BEFORE THE
TENNESSEE REGULATORY AUTHORITY

PREPARED DIRECT TESTIMONY
OF
DANIEL P. YARDLEY

IN RE:
CHATTANOOGA GAS COMPANY
DOCKET NO. _____________

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

A. My name is Daniel P. Yardley. I am Principal, Yardley & Associates and my business address is 2409 Providence Hills Drive, Matthews, North Carolina 28105.

Q. Please provide a brief outline of your professional and educational background.

A. I have been employed as a consultant to the natural gas industry for the past 20 years. During this period, I have directed or participated in numerous consulting assignments on behalf of local distribution companies ("LDCs"). A number of these assignments involved the development of gas distribution company cost allocation, pricing, service unbundling, revenue decoupling and other tariff analyses. In addition to this work, I have performed interstate pipeline cost of service and rate design analyses, gas supply planning analyses, and financial evaluation analyses. I received a Bachelor of Science Degree in Electrical Engineering from the Massachusetts Institute of Technology in 1988.

Q. Have you previously testified before regulatory bodies concerning rate and regulatory matters?

A. Yes. Although I have not previously testified before the Tennessee Regulatory Authority (the “TRA”), I have testified in approximately 25 proceedings before public utility commissions in other states and before the Federal Energy Regulatory Commission. The subject matters addressed in my testimony in these proceedings included cost of service, cost allocation, rate design, revenue decoupling and capacity planning. A summary of my previous expert testimony is provided as Attachment A.

Q. What is the purpose of your direct testimony?

A. I have been asked by Chattanooga Gas Company ("CGC" or the "Company") to evaluate the manner in which it recovers its base distribution revenue requirements from customers and to propose changes that are consistent with the nature of the services it provides as well as important policy objectives. In this regard, my testimony addresses three important topics. First, I will explain significant industry developments that are guiding important changes in the way regulatory agencies and LDCs are approaching rate design matters. Second, I will support the derivation of specific rates and charges for distribution service that fairly apportion the Company's revenue requirement among customer classes and among various rate elements within each class. The new prices are based on important rate design considerations including the results of an allocated cost of service study ("ACOSS") performed in a consistent manner with other elements of the Company's filing. Third, I am sponsoring a revenue decoupling mechanism that fully aligns the economic interests of CGC and its customers by removing the throughput incentive inherent in its existing rate structure. The proposed revenue decoupling mechanism would be implemented at the time new rates are effective at the conclusion of this proceeding.

Q. Please summarize your findings.

A. The five principal conclusions of my testimony are as follows:

(1) **CGC's existing rate structure provides incentives to increase throughput:** The vast majority of the Company's distribution costs are fixed, while a substantial portion of the Company's margin recoveries are through variable charges based on customer volumes or usage. The linkage between margin recovery and customer usage creates incentives for CGC to grow throughput as a means of improving the opportunity to earn its authorized rate of return.

(2) **Removing the link between throughput and base revenue recoveries will align the Company's rate structure with important National and State public policy goals:** Public Utility Commissions across the United States are placing increasing emphasis on the role that utilities provide in promoting the most efficient use of natural gas and electricity by consumers. The result has been a broad reevaluation of rate design in order to remove the existing throughput incentive that is at odds with efficiency goals. Recent legislation in the State of Tennessee also establishes public policy that requires the Authority to implement rate design approaches that align utility financial interests with those of their customers.

(3) **The proposed Alignment and Usage Adjustment ("AUA") tariff is a necessary and effective means of separating throughput and margins:** The proposed AUA tariff adjusts margin recoveries for usage-driven changes in base revenues per customer through a volumetric adjustment applied in a subsequent period. Removing the existing link between throughput and margins through the implementation of the AUA tariff will allow CGC to more fully support increased energy efficiency and conservation, encouraging customers to reduce their gas bills and lower the environmental impacts of their gas consumption.

(4) **The proposed class-specific revenue requirements reasonably apportion the Company's requested revenue increase among rate classes:** The results of the ACOSS indicate that the class-specific rate of return for Residential, Residential Multi-Family and Small Commercial rate classes is significantly lower than that of the remaining customer groups. By assigning the largest proportion of the revenue increase to these classes, the proposed class-specific revenue targets used to design rates promote fairness. At the same time, existing subsidies are not eliminated altogether in order to balance fairness with rate moderation concerns.

(5) **Existing customer charges for many customers are substantially below cost-based levels:** The customer charges for residential customers are approximately one-half of corresponding customer-related costs. Similarly, customer charges for large commercial and industrial (C&I) customers are also approximately one-half of customer-related costs. The below-cost customer charges result in intra-class subsidies as substantial customer-related costs are recovered through distribution charges. This shifts a disproportionate share of customer-related costs to larger customers within a class. Customer charges for small and medium C&I customers are in-line with corresponding customer-related costs.

Q. Are you sponsoring any exhibits that accompany your prepared direct testimony?

A. Yes. I am sponsoring the following twelve exhibits, which will be explained later in my testimony:

Exhibit DPY-1:	Joint Statements of the American Gas Association and the Natural Resources Defense Council
Exhibit DPY-2:	National Action Plan for Energy Efficiency - Executive Summary Documents
Exhibit DPY-3:	National Association of Regulatory Utility Commissioners Resolutions on Energy Efficiency and Rate Design
Exhibit DPY-4:	Listing of Natural Gas Utilities with Decoupled Base Rates
Exhibit DPY-5:	J.D. Power and Associates Customer Satisfaction Survey Results
Exhibit DPY-6	Earned Rate of Return by Customer Class
Exhibit DPY-7:	Allocated Cost of Service Study
Exhibit DPY-8:	Comparison of Monthly Customer Charges and Costs
Exhibit DPY-9:	Summary of Existing and Proposed Rates and Revenues
Exhibit DPY-10:	Comparison of Class-Specific Rates of Return at Present and Proposed Rates
Exhibit DPY-11:	Derivation of Revenue-per-Customer Benchmark
Exhibit DPY-12:	Illustrative Alignment and Usage Adjustment Calculations
Exhibit DPY-13:	Proposed Alignment and Usage Adjustment Tariff

RATE DESIGN POLICY BACKGROUND

Q. What critical energy issues are facing policy makers today?

A. Growth in energy consumption, particularly in electric markets, is leading to a number of consequences for industry participants, retail customers and the environment.

The growth in electric demands, which is being met largely through clean-burning natural gas fired generation, has contributed to significant changes in the demand-supply balance in U.S. natural gas markets. This, in turn, has led, at times, to significantly higher wholesale market prices and volatility in the supply costs passed on to residential and commercial customers who rely on natural gas for heat, hot water, processing and other end-uses. Although the economic slowdown and potential new gas supply sources have recently lowered natural gas supply prices, the long-term impacts on the supply-demand balance are unknown and prices may return once again to an upward trend.

Heightened environmental concerns and the potential for increased climate risks attributed to various human activities, including energy consumption, are leading to a broad reevaluation of potential means to reduce carbon emissions. A common concern being weighed by policy makers is that the economic consequences of alternative consumption decisions are not fully reflected in prices paid by consumers.

Policy makers are increasingly focused on promoting greater energy efficiency and use of renewable alternatives as the primary facets of new energy policy initiatives. These actions are intended to achieve a number of important benefits including the potential to reduce emissions and long-run energy costs for consumers. However, there are significant technological, market and regulatory challenges to achieving the full potential that policy makers and their constituents are calling for. Among these are the need to radically change the technologies available to consumers and the energy consumption choices they make. Many of these challenges are receiving significant focus throughout the U.S., particularly at the state level.

Q. Has Tennessee taken any steps to respond to these challenges?

A. Yes. The Tennessee State Legislature recently passed legislation that established a ratemaking policy that seeks to align utility incentives with helping customers use energy more efficiently. This legislation was signed into law by Governor Bredesen in June 2009 and brings the importance of rate design to the forefront of Tennessee's energy policy.

Q. How does rate design impact the success of energy efficiency initiatives?

A. From a public policy perspective, rate design is a critically important tool for achieving specific energy policy goals that influence the quality of life for Tennessee's citizens and the State's competitive position. Policy goals affected by rate design include end-use fuel mix, energy efficiency and the resulting environmental and cost impacts of energy consumption. Therefore, the form of a utility's rate structure is an important building block that can contribute to achieving important goals that are presently at the forefront of Tennessee's energy policy agenda.

The nexus between rate design and energy policy objectives is receiving increased attention throughout the U.S. as a result of the prevalence of usage-based rate designs. Usage-based rate designs recover a substantial portion of LDC fixed-cost revenue requirements through variable charges applied to the amount of natural gas consumed by customers. The inherent operating incentives under this form of rate structure are for the LDC to add new customers and to increase the consumption of its existing customers.

While growing natural gas loads through the addition of new customers is consistent with public policy favoring the direct use of clean-burning natural gas, the incentive to increase consumption by current customers is at odds with other public policy goals that favor energy conservation and reducing customers' energy bills. LDCs such as CGC are promoting increased energy efficiency to their customers; however, LDCs also have fiduciary responsibilities to shareholders, regulators and customers alike that prevent them from fully embracing the energy efficiency imperative while they continue to operate under a usage-based rate design. Clearly, the existing rate design outcome is at odds with the objective of reducing consumption under longstanding rate design approaches. Recognition of this substantial concern associated with traditional usage-based rate design is leading to the adoption of innovative rate designs that sever the link between customer consumption and utility revenues.

Q. Do CGC's rates reflect a traditional throughput-based rate design?

A. Yes. The Company's rate structure for the vast majority of customers follows the traditional model. While the rates for all customers include a combination of fixed monthly charges and usage-based or variable charges, typically, at least half of base distribution revenues are derived from the variable charge components and are directly linked to customer usage patterns. Under current rates, firm margins from variable charges accounted for 53% of the Company's total firm margin recoveries. In addition, margin reductions attributable to the decline in average use per customer for residential customers since CGC's base rates were last reset has largely offset the incremental margin created through customer growth.

Q. Were circumstances any different when these types of rate designs were first implemented?

A. While energy efficiency has always been an important element of regulated energy delivery services, the public policy objectives were different in years past, particularly in the natural gas distribution sector. The traditional approach to rate design found in many jurisdictions today reflects historical industry drivers and market conditions. The U.S. natural gas delivery system underwent a period of broad expansion that lasted for decades following World War II. This expansion, enabled by advances in metallurgical technologies and welding techniques, brought the benefits of reliable, affordable and clean-burning natural gas to millions of households and businesses throughout the U.S., including Tennessee. Public policy promoted the expansion of natural gas infrastructure and additional penetration of natural gas into more homes and for additional end-uses. This public policy was reflected in throughput-based rate designs as expanding systems and growing loads allowed an LDC's fixed costs to be spread over greater levels of billing units, lowering average costs to consumers.

The historical period up to and including the 1990s was also characterized by relatively low and stable natural gas commodity prices, which in turn contributed to reasonably stable customer consumption patterns. Although many existing appliances were replaced with more efficient ones, customers continued to add burner-tips over this timeframe as natural gas market share grew in many end-uses, including water heating and heating. The net effect of these factors was a gradual decline in average use per customer of approximately one percent per year from 1980 through 2000.

Traditional usage-based rate designs were appropriate under the circumstances in which they were developed. However, the present imperative to promote increased energy efficiency in order to reduce carbon emissions and lower customer bills calls for a reordering of priorities. One of the outcomes of this process must be the supplanting of traditional rate designs with new approaches that remove the financial incentive for LDCs to promote increased consumption.

Q. Why do you believe that the approach to rate design is so important to achieving public policy objectives that seek to promote increased energy efficiency and reduced greenhouse gas emissions?

A. The utility plays a critically important role in reaching technically achievable reductions in energy consumption. This occurs both with respect to resource planning activities as well as the ability to influence consumer behavior. Yet, the existing rate design approach, which unequivocally incentivizes utility behavior, links its ability to recover authorized revenues to customer sales or throughput. Specifically, eliminating the existing throughput incentive is necessary to unlock the potential for utilities to play a significant role in advancing Tennessee's aggressive energy policy agenda.

Q. What level of interest is there in reexamining traditional approaches to rate design?

A. Rate design is receiving increasing focus and attention for the reasons I noted. A number of agencies, industry and environmental associations, and ad hoc groups, recognize the growing need to move away from traditional throughput-based rate designs and are calling for changes to gas utility rate structures.

The American Gas Association ("AGA") and the Natural Resources Defense Council ("NRDC") issued a joint statement in July 2004 on energy efficiency issues. The joint statement concluded:

> 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. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.

The AGA and NRDC issued a second joint statement in May 2008 further emphasizing these recommendations based on experience gained since the first statement was issued. In May 2008, the AGA and NRDC recommended the following:

> Today, AGA and the NRDC again urge state public utility commissions and officials responsible for publicly-owned natural gas distribution systems to actively support natural gas utilities' energy efficiency proposals that use automatic rate true-ups to ensure a utility's opportunity to recover its authorized fixed costs. We also urge state public utility commissions that have adopted such programs on a trial basis to make longer term commitments.

The full text of the 2004 and 2008 joint AGA/NRDC statements are provided as Exhibit DPY-1.

Q. Please describe any other important developments with respect to evaluation of rate design approaches.

A. Perhaps the most significant and influential activities are associated with the National Action Plan for Energy Efficiency (the "National Action Plan"), an initiative facilitated by the Department of Energy and the Environmental Protection Agency. This effort is of particular importance given the broad array of industry participants that endorsed its recommendations.

The National Action Plan is advancing public policy for two important reasons. The first is that broad input was sought in formulating a comprehensive strategy. The second is that the report's findings were structured to be actionable by stakeholders who are in a position to influence the direction of investment and participation in energy efficiency in order to meet the challenges at hand. The initial report released in July 2006 has been followed up with a series of regional implementation meetings and further studies of critical issues.

One of the five principal recommendations advocated by the National Action Plan is the adoption of policies that modify rate design in a manner that aligns utility incentives with the adoption of energy efficiency measures. The July 2006 plan included the following recommendation:

> Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments. Successful energy efficiency programs would be promoted by aligning utility incentives in a manner that encourages the delivery of energy efficiency as part of a balanced portfolio of supply, demand, and transmission investments. Historically, regulatory policies governing utilities have more commonly compensated utilities for building infrastructure (e.g., power plants, transmission lines, pipelines) and selling energy, while discouraging energy efficiency, even when the energy-saving measures might cost less. Within the existing regulatory processes, utilities, regulators, and stakeholders have a number of opportunities to create the incentives for energy efficiency investments by utilities and customers.

The executive summary of the National Action Plan is attached as Exhibit DPY-2. In addition, a follow-up report issued the following year entitled *Aligning Utility Incentives with Energy Efficiency Investment* further examined the rate and recovery issues associated with energy efficiency including comprehensive changes to utility rate design.

Recently, the National Action Plan stakeholder process also developed a vision statement that establishes the goal of achieving all cost-effective energy efficiency by the year 2025. The vision statement is supported by ten specific implementation goals for states, utilities and other stakeholders to consider adopting. Among the implementation goals are the following:

> Goal Two: Developing Processes to Align Utility and Other Program Administrator Incentives Such That Efficiency and Supply Resources Are on a Level Playing Field
>
> Applicable agencies are encouraged to:

- Explore establishing revenue mechanisms to promote utility and other program administrator indifference to supplying energy savings, as compared to energy generation options.
- Consider how to remove utility and other program administrator disincentives to energy efficiency, such as by removing the utility throughput disincentive and exploring other ratemaking ideas.
- Ensure timely cost recovery in place for parties that administer energy efficiency programs.

The executive summary of the vision statement of the National Action Plan is also provided in Exhibit DPY-2.

Q. What has been the response of regulators to these recommendations?

A. The National Association of Regulatory Utility Commissioners ("NARUC") also places significant importance on addressing the challenges of increasing energy efficiency and reducing greenhouse gas emissions. Over the years, NARUC has sought to promote increased understanding and emphasis on these important policy matters among its constituents.

NARUC closely followed each of the significant initiatives described in my testimony that addressed the need to reexamine rate design. Through resolutions adopted in 2004, 2005, 2006 and 2008, NARUC specifically endorsed and recommended that individual commissions consider the rate design recommendations set forth in the AGA/NRDC joint statements and the National Action Plan. These resolutions are provided as Exhibit DPY-3.

Further, NARUC published the *Natural Gas Toolkit* in September 2008 as a resource to state commissions for considering alternative responses to the high and volatile level of wholesale natural gas prices. Among the options discussed in the report are potential changes to rate design that align the LDC's economic incentives with customers.

Q. Please describe the innovative rate design changes that have been implemented recently in other jurisdictions.

A. A number of specific proposals to address the energy efficiency imperative through innovative rate design approaches have been approved in other jurisdictions. Twenty jurisdictions have approved various mechanisms for more than thirty-nine LDCs that decouple an LDC's base revenue recoveries and customer throughput. Exhibit DPY-4 provides a summary of these programs and notes whether the rate design modification occurred through the adoption of a fixed charge rate design or through a revenue decoupling adjustment mechanism.

The approaches arrived at in these other cases reflect circumstances specific to the corresponding LDCs. Nevertheless, the extensive level of activity over a relatively short time span demonstrates that the reevaluation of traditional gas utility rate design is among the most important matters being addressed today. Moreover, these actions in other states share a common approach that entails a comprehensive mechanism that lays the foundation for achieving the new policy objectives.

Q. Did CGC previously propose to implement a rate design approach that accomplished the objective of separating the link between throughput and base revenue recovery?

A. Yes. In Docket No. 06-00175, the Company's last base rate case proceeding, CGC proposed to implement a decoupled rate design. The parties agreed to defer consideration of the proposal and eventually CGC withdrew its request from that Docket. The Company noted that a subsequent proceeding might provide an opportunity to consider appropriate conservation programs and rate design changes that would facilitate the alignment of CGC's economic interests with those of its customers with respect to natural gas consumption decisions.

During the period since the Company withdrew its previous proposal, the legislature and Governor's office have established a clear policy that requires the TRA to implement rate design approaches that support additional energy efficiency efforts. In addition, addressing growing concerns over the emission of greenhouse gases remains a primary focus of national energy policy initiatives. In view of the ongoing policy emphasis on energy efficiency and conservation matters, many other states have implemented significant changes to rate design for other LDCs that address the throughput incentive associated with usage-based rate designs.

Q. Do you believe this is the appropriate time to implement a comprehensive change in the way that CGC recovers its distribution costs from customers?

A. Yes, I believe that it is very important to implement a rate design approach in this proceeding that is fully aligned with the State's energy policy goals and maximizes the potential benefits for customers, including opportunities to lower natural gas bills. It is simply no longer appropriate to continue a form of rate design that preserves a financial disincentive for CGC to promote all forms and avenues of energy efficiency. The opportunities are too significant and the consequences too material to avoid addressing this issue now. Not only does the TRA have the benefit today of a significant and growing number of examples in other states, implementing this type of change is quite simply easier to accomplish within a base rate case proceeding. For these reasons, I believe that there is not likely to be any better time to address this matter than the present.

Q. What modifications to CGC's rate structure do you recommend in order to achieve these objectives?

A. I am recommending a two-fold approach to modifying the Company's rate design to comport with the objective of removing the throughput incentive. The first element entails the adoption of higher fixed charges that are more reflective of the cost of serving customers and the pricing for other services purchased by consumers. Given the difference between current fixed charges and cost base levels,the increases that I recommend do not yield levels that align CGC's economic interests with those of its customers. Therefore, I am proposing a second element that is the implementation of a revenue decoupling mechanism that normalizes revenues-per-customer to the levels that ultimately will be used to establish base rates. Both aspects of the rate design modifications are important and are explained fully in the remaining sections of my direct testimony.

Q. How will customers benefit from these proposals?

A. The potential benefits for customers are both substantial and compelling. The link between reducing consumption and implementation of decoupled rate design is demonstrated. The benefits to customers of reducing consumption are substantial, particularly with respect to natural gas retail rates, which are primarily comprised of natural gas commodity costs, one hundred percent of which are avoided through lower use. As policies to reduce energy use are pursued across the U.S., the impact on the supply-demand balance will favorably impact prices to consumers as a result of the reduced level of consumption that occurs.

Decoupling is an essential tool to create additional opportunities for customers to lower their carbon footprint and manage their utility bills. These opportunities are highly valued by consumers and lead to greater customer satisfaction. The most widely followed industry measures of customer satisfaction are measured by J.D. Power and

Associates ("J.D. Power"). A recent report issued by J.D. Power specifically notes that overall trends associated with improving customer satisfaction "can be attributed in large part to efforts by gas utility companies to educate customers about energy conservation and environmental issues". The recent upward trend in customer satisfaction has occurred even as natural gas prices were rising prior to the survey. J.D. Power researchers noted that LDCs with revenue decoupling programs tend to have higher customer satisfaction because they communicate more frequently with customers about energy efficiency options. This observation is confirmed by the list of LDCs that are ranked above average by J.D. Power in the report summary provided in Exhibit DPY-5, many of which have decoupled base distribution rates.

CGC DISTRIBUTION RATE DESIGN

Q. Please describe the specific rate design goals for CGC that guided the development of the rate design you are recommending.

A. The rate design approach I am recommending seeks to achieve the following five goals:

(1) Energy Efficiency – Reducing energy consumption through energy efficiency and conservation helps implement important policy objectives that will benefit customers and the environment.

(2) Revenue Stability – Revenue stability means that CGC's base rate revenues are more predictable in view of future uncertainties. As customer use patterns have become less predictable, improved revenue stability through rate design takes on greater importance as a way of mitigating the increased risks associated with such unpredictable consumption patterns.

(3) Fairness – Fairness is accomplished through pricing services based on the underlying cost. Fairness is important in many respects including between the

Company and its customers, across the classes served by CGC, and among customers taking service under a common rate schedule.

(4) **Rate Moderation** – Moderation ensures that customers are not exposed to dramatic price changes that could result in undesirable impacts including cost increases or economic decisions by existing customers to cease taking gas service from CGC.

(5) **Simplicity** – Simplicity means a rate structure that is easy for customers to understand and straightforward to administer.

Q. Please describe the Company's existing rate schedules.

A. CGC's existing rate schedules are segregated by sector, nature of service (firm or interruptible) and by customer size. Firm service is provided under six separate rate schedules; two applicable to residential customers and four applicable to C&I customers. The majority of residential customers take service under Rate Schedule R-1 (Residential General Service), while a limited number of multi-family housing locations are served under Rate Schedule R-4 (Residential Multi-Family Housing Service), which is closed to new customers. Firm C&I customers take service under separate size-based rate schedules. C&I customers with less than 4,000 annual therms taking sales service are served under Rate Schedule C-1 (Small C&I General Service). C&I customers with greater than 4,000 annual therms taking sales service are served under Rate Schedule C-2 (Medium C&I General Service). All C&I customers are eligible to take firm transportation service under Rate Schedule T-3 (Low Volume Transport), which mirrors the base rates for Rate Schedule C-2. Lastly, large industrial customers with greater than 365,000 annual therms are eligible to take service under Rate Schedule F-1 (Large Volume Firm Service).

CGC provides interruptible service pursuant to three rate schedules offer varying degrees of gas supply backup. Standard interruptible service is provided to sales customers pursuant to Rate Schedule I-1 (Interruptible Service) and to transportation customers pursuant to Rate Schedule T-1 (Interruptible Transportation Service). Additionally, customers may opt for partial or full gas supply backup under Rate Schedule T-2 (Interruptible Service with Firm Gas Supply Backup).

Lastly, CGC offers service under additional rate schedules targeted to specific market needs. These include natural gas vehicle service under Rate Schedule V-1 and special service pursuant to Rate Schedule SS-1 (Special Service). SS-1 service is subject to price discounting in order to maintain loads on CGC's system that provide benefits that exceed the marginal costs of providing service.

Q. What rates and charges are incorporated into the Residential Service tariff, Rate Schedule R-1 and the Small C&I Service tariff, Rate Schedule C-1?

A. Approximately 97% of the Company's customers take service under these two rate schedules. The existing rate design for the two services is similar and includes two types of base rate charges that are intended to recover CGC's non-gas revenue requirements. The rates are seasonally differentiated between the winter months of November through April and the summer months of May through October. The residential base rates consist of a $12.00 monthly customer charge during the winter and a $10.00 monthly customer charge during the summer. In addition, a three-block distribution or throughput charge that is $0.25444 for the first 25 therms, $0.17547 for the next 25 therms and $0.15354 per therm for all use above 50 therms in the month during the winter. The corresponding block charges for the summer months are $0.18425, $0.13160 and $0.03948. The declining block structure reflects the under-collection of fixed customer-related costs through the customer charge and is a common rate design approach. In addition, the higher winter period charges reflect the peak demand-related costs of providing distribution service, which are not recovered through demand charges for smaller customers.

Under this rate structure, all residential customers pay a minimum amount to CGC equal to the customer charge, regardless of their monthly usage. The rate design also results in customers paying higher amounts as their consumption increases due to the per-therm distribution charge. The distribution charge is considered a variable charge because all of the associated revenues are linked to customer usage or throughput.

The existing rate design for Rate Schedule C-1 customers is similar to that for residential customers; however, there is a single seasonally-differentiated flat block charge applied to all therms consumed. The monthly customer charge for Rate Schedule C-1 is $29.00 during the winter and $25.00 during the summer. The flat distribution charge is $0.18581 during the winter and $0.14589 during the summer.

Q. Do the remaining rate schedules employ the same type of rate design?

A. The rate structures for larger commercial and industrial customers taking service under CGC's other rate schedules employ a rate structure that includes a fixed monthly demand charge in addition to monthly customer and distribution charges. The demand charge is an important means of recovering fixed peak-related costs from customers in an equitable manner.

Q. Are there separate charges for gas supply?

A. Yes. Sales customers that purchase their gas supply from CGC pay a volumetric Purchased Gas Adjustment ("PGA") rate[1] for gas supply. The PGA rate recovers the costs of purchased gas and upstream pipeline capacity and storage resources necessary to ensure firm delivery to customers throughout the year, and is adjusted periodically to track changes in the delivered cost of gas supply. The PGA rate may be adjusted periodically through filings with the TRA to reflect changes in gas costs or recoveries.

Many C&I customers are transportation-only customers, and pay CGC to deliver gas supply that they have purchased from various third-party gas suppliers ("TPS") that may offer competitive pricing or other terms. The gas supply price for a firm transportation customer is negotiated in a competitive marketplace between the customer and the TPS. Gas supply charges (whether through the PGA or from TPSs) now represent 60-75% of the total natural gas bill for the vast majority of CGC's customers.

Q. Did you perform a traditional ACOSS to support your rate design recommendations?

A. Yes. I believe that an ACOSS provides an important means of assessing the reasonableness of existing prices, and guides the development of price changes. In particular, the ACOSS that I performed for CGC examines all of the Company's common costs reflected in its base rate petition, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. The ACOSS is an important tool because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, thereby establishing class-specific total revenue requirements. The

[1] The PGA rate includes the Gas Cost Adjustment and the Actual Cost Adjustment.

class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are used to guide the apportionment of the revenue requirements among all of CGC's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and commodity components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

Q. Please summarize the results of the ACOSS and how these results guided the development of proposed rates for CGC.

A. The primary results from the ACOSS are the rate of return by class, which guides the allocation of the Company's revenue requirement among classes and the unit customer and demand-related costs, which guide the intra-class rate design. The results of the ACOSS indicate that the rate of return for the Residential (R-1), Residential Multi-Family (R-4) and Small Commercial (C-1) are substantially lower than the system-average rate of return at present rates of 6.69%. The rate of return for all medium and large C&I customers is well above the system-average, indicating that these other classes are subsidizing the prices for Rate Schedule R-1, R-4 and C-1 customers. A summary of the rate of return by class and the required increase in rates to yield the overall rate of return on rate base of 8.28% is provided as Exhibit DPY-6.

With respect to unit costs, the ACOSS indicates that the system-wide average monthly customer cost is $21.42, and the cost generally varies with the size of the customer. The lowest average customer cost of $10.11 per month is indicated for the

Residential Multi-Family (R-4) class; however, this class actually reflects multiple billing units associated with customers served off of a shared service line, which reduces the unit cost. The highest average customer cost of $547.96 is associated with industrial customers taking service under Rate Schedules F-1 and T-2. The significant variance between monthly customer-related costs and customer charges is taken into consideration when designing the intra-class rate design.

A full description of the CGC ACOSS as well as the input data and detailed results are presented in Exhibit DPY-7.

Q. What steps did you employ to establish the specific rates you are proposing?

A. First, I determined the class-by-class revenue requirements, which reflect the results of the ACOSS and other rate design principles. Next, I evaluated the existing level of customer charges and proposed increases, where appropriate, to recover a greater proportion of customer-related costs through customer charges. Lastly, I established the appropriate rate structure and rate levels to recover the remaining portion of class revenue requirements.

