BEFORE THE KANSAS CORPORATION COMMISSION

In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve building and Equipment Efficiency And to Educate about Efficient Energy Usage, To Provide for Program Cost Recovery Through A Rider Mechanism, to Establish Administrative Charges and a Program initiation Fee, Permit The Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.	)	**Docket No. 10-KGSG-421-TAR**

DIRECT TESTIMONY OF

PAUL H. RAAB

ON BEHALF OF

KANSAS GAS SERVICE, A

DIVISION OF ONEOK, INC.

DIRECT TESTIMONY
OF
PAUL H. RAAB
ON BEHALF OF
KANSAS GAS SERVICE
BEFORE THE
THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS
DOCKET NO. 10-_____

Q. Please state your name, occupation, and business address.

A. My name is Paul H. Raab, and my business address is 5313 Portsmouth Road, Bethesda, Maryland 20816. I am an independent economic consultant.

Q. On whose behalf are you appearing today?

A. I am appearing on behalf of Kansas Gas Service, a division of ONEOK, Inc. ("KGS" or "the Company").

I. QUALIFICATIONS

Q. What is your educational background?

A. I have a B.A. in Economics from Rutgers University and an M.A. from the State University of New York at Binghamton with a concentration in Econometrics. While attending Rutgers, I studied as a Henry Rutgers Scholar.

Q. Please describe your business experience.

A. I have been providing consulting services to the utility industry for over 30 years, having assisted electric, gas, telephone, and water utilities; Commissions; and intervenor clients in a variety of areas. I am trained as a quantitative economist so that most of this assistance has been in the form of mathematical and economic analysis and information systems development. My particular areas of focus are planning issues, costing and rate design analysis, and depreciation and life analysis. I began my career with the professional services firm that is now known as Ernst & Young, where I was employed for ten years.

Q. Have you testified previously before commissions in regulatory proceedings?

A. Yes. I have provided expert testimony before this Commission in Docket Nos. 174,155-U, 176,716-U, 98-KGSG-822-TAR, 99-KGSG-705-GIG, 01-KGSG-229-TAR, 02-KGSG-018-TAR, 02-WSRE-301-RTS, 03-KGSG-602-RTS, 03-AQLG-1076-TAR, 05-AQLG-367-RTS, 06-KGSG-1209-RTS, 07-AQLG-431-RTS, and 08-WSEE-1041-RTS, as well as the state regulatory authorities of Alaska, the District of Columbia, Georgia, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Missouri, Montana, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia and Wisconsin. I have also provided expert testimony before the Federal Energy Regulatory Commission, the Michigan House Economic Development and Energy Committee, the Pennsylvania House Consumer Affairs Committee, the Province of Saskatchewan and the United States Tax Court.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. With this filing, Kansas Gas Service is requesting approval by the Commission of a natural gas conservation and ratemaking efficiency plan (the Company's "Conservation & Ratemaking Efficiency Plan"). Consistent with prior Commission Orders, the Company's Conservation & Ratemaking Efficiency Plan includes a conservation and energy efficiency initiative and a revenue decoupling proposal. The conservation and energy efficiency initiatives are: (i) an Energy Efficiency Education Program, a consumer education initiative; (ii) a Heating System Check-Up Program; (iii) four customer incentive programs, focused on the items that typically use the most gas in the home: space heating and water heating; (iv) a pilot Natural Gas Direct Use Program; (v) an ENERGY STAR® Residential New Construction Program; and (vi) a Commercial Custom Program. The first purpose of my testimony is to demonstrate the cost-effectiveness of the energy conservation programs, using the benefit cost framework suggested in the Commission's Order in Docket No. 08-GIMX-442-GIV.

The second purpose of my testimony is to provide support for the Company's revenue decoupling proposal, paying particular attention to the concerns as expressed in the Commission's Order in Docket No. 08-GIMX-441-GIV.

III. IDENTIFICATION OF EXHIBITS

Q. Do you sponsor any schedules in support of your testimony?

A. Yes. I sponsor four exhibits. Exhibit PHR-1 summarizes the participation and budget levels for the individual conservation and energy efficiency programs. Exhibit PHR-2 summarizes the input assumptions used to evaluate the programs. Exhibit PHR-3 summarizes the benefit cost evaluations of the energy conservation programs. This framework includes the application of a Participant Test, a Rate Impact Measure Test, a Total Resource Cost Test and a Program Administrator Test. These tests are commonly employed to evaluate conservation and energy efficiency programs and are prescribed by the Commission's Order in Docket No. 08-GIMX-442-GIV. Finally, Exhibit PHR-4 quantifies the lost volumes and margin revenues associated with the Company's proposed conservation programs.

The above-designated schedules were prepared by me or under my direction and supervision.

IV. ORGANIZATION OF TESTIMONY

Q. How is your direct testimony organized?

A. My direct testimony is organized into three additional sections. Section V provides a summary of the conservation and energy efficiency programs proposed by the Company in this proceeding. Section VI provides my evaluation of the Company's proposals. Finally, Section VII provides a summary and my evaluation of the Company's revenue decoupling proposal.

V. THE COMPANY'S CONSERVATION AND ENERGY EFFICIENCY PROPOSALS

Q. Please explain what is contemplated under the general framework of conservation and energy efficiency programs in the Commission's Orders.

A. In Docket No. 08-GIMX-442-GIV (442 Docket), the Commission established basic policy guidelines for energy efficiency programs. The Commission views energy efficiency as a resource to be considered in a balanced approach between traditional and alternative energy sources in meeting Kansas energy needs. Docket No. 08-GIMX-442-GIV, Order Setting Energy Efficiency Policy Goals, June 2, 2008 (442 Order) ¶ 26. As a resource, energy efficiency programs should produce "cost-effective, firm energy savings," and should provide "dependable energy savings supplied throughout the relevant lifetime of the program." 442 Order, ¶¶ 26 & 27. The Commission favors programs or a suite of programs that address energy efficiency "in a comprehensive way," and that address the "total home or building utilizing sound building science principles." 442 Order, ¶ 71. The Commission is particularly interested in energy efficiency programs that target low-income customers, fixed income customers, renters, and customers who reside in residences most in need of energy efficiency upgrades. 442 Order, ¶ 28.

Q. Please describe the Company's energy conservation program offerings and other initiatives.

A. The set of programs covers the types of programs contemplated in the Commission's Order and comprehensively addresses the natural gas energy efficiency needs of the Company's customers. All major natural gas-using appliances are targeted, as well as the thermal integrity of buildings. The programs targeting these areas have the potential to produce energy savings of a long-term nature, perhaps 10-20 years into the future. The Seasonal Check-Up Program targets customers who may not want to make substantial energy efficiency improvements, but instead invest in immediate energy savings on a short-term basis. The Natural Gas Direct Use Program is proposed as a pilot program to encourage the installation of highly energy efficient ENERGY STAR®-rated equipment in residential homes to replace less-efficient electrical equipment. The set of programs that make up the energy conservation programs also includes an ENERGY STAR® Residential New Construction Program, specifically targeting the new home construction market.

While all sales service customers, including smaller non-residential customers, will be eligible for all of the equipment programs described above, KGS recognizes that these programs may not be applicable to some customers, particularly the larger ones whose main usage of natural gas is for process applications. To accommodate larger customers, KGS is proposing a Commercial Custom Program. The Commercial Custom Program is intended to reduce natural gas energy usage by providing for the payment of incentives for the installation of cost-effective energy efficiency measures in the businesses of larger general sales service customers (determined on a customer-specific basis).Finally, the Company is proposing an Energy Efficiency Education Program, which is intended to raise the general awareness of the importance of energy conservation among the Company's customers and to also inform these customers of the specific program offerings that they can take advantage of in order to conserve natural gas and lower their energy bills. This program is described in greater detail in the testimony of David Dittemore.

Q. Please describe the Company's Seasonal Check-Up Program.

A. The KGS Residential Heating System Check-Up Program provides residential customers with an incentive to cover the cost of having a third-party contractor conduct a seasonal check-up. KGS also plans to provide customers a list of preferred plumbers and heating system installers (preferred professionals) who would discount their charge by the amount of the incentive. In the alternative, the customer, at their election, would be eligible to receive an equivalent credit toward a programmable thermostat. A home check-up is typically a 21-point inspection, which may include:

1. Check gas pressure (PSI)
2. Check heat exchanger cells
3. Clean heat exchanger

4. Check gas valve operation
5. Clean and check pilot/spark igniter
6. Clean burners
7. Check and clean burner crossovers
8. Check all safety controls
9. Check oil blower motor
10. Check blower motor rotation
11. Check blower motor amp draw
12. Check and change belts, if necessary
13. Check blower motor bearings
14. Change and clean filter
15. Check for gas leaks
16. Check flue pipe
17. Check humidifier pad
18. Check water connection and drain
19. Check thermostat operation
20. Set heat anticipator
21. Tighten all screws

This inspection of the home's heating system ensures its safe, efficient operation, including a cleaning or replacement of filters if necessary.

