BEFORE THE PUBLIC SERVICE COMMISSION
OF UTAH

IN THE MATTER OF:

Joint Application of Questar Gas	)	
Company, the Division of Public	)	
Utilities, and Utah Clean Energy	)	**Docket Number 05-057-T01**
For the Approval of the Conservation	)	
Enabling Tariff Adjustment Option	)	
And Accounting Orders	)	

SURREBUTTAL TESTIMONY
OF
DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE
UTAH COMMITTEE OF CONSUMER SERVICES

AUGUST 31, 2007

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS?

A. My name is David E. Dismukes and I am a Consulting Economist with the Acadian Consulting Group. My business address is 6455 Overton Street, Baton Rouge, Louisiana. I am the same person that filed direct and rebuttal testimony on the behalf of the Utah Committee of Consumer Services ("CCS" or "the Committee") on June 1, 2007 and August 8, 2007, respectively.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to some of the issues addressed in the rebuttal testimony of the Division of Public Utilities ("DPU" or "the Division") and Questar Gas Company ("Questar" or "the Company"). In particular, my surrebuttal addresses:

(1) The Company and the Division's assertion that Dr. Hansen's residential natural gas demand model appropriately measures the risk shifting nature of revenue decoupling;

(2) The Company's assertion that my testimony presents a biased version of U.S. revenue decoupling progress;

(3) The Company and the Division's assertion regarding utility cost incentives under decoupling;

(4) The Company's assertions regarding the financial implications associated with lost DSM revenues and customer growth; and

(5) The Division's rebuttal of the Committee's prior recommendations as well as their proposals on the CET.

Q. HOW IS YOUR SURREBUTTAL TESTIMONY ORGANIZED?

A. My surrebuttal testimony provides a summary of my recommendations and addresses each of the aforementioned topics.

Q. HAVE YOU PROVIDED ANY EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A. Yes, I have prepared five exhibits to accompany my surrebuttal testimony. These exhibits were prepared by me or under my direct supervision.

II. <u>SUMMARY OF RECOMMENDATIONS</u>

Q. DO YOU HAVE ANY GENERAL COMMENTS ABOUT THE REVENUE DECOUPLING DEBATE THAT HAS TAKEN PLACE THROUGH THE TESTIMONIES OF DIFFERENT WITNESSES IN THIS PROCEEDING?

A. Yes. Mr. McKay makes a very good point in his rebuttal testimony: to paraphrase, no one has said anything new in the second round of this proceeding that hasn't already been said before. Most gas utilities, the Division, and energy efficiency advocates have argued that revenue decoupling is a great thing resulting in a "win-win" for customers and shareholders, while the consumer groups participating in this proceeding have argued that revenue decoupling is an overly broad policy mechanism that shifts considerable risk onto ratepayers with little to no clearly identifiable benefits. In thinking about this from a "big picture" perspective, however, it is clearly the case that revenue neutrality, while growing in importance as a topic of policy debate, has not been widely adopted, and does not have a long and deep practical experience from which to judge its performance. The simple fact of the matter is that there is continued uncertainty about revenue decoupling in the natural gas industry. This uncertainty should raise serious concerns about the continuation of the CET and the unanticipated consequences it may have on ratepayers.

Q. DO YOU THINK THE DECOUPLING DEBATE HAS ANY COMMON ATTRIBUTES WITH OTHER PAST POLICY INITIATIVES?

A. Yes, the speculative nature of this decoupling debate is hauntingly familiar to the debate on electric retail competition. It was not uncommon during that period to evaluate the regularly published and updated Department of Energy ("DOE") maps on restructuring status, and listen to debates strongly encouraging Commissions to "move fast" in the adoption of retail competition since "everyone's doing it." The debate then, like today in decoupling, held out California as the "model" of progressive regulatory policy that other states should replicate in order to attain considerable efficiency benefits for their ratepayers. Given this uncanny similarity, as well as a number of other very important regulatory policy concerns, I would recommend that the Commission discontinue the CET and address many of these policy issues in a more complete fashion in the Company's next rate case, which according to a recent announcement[1] will

[1] According to the Company's second quarter conference call with investors, "Alan Allred and our utility team have worked hard to control costs and thus avoid the need to ask our customers for an increase in our non-gas rates, but it is now looking more likely than not that we will file late this year or next year."

be in the very near future. If the Commission decides to retain the CET through the pilot period as the Company and the Division have recommended, then a number of safeguards and adjustments to the CET need to be made in order to bring it more in line with traditional regulation. This would include capping the overall recovery amounts, and an explicit recognition that the CET results in a shifting of risk from the utility to ratepayers that needs to be addressed in the determination of its allowed return in the next rate case.

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS RELATIVE TO YOUR SURREBUTTAL TESTIMONY?

A. None of the rebuttal witnesses have presented any evidence that would prove that any of the positions in my direct testimony are without merit and should be dismissed by the Commission in considering whether to maintain the CET. In particular:

(1) The Company and the Division's positions on risk shifting are inconsistent, are themselves asymmetrical, typically in error, and rely heavily on a flawed empirical study that can be easily corrected to show the exact opposite of each rebuttal witnesses' conclusions.

(2) No matter how Mr. Feingold attempts to "sugar-coat" the progress of revenue decoupling, it is still a fact that there is little empirical evidence to unequivocally support the adoption of revenue decoupling.

(3) Each of the rebuttal witnesses entirely misrepresents my direct testimony on cost incentives.

