



EB-2010-0018

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing October 1, 2010.

BEFORE: Ken Quesnelle
Presiding Member

Paul Sommerville
Board Member

DECISION AND ORDER

Natural Resource Gas Limited ("NRG" or the "Applicant"), filed an application dated February 10, 2010 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for the 2011 fiscal year, commencing October 1, 2010.

NRG is a privately owned utility that sells and distributes natural gas within Southern Ontario. The utility supplies natural gas to Aylmer and surrounding areas to approximately 7,000 customers, with its service territory stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce to Clear Creek.

In its pre-filed evidence NRG claimed a revenue deficiency of \$462,417 for the 2011 Test Year. If the application were to be approved as filed, a typical residential customer would experience an annual increase of \$22.60 (or 5.05%) to the delivery portion of the bill.

The Board issued a Notice of Application dated March 1, 2010. The Town of Aylmer ("The Town"), Union Gas Limited ("Union"), Integrated Grain Processors Co-Operative Inc. ("IGPC") and Vulnerable Energy Consumers Coalition ("VECC") applied for and were granted intervenor status.

In Procedural Order No. 1 issued on April 1, 2010, the Board made provision for the initial steps in the proceeding including the filing of interrogatories and responses.

Pursuant to Procedural Order No. 3 issued on May 28, 2010, the Board convened a technical conference on June 14, 2010 to address further questions arising from the response to interrogatories and to seek clarification on the evidence filed by the Applicant. The technical conference was immediately followed by a settlement conference. At the end of the settlement conference, the parties agreed to continue discussions on June 28th with the objective of reaching a settlement among the parties. Union did not participate in the settlement conference.

The June 28th discussions led to a settlement on some of the issues. On August 3, 2010, IGPC filed a Notice of Motion in EB-2006-0243. That proceeding was a Leave to Construct application by NRG directed to the facilities required to supply IGPC with natural gas. The Board decided to hear that Motion contemporaneously, given its apparent relevance to the unresolved issues. In the Motion, IGPC indicated that although the facility is in service, IGPC and NRG have not been able to resolve differences over the costs of constructing the pipeline and IGPC requested that the Board resolve these matters.

The Board issued Procedural Order No. 5 on August 9, 2010 to deal with the Motion. The Board scheduled an oral hearing on September 7, 2010 to hear the Motion which was immediately followed by the rates case hearing.

At the commencement of the hearing of the Motion, the Board requested submissions from the parties on the most effective manner in which to proceed given the apparent overlap of issues raised in the Motion and the matters to be determined in the rate case application. The Board ultimately determined that it would hear the issues identified in the Motion that had potential rate impacts as part of the rates case proceeding.

The Board accepted the Settlement Agreement (Partial) that was filed by NRG on August 18, 2010 at the oral hearing.

At the conclusion of the oral hearing on the rates application the Board instructed the Parties to limit subsequent arguments to the rates matters. IGPC indicated it would comply with the Board's expectation that IGPC would recast its motion once informed by the Board's decision on the rates matters.

The pre-filed evidence of the Applicant included a proposal on an Incentive Regulation Mechanism ("IRM") and was identified in the Settlement Agreement as an unsettled issue. However, the Applicant decided at the oral hearing that it would prefer to file its IRM plan as a Phase 2 of the proceeding at a later date. The parties and the Board agreed to defer IRM to a later date and to establish 2011 base rates as part of the current phase of the proceeding.

THE ISSUES

The issues that remained unsettled were raised in the submissions filed by Board staff, IGPC, VECC and the Town of Aylmer. These have been addressed in the following sections of the Decision:

- Capital Cost of the IGPC Pipeline
- Removal of Ancillary Business from Rate Base
- IGPC Period Costs
- Amortization Period of Regulatory Costs
- NRG Gas Costs
- Deferral and Variance Accounts
- Cost of Capital and Capital Structure
- Cost Allocation

Two issues were not raised as concerns by Board staff or intervenors and were not addressed in the Settlement Agreement. However, NRG has sought approval on these two matters. This includes an approval of the revised rules and regulations and a new schedule for service charges. The Board approves NRG's revised rules and regulations and the schedule for service charges as filed.

RATE BASE

Capital Cost of the IGPC Pipeline

IGPC submitted that the pipeline should close to rate base no later than August 1, 2008 and not October 1, 2008 as proposed by the Applicant. IGPC noted that Union Gas began charging NRG for distribution services related to the ethanol facility on July 1, 2008. NRG commenced invoicing and IGPC commenced paying the full delivery charges as of July 15, 2008. IGPC indicated that from July 15th to September 30, 2008, IGPC paid \$372,949.82 to NRG for distribution services.

IGPC argued that according to the OEB's Accounting Handbook, a utility is to cease charging interest and to commence charging depreciation when the pipeline is placed into service. IGPC submitted that the pipeline was placed into service on or before July 15, 2008. IGPC further argued that as of July 15, 2008, NRG was being fully compensated through rates paid by IGPC.

In the alternative, IGPC submitted that if October 1, 2008 was the appropriate date for closing to rate base, then it was inappropriate for NRG to charge full delivery rates for the period July 15, 2008 through September 30, 2008. Accordingly, IGPC submitted that NRG refund IGPC \$372,949.82 less any amounts paid to Union and less any amounts payable pursuant to Rate 1.

NRG in its Reply submitted that the appropriate date for closing the IGPC pipeline should be October 1, 2008 as proposed in the Application. NRG argued that depreciation was supposed to reflect the deterioration of an asset and according to NRG the pipeline began to deteriorate and the asset value began to diminish with the first month of full gas flow, which was October 2008.

Board Findings

IGPC in its submission referenced a range of cost categories related to the IGPC pipeline. However, a number of the cost items in dispute do not impact the rate base or rates for 2011. The Board notes that the amount of the pipeline that is added to rate base is not a function of the cost of the pipeline but is derived from the calculation of the future revenue stream over a fixed number of years. The Board will therefore make a determination only on those matters that impact rates and not all costs that are in dispute.

The oral testimony indicates that the in-service date of the pipeline was just after July 1, 2008¹. The commencement date under the gas delivery agreement was July 15, 2008 and IGPC commenced paying the full delivery charges as of July 15th. NRG has argued that very little gas flowed prior to October 2008. However, the pipeline was in-service after July 1, 2008. The definition of “In-Service” as noted in the Pipeline Cost Recovery Agreement² refers to the date on which the pipeline is able to deliver the full amount of gas contemplated by the Gas Delivery Contract. Based on this definition the Board has determined that the pipeline was used and useful as of the in-service date.

Accordingly, the Board agrees with IGPC that the pipeline should be closed to rate base on August 1, 2008 and NRG is ordered to make the appropriate changes in its Draft Rate Order to reflect this date.

Removal of Ancillary Business from Rate Base

Apart from the capital cost of the IGPC pipeline, all other capital expenditure items were largely settled. However, the Town has submitted that the Board should order NRG to remove any capital property associated with its ancillary businesses from rate base.

The Town submitted that NRG’s rate base of \$13.6 million for 2011 should be reduced by approximately \$1.7 million in order to exclude assets which are related to ancillary businesses. The Town maintained that NRG’s own evidence supports the concern that the ancillary businesses are not sufficiently profitable to justify ratepayers paying a regulated rate of return on these assets. The Town further noted that other regulated gas utilities have separated their ancillary services from their regulated business.

