STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

NATIONAL GRID'S GAS	:	
COST RECOVERY CHARGE	:	**DOCKET NO. 4346**

REPORT AND ORDER

I. NGRID'S SEPTEMBER 5, 2012 FILING

On September 5, 2012, National Grid ("NGrid") filed with the Public Utilities Commission ("Commission") a Gas Cost Recovery ("GCR") filing with decreased rates for effect November 1, 2012. The GCR is an annual filing that allows NGrid to reconcile and recover its estimated costs for gas supplies, including pipeline transportation and storage charges, for the GCR year beginning November 1. This filing proposes to decrease the rates approved by the Commission in Docket No. 4283 for the period November 1, 2012 through October 31, 2013. For a typical residential heating customer using 922 therms per year this will result in a decrease of approximately $112.00 annually.

As part of its filing, NGrid filed a Motion for Protective Treatment of Confidential Information pursuant to Rule 1.2(g) of the Commission's Rules of Practice and Procedure and R.I. Gen. Laws §38-2-2(4)(B).[1] Specifically, NGrid claimed that certain price terms contained in the Distrigas contract, as well as forecast basis numbers,

[1] Rule 1.02 states in pertinent part that "[a]ny party submitting documents to the Commission may request a preliminary finding that some or all of the information is exempt from the mandatory public disclosure requirements of the Access to Public Records Act. A preliminary finding that some documents are privileged shall not preclude the Commission's release of those documents pursuant to a public request in accordance with R.I.G.L. §38-2-1 *et seq.*" and that "claims of privilege are made by filing a written request with the Commission. One copy of the original document, boldly indicating on the front page, "Contains Privileged Information - Do Not Release", shall be filed with a specific indication of the information for which the privilege is sought, as well as a description of the grounds upon which the party claims privilege."

are confidential, commercially sensitive and proprietary and are exceptions to the requirement of public disclosure as set forth in R.I.G.L. §38-2-2(4)(i)(B). Citing the Rhode Island Supreme Court's decision in *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001), the Company asserts that the information it seeks to protect is such that it is exempt from public disclosure because it is the type of information that is voluntarily provided to a public agency and would not customarily be released to the public by the person from whom it was obtained. Specifically, NGrid requests that the information set forth in Attachments EDA-1, EDA-2 and EDA-4 be given protective treatment.[2]

In support of its filing, NGrid submitted the pre-filed testimonies of Elizabeth D. Arangio, Director of Gas Supply Planning for NGrid, Ann E. Leary, Manager of Gas Pricing for NGrid Corporate Service LLC, and Stephen A. McCauley, Director of Origination and Price Volatility Management in the Energy Procurement organization. Ms. Arangio stated that her testimony provides support for the estimated gas costs, assignment of pipeline capacity to marketers and other issues relating to the Company's proposed factors. Ms. Arangio explained that the proposed GCR factors are based on the NYMEX strip as of the close of trading on August 1, 2012 and the difference between the futures contract purchases under the Gas Procurement Incentive Plan ("GPIP") as of July 31, 2012 and the August 1, 2012 NYMEX strip. The factors also reflect storage and inventory costs as of July 31, 2012 and the projected cost of purchasing gas ratably through the summer as provided for in the Natural Gas Portfolio Management Plan ("NGPMP").[3]

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[2] NGrid Exhibit 1, Gas Cost Recovery Filing, filed September 5, 2012.

[3] NGrid Exhibit 1(a) Gas Cost Recovery Filing, Direct Testimony of Elizabeth D. Arangio at 1-4.

Ms. Arangio described how the Company uses a SENDOUT model to calculate projected gas costs. To minimize yearly supply cost, pricing, contract and storage information are used to determine the dispatch of supplies. Ms. Arangio explained the five gas cost components for the GCR: (1) supply fixed costs which includes pipeline demand charges; (2) supply variable costs which includes commodity costs of all firm gas supplies and the associated variable transportation costs; (3) storage fixed costs which includes pipeline underground and LNG storage demand charges and the pipeline demand charges for contracts associated with the transportation of the storage gas; (4) storage variable product costs which includes the commodity cost of the underground-storage gas supplies priced at the weighted-average cost of gas in storage ("WACOG") , the storage injection costs and the cost of LNG supplies including the commodity cost of the gas, trucking costs and demand charges; and (5) storage variable non-product costs which includes all variable costs related to the withdrawal and delivery of storage gas.[4]

