BEFORE THE

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

IN THE MATTER OF

The National Grid Annual	**)**	
Gas Cost Recovery Charge	**)**	**Docket No. 3766**
Filing	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities and Carriers

October 12, 2006

TESTIMONY OF BRUCE R. OLIVER
Docket No. 3766
October 12, 2006

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 National Grid (hereinafter "NG" or "the Company") Annual Gas Cost Recovery (GCR) filing. This testimony reviews and comments on the content of the September 1, 2006 direct testimony of witnesses Czekanski and Beland, as well as the Attachments and Schedules associated with their pre-filed testimonies. Also included as an integral part of this presentation, is a discussion of the Company's "Long-Range Gas Supply Plan" which was filed with the Commission on August 22, 2006.

Q. AT PAGE 3 OF WITNESS CZEKANSKI'S SEPTEMBER 1, 2006 TESTIMONY IN THIS PROCEEDING, HE DISCUSSES THE NATIONAL GRID ACQUISITION OF THE NEW ENGLAND GAS COMPANY'S RHODE ISLAND OPERATIONS AND ASSERTS THAT THE TRANSACTION SHOULD HAVE NO IMPACT ON THE COMMISSION'S CONSIDERATIONS IN THIS FILING. DO YOU AGREE?

A. Yes, I do. National Grid has assumed the New England Gas Company tariffs and National Grid has assumed responsibility for the regulatory filings that were previously required of New England Gas Company under Southern Union ownership. In this context, it is the Division's understanding that any gas procurement or asset management incentives payable to, or charged against, the former New England Gas Company operations would now be applicable to National Grid.

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

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

Exhibit BRO-1	Proposed Changes in GCR Charges by Rate Classification
Exhibit BRO-2	Changes in Costs by GCR Cost Component

Exhibit BRO-3	Comparison of Changes in NYMEX Natural Gas Prices
Exhibit BRO-4	Forecasted Weather Normal Annual Sales & Throughput
Exhibit BRO-5	Forecasted Design Winter Sales & Throughput
Exhibit BRO-6	Assessment of Discretionary Gas Purchasing Activity

Q. IS NG PROPOSING TO INCREASE ITS GCR CHARGES?

A. No. The Company's September 1, 2006 filing proposes to decrease its GCR charges for all firm sales service rate classifications.

Q. HOW DO THE COMPANY'S PROPOSED CHANGES IN GCR CHARGES VARY BY RATE CLASSIFICATION?

A. The Company's September 1, 2006 filing proposes to decrease GCR charges for all rate classifications. For Residential and Small C&I customers, the GCR charge is reduced from $1.1971 per therm to $1.1304 per therm. That represents a decrease of $0.0667 per therm or 5.6%. Exhibit BRO-1, page 1 of 2, details the GCR decreases by rate classification in dollars per therm and percentage terms that NG proposes in the September 1, 2006 testimony and exhibits of witness Peter Czekanski.

Q. WHY ARE THE PERCENTAGE DECREASES IN GCR CHARGES SHOWN IN EXHIBIT BRO-1 NOT UNIFORM ACROSS RATE CLASSES?

A. Three basic factors contribute to the differences in percentage decreases 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.

Q. HOW SIGNIFICANT ARE THE DIFFERENCES IN MAGNITUDE AND DIRECTION OF CHANGES IN COSTS BY GCR COST COMPONENT THAT NG PROJECTS FOR THE 2006-07 GCR YEAR?

A. Exhibit BRO-2 compares the Company's projected GCR costs by component for the 2006-07 GCR year with the costs that it projected for the 2005-06 GCR year in its September 30, 2005 updated filing in Docket No. 3696. Page 1 of that exhibit compares costs by component including reconciliation amounts (i.e., adjustments for over- or under-recoveries by cost component during the prior GCR year). Page 2 of Exhibit BRO-2 depicts the changes in NG's projected gas costs for 2006-07 GCR year compared to prior year projections with "reconciliation amounts" excluded. The comparison on page 2 of Exhibit BRO-2 provides a clearer picture of the actual changes in the costs of gas supply service the NG projects.

With inclusion of reconciliation amounts, page 1 of Exhibit BRO-2 shows more than 20% reductions in both Supply Variable Costs and Storage Variable Non-Product Cost while overall gas supply costs drop 16.7% from the levels projected for the prior GCR year. However, the percentage changes shown on page 1 of Exhibit BRO-2 are heavily influenced by the magnitude of reconciliation adjustments included in the reported data.

Page 2 of Exhibit BRO-2 provides information comparable to that contained on the prior page of Exhibit BRO-2, but this time with reconciliation adjustments excluded. In this context, the Company's projected Supply Variable Costs for its 2006-07 GCR period, excluding consideration of reconciliation adjustments for past over- (under-) recoveries, are a **decrease of 9.9%** from the level projected by the Company in its September 30, 2005 Update filing. Other components of the Company's gas supply costs move in opposite directions. Supply Fixed Costs which are shown to increase 3.6% on page 1 of Exhibit BRO-2, actually decrease 5.1% when reconciliation adjustments are excluded. On the other hand, the projected Supply Fixed Costs are expected to **increase** by 1.4%, Storage Variable Product Costs swing from a 3.4% decrease to a 4.7% increase when the influences of reconciliation amounts are removed. Overall, page 2 of Exhibit BRO-2 depicts a

3.4% decline in Total Fixed Gas Supply Costs and an 8.4% reduction in Total Variable Gas Supply Costs.

Q. HAVE THE COMPONENTS OF THE COMPANY'S GCR COSTS EXHIBITED CHANGES THAT ARE PROPORTIONAL TO THE PROPOSED CHANGE IN THE COMPANY'S OVERALL GAS COSTS?

A. Clearly they have not. However, the primary driver of the reductions in GCR charges that NG has proposed in this proceeding is clearly the projected reduction in Supply Variable Costs.

<u>Natural Gas Price Considerations</u>

Q. HAVE THERE BEEN ANY SIGNIFICANT DEVELOPMENTS RELATING TO THE COMPANY'S PROJECTED COSTS OF GAS FOR ITS 2006-07 GCR YEAR SINCE NATIONAL GRID SUBMITTED ITS TESTIMONY AND EXHIBITS IN THIS PROCEEDING ON SEPTEMBER 1, 2006?