¹ Oral Hearing Transcript, Volume 1, page 60

² IGPC Motion, August 3, 2010, Tab 3, Pipeline Cost Recovery Agreement, Article 1 – Attachments and Interpretations, Page 3

The Town submitted that the inclusion of the ancillary businesses obscures the financial situation of NRG's regulated business in an undesirable and inappropriate manner and there is no benefit to ratepayers to include them in NRG's rate base for ratemaking purposes.

In Reply, NRG refuted the Town's claim that the ancillary businesses are not sufficiently profitable. NRG submitted that its response to Undertaking J3.1 shows that the ancillary services income after tax since 2006 has been around \$200,000, which is more profitable than NRG's utility business.

NRG further noted that the cost allocation methodology employed by NRG ensured that the rate base, operating, maintenance and administration ("OM&A"), depreciation and taxes were appropriately split between the regulated and ancillary businesses.

Board Findings

The Board has historically allowed NRG to keep its ancillary business within the regulated entity. The Board is satisfied that the current cost allocation methodology appropriately separates the costs and assets of the regulated and ancillary business.

The Board considers this longstanding situation to be somewhat unique, and generally inconsistent with good regulatory practice. However, given that this situation has prevailed for a considerable period, the Board does not consider the record in this case on this issue to be sufficiently focused to justify the unbundling sought by the Town. This decision ought not to be seen to have any particular precedential value, and the parties should feel uninhibited in bringing the matter forward in future proceedings.

COST OF SERVICE

IGPC Period Costs

IGPC in its submission disputed the levels of certain OM&A costs. One such issue concerns depreciation. As noted above, IGPC argues that a lower total amount be closed to rate base. It argues that consequentially, a lower depreciation amount should be provided for. The other contested costs items include insurance costs and maintenance costs. The Board will address insurance and maintenance costs below.

Insurance

NRG has added the IGPC pipeline to its overall insurance coverage and has opted for additional coverage in certain areas. Consequently, NRG is seeking to recover total insurance costs of \$284,925 for the 2011 Test Year. A majority of the premium is sought to be recovered from IGPC.

Pursuant to Undertaking J2.6, NRG reduced the amount to be recovered from IGPC through rates from \$221,330 to \$173,067. IGPC in its arguments submitted that NRG's revision still overstates the appropriate cost of insurance. IGPC noted that NRG had not obtained multiple quotes but relied on its current insurance provider for the additional coverage.

Business Interruption Insurance

This is a new insurance policy that NRG is proposing to recover through rates and allocate 100% of the cost to IGPC. IGPC argued that the Board did not have sufficient information to ascertain whether this cost has been prudently incurred, is an appropriate expense to recover from ratepayers, and whether the insurance policy addresses a risk specific to IGPC. IGPC claimed that there was no evidence that the business interruption insurance was a typical expense incurred by other regulated gas utilities.

IGPC further argued that the business interruption insurance which is triggered when service to a customer is interrupted and where the customer has no obligation to pay is a typical business risk and shareholders are compensated for these risks through the return on equity. Furthermore, IGPC argued that there was no evidence that coverage is restricted to interruption of service to just IGPC. Consequently, IGPC submitted that NRG had not substantiated that the cost of the business interruption insurance was prudently incurred, and irrespective of whether it was prudently incurred, IGPC was of the view that the nature of the coverage is such that the costs should be borne by the shareholder and not the ratepayers. On that basis, IGPC submitted that the Board should disallow the recovery of the cost of the business interruption insurance through rates.

General Liability, Umbrella and "Additional Insurance"

IGPC in its submission claimed that there was not enough evidence to support the proposition that IGPC was the causal factor in the incurrence of the premium costs. IGPC further added that there was no evidence that the umbrella and additional umbrella policies insured against risks that were different from those insured under the

general liability policy or that the umbrella policy specifically addressed risks imposed on NRG by IGPC.

Transfer Station Insurance

NRG has allocated 100% of the transfer station insurance costs to IGPC. IGPC submitted that it questioned the logic of incurring an expenditure of \$35,387 to insure a station that costs \$884,003 for an amount of \$1,785,000.

NRG in its Reply noted that on examining its existing liability coverage and after discussions with its insurers, it was determined that it needed additional coverage. Consequently, NRG increased its umbrella liability coverage and it found it far more cost effective to expand coverage under its existing policy rather than set up a new policy for the additional coverage. NRG submitted that since this coverage was added as a result of the IGPC pipeline, IGPC should be allocated 100% of the costs.

With respect to the business interruption insurance, NRG confirmed that it exclusively covers the risks associated with interruption of supply to IGPC and does not cover business interruptions on the other portions of the NRG distribution system. Specifically, this insurance allows NRG to recover its fixed costs associated with the IGPC pipeline. In Reply, NRG maintained that with the addition of IGPC, its revenue structure had been altered significantly considering that one customer was responsible for 29% of the revenue. As a result, NRG considered it prudent to insure against the possibility of an incident wiping out approximately 30% of its revenues for an extended period. Given the size and importance of IGPC to NRG's business, NRG submitted that contrary to IGPC's suggestion, the business interruption insurance was not for the benefit of NRG's shareholder but for all of NRG's ratepayers. NRG submitted that it was appropriate to allocate the cost of the insurance to the entity that caused the cost to be incurred as this was consistent with ratemaking principles.

With respect to the transfer station insurance, NRG clarified that the cost included stations at either end of the IGPC pipeline as well as a station in the middle of the IGPC pipeline which houses the shut-off valve. According to its evidence transfer stations are not typically covered by property and building insurance and the premium was higher than that associated with office buildings due to the fact that the pipe went directly through the station.

Pipeline Maintenance Costs

NRG has a maintenance contract with MIG engineering for providing ongoing maintenance of the IGPC pipeline. NRG is seeking to recover \$112,109 for maintenance of the pipeline and \$43,050 for maintenance of the customer station. IGPC in its argument referred to the Leave to Construct Application that included \$38,000 for maintenance of the pipeline and customer station. IGPC noted that the actual contract value far exceeds the amount estimated in the Leave to Construct Application. IGPC further noted that the contract was sole sourced to a company with no pipeline maintenance experience. IGPC submitted that if the maintenance work was to be carried out on an annual basis to comply with regulatory requirements, the task should have been already performed twice and underlying historical costs would have existed. IGPC further maintained that NRG had made no attempts to ensure that the practice was consistent with other gas utilities in the province.

NRG in its Reply noted that the costs were third party costs pursuant to a maintenance contract and NRG made no profit from this arrangement. NRG further noted that the while IGPC relied on the \$38,000 estimate provided in the Leave to Construct Application it had disregarded other estimates appearing in the same application.

NRG noted that it had no experience in maintaining high pressure steel pipelines. NRG therefore considered it prudent to outsource the maintenance to a qualified third party and was of the opinion that the services outlined in the MIG proposal were commensurate with good utility practice. The reason NRG sole sourced the contract to MIG was because MIG had constructed the IGPC pipeline on time and within budget. Furthermore, MIG is located close to NRG's service area.

NRG noted that the maintenance contract of \$112,109 represented 1.3% of the capital cost of the facility and was considered reasonable in relation to the capital cost of the pipeline.

Referring to specific elements of the MIG contract, IGPC in its arguments disputed the following items:

Pipeline Markers – IGPC claimed the NRG employees were capable of carrying out this work. NRG in its Reply argued that it had approached the maintenance of the pipeline as a comprehensive program and did not consider it appropriate to split it into bits and pieces.

Weekly Observations – IGPC submitted that weekly inspection of the pipeline costing \$12,350 was overkill and bi-weekly inspections were more appropriate considering the limited amount of development in the Aylmer area. NRG responded by asserting that weekly inspections were appropriate and there was no basis for suggesting a different cycle.

