State of Rhode Island and Providence Plantations

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February 5, 2007

Via Electronic Mail and Hand Delivery

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

Re: **National Grid Long Range Gas Supply Plan; Docket No. 3789**

Dear Ms. Massaro:

On behalf of the Division of Public Utilities and Carriers ("Division"), I enclose ten copies of a Report containing the Division's findings and recommendations in connection with National Grid's recently filed Long Range Gas Supply Plan.

Thank you for your attention to this matter.

Very truly yours,

Paul Roberti
Assistant Attorney General
Chief, Regulatory Unit

Enclosures
cc: Thomas F. Ahern, Administrator
Steve Scialabba, Chief Accountant
Bruce Oliver
Service List

RHODE ISLAND PUBLIC UTILITIES COMMISSION
Docket 3789
Division of Public Utilities and Carriers Evaluation of National Grid Long Range Gas Supply Plan

On August 22, 2006 the New England Gas Company filed a new "Long-Range Gas Supply Plan" ("2006 Plan") with the Commission.[1] In testimony filed before this Commission on October 12, 2006 in Docket 3766, witness Oliver on behalf of the Division of Public Utilities and Carriers raised certain concerns regarding the Company's 2006 Plan. This report reflects the results of the Division's investigations to date regarding the issues that Mr. Oliver raised in his testimony in Docket 3766, and suggests areas for further discussion by the parties and/or consideration by the Commission.

EXECUTIVE SUMMARY

For years the Company's gas supply planning has relied essentially on a steady-state forecasting methodology to project future gas supply requirements. It has also generally assumed that variations in heating degree days, which heavily influence the design of its gas supply portfolio, are randomly distributed. The Division observes herein that those forecasting and planning assumptions may no longer be adequate or appropriate, particularly in the context of significant changes in demand expectations that are reflected in National Grid's most recent annual GCR filing. The following is a summary of key elements of the Division's findings based on its review of the Company's 2006 Plan:

- The fixed costs that National Grid has included in its GCR charges for the current (2006-07) GCR year provide a reasonable basis upon which to compute Asset Management Incentives for that year.

- Significant changes in forecasted gas supply requirements reflected in National Grid's September 1, 2006 annual GCR filing are not reflected or even discussed in the Long-Range Gas Supply Plan that the Company filed 10 days earlier on August 22, 2006.

- Despite important changes in the industry, anticipated weather patterns, and cost relationships over the last decade, key elements of the analyses underlying the Company's gas supply planning analyses have not been updated in the preparation of its 2006 Plan.

[1] This report was filed just a few days prior to the closing of National Grid's purchase of the New England Gas Company's Rhode Island assets and its assumption of responsibility for all gas distribution utility operations within Rhode Island. Throughout the remainder of this report, the terms "National Grid" and "the Company" will be used to reference both the current and prior ownership of Rhode Island's gas distribution utility operations.

- The Company needs to provide greater justification for planned capacity reserves and greater information regarding the uncertainties it faces in the planning process.

- The Division recommends expansion of the content of the Company's long-range planning reports, as well as increased frequency of long-range planning studies and extension of the length of the planning periods addressed in those studies;

BACKGROUND

The Company's 2006 Plan addresses a five-year planning period covering the winters of 2006-07 through 2010-11. Through that study, an effort is made to identify the gas supply resources that will be required in future periods to ensure the continued reliability of gas supply for Rhode Island consumers over time. The study also provides important foundation for the determination of appropriate levels of Fixed Gas Supply costs for inclusion in the Company's annual Gas Cost Recovery (GCR) filings.[2] Moreover, determinations relating to the appropriate level of fixed costs for recovery through GCR charges now take on added importance as a benchmark for the calculation of incentive payments to the Company under the Asset Management Incentive Mechanism presently in place.

Under the Asset Management incentive program, the amount of fixed costs established for a GCR period influences both the likelihood that the Company will be able to earn such incentives and the amount of incentives that might be earned. If the Company's portfolio of gas supply resources includes either too much or too little capacity, the effectiveness of the Asset Management Incentive mechanism can be adversely affected. Maintaining greater supply resources than are necessary to ensure reliable supply under extreme adverse weather conditions can result in unnecessarily high fixed cost component in setting the GCR rate. It also provides the Company greater opportunities to earn asset management incentives, even though there may be no real net savings to consumers. On the other hand, a gas supply portfolio that contains too little reliable gas supply capacity would expose Rhode Island consumers to both potential supply disruptions and added costs for incremental capacity that must be obtained under adverse conditions if extreme weather is encountered.