Q. How did you develop the class-by-class revenue requirements?

A. The revenue requirements by customer class are based upon the rates of return under the present rates as well as the required increase by class to achieve the overall rate of return of 8.28%. In particular, I am proposing to allocate a higher proportion of the revenue increase to the Residential (R-1), Residential Multi-Family (R-4) and Small Commercial (C-1) rate classes. While these three rate classes are the only ones that require any increase to yield the overall rate of return, I am proposing to allocate a portion of the overall increase to other classes also as a means of moderating the increase to residential customers. Specifically, I am proposing to increase the base rates for

Medium Commercial (C-2 and T-3) as well as all industrial customer classes by one-quarter of the average base revenue increase.

This approach yields revenue requirement increases of $1.82 million to the Residential R-1 rate class, $2,740 to the Residential Multi-Family (R-4) rate class and $0.48 million to the Small Commercial (C-1) rate class. The resulting increases to these classes, which in all cases are less than five percent of total class revenues, achieve rate moderation objectives and promote fairness by reducing the existing variances in rate of return among customer classes. Disparate rates of return continue to exist at proposed rates because I am not proposing to lower the overall revenue requirements allocated to the industrial customers served under the F-1 and T-2 rate schedules.

Q. Have you prepared a comparison of existing monthly customer charges and monthly customer costs from the ACOSS?

A. Yes. Exhibit DPY-8 shows the difference between existing monthly customer charges and monthly customer costs for all customers as determined in the ACOSS. This Exhibit shows that each of the Company's customer charges for Residential (R-1) and Industrial (F-1 and T-2) customers are approximately one-half of the associated costs. In contrast to these groups of customers, customer charges for the small and medium C&I customers as well as the multi-family customers are in-line with customer-related costs.

Q. Why is the level of the customer charge important?

A. The level of the customer charge is important for a variety of reasons that relate to the Company's rate design goals I described earlier. First, the customer charge provides customers with an important price signal concerning the impact of connecting to CGC's distribution system. Second, recovering customer-related costs through customer charges contributes to intra-class fairness. To the extent that a portion of customer-related costs are recovered through volumetric charges, intra-class subsidies will be created as larger customers pay a disproportionate share of customer-related costs. Third, the customer charge provides revenue stability for the Company by allowing it to recover fixed costs that are incurred to serve customers through a fixed charge.

Q. Please describe the customer charge you propose for Rate Schedule R-1 service and how you derived this amount.

A. I am proposing to increase the customer charge for residential customers to move the charge closer towards a level that reflects the underlying costs allocated to this class of service. Specifically, I propose to increase the monthly customer charge during the winter months of November through April from $12.00 to $16.00 and during the summer months of May through October from $10.00 to $11.00. Continuing the seasonally-differentiated monthly customer charges is an appropriate means of aligning the need to recover a greater proportion of fixed costs through fixed charges with customer expectations that natural gas service provides a higher value during the peak season. The new customer charges represents an average increase of 23% over the existing levels, but remains well below cost-based levels. Even with the increase to the residential customer charge, approximately 49% of the target revenue requirements of the class are recovered through the delivery charge.

Q. What customer charges do you propose for customers taking service pursuant to other rate schedules.

A. Consistent with the results of the ACOSS, I am not proposing any change to the customer charges applicable to Rate Schedule R-4, C-1, C-2 and T-3 customers. For large industrial customers, I propose to increase the monthly customer charge from

$300.00 to $375.00 per month, an increase of 25%, which is comparable to the percentage increase to the Residential Customer charge.

Q. Please explain the next step in the rate design process.

A. Once the customer charges are established, the next step in the rate design process is to design the remaining rate elements for each class to recover the total target revenue requirements less the revenues recovered through the customer charge. For the residential class, I am proposing to retain the existing declining block rate structure and reflect an equal $0.00627 per therm increase to the distribution charge for each block.

The Residential Multi-Family (R-4) and Small Commercial (C-1) rate classes employ a flat block rate design. Given that there is no change to the proposed customer charges for these two classes, the revenue requirement increase is reflected in rates through a $0.03328 per therm increase to the Residential Multi-Family (R-4) delivery charge and $0.06049 per therm increase to the Small Commercial (C-1) delivery charge.

Q. Are you proposing any base rate changes for CGC's remaining customer classes?

A. Yes. Although I am proposing relatively limited changes to the total revenues from CGC's other customer classes, the proposed rates better align prices with underlying costs of providing service. For the medium C&I customers served under Rate Schedules C-2 and T-3, I am proposing to increase the fixed monthly demand charge from $5.50 to $7.50 per dekatherm. The revenue increase is offset by a reduction in the variable distribution charge of approximately $0.02102 per therm. However, I am also proposing to reduce the number of blocks from four to three by combining the initial two blocks into a single head block of 0 – 5,000 therms. The resulting three-block distribution rate structure is appropriate given the increased recovery of fixed demand-related costs through the demand charge as well as the relatively low share of existing test period throughput represented by the existing second block.

I am proposing similar changes to the demand charges for the larger industrial customers served under Rate Schedules F-1 and T-2. Specifically, I am proposing to increase the fixed monthly demand charge $5.50 to $7.50 per dekatherm. I am proposing a similar increase to the partial standby monthly demand charge from $1.35 to $2.35 per month. The revenue increase that results is offset by a reduction in the distribution charges for these rate schedules of $0.00774 per therm. Unlike for the medium classes, I am not proposing to modify the block structure for the large industrial customers as there is a greater size disparity among customers on these tariffs as evidenced by the more even distribution of therms among the blocks.

Q. Have you prepared a summary of the proposed rate changes?

A. Yes. The existing and proposed rates for each class are compared in Exhibit DPY-9. The revenue change and associated percentage impact is indicated for each rate schedule on this exhibit. In addition, Exhibit DPY-9 provides a proof of revenues demonstrating that the proposed charges yield the requested revenue requirements based on the Company’s forecasts of sales and customers.

Q. Are your proposed rates consistent with the results of the ACOSS?

A. The proposed rates result in rates of return that are closer to the system-average rate of return than would be the case if the requested increase had been spread equally to all classes. The resulting changes in rates of return based on the proposed rate design are provided in Exhibit DPY-10. The prices for residential and small commercial customers continue to be subsidized by remaining classes, but to a lesser degree than under the existing rate design.

CGC REVENUE DECOUPLING

Q. What is the central focus of a revenue-decoupling mechanism?

A. Revenue decoupling is simply a mechanism to normalize total base revenue recovery. In particular, a decoupling mechanism operates to recover the difference between (1) a target level of base-revenues approved by the TRA for a defined period in a base-rate proceeding or other rate-setting proceeding, and (2) the base revenues actually collected from customers for that period. A decoupled rate structure is designed to provide for recovery of the approved base distribution revenue level even when the actual number of units or sales volumes varies from the level relied upon to set base rates.

Q. Given the increased fixed charges you are proposing, do you believe that it is still important to implement revenue decoupling?

A. Yes. The fixed charge increases that I propose are moderate and the resulting rates still recover significant base revenues through usage charges. Therefore, it is still necessary to implement a revenue decoupling mechanism to permit the Company to actively engage in promoting energy efficiency and encouraging customers to reduce their consumption and realize associated savings.

Q. Please describe the general approaches to decoupling revenue recovery from sales or throughput.

A. There are three general means of decoupling base rates, i.e., breaking the link between base revenue recoveries and customer throughput. The first approach is to design rates on the basis of how costs are incurred, which is often referred to as straight-fixed-variable ("SFV") rate design. This approach recovers base distribution revenues through a combination of fixed customer and demand charges. The second approach is the use of a single flat monthly charge applicable to all customers within a particular rate class. The flat charge approach is similar to the rate structures for many cable and telephone services. The third general approach is to retain the underlying usage-based distribution rate structure and rely on an adjustment mechanism to recover or credit to customers the base revenue or margin impact associated with changes in average use per customer. I am recommending the adoption of this third approach for CGC.

Q. Why are you proposing the adjustment mechanism approach for CGC?

A. There are two primary reasons for implementing this approach to revenue decoupling for CGC. The first is that this approach is conceptually consistent with the Company's existing weather normalization adjustment ("WNA"). The primary difference is that the revenue decoupling mechanism would address the margin impacts of non-weather related changes in customer usage. The second reason that I am proposing the adjustment mechanism approach is the fact that the Company's existing fixed charges are well-below cost-based levels. The implementation of revenue decoupling through a tariff adjustment under this situation results in lower bill impacts to individual customers than the primary alternatives. However, this does not preclude adopting one of the alternative approaches to revenue decoupling at some point in the future.

Q. What are the key design parameters of a revenue decoupling mechanism implemented through a tariff adjustment?

A. There are four primary components of this type of revenue-decoupling mechanism that must be specified. The first of these is the basic structure of the decoupling mechanism, e.g. use-per-customer or revenue-per-customer decoupling. The form of decoupling establishes the overall framework for aligning customer and shareholder interests. The second component is the development of the benchmark, which establishes the direct link between future revenue recoveries and the approved revenue targets for rate-design purposes. The third component sets forth the method for comparing future experience to the benchmark in order to determine what revenue adjustment, if any, is needed. The fourth and last component establishes the method for reflecting any revenue adjustment in rates. This last component includes the timing of recovery as well as allocation of the revenue adjustment to customer classes.

Q. Please describe the process you followed to develop the revenue decoupling mechanism you are recommending.

A. The first step in the process entailed an analysis of the range of customers served under each of CGC's rate schedules, associated rates and usage trends over time. The purpose of performing this review was to assess the suitability of the various rate schedules and associated rate structures to revenue decoupling, and to identify potential areas that may require special treatment, such as classes with varying types of customers or the revenue implications of cross-over points between rate schedules. Next, I worked logically through each of the four primary design components of the revenue decoupling mechanism to develop an approach that reflects CGC's facts and circumstances.

Thus, at every stage of this process, I evaluated circumstances specific to CGC, such as the customer composition and use characteristics of its various classes of customers, and the components of the rates applicable to each class. Additionally, I took into account the objectives I discussed earlier and the State's policy emphasis on establishing a rate making approach that aligns utility and customer interests.

Finally, I tested the performance of the mechanism based on potential future changes in customer use characteristics. This is an important last step that ensures the mechanism is workable given CGC-specific data. Performance testing also helps to identify potential unintended outcomes of the mechanism, so that these may be addressed during the design phase and prior to implementation.

Q. Please provide an overview of the revenue decoupling mechanism that you are proposing for CGC.

A. The proposed AUA implements revenue-per-customer decoupling, which is a common method of breaking the link between base revenue recoveries and customer throughput. The operation of the AUA is similar to the WNA, and is simpler to calculate in many respects. A benchmark revenue-per-customer would be calculated for each group of customers covered by the mechanism based on the billing determinants and proposed rates in this proceeding. Each year, the Company would calculate the changes in actual revenue-per-customer compared with the benchmark for each group of customers covered by the mechanism. The revenue impacts attributable to all factors that affect customer volumes, including weather and conservation, would be included in the AUA surcharge or credit for the corresponding group of customers and collected or credited over a subsequent annual period.

Upon implementation of the AUA, the Company's WNA would cease to operate except for the recovery or credit to customers of amounts calculated based on weather variances that occurred prior to the effective date of the AUA. In essence, weather normalization is subsumed within the revenue decoupling mechanism.

Q. Why do you propose to perform the calculations on a per-customer basis?

A. Establishing the benchmark on a per-customer basis is appropriate because it is consistent with a significant cost driver on CGC's system. Specifically, the addition of new customers entails substantial capital expenditures that would not be made without retention of incremental base revenues by CGC. This is accomplished through the per-customer approach.

New customers added to CGC's system since the test period are included together with existing customers in the calculation of actual revenue-per-customer. This approach is based on the premise that new customers are similar to existing customers in the corresponding class, which is reasonable for the classes covered by the proposed AUA. Further, the relatively modest level of expected customer growth indicates that including new customers in the mechanism is unlikely to materially influence the actual revenue-per-customer calculations.

Q. Which customer classes would be included in the AUA Rider?

A. The AUA rider would apply to all customers taking service under the Rate Schedules R-1, C-1, C-2 and T-3. This encompasses all of the Company's mass market firm customers, whose usage characteristics are reasonably homogenous. I am not proposing to apply the AUA rider to customers taking service under Rate Schedules F-1, T-2 or any interruptible rate schedule. I am proposing to exclude these customers in part because of the potential for non-conservation related changes in customer use to lead to AUA adjustments that affect the relative competitive position of customers within these classes. The decision to exclude some of the Company's largest customers from the AUA does not affect the AUA adjustment to any of the customers in the rate schedules to which the AUA would apply.

For purposes of calculating and applying the AUA adjustment, customers would be segregated into two separate groups based on the type of customer. The first is the residential group, comprising all customers taking service under Rate Schedule R-1. The second is the C&I group, comprising all Rate Schedule C-1, C-2 and T-3 customers. The use of separate groups enables the AUA to appropriately reflect both consumption characteristic and distribution rate differences between the two types of customers.

Q. Turning now to the development of the decoupling benchmark, which is the second key design feature of the decoupling mechanism you identified, how does the benchmark affect the operation of the decoupling mechanism?

A. The revenue decoupling benchmark determines the total base revenues allowed for recovery. Therefore, the design of the benchmark is critically important to achieving the goal of separating the link between throughput and revenues. Under the RPC decoupling approach that I am recommending for CGC, allowable revenues are equal to the RPC benchmark multiplied by the corresponding number of customers.

It is important to understand that under revenue decoupling, the allowable booked base revenues actually result from two sources. The first revenue source is through current customer bills that generate revenues through the application of current base rates to customer use. The second revenue source is the revenue decoupling adjustment, which is determined by comparing the revenues recovered from customers to the allowed revenues. The decoupling adjustment is recovered through the decoupling mechanism in a subsequent period after the actual base revenues are known and the revenue decoupling adjustment can be calculated. The calculation assesses any difference between the revenues received through the application of base rates to customer bills and the allowed revenues determined based on the benchmark.

Q. Specifically, how would the benchmark revenue-per-customer be established for each of the two groups?

A. The benchmark RPC is calculated separately for each group by dividing the total base revenue requirements by the total number of customers. The derivation is directly linked to the base rate design used to set new rates in this proceeding and set forth in Exhibit DPY-9. Under this approach, all costs recovered through separate mechanisms, e.g., PGA costs, would be excluded from the benchmark revenue-per-customer. The benchmark would be established on a monthly basis. Derivation of the proposed benchmark is reflected in Exhibit DPY-11.

Q. Why is it important to combine commercial customers taking service under different rate schedules into a single benchmark for the revenue decoupling mechanism?

A. The Company's C&I customers are eligible to take service under a number of different rate schedules depending on the customer size and whether the customer has elected firm sales or firm transportation service. While the benchmark RPC is set in the base rate case in which the decoupling mechanism is designed and implemented, the potential for individual C&I customers to switch rate classes between rate cases must be taken into consideration in order to avoid unintended and undesirable impacts on CGC's allowed revenues when customers potentially shift from one C&I rate classification to another if their annual load patterns change.

Q. Please describe the steps necessary to calculate the future revenue impact of changes in customer consumption patterns.

A. The decoupling revenue adjustment or revenue impact is calculated by computing the difference between the benchmark RPC and the actual RPC for a future period. The actual RPC is calculated directly from the actual booked base distribution revenues on a calendar month basis for the corresponding month of the year. Multiplying the difference in RPC by the actual number of customers will yield the revenue adjustment attributable to differences in RPC for each rate class. As is the case with establishing the benchmark

RPC, all C&I customers are aggregated into a single group. These values are accumulated for all rate classes in order to yield the total decoupling revenue adjustment. Use of actual booked base revenues ensures that the revenue decoupling adjustment properly reflects the actual base revenue impacts of changes in customer use as experienced by the Company. Further, these data are used to prepare CGC's financial statements and is readily reviewable by the TRA.

Q. When would the impact of any changes in customer use be calculated and reflected in rates?

A. The AUA rates would be adjusted once each year based on actual data for the period ending April 30th. CGC would perform the calculations and file them with the BPU by June 1st, concurrent with the Company's annual PGA filing. The revised AUA rates would be effective the following July 1st.

Q. Please illustrate how the calculations will be performed each year.

A. The calculation of the adjustment is performed for each of the two customer groups, i.e. Residential and C&I resulting in a single credit or surcharge applicable to all customers within each grouping. The calculations are straightforward and are illustrated in Exhibit DPY-12. The calculation begins with the monthly booked revenues and customers for the period, which are shown in columns (b) and (c) of the sample calculations. The average revenue per customer for each month is calculated by dividing the total class revenue by the number of customers and is provided in column (d). Next, the monthly values are compared to the benchmark revenue per customer which is shown in column (e) and the per customer difference is provided in column (f). The difference shown in column (f) represents the average revenue impact for all customers in the class for the month. In order to determine the total revenue impact for the class, the monthly differences are multiplied by the actual number of customers and provided in column (g). Interest is applied based on the monthly balance. The AUA charge or credit for the group is simply the ending balance for the accumulated monthly margin adjustments as indicated in column (l) divided by the forecasted sales for the recovery period. In subsequent years, the charge or credit would include any over or under-recovery from the prior recovery period as well.

Exhibit DPY-12 provides two sets of example calculations. The first example illustrates the potential impact of a 1% decline in average use and 3% colder-than-normal weather. A single page shows the calculation for each of the two groups. A second example illustrates the potential impact of a 1% decline in average use and 3% warmer-than-normal weather.

Q. Are the proposed terms and conditions of the decoupling mechanism set forth in proposed tariff sheets?

A. Yes. Proposed tariff language detailing the terms and conditions associated with the proposed revenue decoupling mechanism are set forth in Exhibit DPY-13. The proposed tariff specifies how the RPC benchmarks are established. Further, the proposed tariff also sets forth the basis for determining the annual decoupling revenue adjustments and applying these to customer bills.

Q. Please summarize the benefits of the AUA mechanism you propose.

A. The core objective of the proposed AUA mechanism is to break the link between energy sales or throughput on the one hand and CGC's earnings on the other. Severing this link lays the groundwork for potential changes in the manner in which conservation and energy efficiency opportunities are made available so to customers as to reduce customer costs and increase customer satisfaction.

The Company's proposal is fully consistent with Tennessee and National public policy initiatives. Specifically, the recent legislation approved by the State's legislature and signed into law states the following:

> The General Assembly declares that the policy of this State is that the Tennessee regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, with respect to which the authority has rate making authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provides timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.

Further, this approach retains the existing incentive for CGC to extend natural gas service to additional customers, since customer growth will continue to provide revenue growth. By ensuring that CGC continues to have the same incentive to serve new customers, RPC decoupling promotes economically efficient consumption decisions by continuing to facilitate the direct use of natural gas, which also contributes to environmental benefits. Lastly, the approach relies on simple calculations that incorporate readily available Company accounting data.

Q. Will CGC to offer additional opportunities for its customers to reduce their energy consumption with the implmentation of the proposed AUA?

A. Yes. CGC is proposing to implement a combination of consumer education initiatives and additional energy conservation components for residential and commercial customers. The package of programs, denoted energySMART, offers residential customers programs for programmable thermostats and low-income home weatherization. EnergySMART also encompasses customer conservation programs that focus on encouraging customers to install high-efficiency natural gas water heaters (both tank and tankless) and furnaces. The goal of the Company's proposed programs is to create a philosophical and behavioral change in its customers that is sustainable.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Attachment A

Prior Testimony of
Daniel P. Yardley

Jurisdiction	Sponsor	Year	Topics	Docket
Florida	Peoples Gas System	2008	Cost Allocation and Rate Design	Docket No. 080318-GU
Federal Energy Regulatory Commission	Northern Distributor Group	1992	Cost of Service and Cost Allocation	RP92-1
	Northern Distributor Group	1995	Cost of Service and Rate Design	RP95-185
	Atlanta Gas Light, et al.	2001	Storage Cost Allocation	RP01-245
	Bay State Gas and Northern Utilities	2002	Rate Design	RP02-13
New Hampshire	Northern Utilities	2005	Jurisdictional Gas Cost Allocation	DG05-080
Massachusetts	Bay State Gas	1998	Capacity Assignment	D.T.E. 98-32
	Bay State Gas	2001	Contract Approval	D.T.E. 00-99
	Bay State Gas	2006	Declining Use Rate Adjustment	D.T.E. 06-77
	Bay State Gas	2007	Declining Use Rate Adjustment	D.P.U. 07-89
	Bay State Gas	2009	Revenue Decoupling	D.P.U. 09-30
New Jersey	New Jersey Natural Gas	1999	Rate Unbundling	Docket No. GO99030123
	Elizabethtown Gas, *et al.*	1999	Customer Account Services	Docket No. EX99090676
	Elizabethtown Gas	2002	Cost Allocation and Rate Design	Docket No. GR02040245
	South Jersey Gas Company	2003	Cost Allocation and Rate Design	Docket No. GR03080683
	South Jersey Gas Company	2004	Capacity Charge	Docket No. GR04060400
	New Jersey Natural Gas	2005	Revenue Decoupling	Docket No. GR0512020
	South Jersey Gas Company	2005	Revenue Decoupling	Docket No. GR0512019
	South Jersey Gas Company	2007	Annual Decoupling Adjustment	Docket No. GR07060354
	New Jersey Natural Gas	2007	Cost Allocation and Rate Design	Docket No. GR07110889
	South Jersey Gas Company	2008	Annual Decoupling Adjustment	Docket No. GR08050367
	Elizabethtown Gas	2009	Revenue Decoupling, Cost Allocation and Rate Design	Docket No. GR09030195
	South Jersey Gas Company	2009	Annual Decoupling Adjustment	Docket No. GR09060340
Rhode Island	Providence Gas Company	1996	Cost Allocation and Rate Design	Docket No. 2076
Wisconsin	Wisconsin Power and Light	2001	Cost Allocation and Rate Design	Docket No. 6680-UR-111

Joint Statement of the American Gas Association and the Natural Resources Defense Council

Submitted to the National Association of Regulatory Utility Commissioners
July 2004

The American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) recognize the many benefits of using clean-burning natural gas efficiently to provide high quality energy services in all sectors of the economy. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.

NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of 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. Cost-effective opportunities abound to improve the efficiency of buildings and equipment in ways that promote the interests of both individual customers and entire utility systems, while improving environmental quality. For example, when energy supply and delivery systems are under stress, even relatively modest reductions in use can yield significant additional cost savings for all customers by relieving strong upward pressures on short-term prices.

NRDC and AGA also encourage state Commissions to support gas distribution company efforts to manage volatility in energy prices and reduce volatility risks for customers.

The Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency

Local natural gas distribution companies (gas utilities) have very high fixed costs. These fixed costs include the costs of maintaining system safety and reliability throughout the year, staffing customer service telephone lines 24 hours a day and doing what it takes each day of the year to ensure the safe and reliable delivery of natural gas to homes, schools, hospitals, retailers, factories and other customers.

Natural gas utilities typically purchase natural gas on behalf of their customers, and pass through the cost without markup. This means that natural gas utilities do not profit from their acquisitions of natural gas to serve customer needs. The profit (authorized level of rate of return) comes from the rates utilities charge for transporting the natural gas to customers' homes and businesses.

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 certain minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what customers 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. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.[1] We also support performance-based incentives designed to allow utilities to share in independently verified savings associated with cost-effective energy efficiency programs.

Many states' rate structures also place utilities at risk for variations in customer usage based on variations in weather from a normal pattern. This variation can be both positive and negative. Utilities' allowed rate of return is premised on the

[1] For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company (NW Natural) "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* (Sept. 12, 2003). In California, PG&E and other gas utilities have a long tradition of investment in energy efficiency services, including those targeting low-income households, and the PUC 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 an ill-fated industry restructuring experiment. Thus, in March 2004, Southwest Gas Company received an order that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

expectation that weather will be normal, on average, and that customer use of gas will maintain a predictable pattern going forward. Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lowered authorized return. But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills.

Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:

- Customers could save money by using less natural gas;
- Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment.

Natural Gas Consumers, Price Volatility and Resource Portfolio Management. Another area of concern shared by NRDC and AGA is the impact of natural gas price volatility on natural gas consumers, which can be exacerbated by limited diversification of utilities' resource portfolios. Today many of the nation's natural gas utilities find themselves relying on short-term markets for most of their gas needs, with either the encouragement or the acquiescence of their regulators. During much of the 1990's this approach was typically advantageous to consumers, as the market price of natural gas was generally low and did not fluctuate dramatically. As wholesale natural gas prices have risen since 2000 and become more volatile, however, many utilities and commissions are reconsidering this emphasis on short-term market purchases.

While purchasing practices based on short-term supply contracts may offer consumers relatively low-cost natural gas, those consumers are also exposed to more volatile prices and natural gas bills that may rise and fall unpredictably. Public Utility Commissions should favorably consider gas distribution company proposals to manage volatility, such as through hedging, fixed-price contracts of various durations, energy-efficiency improvements in customers' buildings and equipment, and other measures designed to provide greater certainty about both supply adequacy and price stability. Achieving these goals will sometimes require paying a premium over prevailing spot market prices. Like diversified investment portfolios that are designed to mitigate risk, prudent hedging plans should be encouraged as a way to help stabilize gas prices and ensure long-term access to affordable natural gas services.

This Joint Statement also has been reviewed and endorsed by:

ALLIANCE TO SAVE ENERGY
Creating an Energy-Efficient World

Alliance to Save Energy

ACE3

American Council for an Energy-Efficient Economy

Second Joint Statement of the American Gas Association and the Natural Resources Defense Council

May 2008

As the United States confronts the dual challenges of ensuring that Americans have access to affordable, environmentally clean and reliable energy services, while addressing global climate change, the American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) have been working together to accelerate progress toward a clean, energy efficient future. In 2004, AGA and the NRDC issued a joint statement that identified significant regulatory barriers to achieving energy efficiency. AGA and the NRDC encouraged state public utility commissions to consider innovative proposals to promote energy efficiency and conservation in a manner that would benefit both customers and shareholders. The National Association of Regulatory Utility Commissioners encouraged state officials to consider the joint AGA-NRDC recommendations,[1] and the states' initial response has been encouraging.

Today, AGA and the NRDC issue a second joint statement recommending the next steps toward win-win solutions for American consumers and the natural gas utilities that serve them. As we did in 2004, AGA and the NRDC urge state public utility commissions and officials responsible for publicly-owned natural gas distribution systems to consider proposals for implementing cost-effective programs that will increase energy efficiency and reduce the nation's carbon footprint while also balancing shareholder interests.

1. **Removing Disincentives for Utilities to Promote Energy Efficiency and Reduce Greenhouse Gas Emissions, and Uniting to Achieve Increased Savings Through Programs and Standards.**

It is now almost universally recognized that energy efficiency is a large, underutilized, resource that needs to be expanded significantly to reduce consumer costs, improve energy security and reduce greenhouse gas emissions.[2] Numerous studies and extensive experience in many states and countries have shown that improving energy efficiency can be critical to meeting these goals cost-effectively.[3] Consumer surveys

[1] *Resolution on Gas and Electric Energy Efficiency*, sponsored by the NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, and Committee on Energy Resources and the Environment. Adopted by the NARUC Board of Directors, July 14, 2004.

[2] *See, e.g., National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change* (November 2007). http://www.epa.gov/cleanenergy/documents/vision.pdf.

[3] *See, e.g., Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets in the Pacific West*, William Prindle, R. Neal Elliott, Ph.D., P.E., Anna Monis Shipley, American Council for an Energy-Efficient Economy, Report Number E062 (January 2006).

show strong support for coordinated government and utility efforts to increase conservation and energy efficiency.[4]

Yet there are a number of barriers blocking the path forward to increased energy efficiency. One significant barrier has been regulatory policies that unintentionally but effectively discourage gas distribution companies from promoting energy efficiency improvements. AGA and the NRDC pointed this out in our July 2004 joint statement:

> When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction of sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important aspect, traditional rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case.[5]

Since the joint statement was issued in 2004, a significant number of gas distribution utilities have been given permission to adopt ratemaking mechanisms that better align the interests of utility shareholders, their customers and society as a whole. Today 26 natural gas distribution utilities in 13 states have implemented revenue decoupling programs that serve 20 million residential customers. The National Action Plan for Energy Efficiency, which was developed by more than 50 diverse stakeholder groups, included as one of its five recommendations the need to "[m]odify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments."[6] Additionally, Congress passed the Energy Independence and Security Act of 2007, directing each state regulatory authority to consider "separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer."[7] Today, AGA and the NRDC again urge state public utility commissions and officials responsible for publicly-owned natural gas distribution systems to actively support natural gas utilities' energy efficiency proposals that use automatic rate true-ups to ensure a utility's opportunity to recover its authorized fixed costs. We also urge state public utility commissions that have adopted such programs on a trial basis to make longer term commitments. Finally, we will assign high priority to mutual advocacy for improved energy efficiency standards at both state and federal levels, and we will seek urgently needed extensions for federal tax incentives for energy efficiency in buildings and equipment. We will work to ensure that these standards and incentives are designed in ways that avoid inappropriately influencing customers' fuel choices, from both economic and environmental perspectives.