Community Awareness (\$8,000) – IGPC claimed that meetings with fire departments and other groups should deal with all natural gas fires and there was no indication that the program was solely as a result of having a steel pipeline. In Reply, NRG reiterated that the entire maintenance contract was to serve the IGPC pipeline.

Emergency Response (Mock Emergency Training, \$18,000) – IGPC maintained that in case of third party damage to the pipeline, the third party would be responsible for such costs and these costs should not be passed along to IGPC. NRG in response rejected the views of IGPC and maintained that an incident on the pipeline could cause catastrophic damage. Mock emergency training was therefore a prudent cost.

Technician Training – IGPC submitted that it was inappropriate for it to pay for training employees of a subcontractor considering that they would need to be trained and competent in the first place to perform the task. NRG in Reply stressed that training NRG staff on safety manuals related to the IGPC pipeline was appropriate and the information was not generic but rather specific to the IGPC pipeline.

Third Party Observations (\$4,680) – IGPC submitted that costs for third party observations should be recovered from third parties such as municipalities or developers requiring such services in line with the remainder of the distribution system. In Reply, NRG confirmed that it provides line locates and third party observations free of charge on its main system.

MIG Costs – In its argument IGPC suggested that \$19,500 was related to making the pipeline piggable which was a capital expenditure item and should therefore be capitalized. NRG in response clarified that a one-time cost of \$102,000 to make the pipeline piggable was included as a capital expenditure and not included in maintenance costs. NRG noted that IGPC had referred to the cost of the in-line inspection which is an OM&A item.

In its final remarks IGPC submitted that the Board should approve a direct allocation of \$35,000 for maintenance to IGPC. In addition, IGPC maintained that the Board allocate the cost of Community Awareness and Emergency Response across all rate classes using rate base as the allocator. IGPC would then be allocated \$4,500 for the two items noted above and a \$35,000 direct allocation.

In Reply, NRG noted that the \$35,000 referred to the initial estimate provided in the Leave-to-Construct Application and did not reflect the amount of the MIG contract.

Station Maintenance Costs

IGPC disputed the inclusion of Provincial Sales Tax ("PST") for expenditures related to the maintenance of stations. In Reply, NRG agreed with IGPC and noted that the Settlement Agreement included a PST reduction of \$3,189 related to station maintenance. NRG agreed to revise the cost allocation model to reflect this change.

Board Findings

Insurance Costs

One of the major items under dispute is business interruption insurance. Although the evidence is not clear on the coverage provided, it seems that the insurance would cover fixed costs and expenses³ in the event of a *force majeure*. However, there is no information on record with respect to the payment under the coverage, whether there is a deductible in place, the maximum days that the coverage is provided for in case of an event and how the coverage ties in with the contracts in place between NRG and IGPC.

The Board is also aware of a letter of credit that has been provided by IGPC to NRG in the event that IGPC were to become insolvent or shut operations. The letter of credit adjusts for the undepreciated value of the pipeline and essentially protects the other rate classes and the shareholder. In other words, the letter of credit allows for recovery of depreciation. In case of a *force majeure* event, the letter of credit would be extended for an additional period to reflect the duration of the specific event. In other words, NRG would be guaranteed recovery of depreciation despite the declaration of *force majeure*. However, it seems that the coverage through the business interruption insurance would recover fixed costs and expenses during a *force majeure* event. This would imply that a portion of the insurance coverage would recover depreciation expenses of the pipeline during a *force majeure* event. The recovery of depreciation through the business

³ Oral Hearing Transcript, Volume 2, page 61, line 16

interruption insurance will not adjust the amount of the letter of credit during the *force majeure* period. This would lead to NRG recovering the same depreciation expense twice, once during the *force majeure* period and later due to the extension of the duration of the letter of credit.

The Board has determined that with the exception of business interruption insurance, NRG is allowed to recover its total insurance cost of \$259,345 (\$284,925 less \$25,580 representing business interruption insurance premium).

Maintenance Costs

The evidence indicates the existence of two contracts to maintain the IGPC pipeline. One is the contract with MIG Engineering Ltd. to provide administration and engineering services for the IGPC pipeline and the other contract is with Lakeside Process Controls Ltd. to maintain the transfer stations associated with the IGPC pipeline.

IGPC in its submission had expressed concerns about the MIG contract. In case of the contract for the maintenance of transfer stations, NRG agreed to resolve the only issue, that is, the reduction of PST. The Board is satisfied with the contract to maintain the transfer stations and the adjustment agreed to by NRG. The Board will therefore make a determination only on the MIG contract.

The Board is concerned that the contract was sole sourced and there is not enough evidence that all the elements of the contract are required to fulfill the safe administration and maintenance of the pipeline. The Board therefore orders NRG to tender the maintenance of the pipeline and provide written bids to the Board. Specifically, the Board directs NRG to first retain the services of an independent expert in the development of maintenance programs for pipelines similar to that employed in the supply of gas to IGPC. That expert will be retained by way of tender, and all of the documentation associated with that tender will be filed with the Board and the intervenors of record. Following the development of a maintenance protocol NRG shall retain the services of an enterprise experienced in the provision of such services by way of tender predicated on the maintenance protocol. All of the documentation associated with the retention of the maintenance firm will be filed with the Board and the intervenors of record. In the meantime the Board will allow NRG to recover in 2011 rates, 50% of the amount of the contract, which translates to \$56,055. The balance will be moved to a pipeline maintenance deferral account to be adjusted once the Board determines the appropriate maintenance amount. NRG is ordered to provide the written

bids associated with the development of the maintenance protocol to the Board within one month of the date of the Decision. The Board will review proposed pipeline maintenance costs in Phase 2 of the proceeding.

Deferral and Variance Accounts

NRG has requested the following approvals from the Board with respect to its deferral and variance accounts:

1. A request to establish the International Financial Reporting Standard (“IFRS”) deferral account.
2. A request to reset the Purchased Gas Transportation Variance Account (“PGTVA”), and replace the single reference price with two different prices, one for Rates 1 to 5 and one for Rate 6.
3. A proposal to dispose of the net balances in the Regulatory Expenses Deferral Account (“REDA”) and in the PGTVA as of September 30, 2009 through a rate rider.
4. A proposal to assign IGPC with its appropriate share of the balance in the PGTVA by developing a fixed charge rate rider and assigning the appropriate balances to other rate classes based on volumetric deliveries in the 2010 Bridge Year. The net amount is proposed to be recovered from customers over the 12 months of the 2011 Test Year through a fixed charge rate rider.

The only issue raised by intervenors and staff related to the balances in the REDA and NRG’s proposal to recover \$111,123 for legal expenses incurred in the Union Cessation of Service proceeding (EB-2008-0273).

NRG’s position was that the Board order that NRG’s shareholders should bear the costs of that proceeding, extended only to the intervenor costs. In its view, its costs for the proceeding could be recovered from ratepayers⁴. Board staff and VECC did not agree with this view and submitted that the Board clearly indicated that NRG could not recover any costs from ratepayers.