She provided attachments to her testimony; one, summarizing by month gas costs included in the GCR for the period November 2012 to October 2013 and the other providing the supporting detail for those gas costs. She described the calculation of the delivered cost for a particular gas supply as beginning with the NYMEX price, then being adjusted for basis and to reflect fuel retention and finally being added with the cost of transportation on the pipeline.[5]

Regarding marketer capacity assignment, Ms. Arangio indicated that 32,758 Dth per day of capacity on six different pipeline paths is available to marketers. She explained the calculation of the surcharge/credit for each assigned pipeline path as

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[4] *Id.* at 5-6, Attachment EDA-1.
[5] *Id.* at 7-8, Attachment EDA-2.

starting with the system-average cost and then deriving the weighted-average pipeline path cost which is the sum of the 100% load factor fixed-cost unit value, the system-average pipeline unit variable cost and two years of marketer reconciliation represented as a 100% load factor per unit cost. She calculated the weighted average pipeline cost to be $0.8284 per Dth. Ms. Arangio also explained the calculations of the delivered costs for each path released to marketers noting its similarity to the calculations for the system average. She indicated that to calculate the non-gas variable costs, commodity gas costs are subtracted from the total variable costs. She added fixed unit cost to the non-gas variable unit cost to determine the cost of the path. If this cost exceeds the system average, marketers electing that specific path would receive a credit for the difference between the direct cost and the system average cost. Ms. Arangio noted that the Company filed a Long-Range Resource and Requirements Plan ("Supply Plan") on March 8, 2012 with forecast data for November 1, 2011 through October 31, 2016. She stated that the filing included a review of the LNG System Pressure study that NGrid agreed to undertake to determine whether changes were required to its system pressure calculation.[6]

Ms. Arangio indicated that on November 1, 2011 a capacity change occurred with the conversion of the Company's TransCanada long-haul capacity being replaced by two short-haul pipeline capacity, Union Gas Limited and TransCanada Pipelines Limited for a total firm capacity entitlement on the two pipelines of 2,037 MMBtus/day. She noted that this conversation saves customers approximately $500,000 per year. She discussed the bid award to BG Energy Merchants, LLC to manage the Company's assets and provide the Company with deliveries at the Canadian-US border which it then transported

[6] *Id.* at 8-11, Attachment EDA-4.

to its citygates. She asserted that the one year Asset Management and Gas Supply Agreement to supply the Dawn capacity with BG Energy Merchants, LLC for the 2011/12 year allowed the Company the ability to extract value from temporarily-unused assets, subject to market conditions. She noted that Shell Energy North America U.S. was awarded this one year contract for the 2012/13 year. Regarding the Company's plans to supply the east-to-west project for 2012/13, Ms. Arangio indicated that NGrid had awarded EDF Trading North America, LLC the contract to manage the assets and provide the asset management services for the 2012/13 season. Under both contracts, she noted that subject to satisfying the gas supply requirements as set forth in the contract, each Seller had the right to utilize and optimize the transportation agreement for its own account subject to an optimization fee paid to NGrid.[7]

Additionally, on March 31, 2012 the LNG combination vapor/liquid supply contract with Distrigas expired. Ms. Arangio represented that NGrid is currently in negotiations with Distrigas for a similar commitment for the 2012/13 peak and off peak seasons for the coming year. She also indicated that NGrid will contract for dedicated trucking services as it has done in the past to guarantee the availability of trucks and drivers to deliver LNG from Distigas to NGrid's facilities. Lastly, Ms. Arangio asserted that although the Company's process of accounting for customer choice migration has been successful in the past, it needs to be modernized as more customers migrate to transportation in order to ensure the appropriate level of assets are contracted for and the cost of the resources are recovered by the appropriate customers.[8]

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[7] *Id.* at 11-14.
[8] *Id.* at 13-16.