A. Yes. Natural gas commodity prices in the NYMEX futures market have fallen sharply. Exhibit BRO-3 page 1 and 2 illustrate the magnitude of that decline in natural gas commodity prices. As indicated in Schedule GLB-1 attached to witness Beland's September 1, 2006 testimony in this proceeding, the Company's filing is premised on NYMEX gas costs as of August 10, 2006. Page 1 of Exhibit BRO-3 provides a graphic depiction of changes observed in NYMEX natural gas commodity prices since August 10, 2006. Between August 10 and September 1, 2006 only a small change in natural gas commodity prices is observed. But, during September NYMEX commodity prices for natural gas fell precipitously. Within a period of less than one-month NYMEX natural gas prices for the coming winter months (November – March) fell by more than $3.00 per Dth (i.e., 25-30%). Over the same period, NYMEX natural gas commodity prices for non-winter months of 2007 declined roughly $1.50 per Dth or $0.15 per them.

Q. DOES THE RECENT DECLINE IN NATURAL GAS PRICES SIGNAL A CHANGE IN LONG-TERM NATURAL GAS PRICE EXPECTATIONS?

A. I do not believe so. Exhibit BRO-3, page 2 of 3, graphs NYMEX natural gas commodity prices by month through the end of 2010 as they were reported at the close of business on each of six separate trading days starting over a period of a roughly 14 months.

The first date for which data is presented is August 15, 2005. I have included that as an indication of pre-hurricane natural gas price levels in 2005. NYMEX natural gas prices as of the close of business on that date are represented by the bright blue line. If you draw a vertical line up from any month on the X-axis, the point of intersection with the bright blue line indicates the price at which supplies for delivery in the chosen month could have been purchased on that date. For example, the price of gas for November 2007 delivery as of August 15, 2005 was approximately $8.00 per Dth.

Similar lines are graphed for October 4, 2005 (approximately the peak for pricing after hurricanes Katrina and Rita), May 26, 2006, June 29, 2006, August 29, 2006, and October 3, 2006. The May, June, and August dates are somewhat arbitrarily selected to depict some of the fluctuation in natural gas futures price in recent months. The October 3, 2006 data (yellow line) represents the most recent data available at the time of the preparation of this testimony.

Based on the information graphed in Exhibit BRO-3, page 2 of 3, I offer the following observations:

- The volatility in natural gas futures prices over the past year has been substantial, particularly at the front-end of the period portrayed (i.e., for through the fall of 2007).

- Over most of the post-hurricane period, natural gas prices have displayed a somewhat unusual pattern with gas prices for the coming winter at lower levels than those for one or more subsequent winters.

- The somewhat atypical pricing pattern has reached rather extreme proportions over the last few weeks with pricing for the winter of 2006-07 significantly below winter prices for all subsequent winters for which information is presented.

- For periods subsequent to the fall of 2007, there appears to be considerable resistance to pricing below the August 15, 2005 pre-hurricane levels.

- The periods of comparatively high prices for the winters of 2008-09 and 2009-10 tend to correlate closely with speculative trading in the face of actual or anticipated energy supply disruptions and/or large demand uncertainties.

Based on this and other analyses of futures prices for natural gas that I have performed, I find that current natural gas prices for the twelve months ended October 2007 are at atypically low levels that are not likely to be sustainable on a long-term basis. I would note, however, that warmer than normal weather during the coming winter could prolong the period of atypically low near-term natural gas prices.

Natural Gas Storage

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

A. It is reasonable to expect that the U.S. will enter into the winter heating season with full storage inventories. Due to the combined affects of mild winter and spring weather in 2006, reductions in gas use by customers in response to high gas prices in the post-hurricane period, and the lack of major hurricanes or other supply disruptions this fall, natural gas storage inventories are presently well above historic levels. As a result, full storage inventories should be easily achieved prior to the start of the coming winter season.

Exhibit BRO-3, page 3 of 3, depicts patterns in U.S. natural gas storage inventories since the beginning of 2001. The red line toward the top of the graph reflects storage inventory levels during calendar year 2006. As can be readily observed, inventory levels during 2006 have been well above those for all other recent years (contributing significantly to current low near-term futures prices for natural gas). These data provide a high degree of confidence that the U.S. will enter the coming winter season with full natural gas storage.

However, as we approach the end of the storage injection season the differences between storage inventories for 2006 and those for prior years will necessarily narrow since further additions to storage this year are likely to be constrained by available storage capacity. U.S. natural gas storage capacity is presently about 3,450 Bcf. As of September 22, 2006, the U.S. had 3,256 Bcf of natural gas in storage. Thus, attainment of full storage capacity levels requires less than 40 Bcf per week of injections over the remainder of the injection season. Over the most recent four week period for which storage injection data is presently available the U.S. has averaged injections of more than 87 Bcf per week.

Q. DO YOU EXPECT THAT NG WILL ENTER THE WINTER OF 2006-07 WITH FULL STORAGE INVENTORIES?

A. Yes, I do. Nothing in the materials I have reviewed for this proceeding offers any suggestion that the Company will be unable to achieve full storage capacity levels prior to the start of the coming winter season. However, since the objective of the industry every year is to enter the winter with essentially full natural gas storage, once the injection season is completed, there will be no excess or unusually high storage inventories to depress natural gas prices. Therefore, the end of the storage injection season should essentially mark a return to business as usual conditions until either much warmer or much colder than normal weather is experienced.

<u>Assessment of NG's Proposed GCR Charges</u>

Q. HOW WOULD RECOGNITION OF RECENT REDUCTIONS IN NYMEX COMMODITY PRICES FOR NATURAL GAS IMPACT THE COMPANY'S PROJECTED GAS COSTS FOR 2006-07 GCR PERIOD?

A. Replacing the NYMEX price data in the Company's gas cost calculations with the NYMEX natural gas prices November 2006 through October 2007 as of the close of trading on October 3, 2006, I find that the updated gas prices would lower the Company's Total Gas Costs for the 2006-07 GCR year from $319,139,135 to $297,004,231. That would represent a reduction of over $22.1 million (or 6.9%) in NG's projected gas costs for the 2006-07 GCR year. It would also lower the Company's weighted average cost of gas (WACOG) for pipeline gas from $10.351 per Dth to $9.445 per Dth.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION REQUIRE NG TO UPDATE IS 2006-07 GCR COSTS TO REFLECT MORE CURRENT NYMEX NATURAL GAS PRICING DATA?

A. Not necessarily. Even though the most recent NYMEX data could support a further reduction in the Company's 2006-07 GCR charges, I expect the pricing of natural gas to remain highly volatile over the next several years. Reducing the proposed

GCR charge further than has already been proposed will further expose customers to that volatility. Therefore, I am not recommending further reductions in GCR charges at this time based on rather speculative assessments of natural gas prices over the next year.