The EB-2008-0273 Decision states on page 7 –

“In the case of Union’s request for security, NRG did not act in a timely manner. The record suggests that NRG essentially stone-walled Union. This resulted in significant costs for Union, the Board, the Town of Aylmer and the Integrated

⁴ Oral Hearing Transcript Volume 1, Page 112

Grain Processors Co-Operative. This type of brinkmanship is not helpful where 6,500 customers and a recently activated ethanol plant supported by substantial Federal and Provincial funding are involved. **The Board also directs that costs being paid by NRG shall be paid by NRG's shareholder and not passed on to the NRG rate payers.**" (emphasis added)

Board staff and VECC in their final arguments submitted that the Board was clear in the EB-2008-0273 Decision that all costs being paid by NRG were to be borne by the shareholder and not by NRG ratepayers. VECC further added that the concerns raised by Union with respect to the financial viability of NRG related to the issuance of retractable shares by NRG in favour of its shareholder. VECC submitted that the application essentially resulted from NRG's actions in relation to its shareholder's interest and not to the interest of its ratepayers.

Accordingly, Board staff and VECC submitted that NRG should not be able to recover the amount of \$111,123 that it had requested for disposition in the REDA.

In its Argument-in-Chief, NRG indicated that the retractable feature of NRG's common shares had been in existence before 2006 and there was no change in NRG's financial condition, rather there was a change in the accounting rule. NRG further clarified that it had never missed a payment and the Board's assessment that NRG had "stone-walled" Union was incorrect. NRG argued that it was merely protecting its shareholder and ratepayers from an unreasonable request.

NRG further added that Union did not gain anything from the proceeding since the Board merely ordered NRG to postpone the retraction of shares in favour of Union.

In Reply, NRG submitted that the Board's wording in the Decision around costs had to be understood in the specific context. NRG argued that the costs incurred by a utility in a proceeding are never the subject of consideration in a cost awards section of the Board. When the Board adjudicates for cost awards, it typically refers to costs awarded to intervenors. NRG submitted that the EB-2008-0273 Decision does not suggest that the Board referred to all costs.

NRG also refuted VECC's assertion that the proceeding related to NRG's shareholder. NRG noted that since the Board did not order NRG to post financial assurance or change its contract date with Union, it did benefit NRG ratepayers.

NRG further noted that the Board did not have the specialized expertise in the field of cost awards and essentially departed from the general rule applicable to costs by ordering NRG's shareholder to pay intervenor costs. As ordered, NRG's shareholder paid these costs.

NRG submitted that if the shareholder is now asked to pay for NRG's legal expenses, it would be an incorrect and unsupportable decision.

Board Findings

The Board approves NRG's proposal for the creation of the IFRS deferral account in accordance with Board guidelines in the Report of the Board titled *Transition to International Financial Reporting Standards* (EB-2008-0408).

The Board also approves NRG's proposal for the PGTVA and the clearance of the account as of September 30, 2009.

With respect to whether NRG should be able to recover the legal costs associated with the Union Cessation of Service proceeding, the Board has determined that it will allow NRG to recover the costs amounting to \$111,123. In the Board's EB-2008-0273 Decision, the Board ordered NRG to pay the costs and denied recovery from ratepayers. However, the decision does not explicitly state that NRG cannot claim its own costs. The Board agrees with NRG that Board decisions typically refer to costs in the context of intervenor or third party costs as opposed to legal costs of the utility.

Amortization Period of Regulatory Costs

Parties agreed to the quantum of regulatory costs in the Settlement Agreement. However, since the parties did not reach an agreement on the IRM plan and the parties and the Board agreed to move IRM to Phase 2 of the proceeding, the appropriate amortization period of regulatory costs in the absence of an IRM framework remained an outstanding issue.

The Settlement Agreement was premised on regulatory costs of \$450,000 being amortized over 5 years matching the term of the IRM plan. A component of this cost includes \$54,000 related to future administration of the IRM plan.

VECC was the only party to raise this issue in submission. VECC submitted that the total amount of regulatory costs should be reduced by \$54,000 and the remaining

\$396,000 should be amortized over a four year period rather than a 3 years time horizon as suggested by NRG.

VECC also submitted that the recovery of the \$396,000 should be recovered through a rate rider as opposed to be included in base rates. This is in the event that NRG does not get approval for an IRM and does not return for rebasing within the four year period. In case an IRM is approved, the remaining \$54,000 related to IRM administration costs can be embedded in rates for the IRM period.

In Reply, NRG indicated that its views were not very different from VECC's but rather followed a different approach. NRG clarified that it has not withdrawn its request for an IRM plan rather it has moved it to Phase 2 under the same proceeding. NRG proposed that under a five year IRM plan \$90,000 of regulatory costs should be included in rates and under a four year IRM \$116,400 should be recovered in years 2 to 4. In case a three year IRM plan is approved, then \$169,300 should be recovered in years 2 and 3. If no IRM plan is approved, then NRG's position was that \$153,000 should be recovered in each of the two years following the 2011 Test Year.

The position of VECC and NRG differ significantly in their outcomes if the Board approves an IRM plan that is of three years duration or less. NRG's position was that being a small utility, a delay in recovering amounts related to regulatory costs had a considerable impact on the utility's cash flow. NRG further submitted that matching costs to the period that forms the basis for those costs was in line with regulatory rate making principles.

Board Findings

The quantum of regulatory costs has already been settled. The issue before the Board is the amount that is to be included in base rates for 2011. The IRM proposal is still before the Board and it is the Board's expectation that there will be some form of an IRM regime arrived at in Phase 2 of the proceeding.

The Board agrees with NRG's proposal that \$90,000 should be included in 2011 rates and the remaining costs will be dealt with in Phase 2 of the proceeding.

NRG Gas Costs

In the 2006 rates Decision (EB-2005-0544), the Board approved a specific methodology for NRG to calculate the contract price for gas purchased from the related company,

NRG Corp. The contract price was to be recalculated on an annual basis and, in the event that the source from which prices are calculated or the methodology used to determine the price changed, NRG had to seek prior permission from the Board.

In response to Board staff IR #23, the Applicant indicated that the previous management of NRG neglected to follow the Board directive and did not recalculate the purchase price. In other words, the price remained unchanged from 2007 onwards. Board staff in their submission identified several issues associated with gas purchased from NRG Corp.

Overpayment by NRG Ratepayers and Determining Purchase Price in Future

At the oral hearing, NRG confirmed that as of September 30, 2010, the failure to follow the Board-prescribed methodology will result in an overpayment of approximately \$97,000 to NRG Corp⁵. Board staff suggested that the amount of \$97,000 should be refunded to ratepayers and, unless and until the Board recommends an alternative framework for pricing gas, NRG should record the credit/debit balances to the Purchased Gas Commodity Variance Account (“PGCVA”) as of October 1, 2010 until the purchase price is reset on the basis of the Board’s original direction.

At the oral hearing, NRG indicated that the distribution system in the southern district requires dual supply from NRG Corp. gas wells to provide adequate supply and maintain system pressure. NRG estimated that 2.4 million cubic meters was required from NRG Corp. in order to maintain system pressure⁶.

In its Argument-in-Chief NRG suggested a dual approach to pricing gas purchased from the related entity. The proposal was to:

- pay NRG Corp. \$8.486 per mcf whenever the market price for natural gas is \$9.999 per mcf or less; and,
- pay “market price” for natural gas when gas is \$10.00 per mcf or higher.

In submission, Board staff dismissed NRG’s approach and recommended a market price for all gas purchased from NRG Corp. In case NRG wanted to purchase gas from NRG Corp. at a price above market, Board staff submitted that NRG be allowed to recover only the market price from ratepayers.