Ann Leary provided testimony to explain the calculation of the GCR charges for 1) firm sales service customers in the Residential Non-Heating and Heating rate classes as well as Commercial and Industrial ("C&I") customers in the Small, Medium, Large and Extra Large rate classes, 2) Gas Marketer Charges and factors associated with transportation services billed to Gas Marketers and factors associated with transportation services billed to Gas Marketers.[9]

Ms. Leary set forth the calculation for the approximate $161.5 million that the Company expects to incur for the November 1, 2012 through October 31, 2013 period which in addition to gas costs include Working Capital Costs, Inventory Financing costs, a prior Deferred Balance, LNG Ooperation and Maintenance Costs, and credits associated with FT-2 Marketer Storage Demand costs and LNG costs. She described how the Company has simplified gas costs for high and low factor rate classes by combining all the fixed costs into one component and all of the variable costs into one component and how the filing includes the redesigned FT-2 rate approved by the Commission in Docket No. 4270 for effect November 1, 2012.[10]

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[9] NGrid Exhibit 1(b) Gas Cost Recovery Filing, Direct Testimony of Ann E. Leary, filed September 5, 2012 at 1-2.

[10] *Id.* at 3-5. The following modifications were approved by the Commission in Docket No. 4270: 1) the storage service was changed from an injection/withdrawal approach to a cash-out approach; 2) the capacity assignment process was simplified by assigning the capacity and storage entitlements based on the customers' calculated design peak-day use and class load factor; 3) the availability of the FT-2 service was expanded to include the Small Commercial and Industrial class of customers and limit the availability of the FT-1 service to the Large and Extra Large classes; 4) a mechanism to cash out imbalances under the FT-2 service was provided; 5) Electronic Data Interchange (EDI) capabilities for communications with Marketers was developed; and 6) language was added to the tariff to enable the Company to terminate the participation of a Marketer for failing to properly serve customer's supply requirements, pay for their transportation service, or maintain creditworthiness. Additionally, a number of other changes were approved to 1) eliminate the $50 fee imposed on customers who change Marketers or services more than once a year; 2) provide for annual meetings between the company and Marketers; 3) allow changes in nomination and scheduling times; 4) implement changes in the

Ms. Leary described the fixed cost component as including all fixed costs related to the purchase, storage and delivery of firm gas for both high and low factor customers. She explained the derivation of the component as taking the total fixed costs, and subtracting any customer credits, LNG Demand costs associated to the DAC and storage demand costs billed to FT-2 Marketers. Adjustments are then made for Supply related LNG costs, working capital costs and prior period Deferred Fixed Gas Costs under/over-collection balances including an adjustment for the Marketer Fixed Cost Reconciliation. This calculation results in total Fixed Costs of $44,849,323 to be allocated to and collected from ratepayers based on their proportional design-winter use. She identified expected throughput of 952,267 Dths or 2.9% of the total throughput for High Load classes for a factor of $1.8206 per Dth and 23,927,611 Dths or 97.1% of the total throughput for the Low Load classes for a factor of $1.3509 per Dth.[11]

Ms. Leary noted that in Docket No. 4199, Order No. 20230, the Company agreed to provide a reconciliation of Marketer fixed costs and described the calculation of the Marketer Fixed Cost Reconciliation Balance which she stated has been updated and revised to better reflect the difference between projected and actual fixed costs paid by marketers during the 2010-2011 and 2011-2012 GCR years and the system actual weighted average cost of capacity each year. She identified a net surcharge to Marketers of $374,462 that would be credited to firm sales customers fixed costs and included in the 2012-2013 pipeline surcharge/credits set forth by Ms. Arangio. She stated that the design

capacity assignment program; and 5) list the circumstances that would cause a Marketer to be disqualified.

[11] *Id.* at 6-7, Attachment AEL-1.

winter calculation was developed using calendar month degree days[12] which was consistent with the Commission's finding in Docket No. 4097.[13]

In describing the Variable Cost component, Ms. Leary identified total Variable Costs as including all variable costs of gas, supply related LNG O&M, working capital, inventory finance costs, pipeline refund, credit for the balancing related LNG costs to the DAC and deferred cost balances. She calculated variable costs for the November 2012 through October 2013 period to be $116,682,698 which she divided by the projected period throughput of 24,879,878 Dths to calculate a Variable Cost factor of $4.6898 per Dth. She asserted that an estimated deferred balance under-collection of $487,002 is incorporated into the GCR rate as well as the projected deferred gas cost balances for the November 2012 through October 2013 period.[14]

Ms. Leary discussed the Ernst & Young ("E&Y") analysis of gas costs in the Company's GCR filings from September 2006 through June 2012 and the specified the adjustments made as a result of E&Y's analysis. Additionally, she noted that E&Y redesigned spreadsheets used to calculate the monthly GCR deferral and listed the other process improvements recommended that the Company was implementing including the establishment of various spreadsheet checks and balances and the validation of gas costs with the Company's general ledger.[15]