Q. How will the Seasonal Check-Up Program be marketed to customers?

A. The program will be introduced to potential participants through bill stuffers, direct mail, preferred professionals or a web-based site. These communications will contain a rebate form that is to be sent back after the check up has been conducted. This rebate form will initiate payment of the $30 incentive or the reduced cost setback thermostat.

Q. How will customers participate in the Seasonal Check-Up Program?

A. The customer is responsible for hiring a contractor to conduct a home heating system check-up. When the check-up has been conducted, the customer need only mail back the rebate form, along with the contractor invoice, and a $30 incentive payment will be provided. Alternatively, the customer can request that the rebate be applied to a setback thermostat. In lieu of the customer applying for the rebate, they could choose to select one of KGS's preferred installers and apply the $30 rebate to their charge. The Company will require and review copies of all invoices and/or receipts to verify the inspection has actually taken place and reserves the right to perform spot checks if warranted.

Q. Please describe the Company's Water Heater Program.

A. The Water Heater Program actually contains two components: a standard (tank) water heater component and a tankless water heater component. Within the standard water heater component, KGS is proposing an incentive of $50 to encourage customers to choose a standard natural gas water heater with an energy factor of 0.62 or greater. Within the tankless water heater component, KGS is proposing an incentive of $300 to encourage customers to choose a tankless natural gas water heater with an energy factor of 0.82 or greater.

This program, like the other equipment incentive program, is focused on the major appliance representing significant energy consumption in the home. Specifically, the water heater is typically the second largest use of natural gas in most homes. As such, this program has the potential to have a significant impact on natural gas consumption in the home.

Q. How will the Water Heater Program be marketed to customers?

A. The program will be introduced to potential participants through bill stuffers, direct mail, preferred professionals or a web-based site. The mailings will include a rebate form that is to be sent back after the water heater has been installed. KGS' receipt of the rebate form will initiate payment of the incentive.

Q. How will customers participate in the Water Heater Program?

A. The customer is responsible for hiring a contractor to install a qualifying high efficiency natural gas water heater. When the equipment has been installed, the customer need only mail back the rebate form and the appropriate incentive payment will be provided. In lieu of the customer applying for the rebate, they could choose to select one of KGS' preferred professionals and apply the rebate to their charge. The Company will require and review copies of all invoices and/or receipts to verify the equipment has actually been installed and reserves the right to perform spot checks if warranted.

Q. Please describe the Company's Space Heating Program.

A. This initiative will provide residential customers with an incentive to encourage customers to replace natural gas space heating appliances with higher efficiency natural gas space heating appliances. The largest energy consumption in the home is typically for space heating and water heating. With respect to space heating, KGS is proposing a set of incentives designed to encourage customers to move towards more efficient natural gas space heating equipment. These incentives would be provided to encourage customers to choose a natural gas space heating appliance with an efficiency of 92% or greater. The space heater is typically the largest use of natural gas in most homes. As such, this program has the potential to have the greatest effect on reducing natural gas consumption. Installing or replacing equipment generally represents the most expensive proposition for the customer. As such, customers usually only make significant changes during initial construction or at the point of significant failure. The incremental cost associated with higher-efficiency equipment is often more than a customer is prepared to spend. Therefore, rebate incentives encourage customers to purchase more efficient natural gas equipment. Specifically, a customer who elects to install a high efficiency natural gas furnace will be eligible for up to a $600 rebate. It is anticipated that these incentives are sufficient to encourage customers to upgrade their equipment installations to more efficient natural gas equipment.

Q. What are the specific levels of incentives that the Company will pay under this program?

A. The Company will offer a tiered incentive: $200 for a 92% efficient heating system and $600 for a 95%+ efficient heating system. The payment of tiered incentives will encourage consumers to achieve the highest efficiency level possible.

Q. How will the Space Heating Replacement Program be marketed to customers?

A. The program will be introduced to potential participants through bill stuffers, direct mail, preferred professionals or a web-based site. The mailings will include a rebate form that is to be sent back after the appliance has been installed. KGS' receipt of the rebate form will initiate payment of the incentive payment.

Q. How will customers participate in the Space Heating Replacement Program?

A. The customer is responsible for hiring a contractor to install qualifying high efficiency natural gas heating equipment. When the equipment has been installed, the customer need only mail back the rebate form, along with the contractor's invoice, and an appropriate incentive payment will be provided. In lieu of the customer applying for the rebate, they could choose to select one of KGS' preferred professionals and apply the rebate to their charge. The Company will require and review copies of all invoices and/or receipts to verify the equipment has actually been installed and reserves the right to perform spot checks if warranted.

Q. Please describe the Company's Natural Gas Direct Use Program.

A. The Natural Gas Direct Use Program is intended to promote energy efficiency by replacing inefficient residential electric heating appliances with efficient gas heating equipment. This program is designed for existing electric customers who are identified as being located in the KGS service territory and in close proximity to a gas main. Customers will be required to have a home energy evaluation completed which would be paid for by the company if the customer completes the replacement of their sole-source electric home heating system. When the customer receives the results of the evaluation, the evaluator will encourage the customer to adopt additional cost effective and energy efficient technologies commercially available so as to reduce energy consumption and energy bills. This includes changing their electric heating system and/or other appliances to an energy efficient gas furnace and other gas appliances, which will result in greater energy efficiency. An energy conservation level of 26 MMBtu is estimated for each residential dwelling unit treated. At this level, and with an incentive payment of

$1500/dwelling unit, the program is cost-effective, as measured by the Total Resource Cost Test.

Q. How will the Natural Gas Direct Use Program be marketed to customers?

A. The program will be introduced to potential participants through bill stuffers, direct mail, contractors or a web-based site. The mailings will consist of a brochure with a reader response card that is to be sent back to initiate Company contact. It is anticipated that a bill stuffer will go out first.

Q. How will customers participate in the Natural Gas Direct Use Program?

A. After the effective date of these programs and after an energy evaluation has been conducted and results are reviewed with the eligible customer, the evaluator will advise the customer of the availability of the incentive to switch from electric to gas. A residential heating customer or owner may then notify the Company of his or her intention to switch and install a new energy efficient gas furnace with an energy efficiency rating of at least 80% as a conversion from electricity.

In order to qualify for the program, the customer must allow a Company representative to conduct a residential energy evaluation and recommendation of the customer's dwelling within 60 days of the date of notification of acceptance as a participant in this program. The cost of the evaluation will be free if the customer qualifies and completes the replacement of their electric home heating system.

Once the customers provide appropriate written documentation that they have removed the existing electric heating system and replaced it with an 80% energy efficiency furnace or higher natural gas heating system, they will have satisfied the above requirements for participation in the Natural Gas Direct Use Program. Customers who participate in this program may also combine the incentives provided by other programs to achieve greater energy efficiency levels.

Q. Please describe the Company's Energy Star® New Homes Program.

A. This program will be made available to participants in the process of constructing a new home with the possibility of having the home certified as an ENERGY STAR® home. The ENERGY STAR® home construction standard provides for a home that is at least 15 percent more efficient, or uses 15 percent less energy, than the same home built under the 2003 International Energy Conservation Code.

Q. How will the Energy Star® New Homes Program be marketed to customers?

A. The program will be introduced to potential participants through direct mail to and direct contact of builders and developers.

Q. How will customers participate in the Energy Star® New Homes Program?

A. The Company would provide a $250 rebate to be applied against the ENERGY STAR® New Homes certification requirement of pre-drywall and post-construction inspections, testing and modeling. That $250, coupled with the natural gas Space Heating and Water Heater incentive programs, could equate to up to $1,150 per ENERGY STAR® home. All marketing, customer selection (under the supervision of the Company), enrollment, scheduling of the ENERGY STAR® audit, and evaluation of the resulting information will be the responsibility of a KGS-approved contractor. The contractor will complete a Home Energy Rating System (HERS) energy audit. Participants will receive a written evaluation their home's energy status, along with a complete list of recommended actions and measures to take to improve the home's energy performance.

Q. Please describe the Company's Commercial Custom Program.

A. While all customers, including commercial customers, will be eligible for all of the equipment programs described above, KGS recognizes that these programs may not be applicable to some commercial customers, particularly the larger ones whose main usage of natural gas is for process applications. To accommodate larger customers, KGS is proposing a Commercial Custom Program. The Commercial Custom Program is intended to reduce natural gas energy usage by providing for the payment of incentives for the installation of cost-effective energy efficiency measures in the businesses of larger commercial customers (determined on a customer-specific basis). The program is designed to be general in nature so that any cost-effective conservation measure brought to the Company by the commercial customers that it serves will be evaluated and, if found to be cost-effective, will be funded by incentive payments from the Company. These incentive payments will be capped at 80% of Total Resource Cost (TRC) Test benefits for the specific project and a maximum per customer payment of $10,000. Examples of measures that could be funded under this program include high-efficiency natural gas equipment -- including water heaters, booster heaters, food service equipment and hydronic heaters -- and attic/roof insulation, installation of windows, duct sealing and other weatherization measures.