⁵ Oral Hearing Transcript Volume 1, Page 114

⁶ Oral Hearing Transcript Volume 1, Pages 118-119

In Reply, NRG submitted that a single market for all gas fails to recognize the benefit that has accrued to ratepayers over the years as a result of NRG Corp. wells producing and supplying gas in the southern service area. The pricing mechanism proposed by staff did not recognize that NRG Corp. could simply refuse to sell in times of low natural gas prices and shut down its wells. If NRG customers were unable to get the minimum required quantities from NRG Corp. required to maintain system pressure, then they would be faced with an alternative of a pipeline costing approximately \$1.9 million outlined in the Argument-in-Chief. NRG submitted that its pricing methodology was sound, workable and transparent.

With respect to ratepayers overpaying for the price of gas to the extent of \$97,000, NRG submitted that if the Board were to adopt NRG's proposed pricing methodology then no refund would be required since the Board's approval would implicitly provide that the current price being paid to NRG of \$8.486 for system integrity gas was appropriate. However, Board staff dismissed this suggestion indicating that any proposal approved by the Board would be effective at a future date and would not be applied retroactively.

In its Reply NRG proposed a revision to the EB-2005-0544 pricing methodology and suggested adjusting the price on a quarterly basis. Board staff supported this proposal and also supported NRG's suggestion of using the Shell Trading Report as the source to calculate the purchase price. Alternatively, Board staff submitted that NRG could also use Union's Quarterly Rate Adjustment Mechanism ("QRAM") and use Union's *Ontario Landed Reference Price* to fix the purchase price of gas.

Transportation Charge

NRG confirmed at the oral hearing that NRG Corp. sells gas to Union and the gas flows through NRG's distribution system. However, NRG Corp. does not pay NRG a transportation charge for using the NRG system to transport gas to Union.

In response to Undertaking J2.8, NRG provided total volumes that were routed through NRG's distribution system by NRG Corp. Using the rate that NRG Corp. pays to Greentree Gas & Oil Ltd. for transporting gas to Union, Board staff estimated that ratepayers were deprived of \$31,297 in revenues since 2006.

Board staff submitted that NRG should be directed to charge NRG Corp. a transportation rate of \$0.95 per mcf and an administrative charge of \$250 per month for every month the NRG distribution system is used by NRG Corp. to transport gas (based

on the charges of Greentree Gas & Oil Ltd.). In addition, since NRG had not forecasted revenues for transportation in the current proceeding, Board staff submitted that the Board should establish a deferral account to track revenues from transportation which can be cleared through the annual deferral account disposition mechanism.

NRG agreed to this proposal in Reply.

Engineering Study to Explore Alternatives

At the oral hearing, Board staff sought alternatives from NRG in case all natural gas wells of NRG Corp. were to run dry and NRG was no longer able to obtain the required quantities to maintain system pressure. In the undertaking response NRG indicated that based on informal discussions with engineering firms, NRG would have to build a new pipeline to source additional gas and maintain system pressure at an estimated cost of \$1.89 million excluding regulatory, financing and land acquisition costs.

In its submission Board staff advocated an independent third party engineering study which would identify options (including high level cost estimates) to maintain system pressure in the absence of supply from NRG Corp.

Furthermore, in recognition of the fact that NRG ratepayers had been subsidizing the shareholder for the past number of years by way of transporting NRG Corp. gas for free, Board staff submitted that the cost of the independent engineering study to explore alternatives to buying Integrity Gas be borne by the shareholder and not the ratepayers.

In Reply, NRG dismissed the suggestion of the shareholder paying for the study and noted that Board staff's approach was not even-handed and the focus seemed to be to find a benefit to NRG's related company to justify imposing the cost of the study on NRG. NRG further submitted that Board staff had ignored the fact that the real beneficiaries of the system integrity issue were ratepayers who had benefitted from this arrangement for years. NRG ratepayers have benefitted from having a materially smaller asset base for years as a result of NRG Corp.'s gas exploration, development and production activities. Assuming the cost of a new pipeline at \$1.89 million to resolve the issue of integrity gas, ratepayers would pay an additional \$80,000⁷ in the first year for this alternative. This amount was far greater than the \$31,927 that was not paid by

⁷ The \$80,000 estimate refers to the return on equity on an additional \$1.89 million to rate base.

NRG Corp. to NRG for gas transportation over a five year period. NRG submitted that if a study was required, the costs should be borne by ratepayers.

NRG further requested the Board to consider the cost benefit of such a study and determine whether NRG should first submit quotes on the cost of conducting a study. The cost could then be considered in Phase 2 of the proceeding.

Deemed Application of the Affiliate Relationship Code

Although NRG Corp. is not an affiliate of NRG as defined in the Affiliate Relationships Code (which adopts the definition from the *Ontario Business Corporations Act*), Board staff expressed concern that the nature of the relationship presents the possibility that NRG Corp. is benefitting at the expense of ratepayers. Board staff submitted that although NRG Corp. is not technically an affiliate, the provisions of the Board's Affiliate Relationship Code ("ARC") should be made to apply to the relationship between NRG and NRG Corp. Board staff cited the Dawn-Gateway Decision (EB-2009-0422) as an example where the Board determined that the provisions of ARC should apply to the relationship between Union and Dawn Gateway even though Dawn Gateway was not technically an affiliate of Union.

In Reply, NRG submitted that the application of ARC was unnecessary and Board staff had not demonstrated a specific issue that would be resolved as a result of the application of ARC. Moreover, NRG argued that ARC would impose additional regulatory burden on a small utility like NRG with no real benefit to ratepayers.

NRG maintained that the Board has the ability to examine the relationship and dealings between NRG and NRG Corp. in rate proceedings. NRG further noted that if its proposal of adjusting the gas price purchased from NRG Corp. on a quarterly basis as part of NRG's QRAM was accepted then there would be sufficient disclosure of the arrangement in QRAM proceedings.

Board Findings

Board staff identified several issues respecting the cost of gas procured by NRG for distribution to its customers. The Board will deal with each of them in the following section.

Transportation Charge

NRG has agreed to incorporate a transportation rate and administrative charge for providing transportation services. The Board orders NRG to include a transportation charge in the rate schedule accompanying the draft rate order. NRG will also record transportation revenues in a deferral account which will be reviewed in future proceedings.

Refund of Overpayment of \$97,000

NRG's evidence indicates that the overpayment by NRG to NRG Corp. for gas purchases as of September 30, 2010 is \$97,000. This has occurred as a result of the failure of NRG to follow a Board order in EB-2005-0544. The Board is concerned that the management of NRG failed to follow a previous Board order. NRG is now arguing that it would not have to refund the amount if the Board accepts its gas pricing proposal. The Board notes that the amount of the refund is as a result of non-compliance and has no bearing on the price mechanism that the Board puts in place for the Test Year and beyond.

The Board orders NRG to refund the \$97,000 to ratepayers in the form of a rate rider for the 2011 Test Year. The Board also orders NRG to track amounts as of October 1, 2010 in the PGCVA until the implementation of a new price mechanism outlined in this Decision.

Gas Contract Price Determination

NRG requires 2.4 million cubic meters of gas annually from NRG Corp. in order to maintain system integrity in the southern part of the distribution system. NRG has proposed to price this gas differently as compared to other gas that it requires. Essentially, NRG has proposed to purchase the integrity gas at a minimum price \$8.486 per mcf. Board staff objected to this suggestion and argued for applying market prices to all gas.

The Board considers this to be a unique situation and it is difficult to determine at this point in time whether a cost effective alternative exists. The Board also notes that NRG's proposal of \$8.486 per mcf is fairly high considering that current gas prices are under \$5.00 per mcf and not expected to fluctuate significantly in the short term. However, considering the unique circumstances of this issue the Board will allow NRG on a temporary basis to pay NRG Corp. a price of \$6.80 per mcf or market price, whichever is higher, for gas required to maintain system integrity.