(4) Mr. McKay's representation of my prior analysis of lost revenues is simply a "bait and switch" argument that should be disregarded.

(5) The Division's recommendations clearly indicate a concern and explicit acknowledgment that risk shifting can occur under the CET. Further, the Division's position on the Committee's lost revenue adjustment proposal is internally inconsistent and without merit.

III. <u>RESPONSE TO ASSERTIONS ABOUT RISK SHIFTING</u>

Q. WHAT HAVE BEEN THE REBUTTAL WITNESSES' POSITION ON THE RELATIONSHIP BETWEEN REVENUE DECOUPLING AND RISK SHIFTING?

A. All of the rebuttal witnesses have placed considerable stock in Dr. Hansen's flawed natural gas demand analysis as support for the assertion that there is an insignificant customer response to prices, income and just about any other factor potentially influencing demand, with the exceptions of weather and the natural progression of time. According to each of these rebuttal witnesses, Dr. Hansen's analysis proves that there can be no risk shifting with decoupling and specifically the CET. All of these rebuttal testimonies should be disregarded for the following reasons:

(1) Mr. McKay's rebuttal supporting Dr. Hansen's analysis is inconsistent with his prior testimony indicating that prices have played an important role in changing usage patterns;

(2) Mr. Feingold's rebuttal supporting Dr. Hansen's analysis is inconsistent with his prior presentations as well as various sections of his rebuttal testimony;

(3) Each rebuttal witnesses' support of the empirical results of Dr. Hansen's model is inconsistent with a report recently issued by the American Gas Association ("AGA"), the trade organization for natural gas local distribution companies; and

(4) Each rebuttal witnesses' support of the empirical results of Dr. Hansen's analysis is based upon misplaced confidence that is easily dismissed with the use of more appropriate data and modeling techniques.

Q. HOW IS MR. MCKAY'S REBUTTAL INCONSISTENT WITH HIS PRIOR TESTIMONY IN THIS PROCEEDING?

A. Earlier in this proceeding, Mr. McKay clearly indicated that changes in natural gas prices were having a clear and important impact on customer usage patterns. Mr. McKay even went so far as to provide evidence supporting this position in QGC Exhibit 1.6 in his original CET testimony filed on January 23, 2006. In touting the virtues of the CET, Mr. McKay noted:

> 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.[2]

[2] Direct Testimony, Barrie L. McKay, January 23, 2006, lines 194-198, emphasis added.

Q. HOW IS MR. FEINGOLD'S REBUTTAL INCONSISTENT WITH SOME OF HIS PUBLIC PRESENTATIONS ON REVENUE DECOUPLING?

A. Mr. Feingold has given a number of presentations over the past few years related to natural gas prices, energy efficiency, and revenue trackers. Of the presentations that I have been able to review, many indicate an acceptance of the proposition that customers do respond to changes in natural gas prices. Exhibit SR CCS-1.1 provides an example of a slide from one such presentation. The slide highlights a variety of factors (energy markets, regulatory roles and actions, and changes in end user characteristics) contributing to make what Mr. Feingold describes as "the perfect storm" for local distribution companies. The lower part of the slide highlights what Mr. Feingold describes as factors changing customer usage patterns, and one of those factors (highlighted in yellow) includes "response to high prices." In addition to these past presentations, Mr. Feingold's testimony tends to repeatedly take inconsistent positions on customer responses to prices. On the one hand, customers are indicated to respond to prices as they always have; yet on the other hand, Mr. Feingold supports and is equally enthusiastic about Dr. Hansen's analysis alleging that there is no empirical support for any customer reaction to price.

Q. MR. FEINGOLD STATES THAT REVENUE DECOUPLING CANNOT RESULT IN A SHIFT IN COMMODITY PRICE RISK BECAUSE CUSTOMERS WILL CONTINUE TO RESPOND TO PRICES IN THE SAME MANNER. DO YOU BELIEVE THAT IS A SOUND RATIONALE SUPPORTING DECOUPLING?

A. No. Mr. Feingold ignores the fact that while customers may very well continue to respond to natural gas price movements under decoupling, utilities will not. His conclusions also fail to address the underlying problem with natural gas price risk: these commodity prices have been increasing and showing greater volatility over time. Increasing prices and greater volatility indicates a bias in one direction, upwards and against ratepayers. If the movement of prices were symmetrical, with an equal probability of decreasing or increasing, then there may be some limited merit to Mr. Feingold's conclusion. While we all would hope to see some near-term relief from high and volatile natural gas prices, no information has been provided in the record of this docket supporting such a trend or conclusion.

Q. MR. FEINGOLD ALSO STATES THAT ECONOMIC RISK IS NOT SHIFTED TO CUSTOMERS EITHER. DO YOU AGREE?

A. No. Mr. Feingold suggests that somehow traditional regulation allows utilities to recover revenue losses associated with economic downturns. I don't believe this is typically the case, and while utilities may come in for a rate case during the course of such a downturn as Mr. Feingold suggests, it is rarely the case that a utility's test year revenues are based upon the time period of the economic downturn. Commissions try to avoid setting base rates on such extreme events since to do so would be contradictory to most regulatory precedents and definitions utilizing "normal test years" for ratemaking purposes. The CET deviates from this normal test year concept since rates are adjusted every six months. If recessionary conditions prevail during a particular year, then rates will be set according to those circumstances.