In addition to space heating and water heating efficiency improvements, the program envisions that there will be applications for process load efficiency improvements. Because these are unique to specific customers, the program allows those customers to propose their own efficiency measures for Company funding without having to qualify for a prescriptive program that the Company might offer. Therefore, the objective of this program is to reach as many different customers and end-uses as possible. The only restriction on the types of efficiency measures that will be funded is that each project must be cost-effective (as measured by a Total Resource Cost Test). Furthermore, to avoid providing all program funding to a few projects, incentive payments to any individual customer are capped at $10,000.

Q. How will the Commercial Custom Program be marketed to customers?

A. The program will be introduced to current KGS commercial customers through direct mail, contractors or a web-based site. The mailings will include an application form that is to be sent back to the Company. After the project has been evaluated for cost-effectiveness, an incentive amount will be provided to the applicant.

Q. How will customers participate in the Commercial Custom Program?

A. Customers will apply for incentives for projects that involve the more efficient use of natural gas. The Company will evaluate these projects to determine the level of incentives that each project can support. The participating customers are responsible for selecting eligible projects and performing the necessary work. The Company may provide other assistance to customers as needed.

The Company will evaluate all energy efficiency projects submitted to them by large commercial customers to determine the level of incentives that each project can support. Incentives will be determined by calculating 80% of TRC benefits with a cap of $10,000 per application. The incentive payment will be provided after completion of the project. The Company will check all installations to make sure the work is actually done.

Q. What is the projected budget of the proposed programs?

A. Exhibit PHR-1 summarizes the proposed participation and budget levels of the programs. As can be seen, the Company anticipates an annual expenditure of $2,077,999, divided among the programs and activities as shown in the exhibit.

VI. BENEFIT COST EVALUATION OF THE COMPANY'S CONSERVATION AND ENERGY EFFICIENCY PROPOSALS

Q. How does one determine whether these conservation and energy efficiency programs are cost-effective?

A. As stated in the Commission's Order in the 442 Docket, "The Commission agrees with Staff's Report and the comments of the parties and finds that the formulas as set forth in the *California Manual* should be used for benefit-cost calculations." 442 Order, ¶ 37. The *California Manual* discusses five benefit-cost tests and the Commission has indicated that "it considers all five benefit-cost tests in reviewing a program, recognizing that it is important to review each test as each provides a different perspective." 442 Order, ¶ 21.

Q. What are the five tests described in the California Manual?

A. The five tests described in the California Manual are the Participant Test, the Ratepayer Impact Measure Test, the Total Resource Cost Test, the Societal Test and the Program Administrator Cost Test.

Q. Please describe these tests.

A. These tests were first developed for the evaluation of demand side measures in California in the early 1980s. Most recently published in 2001, the California Standard Practice

Manual: Economic Analysis of Demand-Side Management Programs and Projects[1] describes these tests:

- The Participant Test – This test determines whether the demand side measure is cost-effective for the party who receives the demand side treatment.
- The Ratepayer Impact Measure Test – This test determines the impact that the demand side measure will have on non-participants. Because of this, the test is often referred to as the Non-Participants Test, and measures the rate impacts of the utility offering the program.
- The Total Resource Cost Test – This test is designed to measure whether the demand side measure is cost-effective from society's standpoint. Since this test can be derived as the sum of the Participant Test and the Ratepayer Impact Measure Test, it is often referred to as the All Ratepayers Test.
- The Societal Test – A variant of the Total Resource Cost test is the Societal Test, which modifies the TRC in the following ways: uses higher marginal costs to reflect the cost to society of the more expensive alternative resources and to reflect externality costs not captured by the market system, omits tax credits and capital costs in the year in which they occur and uses a societal discount rate.
- The Program Administrator Cost Test – This test is designed to measure the cost-effectiveness of a demand side measure as a utility resource alternative.

1 California Standard Practice Manual: Economic Analysis of Demand-Side Management Programs, October 2001, available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

Q. Have you applied these tests to the conservation and energy efficiency programs proposed by the Company?

A. Yes. With the exception of the Societal Test, which quantitatively proved to be unnecessary because all of the programs passed the Total Resource Cost Test, I have applied these tests to each of the energy conservation programs proposed by the Company. Of course, the results of these tests are critically dependent upon the assumptions upon which the results are based.

Q. Has the Commission also provided guidance on how the assumptions are to be developed?

A. Yes. Wherever possible, I have followed Commission guidance on the development of assumptions. Adherence to Commission guidelines is noted below.

Q. What assumptions did you make in performing these evaluations?

A. The major assumptions that form the basis for my evaluation of the Company's conservation and energy efficiency programs are summarized in Exhibit PHR-2. As can be seen from this exhibit, the major assumptions I have made can be grouped into two different categories: general assumptions that apply equally to all programs and program-specific assumptions. In addition to the assumptions listed there, it is also necessary to make certain assumptions about natural gas utility avoided costs.

Q. What assumptions did you make with respect to the avoided costs?

A. These evaluations assume that the only costs avoided are the commodity costs, which are assumed to be equal to the Cost of Gas Rider (COGR), escalated at the same rate as Henry Hub prices. This is consistent with the Commission's Order in the 442 Docket:

> The Commission agrees that the best estimates of avoided costs are likely to come from a utility's use of its own internal cost modeling. The Commission will permit utilities to use this method. 442 Order, ¶ 103

Q. Why did you not assume any avoided capacity or distribution costs?

A. Natural gas distribution utility costs do not vary with output and are not "avoided" if volumes are reduced. Therefore, the only costs avoided by utility-sponsored conservation and energy efficiency programs are related to gas supply. While there may be some amount of avoided capacity-related costs, these are ignored for purposes of the present analysis. Since inclusion of capacity-related avoided costs will only reinforce the cost-effectiveness of these programs, my results can be considered "conservative."

Q. What discount rate assumptions have you employed?

A. For purposes of the Participant Test, I use a discount rate equal to 10%, consistent with the Commission's Order in the 442 Docket:

> The Commission believes using a rate of 10%, as used by the *NAPEE Planning Guide* and *NAPEE Report* would be appropriate. The Commission adopts a rate of 10% for a discount rate for the Participant Test. 442 Order, ¶ 58

As shown on Exhibit PHR-2, for all other tests reported, I assume a discount rate of 8.32%. This value is equal to the rate of return contained in the Stipulation and Agreement in Docket No. 06-KGSG-1209-RTS. Again, this is consistent with the Commission's Order in the 442 Docket:

> The Commission agrees with Staff, the participants, and the *NAPEE Report* that a utility's most recently approved ROR (weighted average cost of capital) should be used for all tests except the Participant and Societal Tests. 442 Order, ¶ 56

Q. What measure life assumptions have you employed?

A. The assumed measure life varies by program. In the case of the Seasonal Check-Up Program, all benefits will accrue to participants in the year of the treatment. This is reasonable since the program will rely heavily on annual maintenance.

In the case of the other programs, I have relied on the measure lives found in the DEER database. The water heater incentive programs assume measure lives equal to the 15-year appliance lifetime. The space heating incentive programs assume a measure life equal to the 20-year space-heating appliance lifetime. Finally, the ENERGY STAR® Residential New Construction Program assumes a measure life equal to the 20-year space-heating life. These lives are the same as those in the DEER database and are consistent with the Commission's Order in the 442 Docket:

The Commission believes the best solution is to use the widely recognized DEER values for at least a program's first two years until the first EM&V (Evaluation, Measurement and Verification) review. 442 Order, ¶ 44

[T]he Commission finds the maximum useful life will be assumed to be 20 years. 442 Order, ¶ 46

Q. Please describe the other program-specific assumptions you have used in your evaluation of the Company's Seasonal Check-Up Program.

A. In order to evaluate the Seasonal Check-Up Program, I rely on the following input assumptions, as shown on Exhibit PHR-2:

- Measure life: 1 year
- Annual energy savings: 8.9 Mcfs
- Program participants: 6,264/year

- Utility incentive payment: $30/participant
- Net to gross ratio: 0.78

Q. How did you arrive at these assumptions?

A. As discussed above, the measure life is one year, since all benefits will accrue to participants in the year of the treatment. The savings are based on annual maintenance that improves heating system efficiency from 60% to 70%. Program participation is based on an assumption that 1% of eligible customers will participate. The incentive payment is based on a similar program operating in Virginia. The net to gross ratio of 0.78 is based on information found in the DEER database. This is consistent with the Commission 442 Order:

The Commission finds Staff's suggestion of adopting the DEER Net-to-Gross (NTG) ratios until sufficient data can be developed to employ Kansas-specific ratios should be adopted. 442 Order, ¶ 121

Q. What did you assume with respect to this program's impact on alternate fuel suppliers, notably electricity?

A. I assumed that the program would have no impact on alternate fuel suppliers. This is not a totally realistic assumption, since the program improves the performance of electrically powered heating auxiliaries and since the furnace often serves as the air handler for air conditioning needs. However, ignoring these benefits serves to produce a more conservative benefit cost evaluation than is likely to be the case in actuality.