Ms. Leary represented the proposed FT-2 marketer demand rate of $7.3770 per MDQ in Dth/month and the capacity assignment percentages for the high load and low

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[12] In Docket No. 4097, Order No. 19832. the Commission accepted the parties agreed to change in methodology for determining forecasted design-winter requirements from billing cycle design days to calendar month design-degree days.
[13] NGrid Exhibit 1(b) Gas Cost Recovery Filing, Direct Testimony of Ann E. Leary, filed September 5, 2012 at 7-9, Attachment AEL-7.
[14] *Id.* at 9-10, Attachments AEL-1, AEL-3..
[15] *Id.* at 10-11.

load factors to be used in the determination of pipeline, underground storage and peaking capacity for Marketers. She described how the FT-2 marketer demand rate approved in Docket No. 4270 separates storage costs into the fixed costs associated with storage and peaking and the variable underground storage costs, associated commodity costs and loss factors associated with various pipeline contracts to bring gas from storage to the city gate. She explained that in addition to the $7.3770 demand rate, marketers would be charged a variable storage rate at the time that gas is withdrawn from storage and that the rate would include all associated variable costs for transporting that stored gas to the city gate. She represented that NGrid would calculate these variable storage rates and credit firm customers on a monthly basis to ensure that firm customers are appropriately compensated for these variable costs. Lastly, Ms. Leary identified the billing impact on a residential customer using 922 therms per year as a decrease of approximately $112 annually.[16]

Mr. McCauley provided testimony to discuss the results of the Gas Procurement Incentive Plan ("GPIP") for the period July 1, 2011 through June 30, 2102 and the results of the Natural Gas Portfolio Management Plan ("NGPMP") for April 1, 2011 through March 31, 2012. He noted that the GPIP encourages the Company to purchase supply in a way that will reduce risk and stabilize supply. He stated that the GPIP requires NGrid to lock in future gas prices over a 24-month horizon and that these purchases are made in a structured series of monthly increments. The difference between the average unit cost of the mandatory hedges and the average unit cost of discretionary purchases is multipled by the discretionary volumes to calculate total savings or cost. The incentive or penalty is determined by multiplying the total savings or cost by 10% except that the total savings

[16] *Id.* at 12-14, Attachment AEL-4, AEL-6.

is multiplied by 20% for those discretionary purchases made at least 8 months prior to the month of gas flow where the unit cost savings is greater than 50 cents per dekatherm or by 5% for any discretionary purchases made during the four months prior to the month of flow. The Company calculated the incentive to be $355,884, that Mr. McCauley proposed be granted in full. He also asserted that NGrid was not recommending any changes to the GPIP for the coming year.[17]

Mr. McCauley described the NGPMP which changed management of the Company's gas portfolio from an external company to internally within NGrid. He opined that the internal management is superior to the previously external management arrangement because it reduces the potential for performance failure by an external manager and the Company is appropriately incentivized to maximize savings to the level of or in excess of that of the third party manager. Mr. McCauley pointed out how in its second[18] year NGrid saved a total of $5,498,990.90. He noted that based on the NGPMP incentive, customers receive $4,599,192 of those savings while the Company is entitled to receive 20 percent of the total of savings in excess of $1 million which equals $899,798 for the April 2011 through March 2012 period. Finally, Mr. McCauley noted that the terms of the NGPMP require review after years two and four of the plan to make recommended changes. He represented that based on the Commission's approving continuation of the NGPMP through 2014, no changes will take effect starting in 2013. He represented that subsequent to March 2013, the Company and the Division will

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[17] NGrid Exhibit 1(c) Gas Cost Recovery Filing, Direct Testimony of Stephen A. McCauley, filed September 5, 2012 at 1-5, Attachments SAM-1, SAM-2.