A key premise for successful operation of the Asset Management Incentive mechanism is that the peak supply capabilities and Fixed Costs for the Company's Gas Supply portfolio are reasonably consistent with the Company's Long-Range Gas Supply requirements. The Commission has generally not approved specific gas supply capacity additions, and the determinants of what constitutes adequate or sufficient capacity resources are, at best, somewhat vague. These considerations coupled with what appear to be long-term downward trends in both heating degree days and use per

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2 For the 2006-07 GCR year, Fixed Gas Supply Costs and Fixed Storage Costs combined represent about **$55 million** or roughly 16% of the Company's expected total GCR costs for that period.

customer raise the potential that the Company's planning assumptions may overstate its long-term capacity requirements. The result would be an overstatement of the fixed gas supply costs from which asset management incentives are computed. The Division's concerns regarding the appropriateness of the Company's planned long-term capacity resources are further exacerbated by the National Grid's reporting of a significant long-term decline in weather-normalized gas use per customer for residential customers, as well as an even more dramatic one-year decline in weather-normalized gas during the winter of 2005-06, apparently in response to sharp increases in gas costs faced by consumers during that winter.

DISCUSSION OF ISSUES

The issues relating to the Company's long-range capacity plan and Asset Management Incentives that Mr. Oliver presented in his October 12, 2006 testimony in Docket 3766 address two basic areas of concern. The first relates to the appropriateness of the level of fixed costs that the Company included in its GCR filing for the 2006-07 GCR rate year. The second addresses the appropriateness of the analytic methods, data and assumptions that were used in the development of the Company's most recently filed long-range capacity plan, as well as the appropriateness of that plan for determining the gas supply capacity requirements for Rhode Island on a going-forward basis.

A. Fixed Costs for the 2006-07 GCR Rate Year

After further review of the Company's fixed costs for the 2006-7 GCR rate year (i.e., November 1, 2006 through October 31, 2007), the Division concludes that the level of fixed costs included in the Company's September 1, 2006 filing in Docket 3766 should be accepted and should provide a reasonable benchmark for computing asset management incentives for that period. In reaching this conclusion, the Division recognizes that:

1. The Company's planned addition of capacity on the Tennessee pipeline is not expected to be placed in service until November 2007, and therefore, it will have no impact on either available capacity or the Company's fixed costs for the 2006-07 GCR year.

2. The majority of National Grid's capacity release revenues are presently obtained through its contract with Conoco-Phillips, and the revenue derived from that contract is fixed for the contract period which extends through the end of the current GCR year (i.e., through October 31, 2007).

3. Certain of the Company's existing contracts for pipeline and storage services have requirements for advance notice of termination, and can require as much as 5-years advance notice to terminate

such service. Thus, National Grid's ability to limit its fixed costs within the current GCR period through actions other than capacity release appear limited.

B. The Company's Long-Range Planning and Fixed Costs for Future GCR Periods

The 2006 Plan lays a foundation for justification of the Company's Fixed Gas Costs over the next five years. Using a computerized linear programming model (i.e., the SENDOUT® model), the Company computes "least cost gas supply" solutions based on forecasted demands, available capacity resources, and identified planning criteria. Importantly, any individual run of the SENDOUT® model does not examine the costs of alternative resources outside the portfolio specified in the Company's model inputs. Although the SENDOUT® model can be a useful tool, its results are highly input driven. The model does not, in and of itself, test the sensitivity of computed results to changes in input data or assumptions.

A true assessment of the least cost nature of the gas supply portfolio that the Company proposes to use to meet its long range gas supply requirements can only be achieved through comparison of outputs for alternative runs of the model (i.e., alternative input assumptions). However, the Company's 2006 Plan does not present modeling results for alternative inputs, and it does not otherwise test the sensitivity of its results to forecasting uncertainties, changes in planning criteria, or use of other potentially available capacity resources. Thus, representations that the Company's plan depicts a least-cost supply plan are only applicable to the specific supply portfolio for which results are presented. Although the Company may have analyzed results for other configurations of its supply portfolio over its planning period, no results for such alternatives are presented.

1. Appropriateness and Adequacy of Planning Criteria

The August Plan utilizes three major considerations in the determination of gas supply requirements. Those are:

- Estimates of Design Day Demand
- Estimates of Design Winter (December – March) volume requirements
- Estimates of "Cold Snap" requirements (i.e., volume requirements for 10 successive cold days)[3]

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[3] The "cold snap" analysis was added to the Company's planning in its August 2006 Plan to address the system's ability to minimize its need for daily purchases of spot gas supplies at times when regional market prices are likely to reach extremely high levels.