Q. Based on these assumptions, please discuss the results of applying the five tests to the Seasonal Check-Up Program.

A. As shown on page 1 of Exhibit PHR-3, the program passes the Participant Test (benefit/cost ratio of 1.60), the Total Resource Cost Test (1.06), and the Program Administrator Test (1.98). The RIM Test indicates that there will be a modest increase in rate levels in order to allow the Company to recover its program costs, $891,413 in the case of the Seasonal Check-Up Program, over an assumed five-year program life. However, the program should reduce customer bills since the costs incurred by the utility to implement the program ($891,413) are less than the gas costs that are avoided by the program ($1,767,479).

Q. Why do you not show the Societal Test on page 1 of Exhibit PHR-3?

A. As discussed above, although the Societal Test relies on the same evaluation framework as the Total Resource Cost Test, it changes certain of the assumptions to reflect an evaluation from a broader perspective. In all cases, these changes in assumptions will only serve to make the program more cost-effective than would be indicated by the Total Resource Cost Test. Since the program is already cost-effective from a Total Resource Cost Test perspective, it is unnecessary to subject the program to further evaluation to conclude that the program is also cost-effective from a Societal Test perspective. I follow this convention throughout my reporting of cost-effectiveness results in my testimony.

Q. Please describe the program-specific assumptions you have used in your evaluation of the Company's Water Heater Program.

A. As I indicated above, this program has two components: a tank water heater component and a tankless water heater component. With respect to the tank water heat component, I rely on the following input assumptions, as shown on Exhibit PHR-2:

- Measure life: 15 years
- Annual energy savings: 1.2 Mcfs
- Program participants: 626/year
- Utility incentive payment: $50/participant
- Net to gross ratio: 0.58

With respect to the tankless water heat component, I rely on the following input assumptions, also as shown on Exhibit PHR-2:

- Measure life: 15 years
- Annual energy savings: 5.3 Mcfs
- Program participants: 1,253/year
- Utility incentive payment: $300/participant
- Nett to gross ratio: 0.58

Q. How did you arrive at these assumptions?

A. The measure life assumptions are taken from the DEER database. The savings are based on improving the efficiency of water heating from .58 to .62 (in the case of a tank water heater) and .58 to .82 (in the case of a tankless water heater). An annual program participation level of 1,879 (626 plus 1,253) is based on an assumed participation rate among eligible customers of 4.5%. The universe of all eligible customers is estimated to be all customers (626,356) divided by the appliance lifetime of a water heater of 15 years (41,757). It is further assumed that, of the participants, two-thirds will participate in the tankless program and the remaining one-third will participate in the tank program, although it is recognized that actual participation levels could be different from those assumed. Finally, the net to gross ratio of .58 is from the DEER database.

Q. Based on these assumptions, please discuss the results of applying the five tests to the Water Heater Program.

A. As shown on page 2 of Exhibit PHR-3, the water heater program passes the Participant Test (benefit/cost ratio of 1.81), the Total Resource Cost Test (1.21), and the Program Administrator Test (1.38). While the Rate Impact Measure Test indicates that the incentive payments of $1,845,281 over the program's five-year life will place upward pressure on rates, the program should reduce customer bills since the costs incurred by the utility to implement the program ($1,857,204) are less than the gas costs that are avoided by the program ($2,568,698).

Q. Please describe the program-specific assumptions you have used in your evaluation of the Company's Space Heating Program.

A. There are two components of the Company's Space Heating Program:

- 92% Efficient Furnace Program
- 95%+ Efficient Furnace Program

The component-specific assumptions I have utilized in my evaluation of these components are listed in Exhibit PHR-2.

Q. How did you arrive at these assumptions?

A. I generally followed the same logic to arrive these input assumptions as I followed to arrive at the assumptions described above. Specifically, the measure life assumptions are taken from the DEER database. The savings are based on improving the efficiency of space heating from .78 to the component target level. Program participation levels are based on an assumed participation rate among eligible furnace customers of 5.0%, spread among the two efficiency tiers as shown on Exhibit PHR-2. Finally, the net to gross ratio of .60 is from the DEER database.

Q. Based on these assumptions, please discuss the results of applying the five tests to the Space Heating Program.

A. As shown on page 3 of Exhibit PHR-3, the program passes the Participant Test, the Total Resource Cost Test and the Program Administrator Test. While the Rate Impact Measure Test indicates that the incentive payments will place upward pressure on rates, the program should reduce customer bills since the costs incurred by the utility to implement the program are less than the gas costs that are avoided by the program.

Q. Please describe the program-specific assumptions you have used in your evaluation of the Company's pilot Direct Use Program.

A. In order to evaluate the Direct Use Program, I rely on the following input assumptions, as shown on Exhibit PHR-2:

- Measure life: 20 years
- Annual energy savings: 26 Mcfs
- Program participants: 100/year
- Utility incentive payment: $1,500/participant
- Net to gross ratio: 1.00

Q. How did you arrive at these assumptions?

A. As discussed above, the measure life is 20 years, consistent with the life of a furnace in the DEER database. The savings are based on an engineering estimate that compares the usage of a standard efficiency (78%) furnace to the usage of a standard efficiency (7.7 HSPF) heat pump estimated for Topeka, KS. A program participation level of 100 is based on an assumed participation cap. The incentive cost of the program is based on an estimated contribution to receive natural gas service. The net to gross ratio of 1.00 is assumed based on current experience.

Q. Based on these assumptions, please discuss the results of applying the five tests to the Direct Use Program.

A. As shown on page 9 of Exhibit PHR-3, the program passes the Participant Test (benefit/cost ratio of 1.66), the Total Resource Cost Test (1.42), and the Program Administrator Test (3.32). While the Rate Impact Measure Test indicates that the program will place slight upward pressure on rates, this result only obtains because I have performed the evaluation by converting all electricity savings to equivalent natural gas savings. Indeed, there will be a downward pressure on natural gas rates as a result of the Direct Use program.

Q. Please describe the program-specific assumptions you have used in your evaluation of the Company's pilot ENERGY STAR® Residential New Construction Program.

A. In order to evaluate the ENERGY STAR® Residential New Construction Program, I rely on the following input assumptions, as shown on Exhibit PHR-2:

- Measure life: 20 years
- Annual energy savings: 9.4 Mcfs
- Program participants: 100/year
- Utility incentive payment: $250/participant
- Net to gross ratio: 0.48

Q. How did you arrive at these assumptions?

A. As discussed above, the measure life is 20 years, consistent with the life of a furnace in the DEER database. The savings are based on the Energy Star estimate of 15%, applied to space heating usage. A program participation level of 100 is based on an assumed participation cap. The incentive cost of the program is based on an estimated audit cost to achieve an Energy Star® certification. The net to gross ratio of 0.48 is taken from the DEER database.

I have also assumed that the program will have no impact on alternate fuel suppliers. As above, this may not be a totally realistic assumption since the program improves the performance of electrically powered heating auxiliaries. However, ignoring these benefits serves to produce a more conservative benefit cost evaluation than is likely to be the case in actuality.

Q. Based on these assumptions, please discuss the results of applying the five tests to the ENERGY STAR® New Homes Program.

A. As shown on page 5 of Exhibit PHR-3, the program passes the Participant Test (benefit/cost ratio of 3.97), the Total Resource Cost Test (3.43), and the Program Administrator Test (3.43). While the Rate Impact Measure Test indicates that the incentive costs of $25,000/year will place upward pressure on rates, the program should reduce customer bills since the costs incurred by the utility to implement the program are less than the gas costs that are avoided by the program ($390,844).

Q. Did you evaluate the Company's Commercial Custom Program?

A. No, because this program is assured to be cost-effective by design. Specifically, incentives paid under the program will equal 80% of Total Resource Cost Test benefits, subject to caps. Therefore, the program will be cost-effective, as measured by a Total Resource Cost Test, by definition.

Q. How did you evaluate the Community Outreach and Customer Education Program?

A. It is generally regarded as difficult, if not impossible, to evaluate educational programs like the Company's proposed Community Outreach and Customer Education Program. This difficulty stems from the fact that it is generally not possible to attribute any specific energy savings behavior to particular programs. Since there are no measured savings, there can be no benefits and all tests applied to the educational program would fail. This is consistent with the Commission's finding in its Order in Docket No. 09-GIMX-442-GIV:

> The Commission continues to believe educational programs need not be subjected to benefit-cost testing. This is consistent with the guidelines set forth in the *California Manual.* The *NAPEE Report* also indicates educational programs may be exempted from benefit-cost testing. 442 Order, ¶ 29, footnotes omitted.