[18] This is the third year since the Commission approved the NGPMP in Docket No. 4038, Order No. 19627 on March 31, 2009.

review the NGPMP's results and evaluate whether changes are necessary to include in the 2013 GCR filing.[19]

II. DIVISION OF PUBLIC UTILITIES AND CARRIERS

On October 22, 2012, the Division of Public Utilities and Carriers ("Division") submitted the pre-filed testimony of Bruce R. Oliver, its consultant, to address NGrid's filing. Mr. Oliver summarized his conclusions and recommendations to NGrid's filing which are: 1) lowering the forecasted FLS Call Payments to Distrigas by $467,704; 2) crediting $1.1 million of demand related refunds from Tennessee Gas Pipeline against Fixed Supply costs; 3) recommending procedures for passing revenue sharing benefits to NGrid's RI customers; 4) adjusting the portion of LNG-related costs allocated to the DAC System Pressure Factor; 5) concluding the GPIP and NGPMP incentives appear accurately computed; 6) reopening discussions regarding the NGPMP incentive structure; 7) finding that the Long-Range Gas Supply Plan is reasonable and that a new five year planning study be prepared every three years; 8) recommending that the Commission adopt the GCR rates as set forth by the Division which lower the LNG Demand costs and change the allocation of LNG-related costs to the DAC.[20]

Mr. Oliver asserted the Division's concern regarding the short time frame within which it had to review the Company's filing and responses to data requests before the Division's testimony was due. He recommended that to rectify this issue from resurfacing in the future that the Company be required to address all matters that remained open at the time of the Commission's last GCR decision; the Company be required to file its Annual Gas Cost Reconciliation by July 1 of every year; the Company

[19] NGrid Exhibit 1(c) Gas Cost Recovery Filing, Direct Testimony of Stephen A. McCauley, filed September 5, 2012 at 5-7, Attachment SAM-3.
[20] Division Exhibit 1, Testimony of Bruce R. Oliver, filed October 22, 2012 at 1-4.

be required to file its initial GCR direct testimony by August 1 each year with supplemental testimony due on or about September 1; that the Company be required to provide the electronic spreadsheet files used to generate the analyses set forth in its testimony and exhibits; and the Company be encouraged to use its best efforts to respond to the Division's data requests within two weeks of receipt of those data requests.[21]

Mr. Oliver described the how the GCR charges varied by rate class. He stated that with the exception of the FT-2 Marketer Charge, NGrid proposed reductions in the GCR charge for all rate classes. He pointed out how all of the gas cost components are decreasing except for Storage Fixed Costs which are projected to increase by 7.7% as a result of changes in the Company's LNG contract with Distrigas. He noted that in the last docket, the Company did not include forecasted LNG costs from Distrigas which totaled $1,003,726 for the period and are projected to be $1,471,430 for the upcoming GCR year. He asserted that last year he expressed concern that the Company had not entered into a contract for liquid supply prior to the start of the winter season and that at the time of the submission of testimony in this docket, it had not entered into a contract. He stated that even absent the contract, NGrid was forecasting an increase of 31.8% in Distrigas FLS Call Payments. He pointed out that the Company's forecast more than triples the actual fixed payments to Distrigas for the twelve month period ending June 2011. Additionally, he found that a comparison of the forecasted and actual costs over the last two year period reveals a large portion of the increase associated with assumed payments for non-winter months which is inconsistent with actual experience over the past two year period. He claimed that without either a signed contract or rational to support the presumed increases, those increases are inappropriate for inclusion in this

[21] *Id.* at 5-8.

year's GCR. He recommended that the Company be allowed to include $1,003,726 in its forecasted gas costs which was the most recent amount set forth in its reconciliation filing.[22]

Mr. Oliver discussed his testimony in Docket No. 4339 and his recommendation to upwardly adjust LNG-related costs in that docket. He explained that his recommendation to shift approximately $2.5 million in LNG costs to DAC is not a new issue and that the Company's allocation factor used to determine what portion of LNG costs should be allocated to DAC was to be worked out with the Division and addressed in the Company's Long-Range Gas Supply Plan that was to be filed in 2012. He asserted that NGrid used an 18.12% allocation factor and that this factor does not properly identify the portion of LNG costs associated with maintaining system pressure. He identified two problems with the formulation: the allocation factor is not properly constructed to allocated LNG-related costs and the allocation factor does not consider non-peak hours LNG system pressure use. He stated that NGrid did not provide an analysis as to why the factor was appropriate.[23]

Reiterating the testimony that he provided in Docket No. 4339, Mr. Oliver asserted that the allocation of LNG-related costs to the system pressure factor should be accomplished in two steps allocating capacity-related costs based on ratio of LNG capacity required for system pressure support under peak hour conditions to total peak hour LNG vaporization capacity and commodity-related LNG costs based on a ratio of total annual LNG sendout for system pressure purposes under normal winter weather conditions to total forecasted LNG sendout for all purposes under normal winter

[22] *Id.* at 8-11.
[23] *Id.* at 11-14.