Q. ARE THERE ANY OTHER RISKS THAT ARE SHIFTED AWAY FROM THE COMPANY AND TOWARDS RATEPAYERS?

A. Yes. The risk of all non-utility-sponsored efficiency will be shifted away from the utility to ratepayers since ratepayers will be required to make Questar whole for any DNG-revenue impacts of efficiency measures they may take on their own outside of any Company-sponsored DSM program. The Company has noted repeatedly throughout its testimony that these changes in use per customer have important financial implications and create risks in its ability to recover its fixed costs and its ability to earn its allowed rate of return. If this is true, then the risk associated with achieving the allowed rate of return has now been shifted away from the Company and its shareholders and to ratepayers, at virtually no cost. In other words, the revenue risk associated with regulatory lag has been completely moved to ratepayers without any corresponding benefit or compensation. This revenue risk is biased in one direction against ratepayers since the overall trend in use per customer has been decreasing per Mr. McKay's analysis (Exhibit QGC 1.6 in the earlier phase of this proceeding). Even Dr. Hansen's flawed empirical analysis supports this conclusion since he finds various statistically significant decreasing trend impacts on use per customer over the time period he examined.

Q. ARE THE REBUTTAL WITNESSES' POSITIONS INCONSISTENT WITH THE RECENT STUDY BY THE AMERICAN GAS ASSOCIATION?

A. Yes. The AGA recently released a study that examines residential customer reactions to natural gas prices across the U.S. and in different census regions. The study conclusions are in direct opposition to the rebuttal testimony filed by each Division and Company witness. The AGA price elasticity study used LDC-specific monthly data from 46 different companies across the U.S. There were three reported purposes for conducting this study that included:

- Examining whether or not the trend in declining use per customer (residential) has changed in this higher-priced natural gas environment;
- Develop updated residential price elasticity estimates for the U.S. and each of its nine respective census regions;
- Obtain an estimate of changes in residential use per customer attributable to technology-induced gains in appliance and shell efficiency.

Q. WHAT CONCLUSIONS WERE REACHED IN THE AGA STUDY?

A. The AGA study found statistically significant price elasticities nationally and in every region examined. The long run price elasticity of demand on a use per customer basis was estimated to be -0.18 nationally. The study noted that the residential price elasticity of demand (on use per customer basis) has remained relatively constant between the periods in which natural gas prices were relatively low (pre-2000) and when they were relatively high (post-2000). The most important conclusion of the study was that 57 percent of the post-2000 decreases in natural gas residential use per customer were attributable to price. The remaining 43 percent of the decrease in residential use per customer was attributable to longer-term changes in efficiency and turn-over in appliance stock.

Q. WHAT IMPLICATION DOES THIS HAVE FOR THE REBUTTAL WITNESSES' CONCLUSIONS ON THE NATURE OF NATURAL GAS PRICE RISK SHIFTING?

A. The results of the recent AGA study clearly demonstrate that changes in natural gas prices significantly impact U.S. customers' gas usage and that over half of the reduced residential use per customer is explained by responses to price. Maintaining a revenue decoupling mechanism like the CET, without any corresponding adjustment for this shift in risk, results in rates that are inconsistent with the fair, just, and reasonable standards of traditional utility regulation.

Q. WHAT WERE THE RESULTS FOR THE MOUNTAIN CENSUS REGION?

A. The results found statistically significant results for the price elasticity of demand for the Mountain Census Region in which Utah is located. The estimated short run elasticity of demand was -0.07 and the long run was -0.10. Thus, Dr. Hansen's empirical results, and their associated conclusions about risk, are in direct conflict with a study funded, published, and marketed by the leading natural gas LDC trade association in the U.S. The rebuttal testimony of Dr. Hansen, Dr. Powell, Mr. McKay and Mr. Feingold are also equally at odds with these study results.

Q. WHY DO YOU ARGUE THAT EACH OF THE REBUTTAL WITNESSES'

SUPPORT FOR, AND CONFIDENCE IN, DR. HANSEN'S DEMAND MODEL IS MISPLACED?

A. Dr. Hansen's demand analysis has two significant problems that result in highly biased and unreliable results. The first problem is that Dr. Hansen's model specification includes different income variables which can result in some significant biases in the resulting parameter estimates (i.e., the price elasticity of demand). The second problem is that Dr. Hansen uses data that mismatches different classes of prices and usage. A few simple adjustments, and the use of more consistent data, reveal that Questar customers do in fact have a significant and important usage response to natural gas prices, and as a result, do incur risks associated with changes in natural gas prices as suggested in the recent AGA price elasticity study.

Q. HOW DOES THE USE OF INCOME CREATE PROBLEMS IN NATURAL GAS DEMAND MODELING?

A. Income variables, as they are commonly calculated and measured, tend to get "confounded" with energy usage in ways that can result in very strange, unexpected, and sometimes counterintuitive results. While income is very important in theory, variables used to measure its trends can tend to be highly correlated with customer growth, housing appliance stock, and square footage. Wealthier and fast growing areas tend to attract more people, who in turn purchase and construct larger homes with newer and more expensive appliances. Add to this the fact that newer homes tend to be more efficient in both their envelope and appliance mix, and it is easy to see how certain paradoxes can arise in any statistical model (i.e., growing economies use more energy, but tend to be more efficient as the economy expands). The key is either to develop or utilize a measure of income that corrects for these potential factors, utilizes some other empirical technique to correct for these factors, or simply leaves income measures out of the equation. Dr. Hansen's analysis does a poor job at making these corrections, and as a result, his estimates are biased and incorrect.