For the Design Day and the Design Winter, forecasted requirements are premised on conditions that are expected to occur once in every one hundred years. Use of the once in one hundred years criteria dates back at least to a 1994 long range gas supply planning study (prepared by Providence Gas Company). According to the Company's response to Division Data Request 1-09(d) in Docket No. 3766 and testimony during hearings in that docket, the costs of the "once in a hundred years" planning criteria were compared with costs for planning criteria based on demands that it expected would occur "once in forty years" and "once in twenty years" using Long-Run Avoided Costs (LRAC). However, those LRAC analyses were reportedly performed in by Providence Gas Company in conjunction with its development of a 1994 long range gas supply plan. Despite substantial changes in the industry and in components of gas supply costs since that time, no update of the referenced LRAC analysis was undertaken either in the development of the 2006 Plan or in the development of the Company's 1994 Long Range Gas Supply Plan. Considering the substantial changes in the relative magnitudes of gas cost components in recent years, the substantial movement of load for large commercial and industrial accounts to transportation service, indications of declines in average use per customer, and the influences of factors such as "global warming" on heating degree day expectations, the Company's LRAC analyses appear ripe for review at this time. From the Division's perspective, a greater understanding of the expected costs and risks of either maintaining the once in a hundred years criteria or moving to a lesser criteria (e.g., once in 50, 40, 30, or 20 years) would be helpful.

2. Identification Of Design Day and Design Winter Parameters

As stated in the 2006 Plan at page 6, the Company's efforts to identify its design day gas supply capacity requirements began with a statistical analysis of historical peak days experienced over 52-year period (i.e., from the winter of 1940-41 through the winter of 1993-94.[4] Through that statistical analysis, the Company computed a mean number of heating degree days (HDDs) for a peak day, as well as a standard deviation associated with that mean. The reported mean is **57.4 HDDs** and the standard deviation is 4.6 HDDs. Using those results, the Company submits that it can be 99% confident temperature conditions on a peak day will yield **68.5 HDDs** once in every one hundred years.

However, the Company's statistical analysis assumes that variations around its computed mean are randomly distributed. If, as many scientists appear to agree at this point, we are in a period of significant "global warming," and a downward bias in heating degree day expectations for annual peak days in future winters should be expected.[5] In

[4] Despite recent weather experience and highly publicized concerns regarding "global warming," the Company elected not to update its analysis of heating degree days on historical peak days. As a result, the Company's actual heating degree days for peak days in the most recent 11 winters were not considered in the development of its August 2006 Plan.

[5] At this point there appears to be considerable consensus that global warming is occurring. To the extent that a dispute remains, it appears to be focused on whether global warming can be directly tied to the influences of human activity (i.e., factors over which humans can exercise influence or control).

fact, over the most recent 10-year period, the average number of heating degree days on a peak days is only **51.2 HDDs**. Thus, the average number of heating degree days on a peak day over the most recent 10 years is 6.2 HDDs or **10.8% below** the prior 52-year average upon which the Company's planning relies. Moreover, if the recent downward trend in HDDs is extended through the end of the period addressed in the 2006 Plan (i.e., through the winter of 2010-11), the expected HDDs on an average peak day by the winter of 2010-11 could be as low as **49 HDDs**.

Similarly, the Company's August 2006 Plan uses historical mean and standard deviation statistics to estimate design winter gas supply requirement. Using data for the winters of 1905-06 through 1994-95, the mean number of heating degree days for the months of December through March is reported to be **3,946 HDDs**. The computed standard deviation for the same set of historic winter heating degree days for the December – March period is 274 HDDs. On the basis of those statistics, the Company claims 99% confidence that it will experience **4,583 HDDs** once in every one hundred years. Yet, again, the most recent 10 years of winter heating degree day data was not considered in the Company's analysis. For the winters of 1996-97 through 2005-06, total HDDs for the months of December through March averaged **3,692 HDDs**. That is more than 250 HDDs or **6.3% below** the average upon which the Company relies to determine its design winter heating degree day and gas use expectations.

3. Criteria for Planning Capacity Reserves

The 2006 Plan does not specifically address the concept of capacity reserve requirements. Yet, for every forecast year, the Company's planning reflects the maintenance of capacity in excess of that which it believes would be required to meet a demand that could be expected to occur only once in one hundred years. Although the maintenance of some reserve in excess of forecasted requirements might be justifiable, the 2006 Plan does not discuss criteria that it would use to assess the reasonableness or appropriateness of planned reserve capacity.