conditions. Mr. Oliver computed a LNG capacity allocation factor of 60.72% and a LNG commodity-related LNG cost allocation factor of 63.21%. Using these allocations, Mr. Oliver identified a total of $3,672,665 of LNG-related costs to the DAC as opposed to the $1,077,346 that the Company proposed. He noted the increase to the DAC of $2,595,319 would result in a corresponding decrease to GCR costs. He explained that this change in allocation would have no impact on the Company's recovery of its full LNG-related costs. He further explained that the large portion of LNG-related costs would be recovered through the DAC resulting in Firm Transportation Service customers paying a larger share of those costs as the DAC distributes these costs over all Firm Throughput customers which is appropriate because all firm customers derive a benefit from the LNG used for system pressure.[24]

Mr. Oliver found no reason to question the accuracy of the adjustments made by Ernst & Young to the Company's deferred gas cost balance. He noted that NGrid improperly credited demand-related refunds resulting from the Tennessee Gas Pipeline ("TGP") Settlement before FERC against its Variable Supply costs and asserted that the $3,175,532 refund should have been credited to Supply Fixed costs which would have no impact on the Company's total costs. He explained that crediting the refund to Supply Fixed costs would provide a greater share of the refund to the Low Load customers who bear the large majority of the Supply Fixed costs. Additionally, he recommended that the Commission address the issue of revenue sharing should the Company benefit from the revenue sharing provision in the TCP Settlement Agreement which provides for customers of TCP, e.g. NGrid, sharing 75% of revenues achieved by TGP in excess of

[24] *Id.* at 14-18.

$885 million per year, and suggested that the Commission adopt the same revenue sharing agreement as set forth in the TGP Settlement Agreement.[25]

Mr. Oliver pointed out that after problems were identified with NGrid's gas cost accounting by E&Y, it suspended it monthly reporting of deferred gas cost balances for a few months. He noted that when the reports resumed, NGrid had altered the forecasted gas usage for its Sales Service classes. He stated that the Company explained this change in a response to a data request as being done to correct for the higher than expected percentage of Unaccounted For Gas which was revealed from an assessment of differences between projected sales and sendout. He noted that NGrid increased its forecasted sales volumes for July through October 2012 by 21.9%. He alleged that these adjustments are neither reasonable nor appropriate and not supported by actual data for July and August which supports the Company's original forecast. Additionally, he stated that failure of the Company to explicitly notify the Division or the Commission of these changes did not enhance understanding of the new monthly reports.[26]

Regarding the GPIP, Mr. Oliver asserted that the requested incentive of $355,884 is only slightly higher than last year's incentive and equates to only 1.5% of the $23.7 million reduction in Supply Variable Costs that were achieved by the Company this year. He found no reason to question the accuracy of the incentive calculations. He supported NGrid's request for the GPIP changes set forth by Mr. McCauley finding them reasonable and appropriate.[27]

Mr. Oliver indicated that NGrid properly computed the the Natural Gas Portfolio Management Plan ("NGPMP") incentive of $899,798 and found no reason for the

[25] *Id.* at 18-22.
[26] *Id.* at 22-25.
[27] *Id.* at 25-26.

Commission to withhold that incentive. He also pointed out that NGrid achieved benefits for ratepayers of $680,000 more than last year. He stated that total asset management savings equaled $5,498,991 and that ratepayers would receive $4,599,192 of this amount which is the first $1 million and 80% of the remaining $4,498,991. He noted that the Company's share of the total savings amounts to 16.4% of the total or $899,798. Mr. Oliver questioned the appropriateness of the 20% incentive for portions of the Company's program that it has chosen to outsource to third parties pointing out that the intention of the creation of the incentive was for the Company to be able to achieve savings that were comparable or in excess of those realized by the third party manager. He suggested the parties engage in discussions as to the appropriateness of the changes and if they are deemed appropriate they should be adopted and implemented for April 1, 2014. He found the ratepayer credit to be reasonable and appropriate.[28]

As a result of Mr. Oliver's proposed adjustments, he recommended a GCR charge for Low Load Factor classes of $0.6583 per therm and for High Load Factor classes of $0.6127 per therm.[29]