For all other gas, the Board has determined that NRG will use Union's *Ontario Landed Reference Price* every quarter to adjust the contract price with NRG Corp. This will allow NRG to align the price adjustment with its own Quarterly Rate Adjustment Mechanism since Union files its application in the first week of the month prior to the rate change. In addition, this approach will reduce the administrative and regulatory burden of NRG.

Study to Explore Alternatives to Maintaining System Integrity

Board staff proposed an independent engineering study to identify options and obtain cost estimates for a solution to maintaining system pressure in the southern service area. The Board has already determined a short-term solution to pricing of integrity gas. However, a long term solution is required and an independent engineering study would assist the Board in determining whether there is a cost effective permanent solution.

The Board fails to understand why NRG does not have sufficient information about its distribution system to identify the precise alternatives available. The Board also believes that NRG should have been proactive in finding a solution to this problem.

The Board orders NRG to submit the terms of reference for an engineering study within two weeks from the date of this Decision. Once the Board approves the terms of reference, NRG is ordered to provide a report within three months. The cost of this study will be borne equally by the shareholder and ratepayers.

Application of ARC

The Board is concerned about the relationship between NRG and NRG Corp. and its impact on ratepayers. However, the Board has addressed ratepayer issues through the establishment of a transportation rate and an independent pricing mechanism for the purchase of gas from NRG Corp. In addition, the Board will review the dealings between NRG and NRG Corp. in rate proceedings and during the review of NRG's quarterly rate adjustment process (QRAM). The Board is satisfied that it has addressed the major concerns and does not see any benefit in imposing the regulations of ARC on the relationship between NRG and NRG Corp at this point in time.

COST OF CAPITAL

Capital Structure and Return on Equity

NRG requested a deemed capital structure of 58% debt and 42% equity with a return on equity ("ROE") of 50 basis points over the Board determined ROE as per the Board's Cost of Capital Parameter Updates issued on February 24, 2010. In requesting a 42% equity ratio NRG relied on the opinion of its expert Ms. Kathleen McShane who indicated that the 42% ratio adopted by the Board in 2006 and a premium of 50 basis points over the Board determined ROE remains appropriate for NRG.

All intervenors including Board staff made submissions on the proposed capital structure and ROE. Board staff, VECC and IGPC submitted that the actual capital structure of NRG was essentially unstable and there were several methods of calculating the capital structure if factors such as gross (excluding the impact of compensating balance) versus net (including the impact of compensating balance) and the retraction provision of shares was considered.

Board staff submitted that the main reason that NRG received 42% equity ratio in the 2006 Decision (EB-2005-0544) was because that was the actual ratio and Ms. McShane's evidence was that the actual was the most appropriate value to use. The current actual capital ratio of NRG was 37% as indicated in the technical conference⁸. Board staff further referred to a table⁹ in Ms. McShane's report that showed a majority of the utilities operated pursuant to a 40% deemed equity ratio.

IGPC submitted that since 2006 NRG had made no equity contribution and had added over \$4.5 million to the rate base related to the IGPC pipeline. Notwithstanding this, NRG persisted in its claim for a 42% equity component, as in 2006.

VECC submitted that in fact NRG had very little or no equity considering that retractable shares were included as equity. The same view was echoed by the Town in its submission.

The Town in its submission proposed a different calculation to estimate the equity. It used the \$3.4 million equity attributable to utility operations in 2006 as the starting point

⁸ Technical Conference Transcript, Page 54 (Lines 19-20)

⁹ Table 4 in Exhibit E2/Tab 1/Schedule 1, "Opinion on Capital Structure and Equity Risk Premium for Natural Resource Gas"

and used the Board approved ROE of 9.2% for the years 2006 through to 2010 and came up with a 2011 number of \$4.65 million. The Town submitted that the \$4.65 million number should be used as NRG's actual equity underpinning its utility operations for the 2011 Test Year.

With respect to the Return on Equity, NRG's position was that NRG's risk profile remained unchanged from 2006 and it should therefore receive the same 50 basis points premium.

Board staff in its submission noted that the Board's *Report on Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009 was released after the Board's Decision on NRG's 2006 Cost of Service Application. Board staff submitted that the equity risk premium of 550 basis points referred to in the report represents a risk premium that accounts for and considers all utilities across Ontario. In other words, the Board report recognized that the 550 basis points premium did not represent a specific utility but was generally applicable across all utilities. The Town made a similar argument noting that the 550 basis points premium was not based on the individual risk profile of Enbridge Gas and was therefore not appropriate as a base to which a risk premium should apply.

Board staff further noted that in some 2010 cost of service applications intervenors argued that the 550 basis points premium included 50 basis points for floatation and transaction costs. The intervenors submitted that utilities such as Haldimand County Hydro Inc. (EB-2009-0265) and Burlington Hydro Inc. (EB-2009-0259) do not incur any floatation or transaction costs and should therefore not receive the 50 basis points premium. The Board in its Decision agreed with the intervenors but determined that the policy should be applied unadjusted. The reason was that the Board already knew that a number of utilities in Ontario did not issue equity or debt to the public and this was understood throughout the evolution of the Board's approach to setting the ROE.

Board staff used a similar rationale to argue that during the evolution of the report the Board also knew that the utilities shared different risk profiles and were of different sizes but it did not make any distinction on this basis neither made an exception for any of the utilities.

Board staff submitted that there was no compelling evidence to indicate that NRG's risk profile was considerably different from most utilities in Ontario; the Board should therefore award NRG the Board determined ROE of 9.85%.

VECC supported Board staff's argument and noted that in the event the Board decided to depart from policy and award a 50 basis points premium, it would be completely offset by the inclusion of 50 basis points for transactional costs that NRG does not incur.

IGPC in its submission noted that NRG had presented no evidence of the specific risks that distinguish NRG's business from that of other Ontario electricity or gas distributors. With respect to adding the new pipeline, IGPC indicated that NRG was protected by contract terms that obligate contractual payments irrespective of delivery and a letter of credit for the value of the pipeline.

The Town in its submission maintained that the retractable shares that are considered as equity in the Application should in fact be treated as debt until the retraction feature is removed. Accordingly, the Town submitted that the Board should allow a 6.36% return on the value of retractable shares as opposed to 9.85%.

In Reply, NRG stressed that equity injections are atypical to the operation of small private utilities. In 2006, despite the shareholder taking a significant dividend, NRG's actual equity remained at 41.5%. However, with the addition of the IGPC pipeline it had understandably dropped but expected to recover with the retention of earnings. Although NRG's currently actual equity is 37%, NRG argued that over the term of the IR plan NRG's actual capital structure would be 43% equity and 57% debt on a net debt basis. NRG further reminded the Board that the IR plan had not been withdrawn but just moved to Phase 2 and the evidence was still live before the Board.

Addressing the issue of the retractable shares, NRG noted that they have been postponed in favour of the Bank and Union and as long as NRG has some debt, the shares will be postponed in favour of the Bank.

NRG also rejected the Town's method of calculating equity using 2006 utility attributable equity as the starting point and adding a rate of return from 2006 to 2010. NRG argued that the Town had confused retained earnings with over-earning and failed to recognize the concept of just and reasonable rates.

NRG referred to the table¹⁰ in Ms McShane's report and noted that if data for the Ontario electric distribution utilities was omitted, the average equity ratio for the rest of the individual companies was 41.6%.