The GCR already includes a sizeable reconciliation adjustment for over-recoveries of gas costs that most likely will not be repeated next year. Thus, just the elimination of that adjustment next year will increase the potential of an upward adjustment to the Company's overall costs of gas and GCR charges for the 2007-08 GCR year. If the Commission further reduces GCR charges for the 2006-07 GCR year based on recent declines in NYMEX natural gas futures prices and the market subsequently turns upward again, the potential magnitude of a GCR increase next year could be greatly amplified. Thus, given that one of the Commission's objectives in setting gas rates has been increased price stability, re-setting GCR charges at this time based on updated NYMEX natural gas price data may not be consistent with pursuit of that objective.

If the Commission perceives a need to further reduce National Grid's projected gas costs and GCR charges at this time, it may wish to consider other alternatives as well. One alternative might be to provide a one-time refund to customers of some or all of the over-recovery balance in the Company's deferred gas costs while using the further decrease in NYMEX prices since the time the

Company prepared its filing to maintain the GCR levels that NG has proposed in this proceeding. Through the use of such a one-time refund, the Commission could provide additional benefits to customers without lowering NG's GCR charges for 2006-07 or further amplifying the potential for large increases in GCR charges next year.

Another alternative might use a portion of the estimated reduction (e.g., 50%) in gas costs that results from more current NYMEX natural gas prices to provide customers a further reduction in GCR charges. In doing so, the Commission could provide customers additional reductions in GCR charges while still leaving a buffer against the potential for unpredictable increases in natural gas prices during the GCR period.

Q. ARE THE GCR CHARGES THAT NG PROPOSES THROUGH WITNESS CZEKANSKI'S SEPTEMBER 1, 2006 TESTIMONY PROPERLY COMPUTED?

A. The methods that NG 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, I have some reservations regarding the appropriateness of the forecasted measures of gas use that the Company relies upon throughout its GCR filing in this proceeding to develop its projected GCR costs and to allocate those costs among customer classes.

Forecasted Sales and Throughput

Q. PLEASE EXPLAIN THE NATURE OF YOUR RESERVATIONS REGARDING FORECASTS OF FIRM SALES AND THROUGHPUT UPON WHICH THE COMPANY HAS RELIED IN THE PREPARATION OF ITS FILING IN THIS PROCEEDING?

A. As demonstrated in Exhibit BRO-4, the Company's forecasted weather normal sales levels for the 2006-07 GCR year are 5.0% below comparable projections made last year for the 2005-06 GCR year. This is a dramatic change for a company that has been projecting 0.5% per year growth. Yet, nothing in the Company's filing in this proceeding addresses explicitly this potentially important change in expectations.

To illuminate this concern, Exhibit BRO-4 provides comparisons of the Company's forecasted Weather Normal Sales and Throughput from its September 30, 2005 filing in Docket No. 3696 with comparable data from its September 1, 2006 filing in this proceeding. Page 1 of Exhibit BRO-4 compares forecasted Weather

Normal Sales and Throughput by month. Page 2 of Exhibit BRO-4 compares forecasted Weather Normal Sales and Throughput by rate classification.

In addition, Exhibit BRO-5 offers comparisons of the Company's forecasted Design Winter Sales and Throughput by month and by rate classification. Page 1 of Exhibit BRO-5 compares forecasted Design Winter Sales and Throughput by month for the 2005-06 and 2006-07 GCR years. Page 2 of Exhibit BRO-5 offers similar comparisons of forecasted Design Winter Sales and Throughput by rate classification.

Q. WHAT OBSERVATIONS SHOULD BE MADE FROM THE DATA PRESENTED IN EXHIBITS BRO-4 AND BRO-5?

A. I offer three important observations based on the data presented in those exhibits.

First, both forecasted annual throughput (i.e., combined sales and transportation volumes) and forecasted design winter throughput have declined significantly. The Company's forecast of weather normal annual throughput for the 2006-07 GCR year is 6.6% below the level the Company used for its 2005-06 GCR year. Forecasted design winter throughput for the 2006-07 GCR period is 6.2% below the comparable forecast for the prior year.

Second, while both forecasted annual volumes and forecasted design winter volumes declined for sales service customers, similar measures of forecasted gas use for FT-2 transportation service customers have increased sharply.

Third, forecasted design winter sales have fallen by a greater percentage than annual sales. Forecasted weather normal sales for winter months have fallen by 6.6%, while forecasted sales for non-winter months have only declined by 1.7%. In other words, the forecasted decline in sales volumes for winter months (i.e., November through March) is much steeper than that for non-winter months (i.e., April through October).

Q. HOW DO THE CHANGES IN FORECASTED ANNUAL AND DESIGN WINTER SALES THAT ARE REFLECTED IN THE COMPANY'S RECENT GCR FILINGS RELATE TO THE FORECASTED GAS SUPPLY REQUIREMENTS UPON WHICH THE COMPANY BASES ITS LONG RANGE GAS SUPPLY PLANNING?

A. The Long Range Gas Supply Plan filed on August 22, 2006 is premised on the sales forecast that was developed for its 2005-06 GCR period. As a result, the Company's Gas Supply Plan does not reflect the influences of declines in normal weather gas use experienced over the last year. Furthermore, the amount of capacity for which costs are included in the Company's 2006-07 GCR projections may exceed that which is actually required to reliability serve the NG's firm service customers under design winter conditions.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S AUGUST 22, 2006 LONG RANGE GAS SUPPLY PLAN?

A. Yes. I believe a more detailed review of the Company's Long Range Gas Supply Plan is necessary and appropriate. Therefore, I recommend that the Commission continue this proceeding to provide for a more in-depth examination of the Company's latest Long Range Gas Supply Plan and the influences of the Company's long range gas supply planning on its current portfolio of gas supply assets on the level of fixed costs proposed for inclusion in GCR charges in this proceeding. In support of this recommendation, I have identified several preliminary concerns regarding the Company plan as described below.

First, the Company's statistical analysis of data used to compute its design day criteria cuts off with the winter of 1993-94 (i.e., the same period used in the Company's prior long range planning studies, and does not update the data used to provide consideration of the 12 winters of actual experience since that time. This exclusion of more recent data is inappropriate and could bias the Company's planning analyses toward overstatement of its capacity requirements. Over the 54 winters from the winter of 1940-41 to the winter of 1993-94 (i.e. the period analyzed by the Company) only two winters had a peak day that comprised less than 50 degree days (one had 48 degree days and the other 47 degree days). Yet, one out of every three years during that period had 60 or more degree days on the peak day. Since the winter of 1993-94 only one winter has had peak day with more than 57 degree days, and four have been below 50 degree days. Moreover, the peak day for the winter of 2001-02 had only 40 degree days, by far the lowest number of degree days reported for any peak day to date.