IV. NATIONAL GRID OCTOBER 24, 2012 REBUTTAL

On October 24, 2012, NGrid filed the joint Rebuttal Testimony Ms. Leary, Ms. Arangio and Mr. McCauley. Specifically, the testimony addressed Mr. Oliver's recommendation to lower the gas supply forecast by $467,704, to reassign $1.1 million of Tennessee Gas Refund from Variable to Fixed Supply Cost, to reallocate $2,595,319 in LNG-related costs from GCR to DAC, to establish procedures for sharing of FERC approved excess revenue margins resulting from resolution of the TGP Rate case, to

[28] *Id.* at 26-30.
[29] *Id.* at 30-31.

reopen discussions with the Division regarding the appropriateness of the NGPMP incentive structure in the context of the Company's use of third parties to manage its assets, to require the Company's preparing a new five-year planning study at least once every three years, and to change the filing requirements to allow the Division adequate time to review the DAC and GCR filings.[30]

The rebuttal testimony disagreed with Mr. Oliver's $467,704 adjustment to gas costs because the Company's estimate relied on more recent data specifically, it's actual costs through November 2011. The rebuttal agreed in principle with Mr. Oliver's recommendation to reallocate $1.1 million of the Tennessee Refund in March 2012 from Variable Cost to Fixed Supply Cost noting however the small change that would result to the High Load and Low Load GCR factors and offering that the $1.1 million be allocated to fixed costs for the purpose of calculating deferred balances. Regarding Mr. Oliver's recommendation for the System Pressure costs, the rebuttal testimony disputed his calculations as not being appropriate as they relied on Ms. Arango's attachment that represented LNG boiloff volumes which reflect LNG sendout used to most economically meet customer requirements during a normal winter season, not LNG sendout required for system pressure. The rebuttal recommended continuing the use of the 18.12% system pressure factor until the issue can be comprehensively reviewed in a separate docket opened to review the Company's Long-Range Supply Plan. The Company also did not agree with Mr. Oliver's proposed revisions to the High Load and Low Load GCR factors.[31]

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[30] NGrid Exhibit 3, Rebuttal Testimony of Ann E. Leary, Elizabeth D. Arangio and Stephen A. McCauley, filed October 24, 2012 at 1-2.
[31] *Id.* at 2-6.

The rebuttal represented that the Company was agreeable to refunding customers as a credit against gas costs any revenue sharing associated with the Settlement in the Tennessee Gas Pipeline matter as suggested by Mr. Oliver. The Company also agreed to reopen discussions with the Division regarding the appropriateness of the NGPMP incentive structure as it relates to the third party management of its gas supply assets and noted that it has already agreed to file its Long-Range Gas Supply Plan every three years.[32]

The rebuttal also addressed the procedural changes suggested by Mr. Oliver and noted acceptance of all of these procedural changes except the one recommending moving the initial GCR filing from September 1 to August 1. In support of it objection to the earlier filing date, the rebuttal asserted that an August 1 filing date would not allow it sufficient time to develop a proposed GCR factor using the most recent forecasts for the upcoming year as the data to do that is not complete until June. The rebuttal offered that the Company hold a technical session with the Division each year before the Division is required to file its direct testimony in order to provide the Division with responses to any additional questions and to address any concerns that the Division may have with the initial filing.[33]

V. <u>SETTLEMENT AGREEMENT</u>

On October 31, 2012, immediately prior to the commencement of the hearing, the parties filed a Settlement Agreement ("the Agreement") resolving all of the disputed issues. The Settlement Agreement specified that the parties agreed that any revenue sharing amounts received by the Company from the Tennessee Gas Pipeline will be

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[32] *Id.* at 7-8.
[33] *Id.* at 8-10.

treated as credits to customers against gas costs through the reconciliation process. It also specified that the Company and the Division would engage in further discussion regarding the NGPMP incentive structure and that if changes were required, those changes would be implemented and effective April 1, 2014. The parties agreed that NGrid will make every effort to provide greater documentation of the levels of the Distrigas FLS Call Payments included in GCR proceedings. The parties further agreed that LNG costs will be allocated to the DAC in accordance with the Docket No. 4339 Settlement Agreement. The Agreement provided that NGrid's GCR Reconciliation Filing will be made on July 1 of each year instead of August 1. Finally, the Company agreed to reallocate the $1.1 million it received in March 2012 from the Tennessee Refund from variable to fixed costs. In consideration of the above agreements, the parties agreed to recommend that the rates set forth in NGrid's September 5, 2012 filing be approved.[34]

HEARING

Following published notice, a public hearing was conducted on October 31, 2012 at the Commission's offices at 89 Jefferson Boulevard, Warwick, Rhode Island. The following appearances were entered:

FOR NGRID:	Thomas Teehan, Esq.
FOR THE DIVISION:	Leo Wold, Esq. Assistant Attorney General
FOR THE COMMISSION:	Patricia S. Lucarelli Chief of Legal Services

At the hearing, the Chairman granted NGrid's motion for protective treatment of certain of its responses to data requests. After ensuring no objection, the Chairman had

[34] Joint Exhibit 1, Attachment 1 and 2.

all exhibits were marked as full exhibits. Mr. Teehan presented the terms of the Settlement Agreement. He explained the Company's change from using 922 dekatherms to 846 dekatherms when discussing average usage as being consistent with how the Company was representing usage in Docket No. 4323.[35]

COMMISSION FINDINGS

Immediately following the conclusion of the testimony, the Chairman moved that the factors proposed by the Company and set forth in Attachment 1 and Attachment 2 of the Settlement Agreement be approved. Specifically, Chairman moved for approval of a High Load GCR Charge of $0.6193 per therm and a Low Load GCR Charge of $0.6675 per therm which represents a 17% decrease for High Load customers and a 15.5% decrease for Low Load customers. Additionally, the Chairman also moved for approval of a FT-2 Demand charge of $0.7377 per therm and a weighted average upstream pipeline transportation cost of $0.8601 per therm of capacity. Lastly the Chairman moved for approval of the BTU Factor of 1.030. The Commission is satisfied that the rates proposed by NGrid and supported by the Division will ensure that customers pay a just and reasonable rate. The Chairman's motions were approved unanimously.

Accordingly, it is

(20890) ORDERED:

1. The Gas Cost Recovery Factors and the Gas Marketer Charges agreed to by the parties and set forth below are hereby approved.
2. The Gas Cost Recovery factors, set forth on a per therm basis, of: $0.6193 per therm for Residential Non-Heating Customers, Large and Extra Large High Load Factor and $0.6675 per therm for Residential Heating Customers, Small and Medium and Large

[35] Transcript of Hearing, October 31, 2012 at 1-4.

and Extra Large Low Load Factor customers are approved for usage on and after November 1, 2012.

3. The Gas Marketer Transportation factors of: $0.7377 per therm for the FT-2 Firm Transportation Marketer Gas Charge and a weighted average upstream pipeline transportation cost of $0.8601 per therm of capacity are approved for usage on and after November 1, 2012.
4. The Company shall file its Annual GCR Reconciliation by July 1 of each year.
5. The BTU factor of 1.030 is approved.
6. National Grid shall comply with the reporting requirements and all other findings and directives contained in this Report and Order.

EFFECTIVE NOVEMBER 1, 2012 IN WARWICK, RHODE ISLAND PURSUANT TO OPEN MEETING DECISIONS ON OCTOBER 31, 2012. WRITTEN ORDER ISSUED NOVEMBER 29, 2012 .

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Mary E. Bray, Commissioner

Paul J. Roberti, Commissioner

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:	**NATIONAL GRID**	:	
	GAS COST RECOVERY CHARGE	:	**DOCKET NO. 4346**

ERRATA ORDER

Whereas, Pursuant to Rule 1.28(a) of the Rhode Island Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the Commission through this notice of erratum corrects a "clerical mistake" contained in Commission Report and Order No. 20890, previously issued in this docket, on November 29, 2012; and

Whereas, on Page 21, number 3 of the ordering paragraphs which reads:

> "The Gas Marketer Transportation factors of: \$0.7377 per therm for the FT-2 Firm Transportation Marketer Gas Charge and a weighted average upstream pipeline transportation cost of \$0.8601 per therm of capacity are approved for usage on and after November 1, 2012."

is hereby corrected to read:

> "The Gas Marketer Transportation factors of: \$0.7377 per therm for the FT-2 Firm Transportation Marketer Gas Charge and a weighted average upstream pipeline transportation cost of \$0.8601 per dekatherm of capacity are approved for usage on and after November 1, 2012."

Accordingly, it is hereby
(20906) ORDERED:

That the correction described herein is adopted by the Commission and shall constitute a permanent amendment to Order 20890 issued in Docket 4346.

DATED AND EFFECTIVE AT WARWICK, RHODE ISLAND, ON DECEMBER 20, 2012.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Mary E. Bray, Commissioner

Paul J. Roberti, Commissioner