STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

Rhode Island Division of
Public Utilities and Carriers
89 Jefferson Blvd.
Warwick RI 02888
(401) 941-4500

October 11, 2005

Luly Massaro, Clerk
Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: New England Gas Company GCR Filing, Docket 3696.

Dear Luly:

Enclosed are an original and nine (9) copies of the prefiled testimony of Bruce Oliver, on behalf of the Division of Public Utilities and Carriers, in this proceeding.

Sincerely,

Stephen Scialabba
Chief Accountant

Cc: Service list

BEFORE THE

PUBLIC UTILITIES COMMISSION
OF THE
STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

IN THE MATTER OF

The Application of New England	**)**	
Gas Company for an Increase	**)**	**Docket No. 3696**
In its Gas Cost Recovery Charge	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities and Carriers

October 11, 2005

TESTIMONY OF BRUCE R. OLIVER
Docket No. 3696
October 11, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive, Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct its preparation and presentation of economic, utility planning, and policy analyses for our clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. My testimony in this proceeding is presented on behalf of the Division of Public Utilities and Carriers (hereinafter "the Division").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. This testimony addresses issues relating to the September 1, 2004 Annual Gas Cost Recovery (GCR) filing of New England Gas Company (hereinafter “NEG” or “the Company”).

Q. ON SEPTEMBER 30, 2005 NEG FILED SUPPLEMENTAL TESTIMONY AND EXHIBITS IN THIS PROCEEDING. DOES THIS TESTIMONY ADDRESS THE CONTENT OF THAT SUPPLEMENTAL FILING?

A. Only at a cursory level. Given rather significant changes in gas costs and GCR charges contained in the Company's supplemental filing and the limited time between the receipt of that filing and the due date of this testimony, the Division needs additional time to complete its assessment of that filing. Therefore, it is the Division's intent to file supplemental testimony to address more fully the reasonableness and accuracy of the information contained in that filing, as well as its impacts on users of natural gas in Rhode Island. I intend to complete my assessment of that filing as expeditiously as possible, and submit supplemental testimony prior to the scheduled hearing date.

Q. WHAT EXHIBITS ARE YOU SPONSORING AS PART OF THIS TESTIMONY?

A. Attached to this testimony are eight exhibits. They include:

Exhibit BRO-1	Computed Increases in GCR Charges by Rate Classification
Exhibit BRO-2	Changes in Costs by GCR Cost Component Based on NEG's September 1, 2005 filing
Exhibit BRO-3	Changes in Costs by GCR Cost Component Based on NEG's September 30, 2005 filing

Exhibit BRO-4	Changes in NEG's Forecasted Sales by Month
Exhibit BRO-5	Two-Year Changes in NEG's Forecasted Sales by Month
Exhibit BRO-6	Recovery of U.S. Gulf of Mexico Oil and Gas Production
Exhibit BRO-7	Comparison of Changes in NYMEX Natural Gas Prices
Exhibit BRO-8	Announced Residential Gas Rate Increases for Other Utilities

Q. IS NEG PROPOSING TO INCREASE ITS GCR CHARGES?

A. Yes. The Company's September 1, 2005 filing proposes to increase its GCR charges for all firm sales service rate classifications, as well as to increase its charges for marketer transportation services and increase its charges for Natural Gas Vehicle Service. For Residential and Small C&I customers, the Company's September 1, 2005 filing proposes to increase GCR charges from $0.9504 per therm to $1.13705 per therm. That represents an increase of $0.18665 per therm or a 19.64% increase in the GCR charge for those customers. Exhibit BRO-1, page 1 of 2, details the GCR increases by rate classification in dollars per therm and percentage terms that NEG proposes in the September 1, 2005 testimony and exhibits of witness Peter Czekanski. Furthermore, witness Czekanski's Schedule PCC-4 indicates the percentage impacts of those proposed GCR increases on the annual bills of customers in each of the Company's firm service rate classifications. Those increases range from a low of 9.6% for a typical Residential Non-Heating customer to a high of 17.1% for an Extra Large High Load Factor C&I customer that chooses to purchases gas from NEG rather than a competitive supplier. For a typical Residential Heating customer, the Company's September 1, 2005 GCR increase proposals would yield a **13.0%** increase in an annual gas bill.

However, NEG's supplemental filing on September 30, 2005 seeks approval for further increases in its GCR charges. Those further increases are intended to address significant changes in market prices for natural gas that have been experienced over the past couple of months and the impacts those changes in market prices for natural gas are expected to have on the Company's forecasted costs of gas for the 2005-06 GCR period. As I will discuss in more detail later in this testimony, the significant changes in market prices for natural gas are in large part attributable to the effects of hurricanes Katrina and Rita on natural gas production, processing, and pipeline facilities in the Gulf of Mexico region.

Q. HOW DOES THE COMPANY'S SUPPLEMENTAL FILING ALTER THE INCREASES IN GCR CHARGES THAT NEG PROPOSED IN ITS SEPTEMBER 1, 2005 FILING?

A. NEG's September 30, 2005 supplemental filing adds $0.152 per therm to the GCR charge for Residential and Small C&I customers and increases charge for other firm rate classifications in a roughly proportional manner. The supplemental increase request would raise the annual bill for a typical Residential Heating customer by an

additional $167. When combined with the Company's September 1, 2005 increase proposal, the typical Residential Heating customer would face an increase in annual gas service charges of $345, or 23.8%. Exhibit BRO-1, page 2 of 2, details the GCR increases by rate classification in dollars per therm and percentage terms that result from the GCR charges proposed in NEG's September 30, 2005 filing.

Q. HAVE THE COMPONENTS OF THE COMPANY'S GCR COSTS INCREASED IN A PROPORTIONAL MANNER?

A. No. Exhibit BRO-2, page 1 of 2, shows the changes in the components of the Company's projected annual gas costs for the 2005-06 GCR period compared to comparable projections that NEG filed last September for its 2004-05 GCR period. Although all components of the Company's forecasted annual GCR costs have increased, NEG projects only an 8.8% increase in fixed costs while its variable costs increase by more than 33%. Overall the Company's projected total annual GCR costs increase by $75.3 million or 30.5%, and of that increase 86.2% or $64.9 million is attributable to projected increases in Supply Variable Costs. Thus, Supply Variable Costs which primarily reflect the commodity costs of gas, account for the vast majority of the GCR increase proposed in NEG's September 1, 2005 filing in this proceeding.

Q. WHY ARE THE PERCENTAGE INCREASES IN GCR CHARGES NOT UNIFORM ACROSS RATE CLASSES?

A. Three basic factors contribute to the differences in percentage increases in GCR charges by rate class that NEG proposes. Those are:

1. Differences in the rates of change in the size of the GCR cost components; and

2. Differences in the magnitude of over- or under-collections of costs by GCR component; and

3. Differences in the manner in which the five components of GCR costs are allocated among classes.

Exhibit BRO-2, page 2 of 2, depicts the changes in NEG's gas costs from its 2004-05 and 2005-06 GCR periods with "reconciliation amounts" for the recovery of deferred gas cost balances excluded. This comparison provides a clearer picture of the actual changes in current costs of gas service that NEG projects. The data on that page indicate that the Company's Supply Variable Costs for its 2005-06 GCR period, excluding consideration of reconciliation adjustments for past over- (under-)

recoveries, are projected to increase 39.0% over the level for those costs that NEG projected one year earlier. On the other hand, the actual increase in Fixed Costs (i.e., Supply Fixed Costs plus Storage Fixed Costs) is only 1.6%.

Exhibit BRO-3, pages 1 and 2, provide analyses similar to those presented in the pages of Exhibit BRO-2 based on the Company's September 30, 2005 filing. As shown on page 2 of that exhibit, the costs of gas, excluding reconciliation amounts, shown in NEG's September 30, 2005 filing reflect an overall increase of 48%. That overall increase comprises a 1.8% increase in Total Fixed Costs and a 56.6% increase in Total Variable Costs. The overall increase in actual gas costs, excluding reconciliation amounts in the Company's September 30, 2005 filing is more than 50% greater than the gas cost increase contained in its September 1, 2005 filing. That growth in the size of the overall increase is driven primarily by a $38.5 million jump in the Company's projected Supply Variable Costs. The other major component of the increase in the Company's overall gas costs is a change in its projected end-of-period (i.e., October 31, 2005) deferred gas cost balance for the current GCR period which increase by $4.3 million from $10.4 million to $14.7 million.

Q. ARE THE GCR CHARGES THAT NEG PRESENTS IN ITS SEPTEMBER 1, 2005 FILING, THROUGH THE TESTIMONY OF WITNESS CZEKANSKI, PROPERLY COMPUTED?

A. The methods that NEG uses in its September 1, 2005 filing to compute its proposed GCR charges are consistent with those the Company has used, and the Commission has accepted, in past GCR filings. Furthermore, the computations relied upon to derive the specific charges set forth in Mr. Czekanski's testimony and exhibits appear to be mathematically accurate.

However, there are two elements of the Company's calculations with which I had some concern. Those are:

1. The treatment of TSS (Transitional Sales Service) surcharge related costs and revenue; and

2. The monthly distribution of volumes within the sales forecast that underlies NEG's gas cost projections.

Q. PLEASE EXPLAIN YOUR CONCERN REGARDING THE TREATMENT OF TSS SURCHARGE REVENUE.

A. Nowhere in the Company's filing is any documentation or explanation of the Company's treatment of TSS surcharge revenue. Although I would not expect to find reference to TSS surcharge revenue in the Company's gas cost projections for the 2005-06 GCR period, I did expect to find explicit reference to amounts collected through the TSS surcharge in NEG's annual gas cost reconciliation filing (Exhibit PCC-2 attached to witness Czekanski's September 1, 2005 testimony). However, although that filing includes entries that recognize "TSS Peaking Collections" under the heading "Storage Fixed Costs Deferred," there is no reference to TSS Surcharge Revenue.

Through informal communications with Mr. Czekanski, I was provided TSS Surcharge Revenue by month for the reconciliation period, as well as an explanation that TSS Surcharge Revenue was included in Firm Sales revenue under Variable Supply Cost Collections. For the reconciliation period (i.e., July 2004 through June 2005), the total reported TSS Surcharge Revenue is $25,924.

For the purposes of this testimony, I have accepted the Company's reported TSS Surcharge revenue figure as provided. However, in the future I recommend that the Company provide documentation of the TSS Surcharge revenue and volumes by month as part of each of its annual gas cost reconciliation reports. With comparatively high competitive retail market prices for natural gas going into this coming winter, the amount of gas use migrating from competitive gas supply to utility service could increase noticeably. In that context, a more explicit accounting of TSS Surcharge volumes and revenue could be important for both policy and ratemaking considerations.

Q. WHAT ARE YOUR CONCERNS REGARDING THE MONTHLY DISTRIBUTION OF VOLUMES WITHIN THE COMPANY'S FORECASTS OF SALES AND THROUGHPUT?

A. In testimony I filed roughly a year ago regarding NEG's proposed GCR charges for the 2004-05 GCR year, I raised certain concerns regarding the shifting of forecasted sales volumes between summer and winter billing months. In the Company's forecasts of weather-normal and design winter sales for the 2005-06 fiscal year, a somewhat similar pattern of unexplained shifts in the distribution of sales among months is once again observed. Exhibit BRO-4 depicts the changes in sales by month reflected in the Company's weather-normal and design winter sales forecasts for the 2005-06 GCR period. Page 1 of Exhibit BRO-4 compares the forecast of weather-normal sales that NEG has filed for the 2005-06 GCR year with comparable data that the Company used for the 2004-05 GCR year. Page 2 of Exhibit BRO-4 provides a similar comparison for forecasted design winter sales for the 2004-05 and 2005-06 GCR periods.

Page 1 of Exhibit BRO-4 indicates that annual sales for the 2005-06 GCR period are projected to increase 0.9% over the forecasted sales level for the prior year. However, winter month sales, and particularly sales for the month of February increase by much larger percentages. The forecast increase in winter month sales is 1.5% while the forecasted increase in February sales is **6.0%**. Yet, no rationales or analytic support are offered for the greater than average forecasted growth in sales for those winter periods.

Similarly, Exhibit BRO-4, page 2, indicates that overall design winter sales are projected to increase 1.5%. Yet, for the months of December, January, and February the forecasted design winter sales requirements are projected to increase by 2.4%, 3.0% and 5.1% respectively. In other words, the projected increase in design winter sales for the month of January is twice the overall forecast increase, and the projected increase in February requirements is **3.4 times** the forecasted overall increase in design winter requirements. Without documentation of significant changes in customer consumption patterns, appliance ownership, and/or other key underlying assumptions these changes in the pattern of forecasted requirements must be questioned.

It should also be noted that the changes in the monthly distribution of sales under weather-normal and design winter conditions discussed above are in addition to other significant changes in those sales distributions that were observed in the Company's 2004-05 forecast when that forecast was compared to the forecast that NEG had submitted for the 2003-04 GCR period. When the detail of NEG's sales forecast for the 2003-04 GCR period is compared with that for the 2005-06 GCR period as shown in Exhibit BRO-5, the projected increase in overall sales is 2.4%, but the increase in winter sales is 4.6% (i.e., nearly double the overall average) and the increase in projected sales for the month of February is **13.5%** or more than **5.6 times** the overall sales increase. On the other hand, projected summer month sales are projected to fall by 2.1% in comparison with the Company's 2003-04 forecast.

This significant restructuring of the monthly distribution of sales requirements warrants further investigation. My analyses to date suggest that there may be a problem in the manner in which NEG computes weather-normalized sales from historical actual data.