---

[4] *See, e.g.,* M. Kubik, *Consumer Views on Transportation and Energy* (Third Edition), National Renewable Energy Laboratory Technical Report, NREL/TP-620-39047 (Jan. 2006), http://www.osti.gov/bridge.

[5] Joint Statement of the American Gas Association and the Natural Resources Defense Council (July 2004) at 2.

[6] *National Action Plan for Energy Efficiency – A Plan Developed by More Than 50 Leading Organizations in Pursuit of Energy Savings and Environmental Benefits Through Electric and Natural Gas Energy Efficiency* (July 2006) at 2, 7, 8, and 1-10. See also *Aligning Utility Incentives with Investment in Energy Efficiency – A Resource of the National Action Plan for Energy Efficiency* (Nov. 2007) http://www.epa.gov/cleanenergy/documents/incentives.pdf.

[7] *See* Sec. 532(b)(6), *Energy Independence and Security Act of 2007*, P.L. 110-140, Dec. 19, 2007 (In general, "[t]he rates allowed to be charged by a natural gas utility shall align utility incentives with the deployment of cost-effective energy efficiency." "[E]ach State regulatory authority and each non-regulated utility shall consider- (i) separating fixed cost revenue recovery from the volume of transportation or sales service provided to the customer; (ii) providing to utilities incentives for the successful management of energy efficiency programs, such as allowing utilities to retain a portion of the cost-reducing benefits accruing from the programs;").

2. **Developing Performance-Based Incentives for Utilities to Promote Energy Efficiency and Reduced Greenhouse Gas Emissions**

Simply removing utility disincentives to promote energy efficiency may be adequate if the goal is to achieve relatively modest increases in efficiency. But neutrality is no substitute for committed action. If energy efficiency achievements are to reach the level required by the various climate change bills currently being considered by Congress and under review or adoption in states across the country, then utility commissions need to consider linking such achievements to earnings opportunities for the utilities involved.[8] We agree that such opportunities would yield significant increases in energy efficiency and reductions in customer energy consumption. Despite decades of programs designed to promote energy efficiency, it is widely recognized that these programs remain critically underutilized in the nation's energy portfolio.[9] Without carefully considered incentive programs, it seems unlikely that dramatically improved results will occur in the future.

The National Action Plan for Energy Efficiency discusses three different types of utility performance incentive mechanisms: 1) performance target savings, 2) shared savings incentives, and 3) rate of return incentives.[10] Performance target and shared savings mechanisms have been adopted in a number of states, and while differing in structure and operation, typically seek to allow utilities operating at or above a prescribed minimum performance level to capture some portion of net benefits delivered (usually based on energy savings performance).[11] Rate of return incentives might offer a utility an increased return for energy efficiency investments and/or an even higher return on total equity investment for superior performance.[12] While each option has its advantages and disadvantages, we unite in supporting approaches that link energy-efficiency incentives to independently verified net benefits that utilities deliver to customers through either successful administration of cost-effective efficiency programs and other authorized efficiency programs that serve low-income constituencies, or contributions to enactment of cost-effective efficiency standards and tax incentives.[13] AGA and the NRDC encourage state commissions and officials responsible for publicly-owned natural gas distribution systems to adopt energy efficiency incentive

[8] Congress recently encouraged state commissions and unregulated utilities to consider such utility energy efficiency earnings opportunities. *See* Sec. 532(b)(6)(B)(ii), *Energy Independence and Security Act of 2007*, P.L. 110-140, Dec. 19, 2007 ("[E]ach State regulatory authority and each nonregulated utility shall consider- (ii) providing to utilities incentives for the successful management of energy efficiency programs, such as allowing utilities to retain a portion of the cost-reducing benefits accruing from the programs;").

[9] *See, e.g., Aligning Utility Incentives with Investment in Energy Efficiency* at ES-1. For years, groups such as the American Council for an Energy Efficient Economy (ACEEE) have produced numerous studies detailing the dramatic results possible if various energy efficiency measures were adopted. *See, e.g., Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest,* Martin Kushler, Dan York, and Patti Witte (Jan. 2005, ACEEE Report No. U051) (projecting annual Midwest customer cost savings of $2 billion on their natural gas bills by 2010); *Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demands*, R. Neal Elliott, Maggie Eldridge, Anna M. Shipley, John "Skip" Laitner, Steven Nadel, Philip Fairey, Robin Vieira, Jeff Sonne, Alison Silverstein, Bruce Hedman and Ken Darrow (June 2007, ACEEE Report No. E072); *Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets in the Pacific West*, William Prindle, R. Neal Elliott, Anna Monis Shipley (Jan. 2006, ACEEE Report No. E062) (projecting reduced natural gas bills and reduced natural gas consumption if energy efficiency measures were adopted).

[10] *Aligning Utility Incentives with Investment in Energy Efficiency: A Resource of the National Action Plan for Energy Efficiency* (Nov. 2007) at 6-1 (chapter on performance incentives).

[11] *Id.* at 6-3 and 6-4.

[12] *Id.* at 6-11.

[13] Energy efficient incentives do not include rate design mechanisms, such as margin decoupling, which merely reduce utility disincentives. We also agree that consumer education and marketing expenditures are important to the success of many of the energy efficiency programs that this statement references and supports.

mechanisms for natural gas utilities that will reduce consumer costs, reduce greenhouse emissions and align with shareholders' interests.

3. Recognizing the Potential Contributions of Efficient Natural Gas Use in Promoting Reduced Greenhouse Gas Emissions

Among fossil fuels, natural gas applications lead the way in reducing greenhouse gas emissions.[14] Average residential and commercial natural gas consumption is much lower today than in the 1970s, due to improved energy efficiency and conservation. The 64 million households served by natural gas today heat their homes and their water, feed their families and dry their clothing using 1/3 less energy than they did in 1980.

Our paramount joint objective is developing ways to help America extract more economic benefits from the most efficient use of natural gas.[15] There should be continued focus on the environmental benefits of more efficient direct use of natural gas in homes and businesses, which can and should be an important strategy to lower U.S. greenhouse gas emissions.

AGA and the NRDC pledge to continue their efforts to find more ways to use natural gas efficiently, thereby assisting consumers and speeding the transition to a lower carbon future.

This Joint Statement also has been reviewed and endorsed by:

Alliance to Save Energy

ALLIANCE TO
SAVE ENERGY
Creating an Energy-Efficient World

American Council for an Energy Efficient Economy

ACE3

---

[14] When burned in power plants of equivalent thermal efficiency, natural gas emits 45 percent less CO_2 than coal and 30 percent less CO_2 than oil on an energy equivalent basis. This advantage can be further increased by integrating combined heat and power applications with end use efficiency improvements.

[15] Along with natural gas, some natural gas utilities have supplemented their supply needs with renewable sources of supply such as biogas, which can help reduce greenhouse gas emissions.

National Action Plan for Energy Efficiency

A PLAN DEVELOPED BY MORE THAN 50 LEADING ORGANIZATIONS IN PURSUIT OF ENERGY SAVINGS AND ENVIRONMENTAL BENEFITS THROUGH ELECTRIC AND NATURAL GAS ENERGY EFFICIENCY

JULY 2006

The goal is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations.

Improving energy efficiency in our homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change.

The U.S. Department of Energy and U.S. Environmental Protection Agency facilitate the work of the Leadership Group and the National Action Plan for Energy Efficiency.

Executive Summary

This National Action Plan for Energy Efficiency (Action Plan) presents policy recommendations for creating a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations. Such a commitment could save Americans many billions of dollars on energy bills over the next 10 to 15 years, contribute to energy security, and improve our environment. The Action Plan was developed by more than 50 leading organizations representing key stakeholder perspectives. These organizations pledge to take specific actions to make the Action Plan a reality.

A National Action Plan for Energy Efficiency

We currently face a set of serious challenges with regard to the U.S. energy system. Energy demand continues to grow despite historically high energy prices and mounting concerns over energy security and independence as well as air pollution and global climate change. The decisions we make now regarding our energy supply and demand can either help us deal with these challenges more effectively or complicate our ability to secure a more stable, economical energy future.

Improving the energy efficiency[1] of our homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the country—is one of the most constructive, cost-effective ways to address these challenges.[2] Increased investment in energy efficiency in our homes, buildings, and industries can lower energy bills, reduce demand for fossil fuels, help stabilize energy prices, enhance electric and natural gas system reliability, and help reduce air pollutants and greenhouse gases.

Despite these benefits and the success of energy efficiency programs in some regions of the country, energy efficiency remains critically underutilized in the nation's energy portfolio.[3] Now we simultaneously face the challenges of high prices, the need for large investments in new energy infrastructure, environmental concerns, and security issues. It is time to take advantage of more than two decades of experience with successful energy efficiency programs, broaden and expand these efforts, and capture the savings that energy efficiency offers. Much more can be achieved in concert with ongoing efforts to advance building codes and appliance standards, provide tax incentives for efficient products and buildings, and promote savings opportunities through programs such as ENERGY STAR®. Efficiency of new buildings and those already in place are both important. Many homeowners, businesses, and others in buildings and facilities already standing today—which will represent the vast majority of the nation's buildings and facilities for years to come—can realize significant savings from proven energy efficiency programs.

Bringing more energy efficiency into the nation's energy mix to slow demand growth in a wise, cost-effective manner—one that balances energy efficiency with new generation and supply options—will take concerted efforts by all energy market participants: customers, utilities, regulators, states, consumer advocates, energy service companies (ESCOs), and others. It will require education on the opportunities, review of existing policies, identification of barriers and their solutions, assessment of new technologies, and modification and adoption of policies, as appropriate. Utilities,[4] regulators, and partner organizations need to improve customer access to energy efficiency programs to help them control their own energy costs, provide the funding necessary to deliver these programs, and examine policies governing energy companies to ensure that these policies facilitate—not impede—cost-effective programs for energy efficiency. Historically, the regulatory structure has rewarded utilities for building infrastructure (e.g., power plants, transmission lines, pipelines) and selling energy, while discouraging energy efficiency, even when the energy-saving measures cost less than constructing new infrastructure.[5] And, it has been difficult to establish the funding necessary to capture the potential benefits that cost-effective energy efficiency offers.

This National Action Plan for Energy Efficiency is a call to action to bring diverse stakeholders together at the national, regional, state, or utility level, as appropriate, and foster the discussions, decision-making, and commitments necessary to take investment in energy efficiency to a new level. The overall goal is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations.

The Action Plan was developed by a Leadership Group composed of more than 50 leading organizations representing diverse stakeholder perspectives. Based upon the policies, practices, and efforts of many organizations across the country, the Leadership Group offers five recommendations as ways to overcome many of the barriers that have limited greater investment in programs to deliver energy efficiency to customers of electric and gas utilities (Figure ES-1). These recommendations may be pursued through a number of different options, depending upon state and utility circumstances.

As part of the Action Plan, leading organizations are committing to aggressively pursue energy efficiency opportunities in their organizations and assist others who want to increase the use of energy efficiency in their regions. Because greater investment in energy efficiency cannot happen based on the work of one individual or organization alone, the Action Plan is a commitment to bring the appropriate stakeholders together—including utilities, state policy-makers, consumers, consumer advocates, businesses, ESCOs, and others—to be part of a collaborative effort to take energy efficiency to a new level. As energy experts, utilities may be in a unique position to play a leading role.

The reasons behind the National Action Plan for Energy Efficiency, the process for developing the Action Plan, and the final recommendations are summarized in greater detail as follows.

Figure ES-1. National Action Plan for Energy Efficiency Recommendations

- **Recognize energy efficiency as a high-priority energy resource.**
- **Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.**
- **Broadly communicate the benefits of and opportunities for energy efficiency.**
- **Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective**.
- **Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.**

The United States Faces Large and Complex Energy Challenges

Our expanding economy, growing population, and rising standard of living all depend on energy services. Current projections anticipate U.S. energy demands to increase by more than one-third by 2030, with electricity demand alone rising by more than 40 percent (EIA, 2006). At work and at home, we continue to rely on more and more energy-consuming devices. At the same time, the country has entered a period of higher energy costs and limited supplies of natural gas, heating oil, and other fuels. These issues present many challenges:

Growing energy demand stresses current systems, drives up energy costs, and requires new investments. Events such as the Northeast electricity blackout of August 2003 and Hurricanes Katrina and Rita in 2005 increased focus on energy reliability and its economic and human impacts. Transmission and pipeline systems are becoming overburdened in places. Overburdened systems limit the availability of low-cost electricity and fossil fuels, raise energy prices in or near congested areas, and potentially compromise energy system reliability. High fuel prices also contribute to higher electricity prices. In addition, our demand for natural gas to heat our homes, for industrial and business use, and for power generation is straining the available gas supply in North America and putting upward pressure on natural gas prices. Addressing these issues will require billions of dollars in investments in energy efficiency, new power plants, gas rigs, transmission lines, pipelines, and other infrastructure, notwithstanding the difficulty of building new energy infrastructure in dense urban and suburban areas. In the absence of investments in new or expanded capacity, existing facilities are being stretched to the point where system reliability is steadily eroding, and the ability to import lower cost energy into high-growth load areas is inhibited, potentially limiting economic expansion.

High fuel prices increase financial burdens on households and businesses and slow our economy. Many household budgets are being strained by higher energy costs, leaving less money available for other household purchases and needs. This burden is particularly harmful for low-income households. Higher energy bills for industry can reduce the nation's economic competitiveness and place U.S. jobs at risk.

Growing energy demand challenges attainment of clean air and other public health and environmental goals. Energy demand continues to grow at the same time that national and state regulations are being implemented to limit the emission of air pollutants, such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury, to protect public health and the environment. In addition, emissions of greenhouse gases continue to increase.

Uncertainties in future prices and regulations raise questions about new investments. New infrastructure is being planned in the face of uncertainties about future energy prices. For example, high natural gas prices and uncertainty about greenhouse gas and other environmental regulations, impede investment decisions on new energy supply options.

Our energy system is vulnerable to disruptions in energy supply and delivery. Natural disasters such as the hurricanes of 2005 exposed the vulnerability of the U.S. energy system to major disruptions, which have significant impacts on energy prices and service reliability. In response, national security concerns suggest that we should use fossil fuel energy more efficiently, increase supply diversity, and decrease the vulnerability of domestic infrastructure to natural disasters.

Energy Efficiency Can Be a Beneficial Resource in Our Energy Systems

Greater investment in energy efficiency can help us tackle these challenges. Energy efficiency is already a key component in the nation's energy resource mix in many parts of the country. Utilities, states, and others across the United States have decades of experience in delivering energy efficiency to their customers. These programs can provide valuable models, upon which more states,

Benefits of Energy Efficiency

Lower energy bills, greater customer control, and greater customer satisfaction. Well-designed energy efficiency programs can provide opportunities for customers of all types to adopt energy savings measures that can improve their comfort and level of service, while reducing their energy bills.[6] These programs can help customers make sound energy use decisions, increase control over their energy bills, and empower them to manage their energy usage. Customers are experiencing savings of 5, 10, 20, or 30 percent, depending upon the customer, program, and average bill. Offering these programs can also lead to greater customer satisfaction with the service provider.

Lower cost than supplying new generation only from new power plants. In some states, well-designed energy efficiency programs are saving energy at an average cost of about one-half of the typical cost of new power sources and about one-third of the cost of natural gas supply (EIA, 2006).[7] When integrated into a long-term energy resource plan, energy efficiency programs could help defer investments in new plants and lower the total cost of delivering electricity.

Modular and quick to deploy. Energy efficiency programs can be ramped up over a period of one to three years to deliver sizable savings. These programs can also be targeted to congested areas with high prices to bring relief where it might be difficult to deliver new supply in the near term.

Significant energy savings. Well-designed energy efficiency programs are delivering annual energy savings on the order of 1 percent of electricity and natural gas sales.[8] These programs are helping to offset 20 to 50 percent of expected growth in energy demand in some areas without compromising the end users' activities and economic well-being (Nadel et al., 2004; EIA, 2006).

Environmental benefits. While reducing customers' energy bills, cost-effective energy efficiency offers environmental benefits related to reduced demand such as lower air pollution, reduced greenhouse gas emissions, lower water use, and less environmental damage from fossil fuel extraction. Energy efficiency can be an attractive option for utilities in advance of requirements to reduce greenhouse gas emissions.

Economic development. Greater investment in energy efficiency helps build jobs and improve state economies. Energy efficiency users often redirect their bill savings toward other activities that increase local and national employment, with a higher employment impact than if the money had been spent to purchase energy (Kushler et al., 2005; NYSERDA, 2004). Many energy efficiency programs create construction and installation jobs, with multiplier impacts on employment and local economies. Local investments in energy efficiency can offset imports from out-of-state, improving the state balance of trade. Lastly, energy efficiency investments usually create long-lasting infrastructure changes to building, equipment and appliance stocks, creating long-term property improvements that deliver long-term economic value (Innovest, 2002).

Energy security. Energy efficiency reduces the level of U.S. per capita energy consumption, thus decreasing the vulnerability of the economy and individual consumers to energy price disruptions from natural disasters and attacks on domestic and international energy supplies and infrastructure. In addition, energy efficiency can be used to reduce the overall system peak demand or the peak demand in targeted load areas with limited generating or transport capability. Reducing peak demand improves system reliability and reduces the potential for unplanned brownouts or black-outs, which can have large adverse economic consequences.

utilities, and other organizations can build. Experience shows that energy efficiency programs can lower customer energy bills; cost less than, and help defer, new energy infrastructure; provide energy savings to consumers; improve the environment; and spur local economic development (see box on Benefits of Energy Efficiency). Significant opportunities for energy efficiency are likely to continue to be available at low costs in the future. State and regional studies have found that adoption of economically attractive, but as yet untapped, energy efficiency could yield more than 20 percent savings in total electricity demand nationwide by 2025. Depending on the underlying load growth, these savings could help cut load growth by half or more compared to current forecasts (Nadel et al., 2004; SWEEP, 2002; NEEP, 2005; NWPCC, 2005; WGA, 2006). Similarly, savings from direct use of natural gas could provide a 50 percent or greater reduction in natural gas demand growth (Nadel et al., 2004).

Capturing this energy efficiency resource would offer substantial economic and environmental benefits across the country. Widespread application of energy efficiency programs that already exist in some regions could deliver a large part of these potential savings.[9] Extrapolating the results from existing programs to the entire country would yield annual energy bill savings of nearly $20 billion, with net societal benefits of more than $250 billion over the next 10 to 15 years. This scenario could defer the need for 20,000 megawatts (MW), or 40 new 500-MW power plants, as well as reduce U.S. emissions from energy production and use by more than 200 million tons of carbon dioxide (CO_2), 50,000 tons of SO_2, and 40,000 tons of NO_x annually.[10] These significant economic and environmental benefits can be achieved relatively quickly because energy efficiency programs can be developed and implemented within several years.

Additional policies and programs are required to help capture these potential benefits and address our substantial underinvestment in energy efficiency as a nation. An important indicator of this underinvestment is that the level of funding across the country for organized efficiency programs is currently less than $2 billion per year while it would require about 4 times today's funding levels to achieve the economic and environment benefits presented above.[11, 12]

The current underinvestment in energy efficiency is due to a number of well-recognized barriers, including some of the regulatory policies that govern electric and natural gas utilities. These barriers include:

- *Market barriers,* such as the well-known "split-incentive" barrier, which limits home builders' and commercial developers' motivation to invest in energy efficiency for new buildings because they do not pay the energy bill; and the transaction cost barrier, which chronically affects individual consumer and small business decision-making.

- *Customer barriers,* such as lack of information on energy saving opportunities, lack of awareness of how energy efficiency programs make investments easier, and lack of funding to invest in energy efficiency.

- *Public policy barriers,* which can present prohibitive disincentives for utility support and investment in energy efficiency in many cases.

- *Utility, state, and regional planning barriers,* which do not allow energy efficiency to compete with supply-side resources in energy planning.

- *Energy efficiency program barriers,* which limit investment due to lack of knowledge about the most effective and cost-effective energy efficiency program portfolios, programs for overcoming common marketplace barriers to energy efficiency, or available technologies.

While a number of energy efficiency policies and programs contribute to addressing these barriers, such as building codes, appliance standards, and state government leadership programs, organized energy efficiency programs provide an important opportunity to deliver greater energy efficiency in the homes, buildings, and facilities that already exist today and that will consume the majority of the energy used in these sectors for years to come.

The Leadership Group and National Action Plan for Energy Efficiency

Recognizing that energy efficiency remains a critically underutilized resource in the nation's energy portfolio, more than 50 leading electric and gas utilities, state utility commissioners, state air and energy agencies, energy service providers, energy consumers, and energy efficiency and consumer advocates have formed a Leadership Group, together with the U.S. Department of Energy (DOE) and the U.S. Environmental Protection Agency (EPA), to address the issue. The goal of this group is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators, and partner organizations. The Leadership Group recognizes that utilities and regulators play critical roles in bringing energy efficiency programs to their communities and that success requires the joint efforts of customers, utilities, regulators, states, and other partner organizations.

Under co-chairs Diane Munns (Member of the Iowa Utilities Board and President of the National Association of Regulatory Utility Commissioners) and Jim Rogers (President and Chief Executive Officer of Duke Energy), the Leadership Group members (see Table ES-1) have developed the National Action Plan for Energy Efficiency Report, which:

- Identifies key barriers limiting greater investment in energy efficiency.
- Reviews sound business practices for removing these barriers and improving the acceptance and use of energy efficiency relative to energy supply options.
- Outlines recommendations and options for overcoming these barriers.

The members of the Leadership Group have agreed to pursue these recommendations and consider these options through their own actions, where appropriate, and to support energy efficiency initiatives by other industry members and stakeholders.

Recommendations

The National Action Plan for Energy Efficiency is a call to action to utilities, state utility regulators, consumer advocates, consumers, businesses, other state officials, and other stakeholders to create an aggressive, sustainable national commitment to energy efficiency.[1] The Action Plan offers the following recommendations as ways to overcome barriers that have limited greater investment in energy efficiency for customers of electric and gas utilities in many parts of the country. The following recommendations are based on the policies, practices, and efforts of leading organizations across the country. For each recommendation, a number of options are available to be pursued based on regional, state, and utility circumstances (see also Figure ES-2).

Recognize energy efficiency as a high-priority energy resource. Energy efficiency has not been consistently viewed as a meaningful or dependable resource compared to new supply options, regardless of its demonstrated contributions to meeting load growth.[13] Recognizing energy efficiency as a high-priority energy resource is an important step in efforts to capture the benefits it offers and lower the overall cost of energy services to customers. Based on jurisdictional objectives, energy efficiency can be incorporated into resource plans to account for the long-term benefits from energy savings, capacity savings, potential reductions of air pollutants and greenhouse gases, as well as other benefits. The explicit integration of energy efficiency resources into the formalized resource planning processes that exist at regional, state, and utility levels can help establish the rationale for energy efficiency funding levels and for properly valuing and balancing the benefits. In some jurisdictions, these existing planning processes might need to be adapted or even created to meaningfully incorporate energy efficiency resources into resource planning. Some states have recognized energy efficiency as the resource of first priority due to its broad benefits.

Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource. Energy efficiency programs are most successful and provide the greatest benefits to stakeholders when appropriate policies are established and maintained over the long-term. Confidence in long-term stability of the program will help maintain energy efficiency as a dependable resource compared to supply-side resources, deferring or even avoiding the need for other infrastructure investments, and maintain customer awareness and support. Some steps might include assessing the long-term potential for cost-effective energy efficiency within a region (i.e., the energy efficiency that can be delivered cost-effectively through proven programs for each customer class within a planning horizon); examining the role for cutting-edge initiatives and technologies; establishing the cost of supply-side options versus energy efficiency; establishing robust measurement and verification (M&V) procedures; and providing for routine updates to information on energy efficiency potential and key costs.

Broadly communicate the benefits of and opportunities for energy efficiency. Experience shows that energy efficiency programs help customers save money and contribute to lower cost energy systems. But these benefits are not fully documented nor recognized by customers, utilities, regulators, or policy-makers. More effort is needed to establish the business case for energy efficiency for all decision-makers and to show how a well-designed approach to energy efficiency can benefit customers, utilities, and society by (1) reducing customers' bills over time, (2) fostering financially healthy utilities (e.g., return on equity, earnings per share, and debt coverage ratios unaffected), and (3) contributing to positive societal net benefits overall. Effort is also necessary to educate key stakeholders that although energy efficiency can be an important low-cost resource to integrate into the energy mix, it does require funding just as a new power plant requires funding. Further, education is necessary on the impact that energy efficiency programs can have in concert with other energy efficiency policies such as building codes, appliance standards, and tax incentives.

Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective. Energy efficiency programs require consistent and long-term funding to effectively compete with energy supply options. Efforts are necessary to establish this consistent long-term funding. A variety of mechanisms have been, and can be, used based on state, utility, and other stakeholder interests. It is important to ensure that the efficiency programs' providers have sufficient long-term funding to recover program costs and implement the energy efficiency measures that have been demonstrated to be available and cost effective. A number of states are now linking program funding to the achievement of energy savings.

Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments. Successful energy efficiency programs would be promoted by aligning utility incentives in a manner that encourages the delivery of energy efficiency as part of a balanced portfolio of supply, demand, and transmission investments. Historically, regulatory policies governing utilities have more commonly compensated utilities for building infrastructure (e.g., power plants, transmission lines, pipelines) and selling energy, while discouraging energy efficiency, even when the energy-saving measures might cost less. Within the existing regulatory processes, utilities, regulators, and stakeholders have a number of opportunities to create the incentives for energy efficiency investments by utilities and customers. A variety of mechanisms have already been used. For example, parties can decide to provide incentives for energy efficiency similar to utility incentives for new infrastructure investments, provide rewards for prudent management of energy efficiency programs, and incorporate energy efficiency as an important area of consideration within rate design. Rate design offers

Figure ES-2. National Action Plan for Energy Efficiency Recommendations & Options

Recognize energy efficiency as a high priority energy resource.

Options to consider:

- Establishing policies to establish energy efficiency as a priority resource.
- Integrating energy efficiency into utility, state, and regional resource planning activities.
- Quantifying and establishing the value of energy efficiency, considering energy savings, capacity savings, and environmental benefits, as appropriate.

Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.

Options to consider:

- Establishing appropriate cost-effectiveness tests for a portfolio of programs to reflect the long-term benefits of energy efficiency.
- Establishing the potential for long-term, cost-effective energy efficiency savings by customer class through proven programs, innovative initiatives, and cutting-edge technologies.
- Establishing funding requirements for delivering long-term, cost-effective energy efficiency.
- Developing long-term energy saving goals as part of energy planning processes.
- Developing robust measurement and verification (M&V) procedures.
- Designating which organization(s) is responsible for administering the energy efficiency programs.
- Providing for frequent updates to energy resource plans to accommodate new information and technology.

Broadly communicate the benefits of and opportunities for energy efficiency.

Options to consider:

- Establishing and educating stakeholders on the business case for energy efficiency at the state, utility, and other appropriate level addressing relevant customer, utility, and societal perspectives.
- Communicating the role of energy efficiency in lowering customer energy bills and system costs and risks over time.
- Communicating the role of building codes, appliance standards, and tax and other incentives.

Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.

Options to consider:

- Deciding on and committing to a consistent way for program administrators to recover energy efficiency costs in a timely manner.
- Establishing funding mechanisms for energy efficiency from among the available options such as revenue requirement or resource procurement funding, system benefits charges, rate-basing, shared-savings, incentive mechanisms, etc.
- Establishing funding for multi-year periods.

Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

Options to consider:

- Addressing the typical utility throughput incentive and removing other regulatory and management disincentives to energy efficiency.
- Providing utility incentives for the successful management of energy efficiency programs.
- Including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that it must be balanced with other objectives.
- Eliminating rate designs that discourage energy efficiency by not increasing costs as customers consume more electricity or natural gas.
- Adopting rate designs that encourage energy efficiency by considering the unique characteristics of each customer class and including partnering tariffs with other mechanisms that encourage energy efficiency, such as benefit sharing programs and on-bill financing.

opportunities to encourage customers to invest in efficiency where they find it to be cost effective and participate in new programs that provide innovative technologies (e.g., smart meters) to help customers control their energy costs.

National Action Plan for Energy Efficiency: Next Steps

In summer 2006, members of the Leadership Group of the National Action Plan on Energy Efficiency are announcing a number of specific activities and initiatives to formalize and reinforce their commitments to energy efficiency as a resource. To assist the Leadership Group and others in making and fulfilling their commitments, a number of tools and resources have been developed:

National Action Plan for Energy Efficiency Report. This report details the key barriers to energy efficiency in resource planning, utility incentive mechanisms, rate design, and the design and implementation of energy efficiency programs. It also reviews and presents a variety of policy and program solutions that have been used to overcome these barriers as well as the pros and cons for many of these approaches.

Energy Efficiency Benefits Calculator. This calculator can be used to help educate stakeholders on the broad benefits of energy efficiency. It provides a simplified framework to demonstrate the business case for energy efficiency from the perspective of the consumer, the utility, and society. It has been used to explore the benefits of energy efficiency program investments under a range of utility structures, policy mechanisms, and energy growth scenarios. The calculator can be adapted and applied to other scenarios.

Experts and Resource Materials on Energy Efficiency. A number of educational presentations on the potential for energy efficiency and various policies available for pursuing the recommendations of the Action Plan will be developed. In addition, lists of policy and program experts in energy efficiency and the various policies available for pursuing the recommendations of the Action Plan will be developed. These lists will be drawn from utilities, state utility regulators, state energy offices, third-party energy efficiency program administrators, consumer advocacy organizations, ESCOs, and others. These resources will be available in fall 2006.

DOE and EPA are continuing to facilitate the work of the Leadership Group and the National Action Plan for Energy Efficiency. During winter 2006–2007, the Leadership Group plans to report on its progress and identify next steps for the Action Plan.

Table ES-1. Members of the National Action Plan for Energy Efficiency

Co-Chairs

Diane Munns	Member President	Iowa Utilities Board National Association of Regulatory Utility Commissioners
Jim Rogers	President and Chief Executive Officer	Duke Energy

Leadership Group

Barry Abramson	Senior Vice President	Servidyne Systems, LLC
Angela S. Beehler	Director of Energy Regulation	Wal-Mart Stores, Inc.
Bruce Braine	Vice President, Strategic Policy Analysis	American Electric Power
Jeff Burks	Director of Environmental Sustainability	PNM Resources
Kateri Callahan	President	Alliance to Save Energy
Glenn Cannon	General Manager	Waverly Light and Power
Jorge Carrasco	Superintendent	Seattle City Light
Lonnie Carter	President and Chief Executive Officer	Santee Cooper
Mark Case	Vice President for Business Performance	Baltimore Gas and Electric
Gary Connett	Manager of Resource Planning and Member Services	Great River Energy
Larry Downes	Chairman and Chief Executive Officer	New Jersey Natural Gas (New Jersey Resources Corporation)
Roger Duncan	Deputy General Manager, Distributed Energy Services	Austin Energy
Angelo Esposito	Senior Vice President, Energy Services and Technology	New York Power Authority
William Flynn	Chairman	New York State Public Service Commission
Jeanne Fox	President	New Jersey Board of Public Utilities
Anne George	Commissioner	Connecticut Department of Public Utility Control
Dian Grueneich	Commissioner	California Public Utilities Commission
Blair Hamilton	Policy Director	Vermont Energy Investment Corporation
Leonard Haynes	Executive Vice President, Supply Technologies, Renewables, and Demand Side Planning	Southern Company
Mary Healey	Consumer Counsel for the State of Connecticut	Connecticut Consumer Counsel
Helen Howes	Vice President, Environment, Health and Safety	Exelon
Chris James	Air Director	Connecticut Department of Environmental Protection
Ruth Kinzey	Director of Corporate Communications	Food Lion
Peter Lendrum	Vice President, Sales and Marketing	Entergy Corporation
Rick Leuthauser	Manager of Energy Efficiency	MidAmerican Energy Company
Mark McGahey	Manager	Tristate Generation and Transmission Association, Inc.
Janine Migden-Ostrander	Consumers' Counsel	Office of the Ohio Consumers' Counsel
Richard Morgan	Commissioner	District of Columbia Public Service Commission
Brock Nicholson	Deputy Director, Division of Air Quality	North Carolina Air Office
Pat Oshie	Commissioner	Washington Utilities and Transportation Commission
Douglas Petitt	Vice President, Government Affairs	Vectren Corporation

Bill Prindle	Deputy Director	American Council for an Energy-Efficient Economy
Phyllis Reha	Commissioner	Minnesota Public Utilities Commission
Roland Risser	Director, Customer Energy Efficiency	Pacific Gas and Electric
Gene Rodrigues	Director, Energy Efficiency	Southern California Edison
Art Rosenfeld	Commissioner	California Energy Commission
Jan Schori	General Manager	Sacramento Municipal Utility District
Larry Shirley	Division Director	North Carolina Energy Office
Michael Shore	Senior Air Policy Analyst	Environmental Defense
Gordon Slack	Energy Business Director	The Dow Chemical Company
Deb Sundin	Director, Business Product Marketing	Xcel Energy
Dub Taylor	Director	Texas State Energy Conservation Office
Paul von Paumgartten	Director, Energy and Environmental Affairs	Johnson Controls
Brenna Walraven	Executive Director, National Property Management	USAA Realty Company
Devra Wang	Director, California Energy Program	Natural Resources Defense Council
Steve Ward	Public Advocate	State of Maine
Mike Weedall	Vice President, Energy Efficiency	Bonneville Power Administration
Tom Welch	Vice President, External Affairs	PJM Interconnection
Jim West	Manager of *energy right* & Green Power Switch	Tennessee Valley Authority
Henry Yoshimura	Manager, Demand Response	ISO New England Inc.

Observers

James W. (Jay) Brew	Counsel	Steel Manufacturers Association
Roger Cooper	Executive Vice President, Policy and Planning	American Gas Association
Dan Delurey	Executive Director	Demand Response Coordinating Committee
Roger Fragua	Deputy Director	Council of Energy Resource Tribes
Jeff Genzer	General Counsel	National Association of State Energy Officials
Donald Gilligan	President	National Association of Energy Service Companies
Chuck Gray	Executive Director	National Association of Regulatory Utility Commissioners
John Holt	Senior Manager of Generation and Fuel	National Rural Electric Cooperative Association
Joseph Mattingly	Vice President, Secretary and General Counsel	Gas Appliance Manufacturers Association
Kenneth Mentzer	President and Chief Executive Officer	North American Insulation Manufacturers Association
Christina Mudd	Executive Director	National Council on Electricity Policy
Ellen Petrill	Director, Public/Private Partnerships	Electric Power Research Institute
Alan Richardson	President and Chief Executive Officer	American Public Power Association
Steve Rosenstock	Manager, Energy Solutions	Edison Electric Institute
Diane Shea	Executive Director	National Association of State Energy Officials
Rick Tempchin	Director, Retail Distribution Policy	Edison Electric Institute
Mark Wolfe	Executive Director	Energy Programs Consortium

Notes

1 Energy efficiency refers to using less energy to provide the same or improved level of service to the energy consumer in an economically efficient way. The term energy efficiency as used here includes using less energy at any time, including at times of peak demand through demand response and peak shaving efforts.

2 Addressing transportation-related energy use is also an important challenge as energy demand in this sector continues to increase and oil prices hit historical highs. However, transportation issues are outside the scope of this effort, which is focused only on electricity and natural gas systems.

3 This effort is focused on energy efficiency for regulated energy forms. Energy efficiency for unregulated energy forms, such as fuel oil for example, is closely related in terms of actions in buildings, but is quite different in terms of how policy can promote investments.

4 A utility is broadly defined as an organization that delivers electric and gas utility services to end users, including, but not limited to, investor-owned, publicly-owned, cooperatively-owned, and third-party energy efficiency utilities.

5 Many energy efficiency programs have an average life cycle cost of $0.03/kilowatt-hour (kWh) saved, which is 50 to 75 percent of the typical cost of new power sources (ACEEE, 2004; EIA, 2006). The cost of energy efficiency programs varies by program and can include higher cost programs and options with lower costs to a utility such as modifying rate designs.

6 See Chapter 6: Energy Efficiency Program Best Practices for more information on leading programs.

7 Data refer to EIA 2006 new power costs and gas prices in 2015 compared to electric and gas program costs based on leading energy efficiency programs, many of which are discussed in Chapter 6: Energy Efficiency Program Best Practices.

8 Based on leading energy efficiency programs, many of which are discussed in Chapter 6: Energy Efficiency Program Best Practices.

9 These estimates are based on assumptions of average program spending levels by utilities or other program administrators, with conservatively high numbers for the cost of energy efficiency programs. See highlights of some of these programs in Chapter 6: Energy Efficiency Program Best Practices, Tables 6-1 and 6-2.

10 These economic and environmental savings estimates are extrapolations of the results from regional program to a national scope. Actual savings at the regional level vary based on a number of factors. For these estimates, avoided capacity value is based on peak load reductions de-rated for reductions that do not result in savings of capital investments. Emissions savings are based on a marginal on-peak generation fuel of natural gas and marginal off-peak fuel of coal; with the on-peak period capacity requirement double that of the annual average. These assumptions vary by region based upon situation-specific variables. Reductions in capped emissions might reduce the cost of compliance.

11 This estimate of the funding required assumes 2 percent of revenues across electric utilities and 0.5 percent across gas utilities. The estimate also assumes that energy efficiency is delivered at a total cost (utility and participant) of $0.04 per kWh and $3 per million British thermal units (MMBtu), which are higher than the costs of many of today's programs.

12 This estimate is provided as an indicator of underinvestment and is not intended to establish a national funding target. Appropriate funding levels for programs should be established at the regional, state, or utility level. In addition, energy efficiency investments by customers, businesses, industry, and government also contribute to the larger economic and environment benefits of energy efficiency.

13 One example of energy efficiency's ability to meet load growth is the Northwest Power Planning Council's Fifth Power Plan which uses energy conservation and efficiency to meet a targeted 700 MW of forecasted capacity between 2005 and 2009 (NWPCC, 2005).

National Action Plan for Energy Efficiency

Vision for 2025:

A Framework for Change

EXECUTIVE SUMMARY

NOVEMBER 2008

Letter from the Co-Chairs of the National Action Plan for Energy Efficiency

November 2008

To all,

As you know, the National Action Plan for Energy Efficiency is playing a vital role in advancing the dialogue and the pursuit of energy efficiency in our homes, buildings, and industries —an important energy resource for the country.

With the commitment and leadership from more than 60 diverse organizations nationwide we have made great progress in a short time. We have:

- Developed five broad and meaningful recommendations for pursuing cost-effective energy efficiency.
- Brought together more than 100 organizations from 50 states around this common goal to take energy efficiency to the next level.

However, there is much more to do. We remain substantially underinvested in efficiency at a time when using energy wisely can help address rising energy costs, rising emissions of greenhouse gases, and our dependence on foreign fuel supplies.

We need a concerted, sustained effort to overcome what are truly surmountable hurdles to making energy efficiency a larger part of our supply picture. To continue our progress we need to move from our initial Action Plan to implementation. We need a vision for where we want to be and a path for getting there.

Commensurate with that goal, we are pleased to offer this updated 2025 Vision for the National Action Plan. As we released it last year, the Vision outlines what our long-term goals should be if we are to truly achieve all cost-effective energy efficiency. With recent refinements to our approach for measuring progress under the ten key implementation goals, we believe the Vision now provides a complete framework for changing our course on energy efficiency.

This Vision represents the thinking of many leading organizations nationwide. Importantly, we believe that this Vision is a living document that looks out to long-term needs and will be modified to reflect new information and changing conditions.

We thank the Leadership Group for its contribution to this document. It is a pleasure to work with this committed group to advance energy efficiency to address the critical energy and environmental issues facing the country.

Sincerely,

Marsha H. Smith
President, National Association of
Regulatory Utility Commissioners
Commissioner, Idaho Public Utilities Commission

James E. Rogers
President, Chairman, and CEO
Duke Energy

Executive Summary

This Vision for the National Action Plan for Energy Efficiency establishes a goal of achieving all cost-effective energy efficiency by 2025; presents ten implementation goals for states, utilities, and other stakeholders to consider to achieve this goal; describes what 2025 might look like if the goal is achieved; and provides a means for measuring progress. It is a framework for implementing the five policy recommendations of the Action Plan, announced in July 2006, which can be modified and improved over time.

Background

Through the Leadership Group of the National Action Plan for Energy Efficiency (Action Plan), more than 60 diverse leading organizations recognized the importance of bringing greater emphasis to the role that cost-effective energy efficiency[1] can and should play in supplying our future energy needs. Improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70 percent of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, air pollution, and global climate change in the near future. Energy efficiency can play a significant role in meeting our energy requirements, and it is a critical component of the overall modernization of utility energy systems worthy of the 21st century.

Despite the value that cost-effective energy efficiency offers, it is not achieving its full potential for a number of reasons. In July 2006, the Action Plan presented five key policy recommendations (see Figure ES-1) for fully developing the cost-effective energy efficiency resources in this country, building upon experiences in particular states and regions. It was a call to action to take investment in energy efficiency to the next level. As of November 2008, more than 120 organizations have endorsed these recommendations and/or made commitments to take energy efficiency to the next level within their spheres of influence.

As a next step, the Action Plan co-chairs challenged the Leadership Group to define a vision that would detail the steps necessary to fully implement the Action Plan. The Vision presented in this document is the response to that challenge. It includes establishment of a long-term aspirational goal and ten key implementation goals. It also describes what 2025 could look like if the

Figure ES-1. National Action Plan for Energy Efficiency Recommendations

- **Recognize energy efficiency as a high-priority energy resource.**
- **Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.**
- **Broadly communicate the benefits of and opportunities for energy efficiency.**
- **Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.**
- **Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.**

long-term goal were achieved and provides a means for measuring progress over time. The Vision is provided as a framework to guide the changing policies toward energy efficiency for natural gas and electricity; it can be modified and improved over time.

Achieve All Cost-Effective Energy Efficiency

The long-term aspirational goal for the Action Plan is to achieve all cost-effective energy efficiency by the year 2025. Based on studies, the efficiency resource available may be able to meet 50 percent or more of the expected load growth over this time frame, similar to meeting 20 percent of electricity consumption and 10 percent of natural gas consumption.[2] The benefits from achieving this magnitude of energy efficiency nationally can be estimated to be more than $100 billion in lower energy bills in 2025 than would otherwise occur, over $500 billion in net savings, and substantial reductions in greenhouse gas emissions.

Importantly, the energy efficiency resource's role in meeting load and load growth may vary across the country due to regional differences in growth patterns, costs of energy, and other factors. Furthermore, the long-term goal is not a statement about the need for new power supply additions in the future, as new plants may be a critical component of the desired modernization of the energy supply and delivery system. However, the greater the energy efficiency savings, the greater the likelihood that efficiency gains can help replace older, less efficient power supply options, resulting in substantial environmental benefits.

Ten Implementation Goals

Over two decades of program experience support the implementation of a number of policies to enhance the likelihood that the long-term goal will be achieved. Energy efficiency needs to be valued similarly to supply options. Utilities and investors need to be financially interested in saving energy. State activity is key in this transformation of natural gas and electricity supply and delivery, including updating and enforcing codes and standards to ensure that savings are captured as new buildings and products enter the system. Customers must also have the proper incentives to make investments in cost-effective energy efficiency. With such policies in place, cost-effective energy efficiency can be a key component of the modernization of the energy supply and delivery system and help to transform how customers receive and value energy services.

These policies are included in the following ten implementation goals. These goals provide a framework for implementing the recommendations of the Action Plan (see Figure ES-1) by outlining the key steps state decision-makers should consider to help achieve the 2025 Vision. The time line for achieving these implementation goals is by 2015 to 2020, so that the necessary policy foundation is in place to help ensure success of the 2025 Vision.

Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource

Utilities[3] and applicable agencies are encouraged to:

- Create a process, such as a state or regional collaborative, to explore the energy efficiency potential in the state and commit to its full development.
- Regularly identify cost-effective achievable energy efficiency potential in conjunction with ratemaking bodies.
- Set energy savings goals or targets consistent with the cost-effective potential.
- Integrate energy efficiency into energy resource plans at the utility, state, and regional levels, and include provisions for regular updates.

Goal Two: Developing Processes to Align Utility and Other Program Administrator Incentives Such That Efficiency and Supply Resources Are on a Level Playing Field

Applicable agencies are encouraged to:

- Explore establishing revenue mechanisms to promote utility and other program administrator indifference to supplying energy savings, as compared to energy generation options.

- Consider how to remove utility and other program administrator disincentives to energy efficiency, such as by removing the utility throughput disincentive and exploring other ratemaking ideas.
- Ensure timely cost recovery in place for parties that administer energy efficiency programs.

Goal Three: Establishing Cost-Effectiveness Tests

Applicable agencies along with key stakeholders are encouraged to:

- Establish a process to examine how to define cost-effective energy efficiency practices that capture the long-term resource value of energy efficiency.
- Incorporate cost-effectiveness tests into ratemaking procedures going forward.

Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms

Ratemaking bodies are encouraged to:

- Work with stakeholders to adopt effective, transparent practices for the evaluation, measurement, and verification (EM&V) of energy efficiency savings.

Program administrators are encouraged to:

- Conduct EM&V consistent with these practices.

Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms

Applicable agencies are encouraged to:

- Clearly establish who will administer energy efficiency programs.
- Review programs, funding, customer coverage, and goals for efficiency programs; ensure proper administration and cost recovery of programs, as well as ensuring that goals are met.
- Establish goals and funding on a multi-year basis to be measured by evaluation of programs established.
- Create strong public education programs for energy efficiency.
- Ensure that the program administrator shares best practice information regionally and nationally.

Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices

Applicable agencies are encouraged to:

- Have a mechanism to review and update building codes.
- Establish enforcement and monitoring mechanisms of energy codes.
- Adopt and implement state-level appliance standards for those appliances not addressed by the federal government.
- Develop and implement lead-by-example energy efficiency programs at the state and local levels.

Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency

Utilities and ratemaking bodies are encouraged to:

- Examine, propose, and modify rates considering impact on customer incentives to pursue energy efficiency.
- Create mechanisms to reduce customer disincentives for energy efficiency (e.g., financing mechanisms).

Goal Eight: Establishing State of the Art Billing Systems

Utilities are encouraged to:

- Work with customers to develop methods of supplying consistent energy use and cost information across states, service territories, and the nation.

Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems

Utilities and other program administrators are encouraged to:

- In conjunction with their regulatory bodies, explore the development and implementation of state of the art energy delivery information, including smart grid infrastructures, data analysis, two-way communication programs, etc.
- Explore methods of integrating advanced technologies to help curb demand peaks and monitor efficiency upgrades to prevent equipment degradation, etc.
- Coordinate demand response and energy efficiency programs to maximize value to customers.
- Support development of an energy efficiency services and program delivery channel (e.g., quality trained technicians), with specific attention to residential programs.

Goal Ten: Implementing Advanced Technologies

Applicable agencies and utilities are encouraged to:

- Review policies to ensure that barriers to advanced technologies, such as combined heat and power (CHP), are removed; ensure inclusion into the broader resource plans.
- Work collectively to review advanced technologies and determine rapid integration timelines.

Measuring Progress

Measurement of the progress toward full implementation of these ten goals by 2015 to 2020 is an important part of the Vision. Progress will be measured and reported on every few years. As of December 31, 2007, based on information collected from across the country (see Table ES-1), there is a strong basis of experience with these energy efficiency policies upon which to draw and to expand. For example, more than a dozen states have:

- Established a policy to recognize energy efficiency as a high-priority resource.
- Identified the cost-effective, achievable potential for energy efficiency over the long term, and established energy savings goals or targets consistent with this potential.
- Established cost-effectiveness tests for energy efficiency consistent with the long-term benefits of energy efficiency.
- Established energy efficiency programs for their various types of customers.

There is also more progress to make. For example, several states have also implemented the following policy steps to advance energy efficiency:

- Integrated energy efficiency savings goals or expected energy savings targets into state energy resource plans, with provisions for regular updates.
- Provided for stable (multi-year) funding for energy efficiency programs, consistent with energy efficiency goals.

These policies go hand in hand with significant investment in energy efficiency, as well as capturing the energy savings and environmental benefits from these programs. As of 2008, the most recent national benefits data show that:

- Cumulative electricity savings total 63 billion kilowatt-hours (kWh) (about 2 percent of retail sales) as of 2006, including incremental electricity savings of over 8 billion kWh in 2006 alone. These cumulative savings have avoided the need for 16 gigawatts of new capacity, equivalent to 32 new 500-megawatt power plants.[4]
- Cumulative natural gas savings total 135 million therms (0.1 percent of retail sales) as of 2006.[5]

Table ES-1. Progress in Meeting Implementation Goals

	Implementation Goal and Key Steps	States Having Adopted Policy Step as of December 31, 2007			
		Electricity Services		Natural Gas Services	
		Completely	Partially	Completely	Partially
Goal One: Establishing Cost-Effective Energy Efficiency as a High-Priority Resource					
1	Process in place, such as a state and/or regional collaborative, to pursue energy efficiency as a high-priority resource.	14	0	14	0
2	Policy established to recognize energy efficiency as high-priority resource.	21	22	8	8
3	Potential identified for cost-effective, achievable energy efficiency over the long term.	25	1	13	0
4	Energy efficiency savings goals or expected energy savings targets established consistent with cost-effective potential.	15	3	5	2
5	Energy efficiency savings goals and targets integrated into state energy resource plan, with provisions for regular updates.	0	16	0	1
6	Energy efficiency savings goals and targets integrated into a regional energy resource plan.**	TBD	TBD	TBD	TBD
Goal Two: Developing Processes to Align Utility and Other Program Administrator Incentives Such That Efficiency and Supply Resources Are on a Level Playing Field					
7	Utility and other program administrator disincentives are removed.	17	8	18	5
8	Utility and other program administrator incentives for energy efficiency savings reviewed and established as necessary.	10	5	5	2
9	Timely cost recovery in place.**	TBD	TBD	TBD	TBD
Goal Three: Establishing Cost-Effectiveness Tests					
10	Cost-effectiveness tests adopted which reflect the long-term resource value of energy efficiency.	29	2	9	0
Goal Four: Establishing Evaluation, Measurement, and Verification Mechanisms					
11	Robust, transparent EM&V procedures established.	14	6	5	2
Goal Five: Establishing Effective Energy Efficiency Delivery Mechanisms					
12	Administrator(s) for energy efficiency programs clearly established.	24	2	13	1
13	Stable (multi-year) and sufficient funding in place consistent with energy efficiency goals.	4	9	2	4
14	Programs established to deliver energy efficiency to key customer classes and meet energy efficiency goals and targets.	24	2	7	0
15	Strong public education programs on energy efficiency in place.	18	5	13	6
16	Energy efficiency program administrator engaged in developing and sharing program best practices at the regional and/or national level.	30	0	18	0

Table ES-1. Progress in Meeting Implementation Goals (continued)

Implementation Goal and Key Steps		States Having Adopted Policy Step as of December 31, 2007			
		Electricity Services		Natural Gas Services	
		Completely	Partially	Completely	Partially
Goal Six: Developing State Policies to Ensure Robust Energy Efficiency Practices					
17	State policies require routine review and updating of building codes.	28	13	28	13
18	Building codes effectively enforced.**	TBD	TBD	TBD	TBD
19	State appliance standards in place.	11	0	11	0
20	Strong state and local government lead-by example programs in place.	13	24	13	24
Goal Seven: Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency					
21	Rates examined and modified considering impact on customer incentives to pursue energy efficiency.	7	5	2	0
22	Mechanisms in place to reduce consumer disincentives for energy efficiency (e.g., including financing mechanisms).	4	1	0	0
Goal Eight: Establishing State of the Art Billing Systems					
23	Consistent information to customers on energy use, costs of energy use, and options for reducing costs.**	TBD	TBD	TBD	TBD
Goal Nine: Implementing State of the Art Efficiency Information Sharing and Delivery Systems					
24	Investments in advanced metering, smart grid infrastructure, data analysis, and two-way communication to enhance energy efficiency.	5	29	***	***
25	Coordinated energy efficiency and demand response programs established by customer class to target energy efficiency for enhanced value to customers.**	TBD	TBD	***	***
26	Residential programs established to use trained and certified professionals as part of energy efficiency program delivery.	9	0	9	0
Goal Ten: Implementing Advanced Technologies					
27	Policies in place to remove barriers to combined heat and power.	11	24	***	***
28	Timelines developed for the integration of advanced technologies.**	TBD	TBD	TBD	TBD

* See Appendix D of the full *Vision for 2025* report for additional information on how these numbers have been determined.

** See Appendix D of the full *Vision for 2025* report for discussion of why progress on this policy step is not currently measured.

*** Steps 24, 25, and 27 do not apply to natural gas.

TBD = To be determined

Table ES-2. Current Benefits from and Funding for State- and Utility-Administered Energy Efficiency Programs*

Annual Benefits and Funding	Energy Savings		Avoided CO_2 Emissions (million tons)	Efficiency Funding	
	Energy Use (kWh or therms)	Peak Capacity (GW)		2006 Spending ($ billion)	2007 Budgets ($ billion)
Electricity					
Incremental	8 billion	1.3	5.8	$1.60 (0.5% of utility revenues)	$1.88
Cumulative	63 billion (2% of retail sales)	16.0	46.1		
Natural Gas					
Incremental	N/A	—	N/A	$0.29 (0.3% of utility revenues)	$0.28
Cumulative	135 million (0.1% of retail sales)	—	0.8		

Sources: ACEEE (Eldridge et al., 2008), CEE (Nevius et al., 2008), eGRID2007 Version 1.0 (EPA, 2008), EIA energy sales and savings data (EIA, 2007, 2008a, 2008b, 2008c), and American Gas Association statistics (AGA, 2008).

*For information on how these numbers were derived, see Chapter 2 of the full Vision for 2025 report.

N/A = Not available

- Greenhouse gas emissions are being reduced by nearly 50 million metric tons annually, equivalent to emissions from 9 million vehicles per year.[6]
- Approximately $2 billion (approximately 0.5 percent of utility revenues) is being invested annually in state- and utility-administered energy efficiency programs.[7]
- State energy savings goals and utility energy savings targets are in place to encourage cumulative savings exceeding 200 billion kWh in the year 2025, in addition to current energy savings.[8]

Additional details on the estimates for current investments and benefits are provided in Table ES-2. Improving the available data will be an ongoing effort as the Action Plan continues to measure progress toward all cost-effective energy efficiency.

The Energy System in 2025

An energy system in 2025 that would evolve with the suite of energy efficiency policies in place as outlined above and that captures all cost-effective energy efficiency will be different from the one we have today. Some of the key differences based on the effects that some of these policy changes are having in parts of the country, as well as expectations of some of the advantages that new technology and system modernization can bring, are highlighted below from the perspectives of the energy customer and society.

- **Customers** across the residential, commercial, and industrial sectors would have ready, uniform access to comprehensive energy efficiency services across the country. These services would bring a range of efficiency improvements to homes, buildings, and

Table ES-3. Changes to Watch in Evolving Technology, Policy, and Program Practices for Energy Efficiency

Policy Area	Changes to Watch
Evaluation, measurement, and verification	• Development of national standards • Requirements for independent verification • Growing role for smart grid technologies in EM&V • Requirements for state and regional carbon programs
Demand response, advanced metering, and smart grids	• New technologies, such as advanced meters and smart appliances/controls • Data collection networks and data analysis to enhance energy efficiency • New customer interfaces • Increased interoperability
Regional resource planning	• Regional value of energy efficiency identified
Building energy efficiency expertise/workforce	• Development and use of energy efficiency curriculum for various segments of the workforce • Development and broad use of training and certification programs
Integration of R&D, building codes, appliance standards, and market transformation efforts	• Regional and national coordination across these efforts

Sources: PJM, 2007; CEC and CPUC, 2005; Business Roundtable, 2007; Elliott et al., 2007; Roseman and Hochstetter, 2007; Schiller Consulting, 2007; Western Governors' Association, 2006.

facilities and reduce customers' bills below what they would have been without these programs. Customers would also have clear information on the cost of energy and increased awareness of their total energy use. In addition, new efficient appliances and other equipment will help to control the peak demand of utility systems and give large customers greater flexibility in how they manage and control their own operations to reduce energy use, reduce costs, and increase their own competitive positions. New homes and buildings would meet up-to-date energy codes.