Second, the Company makes no attempt to reconcile its estimates of design day demand with estimates of demands by rate class.[1] I note, for example, that PG Energy in Pennsylvania, a former sister Company of New England Gas under Southern Union ownership, builds up its design day demand estimates from class data and individual customer data for large customers as opposed to simply analyzing overall system requirements. I also note that PG Energy's analyses indicate that its residential heating customers' peak day demands had declined faster than the declines in overall sales for that class, and as a result, there was a noticeable improvement in the residential class load factor. The Company's long-term planning study provides no explicit consideration of the potential for similar changes in class load factors.

[1] See National Grid's response to Division Data Request 1-13.

Third, the Company claims that essentially all of it's roughly 3.5% forecasted reduction in design year throughput requirements is attributable to non-winter usage and has no significant impact on design winter requirements. But, the Company has not provided sufficient documentation to determine the reasonableness of the data and calculations underlying those projections.

Fourth, the economic and reliability implications of the one in one hundred year planning criteria that the Company has employed in its Long-Range Gas Supply Plan warrant more detailed review and consideration. In response to Division Data Request 1-09(d), the Company references long-run avoided cost (LRAC) analyses that it used to assess the merits of alternative reliability criteria. But, once again, none of the numeric detail or assumptions underlying those LRAC analyses were included in the Company's long range planning study or provided in data request responses. In light of changing climatic conditions and increasing costs of gas and pipeline capacity, the data and assumptions underlying the Company's referenced LRAC analyses warrant more careful review.

GPIP Incentive Calculations

Q. HAS THE COMPANY COMPUTED GAS PROCUREMENT INCENTIVE AMOUNTS FOR THE 12 MONTH PERIOD ENDED JUNE 2006?

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 NG PRESENTS?

A. As shown in Schedule GLB-9, the Company's computations support a **net incentive** to be credited to NG in the amount of **$114,548.68**.

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

A. I have reviewed of the Company's Mandatory and Discretionary purchases for FY 2006 in considerable detail. I was particularly sensitive to the manner in which mandatory and discretionary purchases were identified and valued. Due to changes in the Gas Procurement Incentive Plan (GPIP) that have been adopted over the last two years and extraordinary measures that were taken as a result of Hurricanes Katrina and Rita in the fall of 2005, the pattern of mandatory purchases was not as regular and predictable as might have been expected. However, based on my review I am generally satisfied that the Company's mandatory and discretionary purchases have been segregated properly. Furthermore, I find no reason to question the accuracy of the mathematical calculations used to compute the incentive.

However, my review did identify five minor instances in which the purchases identified as discretionary purchases were completed before all mandatory purchases made in that month were executed. As indicated in Paragraph III.A.1.d. of the Company's Gas Procurement and Asset Management Incentive Plan:[2]

> *"The first purchases made each month will be deemed the Company's mandatory purchases up to the amount of the Company's uniform monthly purchase requirement unless such purchases are made under the recommended purchase guidelines ('RPG') as defined below."*

None of the identified discretionary purchases that were made out of the prescribed order for such purchases could be considered purchases made subject to the recommended purchase guidelines. Rather, in each instance the questioned discretionary purchase was what the Company labels a "rounding purchase." That is a discretionary purchase that simply rounds out a mandatory purchase to the nearest 100 Dth of daily purchase volume "*consistent with the supplier's policies or with the pipeline contract quantity being filled*."[3] However, the identified out of order discretionary purchases involve only comparatively small volumes. Also, each

[2] The Company has provided a copy of its Gas Procurement and Asset Management Incentive Plan in this proceeding as Schedule GLB-8(b) to witness Beland's September 1, 2006 Testimony.

instance can be characterized as a "rounding purchase" executed in during the month of May 2005 for different gas supply months. I have not attempted correct the Company's incentive calculations, but it is my judgment that they have no material impact on the overall amount of the incentive that the Company has computed.

Q. ON THE BASIS OF YOUR REVIEW OF THE COMPANY'S MANDATORY AND DISCRETIONARY PURCHASE FOR FY 2006, DO YOU RECOMMEND ANY CHANGES TO THE GPIP?

A. Yes. I recommend that on a going forward basis all mandatory purchases be rounded to the next highest 100 Dth of purchased daily volume. This will eliminate the need for small discretionary purchases that are made strictly for "rounding purchases" and greatly simplify the recording and verification of discretionary purchase activity. As shown in Exhibit BRO-6, over 80% of the 171 discretionary purchases reported for FY 2006 were made strictly for rounding purposes. All of those rounding purchases represented less than 100 Dth per day for single month, and in aggregate they account for only 17.6% of reported discretionary purchase volumes during FY 2006.

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[3] See the Company's response to Division Data Request 1-5.b. in this proceeding.

Asset Management Incentive

Q. HAS AN INCENTIVE AMOUNT BEEN COMPUTED FOR THE COMPANY UNDER THE ASSET MANAGEMENT INCENTIVE PROVISIONS OF ITS GAS PROCUREMENT PLAN?

A. Yes. Schedule GLB-11 provides support for the Company's asset management incentive determination. As shown in that schedule NG's calculations support an incentive payment of $234,882.

Q. IS THE AMOUNT OF THE ASSET MANAGEMENT INCENTIVE PROPERLY COMPUTED?

A. Yes. I find the Company's calculations to be mathematically correct and in compliance with the terms of the Commission's approved asset management incentive structure.

Q. DO YOU HAVE ANY FURTHER OBSERVATIONS AT THIS TIME REGARDING THE COMPANY'S ASSET MANAGEMENT INCENTIVE MECHANISM?

A. Yes. The Company's asset management incentive mechanism is dependent upon the Commission approving levels of Fixed Supply Costs and Fixed Storage Costs, as well as a portfolio of pipeline, storage and peaking resources that is reasonably consistent with meeting the Company's design winter and design peak day supply requirements. With the significant declines in forecasted weather normal throughput requirements reflected in the Company's filing in this proceeding, I believe a closer examination of the appropriateness of the Company's gas supply capacity, Fixed Supply Costs and Fixed Storage Costs is necessary. Before the Commission can conclude that the level of fixed costs included in the Company's GCR costs is reasonable, the base of costs from which asset management incentives is computed must be determined to be consistent with the Company's capacity requirements. At this time, I am not in a position to provide the Commission an opinion on either the appropriateness of the Company's Fixed Supply Costs and Fixed Capacity Costs or possible need for adjustments to the Company asset management incentive structure for FY 2007.

I am particularly concerned that the Company's long range gas supply plan is premised in part on the assumption that any costs of excess capacity will be returned to customers through capacity releases to off-system customers. Yet, no explicit data or analysis is provided to quantify either (1) the amount of excess capacity under design winter conditions for the 2006-07 GCR year or (2) the expected value of capacity release revenue to be derived from off-system customers during that period under design winter conditions. Furthermore, if the compensation of firm customers for excess capacity is an integral part of the

Company's rationales for its long range gas supply planning, then the Commission may question whether it is necessary or appropriate to provide the Company asset management incentives to reduce such costs. An alternative may be to place the Company, rather than firm customers, at risk for recovery of costs of excess capacity.

Gas Cost Reconciliations

Q. HAVE YOU REVIEWED THE COMPANY'S RECONCILIATION OF GAS COSTS FOR THE TWELVE MONTHS ENDED JUNE 30, 2006?

A. Yes, I have. Schedule PPC-2 to witness Czekanski's August 1, 2006 testimony provides a copy of the Company's "Annual Gas Cost Recovery Reconciliation." In that report, the Company presents its costs and revenue collections by month for each of the major components of its Gas Supply Costs for the twelve months ended June 30, 2006. I have reviewed that document in detail, as well as electronic worksheets that were used in the development of that document.

Q. SHOULD THE COMMISSION ACCEPT THE COMPANY'S ANNUAL GAS COST RECOVERY RECONCILIATION AS FILED?

A. In general, the Company's Annual Gas Cost Recovery Reconciliation appears to reasonably and appropriately represent its gas costs and GCR revenues for the reconciliation period. However, I have identified a small inconsistency in the reported level of annual firm throughput that should be resolved. The Annual Gas Cost Recovery Reconciliation Report reflects Total Firm Throughput for the twelve months ended June 2006 of 32,647,606. However, the Company's DAC reconciliations for the same period, as determined from the electronic workpapers provided in support of Attachment PCC-7 in Docket No. 3760 reflect total annual firm throughput of provided on page 32,671,977. The difference between these amounts is comparatively small (i.e., less than 25,000 Dth and less than 0.1%). Still, this difference should be explained or eliminated.

Q. SHOULD ANY CHANGES BE MADE IN THE COMPANY'S GAS COST RECONCILIATIONS ON A GOING-FORWARD BASIS?

A. Yes. The Company's current gas cost reconciliations apply the Bank of America Prime Rate to compute interest on over- or under-recovery balances. That approach to computing interest was adopted several years ago due to the unavailability of information regarding Southern Union's short-term costs of debt. The September 1, 2006 testimony of Sharon Partridge in the current DAC proceeding, Docket No. 3760, however, suggests that information regarding cost rates for short-term debt can be obtained. Moreover, the monthly cost rates for short-term debt presented in Attachment SP-1, page 10 of 10, in Docket No. 3760 are lower in most months than the Bank of America Prime Rate. The purpose of the interest rate calculations in the Company's gas cost reconciliations is to compensate the Company for the costs of carrying under-recoveries of gas costs. It was not intended to serve as an additional source of profit for the Company. Yet, to the extent the Bank of America Prime Rate exceeds NG's actual short-term debt costs the potential exists for additional unintended profits to be accrued by the Company. In that context, use of the Company's actual cost rates for short-term debt appears to be a more appropriate alternative. The Bank of America Prime Rate could still be used for estimating interest for prospective GCR periods, but actual short-term rates would be required for use in reconciliation filings.

Q. ARE THE ANY OTHER ALTERNATIVES THAT MIGHT BE CONSIDERED FOR USE IN THE CALCULATION OF INTEREST ON DEFERRED BALANCES IN THE COMPANY'S GCR RECONCILIATIONS?

A. It is my understanding that National Grid currently makes similar interest calculations in its Standard Offer reconciliations using a Customer Deposit Rate that is premised on the costs of 10-year U.S. Treasury Notes. Applying a similar approach to the calculation of interest on deferred gas cost balances might also be an acceptable alternative for prospective application to the Company's GCR reconciliations.

Other Issues

Q. IN PAST PROCEEDINGS YOU HAVE RAISED SOME CONCERNS REGARDING THE REPRESENTATIVENESS OF THE "TYPICAL" CUSTOMER USAGE LEVELS THAT THE COMPANY PRESENTS IN ITS BILL COMPARISONS. HAVE THOSE CONCERNS BEEN ADDRESSED IN SCHEDULE PPC-4 ATTACHED TO WITNESS CZEKANSKI'S DIRECT TESTIMONY IN THIS PROCEEDING?

A. No, they have not. The "typical" usage levels reflected in Schedule PCC-4 consistently understate average usage levels for all rate classes. Moreover, for the Residential Non-Heating, C&I Small, and C&I Medium classes, annualized average weather-normalized use per customer for the 12 months ended June 30, 2006 (as indicated in NG's response to Division Data Request 1-3) is greater than the upper end of the range of usage shown in the Company's bill comparisons. For the Residential Heating class, annualized average weather-normalized use per customer falls within the range of usage levels for which bill comparisons are computed. But, the annualized average use per customer for that class is 12.5% higher that the level of gas use that the Company represents as typical for that class. The following table compares the Company's bill comparison range of usage, its represented typical usage, and its reported annualized average weather-normalized use per customer for the 12 months ended June 30, 2006 for Residential and Small and Medium C&I rate classifications.

	Bill Comparison Range	Company Indicated Typical Use	2006 Avg. WN Annual Use/Cust[4]
Residential Non-Heating	115 - 191	153	242
Residential Heating	776 - 1,294	1,035	1,164
C&I Small	932 - 1,553	1,242	1,608
C&I Medium	7,761 – 12,935	10,348	14,304

Thus, one again, I encourage the Company to update its measures of "typical" customer use and expand the ranges of gas use for which bill comparisons are computed. The Company and the Commission should be sensitive to the fact that bill comparisons for "typical" customers, particularly for the Residential Heating class, are frequently cited in media reports regarding such rate filings, and thus incorrect representations of "typical" gas use may distort the information regarding rate impacts that is reported to the public.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

[4] Average annual weather-normalized gas use per customer for the 12 months ended June 2006.

