withdrawn by agreement of the parties to avoid immediate rate increases during bad economic times. At the same time, the commission decided not to implement the true-up aspect of the ERAM and instead to further defer the unrecovered electric revenues to a future time period with the hope of stronger economic conditions. When economic conditions did not improve, customers faced even larger rate increases. In its review of the Maine ERAM case, the EPA concluded that "responsibility for large rate increases was inappropriately attributed to the revenue decoupling plan, when general economic conditions were primarily responsible.[3] The EPA further concluded that a lesson from this experience was not to allow extended periods of time between rate true-ups.

Q. Do you agree with Dr. Dismukes' contention that "commodity risk" is shifted to the Company's customers under the CET?

A. No. "Commodity risk" is not shifted to the Company's customers under the CET because customers will continue to respond to the market risk associated with gas commodity prices, as embodied in measures of price elasticity. This price response has not changed by the

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domestic product, and Utah per capita disposable personal income.

existence of the Company's CET. To the extent customers reduce their gas usage, under the Company's CET; they will continue to experience reductions in the gas commodity portions of their gas bills. Moreover, the Company is committed to promoting energy efficiency and conservation programs which will have the effect of reducing commodity price risk to the customer. With the expectations of reduced gas usage, I believe the energy efficiency and conservation initiatives offered by the Company will assist in moderating natural gas demand and reducing upward pressure on natural gas prices. Finally, the Hansen Report reaches a similar conclusion that commodity risk is not shifted to Questar Gas customers because of the CET.

Q. In support of his claim of commodity risk being shifted to customers, Dr. Dismukes points out that, "any balances (positive or negative) associated with the Company's CET are clearly not associated with Demand Side Management ("DSM") programs at this time." Is this a relevant consideration in assessing the issue of commodity risk and the CET?

A. No. One of the task force's issues that the CET addressed is the impact on the Company's revenues and income of declining use per customer. The fact that the decline in use may be related to factors other than the Company's DSM programs is not a relevant consideration – it is the fact that there has been a discernable decline in customer use. There is no need to conduct an assessment of what caused the decline in use to evaluate "commodity risk" as Dr. Dismukes has defined the concept. The point is quite simple – customers respond to the gas commodity price in the same way they always have – whether the Company's rates are based on traditional ratemaking concepts or reflect a revenue decoupling approach.

Q. Do you have an opinion on the suggestion by Dr. Dismukes that the Company's return on equity allowance should be adjusted downward because of the change in its risk profile that he alleges occurs under the CET mechanism?

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[3]Environmental Protection Agency, National Action Plan for Energy Efficiency (July 2006), p. 2-5.

A. Yes. I do have certain comments from a ratemaking perspective in response to the assertion of Dr. Dismukes. First, a revenue decoupling mechanism such as the Company's CET does not eliminate a utility's business risks. As always, the utility will have ongoing pressures on earnings in the form of cost increases, infrastructure investment to ensure a safe and reliable distribution system, and an aging workforce. Second, since revenue decoupling mechanisms are designed on a symmetrical basis, the utility's upside opportunities are limited at the same time as its downside risk. Finally, I question the fundamental appropriateness of making a reduction to a utility's ROE allowance to account for the relative risk associated with any enhanced revenue collection capabilities of a particular rate design. I have never seen in any prior utility rate case an explicit risk premium added to a utility's ROE level in recognition of any reduced revenue collection capabilities inherent in the utility's then prevailing rate design or rate structure. The process of determining an appropriate ROE level for a utility is not so granular that the ratemaking methods can have a material influence on the ultimate ROE level. Since regulators have not considered this type of upward adjustment in conjunction with the setting of a utility's ROE allowance, I do not see why <u>now</u> regulators should be pressured by certain parties to make such an asymmetrical adjustment to single out ratemaking as a relevant consideration in the ROE determination process.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.