- **Society** would benefit from significantly modernized energy supply, transmission, and distribution systems and, with increased investment in cost-effective energy efficiency, would benefit from lower overall cost of energy supply, increased fuel diversity, and lower emissions of air pollutants and greenhouse gases. The low-income populations would benefit, in particular, from the lower energy bills resulting from a commitment to deliver energy efficiency to these customer classes. Society may also see economic benefits from the greater employment necessary to build an industry capable of delivering energy efficiency services at this broad scale, from a robust business in energy efficiency products and services, and from using more capital locally.

There are a number of challenges to achieving this Vision, including the necessary evolution of technology, policy, and program practices. Table ES-3 highlights some of these evolving areas, including evaluation approaches for efficiency resources, customer involvement through demand response programs and smart grid technology, regional resource planning, workforce building, and integration across energy efficiency efforts.

Related State, Regional, and National Policies

Other energy and environmental policy decisions at the state, regional, and national levels can affect energy efficiency. Ideally, these policies will be designed and implemented in a manner that helps remove barriers to energy efficiency and helps capture energy efficiency resources for a lower-cost energy system than otherwise would be necessary. Integrating energy efficiency considerations into related policy areas, as appropriate, will be critical to achieving this Vision. Such related policy areas are those designed to:

- Limit emissions of greenhouse gases.
- Encourage the use of clean, efficient distributed generation.
- Promote clean energy supply, such as renewable energy.
- Promote load reductions at critical peak times through demand response.
- Modernize and maintain the nation's electric transmission and distribution system, including "smart grid" and advanced meter infrastructure.
- Maintain a sufficient reserve margin for reliable electricity supply.

Next Steps

This Vision is offered as a framework to assist change in energy efficiency and related policies and programs at the state level across the country, toward the goal of achieving all cost-effective energy efficiency in 2025. It presents a snapshot of where the country is as of December 31, 2007 based on the collection and organization of available information on the existing policy and program options. The decision of whether to adopt a policy or program and particular design details at the state level are, of course, to be determined through state processes that address state goals, objectives, and circumstances. The Action Plan Leadership Group and other public and private sources provide a wealth of tools and assistance to parties taking action to advance the Vision, as summarized in Table ES-4.

The Vision will be updated as new information becomes available and improved as information changes. Information on measuring progress at the state level will be updated on a regular basis at the Action Plan Web site, www.epa.gov/eeactionplan. People are encouraged to provide additional information and their comments for how to refine this Vision to the Action Plan Leadership Group. Please send feedback to the Action Plan sponsors via Larry Mansueti, U.S. Department of Energy (lawrence.mansueti@hq.doe.gov, 202-586-2588) and Stacy Angel, U.S. Environmental Protection Agency (angel.stacy@epa.gov, 202-343-9606).

Resolution on Gas and Electric Energy Efficiency

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review and reconsider the level of support and incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response in both gas and electricity markets; *and*

WHEREAS, The National Petroleum Council (NPC), in its September 25, 2003 report on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, found that greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility and recommended all sectors of the economy work toward improving demand flexibility and efficiency; *and*

WHEREAS, The NPC, in its report, identified key elements of the effort to maintain and continue improvements in the efficient use of electricity and natural gas, including (but not limited to):

(i) enhanced and expanded public education programs for energy conservation, efficiency, and weatherization,

(ii) DOE identification of best practices utilized by States for low-income weatherization programs and to encourage nation-wide adoption of these practices,

(iii) a review and upgrade of the energy efficiency standards for buildings and appliances (to reflect current technology and relevant life-cycle cost analyses) to ensure these standards remain valid under potentially higher energy prices

(iv) promote the use of high-efficiency consumer products including advanced building materials, Energy Star appliances, energy "smart" metering and information control devices

(v) on-peak electricity conservation to minimize the use of gas-fired electric generating plants,

(vi) the use of combined-cycle gas-fired electric generating units instead of less-efficient gas-fired boilers, and

(vii) clear natural gas and power price signals; and

(viii) remove regulatory and rate structure incentives to inefficient use of natural gas and electricity; and

WHEREAS, The NARUC, at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit"* which encouraged the NARUC Natural Gas Task Force, to review (among other things) the findings and recommendations in the NPC report that have regulatory implications for State commissions for improving and promoting energy efficiency and conservation initiatives, including consumer outreach and education, review of regulatory throughput incentives*; and*

WHEREAS, The American Council for an Energy-Efficient Economy ("ACEEE"), in its December 2003 report on *Responding to the Natural Gas Crisis: America's Best Natural Gas Energy Efficiency Programs*, (i) identified States and utilities with programs that many would consider best practice or model programs for all types of natural gas customers and all principal natural gas end-use technologies, and (ii) found that these programs are concentrated in relatively few States and regions and could be expanded in other parts of the country to great benefit; *and*

WHEREAS, the Natural Resources Defense Council (NRDC), the American Gas Association (AGA) and the ACEEE have recently adopted a Joint Statement noting that traditional rate structures often act as disincentives for natural gas utilities to aggressively encourage their customers to use less gas. Therefore, the NRDC, AGA, and the ACEEE have urged public utility commissions to align the interests of consumers, utility shareholders, and society as a whole by encouraging conservation. Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 2004 Summer Meetings in Salt Lake City, Utah, encourages State commissions and other policy makers to support the expansion of natural gas energy efficiency programs and electric energy efficiency programs, including those designed to promote consumer education, weatherization, and the use of high-efficiency appliances, where economic, and to address regulatory incentives to address inefficient use of gas and electricity; *and be it further*

RESOLVED, That the Board of Directors of the NARUC, encourages State and Federal policy makers to: (i) review and upgrade the energy efficiency standards for buildings and appliances, where economic, to ensure these standards remain valid under potentially higher energy prices, and (ii) promote the use of high-efficiency consumer products, where economic, including advanced building materials, Energy Star appliances, and energy "smart" metering and information control devices; *and be it further*

RESOLVED, That Board of Directors of NARUC encourages State Commissions to review and consider the recommendations contained in the enclosed *Joint Statement of the American Gas Association, the Natural Resources Defense Council, and the American Council for an Energy-Efficient Economy; and be it further*

RESOLVED, That the Board of Directors of the NARUC recognizes that the best approach towards promoting gas energy efficiency programs and electric energy efficiency programs for any single utility, State or region may likely depend on local issues, preferences and conditions.

Sponsored by the NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, and Committee on Energy Resources and the Environment
Adopted by the NARUC Board of Directors July 14, 2004

Resolution on Energy Efficiency and Innovative Rate Design

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review the incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response; *and*

WHEREAS, The NARUC at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit,"* which encouraged the NARUC Natural Gas Task Force to review the findings and recommendations of the September 23, 2003 report by the National Petroleum Council on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy* and its recommendations for improving and promoting energy efficiency and conservation initiatives; *and*

WHEREAS, The NARUC at its 2004 Summer Meetings, adopted a *Resolution on Gas and Electric Energy Efficiency* encouraging State commissions and other policy makers to support expansion of energy efficiency programs, including consumer education, weatherization, and energy efficiency and to address regulatory incentives to inefficient use of gas and electricity; *and*

WHEREAS, These NARUC initiatives were prompted by the substantial increases in the price of natural gas in wholesale markets during the 2000-2003 period when compared to the more moderate prices that prevailed throughout the 1990s; *and*

WHEREAS, The wholesale natural gas prices of the last five years largely reflect the fact that the demand by consumers for natural gas has been growing steadily while, for a variety of reasons, the supply of natural gas has had difficulty keeping pace, leading to a situation where natural gas demand and supply are narrowly in balance and where even modest increases in demand produce sharp increases in price; *and*

WHEREAS, Hurricanes Katrina and Rita, in addition to damaging the States of Alabama, Mississippi, Louisiana, and Texas, significantly damaged the nation's onshore and offshore energy infrastructure, resulting in significant interruption in the production and delivery of both oil and natural gas in the Gulf Coast area; *and*

WHEREAS, The confluence of a tight balance of natural gas supply and demand and these natural disasters has driven natural gas prices in wholesale markets to unprecedented levels; *and*

WHEREAS, The present high and unprecedented level of natural gas prices are imposing significant burdens on the nation's natural gas consumers, whether residential, commercial, or industrial, and will likely be injurious to the nation's economy as a whole; *and*

WHEREAS, The recently enacted Energy Policy Act of 2005 contains a number of provisions aimed at encouraging further natural gas production in order to bring down prices for consumers, but these actions, together with any further action on energy issues by Congress, are unlikely to bring forth additional supplies of natural gas in the short term; *and*

WHEREAS, Energy conservation and energy efficiency are, in the short term, the actions most likely to reduce upward pressure on natural gas prices and to assist in bringing energy prices down, to the benefit of all natural gas consumers; *and*

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

WHEREAS, Current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers; *now therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC), convened in its November 2005 Annual Convention in Indian Wells, California, encourages State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices; *and be it further*

RESOLVED, That NARUC recognizes that the best approach toward promoting energy efficiency programs for any utility, State, or region may likely depend on local issues, preferences, and conditions.

Sponsored by the Committee on Gas
Recommended by the NARUC Board of Directors November 15, 2005
Adopted by the NARUC November 16, 2005

Resolution Supporting the National Action Plan on Energy Efficiency

WHEREAS, The United States is in an increasing energy cost environment, both for the cost of energy commodities and new energy infrastructure, such that there is uniform recognition at every level of government and industry that concerted efforts and attention must be focused on ways to conserve energy and utilize it more efficiently in order to reduce the corresponding costs to both consumers and our economy; *and*

WHEREAS, The Department of Energy (DOE), the Environmental Protection Agency (EPA), and other government and non-profit agencies are working with a number of public and private entities in numerous States to identify, implement and improve public policy and planning efforts related to the achievement of energy efficiency objectives; *and*

WHEREAS, The Board of Directors of the National Association of Regulatory Utility Commissioners adopted a "Resolution on Gas and Electric Energy Efficiency" at its July 2004 meeting that encouraged State policy makers to: (1) support the expansion of energy efficiency programs; (2) review and upgrade energy efficiency standards for buildings and appliances and promote the use of high-efficiency consumer products, including smart metering and information control devices; and (3) recognize that the best approach for promoting such programs may depend on local issues, preferences, and conditions; *and*

WHEREAS, The National Action Plan on Energy Efficiency was released on July 31, 2006, recommending key action items for public policymakers and private industry to consider in each region, with the goal of saving consumers billions of dollars in energy costs over the next 15 years; *and*

WHEREAS, The following five recommendation areas comprise the key elements of the 2006 National Action Plan on Energy Efficiency: (1) Recognize energy efficiency as a high priority energy resource; (2) Make a strong, long-term commitment to cost-effective energy efficiency as a resource; (3) Broadly communicate the benefits of and opportunities for energy efficiency; (4) Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective; and (5) Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 2006 Summer Meeting in San Francisco, California, reaffirms its support for the Association's July 2004 "Resolution on Gas and Electric Energy Efficiency"; *and be it further*

RESOLVED, That the Board of Directors commends the commitments made on July 31, 2006 at the opening session of these meetings by a number of State commissions and other stakeholders to take specific actions to move their States aggressively toward increased energy efficiency; *and be it further*

RESOLVED, That the Board of Directors endorses the principal objectives and recommendations of the National Action Plan on Energy Efficiency, and commends to its member commissions a State-specific, and where appropriate, regional review of the elements and potential applicability of the energy efficiency policy recommendations outlined in the Plan, in an effort to identify potential improvements in energy efficiency policy nationwide.

Sponsored by the Executive Committee and the Committees on Consumer Affairs, Electricity, Energy Resources and the Environment, and Gas
Adopted by the NARUC Board of Directors August 2, 2006

Resolution Supporting the National Action Plan for Energy Efficiency VISION FOR 2025: Developing a Framework for Change

WHEREAS, The National Action Plan for Energy Efficiency (Action Plan) was released on July 31, 2006, recommending key action items for public policymakers and private industry to consider in each region, with the goal of saving consumers billions of dollars in energy costs over the next 15 years; *and*

WHEREAS, The Action Plan presented the following five key policy recommendations for fully developing the cost-effective energy resources in this country: (1) Recognize energy efficiency as a high priority energy resource; (2) Make a strong, long-term commitment to cost-effective energy efficiency as a resource; (3) Broadly communicate the benefits of and opportunities for energy efficiency; (4) Provide sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective; and (5) Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments; *and*

WHEREAS, On August 2, 2006, the Board of Directors of the National Association of Regulatory Utility Commissioners adopted a "*Resolution Supporting the National Action Plan on Energy Efficiency*" that endorsed the principal objectives and recommendations of the Action Plan; commended to member commissions a State-specific and regional review of its recommendations to identify potential improvements in energy efficiency policy; and encouraged State commissions and other stakeholders to take specific actions to move their States aggressively toward increased energy efficiency; *and*

WHEREAS, The aspirational goal for the Action Plan is to achieve all cost-effective energy efficiency by 2025; *and*

WHEREAS, The National Action Plan for Energy Efficiency Leadership Group identifies 10 implementation goals necessary to meet the objective of achieving all cost-effective energy efficiency in its *Vision for 2025*: *Developing a Framework for Change*; *and*

WHEREAS, The 10 implementation goals are as follows:

1. Establishing Cost-Effective Energy Efficiency as a High-Priority Resource;
2. Developing Processes to Align Utilities Incentives Equally for Efficiency and Supply Resources;
3. Establishing Cost-Effectiveness Tests;
4. Establishing Evaluation, Measurement and Verification Measures;
5. Establishing Effective Energy Efficiency Delivery Mechanisms;
6. Developing State Policies to Ensure Robust Energy Efficiency Practices;
7. Aligning Customer Pricing and Incentives to Encourage Investment in Energy Efficiency;
8. Establishing State-of-the-Art Billing Systems;
9. Implementing State-of-the-Art Efficiency Information Sharing and Delivery Systems; and
10. Implementing Advanced Technologies; *and*

WHEREAS, NARUC's support for the *Vision for 2025: Developing a Framework for Change* recognizes the key role to be played by State commissions in achieving the full potential of energy efficiency; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened in its 2008 Winter Meetings in Washington, D.C., endorses the principal objectives and recommendations expressed by the National Action Plan for Energy Efficiency Leadership Group in its *Vision for 2025*: *Developing a Framework for Change*; *and be it further*

RESOLVED, That the Board of Directors commends to its member commissions the guidance provided by the *Vision for 2025: Developing a Framework for Change* to advance State-specific policies and frameworks enabling the acquisition of all cost effective energy efficiency by 2025.

Sponsored by the Committee on Energy Resources and the Environment
Adopted by the Board of Directors February 20, 2008

Resolution on Second Joint Statement of the American Gas Association and the Natural Resources Defense Council in Support of Measures to Promote Increased Energy Efficiency and Reduction in Greenhouse Gas Emissions

WHEREAS, On August 2, 2006, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution, *Resolution Supporting the National Action Plan on Energy Efficiency***,** sponsored by the Executive Committee and the Committees on Consumer Affairs, Electricity, Energy Resources and the Environment, and Gas, "endorsing the principal objectives and recommendations of the National Action Plan on Energy Efficiency and commend[ing] to its member commissions a State-specific, and where appropriate, regional review of the elements and potential applicability of the energy efficiency policy recommendations outlined in the Plan, in an effort to identify potential improvements in energy efficiency policy nationwide"; *and*

WHEREAS, In adopting this resolution, NARUC commended the commitments made on July 31, 2006, by a number of State commissions and other stakeholders to take specific actions to move their States aggressively toward increased energy efficiency; *and*

WHEREAS, This Resolution also recognized the five recommendations comprising the key elements of the 2006 National Action Plan on Energy Efficiency including recommendation number five to "[m]odify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments"; *and*

WHEREAS, On July 14, 2004, NARUC adopted a *Resolution on Gas and Electric Energy Efficiency* sponsored by the NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, and Committee on Energy Resources and the Environment, which "encourages State Commissions to review and consider the recommendations contained in the enclosed *Joint Statement of the American Gas Association, the Natural Resources Defense Council, and the American Council for an Energy Efficient Economy*;" *and*

WHEREAS, In May 2008, the American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) issued a *Second Joint Statement*, which has been reviewed and endorsed by the Alliance to Save Energy and the American Council for Energy Efficient Economy; *and*

WHEREAS, The *Second Joint Statement*[1] supports three common objectives: 1) removing disincentives for utilities to promote energy efficiency and reduce greenhouse gas emissions, and uniting to achieve increased savings through programs and standards; 2) developing performance-based incentives for utilities to promote energy efficiency and reduced greenhouse gas emissions; and 3) recognizing the potential contributions of efficient natural gas use in promoting reduced greenhouse gas emissions; *and*

---

[1] http://www.aga.org/NR/rdonlyres/CC8D9622-9E61-47F4-9154-BC46302E41DD/0/0805NRDCAGA2.pdf

WHEREAS, These objectives are consistent with those laid out in the 2006 National Action Plan for Energy Efficiency, objectives recognized in previous NARUC resolutions, and actions taken by a number of State Commissions seeking to remove utility disincentives to promote energy efficiency and to develop mechanisms that link energy efficiency incentives to independently verified net benefits that utilities deliver to customers through either successful administration of cost-effective efficiency programs and other authorized efficiency programs that serve low-income constituencies, particularly in the green-collar job creation opportunities in manufacturing, installation, and weatherization, or contributions to enactment of cost-effective efficiency standards and tax incentives; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2008 Summer Meetings in Portland, Oregon, encourages commissions to consider the principles and recommendations set out in the *Second Joint Statement of the American Gas Association and the Natural Resources Defense Council* and encourages State Commissions and other policymakers to review and give strong consideration to favorably approving gas distribution proposals consistent with these principles and recommendations.

____

Sponsored by the Committees on Gas and Energy Resources and the Environment
Adopted by the Board of Directors July 23, 2008

Natural Gas Utilities
With Decoupled Base Rates

State	Company	Year	Type	Reference
Arkansas	Arkansas Oklahoma Gas	2007	Revenue Adjustment Rider	Docket No. 07-026-U
	Arkansas Western Gas	2007	Revenue Adjustment Rider	Docket No. 06-124-U
	CenterPoint Energy	2007	Revenue Adjustment Rider	Docket No. 06-161-U
California	Pacific Gas and Electric	1981	Revenue Adjustment Rider	Decision No. 93887
	San Diego Gas & Electric	2004	Revenue Adjustment Rider	Decision No. 05-03-023
	Southern California Gas	1997	Revenue Adjustment Rider	Decision No. 97-07-054
	Southwest Gas	2004	Revenue Adjustment Rider	Decision No. 04-03-034
Colorado	Public Service Company of Colorado	2007	Revenue Adjustment Rider	Docket No. 06-656G
Georgia	Atlanta Gas Light	1998	Fixed Charge Rate Design	Docket No. 8390
Illinois	North Shore Gas	2007	Revenue Adjustment Rider	Docket No. 07-0241
	Peoples Gas	2007	Revenue Adjustment Rider	Docket No. 07-0242
Indiana	Citizens Gas & Coke	2007	Revenue Adjustment Rider	Cause No. 42767
	Vectren Energy	2006	Revenue Adjustment Rider	Cause No. 43046
Maryland	Baltimore Gas and Electric	1998	Revenue Adjustment Rider	Case No. 8780
	Elkton Gas	2008	Revenue Adjustment Rider	Case No. 9126
	Washington Gas Light	2005	Revenue Adjustment Rider	Case No. 8990
Massachusetts	Bay State Gas Company	2009	Revenue Adjustment Rider	D.P.U. 09-30
Missouri	Atmos Energy	2007	Fixed Charge Rate Design	Docket No. GR2006-0387
	Missouri Gas Energy	2007	Fixed Charge Rate Design	Docket No. GR2006-0422
Nevada	Southwest Gas	2009	Revenue Adjustment Rider	Docket No. 09-04-003

Natural Gas Utilities
With Decoupled Base Rates

State	Company	Year	Type	Reference
New Jersey	New Jersey Natural Gas	2006	Revenue Adjustment Rider	Docket No. GR0512020
	South Jersey Gas	2006	Revenue Adjustment Rider	Docket No. GR0512019
New York	Central Hudson Electric and Gas	2009	Revenue Adjustment Rider	Case No. 08-G-0888
	Consolidated Edison of New York	2007	Revenue Adjustment Rider	Case No. 06-G-1322
	National Fuel Gas	2007	Revenue Adjustment Rider	Case No. 07-G-0141
North Carolina	Piedmont Natural Gas	2005	Revenue Adjustment Rider	Docket No. G-09-499
	Public Service Company of North Carolina	2008	Revenue Adjustment Rider	Docket No. G-05-495
North Dakota	Excel Energy	2005	Fixed Charge Rate Design	Case No. PU04-578
Ohio	Columbia Gas of Ohio	2009	Fixed Charge Rate Design	Docket No. 08-72-GA-AIR
	Dominion East Ohio Gas	2008	Fixed Charge Rate Design	Docket No. 07-829-GA-AIR
	Duke Energy Ohio	2008	Fixed Charge Rate Design	Docket No. 07-589-GA-AIR
	Vectren Energy	2009	Fixed Charge Rate Design	Docket No. 07-1080-GA-AIR
Oregon	Cascade Natural Gas	2006	Revenue Adjustment Rider	Docket No. UG-167
	Northwest Natural Gas	2002	Revenue Adjustment Rider	Docket No. UG-143
Utah	Questar Gas	2006	Revenue Adjustment Rider	Docket No. 05-057
Virginia	Virginia Natural Gas	2008	Revenue Adjustment Rider	Case No. PUE-2008-00060
Washington	Avista	2007	Revenue Adjustment Rider	Docket No. UG-060518
	Cascade Natural Gas	2007	Revenue Adjustment Rider	Docket No. UG-060256
Wisconsin	Wisconsin Public Service Company	2009	Revenue Adjustment Rider	Docket No. 6690-UR-119

The McGraw-Hill Companies

J.D. POWER AND ASSOCIATES

Press Release

J.D. Power and Associates Reports:
Overall Customer Satisfaction with Gas Utility Companies Increases Considerably As Utilities Promote Energy Conservation in the Midst of Rising Gas Bills

CenterPoint Energy—Minnesota, MidAmerican Energy, Northwest Natural, PSNC Energy and Washington Gas Light Rank Highest in Residential Natural Gas Utility Customer Satisfaction

WESTLAKE VILLAGE, Calif.: 25 September 2008 — Overall customer satisfaction with gas utility companies has improved considerably in 2008, largely due to efforts by utility companies to promote conservation strategies that help reduce customer gas bills and positively impact the environment, according to the J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠ released today.

The study, now in its seventh year, measures residential customer satisfaction with gas utility companies across six factors: company image, communications, price and value, billing and payment, customer service and field service. Utilities are ranked in four geographical regions.

Although customer-reported gas bill amounts have increased by 6 percent since 2007, overall customer satisfaction with gas utility companies averages 640 on a 1,000 point scale in 2008, up 12 points from the previous year. The improvement in satisfaction can be attributed in large part to efforts by gas utility companies to educate customers about energy conservation and environmental issues.

The study finds that nearly one-half (48%) of gas utility customers recall receiving a communication from their gas utility in 2008—up from 39 percent in 2007—and that overall satisfaction among these customers averages 672. In contrast, overall satisfaction among customers who do not recall receiving a utility communication is 62 points lower (610). In particular, customers who received information from their gas utility companies about energy conservation tips or environmental issues were significantly more satisfied than the average customer.

“In these challenging economic times, gas utility companies can positively impact customer satisfaction levels by employing energy conservation communications and initiatives that help customers lower their bills,” said Alan Destribats, vice president of the energy practice at J.D. Power and Associates. “Working with customers on ways to conserve energy also plays an important role in supporting the responsible use of natural resources, which is also particularly satisfying to customers.”

East Region
Washington Gas Light ranks highest in the East Region, followed by South Jersey Gas, New Jersey Natural Gas, Bay State Gas, Public Service Electric & Gas, Elizabethtown Gas and NSTAR Gas, respectively.

Midwest Region
CenterPoint Energy—Minnesota and MidAmerican Energy tie to rank highest in the Midwest Region. In addition, MidAmerican Energy ranks highest in the Midwest Region for a second consecutive year. Following in the regional rankings is Louisville Gas & Electric, We Energies, Citizens Gas & Coke Utility and Aquila, respectively.

South Region
PSNC Energy ranks highest in overall customer satisfaction in the South Region. Following in the regional rankings are CPS Energy, Texas Gas Service, SCE&G, Piedmont Natural Gas, CenterPoint Energy-South and Oklahoma Natural Gas, respectively.

West Region
Northwest Natural ranks highest in the West Region for a second consecutive year. Following Northwest Natural in the regional rankings is Southern California Gas Company.

The 2008 Gas Utility Residential Customer Satisfaction Study is based on more than 29,000 online interviews conducted among residential customers of the 60 largest gas utilities across the continental United States. These utilities serve more than 48 million households. The study was fielded between September 2007 and July 2008.

About J.D. Power and Associates
Headquartered in Westlake Village, Calif., J.D. Power and Associates is a global marketing information services company operating in key business sectors including market research, forecasting, performance improvement, training and customer satisfaction. The company's quality and satisfaction measurements are based on responses from millions of consumers annually. For more information on car reviews and ratings, car insurance, health insurance, cell phone ratings, and more, please visit JDPower.com. J.D. Power and Associates is a business unit of The McGraw-Hill Companies.

About The McGraw-Hill Companies
Founded in 1888, The McGraw-Hill Companies (NYSE: MHP) is a leading global information services provider meeting worldwide needs in the financial services, education and business information markets through leading brands such as Standard & Poor's, McGraw-Hill Education, *BusinessWeek* and J.D. Power and Associates. The Corporation has more than 280 offices in 40 countries. Sales in 2007 were $6.8 billion. Additional information is available at http://www.mcgraw-hill.com.

Media Relations Contacts:
Jeff Perlman
Brandware Public Relations
Agoura Hills, Calif.
(818) 706-1915
jperlman@brandwaregroup.com

John Tews
J.D. Power and Associates
Troy, Mich.
(248) 312-4119
john.tews@jdpa.com

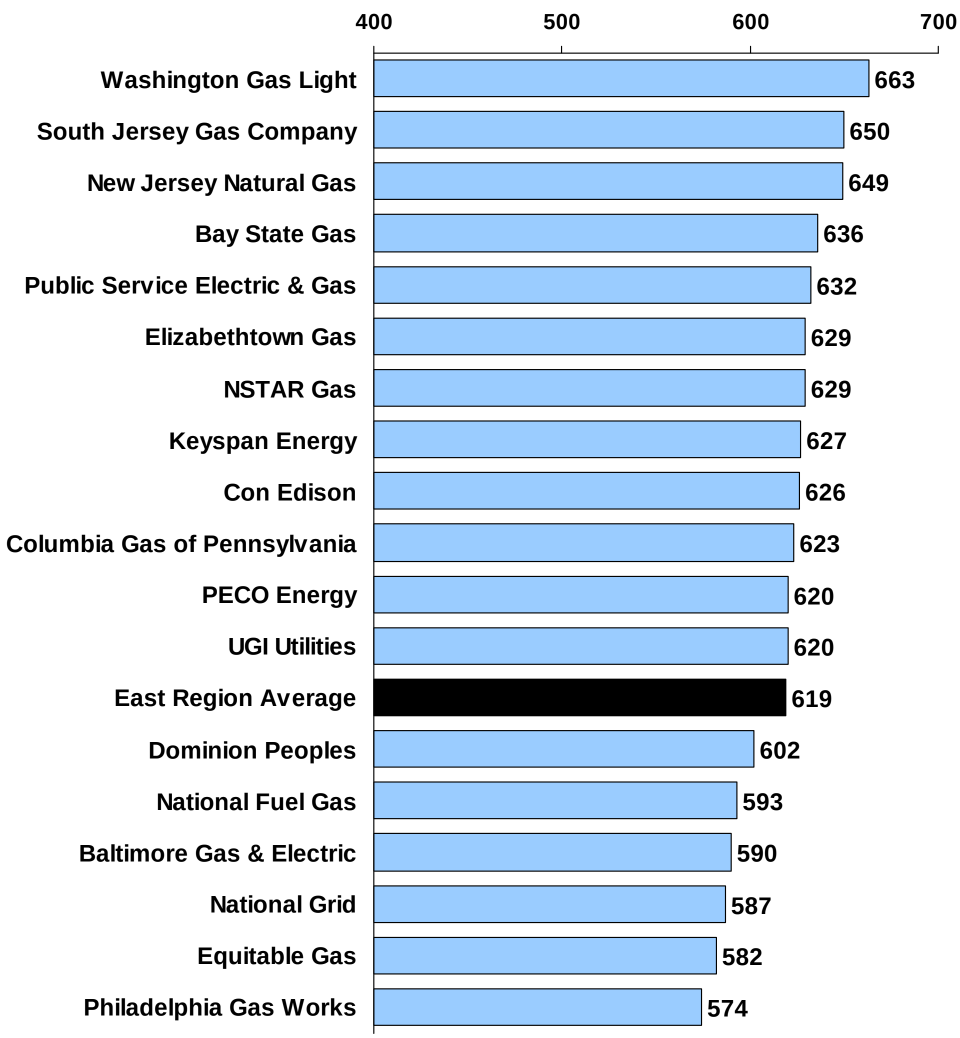
# # #

NOTE: Four charts follow.