Q. HOW DO THE OBSERVED CHANGES IN THE MONTHLY AND SEASONAL DISTRIBUTION OF PROJECTED WEATHER-NORMAL AND DESIGN WINTER SALES IMPACT NEG'S COSTS OF GAS?

A. Greater than average increases in winter month service requirements cause the Company to plan for and purchase greater amounts of gas and peaking capacity than it would require if sales growth were more evenly distributed across the months of the forecast period. Moreover, since winter season requirements tend to be more costly to serve than summer month requirements, NEG's projections of faster growth in winter season sales than summer season sales serves to increase the Company's overall average cost of gas for the GCR period.

Properly weather-normalized sales measures do not typically display such large year-to-year changes in monthly usage levels. Part of the problem appears to arise from NEG's use of only data for the last two years to compute base use while employing longer term averages in the computation of "normal" heating degree days. As a result, the Company's determination of base use appears inconsistent with its degree day adjustments. Another contributing factor appears to be a misalignment of degree day data and measures of usage. Due to the nature of billing cycles, substantial use that occurs in one month may be recorded as sales in the subsequent month. Thus, analyses that apply degree day measures for the calendar month February to February sales data can fail to properly account for billing lags in gas sales. The result is a mismatching of degree day measures and sales data that distorts the computed weather-normalized sales.

In the context of the GCR increases that customers are facing for the coming winter, the Commission should require the Company to more fully explain and justify the greatly disproportionate increases it projects for both overall winter season sales and February sales. Moreover, in the absence of such justification for the observed change in the monthly distributions of sales requirements under both weather-normal and design winter conditions, NEG should be required to recompute its projected costs of gas for the GCR period using a sales forecast that more evenly distributes growth in sales over the months of the year. This may result in lower projected annual gas costs.

Q. DO YOU RECOMMEND ANY CHANGES IN THE MANNER IN WHICH GCR CHARGES ARE DEVELOPED?

A. Yes. I would encourage the Commission to consider a simplification of the GCR charge determinations by merging the charges for some or all of the rate classifications for which separate GCR charges are presently computed. At present, NEG computes six separate GCR charges as well as an FT-2 marketer charge in each of its GCR filings. Yet with increases in the relative magnitude of its Supply Variable costs, the percentage differences among those charges have diminished.

As computed in NEG's September 1, 2005 filing, the differences in GCR charges among rate classifications are quite small. Only the charges for Large High Load Factor and Extra Large High Load Factor C&I customers would deviate from the Residential and Small C&I GCR charge by more than half of one percent (i.e., 0.5%). See Exhibit BRO-1. Moreover, no class would receive a GCR charge that differs from the rate for Residential and Small Commercial and Industrial (C&I) customers by more than 4.4%.

Thus, at a minimum I would recommend that the six GCR charges that NEG currently employs be merged into two charges. One charge would be applicable to

Residential, Small C&I, Medium C&I, Large Low Load Factor C&I, Extra Large Low Load Factor C&I customers. The other would apply to Large High Load Factor (Large HLF) and Extra Large High Load Factor (Extra Large HLF) C&I customers.

However, I would encourage the Commission to go a step further and apply a single GCR charge to all rate classifications. Although the return to a single GCR charge for all classes would in concept result in small percentage increases (i.e., 2.5% to 4.4%) for Large and Extra Large HLF customers who choose not to purchase their gas supplies from competitive supplier, it would help to moderate the proposed GCR increase for Residential and Small C&I customers. The Commission should also recognize (1) that there is a fairly well established competitive market for service to Large and Extra Large C&I customers and (2) the majority of gas supply service for customers in those two rate classes is presently provided by competitive suppliers. For the twelve months ended June 2005, customers in the Large High Load Factor and Extra Large High Load Factor C&I rate classifications used 5,058,231 Dth of natural gas. Of that amount 4,140,293 Dth or over 80% was purchased from competitive suppliers.

Q. WHAT WERE THE INITIAL RATIONALES FOR DIFFERENTIATING GCR CHARGES AMONG RATE CLASSIFICATIONS?

A. The differentiation of GCR charges by rate classification was initially undertaken to provide recognition of differences in class responsibilities for various components of the Company's gas costs. When the PUC approved gas rate restructuring and the introduction of retail competition for medium, large and extra large C&I customers, providing cost-based GCR charges to customers with competitive alternatives was deemed important to ensure that the utility's gas service prices did not inappropriately undercut competitive gas service alternatives and to provide customers in rate classes subject to competition a reasonable benchmark for competitive suppliers to beat.

Q. ARE THE RATIONALES FOR DIFFERENTIATING GCR CHARGES AMONG RATE CLASSES THAT YOU HAVE DISCUSSED ABOVE STILL VALID?

A. No. The only classes for which the present approach to the calculation yields noticeable differences in GCR charges are the Large High Load Factor and Extra Large High Load Factor C&I rate classifications, and the majority of the gas volumes that NEG delivers for those customers are purchased from competitive suppliers. In the context of competitive checks on the price that NEG charges for firm gas supply service through its GCR charges for those rate classes, the comparatively complex and costly procedures that NEG presently uses to assess the gas cost responsibilities of each rate class appears unnecessarily burdensome.

Q. HAS THE COMPANY COMPUTED GAS PROCUREMENT INCENTIVE AMOUNTS FOR THE 12 MONTH PERIOD ENDED JUNE 2005?

A. Yes. The testimony of witness Gary Beland discusses those computations and presents supporting detail for its proposed incentive amounts in Schedule GLB-9.

Q. WHAT AMOUNT OF GAS PROCUREMENT INCENTIVE IS SUPPORTED BY THE COMPUTATIONS THAT NEG PRESENTS?

A. As shown in Schedule GLB-9, the Company's computations support a **net penalty** of **$148,485.29**.

Q. DO YOU FIND ANY REASON TO QUESTION THE ACCURACY OR APPROPRIATENESS OF THE COMPANY'S INCENTIVE COMPUTATIONS?

A. No, I do not. I have reviewed the detail of the Company's incentive calculations, and I find them to be accurate and consistent with the terms of the gas procurement incentive plan that this Commission has adopted for NEG.

Q. SHOULD THE COMMISSION REQUIRE NEG TO ABSORB THE FULL AMOUNT OF THE COMPUTED GAS PROCUREMENT PENALTY?

A. The Company appears prepared to absorb the entire amount of the computed gas procurement penalty. Mr. Beland notes in the Company's defense that much of the computed penalty can be attributed to (1) a newly imposed requirement that 75% of its projected winter sendout requirement be fixed in price before the start of the winter season and (2) the unforeseeable impacts of Hurricane Ivan on natural gas prices. But, he makes no request for relief from the computed penalty. I note that in a rising cost market an argument could be made that the Company could have, and perhaps should have, made more of its discretionary purchases earlier in the buying cycle to avoid the influences of unpredictable short-term market factors. However, I also observe that over the past year, I have found NEG personnel to be open, forthright, cooperative and genuinely interested in working with the Division and the Commission on gas procurement matters.