Q. HOW DOES DR. HANSEN'S ANALYSIS MISMATCH DATA?

A. Dr. Hansen uses GS-1 use per customer, which is a mix of residential and commercial customers, with strictly residential natural gas average prices that are reported by the U.S. Department of Energy. Thus, total GS-1 usage (residential and commercial) is being measured against a residential price alone. The fact that this mismatching of data leads to questionable results is not surprising. Correcting for this mismatch can lead to more accurate results as well as results that are more consistent with common sense, historical academic and industry estimates, and the more recent estimate provided by the AGA price elasticity study.

Q. HAVE YOU PREPARED AN ANALYSIS THAT CORRECTS THE SHORTCOMINGS IN DR. HANSEN'S ANALYSIS?

A. Yes. I have conducted two different analyses that include certain specification and data corrections; these two analyses clearly show Dr. Hansen's risk-shifting analysis is in error. The first analysis uses U.S. Department of Energy, Energy Information Administration ("EIA") data from what is referred to as the EIA-Form 176. The second analysis is based upon Questar-specific data. This provides the Commission with two specific sources of information in reaching its conclusions regarding the risk-shifting nature of revenue decoupling resulting from the CET. I think an objective comparison of these results, coupled with the results from the recent AGA price elasticity study, and the literature review that I provided in my rebuttal testimony leads to a clear conclusion that Dr. Hansen's risk shifting analysis is unreliable. Accordingly, all of the policy conclusions reached by the rebuttal witnesses based on Dr. Hansen's analysis should be discarded.

Q. PLEASE DISCUSS THE NATURE OF THE DATA USED IN YOUR FIRST ANALYSIS?

A. Yes. As noted earlier, I used the data commonly referred to as the EIA-Form 176 database. It is referred to in this manner since its underlying data is developed from the Form 176 survey that all natural gas companies (interstate transportation, intrastate transportation, gathering systems, storage providers, LDCs) are required to provide to the EIA. According to the Form 176, companies failing to provide accurate data to the EIA may be subject to potential civil penalties and fines. This should provide the Commission with some confidence that the data has a good degree of reliability. This data is collected at the company level, on a per state and customer class-specific basis, for a time period extending back to 1997. I pulled the Questar Utah residential data for my first analysis. The purpose in using this data is to ensure that my statistical model was based upon consistent residential usage and price data.

Q. WHAT MODEL SPECIFICATION DID YOU USE?

A. I used a model specification that was similar in nature to that used in the recent AGA price elasticity model. In that model, the authors utilized an equation that consisted of real prices, lagged real prices, and a time trend. The one difference between my model and theirs rests with the lag specifications. Their model utilizes monthly data and therefore incorporates a current period price and 12- month lagged price. The EIA-176 data is annual, and I utilized a current period price and a one year lag structure.

Q. WHAT WERE YOUR RESULTS USING THE EIA-176 DATA?

A. The results are provided in Exhibit SR CCS-1.2. The residential use per customer model yielded a short run price elasticity of demand of -0.2175, a second year elasticity of -0.1584, yielding a long-run price elasticity of demand of -0.3759. The long run price elasticity is simply the sum of the short run estimates. The lagged price reaction (-0.1584), however, is not strongly significant, and could be disregarded in making the longer run calculation. The model estimates a long run trend decrease in use per customer of about 1.4 percent per year. This figure is somewhat higher than the AGA estimate, but is still consistent with the overall results showing there has been some time-dependent decreases in use per customer that are not easily explained by price or any other variable alone.

Q. PLEASE DISCUSS THE DATA YOU UTILIZED IN YOUR SECOND NATURAL GAS DEMAND ANALYSIS?

A. I utilized data that was provided by the Company in Response to CCS DR

4.05. This information has been represented as the underlying data supporting the statistical load forecast included in the Company's 2007 Integrated Resource Plan ("IRP"). The data is monthly and includes usage per customer, price, and weather information. This information appears to be the best source of information in the record which attempts to match total GS-1 use per customer with total GS-1 price. Again, the purpose of this approach was to develop an alternative model using consistent information at the rate class (GS-1) level rather than the customer class (residential, commercial) level.

Q. WHAT SPECIFICATION DID YOU UTILIZE?

A. Again, I utilized a specification comparable to that used in the AGA statistical analysis. The lag structures were modified to only include what would be considered a current period impact only. A longer lag structure was not included since the price variable that was provided by the Company, while not clearly defined, appears to be based upon a moving average process. An error correction for the moving average process has also been included in the model.

Q. WHAT WERE YOUR EMPIRICAL RESULTS?

A. The GS-1 use per customer model estimates a -0.3696 price elasticity of demand. The model estimates a 0.22 percent annual long run trend decrease in use per customer.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE RISK SHIFTING NATURE OF THE CET BASED ON YOUR TWO NATURAL GAS DEMAND ANALYSES?

A. Like the recently released AGA study, I conclude that customers do respond to changes in natural gas prices. Revenue decoupling mechanisms like the CET shift the risk of natural gas price changes away from the utility and its shareholders and onto customers. There are several places in the record of this proceeding where the Company and various energy efficiency advocates have argued that one of the primary purposes of promoting natural gas DSM is to address the ongoing adverse trends in natural gas markets. If this is the case, then the shifting of risk from the Company to its customers is clearly asymmetrical against ratepayers. A reasonable analysis of natural gas demand, based upon consistent data and commonly accepted principles and methods that have been developed over the past 30 years supports this conclusion. The rebuttal witnesses' reliance on Dr. Hansen's empirical results showing otherwise are simply misplaced and should be disregarded by the Commission.