J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

East Region

(Based on a 1,000-point scale)

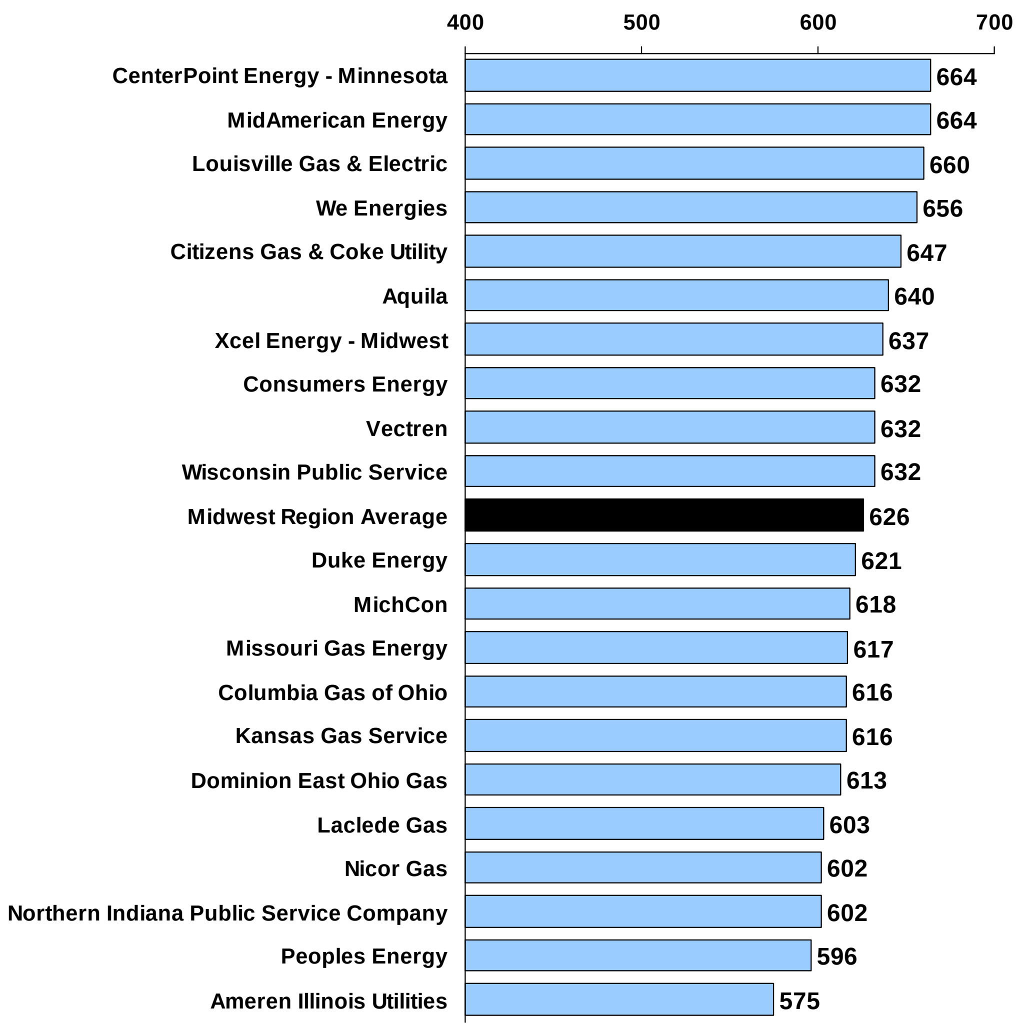


Source: J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

Midwest Region

(Based on a 1,000-point scale)

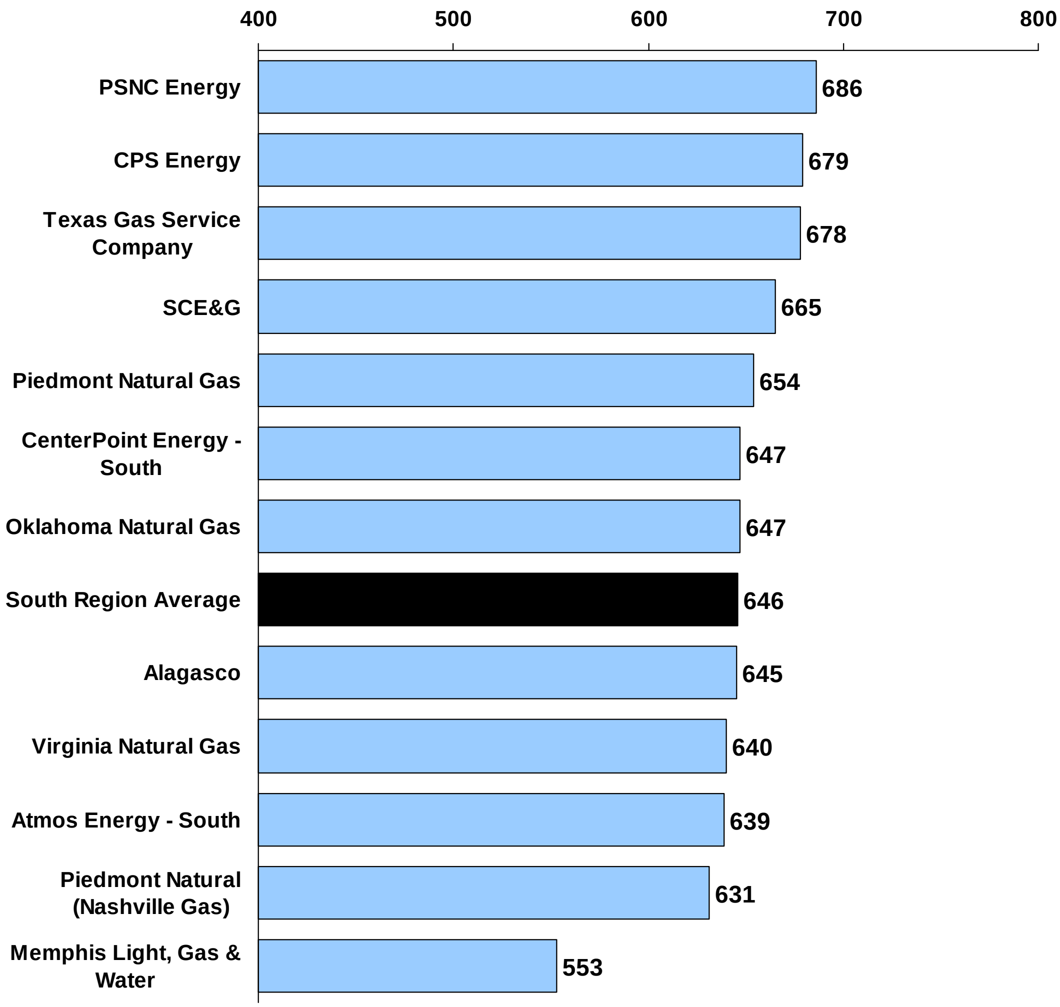


Source: J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

South Region

(Based on a 1,000-point scale)

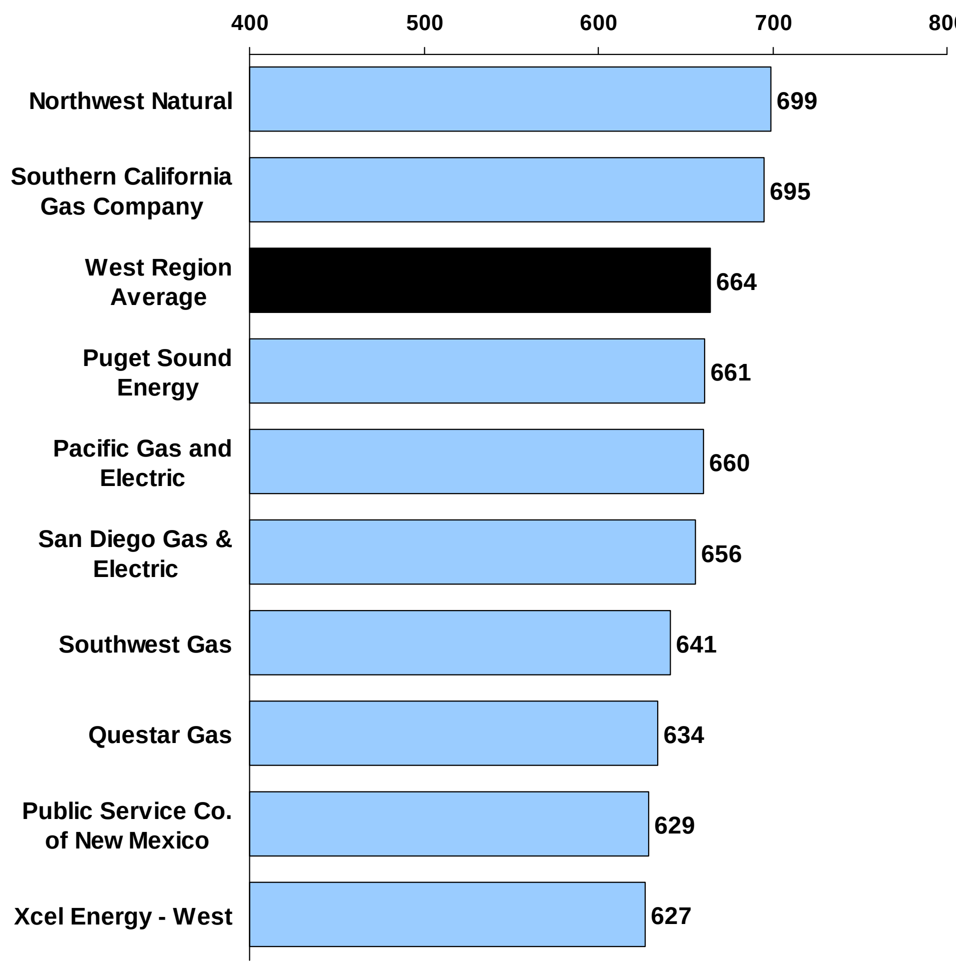


Source: J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

West Region

(Based on a 1,000-point scale)



Source: J.D. Power and Associates 2008 Gas Utility Residential Customer Satisfaction Study℠

Chattanooga Gas Company

Earned Rates of Return by Class and Required Increase to Yield Overall Rate of Return

Customer Class	Existing Revenues	Earned ROR at Present Rates	Required Increase for Equalized ROR	Required Increase % of Margin Revenues
Residential (R-1)	$ 13,273,283	-1.42%	$ 6,208,300	45.5%
Residential Multi Family (R-4)	$ 30,740	-10.27%	$ 40,217	1372.4%
Small Commercial (C-1)	$ 3,519,670	2.41%	$ 919,507	36.1%
Med. Commercial & Industrial (C-2 / T-3)	$ 7,475,290	25.59%	$ (2,552,593)	-39.7%
Industrial (F-1 / T-2)	$ 4,440,550	28.29%	$ (2,042,440)	-51.9%
TOTAL COMPANY	$ 28,915,215	6.69%	$ 2,470,107	8.5%

CHATTANOOGA GAS COMPANY
ALLOCATED COST OF SERVICE STUDY

I. PURPOSE AND GUIDING PRINCIPLES

Chattanooga Gas Company ("CGC") is proposing to change existing rates in connection with a proposed increase in base rate revenue requirements. An allocated cost of service study ("ACOSS") assesses the reasonableness of existing prices, and guides the development of price changes. In particular, the ACOSS examines all of a utility's common costs, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. An ACOSS is necessary to determine the cost responsibility for each customer class because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and rate of return on investment. The class-specific rates of return are used to guide the apportionment of the base rate increase among all of CGC's customer classes in conjunction with the development of proposed rates. The ACOSS also determines the classification of costs among demand, customer and commodity components. The classification of costs within a rate classification is used to guide the development of the form of billing rates for that class. Although the ACOSS is not the only factor relied upon to design rates, it is an invaluable guide to ensuring that the process is fair and reasonable.

The primary principle that guides the ACOSS process is that of cost causation. Each step in the development of the ACOSS is consistent with the factors that drive or contribute to the incurrence of costs on the CGC system. For example, the principle of cost causation requires that the costs incurred by the Company for meter reading be apportioned to classes on the basis of the number of meter readings in each class.

II. Specification of CGC ACOSS

A. Overview

The ACOSS follows a three-part process, which consists of the functionalization, classification and allocation of CGC's total cost of service. First, cost functionalization involves the segregation of costs into categories based on the function that each cost is incurred to provide. In the ACOSS, the functions are production, transmission, storage and distribution – the direct functions associated with costs incurred by the Company. Second, cost classification further separates costs according to the primary cost causative forces exhibited on CGC's system. The cost classifications used in the ACOSS relate to fixed costs required to serve peak requirements (demand-related), fixed costs associated with providing customers with access to and active status on the system (customer-related), and variable costs associated with system throughput (commodity-related). Finally, cost allocation takes each classification of cost for each function and apportions that cost to each of the Company's customer classes. Cost allocation utilizes a variety of factors to apportion the various types of costs among classes in a manner that is consistent with principles of cost responsibility.

B. Customer Classes

The ACOSS groups CGC customers into five groups based on rate schedules set forth in CGC's gas tariff. The ACOSS groups and associated rate schedules are: Residential (R-1), Residential Multi-Family (R-4), Small Commercial (C-1), Medium Commercial and Industrial (C-2 and T-3), and Industrial (F-1 and T-2). Rate Schedules that are grouped together within the ACOSS, *e.g.*, C-2 and T-3, reflect common base rates even though other terms and conditions of service vary including differences between sales and transportation services.

C. Data Sources

The primary data sources fall in two general categories: data related to the establishment of the total cost of service, and data used as the basis for allocating the total cost of service among customer classes. The total cost of service or revenue requirement data utilized in the ACOSS are taken from schedules supporting CGC's base rate application in this proceeding. The Company's forecasts of sales, customers and revenues by class supporting the application as adjusted for pro forma changes are used as allocation bases for several categories of costs. The remaining allocation data are derived from special studies of facility investments. All of the data utilized in the ACOSS correspond to a common time period of May 2010 through April 2011. This is the Attrition Period, which is the period for which rates are to be determined.

D. Cost Functionalization

The functionalization of costs refers to the segregation of costs among the primary functions provided by gas utilities to their retail customers. The chart of accounts prescribed by the Tennessee Regulatory Authority separates the majority of costs into the following four functions:

- *Production:* The production function includes costs associated with the upstream commodity gas supply, interstate pipeline transportation capacity necessary to deliver the supply to CGC's system, and upstream storage facilities. Additionally, the costs of any production facilities and the administrative costs associated with procuring natural gas and transportation are categorized as production-related.

- *Storage:* The storage function includes costs associated with on-system facilities that are able to receive injected supplies or delivered liquid natural gas for later withdrawals.

- *Transmission:* The transmission function includes costs associated with large diameter, high pressure facilities that deliver gas to smaller distribution facilities. Transmission facilities include transmission mains and compressors.

- *Distribution:* The distribution function includes costs associated with delivering supplies within areas that are close in proximity to gas loads, such as distribution mains. The costs associated with connecting customers to the distribution system are also considered distribution-related, which include costs associated with services, meters and regulators.

The majority of CGC's non-gas supply costs are associated with the distribution function. Costs that do not directly fall into one of these primary functions, such as administrative and general expenses, are functionalized on the same basis as other related costs.

E. Cost Classification

Classification is the apportionment of costs among demand, customer and commodity categories. Each of CGC's rate base and expense accounts is classified consistent with the manner in which the associated costs are incurred. Costs that are associated with serving peak requirements on the system are classified as demand-related, e.g., costs associated with transmission accounts. Costs that are associated with providing customers access to and active status on the distribution system are classified as customer-related. Customer-related costs are incurred regardless of the amount of gas a customer consumes in any given period and include the costs of services, meters and regulators, and meter reading and billing expenses. Costs that are associated with the quantity of gas purchased or transported are classified as commodity-related. Examples of commodity-related costs are purchased gas costs. Demand and customer-related costs are considered fixed, while commodity-related costs are variable. Some categories of costs vary with more than one of the classifications described previously.

Lastly, some categories of costs are appropriately classified based on how other related costs are classified. For example, distribution operations supervision and engineering expenses are classified based on the classification of all other distribution operations accounts.

The classification of distribution mains reflects the distinct cost causative factors that drive the Company's investments in these facilities. The first factor is the coincident peak demand on the system. Distribution mains are designed to deliver the maximum quantities that are required during a peak period from CGC's pipeline interconnects to the interconnection with each individual customer service. The second factor is the number of customers on the system. Distribution mains are also designed to deliver supplies in reasonable proximity to customers in order to minimize the length of pipe used to serve all customers in an overall efficient fashion.

The breakdown of distribution mains investment costs between the demand and customer-related components is determined through a minimum-size study. The premise underlying this study is that the size of distribution main installed in a given location is most affected by the peak load that will be served by the main, and that the length of distribution main is most affected by the number of customers that are served. The validity of this premise is supported by the system design criteria taken into consideration by the Company's distribution engineering staff.

The minimum size study evaluates the cost of replacing the existing distribution mains of the system under two different sets of assumptions. The first determines the cost of replacing existing distribution mains with the same type, diameter and lengths of pipe as is currently installed. The second determines the replacement cost assuming that the entire system is replaced with two-inch diameter plastic pipe, which is the smallest, least-expensive size and type of pipe presently being installed. The customer component of distribution mains is equal to the ratio of the replacement cost using the smallest size pipe to the replacement cost using the installed sizes of pipe. Based on the results of this study, 25% of CGC's distribution mains investment is classified as customer-related.

F. Cost Allocation

Cost allocation is the apportionment of individual elements of the Company's classified cost of service among rate classes based on each class' responsibility for the cost being incurred. Cost allocation follows cost causation principles and requires the development of numerous allocation factors that reflect the different types of costs included in CGC's overall revenue requirements. Considerable effort is required to yield the set of allocation factors underlying the ACOSS.

The ACOSS follows system-design criteria in order to allocate costs on the basis of cost causation. The demand allocator used in the ACOSS is the coincident design day demand factor. Under this method, the allocation of demand costs reflects the manner in which the Company designs, plans and constructs its system to satisfy firm demands. Off-peak loads do not increase the Company's demand-related investments, and therefore, are not factored into the demand allocator in a system-design ACOSS.

The other allocation factors used in the ACOSS may be grouped into three categories as follows: (i) class summary statistics reflected in the base rate filing, such as the number of customers and sales by class; (ii) special studies that examine the costs associated with a specific type of investment or expense; and (iii) internal allocation factors, which are composite factors determined on the basis of how related cost items are allocated. All of the various factors must be developed assuming a consistent time period for the ACOSS to be accurate.

Three special studies were performed related to significant capital investment and operations and maintenance ("O&M") expense accounts. The studies are as follows:

- *Meter Investment Study:* The meter investment study establishes the aggregate investment in meters and associated regulators based on the type and replacement cost of various meters installed to serve each class.

- *Service Investment Study:* CGC's investment in distribution services is the largest investment on its books after the Company's investment in mains. The service investment study establishes the aggregate investment in services based on the type and length of services installed to serve each class as well as the associated replacement costs.

- *Labor Expense Study:* A study of the Company's payroll expense examines components of the Company's payroll costs. The labor study is used as the basis for allocating costs that vary with direct payroll costs, such as pensions and benefits costs.

Together, these special studies are utilized to allocate a substantial portion of the Company's total revenue requirements to customer classes.

Gas costs represent a significant proportion of the Company's overall O&M expense. Gas costs are recovered through the Company's Purchased Gas Adjustment clause and are excluded from the ACOSS, which focuses on base rate revenue requirements.

III. Results

Detailed ACOSS results are provided in Exhibit DPY-7, pages eight through thirteen. Pages eight and nine provide an income statement by class at existing and proposed rates, respectively. Pages ten, eleven and twelve contain summaries of allocated rate base, O&M expense and total revenue requirements by classification and rate class. Lastly, page thirteen provides a detailed analysis of the components of monthly customer-related costs.

The ACOSS demonstrates that the rates of return for the Residential (R-1), Residential Multi-Family (R-4) and Small Commercial (C-1) classes are far below the system-average rate of return of 6.25% at present rates. The Residential class is by far CGC's largest class. The rate of return for all other classes is well above the system-average, indicating that these classes are subsidizing the prices for residential small commercial customers.

Page eight of Exhibit DPY-7 also provides the required revenue increase for each of the classes that is necessary to yield the proposed overall rate of return on allocated rate base of 8.28%. The increase to the residential class necessary to achieve parity in terms of rate of return exceeds the total revenue request sought by CGC in this proceeding.

Monthly customer costs are derived from the costs that are classified as customer-related and the apportionment of these costs to CGC's various customer classes. The system-wide average monthly customer cost is $21, and the cost generally varies with the size of the customer. The lowest average customer cost of $10 per month is associated with serving the Residential Multi-Family class.

The results of the ACOSS clearly indicate that class-differentiated base rate revenue increases are appropriate given the wide disparity in rates of return by customer class. In addition, the monthly customer-related costs should be taken into consideration in the development of proposed modifications to existing customer charges.

Chattanooga Gas Company
Income and Rate of Return at Present Rates

	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-2 Industrial
REVENUES						
Margin Revenues	$ 28,739,533	$ 13,273,283	$ 30,740	$ 3,519,670	$ 7,475,290	$ 4,440,550
PGA Revenues	-	-	-	-	-	-
Miscellaneous Revenues	879,209	519,764	1,846	119,642	141,099	96,858
Total	**$ 29,618,742**	**$ 13,793,047**	**$ 32,586**	**$ 3,639,312**	**$ 7,616,389**	**$ 4,537,408**
OPERATING EXPENSES						
Operations and Maintenance	$ 12,022,379	$7,728,462	$30,324	$1,763,205	$1,791,012	$709,377
Depreciation and Amortization	5,119,444	3,349,742	11,122	732,989	751,646	273,945
Deferred Income Taxes	-	-	-	-	-	-
Taxes Other Than Income Taxes	3,710,522	2,247,038	7,756	525,159	679,842	250,726
Total	**$ 20,852,345**	**$ 13,325,242**	**$ 49,202**	**$ 3,021,353**	**$ 3,222,500**	**$ 1,234,048**
OPERATING INCOME BEFORE TAXES	**$ 8,766,397**	**$ 467,805**	**$ (16,616)**	**$ 617,959**	**$ 4,393,889**	**$ 3,303,359**
INCOME TAXES						
Federal Income Taxes	$ 2,049,929	$ 1,211,861	$ 4,304	$ 278,953	$ 328,982	$ 225,830
State Income Taxes	396,154	234,195	832	53,908	63,577	43,642
Total	**$ 2,446,083**	**$ 1,446,056**	**$ 5,135**	**$ 332,862**	**$ 392,558**	**$ 269,472**
RATEMAKING ADJUSTMENTS	**$ 220,005**	**$157,485**	**$667**	**$35,531**	**$13,806**	**$12,517**
NET INCOME	**$ 6,540,319**	**$ (820,766)**	**$ (21,084)**	**$ 320,628**	**$ 4,015,137**	**$ 3,046,404**
RATE BASE	**$ 97,759,976**	**$57,792,965**	**$205,244**	**$13,303,129**	**$15,688,952**	**$10,769,686**
RATE OF RETURN AT PRESENT RATE!	**6.69%**	**-1.42%**	**-10.27%**	**2.41%**	**25.59%**	**28.29%**
PROPOSED REVENUE INCREASE						
Return	$ 1,555,935					
Margin Factor	1.654					
Total Revenue Increase	**$ 2,572,993**					
REVENUE REQUIREMENT INCREASE						
Incremental Income Tax Revenue Req.	$ 1,017,058	$ 601,256	$ 2,135	$ 138,401	$ 163,222	$ 112,044
Incremental Margin Rev. Requirement	1,555,933	5,607,044	38,082	781,106	(2,715,815)	(2,154,484)
Total Incremental Rev. Requirement for Equalized Rate of Return of 8.28%	**$ 2,572,991**	**$ 6,208,300**	**$ 40,217**	**$ 919,507**	**$ (2,552,593)**	**$ (2,042,440)**

Chattanooga Gas Company
Income and Rate of Return at Proposed Rates

	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-2 Industrial
REVENUES						
Margin Revenues	$ 31,315,319	$ 15,092,223	$ 33,480	$ 4,001,999	$ 7,645,568	$ 4,542,050
PGA Revenues	-	-	-	-	-	-
Miscellaneous Revenues	879,209	519,764	1,846	119,642	141,099	96,858
Total	**$ 32,194,528**	**$ 15,611,987**	**$ 35,326**	**$ 4,121,641**	**$ 7,786,667**	**$ 4,638,908**
OPERATING EXPENSES						
Operations and Maintenance	$ 12,037,700	$7,736,362	$30,342	$1,765,103	$1,795,642	$710,252
Depreciation and Amortization	5,119,444	3,349,742	11,122	732,989	751,646	273,945
Deferred Income Taxes	-	-	-	-	-	-
Taxes Other Than Income Taxes	3,710,522	2,247,038	7,756	525,159	679,842	250,726
Total	**$ 20,867,666**	**$ 13,333,142**	**$ 49,220**	**$ 3,023,251**	**$ 3,227,130**	**$ 1,234,923**
OPERATING INCOME BEFORE TAXES	**$ 11,326,862**	**$ 2,278,845**	**$ (13,894)**	**$ 1,098,389**	**$ 4,559,537**	**$ 3,403,985**
INCOME TAXES						
Federal Income Taxes	$ 2,888,029	$ 1,707,322	$ 6,063	$ 393,002	$ 463,484	$ 318,158
State Income Taxes	562,584	332,584	1,181	76,556	90,286	61,977
Total	**$ 3,450,613**	**$ 2,039,906**	**$ 7,244**	**$ 469,558**	**$ 553,770**	**$ 380,135**
RATEMAKING ADJUSTMENTS	**$ 220,005**	**$157,485**	**$667**	**$35,531**	**$13,806**	**$12,517**
NET INCOME	**$ 8,096,254**	**$ 396,423**	**$ (20,471)**	**$ 664,362**	**$ 4,019,573**	**$ 3,036,366**
RATE BASE	**$ 97,759,976**	**$57,792,965**	**$205,244**	**$13,303,129**	**$15,688,952**	**$10,769,686**
RATE OF RETURN AT PROPOSED RAT	**8.28%**	**0.69%**	**-9.97%**	**4.99%**	**25.62%**	**28.19%**

Chattanooga Gas Company
Rate Base

	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-2 Industrial
I. PLANT IN SERVICE						
Demand	$ 103,664,336	$ 51,127,550	$ 361,080	$19,455,765	$23,051,528	$9,668,414
Customer	99,752,581	79,198,871	114,855	10,524,640	7,996,236	1,917,979
Commodity	-	-	-	-	-	-
	$ 203,416,917	$130,326,421	$475,935	$29,980,405	$31,047,764	$11,586,392
II. ACCUMULATED RESERVE FOR DEPRECIATION						
Demand	$ 48,446,868	$ 23,894,198	$ 168,749	$9,092,573	$10,772,992	$4,518,355
Customer	47,724,682	37,944,858	55,470	5,028,548	3,794,875	900,931
Commodity	-	-	-	-	-	-
	$ 96,171,550	$61,839,056	$224,219	$14,121,122	$14,567,867	$5,419,286
III. NET PLANT IN SERVICE						
Demand	$ 55,217,468	$ 27,233,352	$ 192,330	$10,363,191	$12,278,535	$5,150,059
Customer	52,027,899	41,254,013	59,385	5,496,092	4,201,362	1,017,048
Commodity	-	-	-	-	-	-
	$ 107,245,367	$68,487,365	$251,715	$15,859,283	$16,479,897	$6,167,107
IV. RATE BASE ADDITIONS						
Demand	$ 17,291,405	$ 6,105,874	$ 13,744	$1,345,917	$3,687,402	$6,138,467
Customer	889,687	554,261	1,093	105,830	188,213	40,290
Commodity	-	-	-	-	-	-
	$ 18,181,091	$6,660,135	$14,837	$1,451,747	$3,875,614	$6,178,758
V. RATE BASE DEDUCTIONS						
Demand	$ (14,352,306)	$ (7,118,244)	$ (45,936)	($2,581,051)	($3,332,384)	($1,274,692)
Customer	(13,314,177)	(10,236,292)	(15,371)	(1,426,851)	(1,334,175)	(301,487)
Commodity	-	-	-	-	-	-
	$ (27,666,483)	($17,354,536)	($61,308)	($4,007,902)	($4,666,559)	($1,576,179)
VI. TOTAL RATE BASE						
Demand	**$ 58,156,566**	**$ 26,220,982**	**$ 160,138**	**$9,128,058**	**$12,633,553**	**$10,013,834**
Customer	**39,603,410**	**31,571,982**	**45,106**	**4,175,071**	**3,055,399**	**755,851**
Commodity	**-**	**-**	**-**	**-**	**-**	**-**
	$ 97,759,976	**$57,792,965**	**$205,244**	**$13,303,129**	**$15,688,952**	**$10,769,686**