Q. WHAT HAVE BEEN THE IMPACTS OF HURRICANES KATRINA AND RITA ON NATURAL GAS SUPPLY IN THE U.S.?

A. Natural gas production from Federal Offshore areas in the Gulf of Mexico represents approximately 10 billion cubic feet of gas per day (10.1 Bcfd). That is equivalent to 20% of total annual U.S. natural gas production. Another 4% of annual U.S. natural gas production is derived from Louisiana jurisdictional wells. Moreover, U.S. natural gas production supplies about 80% of total annual U.S. natural gas demand. Thus, combined Federal Offshore in the Gulf of Mexico production and Louisiana jurisdictional natural gas production represent about 19% of annual U.S. gas supply requirements. Exhibit BRO-6 depicts the time profile for shut-in natural gas and crude oil production for Hurricanes Katrina and Rita, as well as for Hurricane Ivan which hit last year. As can be observed from this exhibit the production impacts of Hurricanes Katrina and Rita are more substantial and long enduring than even the effects of Hurricane Ivan. Nearly 40 days after landfall for Hurricane Katrina and two weeks after Hurricane Rita, about 65% of Gulf of Mexico natural gas production remains shut-in. Likewise, production has been restored for only 27.2% of Louisiana gas production capacity. That leaves 72.8% of Louisiana production still shut-in.

Significant numbers of offshore production platforms and drilling rigs have been damaged or destroyed by Katrina and Rita. Also, companies that operate those facilities are now scrambling to re-establish contact with employees that were evacuated from offshore platforms and drilling rigs and return them to their jobs. However, efforts to restart production from offshore facilities are being further frustrated by the impacts of these hurricanes on port facilities and staging areas traditionally relied upon to ferry personnel and supplies to offshore facilities and damage to natural gas pipelines and gas processing plants.

In fact, the impacts of Katrina and Rita on natural gas processing plants and pipeline may be just as important as the amount of shut-in natural gas production.

Nearly every natural gas processing plant in Louisiana has been affected. Many have been flooded. Some have been damaged. Nearly all have lost electrical power. Since most gas produced in the Gulf must be dehydrated for safety reasons before it enters high pressure interstate pipelines, the operation of these processing plants is essential.

In addition, pipeline operations have been significantly affected. A number of undersea pipelines that transport crude oil and natural gas from offshore platforms to the mainland have been severed. The Henry Hub, a major natural gas terminal that is used as the basis for pricing NYMEX futures contracts, has been shut down, and Louisiana reports that only 2 of 55 pipeline operators in the state have reopened their facilities as of October 10, 2005. Forty pipeline operators in the state have reported that their facilities remain shut-in, 9 have facilities that are partially shut-in, and 4 pipeline operators could not be contacted. Thus, the restart of gas pipeline and processing facilities may be greater hurdles than re-manning and repairing offshore production platforms.

Q. WILL THE U.S. HAVE ADEQUATE NATURAL GAS IN STORAGE PRIOR TO THE START OF THE WINTER SEASON?

A. That is questionable. Some analysts of the industry suggest that we can take some comfort in the fact that natural gas storage inventories remain above 5-year average levels. Yet, I find such observations a bit misleading for two reasons. First, the five-year averages to which they refer incorporate the influences of storage levels for the winter of 2000-01 which were abnormally low and contributed to large spikes in winter season gas prices. Second, even if natural gas storage fill at the beginning of the winter season are near full capacity (which looks somewhat unlikely at this point for the coming winter season), growth in weather-sensitive gas use in recent years (primarily due to weather-sensitive electric generation uses of natural gas) has caused the demand for storage gas to exceed available gas storage capacity on peak days.

Q. HOW HAVE HURRICANES KATRINA AND RITA AFFECTED GAS COSTS FOR THE COMING GCR PERIOD?

A. Mr. Beland testifies that last year Hurricane Ivan did more damage to natural gas production and pipelines in the Gulf of Mexico than any prior hurricane. Yet, the effects of Ivan pale in comparison to the damage experienced as a result of hurricanes Katrina and Rita this year. As a result, natural gas prices have risen dramatically. For the last two weeks, NYMEX futures prices for the coming winter period (i.e., November 2005 through March 2006) have generally average between $14.00 and $15.00 per Dth. By comparison, natural gas futures contracts for the November 2005 through March 2006 period could have been purchase prior to

Hurricane Ivan a little more than a year ago for an average of about $6.40 per Dth. After Hurricane Ivan, the strip price for the winter of 2005-06 averaged roughly $7.30 per Dth. Thus, the NYMEX futures market prices for gas supply for the winter of 2005-06 have roughly doubled over the past year. However, not all of that increase is attributable to the effects of Hurricanes Katrina and Rita. Substantial increases in gas costs for the winter of 2005-06 had been experienced prior to the onset of those hurricanes.

Q. HOW MUCH OF THE INCREASE IN NYMEX NATURAL GAS PRICES FOR THE COMING WINTER IS ATTRIBUTABLE TO THE EFFECTS OF HURRICANES KATRINA AND RITA?

A. Although the increases in the costs of gas subsequent to Hurricanes Katrina and Rita have been dramatic, gas cost increases prior to those hurricanes were also substantial. By mid-August 2005 the strip price for winter 2005-06 gas supply had risen to more than $10.40 per Dth. After Hurricane Katrina hit the eastern portion of the Gulf of Mexico production area, prices for the winter of 2005-06 spiked upward to more than $12.00 per Dth. Over the next couple weeks, gas prices softened somewhat as significant production was restored, but with the approach of Hurricane Rita and a new shut-in of production, gas prices jumped again.

In percentage terms, prices for winter 2005-06 gas supplies rose more than 40% from post-Hurricane Ivan levels to mid-August 2005 levels. In response to the Hurricanes Katrina and Rita, gas prices for the winter of 2005-06 rose another 35-40%. The combined effects of pre-hurricane price increases and post-Katrina and Rita increases have roughly doubled the costs of gas for the coming winter from the levels that the same gas supplies could have been purchased for a year ago.

Exhibit BRO-7 depicts the changes in NYMEX natural gas prices that have been observed over roughly the last year. Each line plots the monthly NYMEX natural gas futures contract prices for each month through the end of the year 2010 as those prices were reported on the dates identified in the legend. Although the increases in prices for the winter 2005-06 have been dramatic, there has also been a substantial upward movement in the entire forward curve. Furthermore, it should be noted that the differentials between prices for the winter of 2005-06 and subsequent periods have grown to historic record levels. A year ago the average price for the winter of 2005-06 was about $0.73 per Dth above the average price for the winter of 2006-07. As of October 4, 2005, the same price differential was $3.30 per Dth (i.e., roughly 4.5 times the differential observed one year earlier).