IV. <u>CHARACTERIZATION OF U.S. DECOUPLING PROGRESS</u>

Q. PLEASE DISCUSS THE COMPANY'S REBUTTAL OF YOUR ANALYSIS OF REVENUE DECOUPLING ACROSS THE U.S.?

A. The Company's rebuttal testimony suggests that my analysis understates the progress of revenue decoupling across the U.S. Mr. Feingold presents an updated analysis in an attempt to show that revenue decoupling is a much more popular policy regime than my analysis would suggest. However, there are a number of reasons that easily explain the differences between the two approaches and the primary conclusion based on my earlier analysis remains unchanged: while revenue decoupling has become increasingly popular in the natural gas industry over the past six months, it is clearly the case that decoupling mechanisms are still relatively new and untested.

Q. HOW DOES YOUR ANALYSIS DIFFER FROM MR. FEINGOLD'S?

A. Generally, there are four fundamental differences. First, there are two states (Illinois and New Hampshire) that I overlooked in my analysis. Second, there are a large number of states in which a decision was issued after my direct testimony was filed. Third, Mr. Feingold includes legislative initiatives as representing progress toward decoupling, which I did not include since I limited my analysis to decoupling activity that was occurring at the state commission level. Fourth, there are differences in interpretation between what I see as decoupling progress in certain states and what Mr. Feingold observes. Exhibit SR CCS-1.4 provides a table that identifies the states in which Mr. Feingold and I have differences and my explanation of those differences.

Q. WHAT STATES WERE IDENTIFIED BY MR. FEINGOLD AFTER YOU FILED YOUR DIRECT TESTIMONY?

A. Commission decisions in Delaware, Connecticut, Nevada, Colorado, Massachusetts, and Arkansas were issued after I prepared and filed my direct testimony. I would note, however, that Mr. Feingold's representation about Michigan is incorrect since the Commission has approved settlements for both SEMCO Energy and CMS Energy which excluded revenue decoupling or any straight-fixed variable ("SFV") rate design. I noted the SEMCO case in a footnote to Exhibit CCS 1.2. Mr. Feingold also fails to characterize the current status in New Mexico, where the Public Regulation Commission in its recent Final Order was quiet clear in rejecting revenue decoupling by noting:

> Addressing the issue of rejection with prejudice, the Commission finds that rejection with prejudice is appropriate in this case. The proposal put forth by PNM and supported by NRDC/SWEEP and Staff is overly broad and overreaching. If implemented, it would, in effect, make PNM whole for past conservation efforts of consumers that have absolutely nothing to do with the enactment of the Efficient Use of Energy Act on which PNM relies for recovery of lost volumes. Moreover, PNM's proposal fails to take any account of customer growth that has occurred during the time that consumption per customer may have declined. Therefore, the Commission finds that the decoupling proposal advanced by PNM in this case is fatally flawed, and that the Commission will not consider it again in any case.[3]

Q. WHY DID YOU EXCLUDE LEGISLATIVE INITIATIVES FROM YOUR ANALYSIS?

A. I excluded legislative initiatives because in many instances policies that are initiated at the legislative level tend to be very broad and non-specific in nature. While it is not always the case, legislative policies usually set a general policy direction, like the promotion of DSM, but leave specific implementation options open for the subject-matter policy experts, which are typically state utility

[3] New Mexico Public Regulation Commission. Final Order, Case No. 06-00219-UT, at paragraph 119.

regulators. A number of Mr. Feingold's examples fall into this category: the legislation offers broad guidance, which in some instances includes revenue decoupling, but is not specifically limited to this policy mechanism alone. For instance, legislation was recently passed in Connecticut leaving certain details open for Commission determination. One detail which Mr. Feingold has conveniently omitted in his analysis is the legislation's explicit reference to the use of a return on equity ("ROE") adjustment.

Q. WHAT ABOUT THE INTERPRETATION DIFFERENCES YOU HAVE WITH MR. FEINGOLD?

A. There are a few states in which Mr. Feingold and I simply have differences of opinion. In Nevada, legislation was passed very recently, but the Commission rejected decoupling in earlier proceedings. In Washington, the Commission approved decoupling for Avista and Cascade, but rejected a decoupling proposal for Pacificorp. This fact was included in a footnote to CCS Exhibit 1.2 (the original decoupling status map that was part of my direct testimony).

Q. ARE YOUR OVERALL CONCLUSIONS ON THE STATUS OF REVENUE DECOUPLING COMPARABLE TO OTHER POLICY ANALYSES?

A. Yes. The American Council for an Energy Efficient Economy ("AEEE"), a group commonly recognized as being both researchers of, and advocates for, energy efficiency, noted in their review of revenue decoupling:

> We found that despite the surging interest in regulatory decoupling, there are thus far relatively few cases where such an approach has

been enacted and effectively implemented for sufficient period of time to being to assess results.[4]

Even if all the states that Mr. Feingold identified had adopted revenue decoupling unequivocally and immediately, it would still be the case that little information is currently available to assess decoupling results.

V. RESPONSE TO REBUTTAL REGARDING UTILITY COST INCENTIVES

Q. MOST OF THE REBUTTAL WITNESSES HAVE QUESTIONED THE REASONABLENESS OF YOUR ASSERTION THAT DECOUPLING ELIMINATES COST EFFICIENCY INCENTIVES. HOW DO YOU RESPOND?

A. First, let me make it clear that in my direct testimony, I did not state that decoupling completely eliminates all cost efficiency incentives. My direct testimony said that decoupling can "dampen" these incentives. I would agree, in part, that revenue decoupling will preserve some degree of cost efficiency incentives, but this level is certainly not one that would maximize such potential opportunities. There will come a point in which the efficiency is just good enough to preserve the status quo and no more since revenues are known and certain enough to preserve earnings.

Q. ARE YOU AWARE OF ANY EXAMPLES THAT SUPPORT YOUR POINT?

A. Yes, in commenting on 2006 earnings and performance, George A.

[4]Kushler, Martin, et.al. (2006). *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives.* American Council for an Energy Efficient Economy, iii.

Schreiber, Jr., SEMCO Company President and Chief Executive Officer, told investors:

> I am very pleased with the Company's results for 2006. We achieved these results, despite warmer-than-normal temperatures and continued customer conservation, which, when combined, adversely impacted 2006 earnings by an estimated $3.5 million…**One way we overcame the impact of the weather and customer conservation was to keep spending under control***.*[5]

Thus, SEMCO Energy was able to compensate for its efficiency and weather-created revenue losses through cost efficiency. In situations like the one discussed above, the elimination of weather and conservation risk could dampen the longer run importance of making cost efficiency improvements.

VI. RESPONSE TO REBUTTAL ON LOST REVENUES FROM DSM AND CUSTOMER GROWTH

Q. MR. MCKAY TAKES ISSUE WITH YOUR ANALYSIS OF THE REVENUE IMPACT ASSOCIATED WITH CHANGES IN USE PER CUSTOMER, LOST REVENUES FROM DSM, AND CUSTOMER GROWTH. DO YOU AGREE WITH HIS CONCLUSIONS?

A. Not entirely. Mr. McKay has two criticisms of this analysis, which was provided in my direct testimony (CCS Exhibit 1.9). The first criticism is that the analysis uses an incorrect average revenue number as well as different numbers

[5] SEMCO Energy Press Release, PRNewswire-First Call, May 4, 2006, emphasis added.

for existing customers versus new customers. The second criticism is that the analysis is fundamentally flawed since it considers changes in revenues, but does not consider changes in costs.

Q. DO YOU AGREE WITH MR. MCKAY'S FIRST CRITICISM?

A. Only in part. Mr. McKay is correct in stating that the average revenue used in calculating the revenue growth associated with new customers is not accurate since it is based on total DNG revenues and not GS-1 revenues only. However, the impact of making this correction is small (14 cents per Dth) since GS-1 revenue comprises the overwhelming share of all jurisdictional DNG revenues. Thus, the correction does not materially change the conclusions I reached based on my analysis.

The use of different average revenue numbers for existing customers and new customers, on the other hand, is appropriate. Lost revenues associated with existing customers will include only those incremental revenues from lost sales. Since these customers are still connected to the Company's distribution system, there is no need to make an adjustment in revenues from the existing customer charge (because these will not be lost). This will not be the case with new customers since both new customer charge revenues and usage-based revenues will accrue to the Company as new customers are added to the system. A corrected version of what was originally provided as CCS Exhibit 1.9 has been provided in Exhibit SR CCS-1.5.

Q. WHAT ABOUT MR. MCKAY'S ASSERTION THAT THE ANALYSIS IS FLAWED BECAUSE IT HOLDS COSTS CONSTANT?

A. Mr. McKay is missing the point and his criticism actually supports one of the primary points I made in my prior testimony in this proceeding. The purpose of the analysis was to look at the relative changes in revenues and how they impact earnings. The Company's argument all along has been that DSM significantly reduces sales and revenues so the purpose of this analysis was to say, "ok, let's go look at what factors are impacting revenues and their relative order of magnitude."

Q. WHY DID YOU HOLD COSTS CONSTANT IN EXAMINING THIS ISSUE?

A. The origins of Exhibit SR CCS-1.5 go back to the 2006 phase of this proceeding and was offered in my supplemental rebuttal testimony to respond to the common examples offered by energy efficiency advocates, like the Company's witness, Mr. Ralph Cavanaugh, who prepared an exaggerated example of the potential financial harm associated with the implementation of DSM. Both his and my examples included no changes in costs and were simply meant to examine changes in revenues and the impact they would have on earnings. In fact, Mr. Cavanaugh notes, in very bold letters in his testimony, "…the 5 year loss to shareholders from this **steady state utility investment program** would exceed $23 million."[6] Here, "steady state utility investment" means constant costs. In addition, the financial information used by Mr. Cavanaugh to support this overstated claim was provided by Mr. McKay himself in Questar Exhibit SR1.8 which also excludes costs. The purpose of my

[6]Rebuttal Testimony of Ralph Cavanaugh, August 14, 2007: lines 220-221, emphasis added.

testimony (on lines 377-445) and the supporting exhibit was to show that in the grand scheme of things, the typical energy efficiency advocate example is exaggerated since DSM revenue losses are not large relative to other concurrent revenue changes. It is interesting how Mr. McKay finds it entirely reasonable for him and Mr. Cavanaugh to be able to team up and provide a "steady-state utility investment" (i.e., constant cost) example in their testimony, but my attempt to put this example into greater perspective using the same assumptions results in such admonishment.