Chattanooga Gas Company
O&M Expense

	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-2 Industrial
I. STORAGE EXPENSE						
Demand	$ 913,716	$ 450,657	$ 3,183	$ 171,493	$ 203,181	$ 85,202
Customer	-	-	-	-	-	-
Commodity	-	-	-	-	-	-
	$ 913,716	$450,657	$3,183	$171,493	$203,181	$85,202
II. TRANSMISSION EXPENSE						
Demand	$ -	$ -	$ -	$ -	$ -	$ -
Customer	-	-	-	-	-	-
Commodity	-	-	-	-	-	-
	$ -	$0	$0	$0	$0	$0
III. DISTRIBUTION EXPENSE						
Demand	$ 648,138	$ 319,670	$ 2,258	$121,647	$144,125	$60,438
Customer	1,195,262	886,531	1,648	140,572	121,472	45,039
Commodity	-	-	-	-	-	-
	$ 1,843,400	$1,206,201	$3,906	$262,219	$265,597	$105,477
IV. CUSTOMER ACCOUNTS EXPENSE						
Demand	$ 186,072	$ 95,950	$ 221	$ 23,054	$ 56,229	$ 10,619
Customer	1,636,026	1,369,667	4,708	175,106	77,810	8,734
Commodity	-	-	-	-	-	-
	$ 1,822,097	$1,465,617	$4,929	$198,160	$134,038	$19,353
V. CUSTOMER SERVICE AND SALES EXPENSE						
Demand	$ -	$ -	$ -	$ -	$ -	$ -
Customer	184,524	159,463	557	19,489	4,832	184
Commodity	-	-	-	-	-	-
	$ 184,524	$ 159,463	$ 557	$ 19,489	$ 4,832	$ 184
VI. ADMINISTRATIVE AND GENERAL EXPENSE						
Demand	$ 3,569,962	$ 1,755,311	$ 12,342	$666,089	$793,186	$343,034
Customer	3,704,001	2,699,114	5,426	447,653	394,807	157,002
Commodity	-	-	-	-	-	-
	$ 7,273,963	$4,454,425	$17,767	$1,113,742	$1,187,993	$500,036
VII. TOTAL O&M EXPENSE						
Demand	**$ 5,317,888**	**$ 2,621,587**	**$ 18,003**	**$ 982,284**	**$ 1,196,722**	**$ 499,293**
Customer	**6,719,813**	**5,114,775**	**12,339**	**782,819**	**598,920**	**210,959**
Commodity	**-**	**-**	**-**	**-**	**-**	**-**
	$ 12,037,700	**$ 7,736,362**	**$ 30,342**	**$ 1,765,103**	**$ 1,795,642**	**$ 710,252**

Chattanooga Gas Company
Total Revenue Requirements

		Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-2 Industrial
I. O&M EXPENSE							
	Demand	$ 5,317,888	$ 2,621,587	$ 18,003	$ 982,284	$ 1,196,722	$ 499,293
	Customer	6,719,813	5,114,775	12,339	782,819	598,920	210,959
	Commodity	-	-	-	-	-	-
		$ 12,037,700	$ 7,736,362	$ 30,342	$ 1,765,103	$ 1,795,642	$ 710,252
II. DEPRECIATION							
	Demand	$ 2,365,506	$ 1,166,625	$ 8,239	$ 443,923	$ 526,004	$ 220,714
	Customer	2,753,938	2,183,117	2,883	289,066	225,642	53,231
	Commodity	-	-	-	-	-	-
		$ 5,119,444	$ 3,349,742	$ 11,122	$ 732,989	$ 751,646	$ 273,945
III. TAXES OTHER THAN INCOME							
	Demand	$ 1,999,561	$ 978,694	$ 5,721	$ 336,582	$ 475,744	$ 202,819
	Customer	1,710,961	1,268,344	2,035	188,577	204,098	47,907
	Commodity	-	-	-	-	-	-
		$ 3,710,522	$2,247,038	$7,756	$525,159	$679,842	$250,726
IV. RATEMAKING ADJUSTMENTS							
	Demand	$ (100,843)	$ (47,970)	$ (532)	$ (23,943)	$ (16,146)	$ (12,252)
	Customer	(119,162)	(109,515)	(135)	(11,588)	2,340	(264)
	Commodity	-	-	-	-	-	-
		$ (220,005)	($157,485)	($667)	($35,531)	($13,806)	($12,517)
V. RETURN							
	Demand	$ 4,816,390	$ 2,171,560	$ 13,262	$ 755,964	$ 1,046,281	$ 829,322
	Customer	3,279,862	2,614,718	3,736	345,770	253,041	62,598
	Commodity	-	-	-	-	-	-
		$ 8,096,252	$4,786,278	$16,998	$1,101,734	$1,299,322	$891,920
VI. INCOME TAXES							
	Demand	$ 2,052,740	$ 925,516	$ 5,652	$ 322,191	$ 445,924	$ 353,456
	Customer	1,397,873	1,114,390	1,592	147,367	107,846	26,679
	Commodity	-	-	-	-	-	-
		$ 3,450,613	$2,039,906	$7,244	$469,558	$553,770	$380,135
VII. TOTAL REVENUE REQUIREMENTS							
	Demand	**$ 16,451,241**	**$ 7,816,013**	**$ 50,345**	**$ 2,817,002**	**$ 3,674,529**	**$ 2,093,352**
	Customer	**15,743,285**	**12,185,828**	**22,450**	**1,742,011**	**1,391,887**	**401,109**
	Commodity	**-**	**-**	**-**	**-**	**-**	**-**
		$ 32,194,526	**$20,001,841**	**$72,795**	**$4,559,012**	**$5,066,416**	**$2,494,462**

Chattanooga Gas Company
Monthly Customer Cost Detail

	Total System	R-1 Residential	R-4 Multi-Family	C-1 Small Commercial	C-2 / T-3 Medium C&I	F-1 / T-2 Industrial
I. AVERAGE CUSTOMER COSTS						
Customer-Related Revenue Req.	$ 15,743,285	$ 12,185,828	$ 22,450	$ 1,742,011	$ 1,391,887	$ 401,109
Average Customers	61,260	52,940	185	6,470	1,604	61
Average Monthly Customer Cost	**$ 21.42**	**$ 19.18**	**$ 10.11**	**$ 22.44**	**$ 72.31**	**$ 547.96**
II. MONTHLY CUSTOMER COST DETAIL						
O&M Expense						
Mains and Services Expense	$ 0.72	$ 0.70	$ 0.31	$ 0.66	$ 1.49	$ 1.40
Meter & Regulator Expense	0.55	0.35	0.12	0.79	4.19	56.11
Meter Reading Expense	0.59	0.59	0.59	0.59	0.59	0.59
Customer Records and Collections	1.68	1.68	1.68	1.68	1.68	1.68
Uncollectible Accounts	0.17	0.10	0.07	0.20	1.99	9.88
All Other O&M	5.43	4.63	2.79	6.17	21.18	218.54
Total O&M	$ 9.14	$ 8.05	$ 5.56	$ 10.08	$ 31.12	$ 288.20
Depreciation						
Mains	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62	$ 0.62
Services	2.30	2.14	0.35	2.14	7.31	31.02
Meters and Meter Installations	0.19	0.12	0.04	0.26	1.40	18.79
Regulators	0.01	0.01	0.00	0.02	0.09	1.16
All Other Depreciation	0.62	0.54	0.28	0.68	2.30	21.13
Total Depreciation	$ 3.75	$ 3.44	$ 1.30	$ 3.72	$ 11.72	$ 72.72
Taxes Other Than Income Taxes	$ 2.33	$ 2.00	$ 0.92	$ 2.43	$ 10.60	$ 65.45
Deferred Income Taxes	$ -	$ -	$ -	$ -	$ -	$ -
Ratemaking Adjustments	$ (0.16)	$ (0.17)	$ (0.06)	$ (0.15)	$ 0.12	$ (0.36)
Rate Base-Related (Return and Income Taxes)						
Mains	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99	$ 1.99
Services	5.36	4.94	0.83	5.06	17.72	86.49
Meters and Meter Installations	0.54	0.34	0.12	0.77	4.09	54.82
Regulators	0.03	0.02	0.01	0.04	0.23	3.08
All Other Rate Base-Related	(1.55)	(1.42)	(0.54)	(1.51)	(5.28)	(24.42)
Total Rate Base-Related	$ 6.36	$ 5.87	$ 2.40	$ 6.35	$ 18.75	$ 121.96
Total Average Monthly Customer Cost	**$ 21.42**	**$ 19.18**	**$ 10.11**	**$ 22.44**	**$ 72.31**	**$ 547.96**

Chattanooga Gas Company

Comparison of Customer-Related Costs and Customer Charges

Customer Class	Existing Customer Charge	Customer Costs	Difference	Proposed Charge	Increase
Residential (R-1)					
Winter	$ 12.00			$ 16.00	$ 4.00
Summer	$ 10.00			$ 11.00	$ 1.00
Average	$ 11.00	$ 19.18	$ 8.18	$ 13.50	$ 2.50
Residential Multi Family (R-4)	$ 6.00	$ 10.11	$ 4.11	$ 6.00	$ -
Small Commercial (C-1)					
Winter	$ 29.00			$ 29.00	$ -
Summer	$ 25.00			$ 25.00	$ -
Average	$ 27.00	$ 22.44	$ (4.56)	$ 27.00	$ -
Med. Commercial & Industrial (C-2 / T-3)	$ 75.00	$ 72.31	$ (2.69)	$ 75.00	$ -
Industrial (F-1 / T-2)	$ 300.00	$ 547.96	$ 247.96	$ 375.00	$ 75.00

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

Firm Customer Classes

	Post Test Year Billing Units			Present Winter Rates		Present Summer Rates		Present	Proposed Winter Rates		Proposed Summer Rates		Proposed
	Winter	Summer		Nov - April		May - Oct		Total	Nov - April		May - Oct		Total
	Nov-April	May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Residential (R-1)													
Number of Bills	321,672	313,605	635,276	$12.00	$3,860,060	$10.00	$3,136,047	$6,996,107	$16.00	$5,146,746	$11.00	$3,449,652	$8,596,398
Distribution Charges													
0 - 25 therms	7,467,700	3,497,280	10,964,980	$0.25444	$1,900,082	$0.18425	$644,374	$2,544,455	$0.26071	$1,946,904	$0.19052	$666,302	$2,613,206
26-50 therms	6,164,870	691,320	6,856,190	$0.17547	$1,081,750	$0.13160	$90,978	$1,172,727	$0.18174	$1,120,403	$0.13787	$95,312	$1,215,716
Over 50 Therms	16,542,330	508,710	17,051,040	$0.15354	$2,539,909	$0.03948	$20,084	$2,559,993	$0.15981	$2,643,630	$0.04575	$23,273	$2,666,903
Revenue Adjustment													
Total Residential Margin	30,174,900	4,697,310	34,872,210		$9,381,800		$3,891,483	$13,273,283		$10,857,683		$4,234,540	$15,092,223
PGA					$26,918,600		$3,891,300	$30,809,900		$26,918,600		$3,891,300	$30,809,900
Total Revenues					$36,300,400		$7,782,783	$44,083,183		$37,776,283		$8,125,840	$45,902,123
												Increase	**$1,818,940**
												Percent	**4.1%**

	Winter Nov-April	Summer May-Oct	Total	Present Winter Rate	Present Winter Revenue	Present Summer Rate	Present Summer Revenue	Present Total Revenue	Proposed Winter Rate	Proposed Winter Revenue	Proposed Summer Rate	Proposed Summer Revenue	Proposed Total Revenue
Residential (R-4)													
Number of Bills	1,110	1,110	2,220	$6.00	$6,660	$6.00	$6,660	$13,320	$6.00	$6,660	$6.00	$6,660	$13,320
Distribution Charges	62,756	19,448	82,204	$0.21768	$13,660	$0.19350	$3,760	$17,420	$0.25096	$15,749	$0.22678	$4,410	$20,160
Revenue Adjustment													
Total Residential (R-4) Margin	62,756	19,448	82,204		$20,320		$10,420	$30,740		$22,409		$11,070	$33,480
PGA					$55,944		$16,147	$72,091		$55,944		$16,147	$72,091
Total Revenues					$76,264		$26,567	$102,831		$78,353		$27,218	$105,570
												Increase	**$2,740**
												Percent	**2.7%**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

	Post Test Year Billing Units			Present Winter Rates		Present Summer Rates		Present	Proposed Winter Rates		Proposed Summer Rates		Proposed
	Winter	Summer		Nov - April		May - Oct		Total	Nov - April		May - Oct		Total
	Nov-April	May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Commercial (C-1)													
Number of Bills	39,563	38,077	77,640	$29.00	$1,147,330	$25.00	$951,910	$2,099,240	$29.00	$1,147,330	$25.00	$951,914	$2,099,244
Distribution Charges	6,441,514	1,532,171	7,973,685	$0.18581	$1,196,900	$0.14589	$223,530	$1,420,430	$0.24630	$1,586,545	$0.20638	$316,209	$1,902,754
Revenue Adjustment													
Total Commercial (C-1) Margin	6,441,514	1,532,171	7,973,685		$2,344,230		$1,175,440	$3,519,670		$2,733,875		$1,268,124	$4,001,999
PGA					$5,758,500		$1,268,300	$7,026,800		$5,758,500		$1,268,300	$7,026,800
Total Revenues					$8,102,730		$2,443,740	$10,546,470		$8,492,375		$2,536,424	$11,028,799
												Increase	**$482,329**
												Percent	**4.6%**

	Winter Nov-April	Summer May-Oct	Total	Present Winter Rate	Present Winter Revenue	Present Summer Rate	Present Summer Revenue	Present Total Revenue	Proposed Winter Rate	Proposed Winter Revenue	Proposed Summer Rate	Proposed Summer Revenue	Proposed Total Revenue
Commercial (C-2)													
Number of Bills	9,444	9,444	18,888	$75.00	$708,300	$75.00	$708,300	$1,416,600	$75.00	$708,300	$75.00	$708,300	$1,416,600
DDDC (Firm) Demand (C-2) in Dths	158,538	158,538	317,076	$5.50	$871,960	$5.50	$871,960	$1,743,920	$7.50	$1,189,035	$7.50	$1,189,035	$2,378,070
Distribution Charges													
0 - 3000 therms	11,318,000	4,227,952	15,545,952	$0.18744	$2,121,450	$0.14717	$622,230	$2,743,680	$0.16412	$1,857,510	$0.12253	$518,051	$2,375,561
3,001 - 5,000 therms	1,643,869	415,782	2,059,651	$0.17109	$281,250	$0.11683	$48,580	$329,830	$0.16412	$269,792	$0.12253	$50,946	$320,738
5,001 - 15,000 therms	2,230,552	602,545	2,833,098	$0.16666	$371,740	$0.10892	$65,630	$437,370	$0.14564	$324,858	$0.08790	$52,964	$377,821
over 15,000 therms	981,264	110,850	1,092,114	$0.08623	$84,610	$0.08623	$9,560	$94,170	$0.06521	$63,988	$0.06521	$7,229	$71,217
Revenue Adjustment													$0
Total Commercial (C-2) Margin	16,173,686	5,357,129	21,530,815		$4,439,310		$2,326,260	$6,765,570		$4,413,483		$2,526,524	$6,940,007
PGA					$14,100,020		$5,153,908	$19,253,928		$14,100,020		$5,153,908	$19,253,928
Total Revenues					$18,539,330		$7,480,168	$26,019,498		$18,513,503		$7,680,432	$26,193,935
												Increase	**$174,437**
												Percent	**0.7%**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

	Post Test Year Billing Units			Present Winter Rates Nov - April		Present Summer Rates May - Oct		Present Total	Proposed Winter Rates Nov - April		Proposed Summer Rates May - Oct		Proposed Total
	Winter Nov-April	Summer May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Commercial Transportation (T-3)													
Number of Bills	180	180	360	$75.00	$13,500	$75.00	$13,500	$27,000	$75.00	$13,500	$75.00	$13,500	$27,000
DDDC (Firm) Demand (T-3) in Dths	16,124	16,124	32,248	$5.50	$88,680	$5.50	$88,680	$177,360	$7.50	$120,929	$7.50	$120,929	$241,857
Distribution Charges													
0 - 3000 therms	519,600	461,500	981,100	$0.18744	$97,390	$0.14717	$67,920	$165,310	$0.16412	$85,277	$0.12253	$56,548	$141,824
3,001 - 5,000 therms	294,700	220,200	514,900	$0.17109	$50,420	$0.11683	$25,730	$76,150	$0.16412	$48,366	$0.12253	$26,981	$75,347
5,001 - 15,000 therms	872,400	516,800	1,389,200	$0.16666	$145,390	$0.10892	$56,290	$201,680	$0.14564	$127,056	$0.08790	$45,427	$172,483
over 15,000 therms	561,000	160,500	721,500	$0.08623	$48,380	$0.08623	$13,840	$62,220	$0.06521	$36,583	$0.06521	$10,466	$47,049
Revenue Adjustment													$0
Total Commercial Transportation (T-3)	2,247,700	1,359,000	3,606,700		$443,760		$265,960	$709,720		$431,711		$273,850	$705,561
												Increase	**-$4,159**
												Percent	**-0.6%**

	Present Total Revenue	Proposed Total Revenue
MARGIN C-2 & T-3 CLASS		
TOTAL C-2	**$6,765,570**	**$6,940,007**
TOTAL T-3	**$709,720**	**$705,561**
TOTAL MEDIUM C&I GENERAL	**$7,475,290**	**$7,645,568**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

	Post Test Year Billing Units			Present Winter Rates		Present Summer Rates		Present	Proposed Winter Rates		Proposed Summer Rates		Proposed
	Winter	Summer		Nov - April		May - Oct		Total	Nov - April		May - Oct		Total
	Nov-April	May-Oct	Total	Rate	Revenue	Rate	Revenue	Revenue	Rate	Revenue	Rate	Revenue	Revenue
Interruptible Sales (I-1)													
Number of Bills	6	6	12	$300.00	$1,800	$300.00	$1,800	$3,600	$375.00	$2,250	$375.00	$2,250	$4,500
Distribution Charges													
0 - 15,000 therms	90,000	90,000	180,000	$0.08064	$7,260	$0.08064	$7,260	$14,520	$0.07290	$6,561	$0.07290	$6,561	$13,122
15,001 - 40,000 therms	109,600	145,200	254,800	$0.06891	$7,550	$0.06891	$10,010	$17,560	$0.06117	$6,704	$0.06117	$8,882	$15,586
40,001 - 150,000 therms	15,100	44,200	59,300	$0.03908	$590	$0.03908	$1,730	$2,320	$0.03134	$473	$0.03134	$1,385	$1,858
over 150,000 therms	0	0	0	$0.02402	$0	$0.02402	$0	$0	$0.01628	$0	$0.01628	$0	$0
Revenue Adjustment													$0
Total Interruptible Sales (I-1) Margin	214,700	279,400	494,100		$17,200		$20,800	$38,000		$15,988		$19,078	$35,067
PGA					$182,058		$213,655	$395,713		$182,058		$213,655	$395,713
Total Revenues to Customer					$199,258		$234,455	$433,713		$198,047		$232,733	$430,780
												Increase	**-$2,933**
												Percent	**-0.7%**
Industrial Transport with Full Standby (F-1/T-2)													
Number of Bills	162	162	276	$300.00	$48,600	$300.00	$48,600	$97,200	$375.00	$60,750	$375.00	$60,750	$121,500
DDDC (Firm) Demand (T-2) in Dths	57,248	57,248	8,788	$5.50	$314,860	$5.50	$314,860	$629,720	$7.50	$429,359	$7.50	$429,359	$858,717
Distribution Charges													
0 - 15,000 therms	2,308,300	2,044,500	4,352,800	$0.08064	$186,140	$0.08064	$164,870	$351,010	$0.07290	$168,275	$0.07290	$149,044	$317,319
15,001 - 40,000 therms	2,492,600	2,032,800	4,525,400	$0.06891	$171,770	$0.06891	$140,080	$311,850	$0.06117	$152,472	$0.06117	$124,346	$276,819
40,001 - 150,000 therms	2,370,600	1,790,600	4,161,200	$0.03908	$92,640	$0.03908	$69,980	$162,620	$0.03134	$74,295	$0.03134	$56,117	$130,412
over 150,000 therms	3,156,100	3,080,700	6,236,800	$0.02402	$75,810	$0.02402	$74,000	$149,810	$0.01628	$51,381	$0.01628	$50,154	$101,535
Revenue Adjustment													$0
Total Industrial Transport with Full Sta	10,327,600	8,948,600	19,276,200		$889,820		$812,390	$1,702,210		$936,532		$869,770	$1,806,302
PGA					$420,187		$420,187	$840,375		$420,187		$420,187	$840,375
Total Revenues					$1,310,007		$1,232,577	$2,542,585		$1,356,719		$1,289,958	$2,646,677
												Increase	**$104,092**
												Percent	**4.1%**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

	Post Test Year Billing Units Winter Nov-April	Post Test Year Billing Units Summer May-Oct	Post Test Year Billing Units Total	Present Winter Rates Nov - April Rate	Present Winter Rates Nov - April Revenue	Present Summer Rates May - Oct Rate	Present Summer Rates May - Oct Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Proposed Winter Rates Nov - April Revenue	Proposed Summer Rates May - Oct Rate	Proposed Summer Rates May - Oct Revenue	Proposed Total Revenue
Industrial Transport with Partial Standby (F-1/T-2+T-1)													
Number of Bills	72	72	144	$300.00	$21,600	$300.00	$21,600	$43,200	$375.00	$27,000	$375.00	$27,000	$54,000
Demand in Dths													
DDDC (Firm) Demand (T-2)	15,996	15,996	31,992	$5.50	$87,980	$5.50	$87,980	$175,960	$7.50	$119,970	$7.50	$119,970	$239,940
Capacity (Non-Firm) Demand (T-1)	26,938	26,938	53,876	$1.35	$36,370	$1.35	$36,370	$72,740	$2.35	$63,305	$2.35	$63,305	$126,610
Total Demand	42,934	42,934	85,868		$124,350		$124,350	$248,700		$183,275		$183,275	$366,550
Distribution Charges													
0 - 15,000 therms	1,053,300	1,037,900	2,091,200	$0.08064	$84,940	$0.08064	$83,700	$168,640	$0.07290	$76,786	$0.07290	$75,663	$152,448
15,001 - 40,000 therms	1,586,400	1,548,700	3,135,100	$0.06891	$109,320	$0.06891	$106,720	$216,040	$0.06117	$97,040	$0.06117	$94,734	$191,774
40,001 - 150,000 therms	3,495,600	2,813,200	6,308,800	$0.03908	$136,610	$0.03908	$109,940	$246,550	$0.03134	$109,552	$0.03134	$88,166	$197,718
over 150,000 therms	1,109,900	771,600	1,881,500	$0.02402	$26,660	$0.02402	$18,530	$45,190	$0.01628	$18,069	$0.01628	$12,562	$30,631
Revenue Adjustment													
sub-Total Industrial Transport with Pa	7,245,200	6,171,400	13,416,600		$503,480	$318,890	$464,840	$968,320		$511,722		$481,399	$993,121
Special Contracts	3,784,900	4,286,800	8,071,700		$67,788		$69,756	$137,544		$67,788		$69,756	$137,544
Total Industrial Transport with Partia	11,030,100	10,458,200	21,488,300		$571,268		$534,596	$1,105,864		$579,510		$551,155	$1,130,665
PGA					$117,848		$117,848	$235,696		$117,848		$117,848	$235,696
Total Revenues					$689,116		$652,444	$1,341,560		$697,358		$669,003	$1,366,360
												Increase	**$24,801**
												Percent	**1.8%**

	Post Test Year Billing Units Winter Nov-April	Post Test Year Billing Units Summer May-Oct	Post Test Year Billing Units Total	Present Winter Rates Nov - April Rate	Present Winter Rates Nov - April Revenue	Present Summer Rates May - Oct Rate	Present Summer Rates May - Oct Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Proposed Winter Rates Nov - April Revenue	Proposed Summer Rates May - Oct Rate	Proposed Summer Rates May - Oct Revenue	Proposed Total Revenue
Interruptible Industrial Transportation (T-1)													
Number of Bills	156	156	312	$300.00	$46,800	$300.00	$46,800	$93,600	$375.00	$58,500	$375.00	$58,500	$117,000
Capacity (Non-Firm) Demand (T-1)	98,275	98,275	196,549	$1.35	$132,670	$1.35	$132,670	$265,340	$2.35	$230,945	$2.35	$230,945	$461,891
Distribution Charges													
0 - 15,000 therms	2,106,000	2,145,300	4,251,300	$0.08064	$169,830	$0.08064	$173,000	$342,830	$0.07290	$153,527	$0.07290	$156,392	$309,920
15,001 - 40,000 therms	2,648,800	2,793,700	5,442,500	$0.06891	$182,530	$0.06891	$192,510	$375,040	$0.06117	$162,027	$0.06117	$170,891	$332,918
40,001 - 150,000 therms	5,254,200	5,266,700	10,520,900	$0.03908	$205,330	$0.03908	$205,820	$411,150	$0.03134	$164,667	$0.03134	$165,058	$329,725
over 150,000 therms	5,481,000	6,261,900	11,742,900	$0.02402	$131,650	$0.02402	$150,410	$282,060	$0.01628	$89,231	$0.01628	$101,944	$191,174
Revenue Adjustment													
sub-Total Interruptible Industrial Trans	15,490,000	16,467,600	31,957,600		$868,810		$901,210	$1,770,020		$858,897		$883,730	$1,742,628
												Increase	**-$27,392**
												Percent	**-1.5%**

Chattanooga Gas Company
Base Revenue and Total Revenue at Present and Proposed Rates

	Post Test Year Billing Units Winter Nov-April	Summer May-Oct	Total	Present Winter Rates Nov - April Rate	Revenue	Present Summer Rates May - Oct Rate	Revenue	Present Total Revenue	Proposed Winter Rates Nov - April Rate	Revenue	Proposed Summer Rates May - Oct Rate	Revenue	Proposed Total Revenue
Special Service (SS-1)													
Number of Bills	0	0	0	$300.00	$0	$300.00	$0	$0	$375.00	$0	$375.00	$0	$0
Capacity (Non-Firm) Demand (T-1)	0	0	0	$1.35	$0	$1.35	$0	$0	$2.35	$0	$2.35	$0	$0
T-1 Distribution Charges													
0 - 15,000 therms	0	0	0	$0.08064	$0	$0.08064	$0	$0	$0.07290	$0	$0.07290	$0	$0
15,001 - 40,000 therms	0	0	0	$0.06891	$0	$0.06891	$0	$0	$0.06117	$0	$0.06117	$0	$0
40,001 - 150,000 therms	0	0	0	$0.03908	$0	$0.03908	$0	$0	$0.03134	$0	$0.03134	$0	$0
over 150,000 therms	0	0	0	$0.02402	$0	$0.02402	$0	$0	$0.01628	$0	$0.01628	$0	$0
Revenue Adjustment													
sub-Total Special Service (SS-1) Margi	0	0	0		$0		$0	$0		$0		$0	$0
Special Service (SS-1)					$0		$0	$0		$0		$0	$0
Margin Sharing from IMCR (90% of Difference between Special Service and T-1 Tariff)					$0		$0	$0		$0		$0	$0
Company Retained Base Rate Revenue					$0		$0	$0		$0		$0	$0
Total Firm Base Rate Revenues to Customers					$17,628,820		$8,591,533	$26,220,353		$19,542,663		$9,330,848	$28,873,511
Firm SPECIAL CONTRACTS					$67,788		$69,756	$137,544		$67,788		$69,756	$137,544
MISCELLANEOUS REVENUES					$432,098		$271,429	$703,527		$432,098		$271,429	$703,527
TOTAL FIRM Base Rate REVENUES w/ Special Contracts					$18,128,706		$8,932,718	$27,061,424		$20,042,549		$9,672,033	$29,714,581
TOTAL NON-FIRM Base Rate Revenues to Customers					$1,279,910		$1,277,270	$2,557,180		$1,239,637		$1,237,238	$2,476,875
Non-Firm SPECIAL CONTRACTS					$0		$0	$0		$0		$0	$0
TOTAL NON-FIRM base Rate REVENUES w/ Special Contracts					$1,279,910		$1,277,270	$2,557,180		$1,239,637		$1,237,238	$2,476,875
TOTAL FIRM AND INTERRUPTIBLE Base Rate REVENUES					$19,408,616		$10,209,988	$29,618,604		$21,282,186		$10,909,270	$32,191,456
												Total Increase	**$2,572,853**