In the electric industry capacity reserves are typically a function of (a) peak demand forecasting uncertainties and (b) the probability that generator outages will result in insufficient available capacity to serve system demands. However, neither of those criteria translates directly to gas utility capacity reserve considerations. Where electric industry planning is typically premised on normal weather expectations, gas utility planning is generally focused on extreme weather (i.e., design day) demand requirements. Also, most electric utilities draw power from a large number of generators, often as party to a power pool or centrally dispatched wholesale power market, such that no one generator is likely to comprise a substantial percentage of total generation supply at any point in time. By contrast, gas distribution utilities typically draw their supplies from a more limited set of resources (e.g., one or two major pipeline interconnections and a handful of local peaking resources). Also, for electric capacity planning, the potential for unexpected generator outages is generally measured through either Loss of Load Probabilities (LOLP) or loss probability of the one or two largest generating units. For gas distribution utilities the added costs of carrying sufficient excess capacity to protect against the potential that pipeline supplies would be lost during peak periods, is generally not perceived to be an economically viable option. Thus, capacity reserves for gas distribution utilities, to the extent they are specifically included in planning tend to address only (1) forecasting uncertainties associated with extreme peak requirements and (2) unexpected outages of local peaking resources.

The following table reflects by year the effective capacity reserves (i.e. capacity in excess of a "once in one hundred year" design day demand) that are implicit in the Company's 2006 Plan. At this point, the Division takes no position regarding the adequacy or appropriateness of the level of capacity reserves implicit in the Company's planning. However, if some or all of this capacity reserve could be shed by reducing National Grid's pipeline contract commitments, a noticeable reduction in the Company's annual fixed gas costs could result.

Winter	Available Resources Dth	Estimated Design Day Demand Dth	Capacity Reserve Dth	Capacity Reserve %
2006-07	367,892	342,466	25,426	7.4%
2007-08	367,892	344,179	23,713	6.9%
2008-09	367,892	345,900	21,992	6.4%
2009-10	367,892	347,629	20,263	5.8%
2010-11	367,892	349,367	18,252	5.3%

Over the planning period addressed by the Company's 2006 Plan, capacity reserves average more than 20,000 Dth per day based on a "once in one hundred years" design criteria. For the 2006-07 GCR year, fixed costs represent approximately $55 million (or 16%).[6] If some or all of the 20,000 Dth of reserve capacity could be shed by reducing the Company's more expensive pipeline commitments, it is conceivable that a 5%-10% reduction in the Company's fixed costs could result. However, any effort to reduce pipeline capacity commitments must be sensitive to the impacts of such changes on the Company's overall gas supply costs. Shedding fixed costs at the expense of greater variable supply costs may not be a well advised alternative. Furthermore, it is possible that the maintenance of some measure of excess capacity may be justified by commodity cost savings that such extra capacity would allow the Company to obtain. Yet, nothing in the Company's 2006 Plan provides any insight regarding changes in commodity costs associated with changes in the composition of its planned capacity resources.

4. Forecasting of Weather-Normal and Design Winter Gas Use

[6] If a lesser criteria, such as once in every 50 years, is employed the amount of excess or reserve capacity would most likely be even greater. In the context of the influences of "global warming" and identifiable reductions in design day weather conditions, further consideration of a less extreme design criteria may be warranted.

The load forecast which underlies the 2006 Plan is premised on the assumption of 0.5% per year growth in weather-normalized annual throughput requirements. As explained by the Company in response to Division Data Request 1-17 in Docket 3766, the 0.5% growth assumption is premised on 1.0% per year growth in numbers of customers, offset in part by an assumed 0.5% decline in use per customer. Once the Company's base forecast of normal weather requirements is established, Design Winter requirements are computed on the basis of heating degree day adjustments to weather-sensitive components of forecasted normal weather gas use for the months of December through March.[7]

However, the Company's 2006 Plan does not address a significant decline in weather-normalized firm requirements that was experienced during the winter of 2005-06. National Grid's annual GCR filing of September 1, 2006 in Docket 3766 reflects a more than **6% reduction** in projected weather normal firm requirements compared to the forecast of weather normal firm requirements the 2005-06 GCR year that was filed one year earlier in Docket 3696. Yet, despite the fact that the Company's 2006 Plan was filed just 10 days prior to its September 1, 2006 GCR filing, none of the influence of that significant one-year decline in firm requirements is reflected in the 2006 Plan. Nor, is there any mention of the potential impacts of that recent experience.