Q. IS THE COMPANY ATTEMPTING TO SHIFT THE DEBATE ON THIS ISSUE?

A. Yes. It appears that Mr. McKay would now like to shift the debate from one associated with the **revenue** impact of DSM to one associated with **costs**. If this is the case, I believe that cost recovery issues and differences in rate design principles are best handled in rate cases rather than using decoupling as a back-door attrition adjustment/insurance policy. Using costs as the rationale to support revenue decoupling moves the debate away from incentives and energy efficiency and towards some alternative form of regulation that is one-sided in the Company's favor.

Q. IS MR. MCKAY'S DIFFERENCES OF OPINION REGARDING YOUR LOST REVENUE ANALYSIS SIMILAR TO HIS ARGUMENTS REGARDING WHAT HE CLAIMS IS THE "CONFISCATORY" NATURE OF YOUR PROPOSAL TO LIMIT CET RECOVERY TO TEST YEAR CUSTOMERS AND REVENUES?

A. Yes it is a similar argument. It is hard to understand how matching 2005 base (test) revenues to actual revenues is confiscatory in nature. One of the stated goals of the CET is to ensure that there is symmetrical relationship between Questar and ratepayers. If actual revenues deviate from the 2005 base revenue level, then Questar recovers (returns) any revenue shortfall (excess) from (to) customers. However, the fact that the current formula gives Questar the benefit of customer growth, in addition to truing-up revenues based on actual usage, is confiscatory to ratepayers.

VII. <u>POSITIONS RELATIVE TO THE DIVISION'S RECOMMENDATIONS</u>

Q. WHAT IS YOUR OPINION REGARDING DIVISION WITNESS BARROW'S RECOMMENDATION TO CAP CET BALANCES AT 2.5 PERCENT OF DNG REVENUES?

A. I would agree with the recommendation, but note that the Commission needs to ask itself a fundamental question about this recommendation: if there is no risk shifting as the Division and the Company suggest, then why do you need set a cap on CET balances? The presence of a cap is simply an admission that there is risk, and there needs to be some bounds on that risk included in the CET. I agree with Mr. Barrow that risk does exist, and that it is real and meaningful. What is difficult to reconcile is that Division witnesses Dr. Hansen and Dr. Powell testify quite adamantly that there is no risk shifting resulting from the CET, while Division witness Mr. Barrow expresses some caution on this issue by recommending a cap on the CET balance amounts and the duration that the CET can remain in place without a rate case. These positions are entirely inconsistent.

Q. DR. POWELL INDICATED THAT THE DIVISION WILL CONSIDER AN ROE ADJUSTMENT IN THE FUTURE AS WELL. DOES THIS STRIKE YOU AS ALSO BEING SOMEWHAT CONTRADICTORY?

A. Yes, it is difficult to reconcile this suggestion with Dr. Powell's general conclusion that there are no empirically proven risks associated with the CET. If the Division's position is that there is no risk shifting associated with the CET, then why expend the effort in examining an ROE adjustment to account for risk in a future rate case? As I noted in my direct testimony, even some regulated utilities have recognized that there are risks associated with revenue neutrality programs and offered ROE adjustments to reflect at least some portion of that risk shifting. It seems difficult to understand how the Division will defend any recommendation in a future rate case regarding a risk-related ROE adjustment when it has gone to exceptional lengths to prove otherwise throughout the course of this CET proceeding.

Q. DO YOU AGREE WITH THE DIVISION'S PROPOSALS?

A. If the Commission decides to maintain the CET, then I would agree with Mr. Barrow's recommendation to cap the CET balances in the fashion he suggests. I also believe that if the Commission decides to maintain the CET, it should make an explicit finding that the CET does result in a shifting of risk away from the Company and towards customers and the risk shifting nature of the CET needs to be taken into consideration in the Company's allowed rate of return. The quantification of that risk adjustment should be conducted in the Company's next rate case.

Q. CAN YOU EXPLAIN THE DIVISION'S BASIS FOR RECOMMENDING THAT THE COMMISSION REJECT YOUR LOST REVENUES ADJUSTMENT MECHANISM?

A. One cannot help but view the Division's recommendation on the lost revenue adjustment ('LRA") mechanism with a little irony. In a nutshell, the Division effectively notes that (1) the Committee has not offered any specifics on how such an approach would work and (2) even if it had, estimating lost revenues is just too difficult. The irony is in the later justification where Dr. Powell spends close to twenty percent of his written rebuttal testimony discussing the challenges in estimating lost revenues and natural gas demand modeling. This discussion raises all kinds of concerns about model specification, including which variables to examine, whether these variables should be in levels or logarithms (and which associated base), which variables should be included, if the variables should be in monthly, annual, or quarterly terms, and a host of other data and statistical issues. Ironically, these demand modeling approaches that Dr. Powell criticizes are the same as the one used by Dr. Hansen in his risk-shifting analysis. This raises the interesting question that if all of these empirical questions make an LRA unreasonable, what makes them more reasonable to use in a risk evaluation analysis like Dr. Hansen's? If this is genuinely a bad approach, then it should be equally bad in examining risk shifting issues associated with prices, income, and other factors influencing residential natural gas demand.

Q. WHAT ABOUT THE MORE RELEVANT CRITICISM ABOUT THE COMMITTEE NOT OFFERING A FORMAL APPROACH FOR AN LRA?

A. That can be handled quite simply. Since the order of magnitude of the DNG lost revenues associated with the Company's DSM efforts is relatively small, the Committee recommends that the Company be allowed to recover the estimated lost DNG revenues associated with any cost-effective DSM program that has been approved by the Commission. Specifically, these lost revenues would be based on the estimated DSM program savings included in the Company's DSM filing that was approved by the Commission. Future DSM programs would be given the same treatment if approved by the Commission. Allowing the Company to recover these lost revenues in such a fashion would result in a straightforward, easy, and quick recovery process and tied directly to DSM implementation.

Q. WHAT IF THE COMPANY EXCEEDS ITS PROJECTED SAVINGS?

A. The Commission would have plenty of time to develop a "true-up" process/mechanism that would tie DSM-created lost revenues to achieved savings through the DSM stakeholder process. The Company would not be left short on revenues in the interim since the Committee's recommendation would allow the originally-anticipated lost revenues to be recovered immediately. The Committee has also repeatedly supported a strong monitoring and verification ("M&V") process that places considerable emphasis on impact evaluation throughout the course of the Company's three-year DSM pilot. I believe that the M&V process and an effective LRA can be tied to one another in a fashion that should provide all parties with considerable confidence about the lost revenues being recovered from ratepayers. In fact, developing a method for tying lost revenues and actual savings could be a task set forth in the Request for Proposal (“RFP”) that is issued to consulting firms interested in serving as the third-party administrator in the M&V process that has been proposed by the Division. This third-party administrator can develop a formulaic approach to true up savings from projections, and these can be filed for recovery during the DSM cost recovery process.

Q. WHAT ABOUT SALES LOSSES ASSOCIATED WITH THE PROMOTION OF MARKET TRANSFORMATION PROGRAMS?

A. There is nothing within the context of any of my recommendations that would deny Questar the ability to recover any sales losses associated with market transformation programs. But as a practical matter, the Commission needs to recognize that these programs are not going to yield results immediately, and thereby cause financial harm for the Company. Education is a long-term proposition and the results of these market transformation programs will likely be embedded (and difficult to separate) from the trend in usage per customer. A forecasted test year can easily accommodate any lost revenues associated with these longer run trends.

Q. HOW DO YOU RESPOND TO REBUTTAL WITNESSES’ ARGUMENTS THAT LOST REVENUES SIMPLY WON’T PROVIDE THE APPROPRIATE SIGNALS FOR UTILITIES TO ENGAGE IN MARKET TRANSFORMATION?

A. I would disagree, and remind many of them that Questar, like any other regulated utility in this country, has an obligation to serve its customers in a safe, reliable, and economic fashion. Part of that charge should be informing and educating customers about the appropriate use of utility services that rely heavily upon local, regional, and national natural resources. Failure to responsibly inform customers about any actions that may jeopardize these resources would be, or at least should be, imprudent.

Q. WHAT ABOUT THE COMMON CLAIM MADE BY SEVERAL REBUTTAL WITNESSES THAT UTILITIES HAVE STRONG INCENTIVES TO PROMOTE SALES?

A. Contrary to the implication of many utilities and energy efficiency advocates, there is nothing in past regulatory precedents that says "utilities, please feel free to provide safe, reliable, and economic service up to a point that you think it is profitable for you and your shareholders." We regulate utilities because they are said to be "imbued with the public interest." Utilities are allowed to maintain their monopoly status, and the financial rewards of this status, provided they meet these high degrees of responsibility. This standard does not operate in the inverse: that if utilities are given their appropriate incentives and rewards, they will act in the public interest.

Q. WHAT DOES, OR SHOULD, THE PUBLIC INTEREST STANDARD IMPLY ABOUT SALES PROMOTION AND THE PROVISION OF UTILITY SERVICE?

A. Utilities operate in the public interest because they (1) provide basic and necessary customer services and (2) extract and utilize valuable natural resources in the provision of these services (energy, air, water, land) to the public. Public utilities are expected to act and perform in a fashion that is consistent with this invaluable responsibility. Intentionally wasting these natural resources, through the promotion of inefficient sales to reward shareholders, or the failure to educate and inform customers about the consequences of inefficient consumption habits, is simply inconsistent with the underlying principles of close to 100 years of utility regulation. To act in such a fashion would intentionally jeopardize natural resources, unnecessarily increase costs for ratepayers, and prejudice the public interest. If utilities intentionally engage in such inefficient actions, then regulatory commissions ought to consider very stringent penalties, as opposed to incentives, to bring utility actions in line with the public interest.

Q. DO YOU HAVE ANY EXAMPLES OF UTILITIES THAT RECOGNIZE THIS PUBLIC INTEREST REQUIREMENT RELATIVE TO SALES GROWTH AND DECOUPLING?

A. Yes. Last year, Georgia Power Company, which is part of one of the largest electric utilities in the United States, noted in its comments on the Georgia State Energy Strategy:

> Decoupling is typically proposed as a solution to a perceived problem that does not exist … The report assumes that under the current scheme of cost-based regulation…there is an ongoing and significant incentive for electric utilities…to grow its sales and a

corresponding negative incentive to implement energy efficiency because of lost revenues.

[Our] focus is and has always been on reliable, competitively priced electricity and great service for its customers. [Our company] only implements energy sales initiatives where those initiatives can be shown to help reduce the price of electricity to [our] customers.

[We are] also subject to frequent rate proceedings that ensure that there are not long-term incentives to simply increase sales to drive increased profitability… This has ensured that there is not a long-term benefit to [our] earnings from simply increasing electricity sales, as those additional sales are included when revenues and prices are re-set during the rate proceeding.[7]

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY FILED ON AUGUST 31, 2007?

A. Yes it does.

[7] Comments of Georgia Power Company on the State Energy Strategy for Georgia. Comment period June 6, 2006 to July 5, 2006.