Although such programs may not be directly responsible for reducing energy usage, they do have an important role in facilitating the other program offerings, which do reduce energy usage. This suggests that the energy savings (and net benefits) associated with these other programs should be sufficient to carry the educational programs associated with them, as well as all other program overhead expenses, and this forms the basis for the evaluation that I have performed. Specifically, I have evaluated whether the net benefits from all of the other programs are sufficient to support the Company's proposed administrative budget.

The results of this evaluation are provided on page 6 of PHR-3. As shown there, the programs collectively provide net Total Resource Cost Test benefits of $2,584,538. Since this is well in excess of the Company's proposed five-year overhead budget, there are sufficient benefits from the programs to cover the proposed educational expenditures plus all additional overhead expenditures.

It is also important to recognize that the proposed expenditure level is less than the Commission's 5% guideline from the 442 Order:

The Commission believes a 5% level is useful as a guideline for total energy efficiency portfolio funding devoted to educational programs. The Commission values educational programs, however, and notes this is merely a rough guideline, not a bright-line rule. Utilities may present justifications for higher budget allocations. The Commission will be particularly flexible with smaller utilities or in situations where a larger budget percentage would meet Commission objectives. 442 Order, ¶ 32.

Page 6 of PHR-3 also shows that the programs collectively pass the Participant Test (benefit/cost ratio of 1.48), the Total Resource Cost Test (1.17), and the Program Administrator Test (2.45). While the Rate Impact Measure Test indicates that program costs will place upward pressure on rates, the programs should reduce customer bills since the costs incurred by the utility to implement the program are less than the gas costs that are avoided by the program. Since the programs are already cost-effective from a Total Resource Cost Test perspective, it is unnecessary to subject them to further evaluation to conclude that they are also cost-effective from a Societal Test perspective.

Q. Mr. Raab, could you please summarize your analysis of the energy conservation programs in the Company's proposed programs as to their cost-effectiveness under the tests you have conducted concerning those programs?

A. Based on my analysis, the Company's proposed programs, individually and collectively, will avoid energy costs or consumption the customer would otherwise have incurred. In addition, based on the benefit/cost tests prescribed by the Commission, the programs also will be cost-effective programs to accomplish the conservation and efficiency objectives contemplated in the 442 Order.

VII. THE COMPANY'S ENERGY CONSERVATION RIDER (ECR)

Q. PLEASE DESCRIBE THE ENERGY CONSERVATION RIDER.

A. As described in greater detail in the testimony of Company witness David Dittemore, the Energy Conservation Surcharge, or ECS, is a billing adjustment factor computed on an annual basis that creates a credit or a charge to be applied to the monthly Service Charge on the Company's Residential Sales Service (RS) and General Sales Service (GS) rate schedules. A separate surcharge will be calculated for each of those rate classes. As the name suggests, the mechanism is designed to recover from customers the costs that the Company incurs to implement the proposed set of conservation programs. Therefore, this rider will collect direct program costs, program administration costs and lost revenues, I including those lost as a result of program implementation. The Company is proposing to recover these lost revenues through a revenue normalization adjustment (RNA) mechanism within the ECS. The RNA component of the ECS will adjust for the difference in revenues received in a particular year and the Commission-authorized level of revenues. The mechanism is designed to stabilize the level of revenues that are provided by customers to the Company. The revenue level will be determined based on the revenue requirement established in the Company's last base rate proceeding, Docket No. 06-KGSG-1209-RTS.

Q. What level of lost revenues is implied by the above program assumptions?

A. This information is provided in Exhibit PHR-4. As shown there, the Company anticipates lost margins of $1,572,758 for each year that these programs are offered. Over time, this level of lost margins would undoubtedly require the Company to incur a revenue shortfall without any reasonable means to collect the shortfall except through a rate case filing. Rate case filings are an inefficient means to collect this revenue shortfall and do not fundamentally solve the issue on a going forward basis because of the prospective implementation of rate case outcomes.

Q. Has the Commission provided guidance that KGS considered in the development of its RNA mechanism?

A. Yes. In its Order in Docket No. 08-GIMX-441-GIV, the Commission discussed alternative revenue decoupling mechanisms and the features that it believed such mechanisms should include. Initially, the Commission expressed a preference for "full decoupling:" [O]f the various types of throughput mechanisms the Commission believes full decoupling is the best method." 441 Order at 62. The Commission also indicated that it was unlikely to consider "a decoupling proposal without a demonstrated connection to an energy efficiency program application or to existing programs." 441 Order at 70. Accordingly, the KGS RNA proposal is for full decoupling in connection with its proposed energy efficiency program.

In the 441 Order, the Commission also specified certain elements that should be included with utility filings for approval of revenue decoupling mechanisms such as the Company's proposed RNA. These include: (1) a discussion of risk and how it is affected by the proposed RNA, (2) a safety mechanism to address rate volatility, (3) a mechanism to mitigate high carrying charges for deferred accounts, and (4) a quantification of the financial impact of the proposed conservation program with and without the RNA. These topics will be addressed below.

Q. Before doing so, could you please discuss revenue decoupling in general?

A. Yes. A recent Briefing Paper by Ken Costello of the National Regulatory Research Institute entitled "Revenue Decoupling for Natural Gas Utilities" presents a comprehensive evaluation of revenue decoupling mechanisms. A significant number of arguments for the adoption of an RNA, which I will not repeat in my testimony, are delineated in that paper.

At least twelve states have approved such mechanisms: California, Georgia, Indiana, Maryland, Missouri, New Jersey, North Carolina, North Dakota, Ohio, Oregon, Utah and Washington and twelve other states are actively considering such proposals: Arkansas, Arizona, Colorado, the District of Columbia, Illinois, Michigan, Minnesota, Kansas, New Mexico, New York, Tennessee and Virginia. One of the oldest of these mechanisms (that of Baltimore Gas and Electric, or BGE, in Maryland) has been operating for over a decade (since 1998). Perhaps most importantly, certain of these mechanisms have also been through at least one regulatory review cycle and been re-approved. Specifically, the BGE RNA was re-approved in Maryland in 2005 as a result of the Company's base rate case proceeding in Case No. 9036. The Northwest

Natural Gas (NW Natural) RNA was initially approved in 2002 as a mechanism to "defer and then amortize 90 percent of the margin differentials for the residential and commercial customer groups." After a mandatory review three years later in 2005, the Oregon PUC approved a four-year extension of the mechanism, and provided for 100 percent of the deferral and amortization of the margin differentials.

Furthermore, both the Maryland and Oregon Commissions were so pleased with the results of the RNAs that they also approved similar mechanisms for other natural gas distribution companies under their jurisdiction. The Maryland Commission approved an RNA for Washington Gas in 2005, for Chesapeake Utilities Corporation in 2006 and for PEPCO, an electric utility, in 2008. The Oregon Commission enacted decoupling for Cascade Natural Gas in 2006.

Q. Is there other evidence to suggest that past efforts at revenue decoupling have been successful?

A. Yes. In October 2006, Martin Kushler, Dan York and Patti Witte of the American Council for an Energy-Efficient Economy (ACEEE) published "Aligning Utility Interests With Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives." This report provides a state-by-state summary of revenue decoupling activities. With respect to the Oregon RNA mechanism referenced above, the report notes that:

"Oregon is the pre-eminent available exhibit for evaluating recent decoupling policy, because it is the only jurisdiction in the U.S. that has had a current decoupling policy in place long enough to have conducted ex-post assessment of effectiveness." Aligning Utility Interests With Energy Efficiency Objectives, page 56.

The report goes on to state that:

"NW Natural's experience with decoupling was independently evaluated in 2005. This evaluation is the only such evaluation that we found of a modern (post-2000) experience with decoupling. Consequently, <u>the results described in this evaluation are especially noteworthy</u>." Aligning Utility Interests With Energy Efficiency Objectives, emphasis added, page 57.

Q. And what were the findings of this "especially noteworthy" evaluation?

A. This evaluation found the following:

1. The RNA was "an effective means of reducing NW Natural's disincentive to promote energy efficiency."
2. The RNA "improved NW Natural's ability to recover fixed costs."
3. The RNA did not result in a "shift of economic risk from NW Natural to its customers." Instead, "most of the risk reductions experienced by the utility were eliminated rather than shifted to customers."
4. The RNA did not affect "NW Natural's incentives to provide high quality customer service."
5. The impact on customers of the resulting [RNA] adjustments was relatively modest.