As demonstrated in Attachment A, page 1, to this report, the Company's projected weather normal firm sales service requirements are **6.5% lower** in its September 1, 2006 filing in Docket 3766 than comparable forecast of firm sales service requirements for the 2005-06 GCR year in Docket 3696. That decline in sales service requirements is partially offset by increases in FT-2 Transportation throughput volumes, but the net change in forecasted firm sales and throughput requirements under normal weather conditions for the 2006-07 GCR year is still more **6% below** the weather normal firm sales and throughput requirements the Company projected of the 2005-06 GCR year. Given the 0.5% growth rate reflected in the forecast of normal weather firm requirements upon which the 2006 Plan is premised, the decline in the Company's forecasted firm sales and throughput requirements for GCR purposes is the equivalent of more than **12 years** of otherwise anticipated demand growth.

Attachment B to this report provides a comparison of the Company's forecasted Design Winter sales and throughput requirements in its September 1, 2006 filing in Docket 3766 (for the 2006-07 GCR year) with comparable forecast data from the Company's September 1, 2005 GCR filing in Docket 3696 (for the 2005-06 GCR year). That comparison of design winter requirements also reflects a roughly **6% decline** in forecasted requirements. Once again, none of that decline in Design Winter requirements is reflected in the forecasted Design Winter data used in the development of the

[7] See Appendix II attached to the Company's 2006 Plan. Observe that the description of "Step 1" in the bottom portion of that appendix which states, "Source is Normal System sendout as calculated for the 2006 GCR Filing." In other words, the Company indicates that its 2006 Plan is premised on a forecast prepared for its 2005-06 GCR year. Moreover, even though the 2006 Plan was submitted just 10 days prior to National Grids submission of its 2007 GCR filing, the 2006 Plan contains no reference to or discussion of the potential influences of the sharp decrease in weather normalized firm sales and throughput requirements that the Company had identified prior to the submission of the 2006 Plan.

Company's 2006 Plan, nor does the 2006 Plan contain any discussion of the potential influences of such a decline if some, or all, of that decline is sustained.

If any significant portion of the decline in forecasted requirements reflected in the Company's most recent GCR filings is sustained or if that is found to represent the start of a longer term downward trend, National Grid's estimates of future gas supply requirements may be significantly overstated. Further, such a lowering of expectations regarding the Company's long-term supply requirements could have important implications regarding the least cost configuration of a supply portfolio to serve those needs. If, for example, 6.0% reductions in forecasted normal weather and design winter volume requirements translate into a comparable percentage reduction in design day requirements, National Grid could find itself with more than 20,000 Dth of additional capacity reserves. That, in turn, would cause even greater need to focus on the technical and economic justifications for maintaining such reserves.

5. Other Considerations

Recently passed legislation in Rhode Island requires the gas utility to develop and implement energy efficiency programs. In concept these programs should serve to reduce the Company's gas supply capacity requirements. Testimony the Company filed in Docket 3790 on January 29, 2007 indicates the target reductions in gas use under the proposed energy efficiency programs. It appears those programs will not have any substantial impact on the Company's gas supply planning. The Company's targeted reductions in gas use equate less than 0.3% of its annual gas supply requirements. That is well within the range of uncertainty and "noise" associated with the Company's forecasted normal weather gas use requirements.

6. Future Long-Range Planning Reports

The Division's review of the Company's 2006 Plan suggests that the Commission should consider expanding its requirements for the filing of long-range gas supply planning studies. Three areas of particular concern should be considered. Those are:

- The length of the planning period addressed in the Company's long-range gas supply planning;
- The frequency of required long-range planning studies; and
- Expansion of filed planning study reports to include greater information regarding:
  - a. The assessment of alternative gas supply portfolio configurations,
  - b. The potential impacts of load forecasting uncertainties and uncertainties regarding other factors that may

influence the magnitude of design day and design winter supply requirements,

c. The costs and risks associated with use of alternative design criteria, and

d. Economic and technical justification for the magnitude of capacity reserves maintained.

The five-year planning time frame used in the 2006 Plan appears to leave the Company little time to adjust its gas supply portfolio during the planning period. Given that advance notice requirements for termination of certain of the Company's current contractual commitments may be as long as five years, use of a longer planning period would appear to be appropriate. A 7-year or 10-year planning horizon could facilitate consideration of a broader range of portfolio options.

Further, the rather dramatic changes in the Company's recent forecasts of normal weather and design winter supply requirements in its GCR filings suggests a need for more frequent monitoring and examination of the long-range planning forecasts and the implications of changes in those forecasts. Over the past decade the Company has relied essentially on a steady state forecasting methodology which allowed for limited, but steady, year-to-year growth in firm gas supply requirements. With recent changes in the Company's reported and forecasted weather-normal demands, past steady state growth assumptions may no longer be adequate or appropriate. Until a better understanding of the factors driving recent changes in firm service sendout requirements is developed and the Company exhibits greater confidence regarding the long-term impacts of those changes, the Division believes there should be more frequent review of the Company's forecasts of gas supply requirements, as well as the impacts forecasted changes in demand on the Company's long-range gas supply plans. Thus, for at least the next several years, annual review of long-range gas supply plans (including the forecasts and assumptions underlying those plans) should be considered.

In planning for its future gas supply requirements the Company faces numerous uncertainties. However, the Company's 2006 Plan provides the Commission little understanding of the importance and potential cost and operational impacts of such planning uncertainties. The Company's long-range gas supply planning reports need to provide the Commission with greater sensitivity to the types of planning uncertainties it faces, as well as the magnitudes of costs and risks that such uncertainties impose. Focusing primarily on requirements to meet assumed random variations in weather may no longer be adequate or appropriate, particularly in light of a growing body of evidence that year-to-year fluctuations in reported heating degree days may embody a systematic downward bias. Also, several analyses upon which important planning criteria and assumptions are premised have not been updated despite significant changes in industry structure, market conditions and cost relationships.

CONCLUSION

Recent events, including a significant downward adjustment to the Company's forecasted normal weather and design winter gas supply requirements in its 2007 GCR filing, require renewed focus on the Company's long-term gas supply planning. The Division's review of the Company's 2006 Plan finds that it does not provide the Commission with the information needed to understand and appreciate either: (a) the costs and risks associated with increased uncertainties regarding future gas supply requirements or (b) the premises upon which the Company undertakes it's planning. Although the Division finds that the Company's fixed gas costs for the 2006-07 GCR year provide a reasonable basis for computing Asset Management Incentives for that period, the Division cannot confidently conclude that the Company's 2006 Plan reasonably or appropriately depicts Rhode Island's the long-term gas supply requirements. Rather, the Division finds indications that National Grid's estimates of long-range gas supply requirements may be overstated, and that the configuration of the Company's gas supply portfolio that is less than optimal. Thus, the Division recommends that the Commission require more frequent preparation of gas supply planning studies, as well as expansion of the content of such long-range gas supply planning reports.

National Grid

Docket No. 3789

Forecasted Normal Weather Sales & Throughput by Month

From Recent GCR Filings

	Forecasted 2005-06 Sales 1/ (MMBtu)	Forecasted 2006-07 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
December	3,328,347	3,196,190	(132,157)	-3.97%
January	4,866,111	4,593,118	(272,993)	-5.61%
February	5,290,003	4,549,366	(740,637)	-14.00%
March	4,133,276	4,138,755	5,479	0.13%
Total Sales	17,617,737	16,477,429	(1,140,308)	-6.47%
FT-2 Throughput				
December	71,255	83,395	12,140	17.04%
January	97,236	108,695	11,459	11.78%
February	96,959	108,598	11,639	12.00%
March	79,705	103,308	23,603	29.61%
Total FT-2 Throughput	345,154	403,996	58,842	17.05%
Total Throughput	17,962,891	16,881,425	(1,081,466)	-6.02%

1/ Source: Schedule PCC-1, page 12, filed September 1, 2005, Docket 3696.

2/ Source: Schedule PCC-1, page 12, filed September 1, 2006, Docket 3766.

National Grid

Docket No. 3789

Forecasted Design Winter Sales & Throughput by Month

From Recent GCR Filings

	Forecasted 2005-06 Sales 1/ (MMBtu)	Forecasted 2006-07 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
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	20,909,504	19,542,714	(1,366,790)	-6.5%
FT-2 Throughput				
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	401,290	466,617	65,327	16.3%
Total Throughput	21,310,794	20,009,331	(1,301,463)	-6.1%

1/ Source: Schedule PCC-1, page 13, filed September 1, 2005, Docket 3696.

2/ Source: Schedule PCC-1, page 13, filed September 1, 2006, Docket 3766.