Q. HOW LONG CAN WE EXPECT THE EFFECTS OF HURRICANES KATRINA AND RITA TO IMPACT NATURAL GAS PRICES?

A. Barring another major hurricane this fall or other disruptions of natural gas supply, most of the near term effects of Hurricanes Katrina and Rita can be expected to work their way through the system by the end of the coming winter season. However, these hurricanes have fully exposed the fragile nature of supply and demand balances for natural gas in the U.S. In the late 1980's and most of the 1990's the U.S. had considerable gas supply elasticity that softened the impacts of actual or anticipated gas supply shortfalls. But, one of the lessons from these hurricanes is that the U.S. no longer has the ability to rapidly expand natural gas supply. Damage to drilling rigs and production platforms in the Gulf of Mexico, as well as the general disruption of drilling activities in the Gulf Region, may have lingering effects on the timing, amount and costs of new natural gas supply additions for two to three year into the future. Additionally, those losses of anticipated new supply may tighten the overall gas supply and demand balance in the U.S., sustaining higher overall natural gas price levels than had previously been anticipated.

Still, a big unknown is how much consumers will reduce gas consumption in the face of significant natural gas price increases. Although demand reductions in response to higher natural gas prices have typically exhibited significant time lags (i.e., at least a year), the size of the price increases with which consumers are now confronted could potentially induce more substantial near-term usage reductions.

Substantial near-term reductions in natural gas use could noticeably lower gas prices before the end of the coming winter season. Yet, it is unlikely that natural gas prices will return to the levels experienced last year unless world oil prices also fall. Due to fundamental ties between natural gas and oil markets, natural gas prices are not likely to be sustained at levels below $10.00 per Dth unless world oil prices can be maintained at levels below $60.00 per MMBtu.

Q. HOW DO THE RATE INCREASES THAT RESULT FROM NEG'S PROPOSED GCR CHARGES COMPARE WITH GAS RATE INCREASES FOR CUSTOMERS IN OTHER JURISDICTIONS?

A. See Exhibit BRO-8 lists announced or estimated gas rate increases for utilities in other jurisdictions across the U.S. Unless otherwise noted, the rate increase percentages cited in Exhibit BRO-8 reflect total bill changes for typical residential heating customers. The overall rate increase for Residential Heating customers that NEG proposed in September 1, 2005 testimony is near the low end of the range of increases cited. Only one utility among those for which data was available had an increase less than the 13% that NEG computed for a typical Residential Heating customer in its Rhode Island service territory. The 23.8% increase for a typical Residential Heating customer that is found in the Company September 30, 2005 filing is roughly in the middle of the range of increases shown in Exhibit BRO-8.

However, it should be noted that most of these increases were announced prior to Hurricane Rita and do not appear to reflect the further increases in gas costs that have resulted from the combination of Hurricanes Katrina and Rita.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE DATA PRESENTED IN MR. BELAND'S SCHEDULE GLB-4?

A. Yes, I do. I agree with Mr. Beland's observation in his September 1, 2005 testimony where he notes that the changes in the Gas Procurement Incentive Plan (GPIP) that were adopted by the Commission in 2005 have helped to shield customers from current gas price increases for a significant portion of their total requirements. However, I also observe that increasing the percentage of total requirements that is comprised of mandatory purchases, reduces the role of discretionary purchases. And that, in turn, diminishes the relative importance of incentives computed on the basis of discretionary purchases.

Q. HAS AN INCENTIVE AMOUNT ALSO BEEN COMPUTED UNDER THE ASSET MANAGEMENT INCENTIVE PROVISIONS OF THE COMPANY'S GAS PROCUREMENT PLAN?

A. Yes. Schedule GLB-10 provides support for the Company's asset management incentive determination. As shown in that schedule NEG's calculations support an incentive payment of $21,285.

Q. IN THE CONTEXT OF THE INCREASES IN PROJECTED GAS COSTS THAT NEG HAS PRESENTED IN THIS PROCEEDING, IS IT REASONABLE AND APPROPRIATE FOR THE COMMISSION TO GRANT NEG AN ASSET MANAGEMENT INCENTIVE AT THIS TIME?

A. Yes. Under the terms of the incentive plan, NEG has earned an asset management incentive payment. A failure to respect the terms of that plan would undermine the entire incentive program. The Asset Management incentive structure is intended to encourage the Company to control the fixed cost components of its gas costs, and NEG has produced a result for the period from November 2004 through June 2005 that lowers the total fixed gas supply and storage costs by $212,849. Moreover, under the terms of the Asset Management incentive plan, the amount of NEG's Asset Management incentive is reduced from 20% to 10% if its actual gas procurement costs for the reconciliation period exceed NEG's initially projected gas procurement costs for that period. Still, attributing only 10% of the achieved fixed cost reduction to an incentive for the Company provides NEG with an earned incentive of $21,845 and leaves a net benefit of $191,564 for NEG's firm service customers.

I also observe that on a forward looking basis, NEG has been able to project only a small increase in its total fixed costs, excluding reconciliation amounts. As demonstrated in the analysis presented in Exhibit BRO-2, page 2 of 2, the vast majority of the increase in gas costs reflected in NEG's projections represents increases in Supply Variable Costs, not fixed costs. In fact, NEG's Total GCR related Fixed Costs have increased less than 2% compared to the Company's projections from a year ago despite a notable increase in fixed costs associated with its renegotiated Firm Combination Service (FCS) contract.

Q. HAVE YOU EVALUATED THE ECONOMICS OF NEW FCS CONTRACT THAT WITNESS BELAND DISCUSSES IN HIS SEPTEMBER 1, 2005 TESTIMONY?

A. I have attempted to do so, but clear assessment of the costs of that contract relative to those for other peak supply alternatives is not readily attainable.

Although the pricing of service under that contract is quite simple, evaluation of its economics is not as straightforward. Technically the FCS contract is not a storage service contract. Yet, it offers many of the attributes of a storage service with greater operational flexibility. A key benefit of the FCS contract is that it allows NEG to obtain firm supply on a daily basis without paying daily spot market prices.

After the experience of the last two winters, reducing the Company's exposure to daily priced gas purchases during period of high demand was an objective that all parties appeared to support. However, the FCS contract represents a sizable annual cost commitment that may be of limited value under warmer than normal weather conditions. The FCS contract appears to perform well in economic terms when weather approaches design winter or design peak conditions. However, the economics of that contract are more difficult to assess under less extreme circumstances.

Overall value of the FCS contract is a function of (1) the expected frequency that higher priced gas purchases can be avoided, (2) estimated volumes of daily gas purchases that can be avoided, (3) the magnitude of expected differences between FCS contract costs and the costs of avoided daily purchases, and (4) the sum of the annual fixed costs incurred over the term the FCS service agreement. Unfortunately, prices for daily purchase gas can fluctuate widely and are very difficult to predict, as are the frequency and magnitude of requirements for daily purchases of gas supply. Thus, the only way to estimate the net value of the FCS contract is to make assumptions regarding the volume of daily gas purchases that would be avoided by using FCS supply and the prices that would have been paid for such daily purchases. In other words, a full assessment of the economics of NEG's FCS contract would necessarily involve highly assumption driven analyses performed in the context of multiple probability-weighted scenarios. NEG has not performed such an analysis. Moreover, productivity of such analyses is at best unclear given the highly assumption drive nature of estimates of costs and benefits that would be generated.

NEG was encouraged to seek means of reducing its exposure to the high costs of daily purchases of gas. It has done so through the FCS contract with only a comparatively small increase in its total annual fixed gas supply and fixed storage costs. In the process the Company has also gained considerable operating flexibility that would not be achievable through most traditional gas storage service contracts. Thus, while a more definitive assessment of the economics may be somewhat elusive, I can conclude that the Company has addressed a key concern of the Division without a dramatic increase in its annual fixed gas costs.

Q. HAVE YOU REVIEWED THE LNG SYSTEM PRESSURE REPORT THAT WAS FILED WITH THE COMMISSION ON JULY 29, 2005 AND IS ATTACHED TO WITNESS BELAND'S IN THIS PROCEEDING AS SCHEDULE GLB-12?

A. Yes, I have.

Q. ARE THE FINDINGS AND RECOMMENDATIONS CONTAINED IN THAT REPORT REASONABLE?

A. Yes. The revised procedure that NEG proposes would ensure that LNG costs incurred for economic dispatch purposes are not attributed to the DAC as system pressure costs. It also appears to ensure a proper allocation among rate classifications of responsibility for such LNG costs in the development of GCR charges and in subsequent reconciliations of projected and actual GCR costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does. However, as noted earlier, the Division intends to submit supplemental testimony to address more fully the content of the Company's September 30, 2005 filing. The Division will present its recommendations regarding specific GCR charges for implementation by NEG customers as part of that supplemental filing.

New England Gas Company
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Computed Increases in GCR Charges by Rate Classification
Based on NEG's September 1, 2005 Filing

Rate Classification	Current GCR Rate ($/Therm)	NEG Proposed GCR Rate ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$0.95040	$1.13705	$0.18665	19.64%
Heating	$0.95040	$1.13705	$0.18665	19.64%
Commercial & Industrial				
Small	$0.95040	$1.13705	$0.18665	19.64%
Medium	$0.94290	$1.13099	$0.18809	19.95%
Large Low Load Factor	$0.95210	$1.13874	$0.18664	19.60%
Large High Load Factor	$0.93280	$1.10311	$0.17031	18.26%
Extra Large Low Load Factor	$0.97330	$1.13601	$0.16271	16.72%
Extra Large High Load Factor	$0.90970	$1.08741	$0.17771	19.54%
Natual Gas Vehicles	$0.73700	$0.88820	$0.15120	20.52%
Marketer Charges	$0.03991	$0.04491	$0.00500	12.53%

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Computed Increases in GCR Charges by Rate Classification
Based on NEG's September 30, 2005 Filing

Rate Classification	Current GCR Rate ($/Therm)	NEG Proposed GCR Rate ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$0.95040	$1.28904	$0.33864	35.63%
Heating	$0.95040	$1.28904	$0.33864	35.63%
Commercial & Industrial				
Small	$0.95040	$1.28904	$0.33864	35.63%
Medium	$0.94290	$1.28296	$0.34006	36.07%
Large Low Load Factor	$0.95210	$1.29074	$0.33864	35.57%
Large High Load Factor	$0.93280	$1.25502	$0.32222	34.54%
Extra Large Low Load Factor	$0.97330	$1.28800	$0.31470	32.33%
Extra Large High Load Factor	$0.90970	$1.23930	$0.32960	36.23%
Natual Gas Vehicles	$0.73700	$1.03490	$0.29790	40.42%
Marketer Charges	$0.03991	$0.04555	$0.00564	14.13%

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Changes in Costs by GCR Cost Component (Including Reconciliation Amounts)
Based on NEG's September 1, 2005 Filing

GCR Cost Component	Forecasted Annual Cost 2004-05 1/	Forecasted Annual Cost 2005-06 2/	Change $	Change %
Supply Fixed Costs	$ 22,792,100	$ 25,583,833	$ 2,791,733	12.2%
Storage Fixed Costs	$ 9,546,777	$ 9,616,581	$ 69,804	0.7%
Supply Variable Costs	$ 187,088,855	$ 252,051,387	$ 64,962,532	34.7%
Storage Variable Product Costs	$ 25,152,625	$ 31,167,195	$ 6,014,570	23.9%
Storage Variable Non-Product Costs	$ 2,447,918	$ 3,939,264	$ 1,491,346	60.9%
TOTAL	$ 247,028,275	$ 322,358,260	$ 75,329,985	**30.5%**
Total Fixed Costs	$ 32,338,877	$ 35,200,414	$ 2,861,537	8.8%
Total Variable Costs	$ 214,689,398	$ 287,157,846	$ 72,468,448	**33.8%**

1/ Source: Schedule PCC-1, September 1, 2004, pages 2-5.

2/ Source: Schedule PCC-1, September 1, 2005, pages 2-5.

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Changes in Costs by GCR Cost Component (Excludes Reconciliation Amounts)
Based on NEG's September 1, 2005 Filing

GCR Cost Component	Forecasted Annual Cost 2004-05 1/	Forecasted Annual Cost 2005-06 2/	Change $	Change %
Supply Fixed Costs	$ 26,561,416	$ 27,572,799	$ 1,011,383	3.8%
Storage Fixed Costs	$ 10,632,343	$ 10,204,602	$ (427,741)	-4.0%
Supply Variable Costs	$ 171,192,715	$ 237,892,083	$ 66,699,368	39.0%
Storage Variable Product Costs	$ 26,029,061	$ 32,136,415	$ 6,107,354	23.5%
Storage Variable Non-Product Costs	$ 2,679,049	$ 4,107,717	$ 1,428,668	53.3%
TOTAL	$ 237,094,584	$ 311,913,616	$ 74,819,032	31.6%
Total Fixed Costs	$ 37,193,759	$ 37,777,401	$ 583,642	1.6%
Total Variable Costs	$ 199,900,825	$ 274,136,215	$ 74,235,390	37.1%

1/ Source: Schedule PCC-1, September 1, 2004, pages 2-5.

2/ Source: Schedule PCC-1, September 1, 2005, pages 2-5.

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Changes in Costs by GCR Cost Component (Including Reconciliation Amounts)
Based on NEG's September 30, 2005 Filing

GCR Cost Component	Forecasted Annual Cost 2004-05 1/	Forecasted Annual Cost 2005-06 2/	Change $	Change %
Supply Fixed Costs	$ 22,792,100	$ 25,762,290	$ 2,970,190	13.0%
Storage Fixed Costs	$ 9,546,777	$ 9,604,566	$ 57,789	0.6%
Supply Variable Costs	$ 187,088,855	$ 294,532,238	$ 107,443,383	57.4%
Storage Variable Product Costs	$ 25,152,625	$ 31,546,928	$ 6,394,303	25.4%
Storage Variable Non-Product Costs	$ 2,447,918	$ 4,136,314	$ 1,688,396	69.0%
TOTAL	$ 247,028,275	$ 365,582,336	$ 118,554,061	**48.0%**
Total Fixed Costs	$ 32,338,877	$ 35,366,856	$ 3,027,979	9.4%
Total Variable Costs	$ 214,689,398	$ 330,215,480	$ 115,526,082	**53.8%**

1/ Source: Schedule PCC-1, September 1, 2004, pages 2-5.

2/ Source: Schedule PCC-1, September 1, 2005, pages 2-5.

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Changes in Costs by GCR Cost Component (Excludes Reconciliation Amounts)
Based on NEG's September 30, 2005 Filing

GCR Cost Component	Forecasted Annual Cost 2004-05 1/	Forecasted Annual Cost 2005-06 2/	Change $	Change %
Supply Fixed Costs	$ 26,561,416	$ 27,662,799	$ 1,101,383	4.1%
Storage Fixed Costs	$ 10,632,343	$ 10,204,602	$ (427,741)	-4.0%
Supply Variable Costs	$ 171,192,715	$ 276,348,509	$ 105,155,794	61.4%
Storage Variable Product Costs	$ 26,029,061	$ 32,403,487	$ 6,374,426	24.5%
Storage Variable Non-Product Costs	$ 2,679,049	$ 4,279,662	$ 1,600,613	59.7%
TOTAL	$ 237,094,584	$ 350,899,059	$ 113,804,475	**48.0%**
Total Fixed Costs	$ 37,193,759	$ 37,867,401	$ 673,642	1.8%
Total Variable Costs	$ 199,900,825	$ 313,031,658	$ 113,130,833	**56.6%**

1/ Source: Schedule PCC-1, September 1, 2004, pages 2-5.

2/ Source: Schedule PCC-1, September 1, 2005, pages 2-5.

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Changes in NEG's Forecasted Annual Sales by Month

	Forecasted 2004-05 Sales 1/ (MMBtu)	Forecasted 2005-06 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
November	2,068,649	2,050,150	(18,499)	-0.9%
December	3,237,235	3,328,347	91,112	2.8%
January	4,818,748	4,866,111	47,363	1.0%
February	4,991,407	5,290,003	298,596	6.0%
March	4,264,515	4,133,276	(131,239)	-3.1%
April	3,060,343	3,308,743	248,400	8.1%
May	2,008,931	1,861,361	(147,570)	-7.3%
June	1,002,537	996,288	(6,249)	-0.6%
July	800,325	708,731	(91,594)	-11.4%
August	757,306	708,923	(48,383)	-6.4%
September	657,318	688,739	31,421	4.8%
October	1,061,272	1,045,288	(15,984)	-1.5%
Total	28,728,586	28,985,960	257,374	0.9%
Winter Sales	19,380,554	19,667,887	287,333	**1.5%**
Summer Sales	9,348,032	9,318,073	(29,959)	-0.3%
Total Throughput	29,335,819	29,621,696	285,877	1.0%

1/ Source: Schedule PCC-1, page 12, filed September 1, 2004.

2/ Source: Schedule PCC-1, page 12, filed September 1, 2005.

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Changes in Forecasted Design Winter Sales & Throughput

	Forecasted 2004-05 Sales 1/ (MMBtu)	Forecasted 2005-06 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
November	2,098,461	2,050,150	(48,311)	-2.3%
December	3,745,600	3,836,026	90,426	2.4%
January	5,732,988	5,905,405	172,417	3.0%
February	5,732,997	6,025,995	292,998	5.1%
March	5,310,802	5,142,078	(168,724)	-3.2%
Total	22,620,848	22,959,654	338,806	1.5%
Total Throughput	23,054,253	23,409,025	354,772	1.5%

1/ Source: Schedule PCC-1, page 13, filed September 1, 2004.

2/ Source: Schedule PCC-1, page 13, filed September 1, 2005.

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Two-Year Changes in Forecasted Annual Sales by Month

	Forecasted 2003-04 Sales 1/ (MMBtu)	Forecasted 2005-06 Sales 2/ (MMBtu)	Forecasted Sales Incr. 2003-04 to 2004-05 (MMBtu)	% Increase
November	2,009,429	2,050,150	40,721	2.0%
December	3,347,385	3,328,347	(19,038)	-0.6%
January	4,733,438	4,866,111	132,673	2.8%
February	4,661,650	5,290,003	628,353	**13.5%**
March	4,051,827	4,133,276	81,449	2.0%
April	3,080,404	3,308,743	228,339	7.4%
May	1,799,561	1,861,361	61,800	3.4%
June	1,044,377	996,288	(48,089)	-4.6%
July	823,284	708,731	(114,553)	-13.9%
August	782,384	708,923	(73,461)	-9.4%
September	835,458	688,739	(146,719)	-17.6%
October	1,148,647	1,045,288	(103,359)	-9.0%
Total	28,317,844	28,985,960	668,116	2.4%
Winter Sales	18,803,729	19,667,887	864,158	**4.6%**
Summer Sales	9,514,115	9,318,073	(196,042)	-2.1%
Total Throughput	28,966,726	29,621,696	654,970	2.3%

1/ Source: Attachment MJH-1, page 14, filed September 2, 2003.

2/ Source: Schedule PCC-1, page 12, filed September 1, 2005.

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Two-Year Changes in Forecasted Design Winter Sales & Throughput

	Forecasted 2003-04 Sales 1/ (MMBtu)	Forecasted 2005-06 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
November	2,009,429	2,050,150	40,721	2.0%
December	3,855,978	3,836,026	(19,952)	-0.5%
January	5,681,618	5,905,405	223,787	3.9%
February	5,337,734	6,025,995	688,261	12.9%
March	5,000,328	5,142,078	141,750	2.8%
Total	21,885,087	22,959,654	1,074,567	4.9%
Total Throughput	22,351,065	23,409,025	1,057,960	4.7%

1/ Source: Attachment MJH-1, page 15, filed September 2, 2003.

2/ Source: Schedule PCC-1, page 13, filed September 1, 2005.

Exhibit BRO - 6

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October 11, 2005

New England Gas Company

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Recovery of U.S. Gulf of Mexico Oil and Gas Production

As of October 7, 2005

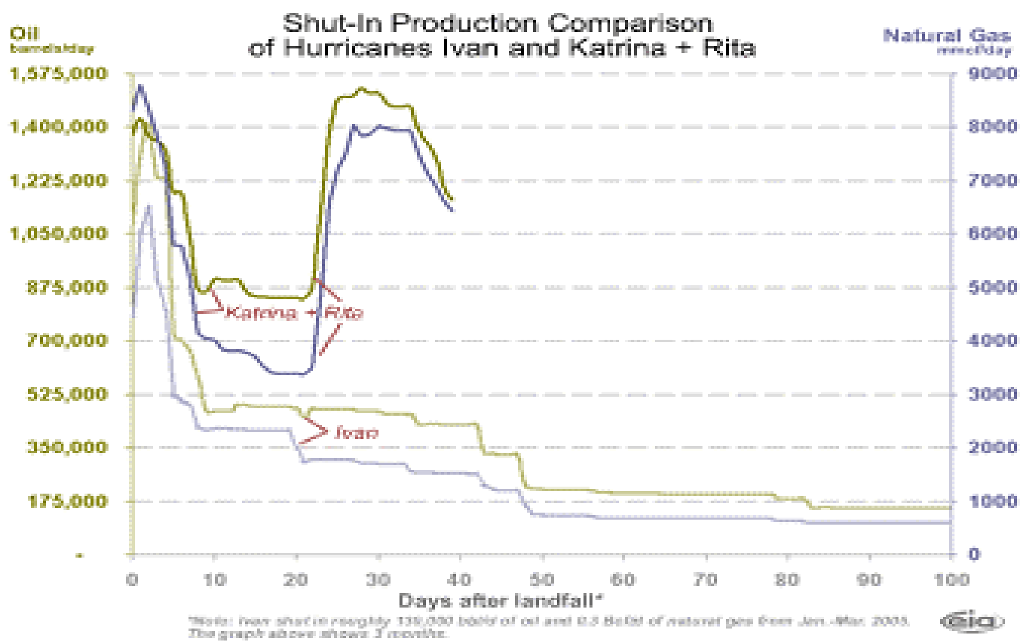

Exhibit BRO - 7
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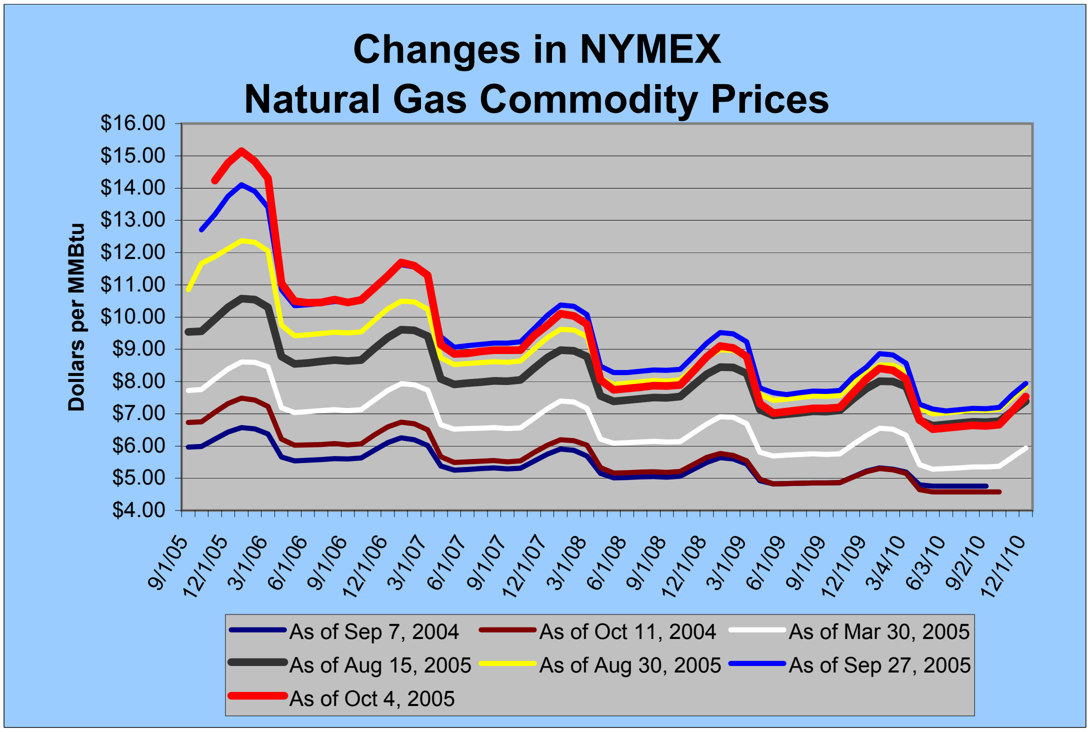

Exhibit BRO - 8
Docket No. 3696
October 11, 2005

New England Gas Company
Docket No. 3696

Recently Announced Residential Gas Rate Increases for Utilities in Other Jurisdictions

State	Utility	% Increase
Arkansas	Centerpoint Energy Arkla	10.0% **
Rhode Island	**New England Gas Company - 9/1/05 Filing**	**13.0%**
Oregon	Cascade Natural Gas	13.6%
Oregon	Northwestern Natural Gas	15.0%
Ohio	Columbia Gas of Ohio	16.0%
Missouri	Aquilla	20.0%
Arkansas	Arkansas Western Gas Co	21.0%
Oregon	Avista	21.9%
Pennyslvania	Dominion Peoples Gas	22.2%
Pennyslvania	Equitable Gas	22.7%
North Carolina	Public Service of North Carolina	23.0%
Idaho	Avista Corp.	23.4%
Washington	Avista Corp.	23.5%
Idaho	Avista Corp.	23.8%
Rhode Island	**New England Gas Company - 9/30/05 Filing**	**23.8%**
Arkansas	Arkansas Oklahoma Gas Corp	26.0%
Washington	Northwestern Energy	27.0%
Idaho	Intermountain Gas	27.6%
Massachusetts	Nstar Gas	28.7%
Wyoming	Cheyenne Light, Fuel & Power	29.0%
District of Columbia	Washington Gas Light Company	32.0% *
Maryland	Washington Gas Light Company	32.0% *
Virginia	Washington Gas Light Company	32.0% *
Maine	Northern Utilities	33.5%
Colorado	Xcel Energy	34.0%
Maryland	Baltimore Gas & Electric Company	35.0% *
New York	Niagara Mohawk	35.0%
Alabama	Alabama Gas Corp	36.7%
Missouri	Laclede Gas Company	40.0%
Wisconsin	WE Energies	40.0%
South Carolina	Piedmont Natural Gas	41.3%
South Carolina	South Carolina Electric and Gas	42.0%
California	Pacific Gas & Electric	43.0%
California	San Deigo Gas & Electric	45.0%
Pennyslvania	Columbia Gas	46.5%
Wisconsin	Alliant Energy	47.0%
Virginia	Roanoke Gas Company	49.4%
Texas	TXU Energy	50.0%
New Mexico	Public Service Company of New Mexico	54.0%
California	Southern California Gas	59.0%
New Jersey	Elizabethtown Gas	59.1%
Kentucky	Louisville Gas & Electric Company	64.0%
Minnesota	Centerpoint Energy	77.0%

* Rate is adjusted monthly: percentage increase reflects utility estimate for the coming winter season

** Utility has a gas buying program under which 80% of requirements are purchased in advance