Q. Have these mechanisms been endorsed by regulatory authorities?

A. In addition to the regulatory authorities cited above that have specifically endorsed mechanisms such as the Company's proposed RNA, NARUC endorsed these mechanisms at its 2005 Fall Meeting in Palm Springs, CA:

RESOLVED, That the Board of Directors of NARUC encourages state commissions and other policy makers to consider in their review innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric in Maryland, Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), "fixed-variable" rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), "customer choice options" (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs that may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of growth of natural gas...

Q. This resolution states that RNA-type mechanisms can actually provide LDCs with incentives to promote conservation. How does this occur?

A. Under a traditional, volumetric-based rate, utilities must increase consumption to maintain their financial health. This is particularly true given the persistent declines in usage per customer that I discussed previously. RNA mechanisms such as the one proposed here provide a stronger incentive for utilities to promote conservation because they "decouple" the utility's volumetric sales from its profitability. Thus, the utility is not penalized in the form of decreased earnings for encouraging the efficient use of natural gas.

Q. Have other regulatory authorities recognized this disincentive?

A. I believe that regulators have long recognized this inherent defect in traditional rate designs and have recently begun to adopt regulatory policies to overcome this disincentive. For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. (See Oregon PUC Order No. 02-634, Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization, September 12, 2003).

In California, natural gas distribution utilities have a long tradition of investment in energy efficiency services, including those targeting low income households, and the Commission is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of their industry restructuring experiment.

Also consistent with the notion that traditional ratemaking discourages natural gas utilities from promoting conservation, Southwest Gas Company received an order from the California PUC in March 2004 that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

Q. Do other industry groups recognize this disincentive?

A. Yes. In July 2004, the American Gas Association and the Natural Resources Defense Council issued a joint statement to the National Association of Regulatory Commissioners that was intended to identify "ways to promote both economic and environmental progress by removing barriers to natural gas distribution Company's investments in urgently needed and cost-effective resources and infrastructure," and encourage regulators to consider "innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders." The primary problem that the Joint Statement identifies is what it refers to as the "Energy Efficiency Problem," under which utilities are "penalized" for aggressively promoting energy efficiency. According to the Statement, the penalty results from the same mismatch of (fixed) costs and (volumetric) rates that I have identified earlier for KGS:

The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what consumers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return.

Q. Are there other reasons that argue in favor of the implementation of RNA mechanisms?

A. Yes. In addition to the benefits cited above, RNA mechanisms can also: (a) provide consumers with a more accurate price signal of the consequences of their consumption decisions, and (b) result in more stable rates for consumers and more stable revenues for the Company.

Q. How can a rate structure that includes an RNA provide customers with a more accurate price signal than a rate structure that does not incorporate an RNA?

A. Because the vast majority of an LDC's distribution-related costs are fixed and a majority of its revenues are collected through volumetric charges, an LDC does not collect the Commission-authorized level of revenues when sales decrease to levels below test year levels. With an RNA in place, this under-collection is remedied and customers receive a more accurate price signal about the value of saved Mcfs.

Q. Why is it important that consumers are provided with a more accurate price signal of the consequences of their consumption decisions?

A. A well designed rate structure providing reliable cost information in the rates makes consumption tradeoff decisions between the cost of energy and other goods economically efficient.

Q. How does an RNA mechanism provide more stable and predictable rates for KGS customers?

A. In today's economic environment, two factors drive the need for rate relief for natural gas LDCs: cost increases and volume reductions. Under traditional regulation, when new rates are put into place, customers face the full impact of both of these factors. Under an

RNA, these impacts are mitigated because the impacts of volume reductions on rate levels are systematically and gradually phased in. The resulting rates are more stable over time and adjusted on a more economically efficient basis through an RNA mechanism, rather than a rate case.

Q. Given this general discussion, please focus once again on the Commission's elements that should be included with utility filings for approval of revenue decoupling mechanisms. How is KGS' risk affected by the proposed RNA?

A. I simply do not believe that there is a quantifiable relationship between the adoption of an RNA mechanism and the Company's financial risk as a utility.

Q. Why not?

A. A natural gas utility customer has an economic choice of purchasing and installing natural gas equipment or electric equipment to meet their household needs. Once that economic decision is made, the resulting usage is generally stable until the equipment fails and needs replacement. Customers can decide not to choose natural gas service, and this inherent risk is not accounted for anywhere in the Company's RNA proposal. In my opinion, the ability for customers to simply leave the system poses much greater risk to the Company than any short-term volatility in consumption that, in theory, will balance out over time. Consequently, the major risk for a natural gas utility is not alleviated with the implementation of decoupling.

Furthermore, the Joint Statement cited above is instructive in this regard: "Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized by utilities as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lower authorized return. *But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including mechanisms that minimize the volatility of customer bills.*" Joint Statement at 3, emphasis added.

Thus, even if it could be argued that the RNA mechanism would somehow lead to reduced financial risk for KGS, there is broad support by many disparate groups for the notion that to do so is bad public policy.

Q. Then you disagree that adoption of an RNA should be accompanied by a reduction in the Commission's authorized return?

A. An ROE reduction as a result of implementing the RNA would be inappropriate for at least four reasons:

1. Comparable companies employ risk management strategies – Many comparable companies already incorporate measures to mitigate risk. Therefore, to not allow some sort of risk mitigation will penalize KGS by not affording them risk protection, but awarding them an ROE that assumes they already have it.

2. Inability to measure precisely enough – The required ROE cannot be measured precisely enough to reflect in the impact of ROE reduction from these measures (i.e., the ROE band is generally wider than any reduction to ROE ever suggested by any party. Therefore, the ROE impact of any reduced risk may already be reflected in the allowed ROE.)

3. Inability to quantify – No one has been able to develop a defensible measure of the impact that such a mechanism has on ROE. And, it could be positive (less revenue

risk) or negative (the uncertainty associated with a rate increase). Therefore, any ROE adjustment is arbitrary and could in fact be exactly the opposite of what should be done.

4. Bad Public Policy - Customers will see benefits from the RNA mechanism as discussed above (more stable bills through time, lower costs, a more financially sound utility and greater incentives to promote energy efficiency). To "punish" the utility for bringing these benefits to consumers seems ill advised.

Q. What are the Commission's concerns with respect to rate volatility caused by such mechanisms?

A. This concern is expressed at paragraph 65 of the 441 Order:

One of the dangers of decoupling is that rates for utility customers can be more volatile between rate cases since it is the utility that has the "price guarantee" and not the customer. Staff Report, 12. Annual caps are a remedy for this potential problem. Staff Report, 12. The Commission will require any decoupling proposal to include such a safety mechanism. 441 Order at 65.

Q. Does the Company's proposal include a safety mechanism to address rate volatility?

A. Yes. The Company under its proposal is constrained from collecting more class revenue than it would have been able to collect in its last rate case. Because customer bills will not be able to be adjusted to a higher revenue level than was authorized by the Commission in Docket No. 06-KGSG-1209-RTS, sufficient safeguards are in place to protect all consumers against unnecessarily high charges.

Q. What are the Commission's concerns with respect to high carrying charges for deferred accounts used by such mechanisms?

A. The Commission states at paragraph 66 of the 441 Order that:

Another potential danger is that if carrying charges are applied to balancing accounts, these accounts can rapidly grow. Staff Report, 12. The Commission will require decoupling proposals to address this issue, as well. As has been noted, the Commission expects utilities to work with Staff to minimize issues, streamline the approval process, and minimize unnecessary costs and delay. Dealing with potential pitfalls is particularly important in light of the uncertain economic times ahead. 441 Order at 66.

Q. Does the Company's proposal include a mechanism to mitigate high carrying charges for deferred accounts?

A. Since the Company does not propose to apply carrying charges to either positive or negative RNA balances, this concern is effectively moot.

Q. Please summarize your testimony regarding the Company's RNA proposal.

A. The Company is proposing to implement an RNA in this case because the factors that are causing significant volatility in sales levels are outside of management control and because the Company's currently approved rate structure is "out of synch" with the Company's cost structure. These types of mechanisms are becoming commonplace in the natural gas industry and the financial risk associated with them, if any, is already reflected in the peer group analysis used to set ROE's. The financial inducements that KGS is offering in this filing to encourage energy conservation creates a special circumstance which warrants the Commission approving a true up of revenues through an RNA mechanism. KGS's proposal to implement energy efficiency programs and the RNA mechanism will provide benefits to both customers and the Company. Outside of a rate case, the RNA is the most practical solution to provide the utility with the

Commission's authorized returns. Finally, adoption of the RNA should not be conditioned upon a reduction in authorized ROE in this case for reasons cited above.

Q. Does that complete your testimony at this time?

A. Yes, it does.

VERIFICATION

STATE OF MARYLAND)
) ss.
COUNTY OF MONTGOMERY)

Paul H. Raab, being duly sworn upon his oath, deposes and states that he is a consultant for Kansas Gas Service Company; that he has read and is familiar with the foregoing Direct Testimony filed herewith; and that the statements made therein are true to the best of his knowledge, information, and belief.

NAME

Subscribed and sworn to before me this15th day of December, 2009.

NOTARY PUBLIC

My appointment Expires:

06-15-12

Program	Cost per Participant	Universe	Projected Participation Rate	Projected Participants	Direct Program Cost	Rebate Cost	Projected Total Cost
Seasonal Check Up	$ 30	626,356	1.00%	6,264	187,907	8,769	$ 196,676
Energy Efficiency Rebates							
Water Heater							
Tank	$ 50	41,757	1.50%	626	31,318	877	$ 32,195
Tankless	$ 300	41,757	3.00%	1,253	375,814	1,754	$ 377,567
Space Heating							
78% to 92% Efficient	$ 200	31,318	2.50%	783	156,589	1,096	$ 157,685
78% to 95%+ Efficient	$ 600	31,318	2.50%	783	469,767	1,096	$ 470,863
Natural Gas Direct Use Program	$ 1,500	-	-	100	150,000	140	$ 150,140
Energy Star New Homes Program	$ 250	-	-	100	25,000	140	$ 25,140
Commercial Custom Program	$ 10,000	-	-	25	250,000	0	$ 250,000
Subtotal Energy Efficiency					$ 1,646,394	$ 13,872	$ 1,660,266
Program Administration							$ 151,656
Education							$ 47,000
Marketing							$ 219,077
Total							$ 2,077,999

Summary of Program Assumptions

	Seasonal Check-Up Program	Energy Efficiency Incentives - Tank Water Heater Program	Energy Efficiency Incentives - Tankless Water Heater Program	Energy Efficiency Incentives - 78-92 Furnace Program	Energy Efficiency Incentives - 78-95 Furnace Program	Direct Use Program	Energy Star® Residential New Construction Program	Total All Programs
Program-Specific Evaluation Assumptions:								
Measure Life (Years)	1	15	15	20	20	20	20	-
Cost of Conservation Measure	$ 58	$ 60	$ 450	$ 1,000	$ 1,500	$ 3,500	$ 250	-
Change in Energy Usage/Participant (Mcfs)	-8.9	-1.2	-5.3	-9.5	-11.7	-26.0	-9.4	-
Incremental Participants	6,264	626	1,253	783	783	100	100	9,909
Total Program Mcf Savings	55,854	11,008	99,877	148,741	183,270	52,005	18,726	569,479
Utility Incentive	$ 30	$ 50	$ 300	$ 200	$ 600	$ 1,500	$ 250	-
Tax Credit (to 12/31/10)	$ -	$ -	$ 600	$ -	$ 1,500	$ -	$ -	-
Net-to-Gross Ratio	0.78	0.58	0.58	0.60	0.60	1.00	0.48	-
General Program Evaluation Assumptions:								
Utility Cost of Capital	8.32%	8.32%	8.32%	8.32%	8.32%	8.32%	8.32%	8.32%
General Inflation Rate	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Real Discount Rate	5.1650%	5.1650%	5.1650%	5.1650%	5.1650%	5.1650%	5.1650%	5.1650%
Avoided Cost	COGR	COGR	COGR	COGR	COGR	COGR	COGR	COGR

Seasonal Checkup Program

Summary of Benefit Cost Evaluations

PARTICIPANT TEST

Benefits:	
Bill Reductions, Primary Fuel (AC)	$1,713,638
Incentives	$827,327
Bill Reductions, Alternate Fuel (AC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$0
Total Benefits	$2,540,965
Costs:	
Participant Costs	$1,585,711
Bill Increases, Primary Fuel (AC)	$0
Bill Increases, Alternate Fuel (AC)	$0
Total Costs	$1,585,711
Net Benefit	$955,254
Benefit/Cost Ratio	1.60

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

RATE IMPACT MEASURE TEST

Benefits:	
Avoided Cost, Primary Utility (MC)	$1,767,479
Revenue Gains, Primary Utility (AC)	$0
Avoided Cost, Alternate Fuel (MC)	$0
Revenue Gains, Alternate Utility (AC)	$0
Total Benefits	$1,767,479
Costs:	
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Revenue Loss, Primary Utility (AC)	$1,767,479
Utility Cost	$39,745
Incentives	$851,668
Revenue Loss, Alternate Utility (AC)	$0
Total Costs	$2,658,892
Net Benefit	-$891,413
Benefit/Cost Ratio	0.66

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

TOTAL RESOURCE COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$1,767,479
Avoided Cost, Alternate Fuel (MC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$0
Total Benefits	$1,767,479
Costs:	
Utility Cost	$39,745
Participant Costs	$1,632,364
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Total Costs	$1,672,109
Net Benefit	$95,370
Benefit/Cost Ratio	1.06

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PROGRAM ADMINISTRATOR TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$1,767,479
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$1,767,479
Costs:	
Incentives	$851,668
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$39,745
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$891,413
Net Benefit	$876,066
Benefit/Cost Ratio	1.98

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PRIMARY FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$1,767,479
Total Benefits	$1,767,479
Costs:	
Incentives	$851,668
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$39,745
Total Costs	$891,413
Net Benefit	$876,066
Benefit/Cost Ratio	1.98

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

ALTERNATE FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$0
Costs:	
Incentives	$0
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$0
Net Benefit	$0
Benefit/Cost Ratio	-

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

Water Heat Program

Summary of Benefit Cost Evaluations

PARTICIPANT TEST

Benefits:	
Bill Reductions, Primary Fuel (AC)	$2,244,037
Incentives	$1,792,543
Bill Reductions, Alternate Fuel (AC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$751,627
Total Benefits	$4,788,207
Costs:	
Participant Costs	$2,647,448
Bill Increases, Primary Fuel (AC)	$0
Bill Increases, Alternate Fuel (AC)	$0
Total Costs	$2,647,448
Net Benefit	$2,140,759
Benefit/Cost Ratio	1.81

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

RATE IMPACT MEASURE TEST

Benefits:	
Avoided Cost, Primary Utility (MC)	$2,568,698
Revenue Gains, Primary Utility (AC)	$0
Avoided Cost, Alternate Fuel (MC)	$0
Revenue Gains, Alternate Utility (AC)	$0
Total Benefits	$2,568,698
Costs:	
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Revenue Loss, Primary Utility (AC)	$2,568,698
Utility Cost	$11,923
Incentives	$1,845,281
Revenue Loss, Alternate Utility (AC)	$0
Total Costs	$4,425,902
Net Benefit	-$1,857,205
Benefit/Cost Ratio	0.58

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

TOTAL RESOURCE COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$2,568,698
Avoided Cost, Alternate Fuel (MC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$751,627
Total Benefits	$3,320,325
Costs:	
Utility Cost	$11,923
Participant Costs	$2,725,339
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Total Costs	$2,737,262
Net Benefit	$583,063
Benefit/Cost Ratio	1.21

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PROGRAM ADMINISTRATOR TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$2,568,698
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$2,568,698
Costs:	
Incentives	$1,845,281
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$11,923
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$1,857,205
Net Benefit	$711,493
Benefit/Cost Ratio	1.38

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PRIMARY FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$2,568,698
Total Benefits	$2,568,698
Costs:	
Incentives	$1,845,281
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$11,923
Total Costs	$1,857,205
Net Benefit	$711,493
Benefit/Cost Ratio	1.38

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

ALTERNATE FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$0
Costs:	
Incentives	$0
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$0
Net Benefit	$0
Benefit/Cost Ratio	-

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

Space Heat Program

Summary of Benefit Cost Evaluations

PARTICIPANT TEST

Benefits:	
Bill Reductions, Primary Fuel (AC)	$7,242,926
Incentives	$2,757,758
Bill Reductions, Alternate Fuel (AC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$1,174,418
Total Benefits	$11,175,101
Costs:	
Participant Costs	$8,617,993
Bill Increases, Primary Fuel (AC)	$0
Bill Increases, Alternate Fuel (AC)	$0
Total Costs	$8,617,993
Net Benefit	$2,557,108
Benefit/Cost Ratio	1.30

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

RATE IMPACT MEASURE TEST

Benefits:	
Avoided Cost, Primary Utility (MC)	$8,661,956
Revenue Gains, Primary Utility (AC)	$0
Avoided Cost, Alternate Fuel (MC)	$0
Revenue Gains, Alternate Utility (AC)	$0
Total Benefits	$8,661,956
Costs:	
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Revenue Loss, Primary Utility (AC)	$8,661,956
Utility Cost	$9,936
Incentives	$2,838,894
Revenue Loss, Alternate Utility (AC)	$0
Total Costs	$11,510,786
Net Benefit	-$2,848,831
Benefit/Cost Ratio	0.75

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

TOTAL RESOURCE COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$8,661,956
Avoided Cost, Alternate Fuel (MC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$1,174,418
Total Benefits	$9,836,373
Costs:	
Utility Cost	$9,936
Participant Costs	$8,871,545
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Total Costs	$8,881,481
Net Benefit	$954,892
Benefit/Cost Ratio	1.11

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PROGRAM ADMINISTRATOR TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$8,661,956
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$8,661,956
Costs:	
Incentives	$2,838,894
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$9,936
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$2,848,831
Net Benefit	$5,813,125
Benefit/Cost Ratio	3.04

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PRIMARY FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$8,661,956
	$0
	$0
	$0
	$0
Total Benefits	$8,661,956
Costs:	
Incentives	$2,838,894
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$9,936
Total Costs	$2,848,831
Net Benefit	$5,813,125
Benefit/Cost Ratio	3.04

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

ALTERNATE FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Alternate Fuel Utility (MC)	$0
	$0
	$0
	$0
	$0
Total Benefits	$0
Costs:	
Incentives	$0
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$0
Net Benefit	$0
Benefit/Cost Ratio	-

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

Direct Use Program

Summary of Benefit Cost Evaluations

PARTICIPANT TEST

Benefits:	
Bill Reductions, Primary Fuel (AC)	$1,890,836
Incentives	$660,429
Bill Reductions, Alternate Fuel (AC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$0
Total Benefits	$2,551,265
Costs:	
Participant Costs	$1,541,001
Bill Increases, Primary Fuel (AC)	$0
Bill Increases, Alternate Fuel (AC)	$0
Total Costs	$1,541,001
Net Benefit	$1,010,264
Benefit/Cost Ratio	1.66

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

RATE IMPACT MEASURE TEST

Benefits:	
Avoided Cost, Primary Utility (MC)	$2,261,287
Revenue Gains, Primary Utility (AC)	$0
Avoided Cost, Alternate Fuel (MC)	$0
Revenue Gains, Alternate Utility (AC)	$0
Total Benefits	$2,261,287
Costs:	
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Revenue Loss, Primary Utility (AC)	$2,261,287
Utility Cost	$635
Incentives	$679,860
Revenue Loss, Alternate Utility (AC)	$0
Total Costs	$2,941,781
Net Benefit	-$680,494
Benefit/Cost Ratio	0.77

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

TOTAL RESOURCE COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$2,261,287
Avoided Cost, Alternate Fuel (MC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$0
Total Benefits	$2,261,287
Costs:	
Utility Cost	$635
Participant Costs	$1,586,339
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Total Costs	$1,586,974
Net Benefit	$674,313
Benefit/Cost Ratio	1.42

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PROGRAM ADMINISTRATOR TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$2,261,287
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$2,261,287
Costs:	
Incentives	$679,860
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$635
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$680,494
Net Benefit	$1,580,793
Benefit/Cost Ratio	3.32

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PRIMARY FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$2,261,287
Total Benefits	$2,261,287
Costs:	
Incentives	$679,860
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$635
Total Costs	$680,494
Net Benefit	$1,580,793
Benefit/Cost Ratio	3.32

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

ALTERNATE FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$0
Costs:	
Incentives	$0
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$0
Net Benefit	$0
Benefit/Cost Ratio	-

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

Energy Star® New Homes Program

Summary of Benefit Cost Evaluations

PARTICIPANT TEST

Benefits:	
Bill Reductions, Primary Fuel (AC)	$326,815
Incentives	$110,072
Bill Reductions, Alternate Fuel (AC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$0
Total Benefits	$436,886
Costs:	
Participant Costs	$110,072
Bill Increases, Primary Fuel (AC)	$0
Bill Increases, Alternate Fuel (AC)	$0
Total Costs	$110,072
Net Benefit	$326,815
Benefit/Cost Ratio	3.97

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

RATE IMPACT MEASURE TEST

Benefits:	
Avoided Cost, Primary Utility (MC)	$390,844
Revenue Gains, Primary Utility (AC)	$0
Avoided Cost, Alternate Fuel (MC)	$0
Revenue Gains, Alternate Utility (AC)	$0
Total Benefits	$390,844
Costs:	
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Revenue Loss, Primary Utility (AC)	$390,844
Utility Cost	$635
Incentives	$113,310
Revenue Loss, Alternate Utility (AC)	$0
Total Costs	$504,789
Net Benefit	-$113,944
Benefit/Cost Ratio	0.77

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

TOTAL RESOURCE COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$390,844
Avoided Cost, Alternate Fuel (MC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$0
Total Benefits	$390,844
Costs:	
Utility Cost	$635
Participant Costs	$113,310
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Total Costs	$113,944
Net Benefit	$276,900
Benefit/Cost Ratio	3.43

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PROGRAM ADMINISTRATOR TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$390,844
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$390,844
Costs:	
Incentives	$113,310
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$635
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$113,944
Net Benefit	$276,900
Benefit/Cost Ratio	3.43

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PRIMARY FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$390,844
Total Benefits	$390,844
Costs:	
Incentives	$113,310
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$635
Total Costs	$113,944
Net Benefit	$276,900
Benefit/Cost Ratio	3.43

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

ALTERNATE FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$0
Costs:	
Incentives	$0
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$0
Net Benefit	$0
Benefit/Cost Ratio	-

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

All Step One Programs

Summary of Benefit Cost Evaluations

PARTICIPANT TEST

Benefits:	
Bill Reductions, Primary Fuel (AC)	$13,418,251
Incentives	$6,148,128
Bill Reductions, Alternate Fuel (AC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$1,926,045
Total Benefits	$21,492,424
Costs:	
Participant Costs	$14,502,224
Bill Increases, Primary Fuel (AC)	$0
Bill Increases, Alternate Fuel (AC)	$0
Total Costs	$14,502,224
Net Benefit	$6,990,200
Benefit/Cost Ratio	1.48

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

RATE IMPACT MEASURE TEST

Benefits:	
Avoided Cost, Primary Utility (MC)	$15,650,264
Revenue Gains, Primary Utility (AC)	$0
Avoided Cost, Alternate Fuel (MC)	$0
Revenue Gains, Alternate Utility (AC)	$0
Total Benefits	$15,650,264
Costs:	
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Revenue Loss, Primary Utility (AC)	$15,650,264
Utility Cost	$62,873
Incentives	$6,329,014
Revenue Loss, Alternate Utility (AC)	$0
Total Costs	$22,042,151
Net Benefit	-$6,391,887
Benefit/Cost Ratio	0.71

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

TOTAL RESOURCE COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$15,650,264
Avoided Cost, Alternate Fuel (MC)	$0
Avoided Cost, Alternate Fuel Equipment	$0
Tax Credits	$1,926,045
Total Benefits	$17,576,308
Costs:	
Utility Cost	$62,873
Participant Costs	$14,928,897
Primary Utility Increased Cost (MC)	$0
Alternate Utility Increased Cost (MC)	$0
Total Costs	$14,991,771
Net Benefit	$2,584,538
Benefit/Cost Ratio	1.17

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PROGRAM ADMINISTRATOR TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$15,650,264
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$15,650,264
Costs:	
Incentives	$6,329,014
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$62,873
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$6,391,887
Net Benefit	$9,258,377
Benefit/Cost Ratio	2.45

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

PRIMARY FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Primary Fuel Utility (MC)	$15,650,264
Total Benefits	$15,650,264
Costs:	
Incentives	$6,329,014
Primary Utility Increased Cost (MC)	$0
Primary Utility Cost	$62,873
Total Costs	$6,391,887
Net Benefit	$9,258,377
Benefit/Cost Ratio	2.45

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

ALTERNATE FUEL UTILITY COST TEST

Benefits:	
Avoided Cost, Alternate Fuel Utility (MC)	$0
Total Benefits	$0
Costs:	
Incentives	$0
Alternate Utility Increased Cost (MC)	$0
Alternate Utility Cost	$0
Total Costs	$0
Net Benefit	$0
Benefit/Cost Ratio	-

MC = Calculation Based on Utility Marginal Cost
AC = Calculation Based on Utility Average Cost

Program	Projected Total Cost	Volumes Saved	Lost Margins
Seasonal Check Up	$ 196,676	55,854	$ 118,577
Energy Efficiency Rebates			
Water Heater			
Tank	$ 32,195	11,008	$ 23,370
Tankless	$ 377,567	99,877	$ 212,039
Furnace			
78% to 92% Efficient	$ 157,685	148,741	$ 315,776
78% to 95%+ Efficient	$ 470,863	183,270	$ 389,081
Natural Gas Direct Use Program	$ 150,140	52,005	$ 110,406
Energy Star New Homes Program	$ 25,140	18,726	$ 39,756
Commercial Custom Program	$ 250,000	184,216	$ 363,754
Subtotal Energy Efficiency	**$ 1,660,266**	**753,696**	**$ 1,572,758**