NRG also referred to the "fair return standard" in the Cost of Capital Report and noted that ultimately the Board determined capital structure and ROE should provide the utility with a fair return. NRG submitted that in an attempt to move to a standardized approach for establishing capital structure and ROE, the Board needed to consider whether the standards provided the utility with a fair return. NRG further argued that mechanically applying the standards would amount to a fettering of the Board's legal discretion.

NRG submitted that the capital structure and ROE established by the Board do not provide a fair return and there was no evidence in the proceeding that supported a different finding from the Board's determination in NRG's previous rates case (EB-2005-0544)

Board Findings

There is no consensus on how to determine NRG's capital structure. NRG has itself provided the capital structure on a gross versus net basis. The issue is further complicated by the nature of its shares, which are retractable in nature and classified as a liability according to Canadian Generally Accepted Accounting Principles. The Board is not confident that a definitive number can be established from the Applicant's evidence and record in this proceeding.

The Board has a Cost of Capital policy in place that is applicable to all electric utilities and NRG's size and profile is similar to a number of electric utilities as opposed to the other two large gas utilities (Enbridge and Union). The Board policy on the appropriate equity ratio is 40% and is not considerably different from the ratio sought by NRG.

NRG has submitted that due consideration should be given to the fact that over the term of the five-year IR plan, the actual debt-equity structure would average 53:47 on a gross debt basis. However, the Board in this proceeding is making a determination on 2011 rates. The Board duly notes that an IR plan remains an issue before the Board but the base year rate determination process does not take into account average forecasts for

¹⁰ McShane's Opinion on Capital Structure and Equity Risk Premium for NRG Exh. 2/Tab1/Sch.1, Table 4, page 21

the entire IR period. This is not done for other areas such as capital expenditures or OM&A. The argument that capital structure should, alone among all other elements, be an area where a five year forecast should be considered in determining an appropriate ratio for the Test Year seems inappropriate.

The Board has determined that the appropriate capital structure for NRG is 40% equity, 56% long-term debt and 4% short term debt in accordance with the Board's 2006 Cost of Capital Report¹¹.

NRG has requested a risk premium of 50 basis points over the Board determined ROE. The Board's current ROE applies to all regulated utilities in Ontario and the Board's 2009 Cost of Capital Report does not make any distinction on the basis of size or risk. The Board during the evolution of setting the ROE already knew that the utilities that it regulates were of different size and risk profiles. This distinction was considered when the 550 basis points premium was determined. NRG has presented no evidence that its risk profile was significantly different from other utilities in Ontario. The Board believes that 9.85% is appropriate and orders NRG to incorporate this ROE in the Draft Rate Order.

NRG alludes to the fair return standard as a legal obligation on the Board. The Board's Cost of Capital Report¹² identifies the elements to ascertain a fair return standard. The Report on page 18 states:

A fair or reasonable return on capital should:

- be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

¹¹ Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006

¹² Report of the Board on Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084

NRG has provided no evidence that a 9.85% ROE will impact the organization adversely. In fact, at the oral hearing, NRG considered itself to be a stronger utility and provided evidence to its financial viability. NRG referred to the Union Cessation of Service Proceeding and specifically noted that it had never missed a payment to Union. NRG has presented no evidence that its financial viability would be at risk if it receives the Board recommended Cost of Capital. In fact at the oral hearing NRG's witness noted that the asset base had increased substantially and the debt was being reduced aggressively¹³.

Although NRG has added the IGPC pipeline, NRG did not face any difficulty in raising the significant amount of capital required to construct the project. There is no evidence to suggest that NRG's lender will change its position if NRG received an ROE that is lower than requested. With respect to equity, NRG has already indicated that the shareholder does not intend injecting any further equity and this was not dependant on the return that is provided. The shareholder has also not provided any evidence that the invested capital can provide a greater return elsewhere with a similar risk profile.

Although NRG has referred to the fair return standard, it has provided no evidence or demonstration how the Board's use of the Cost of Capital parameters will adversely impact NRG or impinge on the fair return standard.

Cost of Debt

The debt portfolio of NRG consists of three components: a fixed rate loan, which will be renewed in March 2011, a variable rate loan and a revolving line of credit that is not being utilized. The long-term debt cost of 6.69% reflects a 7.52% interest rate on one of the Bank of Nova Scotia loans, the forecast rate of 4.10% on the other Bank of Nova Scotia loans, plus amortization costs related to the refinancing of previous debt as directed in the NRG 2007 rates case decision (EB-2005-0544). In addition, NRG maintains a compensating balance of \$2.75 million in the form of a Guaranteed Investment Certificate ("GIC") with the Bank of Nova Scotia. The amount has been borrowed for the purposes of investing in the GIC.

Board staff submitted that by removing the compensating balance, NRG was using a fairly unusual method to calculate the cost of capital. Although NRG was paying a total rate of 6.69% on its long-term debt, the rate that it was seeking to recover from

¹³ Oral Hearing Transcript, Volume 3, page 91 (lines 2-6)

ratepayers was 8.26%. Board staff noted that NRG was seeking to recover its actual cost of debt (\$662,642) rather than the interest rate. Board staff submitted that NRG would benefit under this methodology as it obtains a higher interest rate on its debt which actually forms a much larger portion of the capital structure but is lowered by the compensating balance. Board staff therefore submitted that NRG should be allowed a rate of 6.69% on the debt portion of the deemed capital structure.

The arguments of Board staff were echoed by all other intervenors. VECC submitted that the GIC was not a specific requirement imposed by the Bank of Nova Scotia as a prerequisite to obtain funding. In fact, the GIC was considered by NRG as an alternative to meet one of the covenants imposed on it by the Bank. VECC submitted that ratepayers should not bear the cost of NRG borrowing an additional \$2.75 million for the sole purpose of creating an asset to balance its books as a result of a failure to maintain an adequate amount of actual equity in the company.

VECC submitted that Board deduct the amount of the GIC from the principal owed on the fixed rate loan (7.55%) and then recalculate the effective cost of debt. Using this methodology, VECC submitted that the long-term debt rate for the 56% long term debt component of NRG's capital structure should be 6.36% for the Test Year.

The argument put forth by VECC was adopted by the Town and IGPC.

In Reply, NRG submitted that if the rate proposed by Board staff and intervenors was accepted then it would not be able to recover its actual interest expense which was an unreasonable outcome. NRG argued that the compensating balance was required to maintain the covenants of the utility's loan arrangements. NRG submitted that maintaining a good working relationship with its lender was in the best interests of NRG and its ratepayers.

VECC also made a submission on the short term debt portion. In its Application, NRG used a notional amount of short term debt to fill the gap between its deemed amount of long term debt and its deemed amount of equity. The rate applied by NRG to the notional amount of short term debt is 0.5%. VECC submitted that the Board should order NRG to use a rate of 2.07% for the short term debt component in accordance with the Cost of Capital Parameters issued by the Board on February 24, 2010.

Board Findings

NRG has used a novel method to reduce its debt and increase the equity by using a compensating balance in the form of a GIC. This has resulted in a lower debt ratio and a higher interest rate than actual as NRG tries to recover its actual interest cost.

In addition, the evidence in the proceeding indicates that the requirement to hold a compensating balance is not a requirement of the Bank but is an NRG-devised approach to meet one of the covenants of the loan agreement. NRG did not explore other alternatives and considered using a compensating balance as a suitable technique to meet its loan obligations and maintain a good working relationship with the bank.