Chattanooga Gas Company

Comparison of Earned Rate of Return at Present and Proposed Rates

Customer Class	Earned ROR at Present Rates	Earned ROR at Proposed Rates
Residential (R-1)	-1.42%	0.69%
Residential Multi Family (R-4)	-10.27%	-9.97%
Small Commercial (C-1)	2.41%	4.99%
Med. Commercial & Industrial (C-2 / T-3)	25.59%	25.62%
Industrial (F-1 / T-2)	28.29%	28.19%
TOTAL COMPANY	6.69%	8.28%

Chattanooga Gas Company
Alignment and Usage Adjustment Tariff

Derivation of Revenue-per-Customer Benchmark

Line No.		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	Residential - R1													
2	**Bills**	53,084	52,521	52,088	51,877	51,832	52,204	53,086	53,614	53,806	53,892	53,811	53,463	635,276
3	**Therms**													
4	0 - 25 therms	803,130	512,110	471,020	502,200	463,260	745,560	1,328,420	1,312,900	1,300,540	1,196,010	1,195,330	1,134,500	10,964,980
5	26-50 therms	270,860	102,020	57,680	52,500	54,470	153,790	706,500	1,151,000	1,234,520	1,140,230	1,088,810	843,810	6,856,190
6	Over 50 Therms	238,510	66,870	36,300	28,610	42,670	95,750	700,980	2,851,410	4,731,830	4,501,260	2,789,160	967,690	17,051,040
7	**Revenues**													
8	Customer	$ 583,919	$ 577,727	$ 572,964	$ 570,644	$ 570,153	$ 574,245	$ 849,384	$ 857,822	$ 860,890	$ 862,277	$ 860,971	$ 855,402	$ 8,596,398
9	0 - 25 Therms	153,012	97,567	89,739	95,679	88,260	142,044	346,332	342,286	339,064	311,812	311,634	295,775	2,613,206
10	26 - 50 therms	37,343	14,065	7,952	7,238	7,510	21,203	128,399	209,183	224,362	207,225	197,880	153,354	1,215,716
11	Over 50 Therms	10,912	3,059	1,661	1,309	1,952	4,381	112,024	455,684	756,194	719,346	445,736	154,647	2,666,903
12	**Total Revenues**	$ 785,186	$ 692,419	$ 672,316	$ 674,870	$ 667,876	$ 741,873	$ 1,436,139	$ 1,864,975	$ 2,180,510	$ 2,100,661	$ 1,816,222	$ 1,459,178	$ 15,092,223
13	**Revenues per Customer**	**$ 14.79**	**$ 13.18**	**$ 12.91**	**$ 13.01**	**$ 12.89**	**$ 14.21**	**$ 27.05**	**$ 34.79**	**$ 40.53**	**$ 38.98**	**$ 33.75**	**$ 27.29**	**$ 283.38**
14	**Commercial - C-1, C-2, T-3**													
15	**Commercial C-1**													
16	**Bills**	6,543	6,421	6,327	6,266	6,254	6,265	6,466	6,610	6,644	6,665	6,636	6,543	77,640
17	**Therms**	360,163	296,239	237,245	213,091	207,616	217,817	455,792	1,011,536	1,539,968	1,562,743	1,180,434	691,042	7,973,685
18	**Revenues**													
19	Customer	$ 163,587	$ 160,531	$ 158,173	$ 156,640	$ 156,360	$ 156,623	$ 187,509	$ 191,689	$ 192,668	$ 193,278	$ 192,450	$ 189,735	$ 2,099,244
20	Distribution	74,330	61,138	48,963	43,978	42,848	44,953	112,261	249,141	379,294	384,904	290,741	170,204	1,902,754
21	**Subtotal C-1 Revenues**	$ 237,917	$ 221,669	$ 207,136	$ 200,618	$ 199,208	$ 201,576	$ 299,771	$ 440,830	$ 571,962	$ 578,181	$ 483,191	$ 359,939	$ 4,001,999
22	**Commercial C-2**													
23	**Bills**	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	18,888
24	**Demand**	26,423	26,423	26,423	26,423	26,423	26,423	26,423	26,423	26,423	26,423	26,423	26,423	317,076
25	**Therms**													
26	0 - 3,000 Therms	1,130,417	829,385	617,868	554,337	519,593	576,352	1,035,203	1,836,525	2,558,221	2,284,667	1,982,149	1,621,235	15,545,952
27	3,001 - 5,000 Therms	103,069	72,733	70,942	56,902	61,529	50,606	114,837	266,848	396,404	410,321	287,778	167,682	2,059,651
28	5,001 - 15,000 Therms	156,492	120,808	71,316	74,576	85,005	94,347	157,513	355,434	454,216	589,395	429,384	244,610	2,833,098
29	Over 15,000 Therms	39,458	19,034	9,329	16,093	4,557	22,378	59,755	115,858	196,691	299,673	232,856	76,431	1,092,114
30	**Revenues**													
31	Customer	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 118,050	$ 1,416,600
31	Demand	198,173	198,173	198,173	198,173	198,173	198,173	198,173	198,173	198,173	198,173	198,173	198,173	2,378,070
32	0 - 3,000 Therms	138,510	101,625	75,707	67,923	63,666	70,620	169,898	301,411	419,855	374,960	325,310	266,077	2,375,561
33	3,001 - 5,000 Therms	12,629	8,912	8,693	6,972	7,539	6,201	18,847	43,795	65,058	67,342	47,230	27,520	320,738
34	5,001 - 15,000 Therms	13,756	10,619	6,269	6,555	7,472	8,293	22,940	51,765	66,152	85,840	62,536	35,625	377,821
35	Over 15,000 Therms	2,573	1,241	608	1,049	297	1,459	3,897	7,555	12,826	19,542	15,185	4,984	71,217
36	**Subtotal C-2 Revenues**	$ 483,690	$ 438,619	$ 407,499	$ 398,722	$ 395,197	$ 402,796	$ 531,804	$ 720,749	$ 880,114	$ 863,905	$ 766,483	$ 650,429	$ 6,940,007

Chattanooga Gas Company
Alignment and Usage Adjustment Tariff

Derivation of Revenue-per-Customer Benchmark

Line No.		May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	Total
1	**Commercial T-3**													
2	**Bills**	30	30	30	30	30	30	30	30	30	30	30	30	360
3	**Demand**	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	32,248
4	**Therms**													
5	0 - 3,000 Therms	78,400	72,800	70,400	71,200	80,700	88,000	89,200	84,400	87,800	87,700	87,000	83,500	981,100
6	3,001 - 5,000 Therms	35,800	32,200	34,500	34,000	38,400	45,300	52,300	49,200	52,300	50,300	47,200	43,400	514,900
7	5,001 - 15,000 Therms	88,600	72,100	73,300	79,700	88,600	114,500	140,300	148,400	178,600	156,500	141,000	107,600	1,389,200
8	Over 15,000 Therms	27,800	17,200	17,700	24,500	19,900	53,400	75,000	109,300	150,900	104,100	78,300	43,400	721,500
9	**Revenues**													
10	Customer	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 27,000
10	Demand	20,155	20,155	20,155	20,155	20,155	20,155	20,155	20,155	20,155	20,155	20,155	20,155	241,857
11	0 - 3,000 Therms	9,606	8,920	8,626	8,724	9,888	10,783	14,640	13,852	14,410	14,393	14,278	13,704	141,824
12	3,001 - 5,000 Therms	4,387	3,945	4,227	4,166	4,705	5,551	8,583	8,075	8,583	8,255	7,746	7,123	75,347
13	5,001 - 15,000 Therms	7,788	6,338	6,443	7,006	7,788	10,065	20,433	21,613	26,011	22,793	20,535	15,671	172,483
14	Over 15,000 Therms	1,813	1,122	1,154	1,598	1,298	3,482	4,891	7,127	9,840	6,788	5,106	2,830	47,049
15	**Subtotal T-3 Revenues**	$ 45,998	$ 42,730	$ 42,855	$ 43,898	$ 46,084	$ 52,285	$ 70,952	$ 73,072	$ 81,249	$ 74,634	$ 70,071	$ 61,733	$ 705,561
16	**Commercial Total**													
17	**Bills**													
18	C-1	6,543	6,421	6,327	6,266	6,254	6,265	6,466	6,610	6,644	6,665	6,636	6,543	77,640
19	C-2	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	1,574	18,888
20	T-3	30	30	30	30	30	30	30	30	30	30	30	30	360
21	**Total**	8,147	8,025	7,931	7,870	7,858	7,869	8,070	8,214	8,248	8,269	8,240	8,147	96,888
22	**Revenues**													
23	C-1	$ 237,917	$ 221,669	$ 207,136	$ 200,618	$ 199,208	$ 201,576	$ 299,771	$ 440,830	$ 571,962	$ 578,181	$ 483,191	$ 359,939	$ 4,001,999
24	C-2	483,690	438,619	407,499	398,722	395,197	402,796	531,804	720,749	880,114	863,905	766,483	650,429	6,940,007
25	T-3	45,998	42,730	42,855	43,898	46,084	52,285	70,952	73,072	81,249	74,634	70,071	61,733	705,561
26	**Total**	$ 767,606	$ 703,018	$ 657,491	$ 643,238	$ 640,488	$ 656,657	$ 902,527	$ 1,234,651	$ 1,533,325	$ 1,516,721	$ 1,319,745	$ 1,072,100	$ 11,647,566
27	**Revenues per Customer**	**$ 94.21**	**$ 87.60**	**$ 82.90**	**$ 81.74**	**$ 81.50**	**$ 83.45**	**$ 111.84**	**$ 150.31**	**$ 185.91**	**$ 183.43**	**$ 160.16**	**$ 131.60**	**$ 1,434.65**

Chattanooga Gas Company
Alignment and Usage Adjustment Tariff

Sample Annual Calculations

Line No.	Month	Actual per Books: Base Revenues	Actual per Books: Number of Customers	Actual Avg. Revenue / Cust.	Benchmark Revenue / Cust.	Difference	Total Impact	RNA Deduction	Net Impact	Balance Before Interest	Monthly Interest	Ending Balance
	(a)	(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	(g) = (f) * (c)	(h)	(i) = (g) - (h)	(j) = prior (l) + (i)	(k) = (j) * Int.	(l) = (j) + (k)
1	Residential - R1											
2	Starting Balance - Prior Period Over / (Under) Recovery											$ -
3	May	$ 769,214	52,529	$ 14.64	$ 14.79	$ (0.15)	$ (7,770)	$ -	$ (7,770)	$ (7,770)	$ (19)	$ (7,789)
4	June	685,604	52,529	13.05	13.18	(0.13)	(6,925)	-	(6,925)	(14,715)	(37)	(14,751)
5	July	671,233	52,529	12.78	12.91	(0.13)	(6,780)	-	(6,780)	(21,531)	(54)	(21,585)
6	August	676,522	52,529	12.88	13.01	(0.13)	(6,834)	-	(6,834)	(28,419)	(71)	(28,490)
7	September	670,087	52,529	12.76	12.89	(0.13)	(6,769)	-	(6,769)	(35,258)	(88)	(35,347)
8	October	745,661	52,529	14.20	14.21	(0.02)	(829)	6,636	(7,465)	(42,812)	(107)	(42,919)
9	November	1,467,361	53,880	27.23	27.05	0.18	9,755	24,331	(14,576)	(57,495)	(144)	(57,638)
10	December	1,892,320	53,880	35.12	34.79	0.34	18,088	36,830	(18,742)	(76,381)	(191)	(76,572)
11	January	2,207,796	53,880	40.98	40.53	0.45	24,274	46,109	(21,835)	(98,407)	(246)	(98,653)
12	February	2,122,787	53,880	39.40	38.98	0.42	22,607	43,609	(21,002)	(119,655)	(299)	(119,954)
13	March	1,835,535	53,880	34.07	33.75	0.32	16,974	35,160	(18,186)	(138,139)	(345)	(138,485)
14	April	1,480,584	53,880	27.48	27.29	0.19	10,015	24,720	(14,706)	(153,190)	(383)	(153,573)
15	May						$ 65,806	$ 217,395	$ (151,589)	(153,573)	(384)	(153,957)
16	June									(153,957)	(385)	(154,342)
17						Total Credit / (Deficiency)						**$ (154,342)**
18						Projected Residential Throughput for Recovery Period						34,830,685
19	**Pre-tax Residential AUA Charge/(Credit)**											**$ 0.0044**

20 **Notes:**

21 (1) 0.5% Customer growth from test period

22 (2) -1.0% Change in average Use from test period

23 (3) 3.0% Colder-than-normal weather

24 (4) 3.0% Annual Interest

Chattanooga Gas Company
Alignment and Usage Adjustment Tariff

Sample Annual Calculations

Line No.	Month	Actual per Books: Base Revenues	Actual per Books: Number of Customers	Actual Avg. Revenue / Cust.	Benchmark Revenue / Cust.	Difference	Total Impact	RNA Deduction	Net Impact	Balance Before Interest	Monthly Interest	Ending Balance
	(a)	(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	(g) = (f) * (c)	(h)	(i) = (g) - (h)	(j) = prior (l) + (i)	(k) = (j) * Int.	(l) = (j) + (k)
1	Commercial - C-1, C-2 and T-3											
2	Starting Balance - Prior Period Over / (Under) Recovery											$ -
3	May	$ 745,243	7,990	$ 93.27	$ 94.21	$ (0.94)	$ (7,528)	$ -	$ (7,528)	$ (7,528)	$ (19)	$ (7,547)
4	June	692,930	7,990	86.72	87.60	(0.88)	(6,999)	-	(6,999)	(14,546)	(36)	(14,582)
5	July	655,764	7,990	82.07	82.90	(0.83)	(6,624)	-	(6,624)	(21,206)	(53)	(21,259)
6	August	646,548	7,990	80.92	81.74	(0.82)	(6,531)	-	(6,531)	(27,790)	(69)	(27,859)
7	September	644,702	7,990	80.69	81.50	(0.82)	(6,512)	-	(6,512)	(34,371)	(86)	(34,457)
8	October	671,661	7,990	84.06	83.45	0.61	4,900	11,567	(6,668)	(41,125)	(103)	(41,228)
9	November	930,333	8,238	112.93	111.84	1.09	9,000	18,213	(9,213)	(50,441)	(126)	(50,567)
10	December	1,253,640	8,238	152.18	150.31	1.87	15,378	27,761	(12,383)	(62,950)	(157)	(63,107)
11	January	1,552,770	8,238	188.49	185.91	2.58	21,252	36,568	(15,315)	(78,422)	(196)	(78,618)
12	February	1,531,929	8,238	185.96	183.43	2.53	20,849	35,960	(15,111)	(93,729)	(234)	(93,964)
13	March	1,336,399	8,238	162.22	160.16	2.06	17,008	30,202	(13,194)	(107,158)	(268)	(107,425)
14	April	1,096,406	8,238	133.09	131.60	1.49	12,277	23,118	(10,841)	(118,267)	(296)	(118,562)
15	May						$ 66,471	$ 183,389	$ (116,919)	(118,562)	(296)	(118,859)
16	June									(118,859)	(297)	(119,156)
17						Total Credit / (Deficiency)						$ (119,156)
18						Projected Residential Throughput for Recovery Period						32,780,088
19	**Pre-tax Residential AUA Charge/(Credit)**											**$ 0.0036**

20 **Notes:**

21 (1) 0.5% Customer growth from test period

22 (2) -1.0% Change in average Use from test period

23 (3) 3.0% Colder-than-normal weather

24 (4) 3.0% Annual Interest

Chattanooga Gas Company
Alignment and Usage Adjustment Tariff

Sample Annual Calculations

		Actual per Books								Balance		
		Base	Number of	Actual Avg.	Benchmark		Total	RNA	Net	Before	Monthly	Ending
Line No.	Month	Revenues	Customers	Revenue / Cust.	Revenue / Cust.	Difference	Impact	Deduction	Impact	Interest	Interest	Balance
	(a)	(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	(g) = (f) * (c)	(h)	(i) = (g) - (h)	(j) = prior (l) + (i)	(k) = (j) * Int.	(l) = (j) + (k)
1	Residential - R1											
2	Starting Balance - Prior Period Over / (Under) Recovery											$ -
3	May	$ 769,214	52,529	$ 14.64	$ 14.79	$ (0.15)	$ (7,770)	$ -	$ (7,770)	$ (7,770)	$ (19)	$ (7,789)
4	June	685,604	52,529	13.05	13.18	(0.13)	(6,925)	-	(6,925)	(14,715)	(37)	(14,751)
5	July	671,233	52,529	12.78	12.91	(0.13)	(6,780)	-	(6,780)	(21,531)	(54)	(21,585)
6	August	676,522	52,529	12.88	13.01	(0.13)	(6,834)	-	(6,834)	(28,419)	(71)	(28,490)
7	September	670,087	52,529	12.76	12.89	(0.13)	(6,769)	-	(6,769)	(35,258)	(88)	(35,347)
8	October	732,389	52,529	13.94	14.21	(0.27)	(14,101)	(6,636)	(7,465)	(42,812)	(107)	(42,919)
9	November	1,418,698	53,880	26.33	27.05	(0.72)	(38,907)	(24,331)	(14,576)	(57,495)	(144)	(57,638)
10	December	1,818,659	53,880	33.75	34.79	(1.03)	(55,572)	(36,830)	(18,742)	(76,381)	(191)	(76,572)
11	January	2,115,579	53,880	39.26	40.53	(1.26)	(67,944)	(46,109)	(21,835)	(98,407)	(246)	(98,653)
12	February	2,035,570	53,880	37.78	38.98	(1.20)	(64,610)	(43,609)	(21,002)	(119,655)	(299)	(119,954)
13	March	1,765,215	53,880	32.76	33.75	(0.99)	(53,346)	(35,160)	(18,186)	(138,139)	(345)	(138,485)
14	April	1,431,144	53,880	26.56	27.29	(0.73)	(39,426)	(24,720)	(14,706)	(153,190)	(383)	(153,573)
15	May						$ (368,984)	$ (217,395)	$ (151,589)	(153,573)	(384)	(153,957)
16	June									(153,957)	(385)	(154,342)
17						Total Credit / (Deficiency)						**$ (154,342)**
18						Projected Residential Throughput for Recovery Period						34,830,685
19	**Pre-tax Residential AUA Charge/(Credit)**											**$ 0.0044**

20 **Notes:**

21 (1) 0.5% Customer growth from test period

22 (2) -1.0% Change in average Use from test period

23 (3) -3.0% Warmer-than-normal weather

24 (4) 3.0% Annual Interest

Chattanooga Gas Company
Alignment and Usage Adjustment Tariff

Sample Annual Calculations

		Actual per Books									Balance		
		Base	Number of	Actual Avg.	Benchmark		Total	RNA	Net	Before	Monthly	Ending
Line No.	Month	Revenues	Customers	Revenue / Cust.	Revenue / Cust.	Difference	Impact	Deduction	Impact	Interest	Interest	Balance
	(a)	(b)	(c)	(d) = (b) / (c)	(e)	(f) = (d) - (e)	(g) = (f) * (c)	(h)	(i) = (g) - (h)	(j) = prior (l) + (i)	(k) = (j) * Int.	(l) = (j) + (k)
1	Commercial - C-1, C-2 and T-3											
2	Starting Balance - Prior Period Over / (Under) Recovery											$ -
3	May	$ (7,528)	7,990	$ (0.94)	$ -	$ (0.94)	$ (7,528)	$ -	$ (7,528)	$ (7,528)	$ (19)	$ (7,547)
4	June	(6,999)	7,990	(0.88)	-	(0.88)	(6,999)	-	(6,999)	(14,546)	(36)	(14,582)
5	July	(6,624)	7,990	(0.83)	-	(0.83)	(6,624)	-	(6,624)	(21,206)	(53)	(21,259)
6	August	(6,531)	7,990	(0.82)	-	(0.82)	(6,531)	-	(6,531)	(27,790)	(69)	(27,859)
7	September	(6,512)	7,990	(0.82)	-	(0.82)	(6,512)	-	(6,512)	(34,371)	(86)	(34,457)
8	October	(18,235)	7,990	(2.28)	-	(2.28)	(18,235)	(11,567)	(6,668)	(41,125)	(103)	(41,228)
9	November	(27,427)	8,238	(3.33)	-	(3.33)	(27,427)	(18,213)	(9,213)	(50,441)	(126)	(50,567)
10	December	(40,143)	8,238	(4.87)	-	(4.87)	(40,143)	(27,761)	(12,383)	(62,950)	(157)	(63,107)
11	January	(51,883)	8,238	(6.30)	-	(6.30)	(51,883)	(36,568)	(15,315)	(78,422)	(196)	(78,618)
12	February	(51,071)	8,238	(6.20)	-	(6.20)	(51,071)	(35,960)	(15,111)	(93,729)	(234)	(93,964)
13	March	(43,396)	8,238	(5.27)	-	(5.27)	(43,396)	(30,202)	(13,194)	(107,158)	(268)	(107,425)
14	April	(33,960)	8,238	(4.12)	-	(4.12)	(33,960)	(23,118)	(10,841)	(118,267)	(296)	(118,562)
15	May						$ (300,308)	$ (183,389)	$ (116,919)	(118,562)	(296)	(118,859)
16	June									(118,859)	(297)	(119,156)
17						Total Credit / (Deficiency)						$ (119,156)
18						Projected Residential Throughput for Recovery Period						32,780,088
19	**Pre-tax Residential AUA Charge/(Credit)**											**$ 0.0036**

20 **Notes:**

21 (1) 0.5% Customer growth from test period

22 (2) -1.0% Change in average Use from test period

23 (3) -3.0% Warmer-than-normal weather

24 (4) 3.0% Annual Interest

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. ____ SHEET NO.___

ALIGNMENT AND USAGE ADJUSTMENT

(AUA)

APPLICABILITY

The Alignment and Usage Adjustment (AUA) shall adjust the rates for the applicable Rate Schedules to reconcile actual base revenue recoveries per customer to the benchmark level established by the Tennessee Regulatory Authority. The AUA shall apply to the following Rate Schedules:

R-1: Residential General Service
C-1: Commercial and Industrial Small General Service
C-2: Commercial and Industrial Medium General Service
T-3: Commercial and Industrial Low Volume Transport.

PURPOSE

The purpose of the AUA is to establish on an annual basis a base revenue adjustment, positive or negative, to permit the Company to recover the approved level of base revenues per customer. The AUA provides the Company with the proper incentive to promote conservation and energy efficiency by ensuring that the Company neither over-collects or under-collects base revenues due to changes in average customer consumption levels in between base rate case proceedings.

DEFINITIONS

For Purpose of this adjustment:

"Authority" shall mean the Tennessee Regulatory Authority.

“Actual Base Revenue per Customer” shall be determined on a monthly basis by dividing the actual base revenue for a Customer Class Group by the respective Actual Number of Customers as recorded on the Company’s books.

“Actual Number of Customers” shall be determined on a monthly basis for each Customer Class Group to which the AUA applies. The Actual Number of Customers shall equal the aggregate actual booked number of customers for the month as recorded on the Company’s books of account.

“Benchmark Base Revenue per Customer” shall mean the allowed average Revenue Per Customer (“RPC”) for a given month and Customer Class Group.

“Calculation Period” shall be the twelve consecutive months from May 1 of one calendar year through April 30 of the following calendar year.

‘Customer Class’ shall mean the group of customers all taking service pursuant to the same Rate Schedule.

“Customer Class Group” shall mean the group of Rate Schedules combined for purposes of calculating the Revenue Normalization Adjustment amounts. For purposes of determining and applying the AUA, customers shall be aggregated into two separate Customer Class Groups as follows:

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. ____ SHEET NO.___

Customer Class Group I: Residential customers taking service pursuant to Rate Schedule R-1
Customer Class Group II: Commercial & Industrial customers taking service pursuant to Rate Schedules C-1, C-2 and T-3.

"Recovery Period" shall mean the twelve month period beginning on the July 1st of one calendar year immediately following the conclusion of the Annual Period through June 30th of the following calendar year.

"Revenue per Customer" shall mean the average total base revenues divided by the corresponding number of customer bills.

"Relevant Rate Order" shall mean the final order of the Authority in the most recent litigated rate case of Chattanooga Gas Company (Company) fixing the rates of the Company or the most recent final order of the Authority specifically prescribing or fixing the factors and procedures to be used in the application of this adjustment.

BENCHMARK BASE REVENUE PER CUSTOMER

The Benchmark Base RPC shall be determined separately for each month and Customer Class Group. The Benchmark Base RPC for the applicable Customer Class Group shall be determined by first multiplying the then effective base rates for each Customer Class by the corresponding test period billing determinants utilized to design base rates to yield benchmark base revenues by Customer Class. The base rates and the associated billing determinants shall be those established by the Authority in the Company's most recent base rate case pursuant to a Relevant Rate Order. The resulting benchmark base revenues by Customer Class for all Rate Schedules within the same Customer Class Group shall be added together and divided by the total test period number of customers for the corresponding Customer Classes in order to yield the applicable Benchmark Base RPC. The Benchmark Base RPC for each Customer Class Group by month are as follows:

Month	Residential (R-1)	Commercial (C-1, C-2, T-3)
May	$14.79	$94.21
June	13.18	87.60
July	12.91	82.90
August	13.01	81.74
September	12.89	81.50
October	14.21	83.45
November	27.05	111.84
December	34.79	150.31
January	40.53	185.91
February	38.98	183.43
March	33.75	160.16
April	27.29	131.60
Total	$283.38	$1,434.65

ISSUED: _____________ EFFECTIVE: ____________
ISSUED BY: ___________

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. ____ SHEET NO.___

CALCULATION OF AUA MECHANISM

At the end of the Calculation Period, the Company shall determine for each Customer Class Group the base revenue deficiency or excess to be surcharged or credited to customers pursuant to the AUA mechanism. The revenue deficiency or excess shall be calculated by subtracting the Actual Base Revenue per Customer from the Benchmark Base Revenue per Customer for each month and multiplied by the corresponding monthly Actual Number of Customers. The AUA Revenue Adjustment shall be aggregated for all months during the Calculation Period.

The AUA shall be computed for each Customer Class Group pursuant to the following formula:

$$AUA_{cg} = \frac{\left((ARPC - BRPC) * \sum_{n=1}^{n=j} ACUSTS \right) + I + RA}{TVOL}$$

Where

AUA_{cg}	=	The Revenue Decoupling Adjustment for the Customer Class Group.
ARPC	=	The Actual Base Revenue Per Customer for the applicable Customer Class Group and month for the most recently completed Calculation Period.
BRPC	=	The Benchmark Base Revenue Per Customer for the applicable Customer Class Group and month.
j	=	The total number of Rate Schedules included in the Customer Class Group.
ACUSTS	=	The Actual number of customers for the applicable Customer Class Group and month for the most recently completed Calculation Period.
I	=	Interest on the end-of-month AUA Account balance. The interest rate for each month used shall be the prime rate value published in the " Federal Reserve Bulletin" or in the Federal Reserve's "Selected Interest Rates" for the month preceding the month of the Calculation Period.
RA	=	Reconciliation Adjustment for prior period over or under-recovery of the AUA for the applicable Customer Class Group.
TVOL	=	Forecast throughput Volumes inclusive of all firm sales and firm transportation throughput for the applicable Customer Class Group.

RECONCILIATION OF AUA REVENUE RECOVERIES

The revenues billed, or credits applied, net of taxes and assessments, through the application of the AUA Rate shall be accumulated for each month of the Recovery Period and applied against the AUA

CHATTANOOGA GAS COMPANY
GAS TARIFF
TRA NO. ____ SHEET NO.___

revenue excess or deficiency from the Calculation Period including any cumulative balances remaining from prior periods. Any balance existing at the conclusion of the Recovery Period, positive or negative, shall be reflected as a Reconciliation Adjustment included in the AUA for the subsequent Recovery Period.

FILING WITH AUTHORITY

No later than June 1st of each year, the Company will file with the Authority for approval of rates to be effective under the AUA accompanied by the computations and information required by this adjustment.