A. Yes, it does.

Exhibit BRO - 1
10/05/2006

National Grid
Docket No. 3766

Proposed Changes in GCR Charges by Rate Classification
Based on NG's September 1, 2006 Filing

Rate Classification	Current GCR Rate ($/Therm)	NEG Proposed GCR Rate ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$1.1971	$1.1304	($0.0667)	-5.6%
Heating	$1.1971	$1.1304	($0.0667)	-5.6%
Commercial & Industrial				
Small	$1.1971	$1.1304	($0.0667)	-5.6%
Medium	$1.1906	$1.1239	($0.0667)	-5.6%
Large Low Load Factor	$1.1989	$1.1384	($0.0605)	-5.0%
Large High Load Factor	$1.1607	$1.0913	($0.0694)	-6.0%
Extra Large Low Load Factor	$1.1960	$1.1313	($0.0647)	-5.4%
Extra Large High Load Factor	$1.1438	$1.0767	($0.0671)	-5.9%
Natual Gas Vehicles	$0.9335	$0.8680	($0.0655)	-7.0%
FT-2 Storage Service Charge	$0.0479	$0.0469	($0.0010)	-2.0%

National Grid

Docket No. 3766

Changes in Costs by GCR Cost Component (Including Reconciliation Amounts)

Based on NG's September 1, 2006 Filing

GCR Cost Component	Forecasted Annual Cost 2005-06 1/	Forecasted Annual Cost 2006-07 2/	Change $	Change %
Supply Fixed Costs	$ 25,672,290	$ 26,584,502	$ 912,212	3.6%
Storage Fixed Costs	$ 9,604,566	$ 10,169,127	$ 564,561	5.9%
Supply Variable Costs	$ 294,532,238	$ 233,992,774	$ (60,539,464)	-20.6%
Storage Variable Product Costs	$ 31,546,928	$ 30,463,207	$ (1,083,721)	-3.4%
Storage Variable Non-Product Costs	$ 4,136,314	$ 3,306,953	$ (829,361)	-20.1%
TOTAL	$ 365,492,336	$ 304,516,563	$ (60,975,773)	**-16.7%**
Total Fixed Costs	$ 35,276,856	$ 36,753,629	$ 1,476,773	4.2%
Total Variable Costs	$ 330,215,480	$ 267,762,934	$ (62,452,546)	**-18.9%**

1/ Source: Docket No. 3696, Schedule PCC-1, Updated September 30, 2005, pages 2-5.

2/ Source: Docket No. 3766, Schedule PCC-1, September 1, 2006, pages 2-5.

National Grid

Docket No. 3766

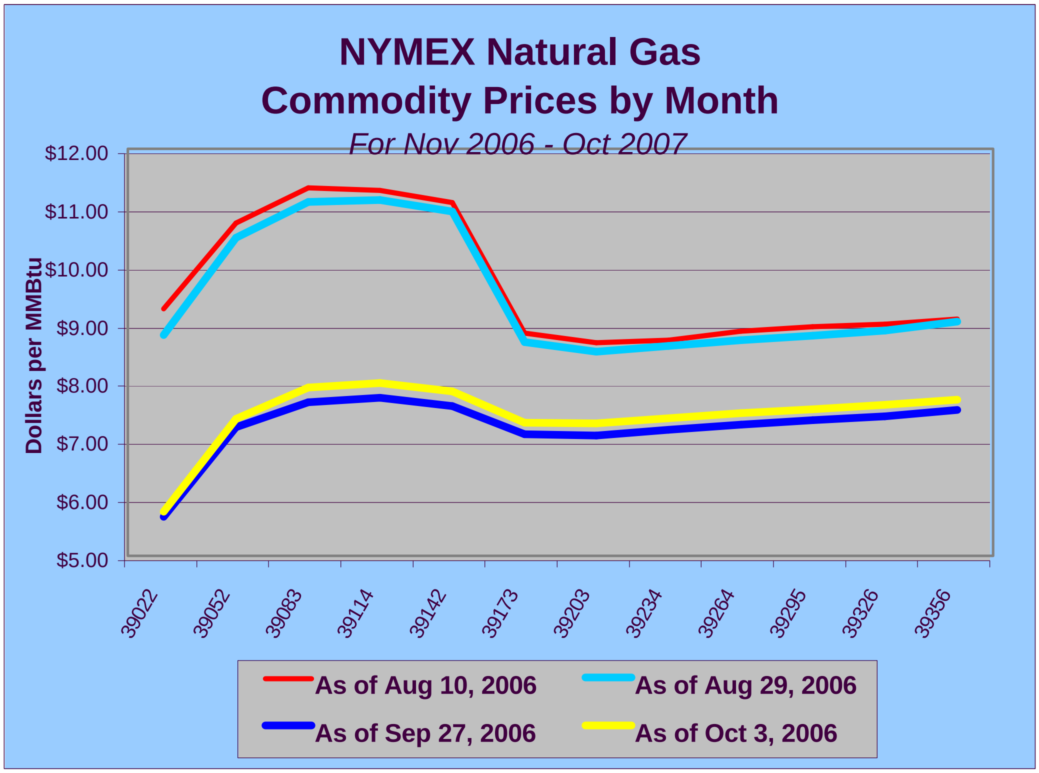
Changes in Costs by GCR Cost Component (Excluding Reconciliation Amounts)

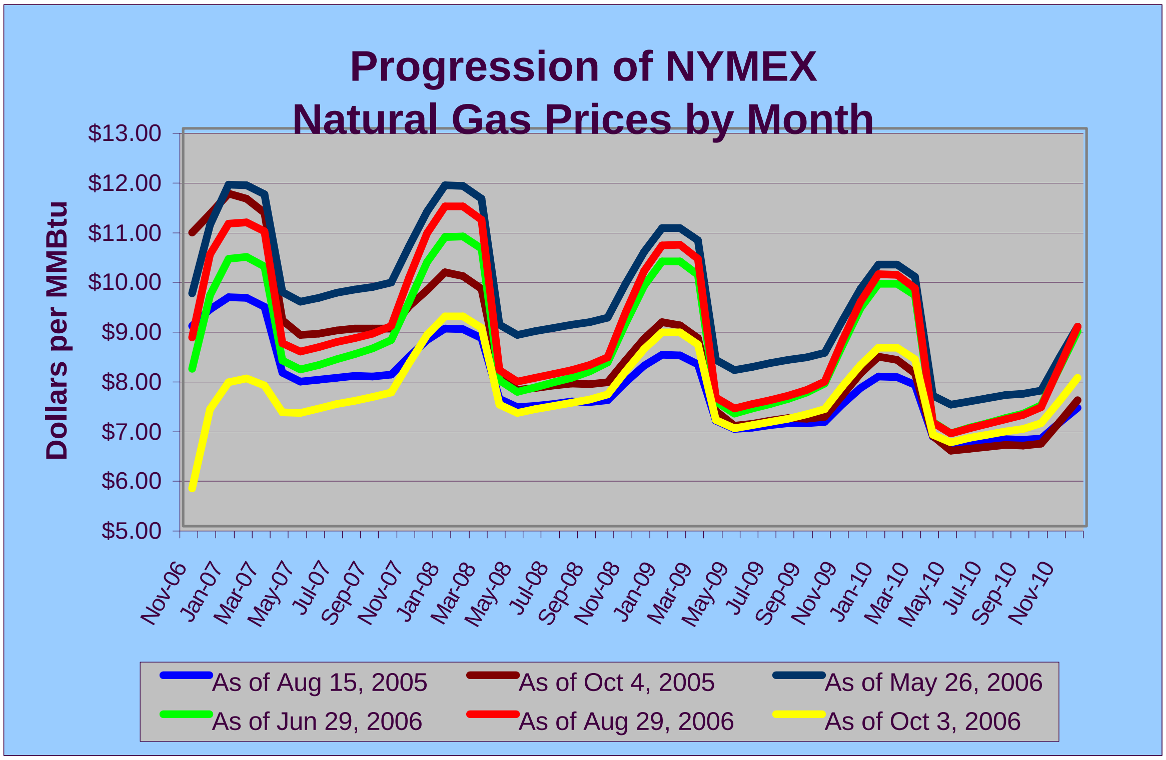
Based on NEG's September 1, 2006 Filing

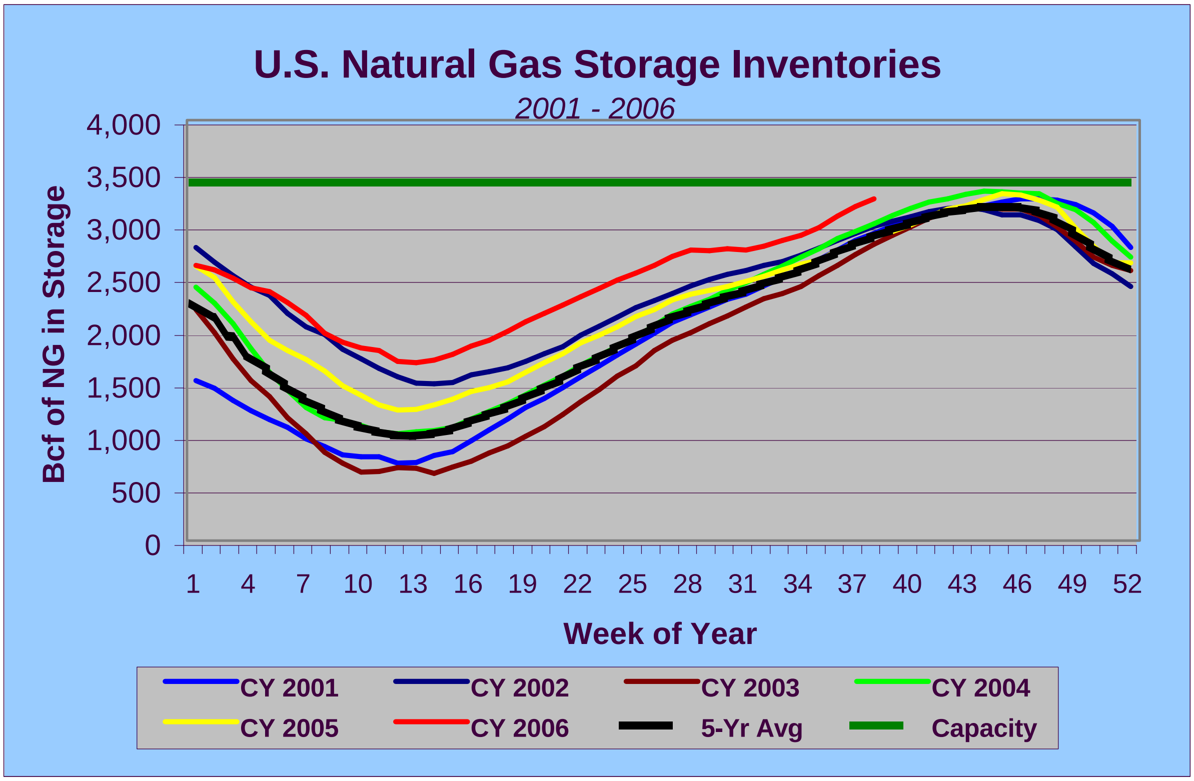
GCR Cost Component	Forecasted Annual Cost 2005-06 1/	Forecasted Annual Cost 2006-07 2/	Change $	Change %
Supply Fixed Costs	$ 27,572,799	$ 26,157,117	$ (1,415,682)	-5.1%
Storage Fixed Costs	$ 10,204,602	$ 10,350,168	$ 145,566	1.4%
Supply Variable Costs	$ 276,348,509	$ 248,987,539	$ (27,360,970)	-9.9%
Storage Variable Product Costs	$ 32,403,487	$ 33,925,885	$ 1,522,398	4.7%
Storage Variable Non-Product Costs	$ 4,279,662	$ 3,730,919	$ (548,743)	-12.8%
TOTAL	$ 350,809,059	$ 323,151,628	$ (27,657,431)	-7.9%
Total Fixed Costs	$ 37,777,401	$ 36,507,285	$ (1,270,116)	-3.4%
Total Variable Costs	$ 313,031,658	$ 286,644,343	$ (26,387,315)	-8.4%

1/ Source: Docket No. 3696, Schedule PCC-1, Updated September 30, 2005, pages 2-5.

2/ Source: Schedule PCC-1, September 1, 2006, pages 2-5.


NYMEX Natural Gas
Commodity Prices by Month
For Nov 2006 - Oct 2007
Dollars per MMBtu
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
39022
39052
39083
39114
39142
39173
39203
39234
39264
39295
39326
39356
As of Aug 10, 2006
As of Aug 29, 2006
As of Sep 27, 2006
As of Oct 3, 2006


Progression of NYMEX
Natural Gas Prices by Month
Dollars per MMBtu
$13.00
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
Nov-06
Jan-07
Mar-07
May-07
Jul-07
Sep-07
Nov-07
Jan-08
Mar-08
May-08
Jul-08
Sep-08
Nov-08
Jan-09
Mar-09
May-09
Jul-09
Sep-09
Nov-09
Jan-10
Mar-10
May-10
Jul-10
Sep-10
Nov-10
As of Aug 15, 2005
As of Oct 4, 2005
As of May 26, 2006
As of Jun 29, 2006
As of Aug 29, 2006
As of Oct 3, 2006


U.S. Natural Gas Storage Inventories
2001 - 2006
Bcf of NG in Storage
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
4
7
10
13
16
19
22
25
28
31
34
37
40
43
46
49
52
Week of Year
CY 2001
CY 2002
CY 2003
CY 2004
CY 2005
CY 2006
5-Yr Avg
Capacity

National Grid
Docket No. 3766

Forecasted Weather Normal Annual Sales & Throughput by Month

	Forecasted 2005-06 Sales 1/ (MMBtu)	Forecasted 2006-07 Sales 2/ (MMBtu)	2006-07 Forecasted Sales vs. 2005-06 (MMBtu)	% Sales Increase (%)
Sales				
November	2,050,150	1,897,136	(153,014)	-7.5%
December	3,328,347	3,196,190	(132,157)	-4.0%
January	4,866,111	4,593,118	(272,993)	-5.6%
February	5,290,003	4,549,366	(740,637)	-14.0%
March	4,133,276	4,138,755	5,479	0.1%
April	3,308,743	3,194,894	(113,849)	-3.4%
May	1,861,361	1,759,724	(101,637)	-5.5%
June	996,288	1,086,981	90,693	9.1%
July	708,731	775,174	66,443	9.4%
August	708,923	654,879	(54,044)	-7.6%
September	688,739	727,728	38,989	5.7%
October	1,045,288	962,067	(83,221)	-8.0%
Total Sales	28,985,961	27,536,012	(1,449,948)	-5.0%
Winter Sales	19,667,887	18,374,565	(1,293,322)	-6.6%
Non-Winter Sales	9,318,073	9,161,447	(156,626)	-1.7%
FT-2 Throughput				
November	48,081	54,736	6,655	13.8%
December	71,255	83,395	12,140	17.0%
January	97,236	108,695	11,459	11.8%
February	96,959	108,598	11,639	12.0%
March	79,705	103,308	23,603	29.6%
April	74,023	81,832	7,809	10.5%
May	51,956	52,833	877	1.7%
June	26,321	36,546	10,225	38.8%
July	20,203	32,698	12,495	61.8%
August	20,032	28,298	8,266	41.3%
September	19,983	27,895	7,912	39.6%
October	29,983	35,558	5,575	18.6%
Total FT-2 Throughput	635,736	754,391	118,655	18.7%
Winter Throughput	393,236	458,732	65,496	16.7%
Non-Winter Throughput	242,501	295,660	53,159	21.9%
Total Throughput	29,621,696	28,290,403	(1,331,293)	-4.5%

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

2/ Source: Schedule PCC-1, page 12, filed September 1, 2006.

National Grid

Docket No. 3766

Forecasted Normal Weather Annual Sales & Throughput by Rate Class

	Forecasted 2005-06 Sales 1/ (MMBtu)	Forecasted 2006-07 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
Residential Non-Heat	635,252	617,594	(17,658)	-2.8%
Residential Heat	19,043,319	18,144,431	(898,888)	-4.7%
Small C&I	2,432,138	2,315,913	(116,225)	-4.8%
Medium C&I	4,314,796	4,067,641	(247,155)	-5.7%
Large LLF	1,435,995	1,431,111	(4,884)	-0.3%
Large HLF	560,249	417,103	(143,146)	-25.6%
Extra Large LLF	220,308	158,520	(61,788)	-28.0%
Extra Large HLF	343,903	383,700	39,797	11.6%
Total Sales	28,985,961	27,536,012	(1,449,947)	-5.0%
FT-2 Throughput				
Medium C&I	389,295	470,979	81,684	21.0%
Large LLF	161,673	161,492	(181)	-0.1%
Large HLF	64,720	80,540	15,820	24.4%
Extra Large LLF	20,048	20,031	(17)	-0.1%
Extra Large HLF	0	21,350	21,350	NM
Total FT-2 Throughput	635,736	754,391	118,655	18.7%
Total Throughput	29,621,697	28,290,403	(1,331,294)	-4.5%

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

2/ Source: Schedule PCC-1, page 13, filed September 1, 2006.

NM indicates Not Meaningful

National Grid

Docket No. 3766

Forecasted Design Winter Sales & Throughput by Month

	Forecasted 2005-06 Sales 1/ (MMBtu)	Forecasted 2006-07 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
November	2,050,150	1,896,755	(153,395)	-7.5%
December	3,836,026	3,602,863	(233,163)	-6.1%
January	5,905,405	5,390,637	(514,768)	-8.7%
February	6,025,995	5,416,008	(609,987)	-10.1%
March	5,142,078	5,133,206	(8,872)	-0.2%
Total Sales	22,959,654	21,439,469	(1,520,185)	-6.6%
FT-2 Throughput				
November	48,081	54,728	6,647	13.8%
December	79,829	91,820	11,991	15.0%
January	115,817	124,303	8,486	7.3%
February	108,968	126,141	17,173	15.8%
March	96,677	124,353	27,676	28.6%
Total FT-2 Throughput	449,371	521,345	71,974	16.0%
Total Throughput	23,409,025	21,960,814	(1,448,211)	-6.2%

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

2/ Source: Schedule PCC-1, page 13, filed September 1, 2006.

National Grid

Docket No. 3766

Forecasted Design Winter Sales & Throughput by Rate Class

	Forecasted 2005-06 Sales 1/ (MMBtu)	Forecasted 2006-07 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
Residential Non-Heat	347,138	332,140	(14,998)	-4.3%
Residential Heat	15,375,866	14,364,142	(1,011,724)	-6.6%
Small C&I	2,078,241	1,928,268	(149,973)	-7.2%
Medium C&I	3,314,464	3,071,414	(243,050)	-7.3%
Large LLF	1,171,765	1,195,784	24,019	2.0%
Large HLF	328,940	237,162	(91,778)	-27.9%
Extra Large LLF	175,950	126,113	(49,837)	-28.3%
Extra Large HLF	167,290	184,446	17,156	10.3%
Total Sales	22,959,654	21,439,469	(1,520,185)	-6.6%
FT-2 Throughput				
Medium C&I	264,152	316,151	51,999	19.7%
Large LLF	131,353	138,136	6,783	5.2%
Large HLF	38,079	40,349	2,270	6.0%
Extra Large LLF	15,787	15,782	(5)	0.0%
Extra Large HLF	0	10,926	10,926	NM
Total FT-2 Throughput	449,371	521,345	71,974	16.0%
Total Throughput	23,409,025	21,960,814	(1,448,211)	-6.2%

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

2/ Source: Schedule PCC-1, page 13, filed September 1, 2006.

NM indicates Not Meaningful

National Grid

Docket No. 3766

Assessment of Discretionary Gas Purchasing Activity

		FY 2006 Discretionary Purchases			
Month	Yr	Total Purchases	Strictly Rounding Purchases	Total Volume Dth	Volume of Strictly Rounding Purchases
July	2005	15	14	44,702	19,964
August	2005	15	15	11,966	11,966
September	2005	15	15	21,060	21,060
October	2005	15	14	76,167	23,033
November	2005	14	12	77,640	15,660
December	2005	14	12	89,435	15,128
January	2006	13	6	205,654	9,424
February	2006	12	6	163,072	7,728
March	2006	13	8	146,723	12,958
April	2006	15	13	69,570	20,310
May	2006	12	10	62,558	19,065
June	2006	18	13	149,280	20,670
Total		171	138	1,117,827	196,966
Percent of Total			80.7%		17.6%

Source: Attachment to National Grid Response to Division Data Request 1-5(a).