It is not known whether NRG could have obtained a better rate or relaxed covenants through a different financial institution. The Board also recognizes the fact that NRG had to significantly increase its debt portfolio to meet its financial commitments related to construction of the IGPC pipeline. At the same time, the Board recognizes that the use of a compensating balance is unusual and there is no evidence suggesting that it will be required on an ongoing basis.

The Board has determined that it will deduct the value of the GIC from the principal of the variable rate loan to calculate the blended cost of long term debt. The resulting cost is 7.67%.

Long-Term Debt	Average Principal	Cost Rate	Carrying Cost
Refinancing Cost Amortization			49,814
BNS Variable Rate Loan	3,943,333	4.12%	162,565
BNS Fixed Rate Loan	5,964,863	7.55%	450,263
GIC (assumed cost of variable rate loan)	-2,751,130	4.12%	-113,347
	7,157,066	7.67%	549,295

The short-term debt rate will be in accordance with the Board's 2010 Cost of Capital Parameters. The Board's decision on NRG's Cost of Capital is summarized below:

Average Cost of Capital

Description	Ratio	Cost Rate	Weighted Avg.
Long Term Debt	56.00%	7.67%	4.30%
Short Term Debt	4.00%	2.07%	0.08%
Common Equity	40.00%	9.85%	3.94%
Total	100.00%		8.32%

COST ALLOCATION

NRG has added a new rate class (Rate 6) to allocate appropriate costs to its largest customer, IGPC. NRG has proposed certain changes to its existing cost allocation model in order to accommodate the new rate class. The proposed cost allocation model allocates certain costs that are directly assignable to IGPC. In addition, NRG has allocated a share of common costs to IGPC.

During the oral hearing, NRG was asked to consider refinements to the cost allocation model to appropriately reflect allocation to the Rate 6 customer class, specifically allocation of insurance costs.

The submissions largely focused on appropriate allocation of insurance costs. In its Application, NRG proposed to recover \$221,330 out of the total insurance cost of \$284,925 from IGPC. Pursuant to Undertaking J2.6, NRG reduced the amount to \$173,067. This was as a result of a letter from NRG's insurance provider, Zurich Global Energy that provided a risk factor of 40% for exposure to the IGPC pipeline.

IGPC in its submission argued that the letter from Zurich did not provide sufficient detail and did not identify the specific components of insurance that the 40% applied to. Considering that Zurich did not provide further details on the 40% allocation, IGPC submitted that it should be allocated 40% of all the insurance coverage as compared to 100% for some of the insurance costs. Additionally, it identified specific elements of the coverage that it did not accept as reasonable.

Transfer Station Insurance

NRG has allocated 100% of the transfer station insurance costs to IGPC. IGPC submitted that it failed to understand the expenditure of \$35,387 to insure a station that costs \$884,003 for an amount of \$1,785,000.

Property, Plant and Equipment Insurance

Since maintenance of the IGPC pipeline is proposed to be subcontracted to a third party, IGPC was of the opinion that no equipment floater and fleet insurance costs should be allocated to IGPC.

Summarizing its position, IGPC recalculated the insurance costs and the allocation to IGPC. The revised calculation excludes business interruption insurance and allocates 40% to IGPC for all the other insurance costs. The resulting allocation reduces IGPC's share of the insurance costs, from \$173,067 to \$103,738. IGPC claimed that despite its proposed adjustment, the insurance costs for other rate classes would decline by 14% as compared to 2008, from \$180,651 to \$155,608.

VECC in its submission agreed with the allocation of administrative and general expenses to Rate 6. With respect to allocation of insurance costs, VECC indicated that the letter from Zurich Global Energy was vague and provided little or no guidance to the Board. VECC was therefore unable to recommend or reject the proposed allocations of the company wide general and umbrella liability costs to IGPC.

VECC however noted that in cases where the new policies are caused by the addition of IGPC as a customer, the proposed allocation of 100% to that customer sounds reasonable. Accordingly, VECC submitted that if the Board were to find the costs to be prudent then the transfer station insurance costs, business interruption insurance and the additional umbrella liability coverage should be 100% allocated to IGPC.

The Town and IGPC also submitted that the Board should require NRG to conduct a comprehensive cost allocation study for approval in its next cost of service rate application.

In Reply NRG agreed with VECC that the letter from Zurich did not provide sufficient rationale or basis for its determination. However, NRG indicated that this was the best available estimate.

Board Findings

The Board agrees with VECC that evidence to determine the appropriate allocation of insurance costs to IGPC is lacking. The only number before the Board is the 40% recommended by Zurich Global Energy. The Board will accept the 40% allocation of insurance costs as it is the best available evidence on the question in this proceeding. As a result of the Board's determination on business interruption insurance, IGPC will be allocated \$147,487 in insurance costs.

With respect to conducting a review of the cost allocation methodology, the Board is of the opinion that as NRG gains experience of managing its operations with the addition of a new rate class, it will have better information on how IGPC impacts its costs. The question of whether NRG should conduct a review of its cost allocation methodology will be addressed in the next cost of service proceeding. By that time NRG will have better data and understanding of how the rate classes impact its cost structure. In the interim, NRG is directed to ensure that it retains all information relevant to this issue.

EFFECTIVE DATE

NRG is seeking rates effective October 1, 2010. Its current rates were declared interim on September 9, 2010. The Board approves an effective date of October 1, 2010 and the recovery of the revenue shortfall arising in the period between October 1, 2010 and the implementation of the new rates.

The Board has made findings in this Decision which change the revenue deficiency and therefore the proposed 2011 distribution rates. These are to be properly reflected in a Draft Rate Order incorporating an effective date of October 1, 2010 for the new rates.

In filing its Draft Rate Order, the Board expects NRG to file detailed supporting material, including all relevant calculations showing the impact of this Decision on NRG's proposed revenue requirement, the allocation of the approved revenue requirement to the classes, the variance account rate riders and the determination of the final rates, including bill impacts. NRG is also directed to file an accounting order related to the new deferral and variance accounts established in this Decision.

A Rate Order and a separate cost awards decision will be issued after the processes set out below are completed. The Board also expects NRG to file Phase 2 of the

proceeding that deals with IRM and other matters identified in this Decision by March 2011.

COST AWARDS

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

All filings with the Board must quote the file number EB-2010-0018, and be made through the Board's web portal at www.errr.oeb.gov.on.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.oeb.gov.on.ca. If the web portal is not available you may e-mail your documents to the attention of the Board Secretary at BoardSec@oeb.gov.on.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's Practice Directions on Cost Awards.

THE BOARD ORDERS THAT:

1. NRG shall file with the Board, and shall also forward to IGPC, VECC, Union and the Town (collectively, "The Intervenors") a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 21 days of the date of this Decision. The Draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.
2. The Draft Rate Order shall also include accounting orders related to three new deferral accounts: IFRS Deferral Account, IGPC Pipeline Maintenance Deferral Account and the Transportation Revenue Deferral Account.

3. The intervenors shall file any comments on the Draft Rate Order with the Board and forward to NRG within 12 days of the filing of the Draft Rate Order.
4. NRG shall file with the Board and forward to the intervenors responses to any comments on its Draft Rate Order within 5 days of the receipt of any submissions.
5. The intervenors shall file with the Board and forward to NRG, their respective cost claims within 40 days from the date of this Decision.
6. NRG shall file with the Board and forward to the intervenors any objections to the claimed costs within 45 days from the date of this Decision.
7. The intervenors shall file with the Board and forward to NRG any responses to any objections for cost claims within 50 days of the date of this Decision.
8. NRG shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, December 6, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary