- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Joint Application of Questar Gas Company, the | Docket No. 05-057-T01
Division of Public Utilities, and Utah Clean Energy, | Utah Division of Public Utilities
Approval of the Conservation Enabling Tariff | Exhibit No. DPU 2.0
Adjustment Option and Accounting Orders |

Prefiled Direct Testimony of

George R. Compton, Ph.D.

For the Division of Public Utilities

Department of Commerce

State of Utah

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I. INTRODUCTION

Q. What is your name, and by whom are you employed?

A. George R. Compton. I am a Technical Consultant for the Division of Public Utilities (UDPU, DPU, or Division) of the Utah Department of Commerce.

Q. What is your education and work experience?

A.. I hold a Bachelor's Degree from Brigham Young University, with majors in Mathematics and Psychology, and a minor in Philosophy. A portion of my undergraduate experience also took place at Stanford. Subsequent to earning a Master's Degree at BYU in Statistics, with minors in Psychology and Philosophy, I worked for McDonnell Douglas Astronautics in Southern California, principally as a probabilist.

Apart from some part-time teaching at BYU, my entire career since earning a Ph.D. in economics from UCLA in 1976 has been spent in utility regulation. For all but two of those years I have been employed by the Division, on whose behalf I have testified countless times before this Commission in cases involving electric, gas, and telephone utilities. In the two odd years, I was an independent consultant. My clients included UAMPS, UP&L, and U S WEST. The main area of my professional interest has been the application of economics principles to utility pricing and costing. For a number of years I was also the Division's primary cost-of-capital witness. In recent years I have been the primary witness within the Energy Group in the areas of rate design and cost of service.

Q. What is your role in this case?

A. I will be discussing pros and cons regarding both the "conservation enabling tariff" (or CET), per se, and the principal alternatives to it that have been proposed for dealing with the motivating problem that underlies this case.

Q. What do you believe is "the motivating problem that underlies this case"?

A. For a number of years, Questar has complained – with just cause – that earning its authorized return has been very difficult due to the combination of declining average consumption over time, the use of a historical test year in general rate cases, and the fact that most of its fixed/non-fuel costs are recovered through a volumetric charge. The upshot has been revenues that in normal-weather years fell short of their own non-gas costs – because average-customer sales in the rate-effective years fell short of the (historical) test-year figures that were used to set rates.

Q. Did you participate in the "Working Group" that was formed to address the problem you just described?

A. I attended some of the early sessions. Frankly I lost interest in continued participation because a) none of the proposals then on the table were very appealing, (the Committee of Consumer Services had not yet brought attention to the mechanism that is now being proposed in this Joint Application); b) Group progress seemed to be painfully slow; and c) I personally was bringing nothing to the table to help resolve the matter (which meant my efforts were better dedicated elsewhere). I developed a keen interest in this matter upon learning of the conservation enabling tariff and observing how well aspects of it conformed with a position I had advocated on behalf of the Division in recent PacifiCorp venues.

Q. How would the "conservation enabling tariff" (CET) mitigate that problem?

A. The tariff would isolate, or "decouple," Questar's non-gas revenues from year-to-year movements in the per-customer average consumption levels for the GS (general service) classes. The mechanics of the decoupling is to employ a balancing account to recover non-gas related revenues lost/gained when average consumption drops below/rises above the projected average.

Q. Why does the Division believe it is appropriate to attempt to mitigate the problem underlying Questar's historic complaint?

A. Regulation's end of the "regulatory compact" is to grant a monopoly utility the *opportunity* (i.e., not a guarantee) to recover its full costs, including its capital costs. In the past, the only way, given normal weather conditions, that that opportunity could be realized would be for Questar to have per-customer average costs sufficiently below its test-year projections to compensate for per-customer average revenues that would (due to declining usage) also be below projections. To achieve actual costs that were below projections, the utility would either have to get away with inflating its rate case cost projections to a level that exceeded what would be just and reasonable within the test-year context, or subsequently cut costs to a level below what were determined in the rate case to be just and reasonable. The latter course would cause service quality to decline to a level lower than what was implicit in, or associated with, the recognized rate case costs. Regulation is most successful when both sides keep their part of the regulatory compact -- when regulatory incentives do not encourage the utility to over-estimate its costs or compromise its service quality.

The testimony of DPU's policy witness, Dr. Artie Powell, provides our broad rationale for supporting the Joint Application.

Q. Are there mechanisms besides rates "decoupling" for dealing with the problem you have just describe?

A. There are. But the Division recommends decoupling as being generally superior to those other mechanisms.

Q. On what basis do you make that claim?

A. It is made largely on equity grounds. The testimony that follows will elaborate.

II. A CLARIFICATION OF THE MEANING OF "CONSERVATION ENABLING"

Q. The joint application seeks this Commission's endorsement of a "conservation enabling tariff" (or CET). In what sense would it "enable" conservation above and beyond what would happen under the current tariff structure?

A. Superficially, the average ratepayer would not see any difference. The pricing/rates structure would remain the same as is currently the case; and over the long run the rates themselves would be pretty much the same as if there were no CET. Insofar as DSM and other conservation-fostering programs are cost-effective, the fuel cost portion of the tariff will go down due to reduced demand by Questar for expensive market purchases.

What is conspicuously different under the proposal is that the utility, Questar, would no longer be faced with the disincentive that now exists against promoting conservation, through DSM or any other means. Clearly, DSM and other conservation programs will be more successful insofar as there is enthusiastic utility support rather than self-interested foot-dragging. (Unlike the case with PacifiCorp, Questar has no formal DSM program in effect.)

Q. What is the nature of the disincentive that now exists?

A. Since most of the Company's non-gas costs are recovered through the volumetric Distribution Non-Gas Cost (DNG) charge, reduced consumption – due to conservation or whatever – now translates to reduced recovery of those non-gas costs. Conversely (or adversely), Questar now *profits* when people engage in the opposite of conservation, i.e., when gas consumption, and therefore non-gas revenues, exceed test year projections.

I will note at this time, and discuss in greater detail later in this testimony, that more conservation is fostered by leaving fixed-cost recovery via a volumetric charge than through the “obvious” alternative mechanism for literally decoupling revenues from consumption, i.e., through substituting a fixed customer/delivery charge as the mechanism for recovering the fixed, non-gas costs.

III. THE MECHANICS OF THE PROPOSED REVENUE DECOUPLING APPROACH AND ITS IMPLICATIONS FOR THE OPERATIONAL EFFICIENCY OF QUESTAR

Q. Would you please explain in layman’s terms just how the CET revenue decoupling mechanism works. In particular, how does it insulate Questar’s revenues from the effects of declining consumption?

A. On a month-by-month basis Questar will measure the difference between the actual DNG revenues for the GS class that are observed for that month and what are “allowed.” That difference will go into a CET balancing account which in turn is amortized over future “Distribution Non-Gas Cost” rates in a manner identical to the way the 191 Account balances affects the “Commodity Cost” rates. The monthly revenue differences are produced by consumption levels that depart from the consumption levels that, in conjunction with the annual revenue requirement, went into constructing the proposed DNG charge or tariff amounts. The essence of decoupling by this approach is the recapturing of revenues otherwise lost when average consumption falls below levels that were used in producing the instant DNG rates.

The monthly “allowed” revenues and DNG Balancing Account accruals are determined (in somewhat “supra-layman’s terms”) per the steps listed below. The indicated spreadsheet cell and column notations refer to Exhibit 2.1, which explains the mathematical operations in somewhat greater detail.

1) The annual DNG revenues established as being required, or “allowed,” from the average customer are obtained by dividing the developed DNG revenue requirement (C28) by the adjusted test period average customer count (D28). That allowed revenue (E28) is $254.23 per customer per year. Both the proposed annual revenue requirement and the average number of customers reflect annualizations of end-of-year elements. The DNG revenue requirement has incorporated the Company’s proffered $10.2 million reduction, which is approximately 4.5% of the DNG tariff component.

2) The per-customer annual allowed revenue of $254.23 (E28, I23, and L23) is spread across the months (Column I) in proportion to each corresponding month’s share of the adjusted actual per-customer average DNG revenues for 2005 (Column F). These figures are the per-average-customer monthly allowed DNG revenues (Columns I and L). The adjustment (in Column C, Rows 11-20) reflects an annualization of the DNG rate reduction that went into effect on November 1 of 2005. Multiplying the monthly per-customer allowed revenues (Column I) by the test-period-augmented customer quantities (Column J) and adding the products

(Column K) across the twelve months of the year yields the proposed test period DNG annual requirement (C28). The test-period-augmented customer quantities (Column J) were obtained by scaling up the 2005 observed quantities (Column D) by a uniform percentage so that the annual average of the augmented figures would equal the year-end/December 2005 actual (D22).

3) The monthly allowed revenues for the year(s) following the test year (Column N) is calculated as the product of the per-average-customer monthly allowed DNG revenues (Column L) and the actual number of customers observed in that month (Column M).

4) The monthly DNG Balancing Account accrual (Column P) is found by subtracting the observed DNG revenues for the month (Column O) from that month's allowed figure (Column N).

Q. I noticed that in your exhibit's numerical example you assumed a 1% drop in average consumption to illustrate the balancing account consequences of reduced consumption. Was that number simply plucked out of the air or does it have significance in its own right?

A. The American Gas Association's study, *Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020*, observed an average annual residential usage decline of 1.1% per year since 1980, and projects a decline of 0.54% annually for the future up through 2020. Given those two figures, 1% seemed like a natural for my illustration.

Q. Based upon what you just described, am I correct in concluding that with revenue decoupling the Distribution Non-Gas revenues will not be affected by variations in Questar's GS sales volumes?

A. Not quite. The Distribution Non-Gas sales are a function of both the number of customers and the average use per customer. Accordingly, the revenues associated with those sales will rise and fall according to what happens to the customer count as well as what happens to average usage. But regardless of how many customers there are, balancing account accruals won't appear without per-customer average consumption levels departing from the test-period levels.

Again, total Distribution Non-Gas revenues will go up and down according to the number of customers in service. That means that if Questar suddenly lost a large share of its customer base, it would in turn suffer a major loss of revenues that would have gone to support its (largely fixed) distribution non-gas costs, but, insofar as average consumption of the remaining customers was unaffected, those losses would *not* be made up through the CET decoupling/balancing account mechanism. Conversely, if Questar added a lot of new customers, total DNG revenues would naturally not be fixed at the level associated with the original test period sales, but would be allowed to increase so as to cover the additional costs associated with an enlarged service territory.

Q. Does the ability of Questar to essentially lock-in its per-customer average Distribution Non-Gas revenues have implications with respect to its incentives to minimize its costs consistent with maintaining desired service quality and safety standards?

A. Simply stated, with revenues fixed, the Company would have the same incentive to increase profits by cutting costs as it would under the status quo. But as was discussed in the introductory section to this testimony, by avoiding systematic profit attrition due to declining per-customer average sales, Questar should be less inclined to try to compensate for such losses by cutting costs beyond the level that begins to compromise service quality and safety.

IV. REVENUE DECOUPLING AND THE BEARING OF RISKS

Q. You have described a mechanism by which Questar is protected from revenue losses occasioned by reduced sales owing to either explicit conservation (based on DSM or other factors) or to the long-term trend of declining average gas consumption. Are there other causes of reduced sales besides conservation and the long-term trend for more energy-efficient housing and domestic appliances?

A. A warmer than normal winter, price shocks which induce significant behavioral changes, or an economic recession which shrinks commercial activity and household budgets can all lead to reduced consumption.

Q. Would the proposed revenue decoupling mechanism protect Questar from revenue losses due to those factors?

A. Actually, there is already in place in Utah a weather normalization adjustment to customers' usages which protects Questar from weather risks. But, yes, the proposed decoupling mechanism will also protect Questar's revenues from shortfalls due to price shocks and economic downturns.

Q. Isn't it true that utilities have historically been forced to bear the brunt of the risks associated with those factors?

A. It is true. But insofar as utilities were awarded equity returns which covered their full, risk-influenced capital costs, they were compensated for bearing those risks. It is noteworthy that the only "disadvantage" that the AGA (American Gas Association) mentioned in its report on decoupling mechanisms was "that regulators and advocates may seek a reduced [rate-of-]return or other concessions as a trade-off or as a bargaining chip."

Q. Are there devices that could be employed to separate out the sales reductions caused by conservation and efficiency trends from those other factors which you mentioned?

A. Models can and have been developed which relate gas consumption to weather, prices, and regional economic growth or decline. The problem with such approaches is that they vastly increase decoupling's implementation complexity. Given that there is to be a policy choice regarding who's to bear the risk of variations in consumption due to factors other than conservation, it would be my judgement that both customers and the utility are better served by having the customers bear those risks while being compensated via a utility rate-of-return adjustment. Such would serve the regulatory values of both equity and simplicity. Just because utilities explicitly bore those risks in the past, it does not necessarily follow that such would be in the public interest in the future.

V. A BRIEF REVIEW OF TWO SUBSTITUTES FOR THE DIRECT DECOUPLING OF REVENUES FROM COMMODITY SALES

Q. You have discussed at some length how the decoupling of revenues from average consumption levels can insulate a utility's profits, in part, from the effects of conservation and the long-term declining consumption trend. Are there other means in the regulatory realm for accomplishing that objective?

A. Two approaches come immediately to mind. One takes advantage of the ability, as provided for by recent Utah legislation, for regulation to employ a future test year rather than a historical test year. The other approach was dealt with at some length in the Utah "Working Group" that addressed this general subject. It was to employ a band about the authorized rate of return, with more or less automatic rate adjustments to compensate for when the utility's achieved return falls outside that band.

Q. Would you briefly describe the advantages and disadvantages of employing a future test year?

A. Yes. Insofar as future sales can be accurately forecasted (anticipating conservation and extrapolating from recent consumption trends), a utility's volumetric prices can be set so that the product of those sales and prices will generate revenues that equal the utility's full costs – both fixed and variable. The challenge comes with the difficulty in making accurate sales forecasts. There will be a natural tendency for the utility to under-forecast sales, and for consumer advocates to over-forecast them. By contrast, with the CET the per-customer average consumption that is used in developing the prices in the first instance, and the subsequent per-customer average consumption that drives the conservation enabling tariff balancing account can always be based upon observations rather than projections. Another disadvantage of relying upon future test years to keep sales matched with costs is inherent in the fact that one year out into the future (which is what the legislation provides for in terms of how far into the future the test period can extend beyond when new rates are implemented) will transform into the past just one year later. In other words, staying on top of declining usage will require the regulatory burden of annual general rate cases.

Q. Would you briefly describe the advantages and disadvantages of employing a rate-of-return banding approach?

A. The benefit is that as profits shrink over time due to declining average usage, rates will automatically be adjusted upwards without the necessity of a new general rate case. Recognizing that declining profits can reflect increased costs as well as declining revenues, automatically preserving a profit level can create a "cost-plus" environment whereby a utility becomes less disciplined in its attempts to minimize its costs (consistent with preserving the desired level of service quality). That is the primary conceptual disadvantage. The Division's cousel believes there is also the practical impediment of requiring legislative approval.

VI. THE TRADITIONAL DECOUPLING MECHANISM, i.e., THE LUMP-SUM CUSTOMER DELIVERY CHARGE, VERSUS THE "CONSERVATION ENABLING TARIFF"

A. The Distribution Non-Gas Customer Charge as a Decoupling Mechanism

Q. Earlier you indicated that most of Questar's distribution non-gas costs are fixed. "Regulation 101" suggests that fixed costs should not be collected on the basis of a consumption/volumetric charge but rather through a flat or lump-sum charge – i.e., a customer charge. Wouldn't substituting a greatly enlarged customer charge for the "Distribution Non-Gas Cost" rate achieve the regulatory objectives you've described, i.e., by not penalizing Questar for conservation or declining consumption over time?

A. It would. The lump-sum customer charge obviously collects revenues that are decoupled from any variations in per-customer consumption levels. For that reason, utilities have long favored large customer charges.

Q. Given the obvious simplicity advantage of having a large customer charge rather than the Conservation Enabling Tariff (which has the extra baggage of an average non-gas revenues balancing account), why aren't the parties of the Joint Application advocating the customer charge option?

A. The different parties have their own reasons. From a practical/procedural point of view, the conservation enabling tariff was viewed as being most likely to attract consensual support from the interested parties (including the Committee of Consumer Services [or Committee]) as well as the endorsement by this Commission. Beyond that, and given an equal likelihood of PSC ratification, Questar would undoubtedly have preferred the customer charge approach. Utah Clean Energy definitely prefers the CET because it maintains the high, conservation-motivating volumetric price signal. The CET is also more in keeping with the Committee's long-standing opposition to elevating customer charges. All three of those factors (i.e., likelihood of parties' support and PSC endorsement, promotion of conservation, and favoring a customer charge that is limited to explicit customer costs) entered into the DPU's decision to support the Joint Application's method of decoupling. As is attempted with all our positions, the DPU believes this one can be justified on both efficiency and equity grounds.

B. The Conservation Enabling Tariff and Economic Efficiency in Consumption

Q. You have already presented efficiency and equity arguments in support of the CET in terms of how the utility is treated. How about from a consumer perspective? What is the economic efficiency argument in favor of the CET over an enlarged customer charge?

A. Perhaps the most fundamental conclusion from economic theory is that economic efficiency is fostered by prices that equate to marginal costs. Marginal costs, properly viewed, include both private and external costs. The best estimate of current private costs is the spot price of gas delivered to pipelines. According to the most recent *Platts Inside FERC's Gas Market Report (January 2006)*, the index of the Rocky Mountain price recently paid by Questar is $8.78 per Dth. That same report shows a national average of $9.95/Dth. Both figures are well below what they were earlier in the year. External costs pertain both to air quality degradation (including global warming implications) from CO2 and other pollutants produced by the combustion of natural gas as well as to strategic defense implications of an increasing dependency on foreign natural gas and oil sources. I don't have a figure for those external costs, but they are surely greater than zero.

The explicit commodity portion of Questar's tariff is set equal to the average of the cost of the Company's own production and its purchases. Given the relatively low value of the first of those two cost components, that average tends to run below the cost of gas purchased from market sources. Depending on the contractual mix and their vintages, the average purchase price will be above or below the current spot price.

The current commodity price that applies to the vast majority of gas consumption (i.e., for the first 45 Dth's) is $10.07/Dth in the summer and $10.96/Dth in the winter. If the DNG portion of the price were eliminated (due to a customer charge substitution), the summer price would fall to $8.31/Dth and the winter price would fall to $8.88/Dth. Those levels are either below current marginal private costs, or, at least, leave no margin for when market prices exceed the tariff price. Furthermore, little or nothing would be left over for accommodating the unquantified external costs. Given the obvious conservation benefits of maintaining as high of a volumetric charge as can be justified, the Division would strongly oppose reducing Questar's volumetric charge to a level that threatens to be below observable marginal costs. Such would be the consequence of substituting a large customer/delivery charge for the volumetric DNG tariff.

C. Recovering Distribution Non-Gas Costs – A Matter of Equity

Q. I must confess to not being immediately persuaded by your economic efficiency argument for preserving a volumetric charge for recovering the distribution non-gas costs. I would assume that your equity argument is stronger.

A. It is.

Q. Let's hear it.

A. As previously indicated, distribution non-gas costs are largely fixed – i.e., they do not vary with the volumes of gas that particular customers consume. If consumption levels have little to do with distribution non-gas cost causation, what are the main cost drivers? They are primarily demographics related. Yes, peak consumption will determine the size of distribution feeders and mains, but the marginal capacity costs of pipes are small relative to the other costs that go into the distribution system. Those other costs have to do with rights-of-way, trenching, physically laying the pipe and then burying it, and then, where required, re-applying asphalt or concrete so as to restore the road or street to its original state. Clearly, those costs are more a function of distances and terrain traversed (i.e., demographics) than the maximum volume that can be transferred.

The conclusion is that it is pretty much impossible to attribute individual cost causation to most of the primary distribution system costs. The logically unwarranted conventional industry approach to not being able to attribute costs to some volumetric factor is to say that all customers are equally responsible, and the costs should be recovered through a single, lump-sum customer charge. Fortunately, a relatively well known regulatory principle provides a better (i.e., more fair) solution to how cost recovery of joint-and-common costs should occur. It is that where cost-causation is not readily discoverable, then payment should be in accordance with benefits received. Given shared costs that, by definition, can't be identifiable with particular customers, requiring those who receive the greater benefits or value to pay more than would those who receive little value is generally accepted without further ado. And within the gas utility arena, the volume of consumption is the most direct indicator of value or benefits received.

An example illustrating the fairness of having heavier users pay more than would light users for the shared distribution non-gas costs: My 1977 vintage (and relatively small vis a vis the rest of the community) Alpine house of about 3800 square feet includes a semi-private "mother-in-law" apartment that, by city ordinance, is served off the same electric and gas meters as the primary dwelling. As a rule, six adults (two of whom were renters) occupied the premises in the last few years. To accommodate us all, there were two gas water heaters, two gas clothes dryers, a gas kitchen stove (in addition to an electric stove), and a gas log, along with a gas boiler for the five zones of space heating. Next door lived alone a widow in a smaller, newer, and probably more energy-efficient, house. I'm confident her household used considerably less gas than did ours. I would defy anyone to say that it would be fair for the next-door widow and the Comptons to have paid identical amounts to cover distribution non-gas costs. Clearly the Compton household received greater value from the distribution system than did our neighbor.

Q. Your example depicted a case where large use was attributable to heating a relatively large residence, which also had numerous gas appliances. Another example of heavy use would be the many cases of older, smaller homes that are poorly insulated. These are typically occupied by citizens with below-average incomes. Would it be fair for their larger-than-average distribution non-gas payments (due to continuing the volumetric charge) to subsidize the consumption of more prosperous people who enjoy below-average use attributable to their newer, energy-efficient homes?

A. I'm sorry, but first I must correct your use of the term, "subsidize." I would say that consumer A only subsidizes consumer B when the former picks up costs that are directly caused by B. That does not happen with a volumetric charge for distribution non-gas costs because, by and large, their costs are not directly caused by any single consumer. Furthermore, recall that just because most of distribution non-gas costs are shared rather than attributable to specific consumers' uses, it does not inevitably follow that every consumer is "equally responsible" for bearing such costs, and that, therefore, the costs should be covered by equal customer charges. One can posit a *policy* preference for an equal customer charge for recovering such cost, but just as easily – and, I believe, more defensibly – one can posit that cost-recovery should track benefits received, i.e., through a volumetric charge.

Now to answer your direct question, let's refer to a parallel – the recovery of highway costs, which are also largely fixed rather than dependent upon current usage. Those costs are mostly covered from fuel taxes, i.e., which roughly track benefits received as measured by ton-miles driven. But, it might be argued, how about the poor, who drive older, heavier, and less fuel-efficient vehicles? Aren't they unfairly having to subsidize driving by owners of newer, fuel-efficient vehicles? I would answer that perhaps in a perfect world some allowance could be made for them. But 1) society is no more able to measure "worthiness" at the gasoline pump than to measure "worthiness" at the natural gas meter; and 2) some degree of compensation is transmitted via the fact that while fuel is costlier with old cars (or houses), the old cars (or houses) are themselves much cheaper than the new ones. So when measuring the cost of transportation or housing *services* rather than just the fuel component of those services, it is still true that poorer citizens generally pay less than do their wealthier counterparts. Finally, I would remind you that HEAT, HELP, and other such programs are in place for assisting those who struggle in paying their utility bills.

D. A Distribution Non-Gas Customer Charge, Rate Shock, and Prior Commission Policy Regarding the Rates Treatment of Customer Costs

Q. In its white paper that presented pros and cons regarding the various approaches to stabilizing revenues in the face of declining average consumption, Questar mentioned customer resistance to large increases in their summer bills. A related concern was "[p]otential losses from increased seasonal shut-offs." Do you agree with those concerns?

A. "Public acceptability" and "rates stability" are long-recognized criteria for evaluating the desirableness of a rate structure. A twenty-dollar customer charge would violate the latter, per se, and create problems with the former – especially in the first summer after the large "delivery charge" was introduced, causing many customers to have bills that were double the levels of the prior summer. As regards the potential losses from shut-offs, such can be prevented by instituting a re-connection charge that is substantial enough to collect the lost delivery charges.

Q. Early in this testimony you mentioned a perception of Utah Commission resistance to a large customer/delivery charge. Please comment.

A. Some time ago the Commission, in an order approving a "customer charge, as opposed to a minimum billing," iterated what should properly go into such a charge. The Division has long supported that ruling, and has interpreted it narrowly as holding that the customer charge should be limited to covering costs that are expressly and unambiguously caused by individual customers. In the gas arena, those costs are associated with the service line that connects the customer's meter with the underground main that usually runs down his street, the meter itself, meter reading, and billing. I would assume that those customer-specific costs add up to roughly five dollars per month, the current Questar residential customer charge. That leaves approximately $15/month in distribution non-gas costs that would be recovered by a "delivery charge" in the neighborhood of $20. As discussed above, most of the "distribution non-gas costs" that would be covered by such a charge – while "independent of actual energy consumption during a given month" by a particular consumer – are not "costs that he imposes upon the system," which the Order cites as billing and meter reading and maintenance. Distribution non-gas costs appear to be exactly the kind of "customer costs" that the Commission wants to continue to be collected through a volumetric charge. This testimony affirms that position in its advocacy of a volumetric "decoupled" conservation enabling tariff rather than accomplishing the primary utility objective of that tariff through a large delivery/customer charge.

VII. RESPONDING TO PROBLEMS WITH THE PROPOSED REVENUE DECOUPLING APPROACH AS LISTED IN A RECENT NRRI PRESENTATION

Q. Very recently (Jan. 13, 2006), the National Regulatory Research Institute (NRRI) sponsored a presentation by it Senior Institute Economist, Ken Costello, titled, "Revenue Decoupling for Natural Gas Utilities: Issues and Observations." Are you familiar with it."

A. I've read the PDF-filed presentation.

Q. On pages 20 and 21 of that presentation, Dr. Costello lists, without any explicit rebuttal, 16 "Identified problems by PUCs and interveners." Would you list those 16 problems and provide responses?

A. Certainly.

1) "conditions don't warrant a true-up mechanism that in essence is retroactive ratemaking (i.e., extraordinary conditions do not exist)" Comment: What constitutes "extraordinary" is a matter of judgement, which, in this case, will ultimately rest with the Commission. The judgments of the Joint Applicants regarding DNG revenue stabilization, a timely DNG rate decrease, and DSM, have been expressed by their respective advocates. "Retroactive ratemaking" can have two meanings. a) The illegal form of retroactive ratemaking would be to go back and charge a customer again, or more, for *past* consumption. That is not being proposed. Yes, aggregate "under-consumption" will create a balancing account accrual, but such will affect rates that will apply to all customers within the class and such rates will apply to *future*, not past, consumption. b) Costs incurred, but not recovered (fully or at all), in the past can nevertheless be recovered in the future via balancing accounts, deferred accounting, etc. These are well recognized and established ratemaking tools. What is novel (in Utah, but not elsewhere) is applying such a tool to in-service plant and other non-fuel/energy costs.

2) “questionable that declined gas use per household will continue in the future and that it will significantly affect the ability of utility to earn its authorized return.” Comment: Past reductions have been substantial enough to lead to general rate cases and their attendant rate increases. Insofar as average use does not drop in the future, nothing will go into the DNG balancing account – so what’s the problem? (“No harm, no foul.”) Perhaps the concern reflects an unwillingness to allow a gas utility to recover lost revenues due to mild weather. But that issue has already been resolved in Utah – in the utility’s favor. Almost all GS1 customers pay rates that are weather normalized so that undue losses aren’t experienced by Questar in warm winters.

3) “risks are shifted to consumers” Comment: First, note the response to 2). And as stated earlier, there is nothing intrinsically wrong with risk shifting *to* or *away from* customers *or* shareholders as long as the offsetting compensations are equitable.

4) “no evidence that RD [revenue decoupling] is needed for successful implementation of EE [energy efficiency, e.g., DSM]] initiatives” Comment: It is self-evident that if the utility’s full cooperation with EE, not to mention its sponsorship, is desired, then such should not be contrary to the utility’s own self-interest.

5) “inappropriate to single out revenues without considering deviations in [from?] actual and test-year revenue requirements” Comment: Dr. Costello’s final comment in his presentation (appearing on page 32) includes this: “It would seem inappropriate (i.e., asymmetrical) to adjust rates when actual sales deviate from targeted or test-year sales but not do the same for expenses and other revenue-requirement components of rates....” From this statement I would interpret Dr. Costello’s objection in this instance to saying “deviating” costs and achieved rates of return should be “balanced out” and not just revenues. My comments on the waste and inefficiency hazards of not limiting the balancing to the proposed revenues element (i.e., average, not total, revenues) has been discussed at some length earlier. In particular, refer to the “rate-of-return banding” discussion that began on page 10.

6) “a rate case is the proper the [sic] forum for determining whether the decline in per customer gas use will continue and, if so, how it should be reflected in new rates” Comment: The Commission may well reach that legal conclusion; but, particularly in light of the recent large rate increases, we see no evidence that declines won’t continue. It is hoped that the evidence contained in this and other witness’s testimonies will be sufficient to enable the Commission to confidently place the conservation enabling tariff into effect on a trial basis. Some confidence enhancing suggestions are included at the end of this testimony.

7) “better, more incremental alternatives are available for addressing the problem of reduced sales per customer” Comment: What are they? I would assume Dr. Costello would suggest what he listed on page 23 as “Alternatives to RD (in promoting same objectives..., for example high earnings variability and shareholder losses in promoting energy efficiency)” After allowing that the alternatives “have their own problems,” he lists them as follows (with my comments attached):

a) “raising the customer charge (which, according to proponents, has the desirable effect of levelizing customer bills throughout the year, make utility earnings less vulnerable to changes in sales, represents a more economically efficient way to allocate fixed costs and may diminish the frequency of rate cases” Comment: Those advantages are all true, but the equity and other disadvantages described in the previous major segment of this testimony argue in favor of the proposed CET.

b) “creating a demand charge” Comment: Demand charges for gas utilities are highly problematic insofar as, like residential electric meters, gas meters don’t normally measure demand. A substitute might be to base the demand charge on what appliances customers possess, but how would that be established initially and monitored continually in an expeditious fashion?

c) “implementing declining block rates” Comment: Questar already has declining block rates, but, granted, relatively few customers get out to the second block. Declining blocks have long been criticized on the same grounds as having large customer charges – i.e., as being unfair to low-use customers and not adequately fostering conservation.

d) “using a multi-year forecast horizon in setting new rates” Comment: Utah statutes now allow future test period, albeit not multi-year test periods. While such would mitigate the general declining usage problem they would not address the matter of having the utility be pro-active regarding DSM and other conservation programs, and wouldn’t deliver an immediate (albeit small) rate reduction.

e) “implementing a targeted incentive plan which allows a utility to earn profits from successfully carrying out desirable energy efficiency initiatives” Comment: This does not address the primary matter of dealing with generally declining usage over time.

8) “RD [revenue decoupling] can lower the quality of service” Comment: This one mystifies me. As discussed earlier in this testimony, the proposed decoupling allows the utility a better opportunity to earn its allowed return without having to resort to inappropriate cost-cutting – i.e., that which would reduce service quality or compromise safety.

9) “RD can destabilize rates” Comment: What constitutes stability? The proposed decoupling plan substitutes frequent (i.e., bi-annual) small rate increases for less frequent, but much larger, increases.

10) “RD can reduce customer incentives for conserving natural gas” Comment: It is true under the proposal that when aggregate/average consumption drops, there is a follow-up rate increase that will recapture some of the lost revenues. But a) the permanent savings to ratepayers will be four or five times greater than the recaptured revenues; b) the price signal to each individual is to receive the full savings advantage of his conservation -- because the future rate increase will occur independent of that individual’s behavior; and c) a key reason that the Utah Clean Energy party joined this joint application is precisely because the CET is more conservation-friendly than the other known and feasible alternatives for accomplishing the objectives of the joint applicants.

11) “RD reduces the incentive to implement appropriate rate design” Comment: This one also mystifies me.

What is Dr. Costello's notion of an "appropriate" rate design? Large customer charges? Steeper declining blocks? He doesn't give any hints – beyond the unsatisfactory alternatives mentioned above.

12) "RD [is] too blunt of a tool in that it allows rate adjustments regardless of reasons for reduction in gas use per customer" Comment: "The horse is already out of the barn" in the sense that "rate adjustments" are already allowed in Utah for warm weather – the primary non-conservation cause of reductions in gas use. Separating out other non-conservation reasons for average-use reductions would be highly problematic, to say the least.

13) "by itself RD does not provide incentive to a utility to promote or support EE initiatives" Comment: The more modest intention is to just remove the disincentive to promote such initiatives. Other programs would hopefully constitute the desired "sharp instrument," or positive incentive.

14) "in both theory and practice, regulation does not guarantee a utility to earn its authorized rate of return because of (say) increase[d] competition, economic trends, changes in consumption patterns and technological changes that may move against the industry or individual gas utilities" Comment: Because of the multitude of factors affecting a utilities rate of return, there are no practical guarantees that a utility will earn its authorized return under any regulatory regimen currently imaginable in Utah, the proposed CET notwithstanding. Yes, risks can be reduced. But that is not, per se, bad. As discussed at length earlier in this testimony, risk reduction can be mutually advantageous to ratepayers and utility shareholders alike. Also, see the comments for 12), above.

15) "RD will generally increase short-term gas prices (assuming lower sales than otherwise)" Comment: What counts for ratepayers, is the long-term average, which will likely be unaffected, or even improved (i.e., lowered), by the proposed decoupling program – for reasons discussed immediately below.

16) "RD could thwart economic development" Comment: If Dr. Costello is suggesting that the proposed decoupling would lead to higher-than-otherwise average rates, his allegation is questionable at best, for the following reasons: a) there may be compensatory rate-of-return reductions, leading to lower-than-otherwise rates; b) the DNG balancing account treatment substitutes regular, small increases for irregular, larger increases (with the potential distortions and biases described earlier in this testimony) – one can't say, a priori, which would lead to a larger average over time; c) insofar as cost-effective DSM is fostered, fuel costs will go down as Questar is enabled to avoid the more expensive gas purchases (which substitute for its cheaper, self-supplied gas).

VIII. SOME EARLY, PILOT PHASE CONSIDERATIONS

Q. You and the other witnesses who represent the joint applicants have described a number of benefits accruing from the conservation enabling tariff program. From a regulator's perspective do any other benefits come to mind?

A. Yes, there is a major rates simplicity benefit that could come by way of altering how rates/ usage levels are weather-normalized.

Q. Please explain the nature of the current rates complexity that now exists and that pertains to this case.

A. Recall that Questar has removed weather-variability risks by way of its weather-normalization adjustment to customers volumes/rates. That adjustment is extremely complicated, and in practice has led to some customer (and even regulator) confusion and complaints. The adjustment works by taking into consideration customers' summertime use so that only the winter-related use can be adjusted for weather. Because any two neighboring customers will likely have different summer usage patterns, those neighbors will have different rates being charged for their winter usage. So on those (fortunately rare) occasions when neighbors compare their bills, questions/complaints arise as to why they aren't paying the same rates.

Q. Can a revenues decoupling mechanism enable the elimination of the problem of multiple rates that you just described?

A. It can. The first step would be to remove the weather-normalization adjustment from the way individual customers' bills are calculated. Consequently, the actual revenues that will be used in establishing the monthly DNG balancing account accruals will *not* be weather normalized. But since the target/allowed revenues would still be based on weather-normalized figures, the DNG balancing account accrual would now *itself* capture the differences between allowed revenues and actual revenues as the latter is affected by weather.

Q. What you described continues to minimize weather-related risks for the Company while simplifying the construction, understandability, and administration of retail rates. Are there any downsides to implementing such a program?

A. There is, and it's not unsubstantial. While the current mechanism might be accused of being maximally complicated, it is also very fair inasmuch as the highly seasonal customers have their own weather-related risks minimized directly and immediately. (In a very cold winter, for example, the rates currently in effect are automatically lowered as compensation.) Under what was just described, lower average use due to a very cold winter will in fact reduce rates (via the negative accrual into the DNG balancing account) from what they would have otherwise been, but the reduction won't be seen until the semi-annual balancing account "pass-through," the amount of the reduction will depend on aggregate consumer behavior rather than an individual customer's actions, and all users will benefit from the reduction, not just the seasonal, weather-related usage.

Q. I take it that the Division is not formally proposing such a major restructuring of rates at this time?

A. We aren't "informally" proposing it either. I have just thrown out an idea to suggest that during the proposed pilot study period there may be any number of matters that might be considered as having implications and ramifications regarding the CET.

Q. As has been made clear, the Company's primary interest in the CET is to protect its DNG revenues from perpetually declining average consumption rates. Regulators don't always share that same enthusiasm. There may be some concern under the CET that an "unconscionable" share of the $10.2 million rate reduction could be "given" back to Questar in the event of a major drop in average consumption. Is there

something that might ameliorate that fear?

A. One of the conditions of the pilot-study nature of the proposal is that it can be terminated at any time that the outcomes are unacceptable – to any party, including Questar. It's likely that regulators will have in mind some DNG balancing account ceiling/alarm-threshold, beyond which they would want the CET cancelled.

But I need to caution you on your "give-back" notion. Had there been a general rate case, *with a future test year that took declining usage into consideration*, it is highly questionable that there would have been a $10.2 million reduction in the first place. Consider the strategy of substituting a general rate case for the CET. Hypothetically, instead of having an immediate $10.2 million rate increase and a subsequent $2 or $3 million DNG balancing account accrual in 2006, there would have been a general rates decrease of, say, $5 or $6 million put into place by the end of 2006 and no DNG balancing account. "Giving back" within the context of the joint application really means refunding a potion of an "undeserved windfall," i.e., what would not ordinarily have been received in the first place.

Q. You said "substituting a general rate case for the CET" as if the two actions are mutually exclusive? Is that the case?

A. No. Any potential party is free under the joint application agreement to obtain earnings and other information from Questar and petition for a general rates decrease if, in its mind, the evidence so warrants.

Q. How might the DNG balancing account accrual ceiling you mentioned be quantified?

A. One approach might be to say that average usage reductions beyond two or three percent should not add to the DNG balancing accruals. Halfway between those two figures translates to a cumulative balancing accrual ceiling in the neighborhood of $5 million. If the AGA-projected decrease of about 0.5% for the average residential customer is even "close" (i.e., off by 100% or less), then that $5 million ceiling won't remotely be approached. But again, this is not a proposal, but a representation of matters that can be duly considered during the pilot-study period.

Q. Does that conclude your testimony?

A. It does, thank you.